Gas
2020

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Abstract

2020 is on its way to experiencing the largest recorded demand shock in the history of global natural gas markets. The Covid-19 pandemic hit an already declining gas demand, faced with historically mild temperatures over the first months of the year. Gas consumption is expected to fall by 4% in 2020, under the successive impacts of lower heating demand from the warm winter, the implementation of lockdown measures in almost all countries and territories to slow the spread of the virus, and a lower level of activity caused by the Covid-19 induced macroeconomic crisis.

Faced with this unprecedented shock, natural gas markets are going through a strong supply and trade adjustments, resulting in historically low spot prices and high volatility. Natural gas demand is expected to progressively recover in 2021, however the Covid-19 crisis will have longer-lasting impacts on natural gas markets, as the main medium-term drivers are subject to high uncertainty.

This report provides a detailed analysis of recent natural gas market developments, assesses the impact of the Covid-19 crisis on the short to medium terms and discusses the main drivers and uncertainties to future gas supply and demand to 2025.

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Executive summary

Executive summary

Natural gas is expected to experience its largest demand shock on record in 2020 as the Covid-19 pandemic hits an already weakened market. After a slowdown in annual growth in 2019, natural gas consumption was negatively impacted in early 2020 by an exceptionally mild winter in the northern hemisphere. This was soon followed by the imposition of partial to complete lockdown measures in response to Covid-19 and an economic downturn in almost all countries and territories worldwide. As of early June, all major gas markets are experiencing a fall in demand or sluggish growth at best as is the case of the People's Republic of China (hereafter, "China"). Europe is the hardest hit market, with a 7% year-on-year decline so far in 2020. The global oversupply is pushing major natural gas spot indices to historic lows, while the oil and gas industry is cutting spending and postponing or cancelling some investment decisions to make up for the severe shortfall in revenue.

Although confinement measures are being gradually lifted, our forecasts do not assume that economies recover promptly. **As a result, global natural gas consumption is heading for an estimated 4% drop in 2020.** All regions are impacted, with mature markets across Europe, North America, Asia and Eurasia together accounting for about 75% of lost gas consumption in 2020. Across different sectors, power generation is the hardest hit, making up half of the total demand decline, followed by the residential and commercial sector and the industrial sector.

In spite of an expected gradual recovery in 2021, the Covid-19 crisis will have long-lasting impacts on natural gas markets. This is because the main medium-term drivers of demand growth are subject to several key uncertainties. Although this forecast aims to provide early estimates for a medium-term recovery path for natural gas, it does not assume market conditions will automatically return to pre-crisis conditions. Natural gas demand is expected to recover progressively in 2021 in mature markets and grow in emerging markets thanks to low prices. But the repercussions of the 2020 crisis on growth are set to result in 75 bcm of lost annual demand by 2025, which is the same size as the global annual increase in demand in 2019. Most of the post-2021 growth takes place in Asia, led by China and India where gas benefits from strong policy support. In both those countries, the industrial sector is the main source of demand growth, making it highly dependent on the pace of the recovery in domestic and export markets for industrial goods. The majority of incremental gas production comes from US shale and large conventional projects in the Middle East and the Russian Federation, for which the current price collapse and short-term market uncertainty represent a substantial downside risk. Liquefied natural gas is expected to remain the main driver behind global gas trade growth, but it faces the risk of prolonged overcapacity as the build-up in new export capacity from past investment decisions outpaces slower than expected demand growth.

2019 – Cool down

After two years of very strong gains, natural gas consumption growth cooled in 2019 with an increase estimated at 1.8% y-o-y

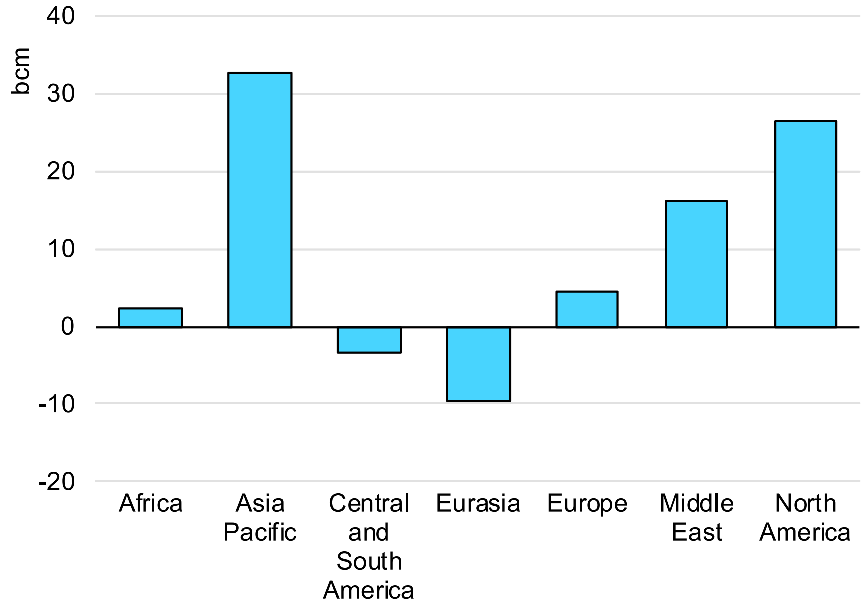
Natural gas consumption grew by an estimated 70 bcm in 2019, or 1.8% y-o-y, in line with the average growth rate experienced over the period 2010-17. This result reflects a cocktail of mixed signals – positive from fuel switching to gas and negative from slower economic growth and mild temperatures. The United States and the People's Republic of China (hereafter, "China") remained the two main driving markets in 2019, albeit both returning to single-digit growth rates. Together they accounted for over two-thirds of the uplift in global natural gas consumption.

China's economic growth rate fell to an estimated 6.1% according to the IMF, its lowest annual increase since 1990. Natural gas demand kept growing, but returned to a single-digit rate of 8.6% (less than half the 18.1% y-o-y increase of 2018). City gas distribution and industry remained the main drivers of consumption growth in 2019, resulting from a combination of fuel switching measures and network expansion. The rest of the Asia Pacific region played an important role in natural gas market expansion in 2019. Growth in South Asia was mainly driven by higher LNG deliveries, especially to India and Bangladesh, while Pakistan's imports almost stagnated. Natural gas consumption also increased in most South East Asian markets.

Beyond Asia Pacific, most growth occurred in natural gas producing regions. In the United States demand was primarily driven by power generation (see next page) and the energy industry's own consumption to support the expansion of domestic natural gas production. Natural gas consumption continued to grow in the Middle East and North Africa due to a combination of higher electricity demand and expansion of the supply network for residential customers in Algeria and Iran. However, consumption growth in Egypt slowed after two years of strong increases.

Natural gas consumption decreased in Eurasia and South America in 2019. After three consecutive years of growth, the Russian Federation's (hereafter, "Russia") natural gas consumption fell by 2.5% in 2019, reflecting the country's low economic growth. Consumption slightly decreased in South America, with stagnating gas needs for power in Argentina and Brazil, lower domestic production in Colombia, and a further decline in Venezuela's output.

Annual change in natural gas consumption per region, 2018-19



Coal-to-natural-gas switching was the largest single contributor to consumption growth in 2019

Switching from coal to natural gas was the largest single contributor to consumption growth in 2019, accounting for over 55 bcm of additional demand. Low spot prices drove fuel switching for power generation, while clean air policies remained the principal driver of fuel conversion in China.

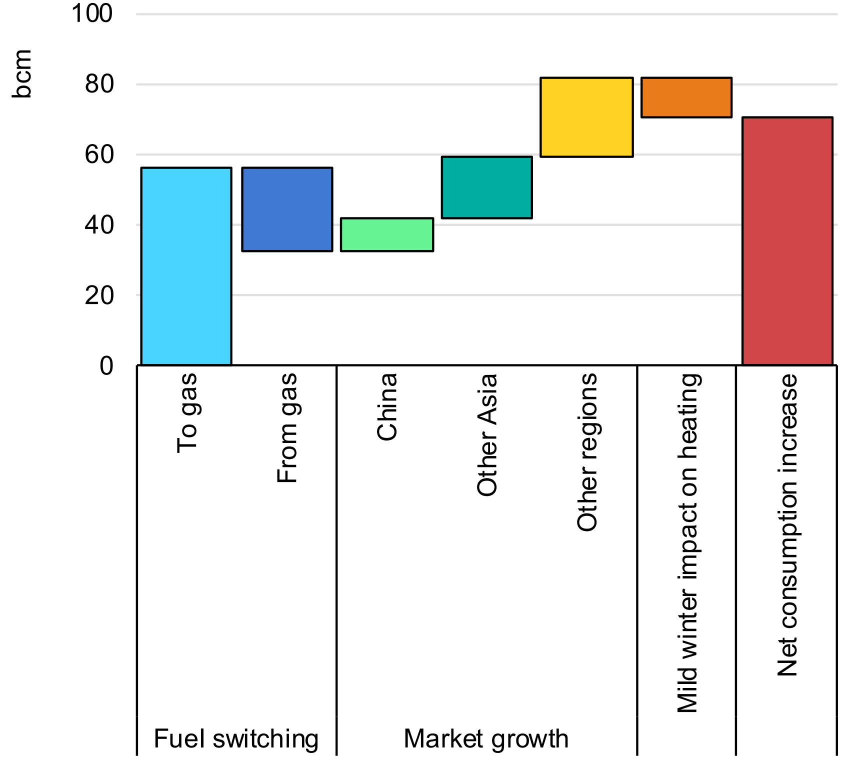
In the United States output of gas-fired power generation reached new highs, rising to a record share of about 38% of total generation. It increased by 8% or 123 TWh in 2019, against a sharp decline for coal (down 181 TWh). However, growth was lower than in 2018 when incremental gas burn accounted for 172 TWh.

Gas-fired power plants in Europe saw their output increase by about 11% or almost 70 TWh, against a sharp decline for coal (down 24%). Spain was the single largest contributor to higher gas burn with an annual increase of almost 50%, which accounted for about 40% of the growth in gas demand in the European Union.

In China the coal-to-gas conversion programme (launched in 2017 to battle air pollution) helped to further increase the share of natural gas in the industrial and residential sectors in 2019. Fuel switching in industry and city gas distribution for residential and commercial uses accounted for over half of the total increase in natural gas consumption.

However, this growth is partly offset by a reduction in natural gas burn in several markets. Nuclear output rebounded in both Japan and Korea, which led to a decrease in gas for power estimated at 12% and 2% respectively. Turkey experienced record hydro generation, which strongly impacted gas needs for power generation. Iran also saw a surge in hydro output and had to switch back to oil products for power generation due to gas supply constraints.

Breakdown of estimated natural gas consumption growth by main driver, 2019



Production growth outpaced demand, driven by US shale expansion, leading to storage build-up

Global natural gas production continued to grow at a rapid pace, up by 3% in 2019, surpassing the 4 tcm mark for the first time in history. This was largely driven by the United States, accounting for over 70% of incremental gas supply last year. Gas production in the United States grew by slightly more than 10% (or 85 bcm), with the Appalachian and Permian basins contributing almost two-thirds of this growth.

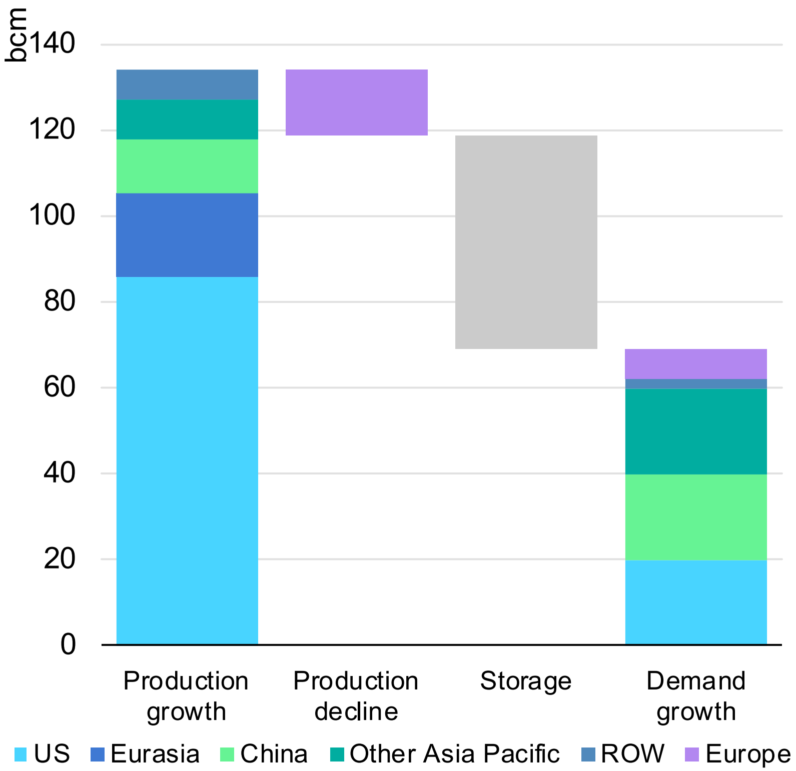
Incremental supply in Eurasia was largely driven by export-oriented projects. Russian gas production grew by 1.7% (or over 12 bcm), supported by the ramp-up of the Yamal LNG project, while Azeri gas production grew by an impressive 28% (over 5 bcm) as the country rapidly increases gas output and exports from Shah Deniz II.

China's gas output grew by close to 10% (or 16 bcm), supported by the traditional producing regions, with Shaanxi and Sichuan accounting for almost half of total growth. Shale gas and coalbed methane accounted for 40% of incremental production. In the rest of the Asia Pacific, strong growth in Australia (led by the ramp-up of LNG exports) was counterbalanced by declines in other parts of the region.

European gas production fell by over 6% (or 15 bcm), driven by lower output from Norway's swing fields (Troll and Oseberg) and rapidly declining Dutch gas production from the Groningen field operating under tightening production caps.

Production growth outpaced demand during 2019, resulting in a strong storage build-up both in Europe and the United States.

Breakdown of production and demand growth, 2019



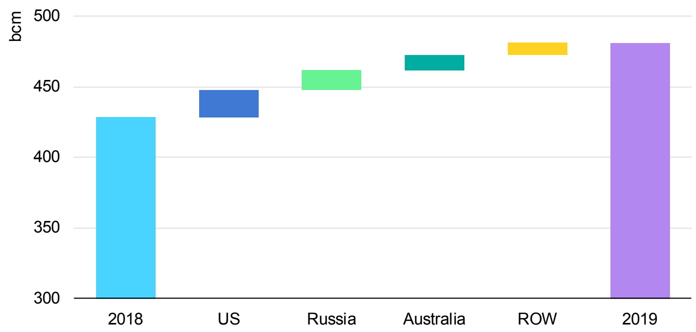
Global gas trade expansion was driven by LNG, which grew by 12% in 2019 – its fourth consecutive year of double-digit growth

The global LNG trade grew by 12% in 2019, with supply increasing by a record amount of over 50 bcm. This was primarily driven by the United States, Russia and Australia, together accounting for over 75% of incremental supply. US LNG exports grew by an impressive 70%, supported by the commissioning of over 30 bcm/y of liquefaction capacity. With LNG exports above 45 bcm, the United States became the world's third-largest LNG supplier after Qatar and Australia.

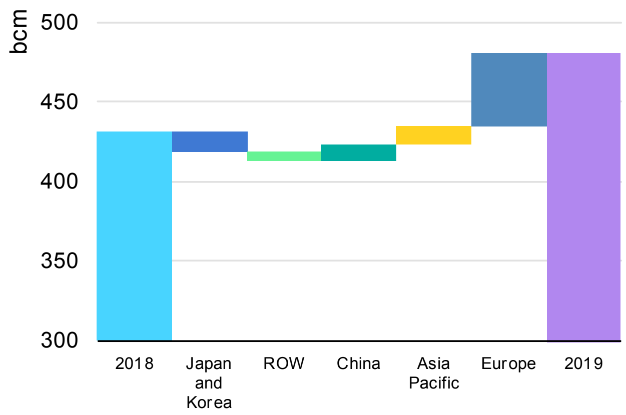
Russia's LNG exports rose by over 50%, primarily driven by the ramp-up of Yamal LNG. Australia's LNG exports grew by over 10%, supported by higher production at existing liquefaction plants and the commissioning of Prelude FLNG. Consequently, Australia joined Qatar to become the second nation with annual LNG exports exceeding 100 bcm.

Asia continued to be the key destination region for LNG, accounting for 70% of total LNG imports. However, it represented less than 15% of incremental LNG demand, in sharp contrast to the previous three years when it accounted for 90% of growth. In 2019 Japan's and Korea's LNG imports fell by 7% (or over 10 bcm) amidst nuclear restarts, while China's LNG import growth halved in absolute terms (from 21 bcm in 2018 to just above 10 bcm last year) as a consequence of lower economic growth and slowdown of the coal-to-gas switching programmes. Other Asia Pacific markets grew by over 10 bcm, with new importer Bangladesh accounting for half of that growth. With Asian demand lower than expected, Europe alone absorbed over 80% of incremental LNG supply last year, with LNG imports increasing by almost 70% to reach an all-time high of 115 bcm or the equivalent of 20% of European gas demand.

LNG export growth in 2019



LNG import growth in 2019



Source: ICIS (2020), *ICIS LNG Edge* (subscription required).

2019 was a record year for investment in LNG export projects, with almost 95 bcm/y of new capacity being confirmed

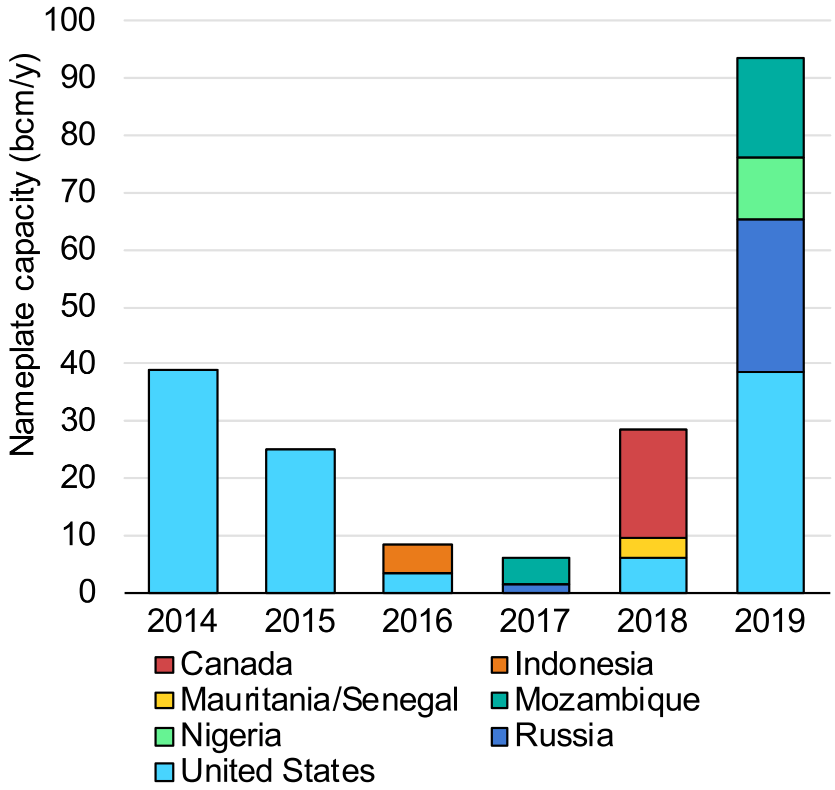
A record of nearly USD 65 billion was committed to investment in LNG liquefaction facilities in 2019, setting the stage for global capacity to increase by over 16%. Much of this investment was supported by developers and partners taking equity stake in future projects, enabling them to reach project milestones at a more rapid pace than typical LNG project financing based on long term supply agreements with third parties.

