Gas Market Report, Q3-2022

including *Gas 2022 medium-term forecast to 2025*

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Abstract

Russia's invasion of Ukraine has exacerbated the tightening supply of natural gas underway since mid-2021, further pushing up prices for consumers and leading to fuel switching and demand destruction. It also casts longer-term uncertainty on market prospects for natural gas, especially in developing markets where it was to play a central role in energy transitions.

Natural gas demand is expected to decline in 2022 and remain subdued up to 2025. Europe's surging pursuit of LNG to phase out Russian pipeline supply and limited global LNG export capacity additions raise the risk of prolonged tight markets. Faster development and implementation of clean energy transition policies, especially in mature gas markets, would ease price competition and help emerging markets access supplies that can contribute to short-term improvements in carbon intensity and air quality.

This new issue of the Gas Market Report offers a medium-term forecast and analysis of global gas markets to 2025, as well as a review of recent developments in major regional gas markets during the first half of 2022.

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Gas 2022

Executive summary

The global natural gas market began 2022 with expectations of modest demand growth, but that all changed with Russia's invasion of Ukraine on 24 February. In addition to representing a massive human tragedy, the invasion triggered a major energy supply crisis, with broad repercussions for the global economy and energy outlook.

Russia's invasion of Ukraine redefines global natural gas markets

The high price and tight supply environment that built up during the second half of 2021 further intensified following Russia's invasion of Ukraine, leading to fuel switching and demand destruction. Today's record prices and supply disruptions are damaging the reputation of natural gas as a reliable and affordable energy source, casting uncertainty on its prospects, particularly in developing countries where it had been expected to play a growing role in meeting rising energy demand and energy transition goals.

Global gas consumption is forecast to contract slightly in 2022, with limited growth over the next three years, resulting in a total increase of about 140 bcm between 2021 and 2025. That is less than half the 370 bcm increase seen in the previous five years and well short of the exceptional jump in demand of close to 175 bcm seen in 2021.The Asia Pacific region and the industrial sector are the main engines of growth, accounting for 50% and 60% of the growth to 2025 respectively, although both are subject to downward risks from high prices and potentially lower economic growth.

The European Union's commitment to speed up the phase-out of Russian imports – historically its largest supplier – is transforming Europe's gas market, with repercussions for global gas dynamics. The IEA's 10-Point Plan to Reduce the European Union's Reliance on Russian Natural Gas identified measures to reduce gas imports from Russia by over one-third within a year, and the European Commission's REPowerEU Plan aims at a complete phase-out well before the end of the decade. This report's base case assumes Russian pipeline gas exports to the EU will fall by over 55% between 2021 and 2025; we also consider an accelerated case in which Russian pipeline gas exports to the EU fall by over 75% compared to 2021. The huge uncertainties in this area are amplified by the possibility that Russia will further restrict its export flows unilaterally, as it has done already in 2022 to certain countries.

Tighter for longer?

Europe's surging demand for LNG to replace Russian pipeline gas supply has led to an exceptionally tight global market. Record high European gas prices have turned the continent into a premium market for LNG, drawing deliveries from other regions, and resulting in supply tensions and demand destruction in several markets. Europe's LNG needs are expected to outpace supply capacity additions in 2022, and to account for more than 60% of the net growth in global LNG trade through 2025.

LNG liquefaction capacity additions are set to slow down significantly over the forecast's horizon, raising the risk of prolonged tight market conditions. This results from a combination of curtailed investment decisions during the period of lower oil and gas prices throughout the mid-2010s, and construction delays stemming from Covid-19 lockdowns (additional final investment decisions for LNG liquefaction capacity taken over the last year will come to fruition only after the end of our forecast period). Global LNG trade is forecast to grow at an annual average rate of just under 4% during 2021-2025, well below the 7% rate recorded over the previous five years. Long-distance pipeline trade is set to decline by an average 1.9% per year, principally driven by declining Russian flows to Europe.

The scaling up of low-carbon gas production and methane abatement can help ease supply pressure while reducing emissions. We forecast biomethane production to double through 2025, with further upside potential if additional policy measures are quickly implemented. Low-carbon hydrogen development also continues to gain traction, principally driven by Europe's strong portfolio of projects. The IEA's Global Methane Tracker shows that leaks from oil, gas and coal operations in 2021, if captured and used, could have brought an additional 180 bcm of gas to market – more than the projected consumption increase to 2025.

Slower natural gas demand growth does not mean a faster energy transition

In our base case, global natural gas demand grows at an average of 0.8% per year through 2025, a marked slowdown on the previous edition of this report. However, about four-fifths of the downward revision is the consequences of slower economic activity, and from reduced coal- and oil-to-gas switching as high gas prices delay conversion plans. The joint impact of efficiency and substitution of gas only accounts for one-fifth of the difference. Mature gas markets account collectively for over 55% of the downward revision, with Europe taking a large share of this difference.

Additional energy transition policies would need to be implemented in mature markets to further accelerate the decline of gas consumption. Such measures would also ease pressure on prices globally and help price-sensitive emerging markets access supplies that can contribute to delivering short-term improvements in carbon intensity and air quality by quickening their move away from coal.

Main assumptions behind the forecast

Global GDP registered strong growth of 5.9% in 2021, recovering from the pandemic-induced 3.2% decline of 2020 and with the outlook for the global economy at the start of 2022 being prolonged and robust expansion. But in addition to the humanitarian cost, Russia's invasion of Ukraine in February 2022 creates new challenges for the global economy at a time when most markets around the world had recovered from the economic impacts of the Covid-19 pandemic. The war is exacerbating pre-existing headwinds by exerting further inflationary pressure on commodity prices, causing supply chain disruption and increasing uncertainty.

Our forecast is based on the assumption of average annual GDP growth of 3.5% for the 2022 to 2025 period. GDP growth is assumed to be 3.4% globally in 2022, curtailed by a close to 11% y-o-y drop in Russia's economy affecting the whole Eurasian region's performance (down 7%). Other regions see their growth rates more or less halved compared to 2021. Europe is one of the most affected regions and sees its economic growth drop by close to two-thirds, from 6% in 2021 to an anticipated 2.3% in 2022. China's economy, under pressure from the combined challenges of slower growth in activity, spiralling commodity prices and the resurgence of Covid-19, is assumed to grow at slightly above 4.8% in 2022.

Global GDP growth is expected to progressively increase in the following three years, oscillating around 3.6-3.7% during 2023-2025.

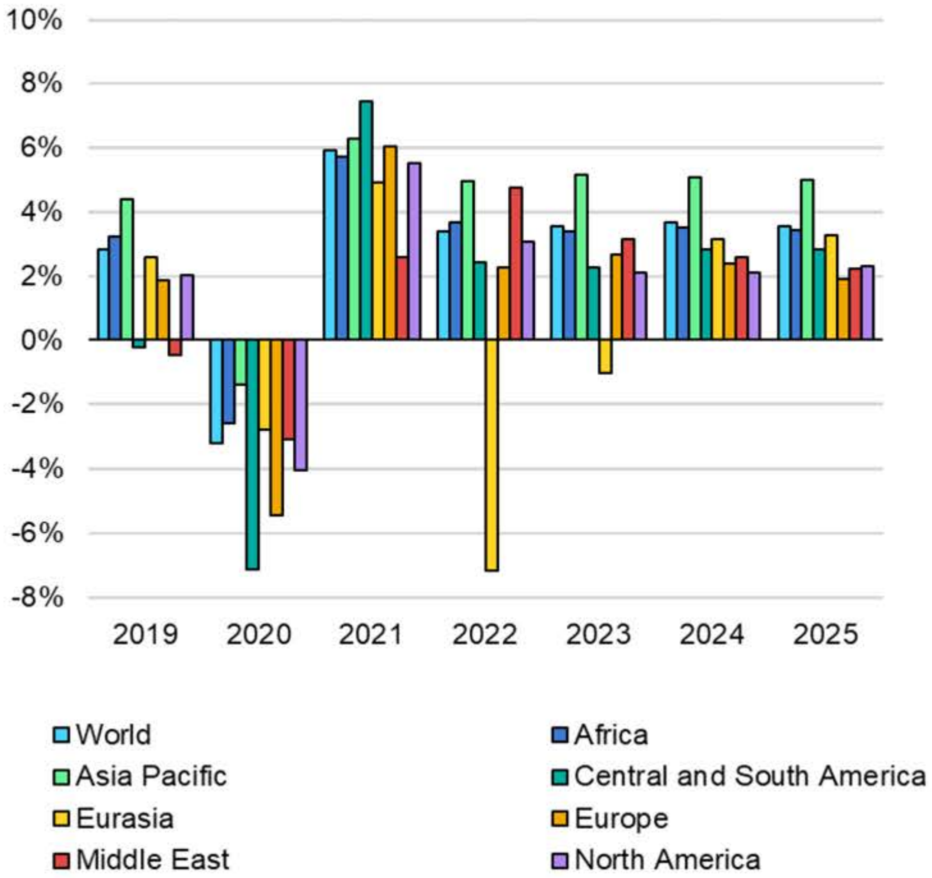
Levels of uncertainty are very high and principally hinge on the evolution of the war. Risks to the macro-economic outlook, in terms of activity and inflation, weigh on both natural gas demand dynamics and supply availability and competitiveness. The evolution of the Covid-19 health situation remains another major risk factor, specifically the appearance and spread of new variants, with higher risk of contagion and increased resistance to vaccines. The return of lockdown measures in China early in 2022 is an illustration of this risk, although a return to the widespread lockdowns seen in 2020 looks less likely.

Natural gas consumption is particularly sensitive to the weather, notably temperature; this forecast is based on the assumption of average winter conditions for the forthcoming heating seasons.

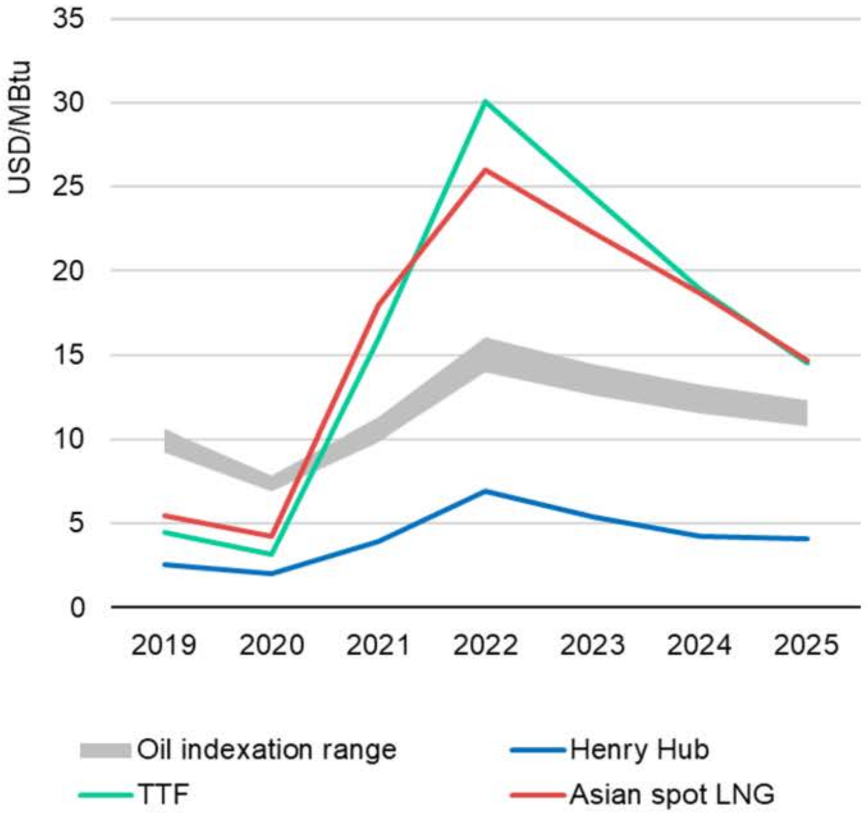
We use external energy price assumptions in our forecast, based on the average futures' market prices observed during the month of April 2022.

Economic activity and energy price assumptions

GDP growth assumptions, global and regional, 2019-2025



Natural gas price assumptions, 2019-2025



Sources: IEA analysis based on IMF (2022), World Economic Outlook; Oxford Economics (2022), Economic Forecasts (subscription required); CME (2022), Henry Hub Natural Gas Futures Quotes; Dutch TTF Natural Gas Month Futures Settlements; EIA (2022), Henry Hub Natural Gas Spot Price; ICE (2022), JKM-Japan Korea Marker LNG Future; ICIS (2022), ICIS LNG Edge (subscription required); Powernext (2022), Spot Market Data.

Phasing out Russian gas: An accelerated case

Russian gas in the European Union: A state of interdependency

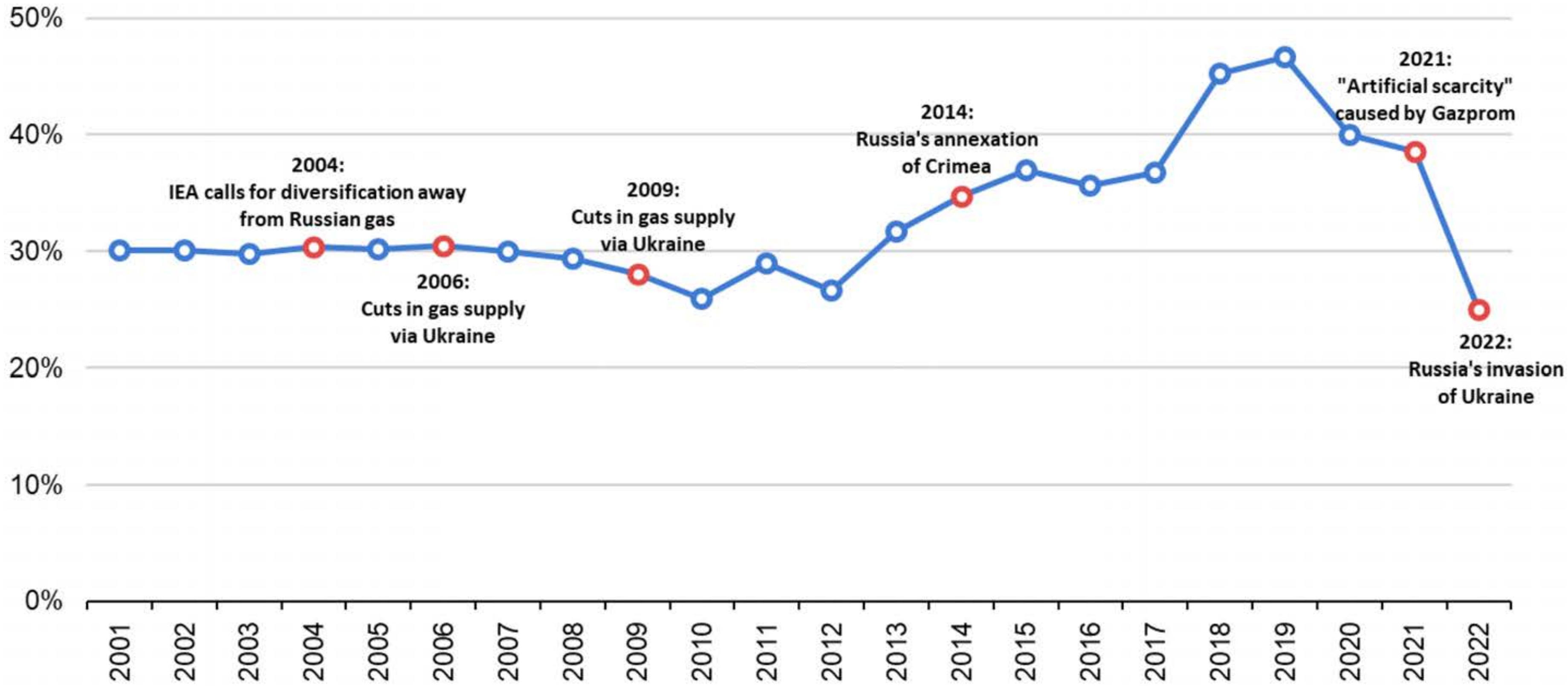
Europe's dependence on energy imported from the Russia Federation (hereafter "Russia") has been thrown into sharp relief by Russia's invasion of Ukraine. The European Union's commitment in the Versailles Declaration to phase out Russian fossil fuel imports "as soon as possible" is set to transform Europe's energy and gas markets in the years to come, with implications for global trade and market dynamics.