After little activity in 2016 and 2017, the market has transitioned to a new phase in the investment cycle. This began in 2018 with a strong increase in final investment decisions (FIDs) for liquefaction facilities, totalling 29 bcm/y: Corpus Christi LNG train 3 in the United States, LNG Canada, and Greater Tortue FLNG 1 across the maritime border of Mauritania and Senegal.

This surge in investment continued into 2019, with last year seeing the most liquefaction capacity ever sanctioned in a single year at 96 bcm, eclipsing the previous peak of almost 70 bcm in 2005. Projects reaching FID in 2019 included Sabine Pass LNG train 6, Golden Pass LNG trains 1–3 and Calcasieu Pass (all in the United States), Mozambique LNG trains 1 and 2, Arctic LNG 2 (Russia) and Nigeria LNG train 7. Some of these projects have the largest capacities ever sanctioned and, in many cases, could become the largest private-sector investments in the history of their respective countries. Four projects sanctioned over the past two years report that that each if their total capital expenditure will exceed USD 20 billion.

This additional infrastructure will produce gas equivalent to the LNG import needs of the entire European Union in 2019 – even more impressive considering that last year's EU imports were higher than average.

FIDs for new LNG liquefaction capacity, 2014-19

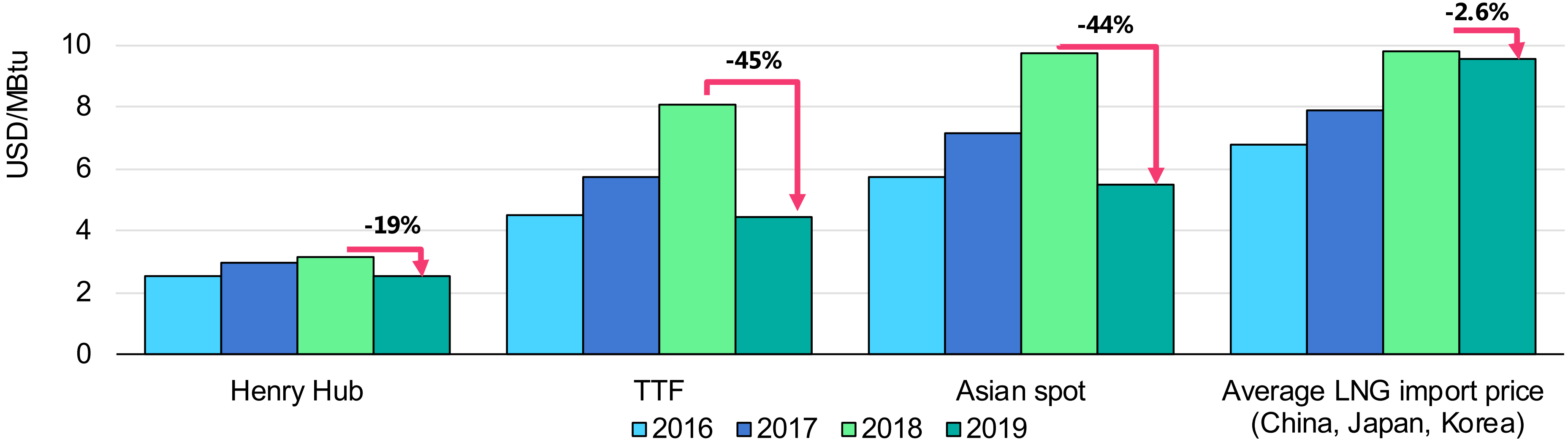


Asian and European spot prices fell to decade lows amidst an increasingly loose global gas market, while oil-indexed prices showed resilience

After strengthening in 2017 and 2018, gas prices fell across key consuming regions in 2019, with global gas production growth outpacing incremental gas demand. In the United States, Henry Hub fell by almost one-fifth y-o-y to USD 2.6/MBtu, its lowest price level since 2016. In Europe the record high LNG influx combined with continued strong pipeline deliveries and an unseasonably mild winter resulted in the Title Transfer Facility (TTF) decreasing by 45% y-o-y to reach an annual average of USD 4.5/MBtu – the lowest since 2004.

LNG spot prices followed a similar pattern in Asia, declining by 44% y-o-y amidst ample LNG supply and subdued demand from traditional LNG import markets (including Japan and Korea), while China's demand growth halved. However, this did not translate into a lower import price for the main Asian LNG importers, with the average import price of China, Japan and Korea decreasing by less than 3%. This was due to the persistence of a high share of oil indexation in their long-term LNG import contracts which account for a majority of their imports.

Natural gas prices in selected markets, 2016-19



Sources: IEA based on EIA (2020), *Henry Hub Natural Gas Spot Price*; GasunieTransportServices (2020), *Gas Prices Reconciliation*; ICIS (2020), *ICIS LNG Edge* (subscription required); General Administration of Customs of People's Republic of China (2020), *Customs Statistics*; Portal Site of Official Statistics of Japan (2020), *Trade Statistics Data for Japan*; Korea Customs Service (2020), *Trade Statistics*.

2020 – Meltdown

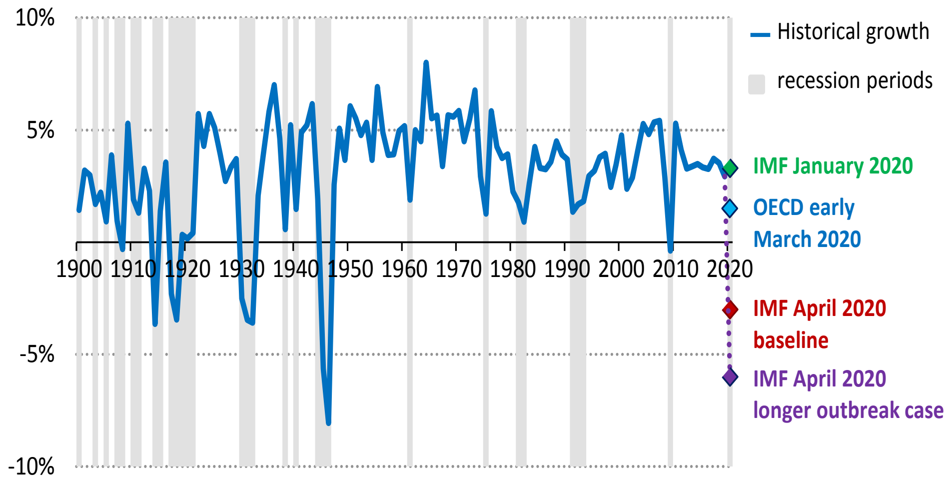
Uncharted macroeconomic territory

The coronavirus (Covid-19) pandemic has triggered an unprecedented macroeconomic shock. At the time of writing (early June 2020), the World Health Organization reported over 6.2 million confirmed cases, affecting almost 200 countries and territories to varying extents. Governments across the world have been reacting to the situation by enforcing different degrees of restriction on most social and economic activities. As a consequence of the containment efforts to slow the spread of the virus, 4.2 billion people or 54% of the global population, representing almost 60% of global GDP, has been subject to complete or partial lockdown. Nearly all the global population is affected by some form of containment measure.

The restrictions represent a challenging combination of macroeconomic shocks in both supply and demand. The supply shock component arises from the intentional constraints on economic activity: restaurants, shopping malls and, in some countries, factories are closed down to prevent the spread of the virus which have caused historically unprecedented spike in unemployment in every country. The demand-side shock is arising from the impact on mobility as well as on consumer disposable income and corporate investment activity. Overall, estimates suggest that economies can expect a 20–40% decline in economic output during the lockdown phase, depending on the share of the most-affected sectors and the stringency of measures. At the global level, this translates into a 2% drop in expected annual GDP for each month of containment measures.

This report uses the scenario-based approach developed in the IEA Global Energy Review 2020 report. A base scenario quantifies the impact on natural gas demand of a widespread global recession caused by multi-month restrictions on mobility and social and economic activity. This base scenario – where recovery is only gradual and accompanied by a permanent loss of economic activity – is broadly in line with the "pessimistic scenario" of the IMF World Economic Outlook April 2020 update, where the world struggles with a prolonged first outbreak period leading to a global GDP contraction of 6%.

Global annual change in real GDP, 1900-2020



Source: IEA (2020), *Global Energy Review 2020*, based on IMF World Economic Outlook (January and April 2020), OECD Interim Economic Outlook Forecasts (March 2020) and Maddison Project Database (2018).

European gas markets are facing a perfect storm…

European gas markets have been facing a perfect storm since the beginning of 2020. The successive impacts of mild temperatures, strong wind generation and Covid-19 induced nationwide lockdowns have depressed natural gas consumption, which fell by 7% y-o-y in the first five months of the year.

Under the weather

Europe experienced a mild winter in 2019/20: heating degree days fell by over 5% across its main gas-consuming regions compared with a year earlier, consequently cutting space-heating requirements. Gas demand in the residential and commercial sectors decreased by more than 3% y-o-y during Q1 2020.

Falling gas prices supported further coal-to-gas switching in Europe's power sector during the first quarter, with the share of gas-fired generation in thermal generation increasing from 45% to 49% at the expense of both coal and lignite. However, strong wind power generation during Q1 weighed on thermal generation requirements, including gas-fired power. Preliminary data suggests that while wind power output increased by over a third (or 30 TWh) y-o-y, gas-fired generation fell by 10 TWh, depressing gas demand by an estimated 2.5 bcm. Contrary to the rest of Europe, Turkey's gas-fired power generation grew by an impressive 35% in January and February, amid falling lignite-fired power generation and lower hydro output, before plummeting by over 40% in March as hydro recovered.

Under the lockdowns

The implementation of nationwide lockdowns in several European countries resulted in a sharp drop in natural gas consumption, falling by 11% between the start of the lockdowns (11 March) and end of May, translating into a 10 bcm drop in absolute terms.

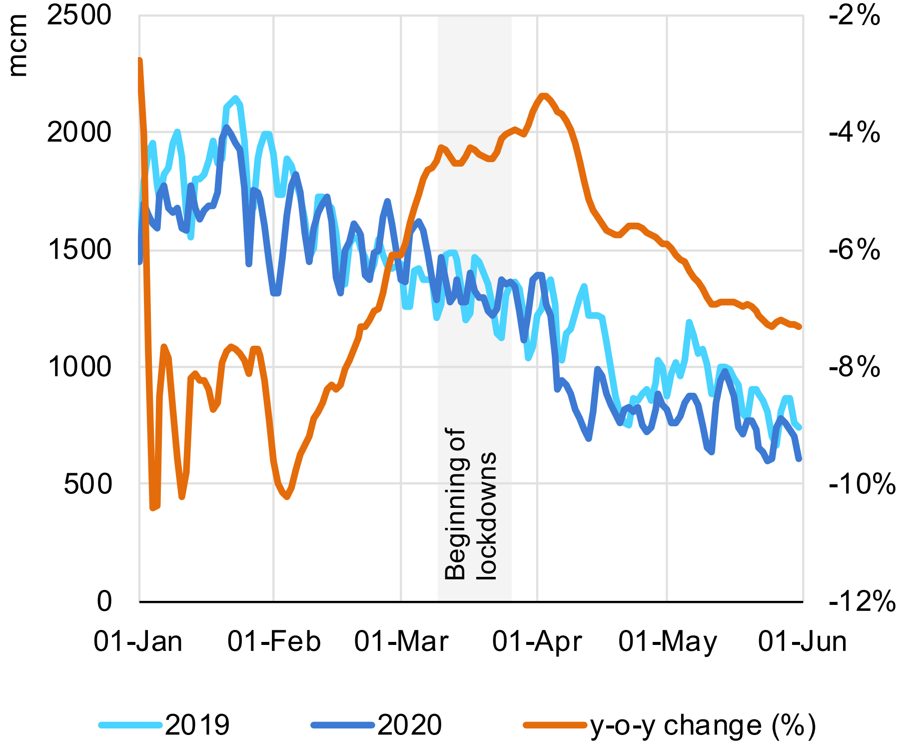
This drop has been primarily due to lower demand from the industrial and power generation sectors, while distribution network consumption was less affected – residential consumption benefitted from colder temperatures in the second half of March, but declined in April and May due to lower heating degree days and decreasing activity in the service sector.

European electricity consumption decreased by 12% between 11 March and end of May, severely weighing on gas-fired power generation, which fell by over 20%, equivalent to an estimated 5 bcm of lost gas use. This has been largely driven by Europe's two largest consumers of gas-fired electricity, Italy and the United Kingdom, where gas-fired generation dropped by 25% and 36% respectively between early March and end of May. In Turkey, where electricity consumption fell by 15% during April and May, gas-fired power generation practically halved during that period.

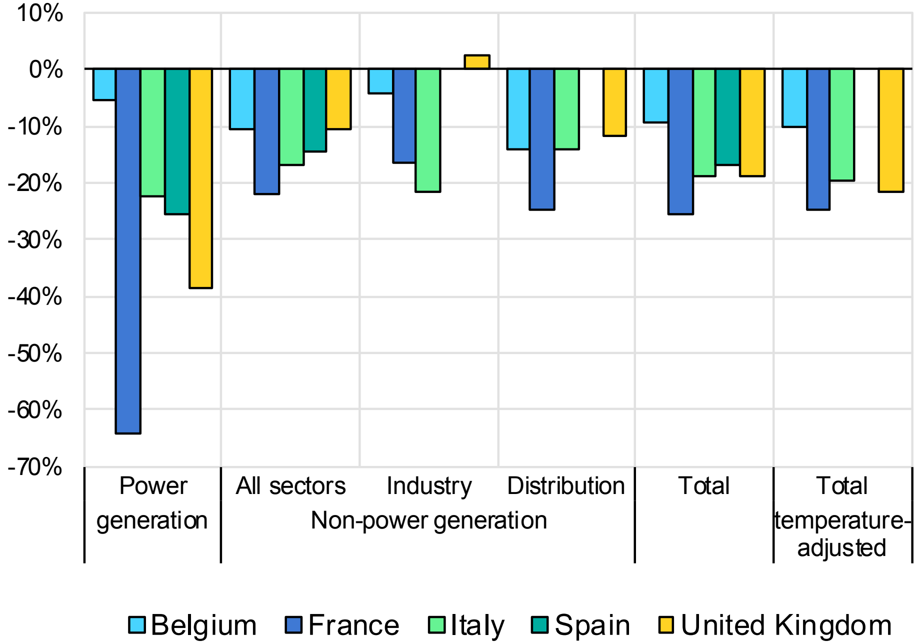
Industrial gas demand in the countries imposing stricter lockdown measures (Belgium, France, Italy, Spain and the United Kingdom) fell by over 15% y-o-y (above 1 bcm) from March to May.

...with consumption declining by 7% in the first five months of 2020

Evolution of European natural gas consumption, 2019 and 2020



Y-o-y change in natural gas consumption per sector for a selection of European countries from first day of lockdowns until end of May



Notes: Temperature adjustment is based on heating degree days and applies to demand from the distribution network. Daily data for Spain provides consumption data for power generation, conventional and trucks; daily breakdowns for industry and distribution are not available.

Sources: IEA based on ENTSOG (2020), *Transparency Platform*; Gaspool (2020), *Consumption Data*; NCG (2020), *Consumption Data*; EPIAS (2020), *Transparency Platform*.

Consumption remains resilient in North America, thanks to US coal-to-gas switching in power generation

US natural gas consumption decreased by 2.8% y-o-y for the period from January to May 2020. This was a rather limited decline in spite of mild temperatures throughout the first quarter and the imposition of lockdown measures in most states in March. Adjusting for temperatures, consumption grew slightly at 0.4% for the same period.

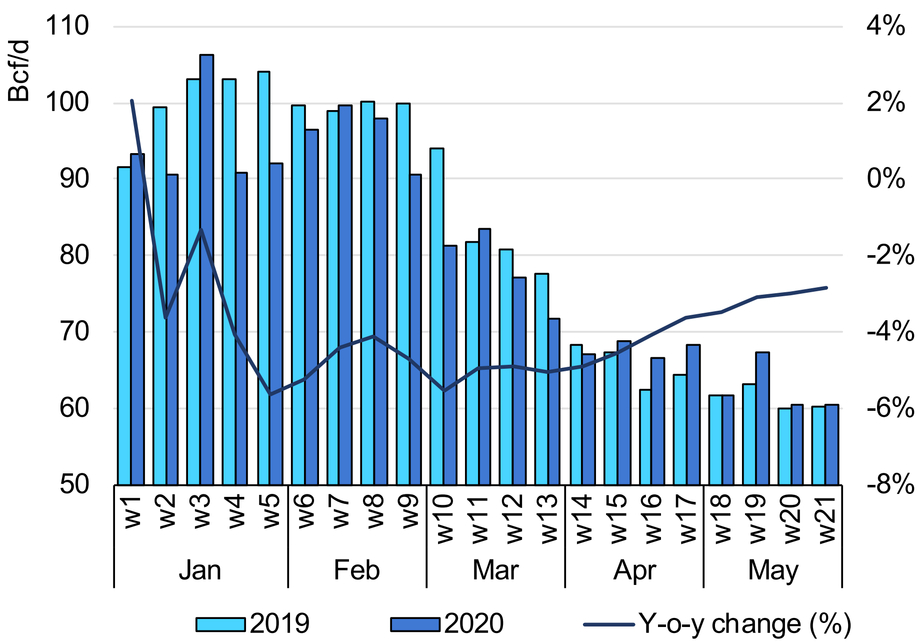
Warmer than average temperatures during winter 2019/20 had a strong impact on heating demand, resulting in a 14% y-o-y drop in natural gas consumption in the residential and commercial sectors for the first quarter. Lower heating demand also hit electricity consumption, which declined by about 5% over the same period. However, natural gas-fired power generation increased during the winter in spite of lower demand, helped by low fuel prices and additions of new combined-cycle capacity in 2019. Natural gas-fired generation grew at the expense of coal, with fuel switching occurring even in traditional coal-driven markets such as the Midwest, where the share of natural gas rose to the same level as coal during the first quarter, and became the dominant source of electricity generation in April.

The outbreak of Covid-19 led to the imposition of lockdown measures in most US states, enacted during the second half of March. At the end of April only five states had few to no restrictions, states progressively reopening in May (some 31 states had lifted most of their restrictions as of end of May). In spite of the substantial impact of lockdowns on economic activity, natural gas demand remains relatively resilient, increasing slightly by 0.5% between mid-March and end of May compared with 2019. Consumption in the industrial sector, which was comparable to 2019 until mid-March, declined by 3.6% y-o-y in between mid-March and mid-May. This decline was offset by the power generation sector, up by 3.4% y-o-y over the same period, and by some gains in residential and commercial use (up 1.5%).

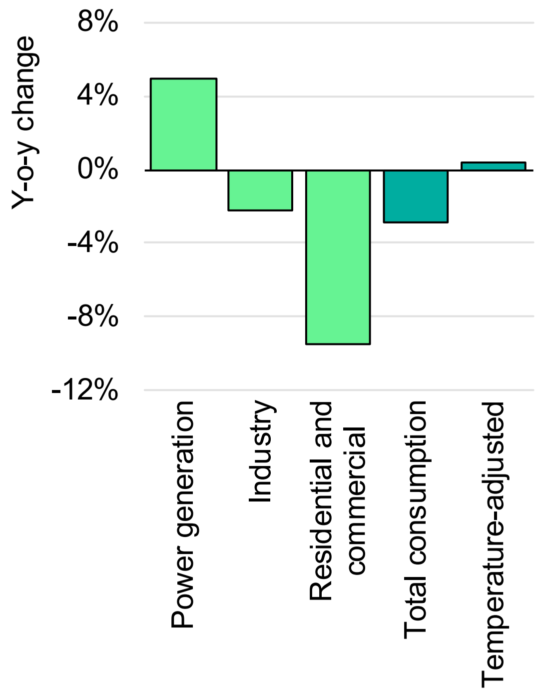
Natural gas demand in Mexico fell by an estimated 5% y-o-y during the first quarter, impacted by slow economic activity that drove down demand from the industrial and power generation sectors. Pipeline flows from the United States – the largest source of imports – grew by 6.5% y-o-y over the first five months. The introduction of nationwide emergency measures in April coincided with a slowdown in pipeline imports (up by 2% in April following an increase of 15% in March, y-o-y, and down 4% in May). LNG imports halved over the first five months of the year compared with the same period in 2019.

US consumption declined 2.8% y-o-y as of end of May, primarily due to mild weather

Evolution of weekly US natural gas consumption, 2019 and 2020



Y-o-y change in US natural gas consumption since 1 Jan per sector



Source: IEA based on EIA (2020), *Natural Gas Weekly Update*.

Apparent consumption continued to grow in most Asian markets over Q1 2020, but impacts have started to become visible

In spite of reduced economic activity, the impact of the Covid-19 crisis on demand growth remained limited for major Asian gas importers during the first quarter of 2020. However, stable or growing imports in some cases compensated for declines in domestic production or added to a build-up in storage levels.

China experienced sluggish growth in gas demand in the first months of 2020, negatively affected by mild temperatures in January and the introduction of lockdown measures in February. According to the National Reform and Development Commission (NDRC), apparent gas consumption increased by 1.6% y-o-y in the first quarter of 2020. The progressive restart of industrial activity in March and April had a limited impact on gas use as lockdowns in other parts of the world sharply reduced demand for exported goods. Preliminary data from the Chongqing Oil and Gas Exchange suggest that after a rebound in March, demand grew by 3.8% y-o-y in April, principally thanks to city gas demand (up 15.8% y-o-y). Consumption in the industrial sector decreased by 6.7% y-o-y. First estimates for May indicate a limited y-o-y demand increase, close to 1%.

Japan, the world's largest LNG importer, saw its imports decrease by close to 5% y-o-y over the first five months of 2020, affected by warmer than usual weather, slower economic activity and the decreasing share of natural gas in the country's electricity mix.

Korea's LNG imports increased by about 14% y-o-y during the first five months of 2020, though state-owned incumbent KOGAS reported a 4% drop in domestic sales over the first quarter, and a 17.4% fall in April. However, the impact of reduced economic activity was partly offset by gains in power generation in March, supported by temporary shutdowns of 60 coal-fired plants to reduce air pollution. KOGAS reportedly asked for deferral of LNG cargoes scheduled for the second quarter, citing high inventory levels due to reduced domestic demand caused by Covid-19 impacts on economic activity.

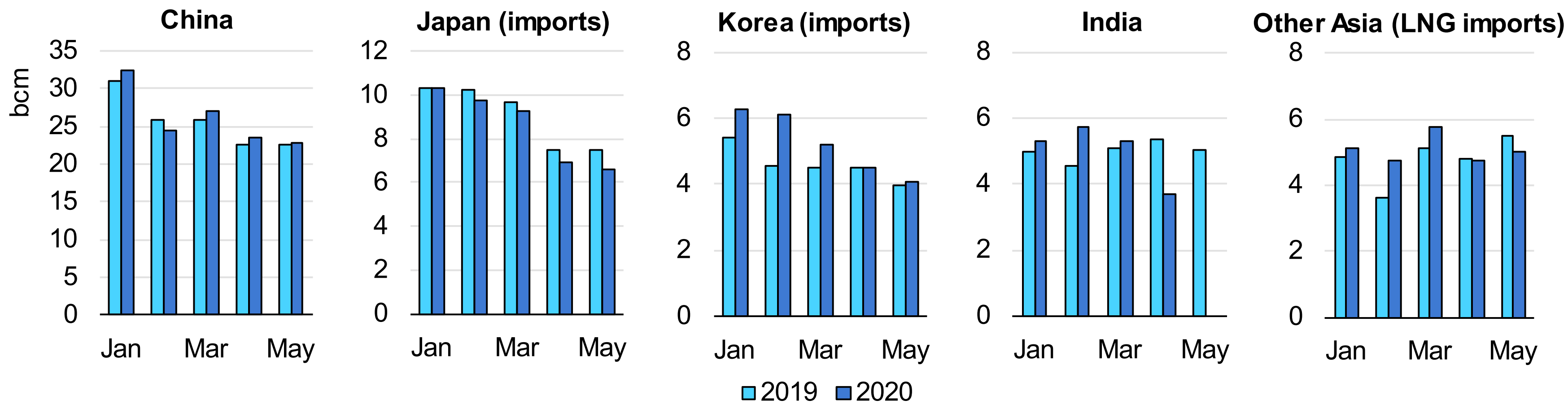
Natural gas consumption in India rose by an estimated 10% y-o-y during the first quarter of 2020. However, the introduction of a nationwide lockdown on 25 March led to a sharp and immediate decrease in demand. Preliminary data indicates that gas consumption was down by 25% yoy in April, with small industry and CNG distribution for transport being the hardest hit, while gas-fired generation was up 14% in spite of a 24% fall in electricity demand, as cheap imported natural gas was used to meet peak demand. The progressive lifting of restrictions in May has allowed chemical plants, factories and downstream industries to restart, leading to a rebound in gas consumption. State-run operator GAIL reported a 50% jump in sales in between the first week of lockdown and mid-May, although still below pre-lockdown level. Demand for fertilisers, the largest component of India's natural gas consumption, started to recover gradually ahead of the sowing season, with some plants restarting since late April.

LNG imports into other Asian markets collectively increased by 7% y-o-y during the first five months of 2020. However, this growth may also mask supply-side adjustments. In Bangladesh, state-owned Petrobangla reported cuts to domestic production in April to offset an average 30% drop in consumption since the implementation of a nationwide lockdown.

Pakistan is one of the few emerging Asian markets where LNG imports actually declined over the first five months of 2020, falling by almost 14% y-o-y. Network operating companies reported a 50% drop in daily consumption as of early April compared to monthly operational forecast. A number of factors contributed to this sharp decline, including lower electricity demand and higher hydropower production which cut gas-fired power generation by half. As well, plant closures reduced industrial gas demand by 50% relative to the forecast, and restrictions on transport pushed CNG demand to 65% below projected levels.

The Covid-19 outbreak hit domestic demand in major gas-producing countries across Asia. Indonesia's state electricity company PLN estimated that consumption has fallen on average 9.7% y-o-y for year 2020 to date, and the government introduced a cap on natural gas prices for electricity generators and several industrial sectors in early April to support economic activity. In Thailand, where natural gas accounts for 60% of electricity generation, the government introduced a range of electricity bill subsidy measures to support electricity consumption in late April. These relief measures were introduced retroactively for three months to the end of May 2020. Malaysia has also introduced an electricity bill discount scheme for six months, eligible to both residential and industrial customers.

Natural gas consumption in major Asian markets



Sources: IEA based on CQPGX (2020), *Nanbin Observation*; ICIS (2020), *ICIS LNG Edge*, (subscription required); PPAC (2020), *Gas Consumption*.

2020 is on its way to experiencing the largest recorded demand shock in the history of global natural gas markets

Global natural gas demand could fall by about 150 bcm/y or 4% y-o-y in 2020, based on our broad assumptions for the year and latest market observations. The decline in demand has been revised from the initial 5% estimate published in the *Global Energy Review 2020* report, and is based on revised Q1 data and market observations from the two first months of Q2.[1] The magnitude of the impact remains however unprecedented: this would be the largest recorded annual decrease in consumption since the natural gas market developed at scale in the second half of the 20th century, and the drop would be twice bigger than the latest downturn in 2009, when natural gas demand fell by 2%. Natural gas consumption is expected to fall in every sector and region in 2020, but most of the declines are in mature markets and power generation.

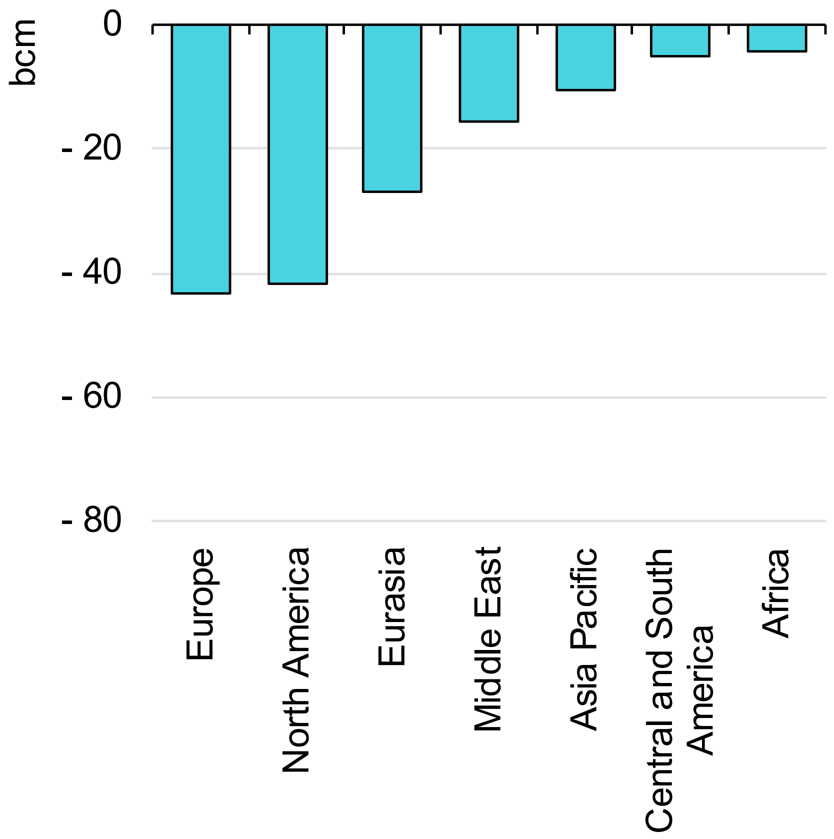
Geographically, the bulk of consumption decline is expected in mature markets across Europe, North America, Eurasia and Asia, which would together account for 75% of total demand loss in 2020. These markets concentrate most of the loss in residential and commercial consumption, resulting from the joint impact of lower space heating needs in the first months of the year, followed by the implementation of lockdowns weighting on consumption from the commercial sector. Gas-fired generation is particularly hit in Europe, squeezed in between lower electricity demand and growing renewable output. The volumetric impact is less important in emerging markets, due to the lower share of natural gas in power generation (apart from the Middle East) and marginal role of space-heating use.

Sector wise, our projection sees consumption for power generation drop by around 5% y-o-y, accounting for half of the decrease in global demand. Gas use in the residential and commercial sector falls by close to 4% globally – mainly in the abovementioned mature markets – and accounts for 20% of total consumption loss. The industrial sector also accounts for close to 20% of the global decrease, dropping by about 4% y-o-y in 2020. In addition to the direct impact of reduced activity during lockdowns, natural gas demand from industry is further dampened by the slowdown in consumer spending for manufactured goods, which affects gas use in export-driven economies (especially in Asia). The energy sector itself accounts for around 10% of the fall in global gas demand, dropping by 4% y-o-y. This reflects the overall decline in global supply, which reduces gas needs for upstream operations, as well as for energy transformation (refining) and transportation (pipeline gas compression).

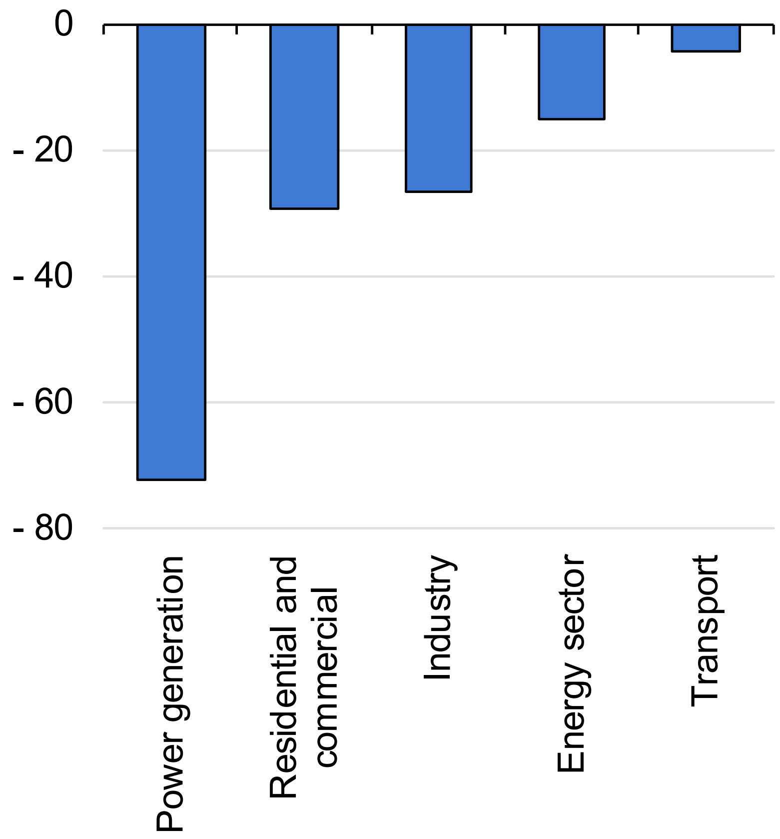
[1] These include among other higher fuel switching in power generation and greater resilience of industry consumption in the United States, a lesser than expected impact on European total consumption during the lockdown phase, and lower downturn in China's demand during and after the lockdown phase.

Demand loss could reach 150 bcm, hitting mainly mature markets and power generation

Natural gas demand decline per region, 2019-20



Natural gas demand decline per sector, 2019-20



The impact of lower demand is not (yet) fully visible in supply indicators

Supply-side indicators are sending mixed signals on the initial months of 2020, with US domestic gas production and global LNG supply still increasing compared to 2019, while Russian production and European imports show some decline.

US natural gas production increased by 5.3% y-o-y on average from January to the end of May in spite of lower domestic consumption, which dropped by 2.8% over the same period due to the joint impacts of warmer than average temperatures and the introduction of lockdowns in multiple states. This relative resilience in domestic production was offset by adjustments to the US gas trade balance: net pipeline imports from Canada declined by 11.1% y-o-y January to May, while pipeline exports to Mexico grew by 6.6% and LNG exports almost doubled. At end of May, daily dry gas production was close to its previous year level.

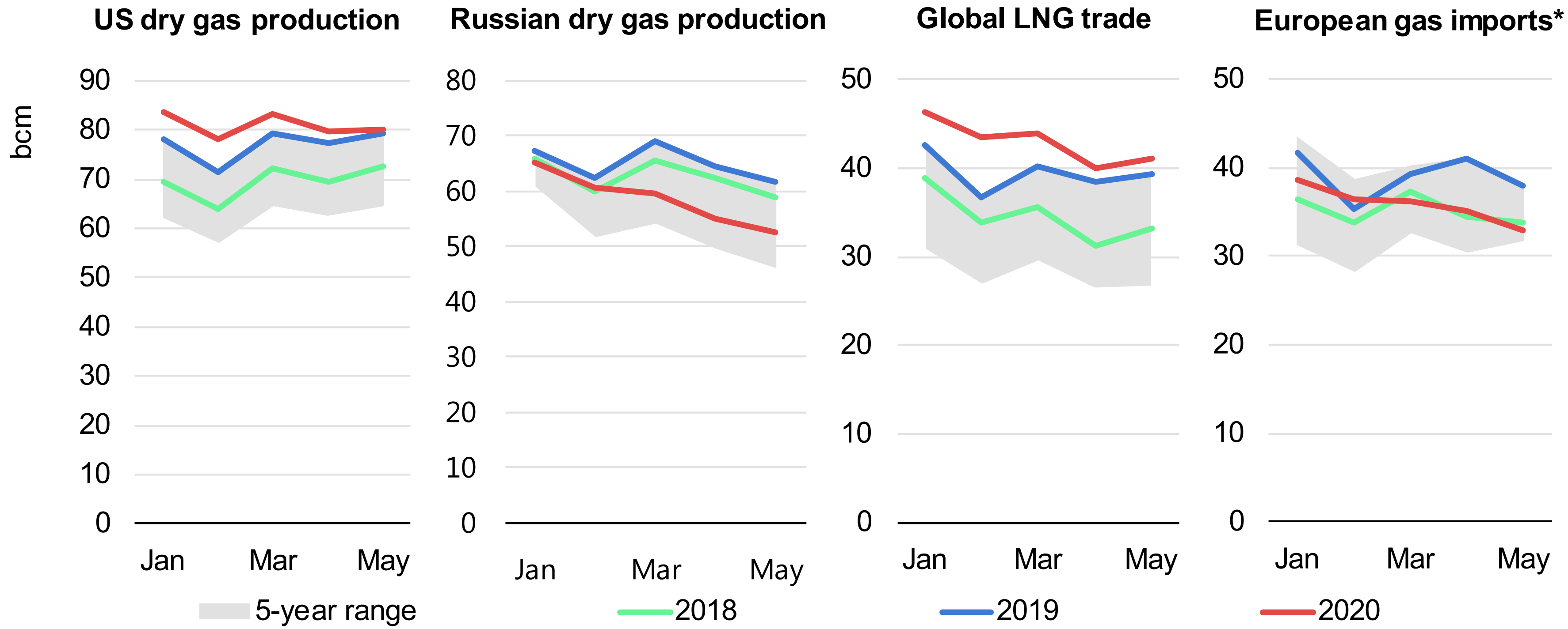
Russian gas production fell by over 9% y-o-y (or 30 bcm) in in the five first months of 2020. This results from lower pipeline export volumes to Europe, and lower domestic consumption amidst a particularly mild winter (heating degree days were down by 15% y-o-y through the heating season).