The reliance of EU states on Russian gas has increased steadily over the past decade. EU natural gas consumption stayed broadly flat over this period, but production has fallen by two-thirds since 2010 and the gap has been filled by rising imports. The IEA was among the first to raise concerns about this rising dependence. The reliance on Russian gas imports increased despite rising tensions and crises, including the supply cuts in January 2009 and Russia's annexation of Crimea in 2014. The share of Russian gas (including LNG) meeting total EU demand rose from 30% in 2009 to 47% in 2019. The strong LNG inflow in 2020, amid global oversupply, depressed the share of Russian gas to around 40%. It stayed at a similar level in 2021, driven by Gazprom's own strategy of reducing short-term sales to the bloc, despite spare supply capacity being available and high revenue potential on the export markets. The artificial scarcity created by Gazprom tightened the EU gas market further, drove up prices to record levels and led to several price spikes during the 2021/22 heating season. Despite lower pipeline supplies, the European Union accounted for 60% of Russia's gas exports and around 70% of its gas export revenues in 2021, highlighting strong interdependency. The drop in Russian pipeline supplies continued in H1 2022, falling by 30% y-o-y. Gazprom's unilateral supply cuts to several EU member states in Q2 further contributed to lower deliveries and heightened market uncertainty. The company sharply reduced gas supplies via Nord Stream in the second half of June. Assuming that flow patterns remain unchanged, EU imports of Russian pipeline gas are set to decline by over 45% in 2022 to below 80 bcm, while Russian LNG inflows are expected to be sustained at above last year's level. The share of Russian gas in EU gas demand is expected to drop to just 25% in 2022 – its lowest level in more than two decades.

In our forecast, Russian pipeline supplies to the European Union decline by over 55% by 2025 compared to their 2021 levels, with Russia meeting 20% of EU gas demand. This is based on the gradual expiry of Gazprom's long-term supply contracts and the assumption that the sanctions imposed by Russia will restrict the use of the YAMAL–Europe pipeline and prevent gas deliveries to Gazprom Germania's daughter companies over the medium term. Available measures could accelerate the phase-out of Russian gas, putting it on track to drop to zero by 2027. The current forecast is subject to unusually large uncertainty due to Russia's unpredictable behaviour. A complete cut of Russian gas flows cannot be excluded, which would overwrite the current outlook.

The European Union's reliance on Russian gas increased steadily over the last decade

Share of EU gas demand met by Russian supply, 2001-2022



Sources: IEA analysis based on IEA Energy Data Centre and various external sources.

Phase-out commitments are building up across the European Union

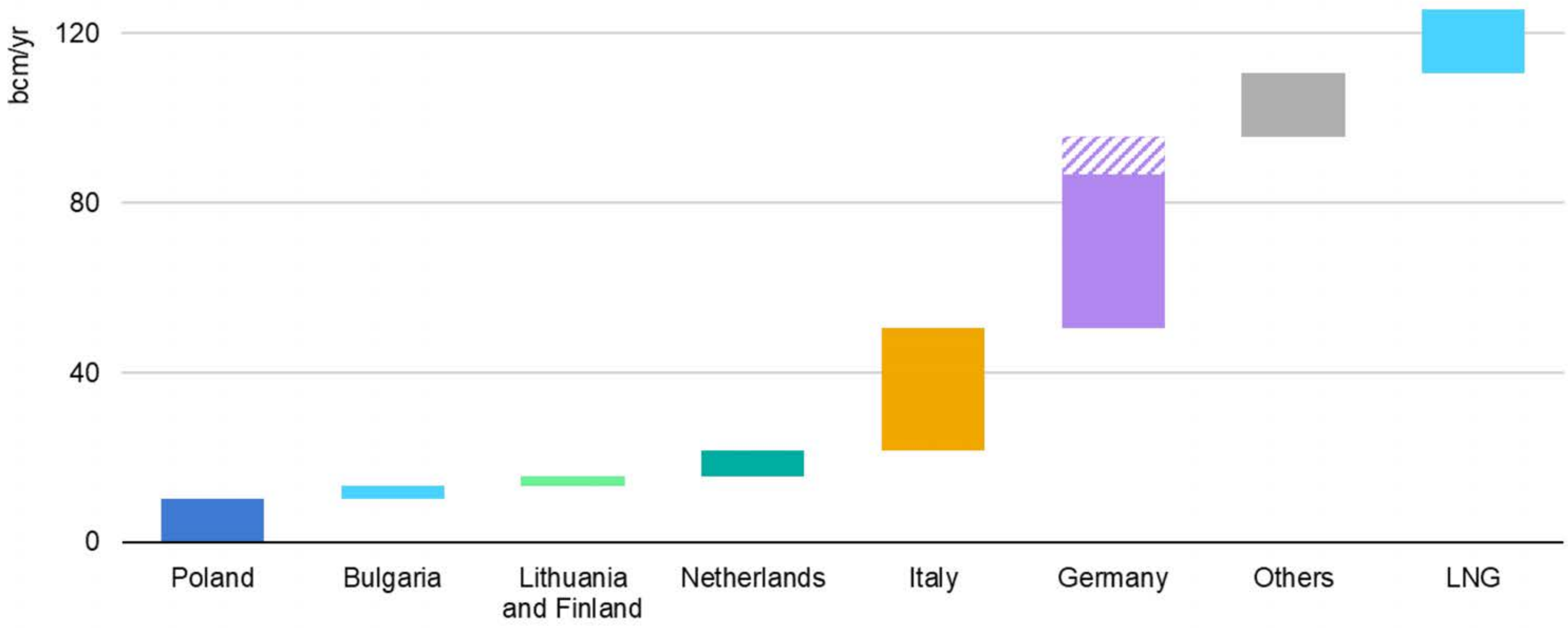
Following Russia's invasion of Ukraine, the European Commission's REPowerEU Communication outlined a plan to phase out dependence on Russian fossil fuels well before the end of this decade. In the Versailles Declaration of 11 March EU leaders committed to phasing out Russian fossil fuel imports "as soon as possible". The European Union introduced a full embargo on Russian coal in April, taking effect from August. A partial embargo on oil and oil products was adopted on 6 June to cut around 90% of oil imports from Russia by the end of the year. Building on the strong commitment expressed in the Versailles Declaration, the European Commission published on 18 May the REPowerEU Plan detailing the measures and investments required to reduce fossil fuel dependence on Russia to zero by 2027.

A number of EU member states are already moving ahead with phasing out Russian gas. Lithuania ceased Russian gas imports at the beginning of April. Estonia's and Latvia's imports of Russian gas also dropped to zero at the start of April. Bulgaria, the Netherlands and Poland all announced that they do not intend to renew long-term contracts with Gazprom, which are coming to an end this year. This is well aligned with the IEA 10-Point Plan to Reduce the European Union's Reliance on Russian Natural Gas, which identified the expiry of long-term Russian contracts as a clear near-term opportunity to significantly diversify gas supplies. Moreover, Gazprom abruptly cut gas supplies to both Bulgaria and Poland on 27 April, to Finland on 21 May and to Denmark and the Netherlands on 1 June following their refusal to adhere to the rouble payment system unilaterally introduced by Russia. Gazprom's supply cuts effectively ensured the phase-out of Russian gas in those countries. Germany – Russia's largest gas importer among EU countries – aims to reduce the share of Russian gas in its gas supply to 10% by the summer of 2024. In absolute terms, this would translate into a decline in Russian gas imports of over 35 bcm/yr based on 2021 levels. According to RWE, Russian gas could be fully phased out by 2025. Italy intends to phase out its dependence on Russian gas by the second half of 2024, compared with the 29 bcm imported in 2021. Austria and France both aim to phase out their Russian gas imports by 2027. Rerouting Russian LNG away from EU markets would further decrease Russian gas imports by 15 bcm compared with 2021.

Altogether, Russian gas supplies to the European Union could fall by over 120 bcm/yr from their 2021 levels to just 30 bcm by 2025. This would effectively reduce Russia's share of total EU gas demand to below10%, putting it on a pathway to zero by 2027. An accelerated and orderly phase-out of Russian gas would require the implementation of both supply- and demand-side measures as soon as possible.

Several EU member countries are aiming to accelerate the phase-out of Russian gas

Volumetric impact of phase-out commitments/statements and rerouting of Russian LNG imports, EU countries, 2025 vs 2021



Note: Comments from private companies suggest that Germany could completely phase out Russian gas by 2025 (marked as hatched area in the figure).
Sources: IEA analysis based on various public statements.

Measures to implement an accelerated and orderly phase-out of Russian gas

An accelerated and orderly phase-out of Russian gas, reflecting the announcements and statements of EU member states, will require a combination of short-term measures on both the supply and demand sides. They should be fully aligned with EU climate ambitions and carefully crafted to reinforce and not undermine the energy supply security of the European Union.

Reinforcing gas infrastructure and supply diversity are key to reducing Russian gas imports in our base case

The global LNG market provides the European Union with the greatest near-term potential to diversify its gas supplies. In our base case – where Russian pipeline supplies to the European Union decline by over 55% by 2025 compared to their 2021 levels – EU LNG imports are expected to hover at around 120 bcm/yr between 2022 and 2025, or 55% higher than their 2021 levels. While EU regasification capacity currently stands at over 160 bcm/yr, it is unevenly distributed with over 40% located in Iberia, which is poorly connected to the rest of the continent. Enabling higher LNG inflow would require additional interconnectors and the scale-up of importing capacity in certain markets. The REPowerEU Plan foresees EUR 10 billion of investment in new LNG infrastructure and pipeline corridors during the 2022-2030 period.

Floating storage and regasification units (FSRUs) have been in the spotlight since EU countries doubled down on their diversification efforts in the aftermath of Russia's invasion of Ukraine. FSRUs – when available on the market – have considerably shorter lead times compared with onshore terminals, and do not have the same lock-in risks (as they can be chartered for shorter periods). FSRUs chartered by EU companies (potentially facilitated by state-backed risk-sharing mechanisms) could add over 60 bcm/yr of regasification capacity by 2025. In addition, several onshore terminals are under consideration, currently undergoing market testing to assess levels of interest. It will be crucial to provide landlocked Central and Eastern European countries with access to the LNG, including via the joint use of LNG terminals located in neighbouring countries. The reconfiguration of EU gas flows is expected to affect the utilisation levels of existing interconnectors and could lead to the reassessment of additional infrastructure requirements. With careful investment planning, this infrastructure could be repurposed to supply hydrogen and/or ammonia in the future. Non-Russian pipeline imports increase by close to 20 bcm/yr from their 2021 levels during the forecast period in our base case.

An accelerated phase-out of Russian gas would not necessarily entail higher LNG and gas imports over the medium term

Considering the limited additions to global LNG liquefaction capacity over the 2022-2025 period, any increase in EU LNG imports beyond the 120 bcm/yr foreseen in our base case would further tighten the global LNG market, with negative repercussions for more price-sensitive importing regions. This would also provide additional upward pressure on European gas prices and contribute to additional revenues for Russia. In this context, an accelerated phase-out of Russian gas should primarily focus on reducing gas demand and scaling up domestically produced low-carbon gases.

More rapid deployment of renewables, heat pumps and behavioural change can further reduce the call on Russian gas

As highlighted in the IEA Renewable Energy Market Update 2022, wind and solar PV expansion in the European Union has significant potential to reduce the bloc's dependence on Russian gas for power generation. Fast-tracking the deployment of renewable capacity additions, including simplifying and speeding up administrative procedures, would alone reduce EU gas-to-power demand by over 10% in 2025 compared to our base case. Energy efficiency measures and a more rapid deployment of heat pumps could reduce gas use in the residential and commercial sectors by 37 bcm/yr by 2030 according to the REPowerEU Plan. Considering the lead time of these projects, the accelerated case assumes a reduction of 10 bcm/yr by 2025, resulting from the quicker adoption of heat pumps and energy efficiency programmes. Behavioural change, including the reduction of thermostats by 1°C, could save around 10 bcm of gas per year. Nevertheless, weather patterns – particularly a cold winter – could erode these savings relative to average weather conditions.

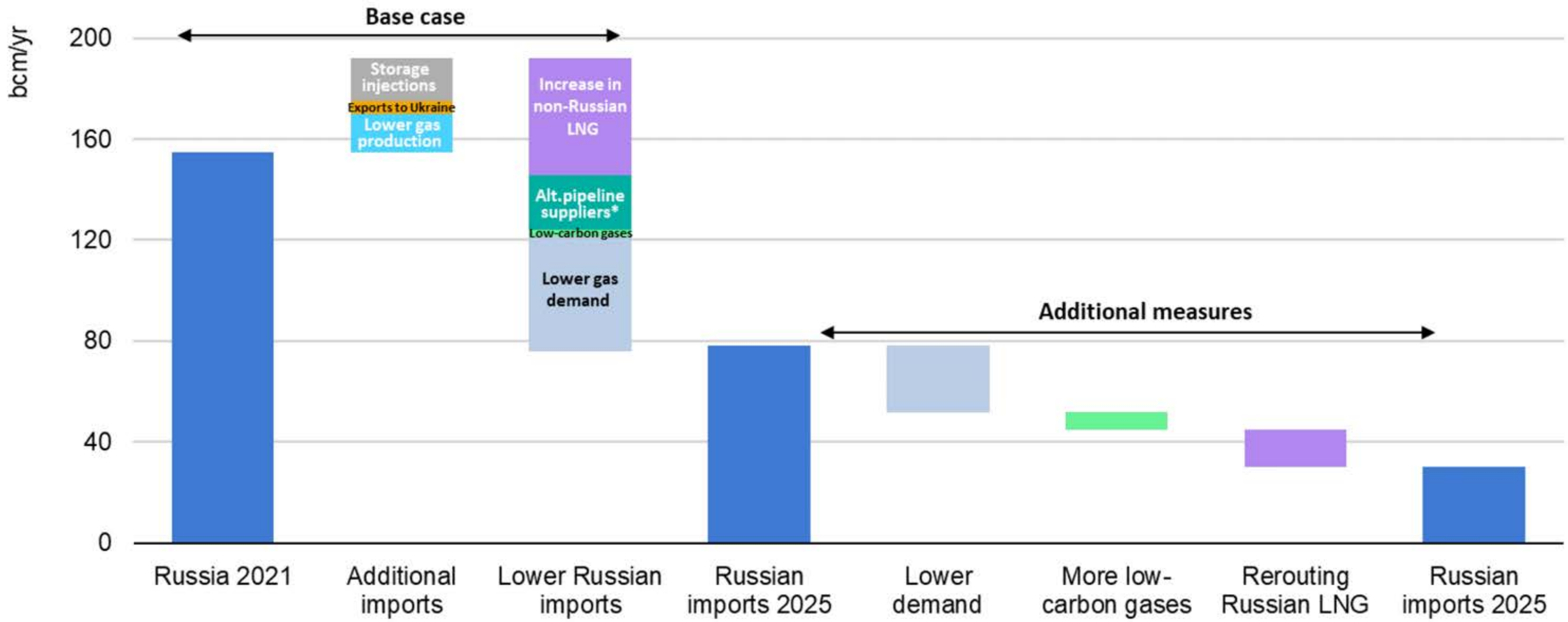
Scaling up domestically sourced low-carbon gases offers medium-term benefits

Domestically sourced low-carbon gases can play a crucial role in reducing EU dependence on fossil fuel imports in the medium term The REPowerEU Plan foresees biomethane production ramping up to 35 bcm/yr and low-carbon hydrogen to 10 Mt/yr by 2030. Considering the lead times of biomethane and low-carbon hydrogen projects, this forecast assumes that low-carbon gases could replace between 10-15 bcm/yr of natural gas demand by 2025. Boosting biomethane production in the short term would require increasing the utilisation rates of the existing upgrade facilities, shortening permitting processes and promoting biomethane pooling initiatives. Accelerating hydrogen deployment could have a sizeable effect in the second half of the decade. Based on projects under development, low-carbon hydrogen production could reach 2.5 Mt/yr by 2025 – enough to replace 4-8 bcm/yr of gas.

Altogether these measures could reduce Russian gas imports to 30 bcm/yr by 2025. Most of the remaining demand for Russian gas would be concentrated in the landlocked Central and Eastern European countries, which have historically been the most dependent on Russian gas. Considering the strong variability of gas demand, including year-on-year fluctuations depending on weather conditions, improved security of gas supply will be central to ensuring an orderly phase-out of Russian gas in the medium term, including via mandatory storage fill levels, spare regasification capacity and better interconnectivity.

A combination of supply- and demand-side measures will be necessary to phase out Russian gas in an orderly manner

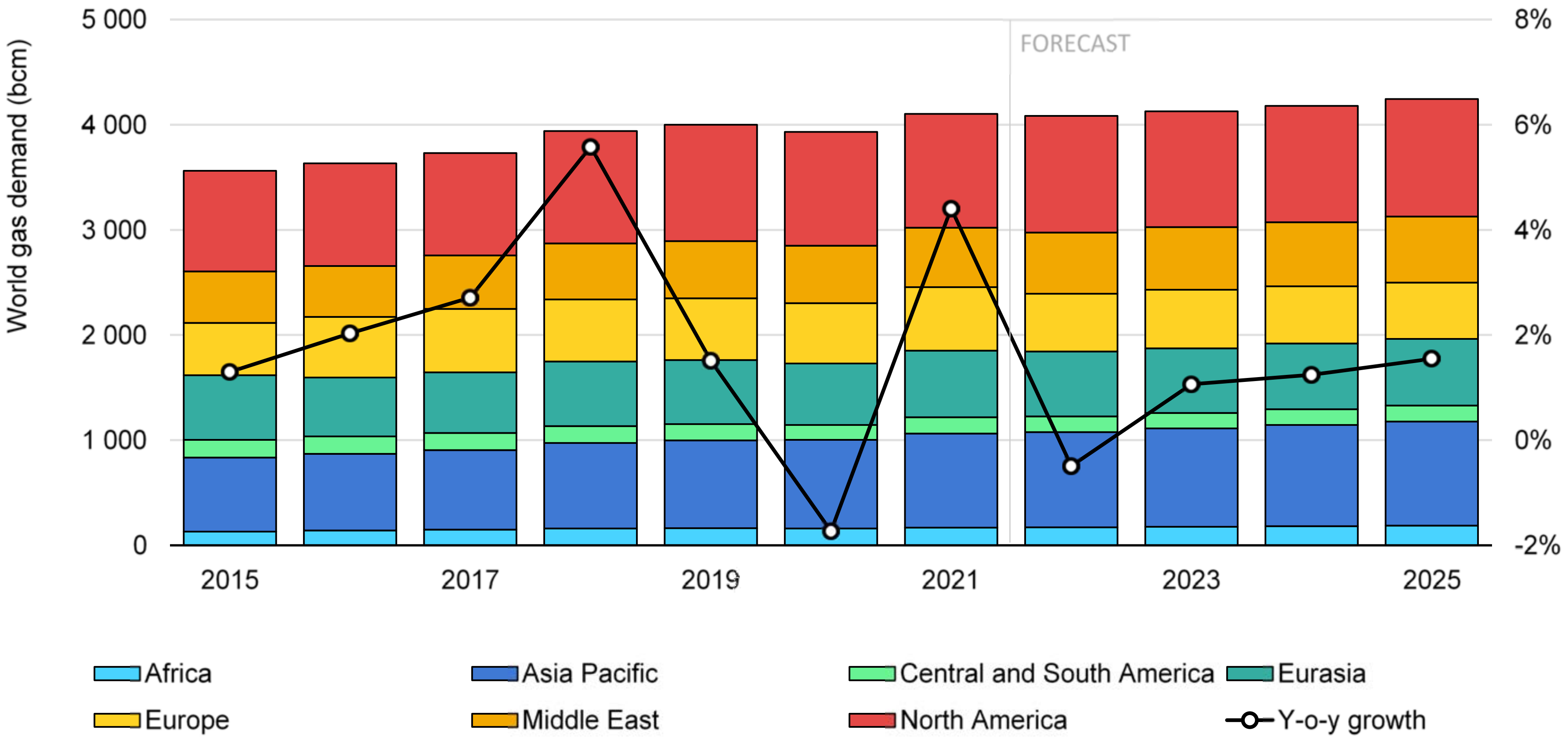
Outlook for Russian gas imports into the European Union, 2025 vs 2021



Demand

Global gas demand growth dips in 2022 after a strong 2021, with a modest increase expected in the following years

Global natural gas demand by region, 2015-2025



Short-term gas demand growth comes to a halt, while longer-term uncertainty limits growth potential in the following years

Global natural gas consumption is expected to grow at an annual average rate of 0.8% from 2022 to 2025, reaching around 4 240 bcm by the end of this forecast, a limited 3.4% increase or close to 140 bcm compared with 2021. This is a strong downward revision of our forecast in last year's edition, where we anticipated an increase of close to 210 bcm for 2021 to 2024 (or a compound average growth rate [CAGR] of 1.7%), against around 75 bcm (or a CAGR of 0.6%) for the same period in this year's edition.

The current high price and tight supply environment that built up in the second half of 2021, and further intensified after Russia's invasion of Ukraine in February 2022, is putting natural gas demand under strong pressure. It is expected to result in slightly negative growth for 2022, followed by meagre consumption increases in the following years. Thus, global gas demand declines by 0.5% in 2022 and then grows progressively over the following years to reach 1.5% in 2025.

Gas consumption in the industrial sector remains the strongest component in global growth, and accounts for about 60% of the total increase in gas demand during the 2021 to 2025 period. Uncertainty remains high, however, as industrial activity is particularly vulnerable to high energy and raw material prices.

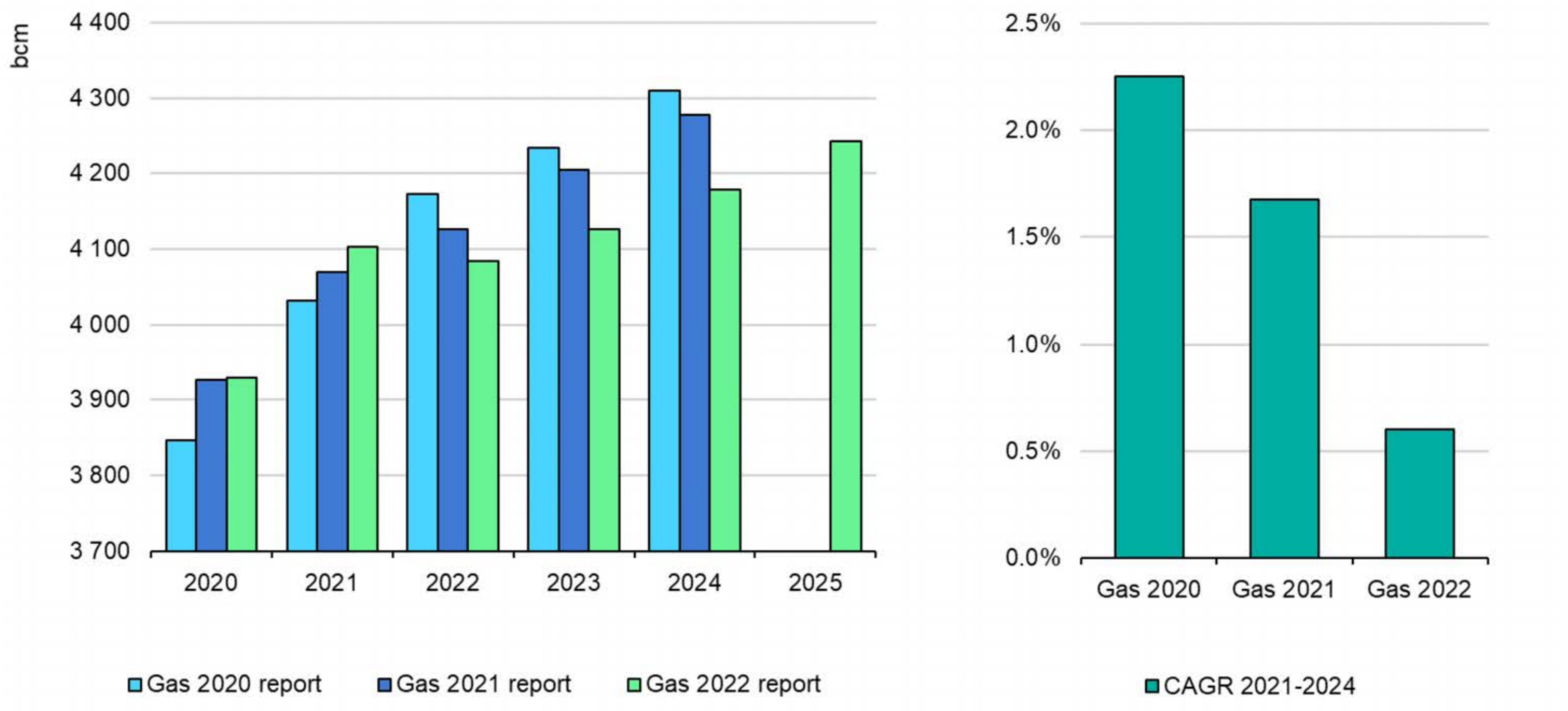
Demand growth is geographically concentrated, with two regions responsible for close to 80% of the increase. The Asia Pacific region as a whole account for almost half of global gas consumption gains to 2025, followed by the Middle East at one-third. North America and Africa provide more modest contributions, while gas consumption is expected to broadly stagnate in Central and South America and Eurasia, and to decline more significantly in Europe.

The risks to this forecast, in the form of lower economic activity and resulting natural gas consumption, are heavily dependent on the evolution of the war. Beyond the threat of further potential gas supply disruptions, uncertainty relating to additional problems in commodity and manufacturing supply chains and further inflationary pressure on commodities could result in a situation of stagflation (low growth and rising prices). The Covid-19 situation remains a risk factor, as shown in the first half of 2022 with the return of lockdowns in the People's Republic of China (hereafter "China").

Our forecast's lower gas demand growth compared to last year does not guarantee an accelerated transition to net zero emissions, as the bulk of the revision comes from lower GDP and fuel switching rather than by faster gas-to-electricity conversion and efficiency gains.

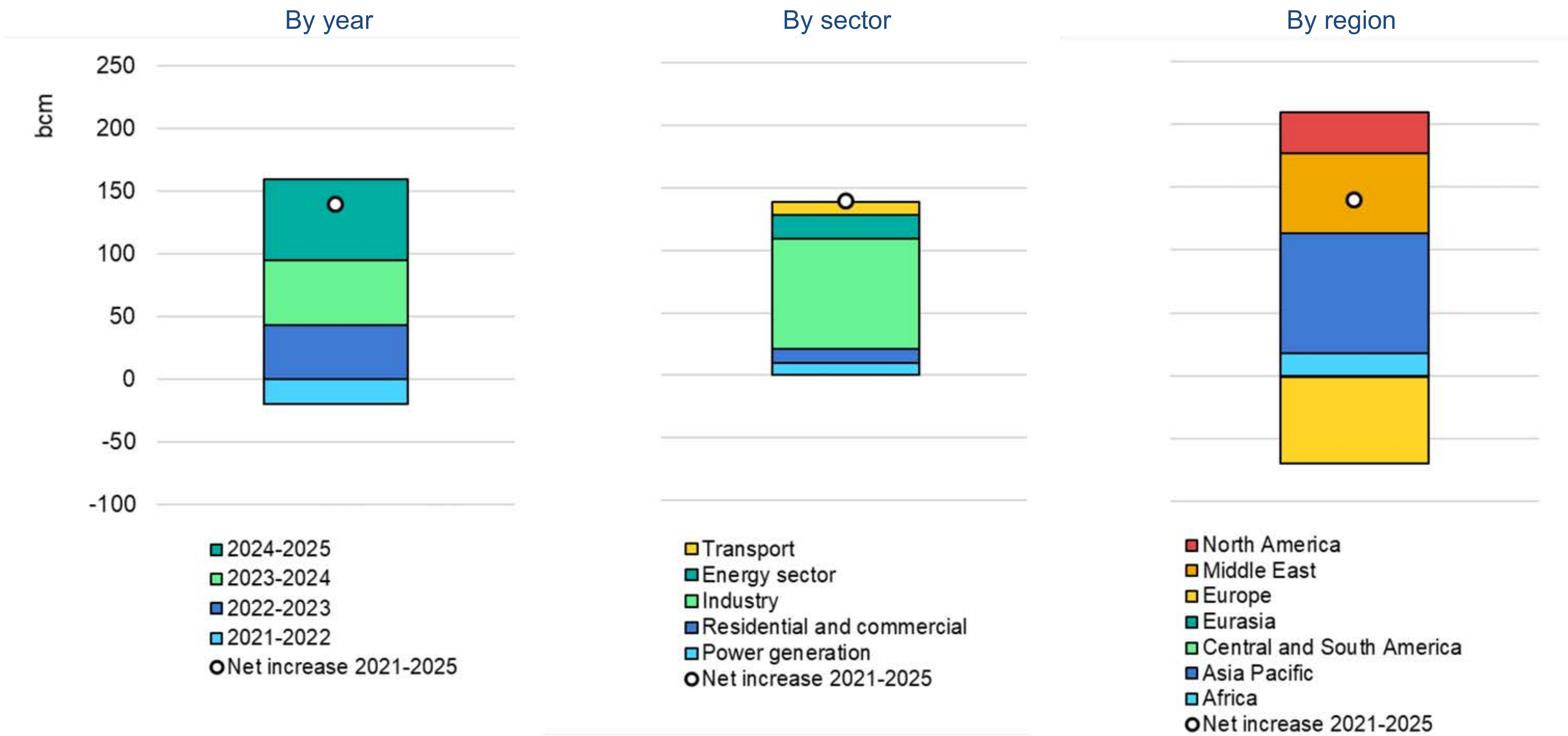
Current market tensions and medium-term uncertainty result in a 60% cut in our forecast of average growth in gas demand to 2024, compared to our previous outlook

Evolution of global gas demand forecasts in the three latest issues of the IEA medium-term gas report, 2020-2025, and CAGR, 2021-2024



Lower global gas growth potential further highlights the outsize role played by Asia and the industrial sector in the medium-term consumption increase

Breakdown of forecast growth in global natural gas demand, 2021-2025



Natural gas growth is slower than previously expected, but this does not guarantee an acceleration in clean energy transitions

This forecast shows a sizeable downward adjustment to medium-term gas demand growth compared to our previous 2021 edition. We now expect less than 2% growth (or about 75 bcm) for the 2021 to 2024 period compared to the previous 5% (or 210 bcm). However, such a revision does not necessarily imply that gas consumption is on course to achieving its transition to net zero emissions.