LNG trade volumes remained high in the first five months of 2020, up 8.5% y-o-y. Europe continues to play the role of balancing market in a context of loosening supply, accounting for two-thirds of incremental LNG imports since the beginning of the year, amid subdued demand growth in Asia. Asian imports fell in April close to its 2019 value, as the sharp drop in Indian imports caused by the country's lockdown further exacerbated the traditional lower demand from Japan and Korea at the end of the heating season – this being partly offset by a uptick in China's imports after two months of lower LNG demand. China and India's imports grew in May, supporting the modest m-o-m increase in global LNG trade as European flows remained stable.

In spite of its plummeting gas demand, European LNG imports increased by above 20% y-o-y over the first five months of the year to 60 bcm, thanks to its ample regasification capacity and flexible pipeline supply sources. The United States became the largest source of LNG supply to Europe, overtaking Qatar and Russia, and accounting for over 25% of Europe's LNG imports. The LNG influx into Europe primarily weighed on the import flows of traditional pipeline suppliers: imports from Russia and North Africa both decreased by about 25% and Norwegian flows fell by 4% y-o-y in the first five months of the year. Overall, natural gas flows to Europe (including both LNG and pipeline gas, notably Norwegian pipeline flows) fell 9% y-o-y in the first five months of 2020.

Supply-side indicators are sending mixed signals about the initial months of 2020

Monthly evolution of major natural gas supply indicators, 2018-20 and 5-year range



** including Norwegian pipeline gas flows to the United Kingdom and continental Europe*

Sources: IEA based on Analytical Center of the Government of the Russian Federation (2020), *Gas Production*; ENTSOG (2020), *Transparency Platform*; IEA (2020), *Gas Trade Flows*; ICIS (2020), *ICIS LNG Edge* (subscription required).

Global gas benchmark prices are searching for new lows…

The combination of continued strong supply growth, mild winter temperatures and the imposition of Covid-19 related lockdowns pushed natural gas prices to lows not seen in over a decade across all major consuming regions.

In the United States, Henry Hub prices in Q1 2020 fell by over 33% y-o-y to an average of USD 1.9/MBtu, its lowest quarterly price level since 1999. Prices continued to face downward pressure from growing supply (7% y-o-y) and subdued demand due to mild weather conditions, falling to an average of USD 1.75/MBtu in May.

In Europe gas prices on TTF more than halved compared to last year, averaging at USD 2.60/MBtu during the first five months of 2020, impacted by plummeting demand and strong LNG influx.

Since the imposition of the first lockdowns at the beginning of March, prices on TTF fell further to USD 1.50/MBtu in May – their lowest monthly average since the Dutch hub was established in 2003 – with day-ahead prices seen trading below the USD1/MBtu mark during mid-May.

Asian LNG spot price assessment halved y-o-y during the first five months of the year to an average of USD3/MBtu. Following the imposition of the lockdowns in India, Pakistan and Bangladesh in March, spot prices have fallen to new historical lows, with month-ahead contracts trading at an average of USD 2/MBtu.

The tightening price spreads between global gas benchmarks is practically closing the opportunity for any inter-regional arbitrage and potentially resulting in negative netbacks for certain suppliers.

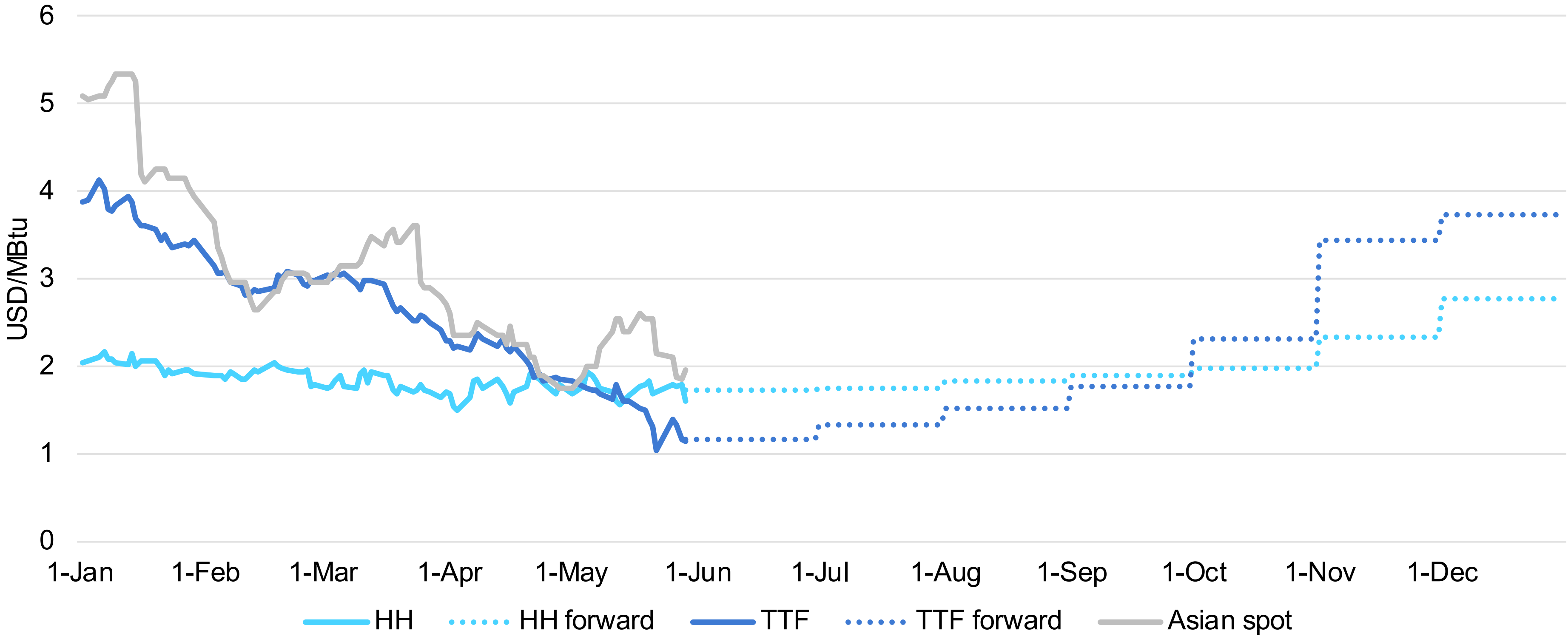
Natural gas prices are expected to remain depressed through the summer, amid a bleak demand outlook, high storage levels and continued growth in LNG supply from newly commissioned liquefaction projects. The current forward curve suggests that TTF could trade at a discount to Henry Hub through the summer months, reflecting an expected persistent oversupply. Prices are expected to start to recover at the beginning of the heating season, as increasing demand tightens the market and eventually leads to a renewed decoupling of global spot prices.

It is important to highlight that oil-indexed LNG contract prices did not experience large falls during the first quarter of the year. Given their predominance in the import portfolios of Asian LNG buyers, the weighted average LNG import price of China, Japan and Korea only decreased by just over 15% y-o-y in the first four months of 2020, to USD 8.8/MBtu.

However, the persistence of low oil prices since early March should have a significant impact on oil-indexed LNG contracts prices by Q3/Q4 of the year, as low oil prices filter through the price-setting reference period, usually between 3 and 6 months ahead. Current forward curves suggest that oil-indexed LNG prices could halve by the beginning of Q4 to a range of USD 4-5/MBtu. European supply is much less impacted by oil price dynamics as most of its pipeline and LNG imports are indexed on hub prices.

...tightening up price spreads and weighing on arbitrage opportunities

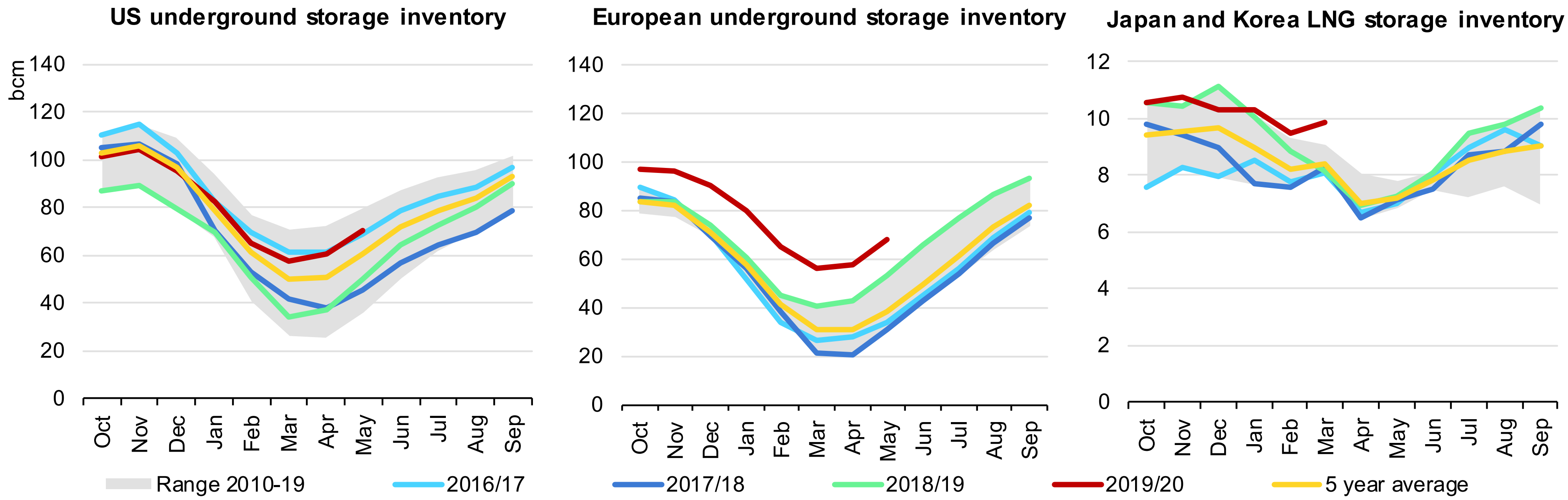
Evolution of main spot and forward gas prices – US Henry Hub, European TTF and Asian LNG spot index



Sources: IEA based on CME (2020), *Henry Hub natural gas futures quotes* and *Dutch TTF Natural Gas Month Futures Settlements*; EIA (2020), *Henry Hub Natural Gas Spot Price*; ICIS (2020), *ICIS LNG Edge* (subscription required); Powernext (2020), *Spot market data*.

Strong storage build-up reduces injection needs during 2020 summer season

The growth in supply outpaced incremental gas demand through 2019, resulting in a particularly strong storage build-up. In the United States strong net injections during April–October (36% above the 5-year average) and low withdrawal rates through the winter resulted in inventory levels 19% (or 12 bcm) higher than their 5-year average at the end of May. Europe saw strong injections through the summer, combined with an unseasonably mild winter and continuation of strong LNG influxes. This led storage sites to close the heating season 55% full and 25 bcm above their 5-year average. As of end of May, European working gas storage capacity was over 70% full, with less than 30% remaining spare capacity. Should injection rates continue at the same pace as observed in April and May, incentivised by seasonal price spreads, European storage capacity could be saturated before the end of the injection season. Strong LNG supplies resulted in an LNG storage build-up in Japan and Korea, with closing stocks standing 17% above their 5-year average at the end of March.



Source: IEA based on EIA (2020), *Weekly working gas in underground storage*; GIE(2020), *AGSI+ database*; IEA (2020), *Monthly Gas Data Service* (subscription required).

2021-25 – Rebound and beyond

Key drivers and uncertainties in the medium-term forecast

Demand - After a 4% drop in 2020, natural gas demand is expected to progressively recover in 2021 as consumption returns close to its pre-crisis level in mature markets, while emerging markets benefit from economic rebound and lower natural gas prices. The impact of the 2020 crisis is, however, expected to have repercussions on the medium-term growth potential, resulting in about 75 bcm of lost growth over the forecast period, 2019 to 2025. This forecast expects an average growth rate of 1.5% per year during this period.

The Asia Pacific region accounts for over half of incremental global gas consumption in the coming years, driven principally by the development of gas in China and India. While the prospects of natural gas remain strong for these two markets, the outlook is highly dependent on China's and India's future policy direction and recovery path in the post-crisis environment. In spite of the current economic headwinds and uncertainty, natural gas still benefits from strong policy support in both countries, with ongoing reforms to increase the role of gas in the energy mix. Future growth in the industry sector, which constitutes the main driver of incremental gas demand in both countries, will however highly depend on the pace of economic recovery, both for domestic and export markets for industrial goods.

Supply – If almost all regions are expected to contribute to the growth in natural gas production in the next five years, half of the net increase in supply comes from North America and the Middle East. The US shale industry, the main driver of global gas output growth over the recent years, is particularly vulnerable in the current crisis context – the IEA report *World Energy Investment 2020* estimates that upstream spending on shale tight oil and gas is set to decline by 50% y-o-y in 2020. The sector's ability to rebound in a post-crisis environment will be pivotal to deliver the incremental gas production needed by the US market to replace its declining conventional production and supply its additional LNG export capacity under development. Production growth in the Middle East is driven by the ramping up of large conventional projects in Saudi Arabia, Iran, Israel, Iraq and Qatar – for which the oil price collapse and uncertainty represent a substantial downside risk in the first years of the forecast. Gas production in Russia, the other large contributor to incremental supply, is almost entirely driven by export-oriented projects; while most of the additional production is expected for the second half of the forecast, shorter-term uncertainty on demand growth could negatively impact its development schedule.

Trade – LNG remains the main driver of international gas trade, as the 2018-19 wave of investment in liquefaction projects delivers additional export capacity in North America, Africa and Russia. However slower growth in gas demand post-2020 results in liquefaction capacity additions outpacing incremental LNG import through 2025, thus limiting the risk of a tight LNG market over the forecast period. China, India and emerging Asian markets account for most of the growth in future LNG imports, while Europe should return to its pre-2019 levels after reaching record levels as a balancing market. Additional pipeline trade comes principally from the progressive ramp-up of export infrastructure from Eurasia (TANAP and TAP to Europe, and Power of Siberia to China).

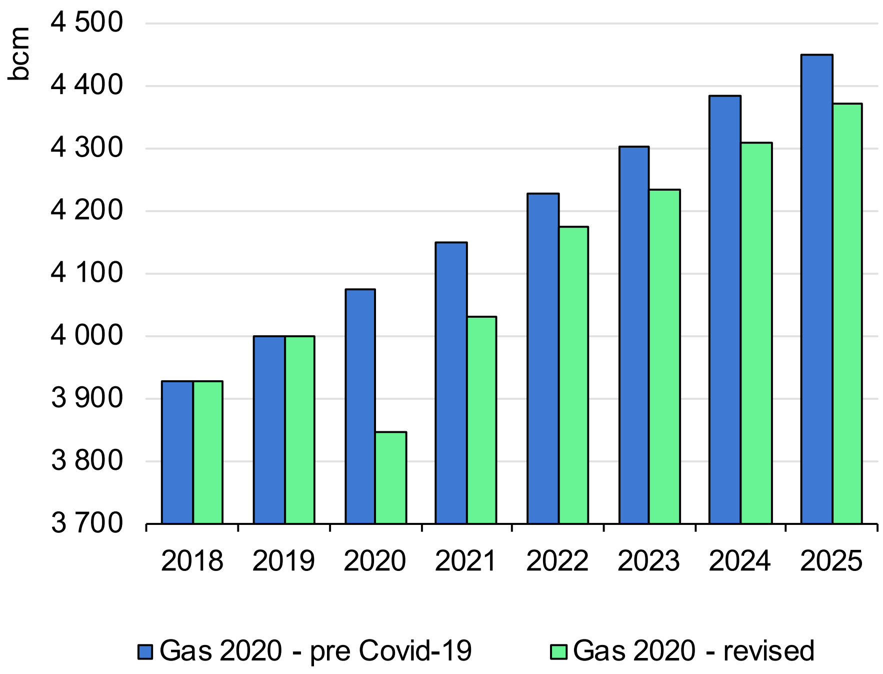
Demand

The Covid-19 crisis results in 75 bcm of lost annual demand by 2025

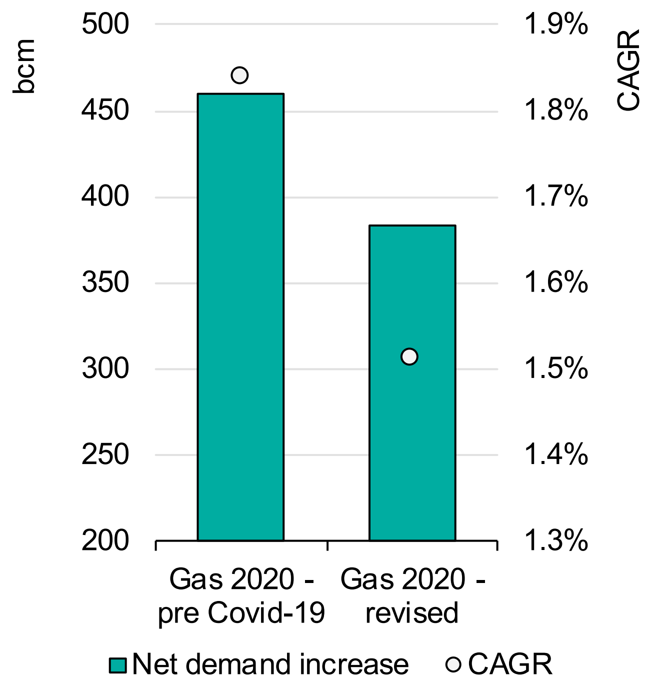
We have adjusted this year's forecast to account for Covid-19 resulting in expected global natural gas demand reaching over 4 370 bcm annually in 2025, or an average annual growth rate of 1.5% per year for the 2019-25 period, compared to initial forecast which assumed an average growth rate of 1.8% per year over the same period.

Even if most of the 2020 losses are to be recovered in 2021, the Covid-19 crisis has longer-lasting impacts on natural gas demand growth. This results in about 75 bcm/y of lost growth over the forecast period – more than the equivalent of incremental demand for 2019.

Evolution of global gas demand projections – initial forecast for 2020 and revised accounting for Covid-19 impact, 2019-25



Incremental gas demand and CAGR in initial and revised forecasts, 2019-25

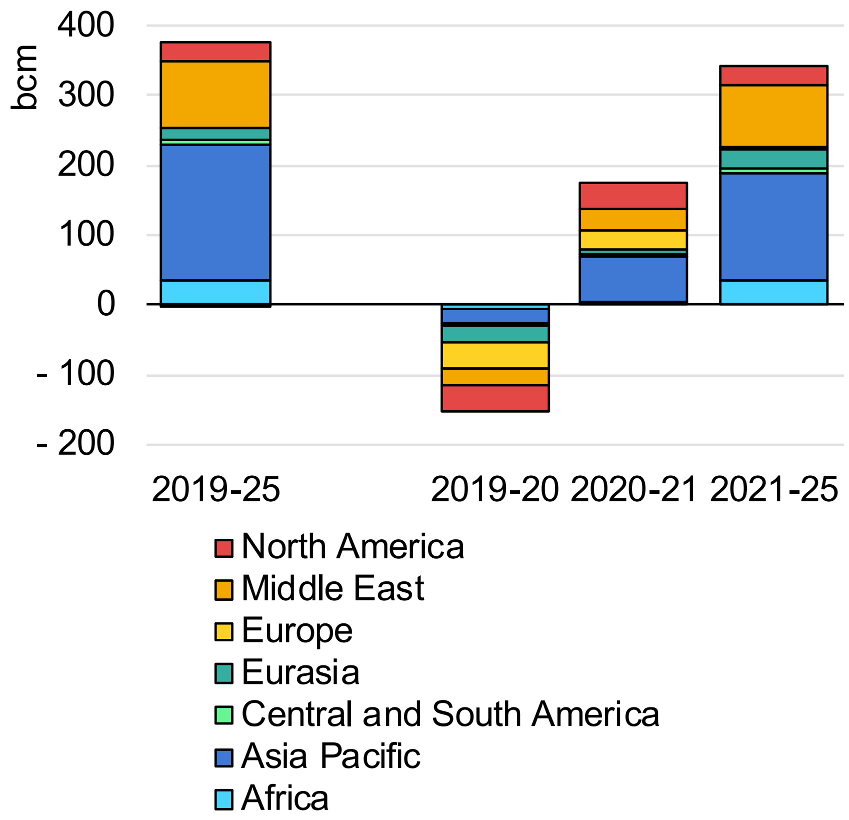


Global gas demand rebounds in 2021, Asia drives growth in the following years

Most of the gas demand lost in 2020 is expected to be recovered in 2021, supplemented by growth from the Asia Pacific region, as China and Asian emerging markets recover economically and benefit from attractive gas prices. Mature markets in Europe, Eurasia and North America, which were the hardest hit in 2020, are expected to recover most of their consumption losses in 2021 as demand from the industrial and power generation sectors gradually returns. Some marginal gains are also expected from coal-to-gas switching, helped by low gas prices and ample supply, while residential heating demand is assumed to return to normal after an exceptionally mild winter in 2019/20. Additional growth comes from faster-growing markets in the Asia Pacific region (and to a lesser extent in the Middle East), fostered by the economic rebound and competitive gas prices. The return to growth in global gas and oil demand also drives consumption from the energy sector in gas-producing and exporting regions (such as Eurasia, the Middle East and North America).

Further growth during the 2022-25 period is mainly driven by fast-growing Asian markets. The Asia Pacific region accounts for over half of incremental consumption from 2022, led by China and India. Additional demand in the Middle East (about a quarter of the total increase) is primarily driven by large gas-producing markets such as Saudi Arabia and Iran. Most of the residual growth occurs in Africa and North America, coming from domestic market needs and export-driven energy sector demand.

Regional breakdown of demand growth over the forecast period, 2019-25



Regional demand outlook to 2025

Our outlook sees Asia remaining the primary driver of global demand growth, with China, India and emerging Asia together accounting for over half of the net increase in 2019-25. China is the single largest contributor, led by the industrial sector. India's post-2020 growth is fuelled by a combination of supportive government policies and improved infrastructure, while emerging Asia's demand expansion is power sector-driven, underpinned by the addition of 15 GW of gas-fired generation capacity across the region.

Gas consumption in North America grows at just 0.4% annually in the forecast period, mostly thanks to growth in industrial consumption in the United States. Mexican gas consumption grows at a moderate clip of 1.3% annually, in line with new gas-fired power generation. Canadian demand grows at similar rates annually, largely a result of an increase in industrial consumption for process energy and for use as a feedstock. Despite Canadian coal phase-outs, the forecast presents limited growth in gas-fired power generation due to increases in renewable generation.

European gas demand is expected to remain stable through the forecast period. In the power sector, the gradual phase-out of over 50 GW of nuclear-, coal- and lignite-fired power generation capacity creates additional market space for gas-fired power plants. However, growth is limited by the rapid expansion of renewable power generation, set to increase by almost 30% over the medium term. Natural gas demand in industry is expected to recover to its pre-crisis levels, while further growth potential remains limited.

Natural gas demand in Eurasia grows by 0.5% per year between 2019-25, limited by the modest economic growth prospects of the region and the already very high gas-intensity of those economies. The industrial sector alone will account for almost half of incremental gas demand, driven primarily by chemicals and fertilisers, benefitting from the relatively low feed gas costs in the region. Energy industry own use is expected to grow at an average rate of 3% per year, driven by the region's export-oriented growth in gas production.

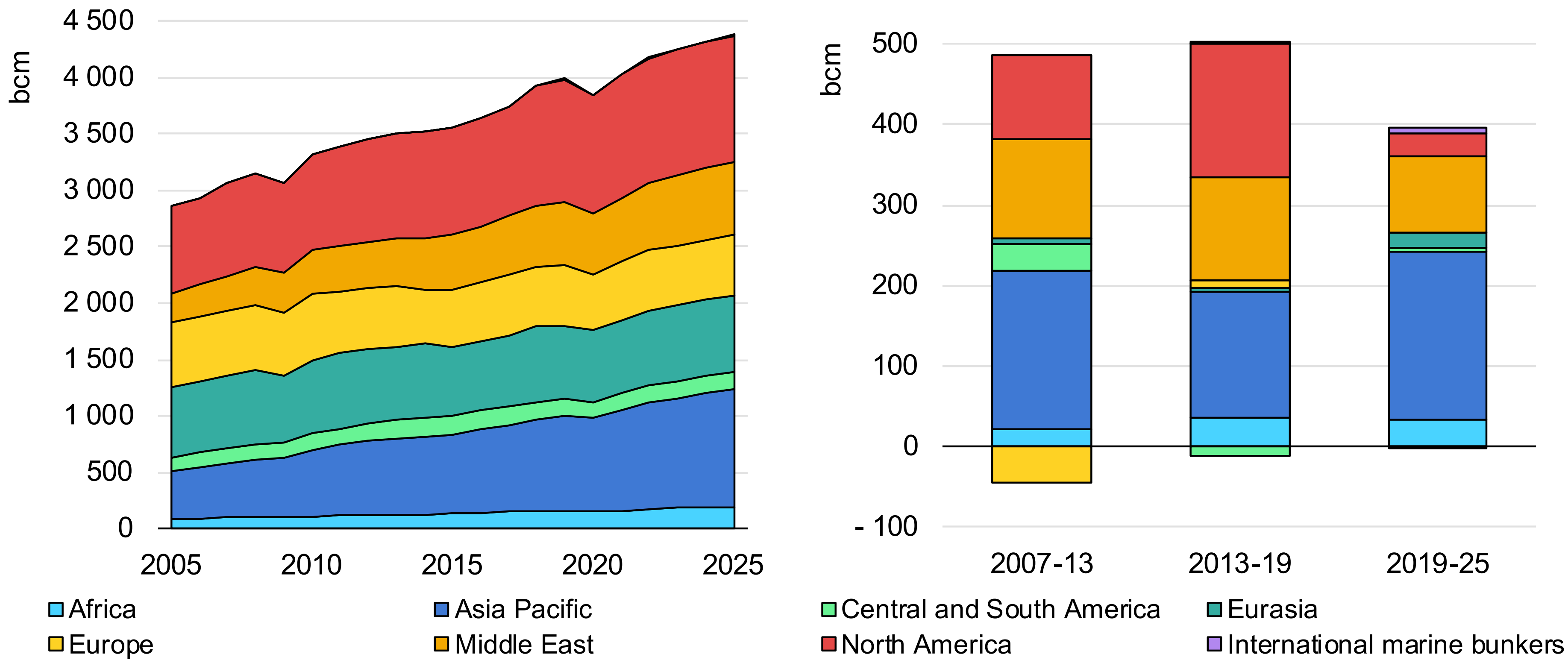
Middle East gas demand increases by nearly 100 bcm/y and reaches almost 660 bcm/y by 2025. The largest increments come from Iran and Saudi Arabia (accounting for up to 70% of the total consumption increase), supported by growing domestic supply availability. More than 60% of the net demand increase in the region is from the power and water desalination sectors.

Natural gas consumption in Central and South America is expected to grow at an average annual rate of 0.6% over the forecast period, adding about 5 bcm/y by 2025. Demand growth is led by the power sector, both in terms of volume and rate of growth, with an annual growth rate of 1.1%, driven by growing electricity demand and fuel switching.

African natural gas consumption grows at an average of 3.3% per year to reach almost 195 bcm in 2025. It remains primarily driven by industrial and power generation needs in North Africa's major markets of Algeria and Egypt, followed by Nigeria. The development of domestic production in West African countries drives the sub-region, which sees an average 6% growth rate per annum (excluding Nigeria), but the overall size of the market remains limited at about 14 bcm per year in 2025.

The Asia Pacific region accounts for over half of incremental demand to 2025

Global natural gas demand per region, 2005-25



Industrial uses account for 40% of gas demand growth to 2025

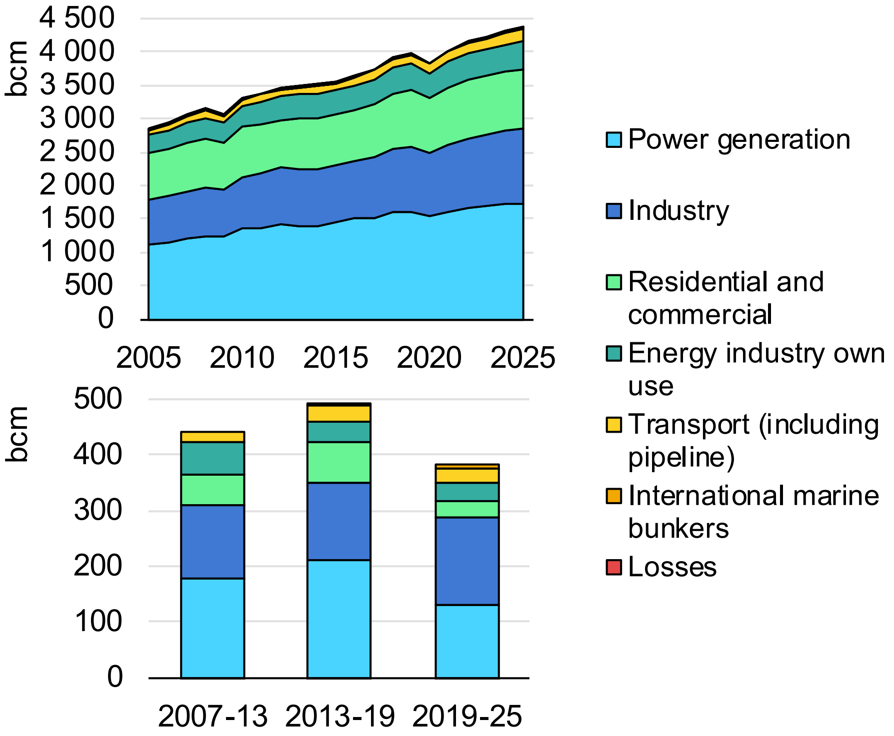
Gas consumption by industrial uses is the main contributor to demand growth to 2025, increasing at an average rate of 2.5% per year and accounting for 40% of incremental consumption. Additional demand for gas as a fuel for industrial processes principally comes from China, India and other Asian markets, while demand for gas as a feedstock is driven by gas-rich countries and regions such as the United States, Russia, North Africa and the Middle East, for manufacturing fertilisers and petrochemicals for both exports and domestic markets.

Growth from the power generation sector is expected to average 1.3% per year during the forecast period (much lower than the average 2.6% observed over the past decade). Demand growth loses speed in mature markets as additions of renewables capacity further reduce the space for thermal sources, while the bulk of coal-to-gas switching has already taken place. In faster-growing markets, the role of gas in power generation remains challenged by fuel cost competition as well as the emergence of renewables.

In the residential and commercial sectors, higher demand from the development of city gas distribution is seen in a handful of countries – China, India, Russia, Iran and Algeria. This is partly offset by structural decline in mature regions and lack of growth potential in most emerging areas where heating needs are limited.

Gas as a transport fuel is expected to grow at an average rate of 2.6%, principally driven by Asia with the growing use of LNG for trucks and river transport. This forecast assumes a tenfold increase in LNG as an international maritime fuel, reaching over 10 bcm by 2025, principally for us in container ships.

Global natural gas demand per sector, 2005-25



Fertilisers and methanol drive growth in gas feedstock consumption

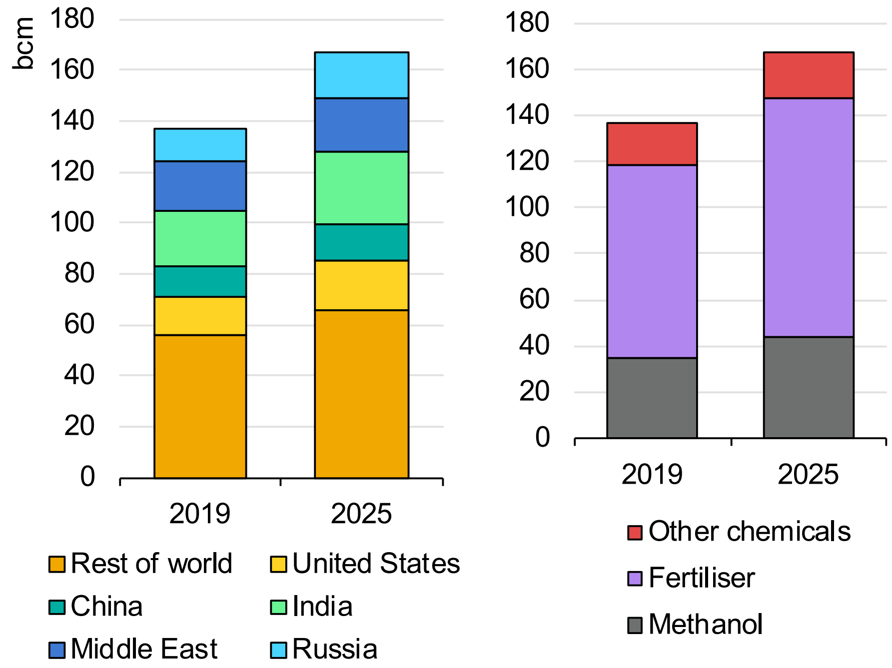
Industrial consumption of gas for chemical feedstock application is forecast to increase at an annual rate of 3.4%, thanks mostly to new fertiliser and methanol projects.

Gas-to-chemicals projects manufacture specialised products, including methanol, ammonia, ammonium nitrate, urea and other high-value chemicals. Fertiliser represents the greatest growth sector among feedstock uses over the forecast period, increasing by 3.5% annually to reach over 100 bcm in 2025. Production in India shows the largest increase, with urea production rising to 30.1 Mtpa by 2025, supported by government subsidies for the fertiliser sector and the objective of reducing dependence on imported urea. Fertiliser growth in Pakistan and Bangladesh also support this trend.

The United States leads growth in feedstock use for methanol. Developers have been attracted by low US gas prices following the country's rapid increase in production. Globally, consumption for methanol feedstock represents over 30% of the growth in this industrial sub-sector.

Eurasia accounts for 15% of global gas consumption in the petro- and agrochemical sectors. Around half of the region's industrial demand is consumed as a feedstock, also benefitting from relatively low gas prices (below USD 2/MBtu in 2019). In our forecast, gas demand in the chemical sectors grows at a rate of 3% per year, primarily led by Russia, which accounts for over 60% of the region's growth.

Natural gas consumption for non-energy use by market and application, 2019-25



China remains the main driver of global demand growth post-crisis

When the dust settles after the 2020 coronavirus crisis, China will be in a strong position to return to a trajectory of rapid growth, adding more than 130 bcm/y of incremental gas demand between 2019 and 2025. This makes it the single largest contributor to global gas consumption growth in our forecast.

China's post-crisis demand recovery is led by the industrial sector, its demand for gas growing by 60 bcm/y between 2019 and 2025. This is fuelled in equal parts by:

- Energy-intensive heavy industries, especially chemicals, where the prevalence of coal feedstock offers further fuel-switching opportunities.
- The growing profile of light industries in China's economy, where gas is already cost-competitive with liquid fuels and has significant convenience benefits over coal.
- The continuing policy-driven conversion of small coal-fired industrial boilers to mitigate urban air pollution, which we expect to remain a top priority post-2020.

The residential and commercial sectors also register strong growth, adding almost 30 bcm/y on the back of continuing urbanisation and coal-to-gas conversions, including in rural households. However, the government's 10 bcm/y biomethane target by 2025 could create some headwinds for natural gas use in rural areas towards the end of our forecast period.

The relatively strong 20 bcm/y demand increase in the transport sector is driven by China's expanding fleet of LNG-fuelled trucks (already the largest in the world with 431 000 vehicles as of 2019). This trend is supported by local diesel bans and subsidies in many parts of China, as well as by favourable economics compared to diesel trucks. A sustained low oil price environment could reduce the rate of growth in this segment relative to our forecast. Compressed natural gas demand expands more slowly as government policies tend to prioritise electric vehicles in the light-duty segment, while LNG use in domestic shipping is limited during the forecast period by the relatively slow buildout of bunkering infrastructure.

The outlook for natural gas in the power generation sector is more challenging, and the 20 bcm/y demand growth largely comes from the policy-driven expansion of the gas-fired generation fleet, which we expect to continue after 2020. Load factors in the expanding fleet will not increase materially, however, as the latest recommendation by the China Electricity Council calls for a mere peak-shaving role for new gas-fired power plants. The scope for economic coal-to-gas switching remains limited in the medium term, and, during the first phase of China's national emissions trading scheme, we do not expect a strong enough carbon price to tilt the balance in favour of gas in the generation stack.