The consequences of Russia's invasion of Ukraine on global gas prices and supply tensions, as well as its repercussions on the longer-term economic outlook, are reshaping the outlook for natural gas. The European Union has responded with the acceleration of its supply diversification and energy transition policies in the framework within the REPowerEU programme, while high gas prices and the risk of supply shortages are pushing other natural gas importing markets to adopt similar policy measures. We have included these considerations in our forecast of medium-term gas demand growth, but do not speculate on potential policy measures yet to be announced at the time of writing.

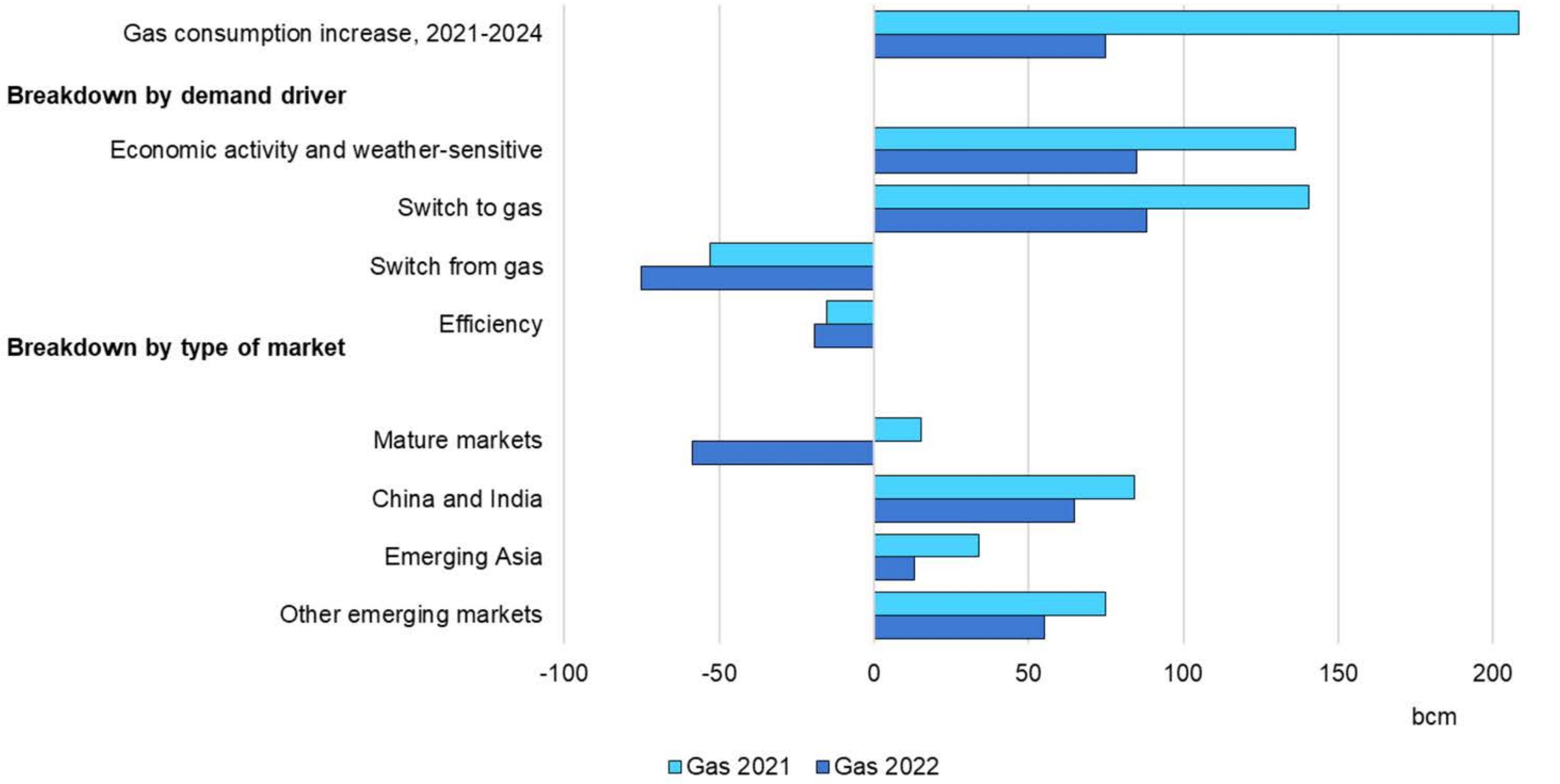
As regards demand drivers, the large majority of this revision is related to price- and GDP-related impacts. About 40% of the adjustment from last year's forecast is from the consequences of a downgraded economic environment and temperature-related factors – assuming average temperature conditions compared to 2021's higher demand from a combination of cold winter and dry summer. Another 40% relates to a slowdown in switching to gas from other fossil fuels, as high gas prices delay conversion plans and investment or limits access to gas supply for newly built or converted infrastructure. The joint impact of the substitution of gas with other energy sources and efficiency factors only account for 20% of the difference.

As for the regional breakdown, mature markets across Asia, Eurasia, Europe and North America account for over 55% of the demand revision, with the bulk taking place in Europe. China and India jointly account for close to 15%, and the remaining 30% is covered by emerging markets.

Additional energy transition policies would need to be implemented in the coming years to accelerate the decline in gas use among mature markets, to reduce the pressure on supply and prices, and to facilitate access to more price-sensitive emerging and developing economies, where natural gas can help to deliver shorter-term improvements in emissions and air quality and thus contribute to these countries' transitions to cleaner energy supply.

Gas demand growth to 2024 shrinks by 60% compared to the previous forecast

Global gas consumption forecast in the two latest issues of the IEA medium-term gas report, 2021-2024



The industrial sector plays the lead role in medium-term growth

The strong rebound in natural gas consumption in 2021 was supported by economic recovery and a series of temperature-driven factors, leading to positive contributions from all sectors. The anticipated slight contraction in demand for 2022 is driven by lower gas use for power generation and in the residential and commercial sectors, partly counterbalanced by limited increases in other sectors. Net gas demand increases from 2023 are principally driven by the industrial sector, but are exposed to downward risks associated with high prices and potential lower economic growth.

Gas use in the **industrial sector** is by far the largest contributor to growth, in spite of its sensitivity to high prices in markets where prices are not regulated. It is expected to grow at an average annual rate of 2% and to account for about 60% of the total increase during the 2021 to 2025 period. China alone comprises close to 40% of the global net increase – partly supported by the government-mandated replacement of small coal-fired industrial boilers to improve air quality, and partly by the growth in industrial activity, which is more at risk of headwinds from high gas prices and economic activity in both the domestic and export markets. Countries in the Middle East and North Africa (MENA) together account for over 30% of the global increase, with more limited exposure to supply and price risk. North America, India, emerging Asia and sub-Saharan Africa provide more modest contributions, while Eurasia and Europe are expected to see declines.

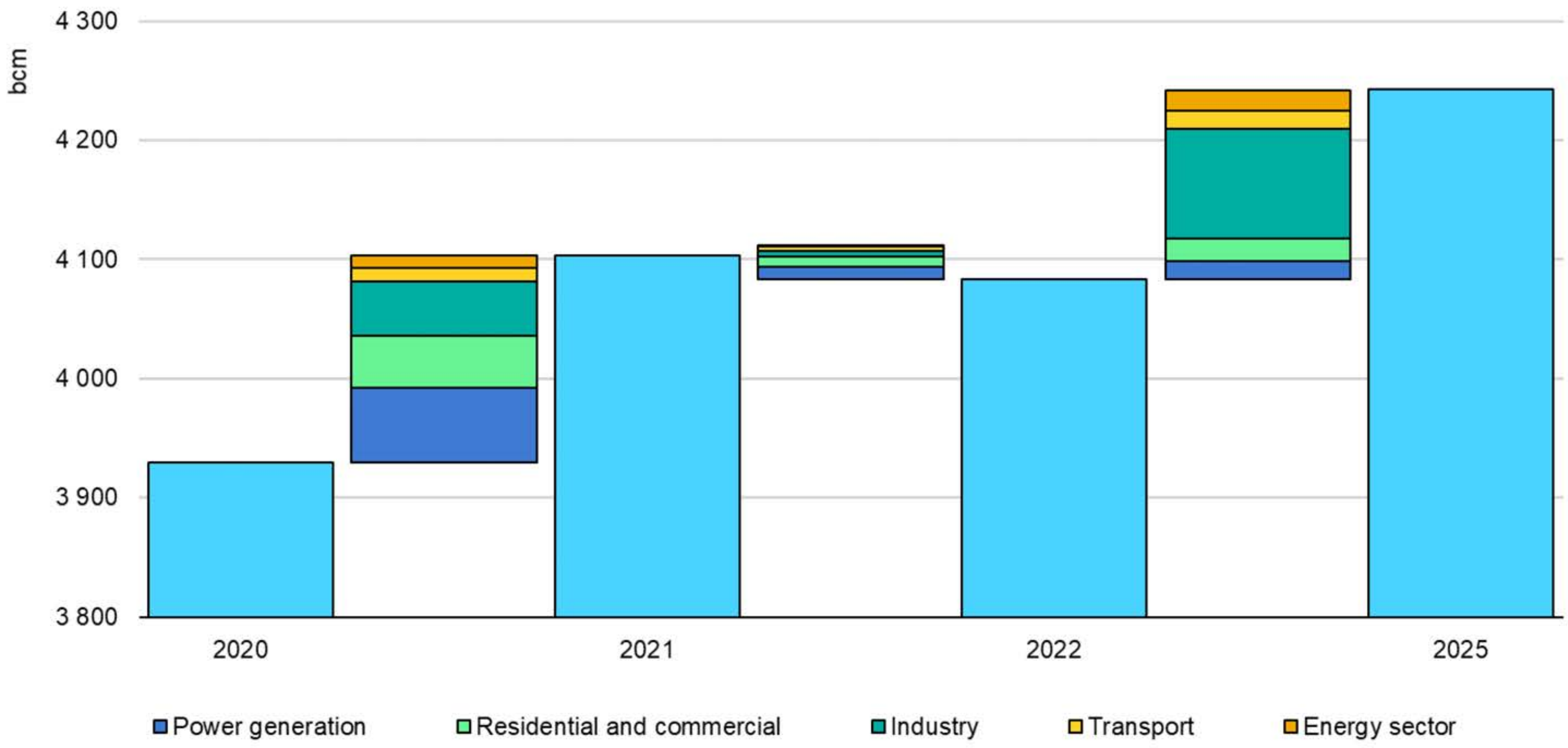
The **power generation** sector was the largest single contributor to gas demand growth in 2021 with an estimated 36% share, but sees its net contribution shrink to less than 10% during 2021-2025 (with average annual growth of 0.2%) on a combination of high gas prices, lower electricity growth and renewable capacity additions. Net gas exporters such as North America and MENA still see some increase, Asia is more balanced between reductions in mature markets and price-sensitive growth potential in emerging markets, while Europe’s gas for power consumption declines by a sharp 17% due to its accelerated transition to limit its exposure to gas imports.

Consumption in the **residential and commercial** sectors bounced back in 2021, principally due to higher heating demand in response to colder than average temperatures. We forecast moderate average annual growth of 0.3%. Retail consumption is principally driven by planned distribution network expansion in China, Iran and India, while heating demand is expected to decline in all mature markets on the assumption of a return to average temperature conditions and efficiency gains.

The **energy** and **transport** sectors account for about 25% of the growth, the former supported by the increase in gas production capacity (the main contributor being MENA), and the latter by plans for further gas use in transport in China, India and the Middle East.

The industrial sector accounts for over half of global gas consumption growth over 2022-2025

Sectoral breakdown of global gas demand growth, 2020-2025



Gas demand for non-energy uses – tension in global fertiliser markets

Natural gas is the main feedstock for the production of ammonia via gas-based steam reforming, currently accounting for over 70% of global ammonia output – most of the remainder being obtained by coal gasification, principally in China. An estimated 170 bcm of gas is used each year for ammonia production, close to one-fifth of the industrial sector's total gas use. The majority of ammonia (about 70%) is used to produce nitrogen-based fertilisers, such as urea. It is also used to make ammonium nitrate, sulphates and phosphates.

Natural gas consumption in the ammonia industry grew at an average annual rate of 2.2% during the period 2005-2020. It accelerated after 2015 to 2.6% with the development of new ammonia production capacity in large natural gas producing countries such as the United States, Russia, Egypt, Saudi Arabia, Iran and Nigeria. Tensions in natural gas supply since 2021 have affected ammonia and derived products, including urea, resulting in record price levels for fertilisers. Urea prices more than tripled compared with pre-Covid market conditions, from USD 215/t in January 2020 to USD 708/t in May 2022, and reached a peak of USD 925/t in April 2022. According to the International Fertilizer Association (IFA) Short-Term Fertilizer Outlook 2021-2022, ammonia production fell by an estimated 3% in 2021 due to rising costs and supply constraints, the same trend applying to urea.

High natural gas prices since mid-2021 have led to ammonia and urea production curtailment and temporary plant closures in Europe. Russia and China, the world's two largest exporters of nitrogen-based fertilisers, restricted exports in late 2021 to maintain supplies and food security for their domestic markets. Energy supply constraints in China further hampered its fertiliser industry, as electricity shortages in southwest China during the late summer and autumn led to production cuts for energy-intensive industries. This combination of high natural gas prices and export restrictions has led to price and supply tensions in nitrogen-based fertiliser and specialty chemical markets, for example affecting diesel exhaust fluids (DEF, commercially known as AdBlue), which is widely used in diesel engines to reduce polluting gas emissions by breaking down nitrogen oxides into nitrogen and water. DEF tensions were particularly evident in late 2021 in several Asia Pacific markets such as Australia and Korea as a result of China's urea export limitations.