While the prospects of natural gas remain strong, the outlook is highly dependent on China's future policy direction. Industrial gas demand may benefit or suffer during the post-crisis recovery, depending on whether the government chooses to stimulate the economy via fuel price cuts and fiscal incentives or by loosening environmental restrictions on coal use, for example. The future of China's coal-to-gas policies remains similarly uncertain, particularly following the relaxation of the government's strict switching rules in July 2019 to ensure adequate supplies during the winter. It is yet to be seen how the balance between coal and gas will change in the 14th Five-Year Plan for the 2021-25 period, and whether the slowdown in coal-to-gas conversions is a temporary or structural shift in China's energy policy landscape. Ongoing gas market reforms, which hold out the prospect of better supply availability and lower end-user prices, nonetheless support a robust outlook for gas consumption growth, especially if the low price environment continues in the foreseeable future.

India: Favourable conditions for greater gas use post-2020

Notwithstanding the current macroeconomic headwinds, natural gas enjoys broad policy support in India. This is reflected in the government's stated ambition of building a gas-based economy and increasing the share of natural gas in the primary energy mix to 15% by 2030, from 6% today. After a temporary slowdown in 2020, India is set to emerge as one of the primary drivers of growth in gas demand in Asia. The prospect is for an estimated 28 bcm/y increase in total consumption during 2019-25, thanks to a combination of supportive government policies and improved LNG and pipeline infrastructure. The outlook for gas, however, will greatly depend on the timely execution of planned infrastructure projects, further gas market reforms and the affordability of imported gas for India's price-sensitive consumers. The evolution of domestic production, which met half of total consumption last year and has historically been priced lower than imported LNG, can also influence the demand trajectory in some sectors. Currently power generation receives the largest proportion of cheap domestic gas allocation followed by fertilisers and city gas distributors, while refining, petrochemicals and other industries depend less on domestic gas supply.

The primary driver of India's post-crisis demand expansion is the industrial sector, representing 36% of the incremental growth between 2019 and 2025. The energy industry – led by refining – contributes another 10% to the total consumption increase. This rapid growth in industry and energy own use is fuelled by improved access to natural gas, both in traditional gas-consuming sectors, such as fertilisers, and in a range of light industries where gas is already cost-competitive with liquid fuels. Expansion of India's pipeline network will enable greater gas use over time. The ongoing roll-out of city gas distribution networks is targeting more than 35 million additional household connections and over 7 000 new CNG filling stations by 2029. The growing networks should drive robust demand growth in the residential and transport sectors, which account for 19% and 34% of incremental demand, respectively. Absent much stronger policy support, gas will struggle to gain further ground as a baseload fuel in electricity generation. This forecast expects power sector gas use to increase only marginally in the 2019-25 period, thanks largely to improving supply availability from growing domestic production.

Domestic production prospects and commodity prices could alter the outlook for sectoral demand over the forecast horizon. If lower oil and gas prices persist for an extended period, then imported LNG could gain further ground in the supply mix, especially in the industrial sector, while domestic production growth could stall, limiting gas availability in sectors that depend more heavily on the allocation of domestic gas at a low cost, particularly power generation.

Emerging Asia: Good prospects, great uncertainty after the crisis

Emerging Asia, which excludes China and India for the purposes of this analysis, is the second biggest contributor to global gas demand growth in Asia Pacific after China, adding about 35 bcm/y during the 2019-25 period. However, the region's growth trajectory is highly dependent on the pace of infrastructure development and the scale of policy support within each country. The medium-term outlook is subject to considerable downside risks in the aftermath of the 2020 coronavirus crisis. Emerging Asia is characterised by declining indigenous production, rising demand – which often remains unmet due to infrastructure and affordability constraints – and a growing dependence on LNG imports to bridge a widening supply gap in a region that lacks inter-regional pipeline connections. These market features are not expected to change materially throughout the forecast period.

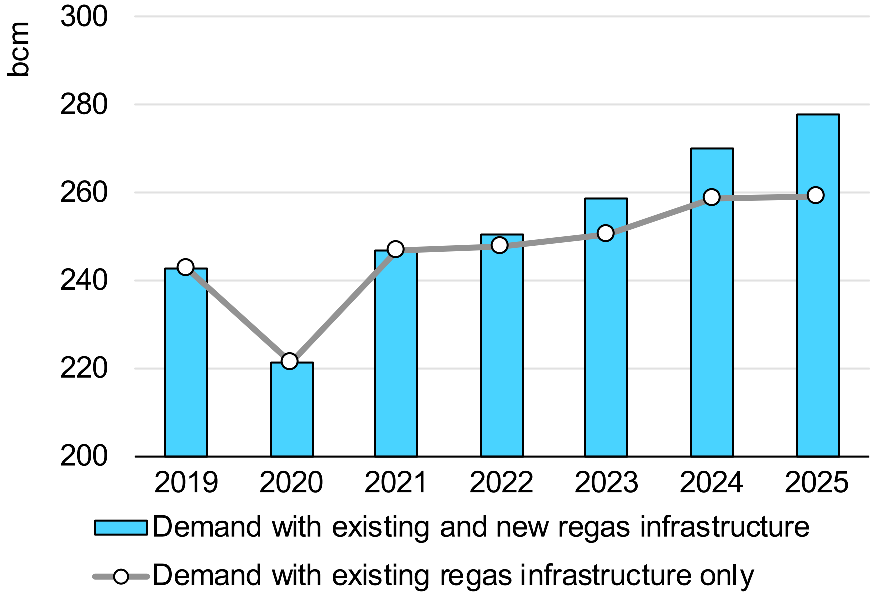
Gas demand is primarily driven by the power generation sector in the region, which accounts for more than 60% of the incremental growth between 2019 and 2025. This power sector-led demand expansion, which is underpinned by the addition of nearly 15 GW of new gas-fired generation capacity across Emerging Asia, will be fuelled by urbanisation, income growth and demand for cooling. The industrial sector – led by fertilisers and light industries – is a prominent driver only in Pakistan, Bangladesh and Indonesia, which together account for the bulk of industrial demand growth in 2019-25.

Gas use in the residential and commercial sectors is not widespread across the region. However, Indonesia's plan to extend the gas grid to 5 million households by 2025 (from less than 500 000 in 2019) could lead to more rapid uptake in this sector, if the ambitious programme, which is currently excluded from the forecast, is fully implemented. Pakistan, Bangladesh and Thailand have sizeable CNG fleets, and governments in these countries continue to promote the use of gas in the transport sector, leading to a 2 bcm/y demand expansion in our forecast. More rapid adoption of natural gas vehicles, however, is hampered by gas supply constraints and the low priority given to CNG users relative to other sectors during times of periodic shortages.

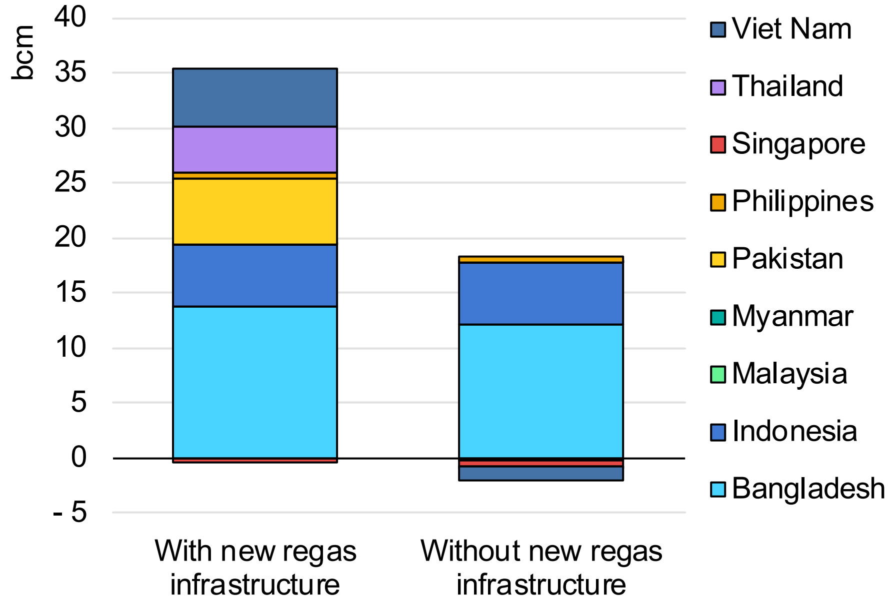
The post-crisis growth prospects for gas remain relatively strong in Emerging Asia. However, infrastructure constraints, shifting policy priorities and the dependence on external financing could impose limits on gas consumption growth in the medium term, particularly if the Covid-19 crisis has a lasting negative impact on state and international financing. Our demand projection assumes that the buildout of LNG import infrastructure continues throughout the forecast period. We estimate, however, that the region's total demand growth would be cut by half between 2019 and 2025 if planned LNG terminal projects falter and only the existing regasification infrastructure is available to bridge the supply gap. This would mean that much of the region's rising power demand remains either unmet or met primarily by domestic coal and fuel oil. Conversely, more active participation by LNG traders and portfolio players – and support from development banks and foreign governments – to develop natural gas infrastructure and gas-fired power in the region could unlock additional demand beyond the forecasted levels, especially if market and regulatory structures are adapted simultaneously to make investment more enticing for the private sector.

Without additional import capacity, growth in Emerging Asia could be cut by half

Natural gas demand in Emerging Asia, 2019-25



Incremental gas demand growth in Emerging Asia, 2019-25



Note: Our forecast anticipates the addition of new LNG import infrastructure in Bangladesh, Pakistan, Thailand and Viet Nam in the 2019-25 period, which is necessary to meet projected demand in these countries. The analysis compares our gas demand forecast for emerging Asia, which incorporates some new regasification facilities, with a downside case where only existing regasification infrastructure is available to meet projected demand. The growth that still occurs in the downside case is due only to increased utilisation of existing infrastructure. The analysis assumes that the proportion of demand that cannot be met with existing regasification capacity in a given country will be lost, and not be met by other supply sources, such as domestic production or pipeline imports.

Supply

Regional production outlook to 2025

North American gas production represented over 28% of total gas supply in 2019, and production in the region increases 1.5% annually through 2025 according to our forecast. Over 70% of this growth occurs in the United States to service new LNG export facilities. Canada continues to increase production at a projected rate of 3% annually, mostly from the Montney shale to reach the levels needed to service the 19 bcm/y LNG Canada project. In Mexico production continues to decline, but at a more moderate rate of 2% annually compared to historical reductions.

Eurasian gas production is expected to grow at a rate of 1.8% per year through the forecast to reach almost 1 030 bcm in 2025, primarily supported by export-oriented projects. Russia alone accounts for over 70% of the region's growth, as its pipeline supplies to China and LNG exports ramp up. Azeri gas production is set to expand by over 30%, with the TANAP and TAP pipeline system ramping up to supply the European market from the Shah Deniz field. Central Asian production grows at a rate of 2%, as Turkmen and Kazakh production growth outpaces declining output in Uzbekistan.

Middle East production is expected to reach almost 790 bcm in 2025, increasing at an annual average of 2.4% for the next five years. This makes the region the second-largest contributor to natural gas supply growth after North America. The Middle East combined with North Africa (MENA) represents the single-biggest driver of gas production growth globally. Five countries – Saudi Arabia, Iraq, Israel, Qatar and Iran – account for three-quarters of the net production increase. The vast majority of incremental supply serves domestic and regional demand.

Gas production in the Asia Pacific region increases from 637 bcm in 2019 to 676 bcm in 2025. While traditional gas-producing countries (including Indonesia, Malaysia, Myanmar and Thailand) experience gradual declines, China adds 54 bcm/y of new production by 2025 thanks in part to continued policy support for domestic production. Gas supply from Australia, the second-largest producer in the region, stabilises at slightly above 150 bcm/y as new developments largely offset declines from mature fields. India boosts production by 12 bcm/y in 2019-25, with most of the net increase coming from a handful of ongoing deepwater development projects.

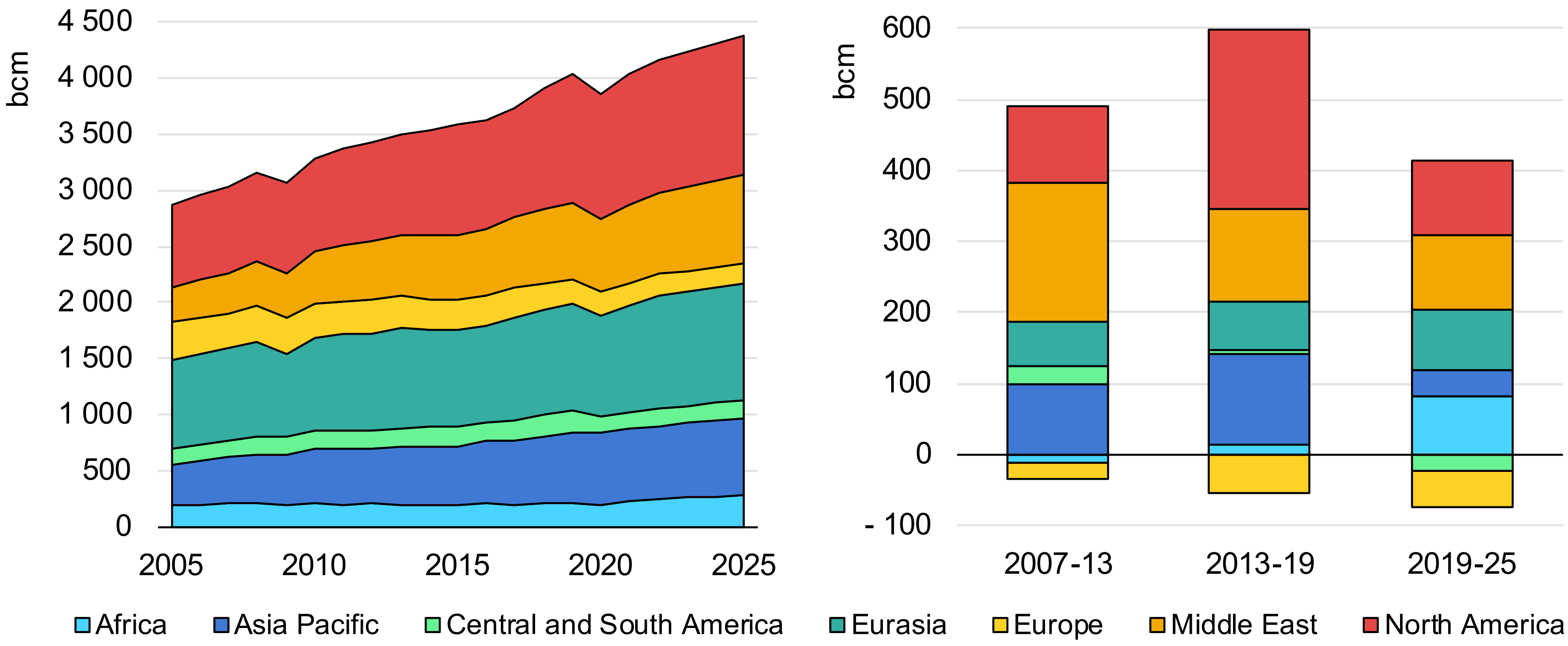
Africa is the fastest-growing region of production at an average of 5.6% per year, supplying close to 295 bcm in 2025. The bulk of this growth comes from LNG export-driven production developments in Mozambique and Nigeria and the joint offshore development in Mauritania and Senegal, as well as from North African assets to support domestic market growth.

European gas production is expected to fall by 40% (outside Norway) in the next five years. This is primarily driven by the Netherlands and the United Kingdom, accounting together for over 80% of the total decrease. In the Netherlands, the giant Groningen field (almost half of the country's production in 2019) is set to close by gas year 2024/25 at the latest, to prevent further earthquakes in the producing region. In the United Kingdom the recent discoveries of Glendronach and Glengorm improved the production outlook, but will not be sufficient to offset declining production rates from the continental shelf's depleting fields. Norwegian gas production is expected to remain stable through the forecast period, averaging at 120 bcm/y.

This forecast expects an average annual decrease in natural gas production in Central and South America of 2.1%, resulting in close to 160 bcm being supplied in 2025. Increases in Argentina are not sufficient to compensate for the decline from legacy producers, while the current market environment does not support the development of other new (and more expensive) sources of production.

Supply – Regional outlook

Global natural gas supply per region, 2005-25



Biomethane production set to double by 2025

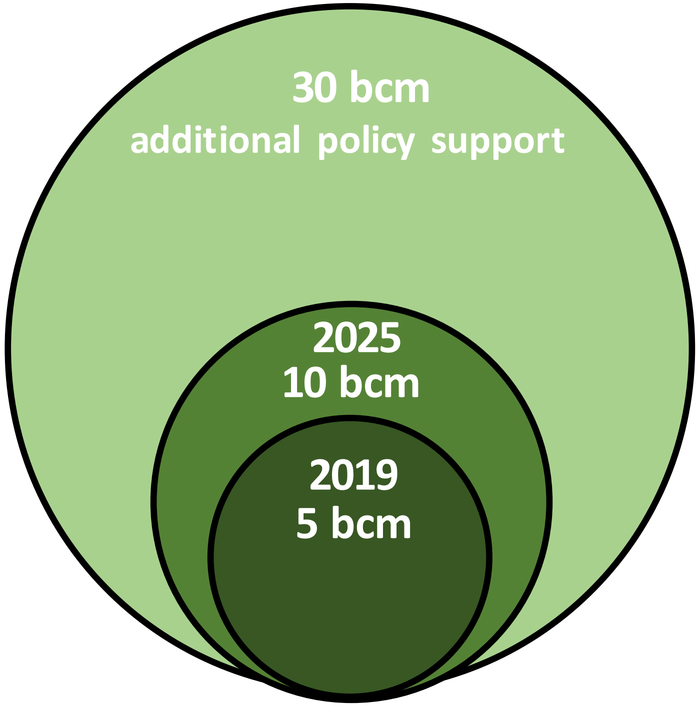
Biomethane is produced either by upgrading biogas into near-pure methane (90% of current biomethane production) or via the gasification of solid biomass followed by methanation. Given that its chemical properties are identical to natural gas, it can be transported by the existing gas transmission system and can serve as a substitute to fossil-derived natural gas.

Global biomethane production stood at 5 bcm in 2019, accounting for 0.1% of global gas supply. Europe currently accounts for over 60% of global biomethane production. Globally the power and heat sector accounts for almost 40% of biomethane consumption, followed by transport (29%) and the residential and commercial sectors (~20%).

Biomethane production is expected to continue to grow at an impressive rate of 12% through the forecast period to reach 10 bcm by 2025. Reflecting the pipeline of biomethane projects, this growth is primarily driven by Europe and North America, which benefit from well-developed and interconnected gas grids.