Urea supply constraints partially eased in early 2022, then surged to new highs with Russia's invasion of Ukraine in late February. Urea prices grew by 25% between February and April 2022, then declined in May to close to their February level. Sanctions on Russia – a major exporter of nitrogen products such as ammonia and urea, and other primary nutrients such as potash and phosphate – have disrupted fertiliser trade flows and led to further tensions on fears of shortages. Russia is a major supplier to EU countries, accounting for about 26% of their urea and phosphate imports, and 21% of their potash imports. Brazil, a major agricultural producer and the world's second largest exporter of grain, is also the largest importer of fertilisers and relies on Russia for 46% of its potash, 20% of its urea and 13% of its phosphate imports.

India is another large consumer of fertilisers relying on imports, which account for about 25% of its urea needs and almost all of its phosphates and potash. The fertiliser industry is India's largest consumer of natural gas, accounting for 30% of its total consumption in 2021. Two-thirds of the fertiliser industry's gas needs are met by LNG imports. The government of India reformed its urea subsidy policy in 2015 with the New Urea Policy in order to maximise domestic production and attain self-sufficiency; it introduced a single natural gas reference price for feedstock from domestic and imported sources. The growing share of (more expensive) imported LNG in India's overall supply to industry in recent years has driven up its subsidy budget to allow prices to remain fixed, with the subsidy covering about 20% of production costs.

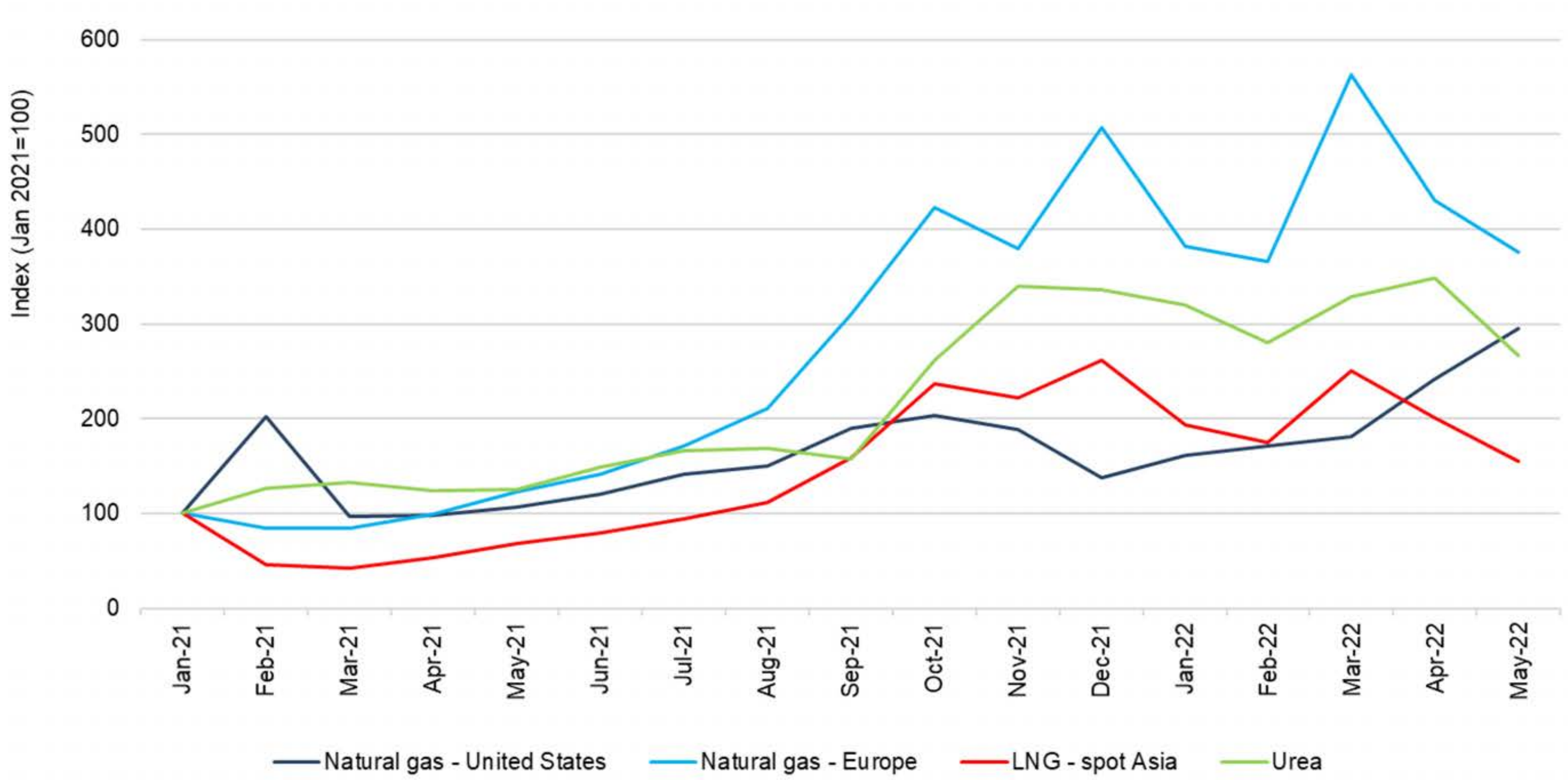
India is a world leader in developing new ammonia and urea production capacity to meet its objective of becoming self-reliant in the next three years. Two major plant conversions to natural gas have been inaugurated recently: one in Gorakhpur in December 2021 and the other in Ramagundam in May 2022. Their production capacity is 2 200 t/d and 3 850 t/d of ammonia respectively, both running on natural gas. Other major ammonia and urea capacity developments include Nigeria with the ramping up of the 2 900 t/d Dangote ammonia and urea plant after inauguration in March 2022, Brunei with the start of the 3 900 t/d BFI urea plant in January 2022, and Russia with several export-driven projects under development, subject to greater uncertainty in the current context.

This forecast expects slower growth in natural gas consumption in the ammonia industry, from an average annual rate of 2.6% in 2015-2020 to 0.8% in 2020-2025. This is based on the latest IFA Medium-Term Fertilizer Outlook 2021-2025 (published in August 2021), which envisaged a compound average growth rate of 1.2% for nitrogen-based fertiliser demand during 2022-2025 – adjusted downwards to reflect the impact of supply restrictions seen since late 2021 and trade tensions following the invasion of Ukraine.

The IEA Ammonia Technology Roadmap shows that, in spite of this short-term slowdown, the industry's current trend is not sustainable, and that a shift to low-emission production technologies combined with more efficient use of fertilisers is required to move towards more sustainable ammonia production. Investment in new low-emission hydrogen-based plants and in the retrofitting of existing plants with CCUS will enable a switch to this more sustainable model, and will enable major fertiliser-consuming countries such as India to reduce their subsidy budget and dependence on LNG imports.

The urea price has jumped since September 2021 on a combination of high natural gas costs and export limitations

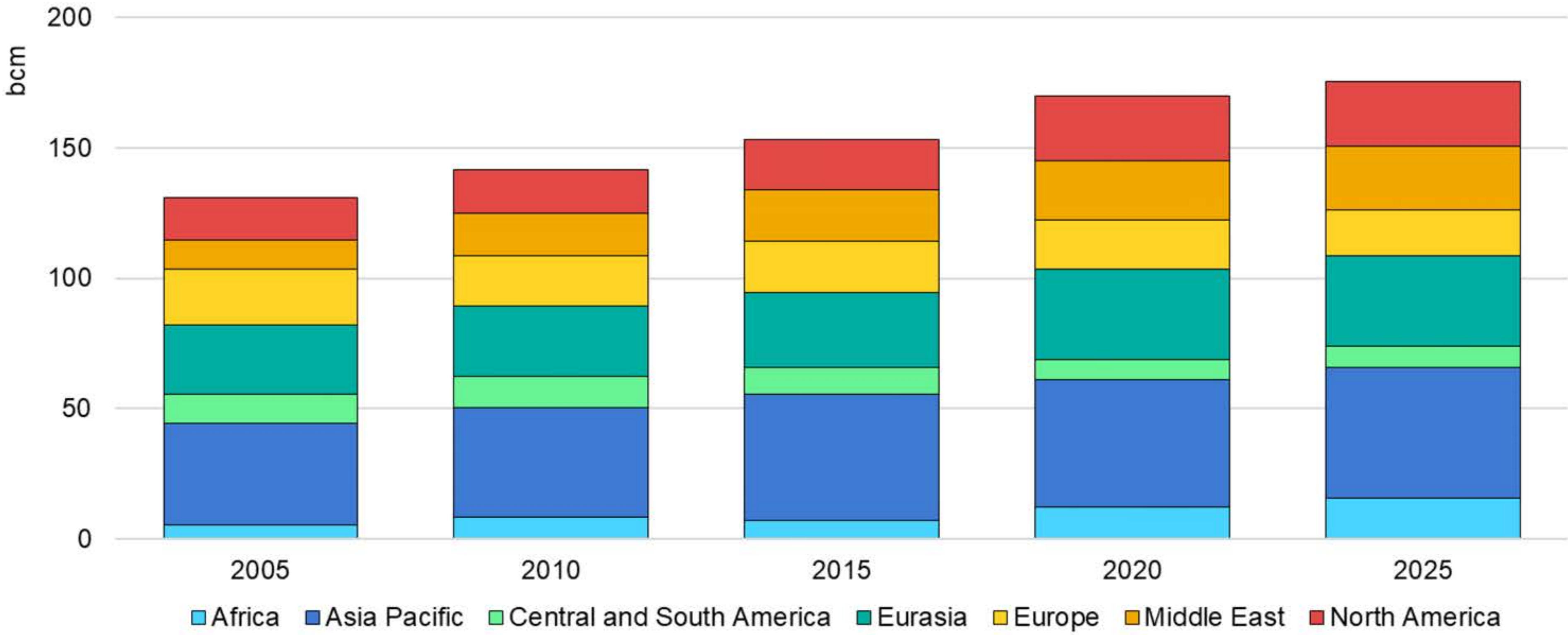
Monthly natural gas and urea price index, 2021-2022



Sources: IEA analysis based on EIA (2022), Henry Hub Natural Gas Spot Price; ICIS (2022), ICIS LNG Edge; Powernext (2022), Spot Market Data; World Bank (2022), Commodity Prices – "Pink Sheet" Data.

Natural gas consumption growth in the fertiliser industry is expected to slow to an average of 0.8% in the period 2020 to 2025

Natural gas consumption for ammonia production, 2005-2025



Asia and the Middle East account for about 80% of medium-term gas demand growth

The **Asia Pacific** region remains the main source of natural gas consumption growth between 2021 and 2025, contributing for close to half of global consumption gains (or nearly 70% of the net demand increase) during the outlook period. However, the region's annual average growth rate, at 2.6% during 2021-2025, is well below that of the 2017-2021 period when it was 4.3%. High prices and a softening economic outlook weigh on the region's demand prospects. China, India and emerging Asia remain the primary growth markets throughout the forecast period (although each faces considerable downside risks in today's uncertain market environment), while Japan and Korea lead the declining markets on falling gas use for power generation in both countries. China – driven by the industrial sector – is the single biggest contributor to consumption growth, accounting for more than 75% of the region's increase in gas demand during the 2021-2025 period. In India industry also maintains its leading role in gas demand growth, complemented by the residential and transport sectors in the country's fast-growing city gas segment. Emerging Asia's growth is mainly driven by growing electricity requirements and continuing additions to gas-fired generation capacity.

Gas consumption in the **North American** region is expected to grow at an average annual rate of 0.7% during the forecast period. 2022 sees 2.3% growth in spite of high prices, due to the combination of constraints on US coal supply and stocks, which support gas-fired power generation, and temperature-sensitive demand in the initial months of the year. US gas consumption is then expected to more or less stagnate between 2023 and 2025. Canada's natural gas demand grows at an average rate of 1.1% during the forecast, which is principally supported by the power generation sector on the completion of the coal phase-out in Alberta. Gas use in Mexico grows at an average of 1.4%, with a progressive slowdown in demand from the power sector and limited contributions from the industrial and retail sectors that are partly balanced by declining use in the energy sector.

Europe's gas demand rose by over 5% in 2021, driven by recovery in economic activity and colder spring and winter temperatures supporting higher space heating requirements. In 2022 European gas demand is expected to decline by close to 9%, as record high gas prices are weighing on gas demand in the industrial and power sectors. The return to average weather conditions is assumed to reduce gas demand in the residential and commercial sectors. Russia's invasion is leading to direct demand destruction in Ukraine, primarily in the industrial sector. Ukraine's gas demand is set to decline by 25-30% in 2022. The strong deployment of renewables, together with the gradual implementation of energy efficiency measures, is set to weigh on European gas demand, declining at a rate of 3% per year over our forecast.

Natural gas demand in **Eurasia** rose by over 8% in 2021, largely supported by strong growth in Russia, higher gas use in the power sector and cold weather conditions boosting gas demand for heat generation. Gas demand in 2022 is expected to decline by 3% on a worsening macro-economic outlook, despite colder than average temperatures in Q2. The sanctions imposed on Russia following its invasion of Ukraine are set to weigh on economic growth, with the country's GDP expected to decline by over 8% in 2022. The region's gas demand is projected to stay broadly flat over the forecast period, with demand recovering close to its 2021 levels by 2025.

The **Middle East** is the second-largest contributor to global gas demand growth after Asia Pacific, growing at an average annual rate of 2.7% in the forecast period, which is broadly in line with the 2017-2021 average of 2.6%. The region's biggest increase is in Saudi Arabia, driven by the growing availability of domestic gas supply for both the power and industrial sectors. The United Arab Emirates is projected to see the largest demand drop within the region due to the rapid growth of nuclear and renewable generation at the expense of gas in the country's electricity mix.