The relatively high production costs of biomethane (averaging at USD 20/MBtu) remain a challenge through the medium term, especially in the current low gas price environment. However, the right set of policies could provide additional upside potential for biomethane development, especially in the rapidly growing markets of the Asia Pacific region. China is targeting biomethane production of 10 bcm by 2025, while India plans to expand the use of biomethane in transport, with the buildout of 5 000 small-scale bio-CNG plants by the end of the forecast. For an in-depth review of the biomethane market, please refer to the IEA World Energy Outlook special report, Outlook for Biogas and Biomethane.

Global biomethane production, 2019-25



US shale: Short-term volatility, long-term resilience

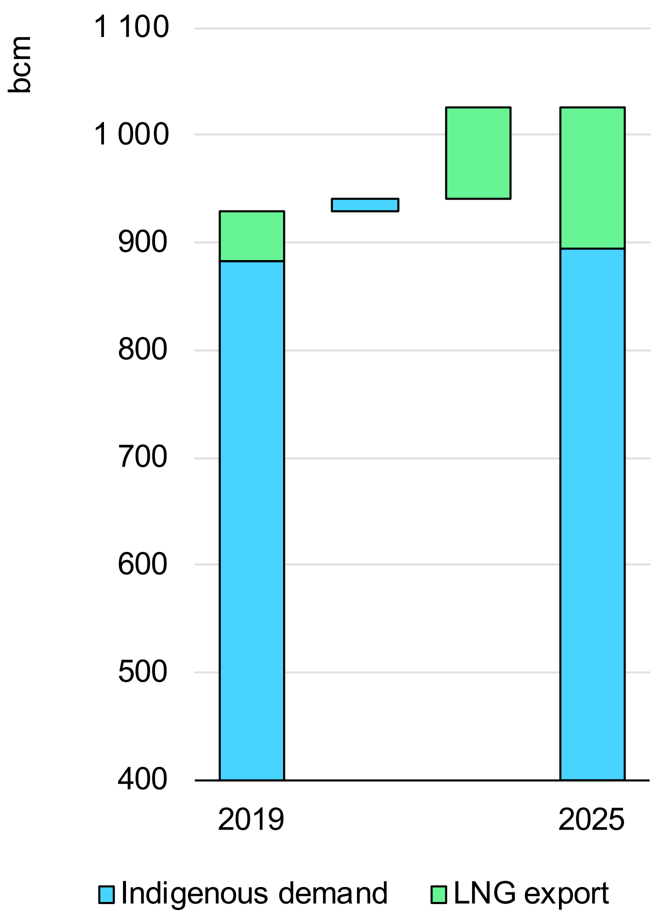
The Covid-19 outbreak triggered an unprecedented oil demand shock, resulting in a 40% decline in oil prices over the first quarter of 2020. Operators report oil production curtailment in excess of 1 million barrels per day in May and June 2020, mostly from the Permian and Bakken producing areas. US crude production is estimated to fall by 2.4 mb/d by year-end compared with 2019. The risk prolonged curtailment poses to gas production depends on the characteristics of the producing wells. In 2019 almost 30% of US gas production (230 bcm) was produced as a secondary product from oil wells in areas such as the Permian basin. Just over 20% of this gas comes from wells with a break-even price above USD 30/bbl WTI (December 2020). At USD20/bbl WTI, only 55% (126 bcm) can be produced economically.

Revisions to 2020 CAPEX guidance show oil and gas operators have responded to changing market conditions, where we estimate a y-o-y fall in investment of around one-third. This has already triggered an increase in borrowing as well as the likelihood that restrained spending will continue well into 2021. Prior to the oil demand shock, the gas play horizontal rig count in the United States had already plummeted by almost 50% versus its June 2019 peak, all in the midst of weak gas prices.

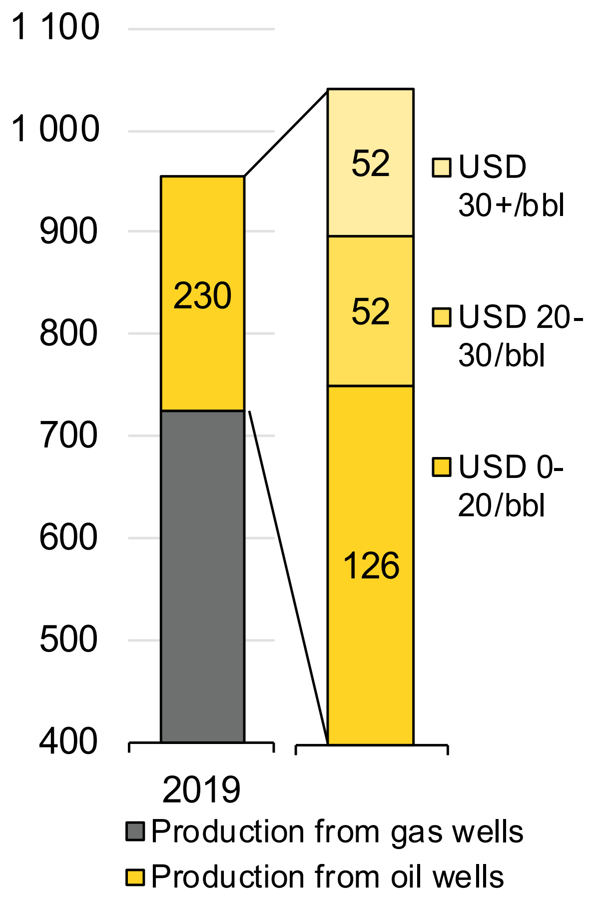
With a protracted low oil price, producers will need to look beyond the Permian basin to make up for a shortfall in associated gas production to service domestic demand and export need. In the short term, plays like the Appalachian basin and Louisiana's Haynesville shale would need to compensate with a production increase, depending on greater domestic price strength. Even so, a period of rapid growth may test constraints of infrastructure, labour and capital, which had seemed sufficient before the fundamentals shifted. In these conditions, a geographic shift in gas production and operator strategy may be observed if gas demand remains steadfast. At higher prices, a recovery in associated gas in the Permian and other locations could be rapid, but a considerable portion of the short-term projected growth in gas production from the play has been discounted.

Although details concerning short-term outcomes of this reduction are uncertain, by 2025 annual US production is forecast to reach over 1 030 bcm, increasing by 1.2% annually over the period. Additional supply is mostly needed to service new LNG export capacity set to enter service over the coming years.

US gas production growth, 2019-25



Production by field type and break-even cost



Source: IEA (2020), Rystad Energy (2020), GasMarketCube (subscription required).

Exports set to drive Russia's production growth

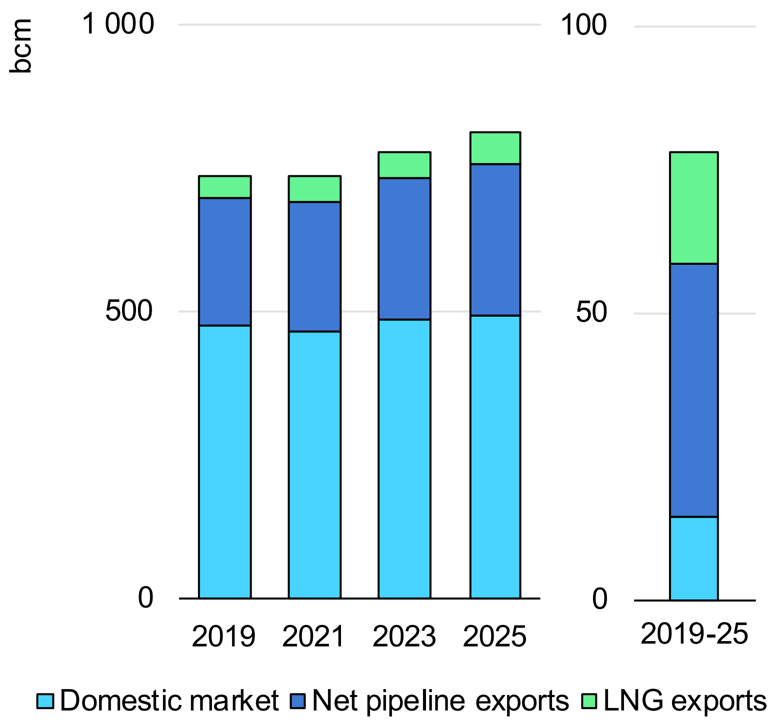
Russia is expected to be the second-largest source of incremental gas supply, after the United States, through the forecast period, accounting for just over one-fifth of global growth between 2019 and 2025. Production growth, at a rate of 1.7% per year, is almost entirely driven by export-oriented projects, further solidifying Russia's position as the world's largest natural gas exporter. This is accompanied by continued diversification away from Russia's traditional gas-producing region, Nadym-Pur-Taz, caused by its maturing and gradually depleting fields.

In Western Siberia, Gazprom continues to develop the Yamal production centre, with the giant Bovanenkovo field expected to reach its nameplate capacity of 115 bcm/y by 2022 and with the start-up of the Kharasavey field in 2023, reaching 32 bcm/y production by 2026. Supplies via the Bovanenkovo–Ukhta pipeline corridor are due to supply both domestic consumers and the European export market.

The Arctic LNG-2 project reached FID in September 2019, with a total nameplate capacity of bcm/y. The first two trains are expected to be commissioned in 2023 and 2024, supplied with feedgas from the Utrenneye field, located in the northern part of the Gydan peninsula.

In Eastern Siberia, the Power of Siberia pipeline system started commercial deliveries into China in December 2019 and should reach the full contracted capacity of 38bcm/y in 2025. Gas supplies are scheduled to be supported by the Chayandinskoye and Kovytka fields located in East Siberia, which reach their 25 bcm/y nameplate capacity by 2024 and 2025 respectively.

Russian gas production per destination, 2019-25



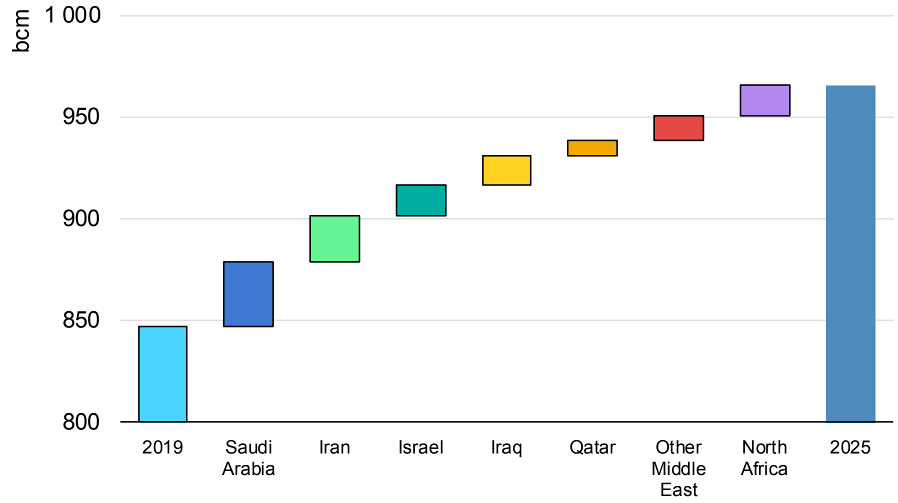
The MENA region will be the largest contributor to global gas supply growth

The combined Middle East and North Africa (MENA) region becomes the largest contributor to global gas production growth in the forecast period, adding nearly 120 bcm/y of incremental supply in 2019-25. Despite being the second-largest gas surplus region in the world (after Eurasia), the vast majority of new production is expected to serve domestic and regional demand, which, in turn, is seen predominantly to come from the power and water desalination sectors.

Production growth is heavily concentrated in only a handful of countries, with Saudi Arabia, Iraq, Israel, Qatar and Iran accounting for more than 75% of the net increase in gas supply across the MENA region. The bulk of this growth is driven by the ramp-up of production at a few large development projects. These include Hasbah, Hawiyah and Marjan in Saudi Arabia, Halfayah and Ar-Ratawi in Iraq, Leviathan and Karish in Israel, Barzan in Qatar and South Pars in Iran. A number of prominent megaprojects, including the Jafurah shale development in Saudi Arabia and the North Field development phases underpinning Qatar's LNG expansion, are not anticipated to contribute materially to gas supply growth until after 2025.

The 2020 oil price collapse represents a considerable downside risk to the production outlook in the early years of the forecast, as diminished oil revenues could translate into lower capital expenditure in key producing countries. Associated gas represents another key uncertainty. The region produced approximately 100 bcm of associated gas in 2019, nearly all of it in members of OPEC – and half of it in Saudi Arabia alone. This introduces a degree of unpredictability, as some future production could be affected by oil market dynamics and OPEC policy. Geopolitics is yet another risk factor, which could fundamentally alter the production outlook across the MENA region.

Incremental gas supply growth in the MENA region, 2019-25



Note: The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by 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.

Trade

LNG, the main driver of international gas trade, increases by 21% between 2019 and 2025

Global LNG trade is expected to reach 585 bcm/y by 2025, an increase of 21% compared to 2019. Emerging Asian markets remain the driving force behind the expansion of LNG imports, led by China and India, while the United States accounts for almost all of the net growth on the export side. LNG trade is expected to increase at a slower rate than liquefaction capacity additions, thus limiting the risk of a tight market over the forecast period.

The Asia Pacific region further increases its share of total LNG imports, from 69% in 2019 to 77% by 2025. China alone accounts for 22% of total LNG demand in 2025, contributing almost 40% of growth in total imports over the forecast period. India also leads LNG growth accounting for about 20% of incremental trade, and sees its imports increase by 50% between 2019 and 2025 to support strong growth in demand. Bangladesh and Pakistan, two more recent LNG buyers, also experience strong import growth rates to support their increasing consumption and offset the decline of domestic production. South East Asian markets also increase their imports to supply the development of new import capacity in Thailand and Viet Nam.

Europe remains the main importing market after Asia, as LNG offers a source of diversification of supply in the context of declining domestic production. After reaching record levels in 2019, the region having played the role of balancing market to absorb oversupply, European imports are expected to return to an average of 90 bcm/y throughout the forecast period (25% above the average import level of the past five years). Contributions from other regions – Africa, Central and South America, the Middle East and North America – are expected to remain stable.

On the supply side North America is almost the sole source of growth, accounting for close to 80% of additional exports between 2019 and 2025. North American exports are expected to almost triple in the next five years, driven by the wave of recently sanctioned US liquefaction projects, as well as the commissioning of Canada's first export project by the end of the forecast period.

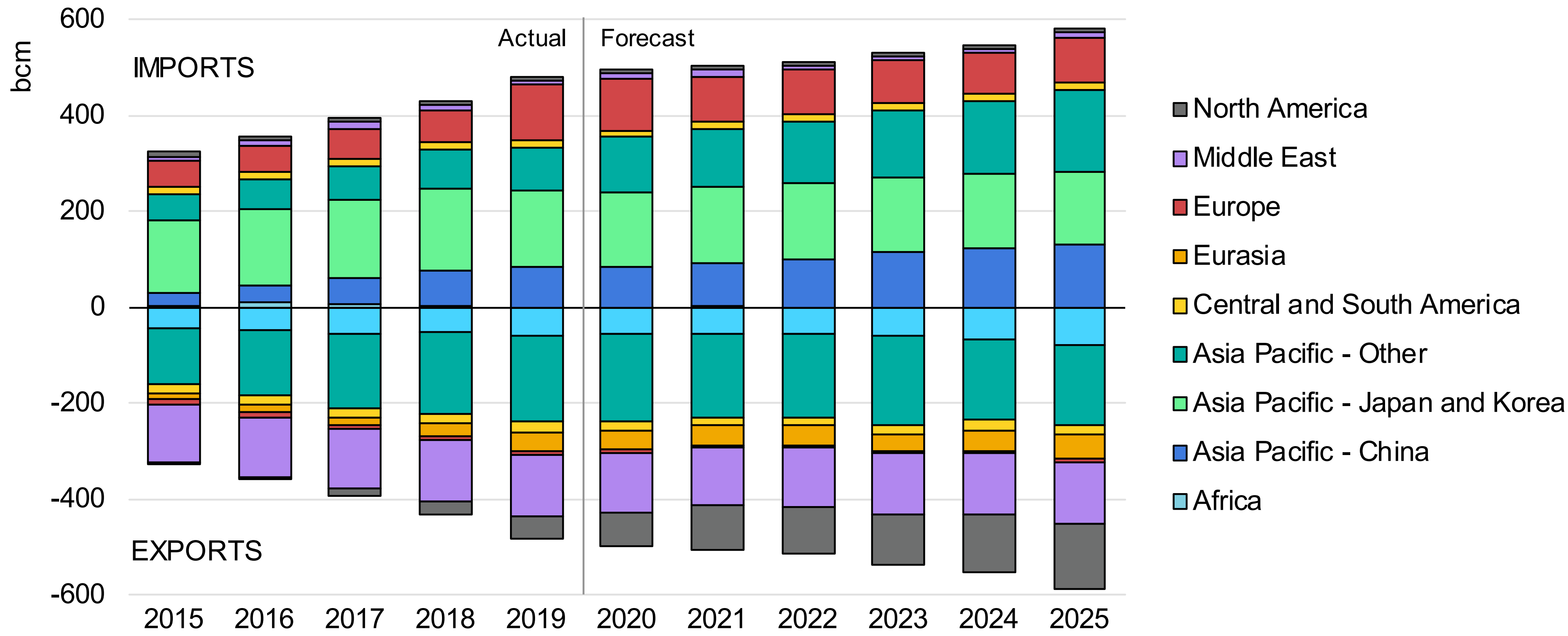
Africa accounts for most of the residual growth in exports, sourced from projects under development in Mozambique (Coral FLNG, Mozambique LNG), capacity expansion in Nigeria (NLNG train 7) and a cross-border offshore project in Mauritania and Senegal (Tortue FLNG).

Russia's LNG exports are set to increase by almost 20% by 2025, driven by capacity development from the Yamal peninsula. Supply from the Middle East should remain stable based on Qatar's current[2] export capacity, as are LNG exports from the Asia Pacific region, with Australian exports plateauing and output from traditional exporters such as Indonesia and Malaysia decreasing slightly.

[2] This report only considers liquefaction projects that had taken their FID as of late May 2020 as contributing to future export capacity for the forecast period.