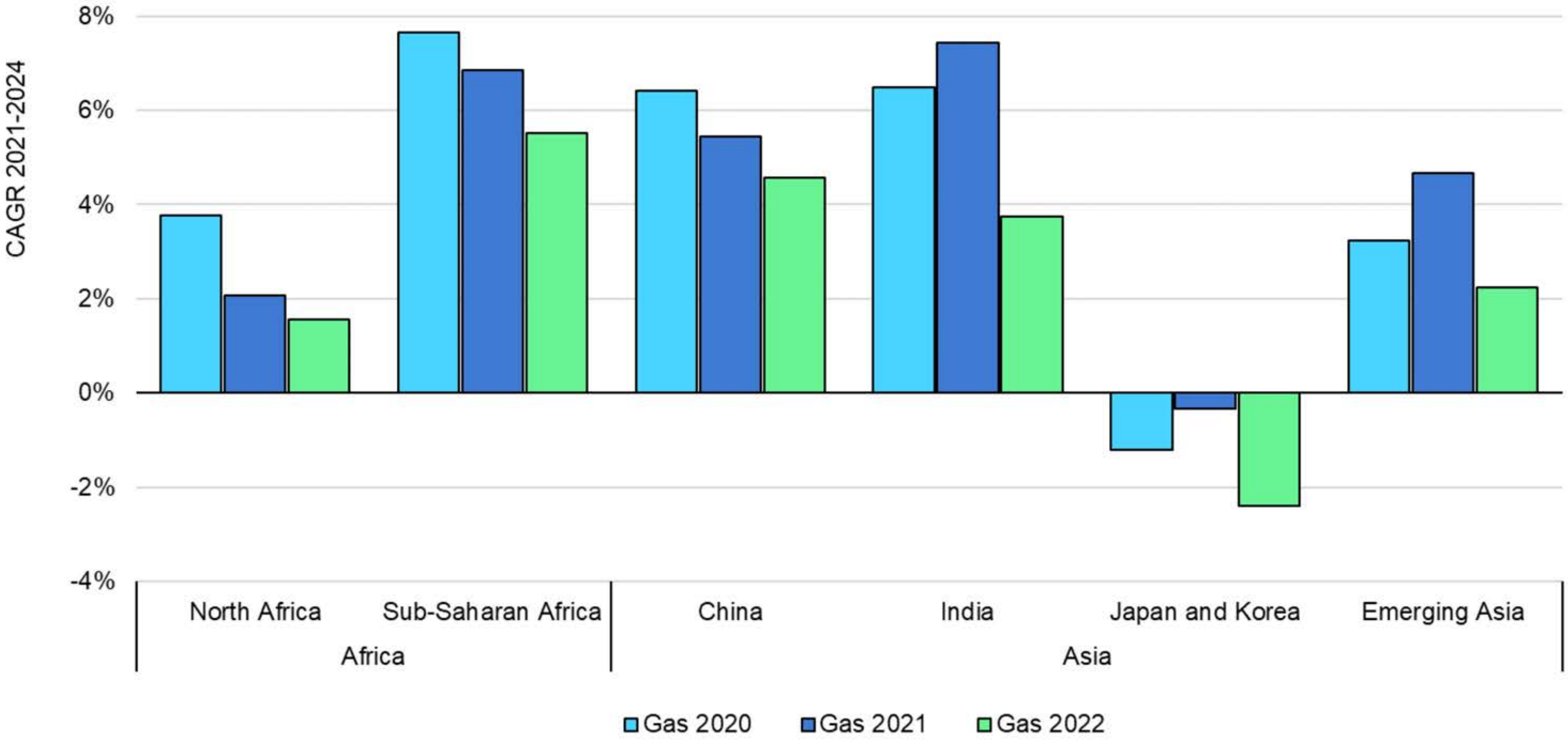
Central and South America is expected to see its gas consumption drop by 4% in 2022 after having almost recovered its 2020 losses in 2021. It then progressively recovers to its 2021 level by 2025. The strong 8.2% growth in gas use observed in 2021 was partly supported by extreme weather conditions, as record droughts in Brazil led to a close to 60% y-o-y increase in gas use for power generation to compensate for historically low hydropower availability. Gas demand in Brazil is declining in 2022 from its 2021 highs as hydro conditions improve; it then sees a moderate increase in the following years, which only partly compensates for this initial drop. The result is an average annual decline of 2% during the forecast period. Argentina's gas consumption grows at an average annual rate of 1.2% in the coming years to 2025, as the expected increase in domestic production supports further use in the power generation and industrial sectors. Limited consumption growth in smaller South and Central American markets is practically offset by the expectation of a continuing decline in Venezuela's production and domestic demand.

Natural gas consumption is expected to grow in **Africa** at an average annual rate of 2.6% over the forecast period. Demand growth is expected to slow compared with recent years, as natural gas has already reached a high share of the mix in mature North African markets, while growth potential in sub-Saharan Africa is challenged by the current high price environment. This report includes a special focus on African natural gas markets, providing a more detailed view on the region's demand dynamics.

Spotlight on fast-growing regions in a high gas price and tight supply environment

Gas demand growth prospects are slowing, but are still there

Evolution of forecast CAGR for gas demand in the three latest issues of the IEA medium-term gas report, selected markets, 2021-2024



China's gas consumption growth is set to continue, but shift into a lower gear in 2022-2025

After a rapid 12% demand increase in 2021 – driven by weather-related factors and a strong rebound in economic activity – the rate of growth in China's natural gas consumption is projected to slow markedly in 2022 to 3%. This is the lowest rate since 2015 and reflects high import prices, slowing economic growth, mild temperatures and Covid-related lockdowns. Annual consumption growth is expected to average only 5% between 2023 and 2025 amid sustained high LNG prices and lacklustre GDP growth. China retains its role as the greatest contributor to global gas demand growth over our forecast horizon, adding 74 bcm to annual demand between 2021 and 2025. But the country's average increase of under 5% during this period is less than half the average of 11% achieved in 2017-2021.

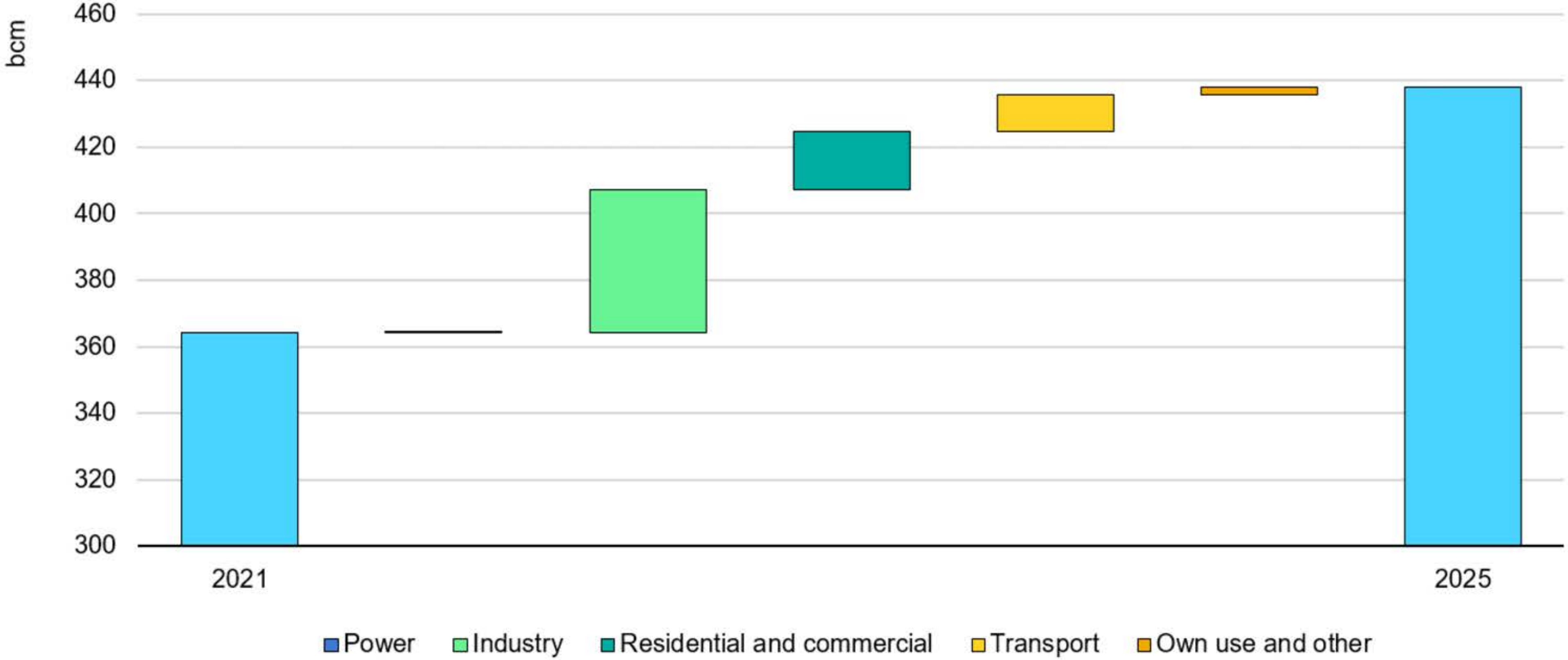
The industrial sector remains the primary driver of consumption growth, accounting for nearly 60% of China's demand increase between 2021 and 2025. Despite the headwinds from higher prices, industrial demand growth is supported by expanding industrial production and ongoing coal-to-gas switching that targets small and inefficient coal-fired boilers. Growth in the power generation sector is projected to remain modest, adding only less than 1 bcm of demand during the forecast period. Gas-fired generation remains under pressure in the Chinese electricity mix from renewable, coal-fired and nuclear generation throughout the forecast period. Residential and commercial users and the transport sector together make up almost 40% of the total demand growth in China (adding 29 bcm by 2025). Growth in these segments is driven by new grid connections and a continuing (albeit slower) adoption of LNG-fuelled trucks, respectively.

About a third of China's gas supply requirements between 2021 and 2025 are met by domestic production, another third by pipeline gas deliveries, and the remainder from growing LNG imports.

The signing of more than 60 bcm of new LNG term contracts by Chinese companies since the beginning of 2021 is set to reduce the country's exposure to volatile spot LNG prices considerably during the 2022-2025 period. About two-thirds of the newly contracted volume is scheduled to start arriving before the end of 2023 and almost 90% will be active before the end of 2025. The government's goal under the 14th Five-Year Plan to more than double China's gas and LNG storage capacity to 55-60 bcm by 2025 can mitigate the risk of damaging winter price spikes and fuel shortages in particular. Both developments can help bring stability to China's domestic gas market, improve energy resilience and safeguard the role of natural gas in the energy system in the face of considerable market uncertainty and turbulence in global LNG markets.

China's demand growth is fuelled by industry, while power sector use stagnates in 2022-2025

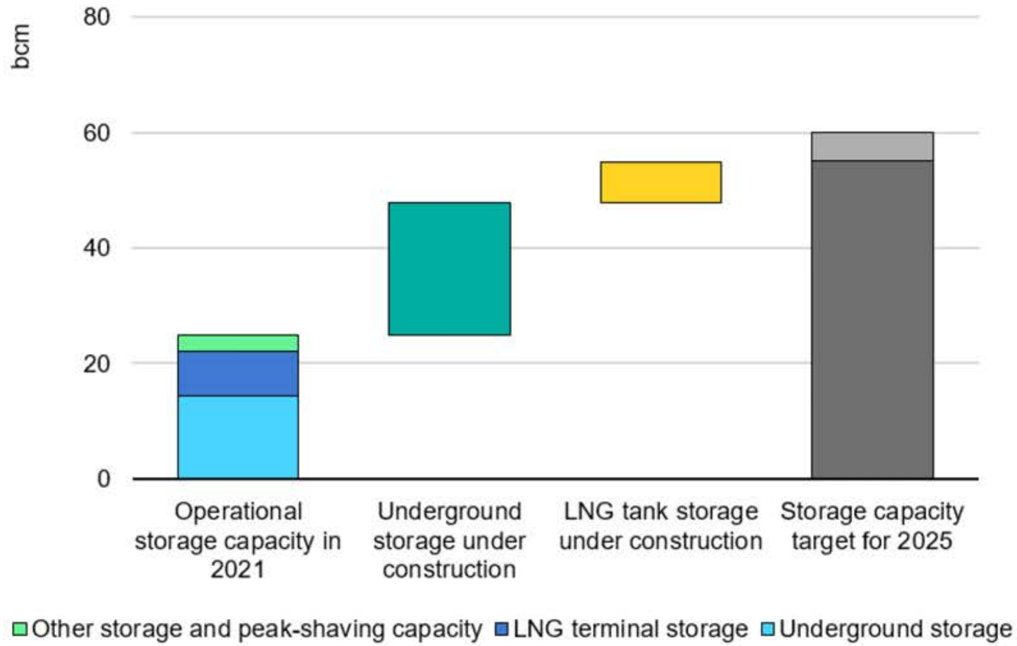
Gas demand by sector, China, 2021-2025



China's drive to sign new LNG contracts and expand domestic storage could reduce exposure to market volatility in the medium term

New LNG contracts signed since January 2021

Gas storage capacity in China, 2021-2025



Sources: IEA analysis based on ICIS (2022), ICIS LNG Edge; CEDIGAZ (2022), UGS dataset; GIIGNL (2022), Annual Report.

India’s gas demand growth prospects: Down but not out

After a period of stagnating gas use in 2018-2020, India’s total consumption increased by 4% in 2021, proving that a relatively healthy rate of demand growth is possible in India even in the face widespread Covid-19-related disruption, record-high LNG prices and extensive fuel switching away from gas in the more price-sensitive sectors of the economy (especially in power and refining). This resilience is partly due to the fact that much of the growth occurred in the city gas segment (primarily covering residential and commercial uses, transport and light industry), where the distribution infrastructure is undergoing major expansion, and partly due to rapidly rising domestic production, which comes at a substantially lower cost than imported LNG.

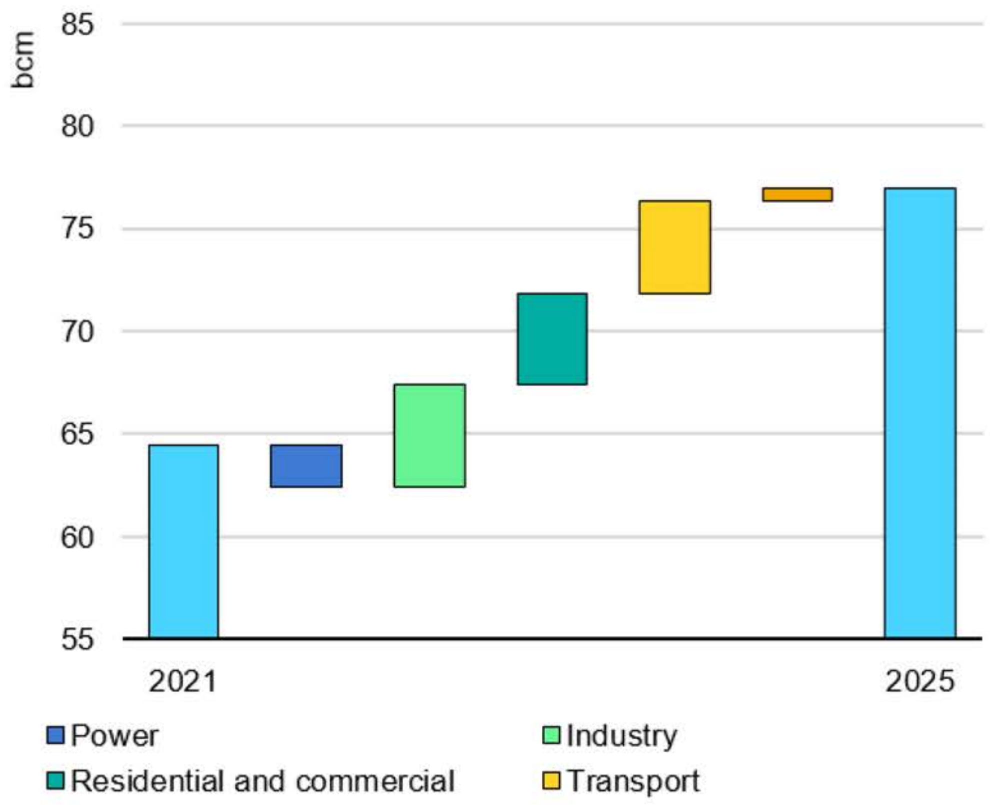
These trends are expected to continue over the medium term. India’s total gas consumption is projected to increase by 19% (13 bcm) during the 2021-2025 period, which is equivalent to a 4% annual average growth rate. This makes India the fifth-largest contributor to gas demand growth globally, and the second-largest driver of growth in the Asia Pacific region after China. Nevertheless, our total consumption forecast for 2025 has been revised down by nearly 18 bcm (or 19%) compared to the level anticipated for 2025 a year ago. This reflects the unfavourable global LNG price environment and the uncertainties facing natural gas in India’s price-sensitive energy economy.