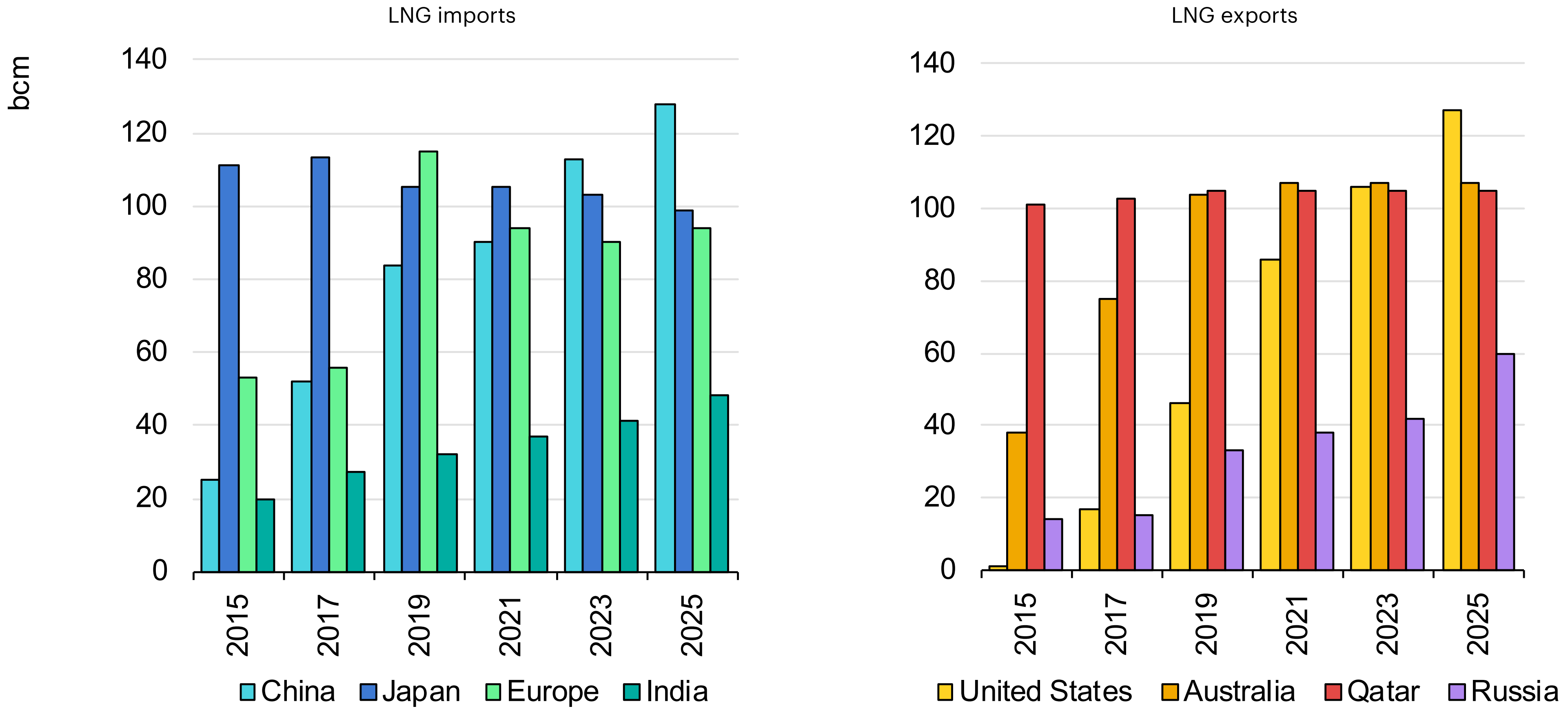
Global LNG trade reaches close to 600 bcm by 2025

World LNG imports and exports by region, 2015-25



China becomes No. 1 LNG buyer in 2023, the United States No. 1 LNG seller in 2025

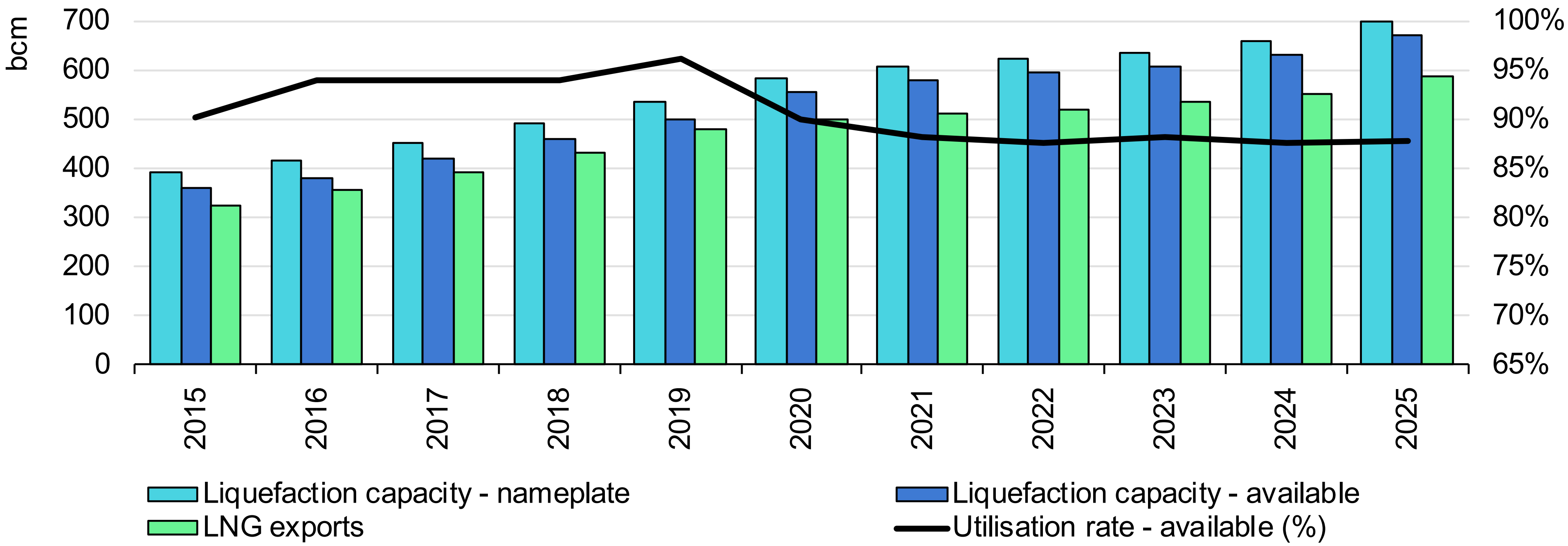
World LNG trade for a selection of importers and exporters, 2015-25



LNG trade grows more slowly than liquefaction capacity

FIDs taken in the recent years lead to a strong uptick in LNG liquefaction projects, which is expected to add up to 120 bcm/y of export capacity in between 2020 and 2025 – or an increase of 20%. Slower growth in natural gas demand is likely to weight on average utilisation rates of liquefaction plants, creating a situation of overcapacity as liquefaction growth outpaces incremental LNG trade, thus limiting the risk of a return to a tight market before 2025. Such a situation would leave some LNG players with growing net selling positions and sunk costs, which would in turn exacerbate competition among suppliers – both in the context of renewal of expiring contracts and for the development of new markets in emerging regions.

LNG trade and liquefaction utilisation rate, 2015-25



LNG demand is rising in China and India, but shrinking in Japan and Korea

China to cement its position as the largest natural gas importer

China widens its lead as the world's largest natural gas importer during the forecast period, with combined pipeline and LNG imports increasing from 134 bcm/y to 210 bcm/y in 2019-25. The country also overtakes Japan as the world's largest LNG market within the next five years: China's LNG imports are projected to reach 128 bcm/y by 2025 thanks to the continuing expansion of the country's regasification capacity. Its pipeline gas imports also increase by more than 30 bcm/y due to the scheduled ramp-up of Russian deliveries through the Power of Siberia system and additional flows from Central Asia.

India's LNG imports could increase by half by 2025

India's LNG imports increase by 16 bcm/y and reach 48 bcm/y by the end of the forecast period. With the recent addition of the Ennore and Mundra terminals and the expansion of the Dahej facility, effective regasification capacity stands at 53 bcm/y. After the completion of five new terminals and a breakwater facility at Dabhol, which are already under construction, India's import capacity could increase by another 31 bcm/y, implying an average utilisation rate of 57% in 2025, a slight decrease from 69% in 2019. This – combined with improving downstream connectivity – could enable the county not only to bridge its widening supply gap, but also to take advantage of favourable market conditions during periods of low spot prices. Our forecast envisages no pipeline imports into India through 2025.

Japanese LNG imports set to decrease with nuclear restarts and steady renewables

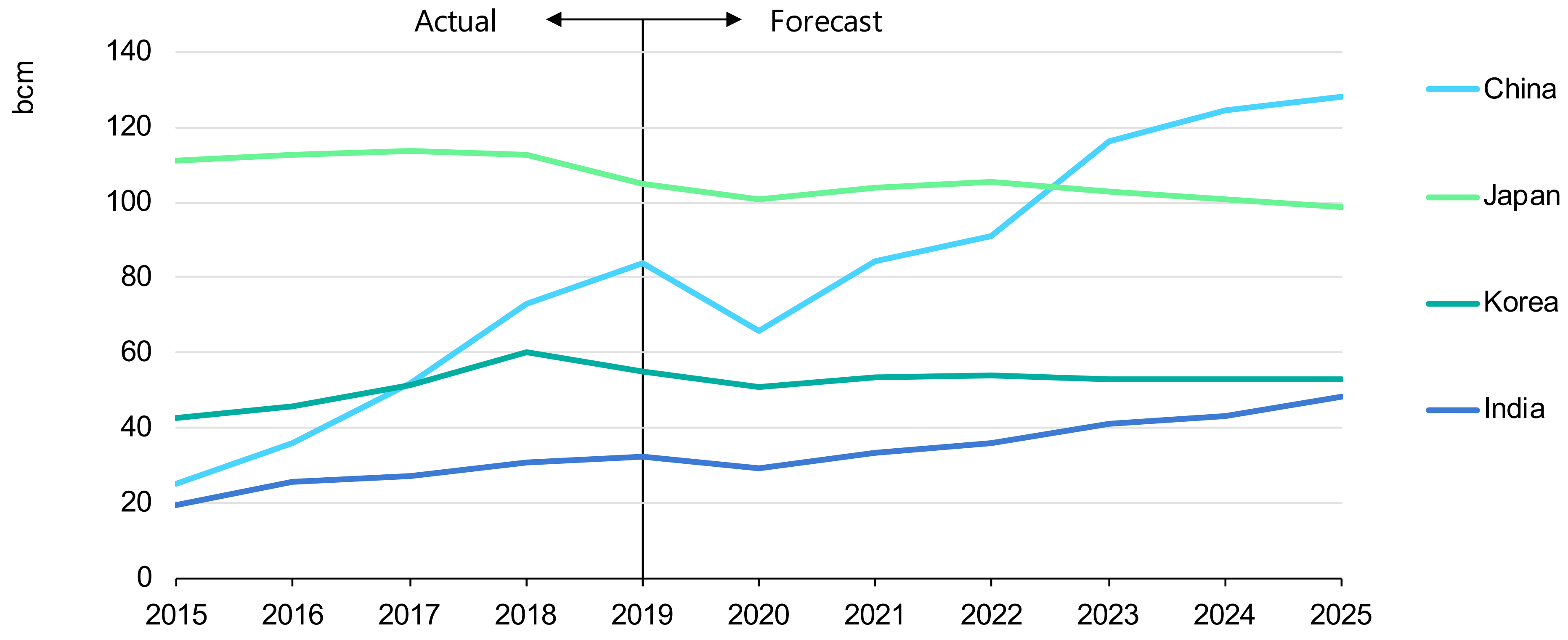
Japan imports LNG as part of a diverse energy mix. The country relied on LNG for 34% of its power generation in 2019 due to the slower than planned restart of nuclear reactors. Japan imported 105 bcm of LNG in 2019, and the volume is set to decline by an estimated 10 bcm/y to 2025 as scheduled nuclear reactors restart and increased renewable capacity reduces the share of gas in power generation.

Korean LNG imports to ease with additions of coal and nuclear

After reaching a peak at 60 bcm in 2018, Korea's LNG imports are expected to weaken in the 2019-25 period with the addition of long-planned nuclear (5.6 GW) and coal-fired (7.3 GW) generation capacity by 2023. Those new plants – with their higher efficiency – will be among the lowest-cost sources of generation, putting pressure on LNG-fuelled power plants. The country's LNG demand is likely to rise in the longer term. The draft version of the government's 9th Basic Plan for Electricity Supply and Demand, which was published in May, recommends the shutdown of 30 ageing coal-fired power plants (15.3 GW) by 2034, of which 24 will be converted to LNG-fired units (12.7 GW). However, the final plan, which will be released later in 2020, is not expected to alter the medium-term outlook, as any change in Korea's generation mix is likely to be gradual rather than immediate.

China to overtake Japan as the top LNG importer, India is closing in on Korea

Evolution of LNG imports in the top four LNG importing countries in 2015-25



Europe’s gas import requirements grow amid declining domestic production

Europe’s import requirements are expected to increase by over 10%, or 45 bcm/y, in the next five years, despite stagnant demand. This is driven by a rapidly declining domestic production in northwest Europe.

Norwegian pipeline supplies to the rest of the continent remain stable. The relative proximity of its production assets – including swing fields such as Troll and Oseberg – allow Norway to play a key role in providing flexible gas supplies to an increasingly import-dependent European market.

Europe’s growing import requirements and progressive expiry of existing long-term supply contracts create market opportunities for both traditional and emerging pipeline suppliers, as well as for LNG.

The start of commercial deliveries via the Trans-Adriatic Pipeline in October 2020 should allow Azeri gas supplies to increase by 8 bcm/y through the forecast period. Pipeline imports from Russia are expected to fluctuate in a range of 170-200 bcm/y, supplied through a combination of long-term contracts, short-term auctions and direct spot sales to the European hubs.

Following a record of 115 bcm of LNG imports in 2019, we expect Europe to continue to play a key role in balancing the global gas market – providing access to its spare regasification capacity, ample storage space and liquid pricing hubs. LNG imports are expected to oscillate in a range of 90-110 bcm/y through the medium term.

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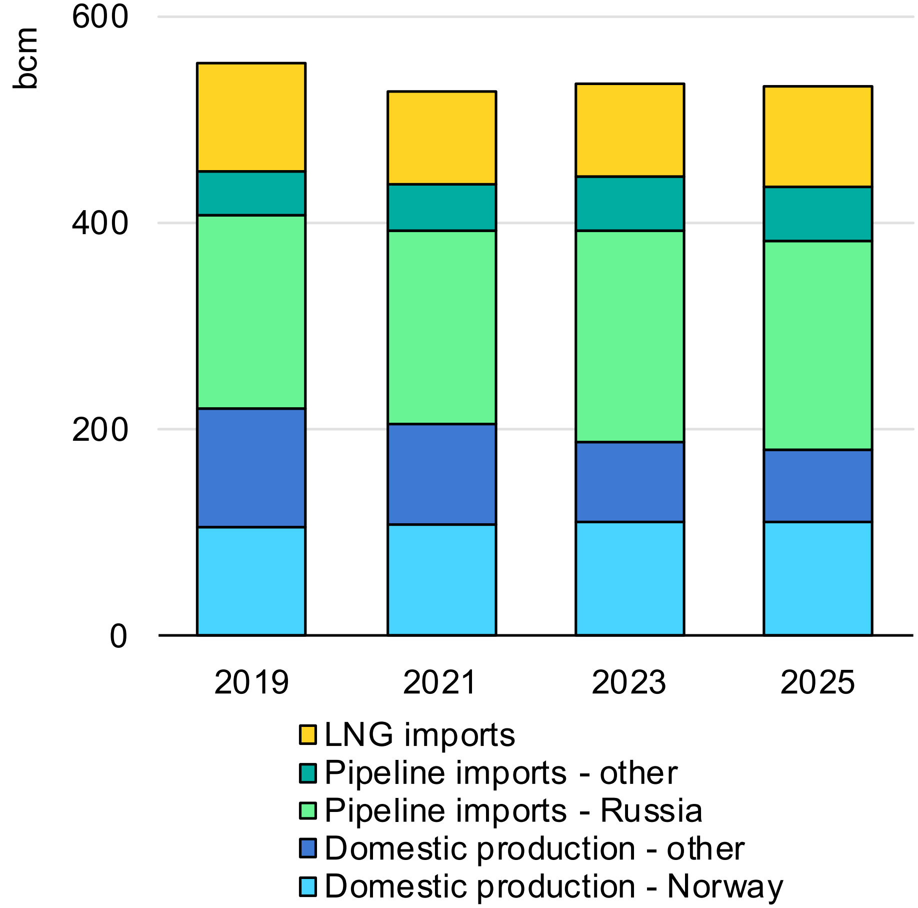
Evolution of European natural gas supply, 2019-25



Annex

Regional and country groupings

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

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

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.[4]

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

Europe – Albania, Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,[5,6] 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,[5,6] Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain and Sweden.

Middle East – Bahrain, the Islamic Republic of Iran, Iraq, Israel,[8] 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.

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

[2] Including Hong Kong.

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

[4] 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.

[5] 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".

[6] 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] 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.

Abbreviations and acronyms

CAGR	compound average growth rate
CME	Chicago Mercantile Exchange (United States)
CNG	compressed natural gas
CQPGX	Chongqing Petroleum and Gas Exchange (China)
EIA	Energy Information Administration (United States)
ENTSOG	European Network of Transmission System Operators for Gas
EPIAS	Enerji Piyasaları İşletme A.Ş (Turkey)
FID	final investment decision
FLNG	floating liquefied natural gas
GDP	gross domestic product
GIE	Gas Infrastructure Europe
HH	Henry Hub
ICIS	Independent Chemical Information Services
IMF	International Monetary Fund
LNG	liquefied natural gas
MENA	Middle East and North Africa
NCG	NetConnect Germany
NDRC	National Development and Reform Commission (China)
NLNG	Nigeria LNG Limited
PPAC	Petroleum Planning & Analysis Cell (India)
TANAP	Trans-Anatolian Natural Gas Pipeline
TAP	Trans-Adriatic Pipeline
TTF	Title Transfer Facility (the Netherlands)
USD	United States dollar
WTI	West Texas Intermediate
y-o-y	year-on-year

Units of measure

bcf	billion cubic feet
bcf/d	billion cubic feet per day
bcm	billion cubic metres
bcm/y	billion cubic metres per year
mcm	million cubic metres
tcm	trillion cubic metres
TWh	terawatt hour

Acknowledgements, contributors and credits

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

Other IEA colleagues provided important contributions including Ali Al Saffar, Mariano Berkenwald, Alessandro Blasi, Louis Chambeau, Joel Couse, Laura Cozzi, Mathilde Daugy, Carlos Fernández Alvarez, Rebecca Gaghen, Tim Gould, Tae-Yoon Kim, Rebecca McKimm, Alan Searl, Siddarth Singh, Aad van Bohemen, László Varró, Daniel Wetzel and Peter Zeniewski.

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

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

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

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

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Typeset in France by IEA – June 2020

Cover design: IEA

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