The industrial sector remains the biggest driver of growth between 2021 and 2025, accounting for about 40% of the net increase in India’s natural gas consumption. The residential and commercial and transport sectors make similarly strong contributions thanks to the continued expansion of the domestic gas grid. Gas use in the power generation sector is set to decline by 14% in the 2021-2025 period as high imported and rising domestic prices render gas-fired power uncompetitive relative to other fuels. Approximately two-thirds of India’s incremental gas demand is set to be satisfied with growing domestic production. The remaining one-third has to be met with imported LNG, but even after the 11% increase in LNG inflows foreseen in 2021-2025, total LNG demand in 2025 will stay slightly below the 2020 peak as high prices discourage greater LNG use in the years ahead.

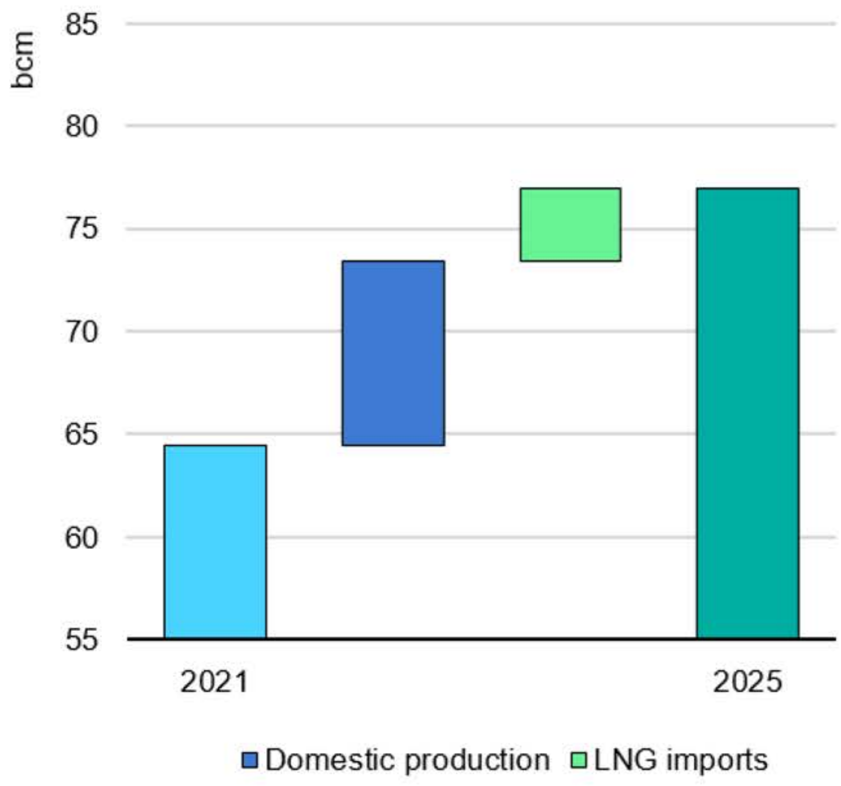
The policy framework remains supportive for natural gas use in India, although affordability has emerged as a major concern. The expansion of the city gas distribution grid is set to continue (and accelerate further after the conclusion of India’s 11th bid round this year). The size of India’s gas transmission network could increase by 75% and LNG import capacity could grow by 40% during the forecast period with the completion of projects currently under construction. Gas price reforms and efforts to simplify natural gas taxation have progressed slowly but could boost gas penetration further over time.

India's demand growth is set to come mostly from industry and city gas segments; domestic production provides more than two-thirds of incremental supply

India's gas demand by sector, 2021-2025



India's gas supply by source, 2021-2025



Japan and Korea face a declining gas demand trajectory in the 2021-2025 period

Japan’s gas demand was flat in 2021 as the demand boost from a cold winter was fully offset by a series of nuclear restarts, which negatively affected gas consumption in the power sector. After flat demand in 2021, the long-term trend of declining demand is set to reassert itself in 2022-2025. Total gas consumption is expected to drop by 11% between 2021 and 2025. This is mainly due to declining gas use in the electricity sector, where continuing nuclear restarts and the increase in renewable generation reduce the need for gas-fired generation. Gas demand in industry is set to see a modest 3% increase in 2021-2025, but this is not enough to offset the decline in the power sector.

Japan’s 6th Strategic Energy Plan, which was introduced in October 2021, sets a 60% non-fossil fuel target for electricity generation by financial year (FY) 2030. The plan envisages a substantial increase in the proportions of both nuclear output (from 6% in FY2019 to 20-22% by FY2030) and renewable generation (from 18% in FY2019 to 36-38% by FY2030), which, in turn, is expected to reduce the share of LNG in the power mix from 37% in FY2019 to around 20% by FY2030. Discussions about restarting nuclear capacity are ongoing, but the plan is viewed as highly ambitious, requiring a step change in the speed and scale of restarts and an increase in the number of operational reactors from the current 10 to around 25, which include reactors still applying for safety approval by the Nuclear Regulation Authority. Any implementation delays present an immediate upside risk for gas demand in the medium term.

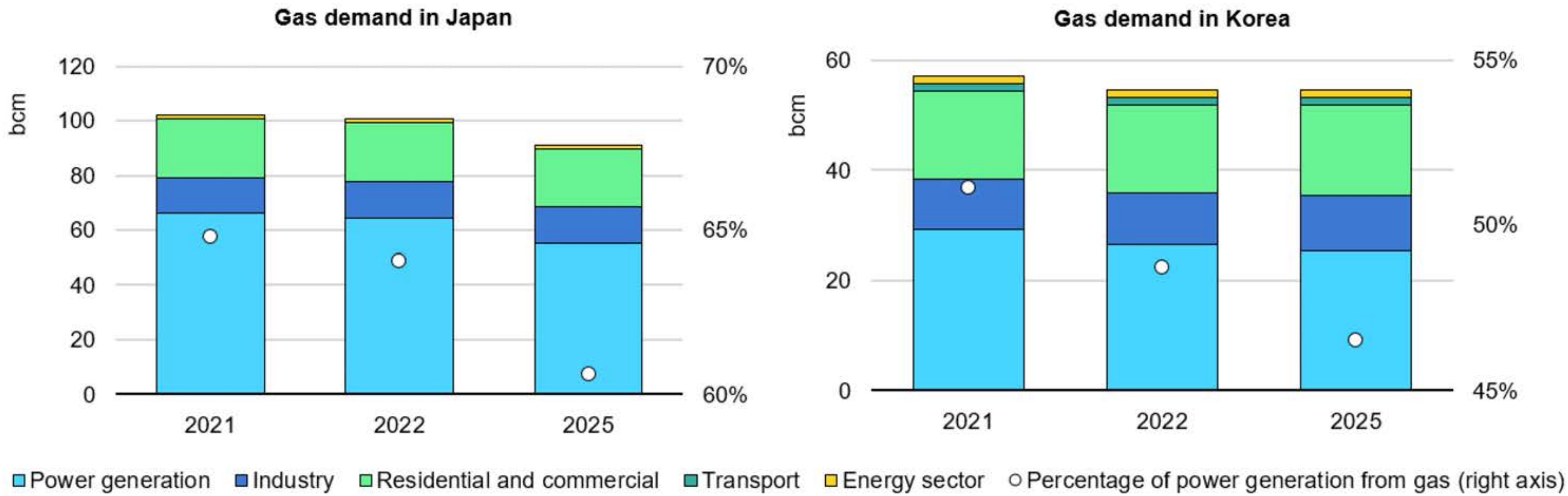
Korea’s gas consumption increased by 10% in 2021 due to cold temperatures in early 2021 and a strong post-Covid economic recovery during the first nine months of the year. However, high prices – combined with increased coal-fired and nuclear generation – led to zero growth in Q4 2021. Total gas demand is expected to drop by more than 4% in 2022 and stay flat during 2023-2025.

Gas consumption for power generation is on course to decrease by 13% between 2021 and 2025 due to the start-up of several new nuclear and coal-fired plants. Korea’s new government plans to fulfil the country’s 2030 nationally determined contribution in part by increasing the share of nuclear in the primary energy mix from 29% in 2020 to 35-40% by 2030, which, in turn, will put pressure on gas demand in the power generation sector. The new government is also expected to accelerate the completion of nuclear units under construction and extend the life of existing plants. As many as four new reactors (with a total capacity of 5.6 GW) are expected to come online between 2022 and 2025.

Gas demand in the city gas segment (encompassing most of the industrial and transport sectors) is expected to grow by 9% in the 2021-2025 period, which contributes to offsetting declines in power sector gas use from 2022 onwards.

Demand decline in both Japan and Korea is driven by a squeeze on gas in power generation

Natural gas demand by sector, Japan and Korea, 2021-2025



Emerging Asia's outlook is caught between strong fundamentals and lack of LNG affordability

Emerging Asia's natural gas consumption is expected to increase by 9% between 2021 and 2025, adding nearly 21 bcm of incremental gas demand during the forecast period. This relatively robust expansion is testament to the region's strong underlying fundamentals for gas demand growth: rising incomes, urbanisation, growing demand for cooling and an ongoing economic recovery from Covid-19. However, we have reduced Emerging Asia's 2021-2025 demand growth by more than 50% compared with last year's forecast to reflect the particular sensitivity of the region's appetite for gas to sustained high LNG prices over the medium term.

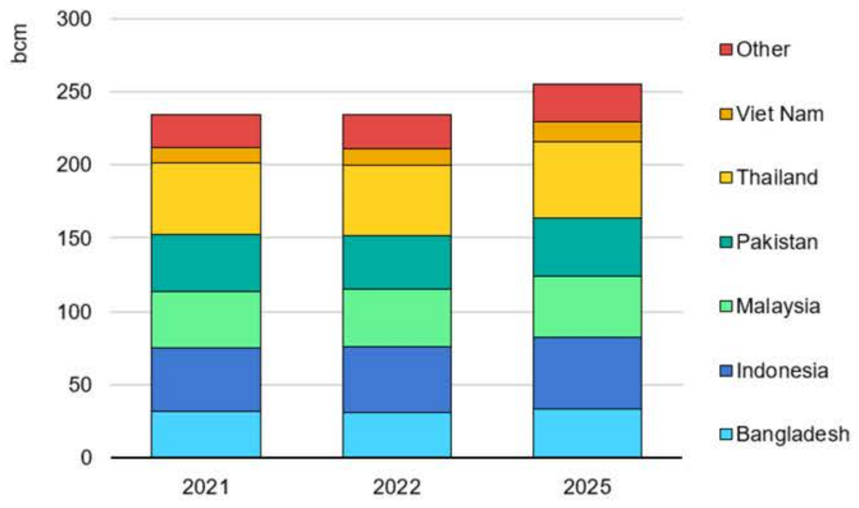
Over two-thirds of the region's demand expansion in the forecast period is expected to come from the power sector, driven by the addition of more than 65 TWh of gas-fired generation to satisfy the region's rapidly growing need for electricity. Virtually all of the remaining growth occurs in industry – led by fertilisers and light industry – with the biggest increments expected in Indonesia, Malaysia, Pakistan and Thailand. Consumption growth in residential and commercial applications and in the transport sector is negligible across the region (due to high prices and limited supply availability) and is fully offset by declining gas use in the energy sector as the region's indigenous production of hydrocarbons dwindles.

Emerging Asia is characterised by a growing dependence on LNG imports to bridge a widening gap between declining natural gas production and rising demand. As of mid-2022, about 22 bcm of new LNG import capacity is under construction across the region (located in Thailand, Viet Nam, Indonesia and the Philippines) and another 25 bcm is in various stages of development with planned start dates before the end of 2025. However, the region's growth trajectory is highly dependent on the affordability of imported LNG for the region's cash-strapped utilities and other end users further downstream.

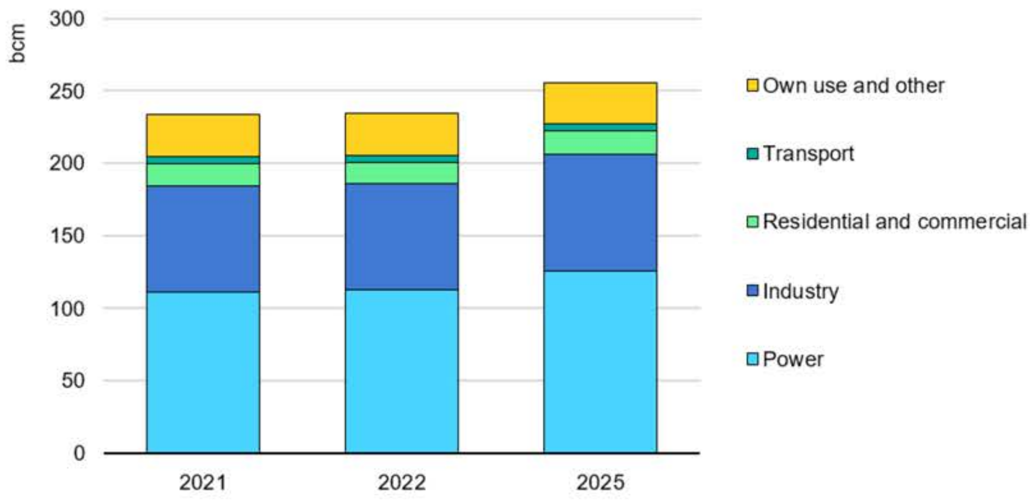
Soaring LNG prices in H2 2021 and H1 2022 have already prompted periodic gas shortages, power cuts, fuel switching away from gas and demand destruction in certain industries across the region. Moreover, Emerging Asia's already high exposure to spot LNG prices is only expected to increase, as neither Viet Nam nor the Philippines – the region's two prospective new LNG importers – have signed any long-term contracts to date, and thus would have to compete with Europe and Northeast Asia for limited short-term LNG supplies in the years ahead. Therefore, sustained high prices throughout the forecast period could further derail Emerging Asia's gas and LNG demand growth prospects, and leave much of the region's planned new LNG-to-power infrastructure further delayed or even uncompleted.

Emerging Asia's 2021-2025 gas demand growth is modest but broad-based, driven mainly by power generation

Gas demand by country, Emerging Asia, 2021-2025



Gas demand by sector, Emerging Asia, 2021-2025



Fuel for growth: Focus on African natural gas markets

Natural gas consumption has almost tripled in Africa since 2000, yet its development has remained relatively limited outside the main producing or transit countries of North Africa and Nigeria, where gas production capacity was initially developed principally for export purposes.

Africa has accounted for close to 40% of new natural gas discoveries in the past decade – mainly in Mozambique, Mauritania, Senegal and Tanzania. However, nearly half of the continent's production is exported, and the role of natural gas in Africa's energy consumption remains limited. New natural gas markets are emerging, mainly for power generation, in order to address growing electricity needs and as a substitute for liquid fuels. These new markets are supported by the development of domestic production as well as the commissioning of new import infrastructure. The current high price and tight supply market environment is particularly challenging for these price-sensitive emerging African markets, and likely to have negative impacts on future natural gas consumption growth prospects.

Gas demand growth is expected to slow in mature North African markets

North Africa currently accounts for about three-quarters of the continent's natural gas consumption. It has experienced robust growth in the past decade, with an average increase of 4.1% per year. This continuous development, favoured by access to domestic production, subsidised prices and strong electricity demand, substantially increased the role of natural gas in North Africa's energy consumption to reach an estimated share close to 55% – compared with a global average of 25%, and 30% for Africa as a whole. This forecast expects slower natural gas consumption growth in these mature North African markets, at an average rate of 1.7% per year for the 2021 to 2025 period.

Egypt is the continent's largest natural gas market, consuming close to an estimated 65 bcm in 2021 – almost equivalent to Africa's total LNG exports in 2021 (58 bcm). Domestic consumption has increased steadily since the mid-2010s, triggered by the development of offshore production in the Mediterranean. This forecast expects an average 1.6% annual increase in Egypt's natural gas consumption, slowing from the previous years' strong growth rates. Consumption growth has principally been driven by the power sector's needs, a sector dominated by gas-fired generation and which accounts for over 60% of the country's total gas consumption. Electricity demand remained strong in 2021 with an estimated 8% y-o-y increase, but the trend has generally slowed in recent years on rising electricity prices, as part of the government's plan to phase out energy subsidies by 2025. Slower electricity demand growth and further development of renewable capacity is expected to strongly affect growth in the use of gas for power generation, down from an observed annual average of 7% during 2017-2021 to 1.4% during the forecast period.

The industrial and energy sectors are the other strong component in Egypt’s gas consumption, accounting for 30% of total gas use. Non-energy uses are a main application of gas in Egypt’s industrial sector. Egypt is an important producer and exporter of fertilisers – the sixth largest producer of urea in 2021 – and has several capacity expansion projects under development and planned to start operations during the forecast horizon. The potential for further growth could, however, be limited by rises in export taxes on fertilisers, which increased almost fivefold in 2021. Gas consumption in the industrial and energy sectors is expected to see average growth of 2% per year until 2025.

Algeria’s natural gas demand grew at an average annual rate of 4.8% over the past decade, and it can now be considered a mature gas market. The country has followed ambitious energy access policies, funded by heavily subsidised gas and electricity tariffs and strong network development programmes. Coverage reached over 99% of the population for electricity and of 62% for gas in 2021. The power sector is the largest consumer of natural gas with a 40% share, and has been a strong driver of the country’s gas demand growth. Close to 95% of Algeria’s electricity comes from gas-fired generation, and the country saw its electricity consumption grow at an average rate of 5.7% per year over the past decade. Consumption by distribution network consumers is the second-largest source of gas use, which also experienced strong growth in the past decade as the number of connections increased. Demand from the industrial sector, driven principally by petrochemicals and building materials, accounts for about 20% of total consumption and grew at a strong 6% average rate over the past five years. Algeria’s energy regulator, CREG, assumes in its ten-year natural gas development plan an annual growth rate of 2.3% to 2030. In order to contain the growth of gas consumption, it advises the further development of renewables and energy efficiency, as well as gradual increases in gas and electricity tariffs. This forecast expects more conservative growth in domestic gas demand, at an average of 1.9% until 2025, due to gas supply constraints and a downgraded economic environment.

Other North African gas markets are expected to experience limited growth in the next three years, principally due to supply constraints. **Morocco** uses gas essentially for power generation and used to rely principally on pipeline imports from Algeria, which were discontinued in late 2021. An increase in alternative thermal sources of power generation and options to develop alternative supplies from both domestic and import sources are expected to help bridge the gap. **Tunisia**’s gas demand has not grown significantly over the recent past and is expected to remain close to stagnant in the near future at an average 1% increase per year. Future growth from the power generation sector (which accounts for over 70% of the country’s gas use) is expected to be met by renewable capacity increases. Gas demand in **Libya** has declined over the past decade due to the impacts of the country's internal conflicts and limitations on access to supply; this forecast expects limited annual growth of less than 1% on average until 2025.

Growth prospects in sub-Saharan Africa are challenged by the current high price environment

The role of natural gas in sub-Saharan Africa remains limited, with an estimated 15% share of the energy mix. Regional organisations such as the African Union, as well as several governments, have underlined the importance of gas as a transition fuel for Africa on its journey to achieving greater energy access, clean cooking and net zero emissions. Developing new gas outlets and sources of supply – either from domestic or imported sources – in emerging African markets raises the question of affordability, which proves particularly challenging in the current high price and high uncertainty market environment.

Nigeria is the largest natural gas market in sub-Saharan Africa, with an estimated 22 bcm consumed in 2021. The power generation sector is the main user of natural gas, accounting for 40% of total consumption, but suffers from a lack of gas supply and network capacity to run power plants. The Nigerian presidency launched the "Decade of gas" initiative in 2021, which aims to accelerate the monetisation of domestic gas resources and transform the country into a gas-based industrialised nation. The new Petroleum Industry Act, which was passed by parliament and signed by the president in summer 2021, is a major reform milestone after two decades of preparation and is set to overhaul the country's oil and gas sector by introducing a new legal, regulatory and fiscal regime. These reforms are expected to attract further investment in both oil and gas production and midstream infrastructure, while optimising gas production by implementing stronger penalties for gas flaring. Downstream market development is also expected to be fostered by the introduction of more detailed regulations, the implementation of domestic gas delivery obligations, and the creation of a midstream gas infrastructure fund financed by a new 0.5% tax on all oil products and gas purchases by wholesale customers. The government intends to use the fund to invest in public-private partnerships that build infrastructure to increase domestic access to gas. This framework complements the Presidential Power Initiative, an ambitious development plan that aims to increase the country's electricity capacity to 25 GW by 2025[1] through investment in the transmission network and new gas-fired and renewable generation. The industrial sector has been a strong source of gas demand growth, principally due to investment in fertiliser production capacity in order to reduce the country's dependence on imports. Further growth is anticipated, as Nigeria inaugurated the continent's largest fertiliser plant in March 2022 and the presidency aims to turn

[1] From a current 13 GW of installed capacity, relying on gas for about 80%, but capped by transmission capacity bottlenecks with a maximum of 5 GW of transmission.

Nigeria into Africa's fertiliser powerhouse. This forecast expects average annual gas consumption growth of 3.4% during the 2021 to 2025 period, taking into consideration uncertainties regarding access to investment, but with some potential upside if the development of electricity production and transmission capacity through the Presidential Power Initiative can be accelerated.

Other **West African** countries have identified prospects to unlock their domestic natural gas markets, but tangible implementation and timing remain highly uncertain in the current context of high gas prices. **Senegal** and **Mauritania** are aiming for first gas from Phase 1 of the Grand Tortue Ahmeyim offshore development by 2023, with plans to use their respective shares of production not earmarked for LNG exports to supply new gas-fired power stations. A 300 MW combined-cycle plant is under development in Senegal, which will provide the equivalent of one-quarter of the country's current electricity production and help reduce its dependence on imported oil products for power generation. There are also plans to convert an existing 125 MW coal-fired plant to gas if additional supply is available. Mauritania's share of Phase 1 gas would be allocated to an existing 180 MW flex-fuel power plant, while the government signed a memorandum of understanding in late 2021 to develop additional gas-based electricity and ammonia production. The country aims to reduce its use of oil products (currently accounting for close to 80% of power generation) and achieve countrywide electricity access by 2030. Further domestic market growth will hinge on the development of new phases of the Grand Tortue Ahmeyim complex, which could be envisaged by 2027 or 2028 if a final investment decision is taken in the coming year. It is therefore subject to the significant current market uncertainty.

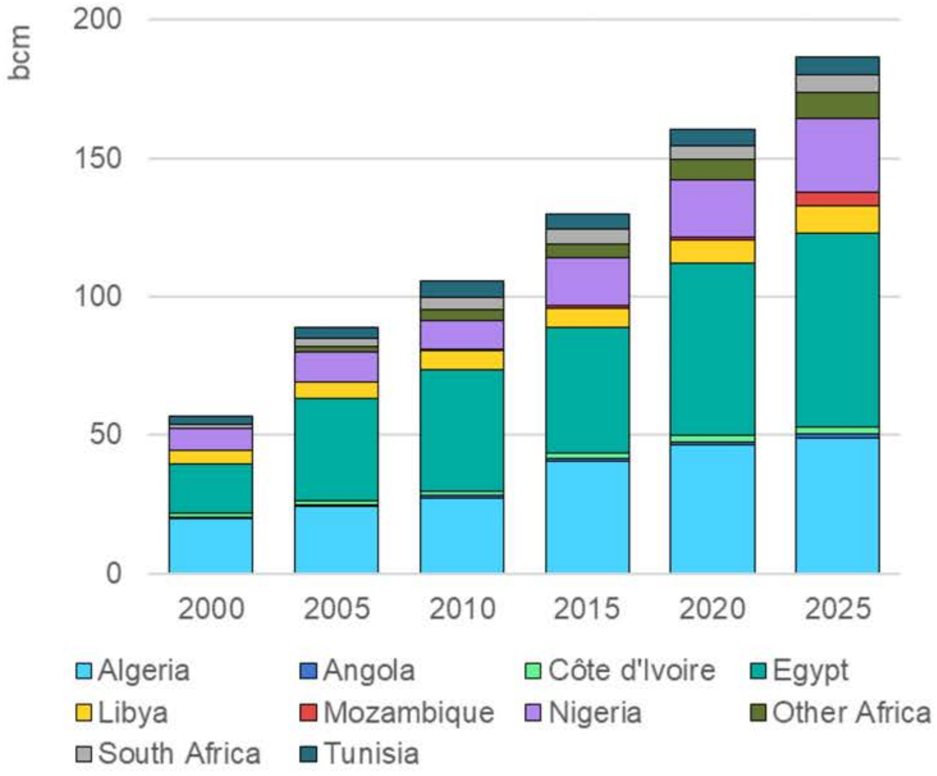
The high price environment is also hampering the fast-track transition to gas in Senegal – an FSRU arrived in Dakar in May 2021 to supply LNG to a power generation vessel that has been running on oil products since its commissioning in October 2019. However, due to the tight LNG market situation over the past year, the FSRU has remained idle since its arrival. A similar situation has been observed in **Ghana**, where the offshore Tema LNG terminal (another FSRU) has been operational since January 2021, but has yet to receive its first LNG cargo. Future LNG from the Tema terminal is expected to supply 1 500 MW of gas-fired electricity generating capacity. Similar LNG import projects planned in **Côte d'Ivoire** and **Benin**, designed to increase energy access and reduce oil burn for power generation, have apparently been put on hold. Côte d'Ivoire announced in June 2022 its ambition to fast-track the development of the Baleine offshore oil and gas field discovered in 2021, aiming for first gas in 2023.

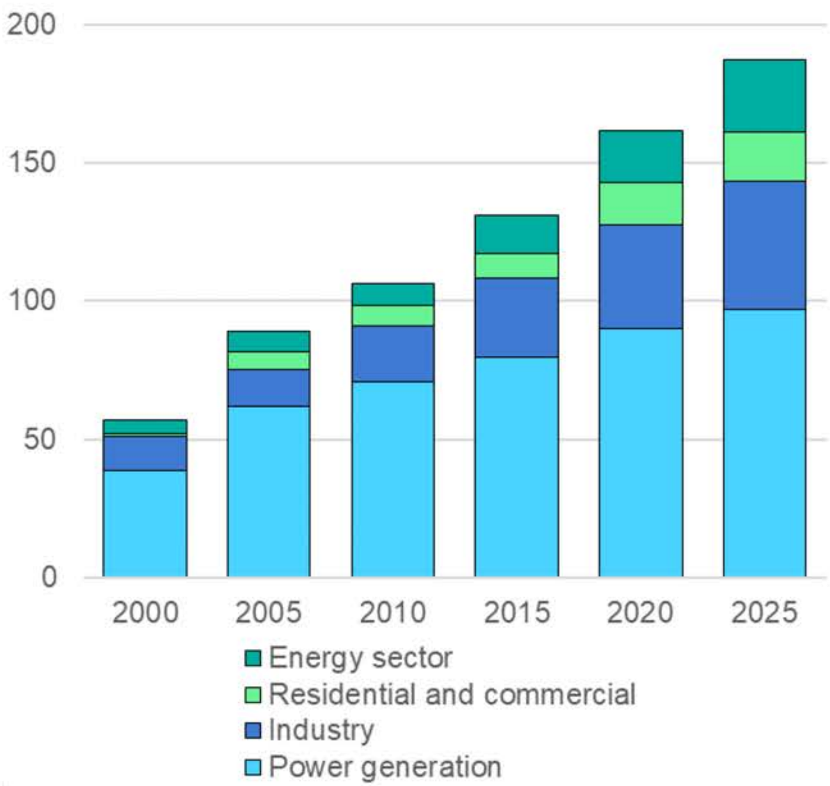
The potential development of gas demand in **Southern Africa** is principally contingent on decisions to invest in domestic production. Natural gas consumption in **South Africa** has remained stagnant in the recent past, accounting for less than 3% of the country's energy mix according to the latest version of country's Gas Master Plan, which was issued in late 2021. The plan highlights the benefits of developing a domestic gas market to reduce emissions from coal and drive economic activity and employment if sourced from domestic resources. It identifies a list of priorities, principally in the power sector, such as coal-fired power plants reaching the end of their life or potentially convertible oil-fired power plants. However, considering the lead time to develop new supply chains, our forecast does not expect significant change in South African gas demand by 2025; moreover, the Gas Master Plan emphasises the importance of affordability as a key success factor to the development of gas, which again casts a potential shadow on gas-based supply options, especially LNG import projects, in the current price environment. The country's short-term power supply plan (Risk Mitigation Independent Power Producer Procurement Programme), launched in 2020 and initially expected to deliver 1 845 MW of renewable and LNG-fired capacity for 20 years from 2022, is still on hold at the time of writing due to multiple delays.

Neighbouring **Mozambique**, the main gas supplier to South Africa, is expected to export its first LNG in 2022, with some additional gas production to supply its local market. This would supply a 450 MW combined-cycle gas-fired power plant due to start operations in 2024, as well as provide feedstock for fertiliser production as part of the implementation of a Special Agro-Industrial Processing Zone in the north of the country, funded by the African Development Bank. **Tanzania**'s government resumed discussions with international energy companies in late 2021 over the construction of an LNG export project, and signed a framework agreement in June 2022 with Shell and Equinor that could lead to a final investment decision by 2025. If confirmed, it could provide new sources of gas supply for the country's domestic market and support the development of its power generation and industrial sectors. Considering the envisaged timeline, the material consequences for gas supply would scarcely be visible before the end of this forecast's horizon.

Sub-Saharan Africa accounts for more than half of the continent's growth to 2025; demand potential is hampered by a challenging price environment

Natural gas consumption by country and by use, Africa, 2000-2025





Supply

North America and the Middle East take a strong lead on additions to gas production while Russia dips on declining export prospects

Natural gas supply increased by an estimated 4.1% globally in 2021, supported by the market recovery but hampered by a series of planned and unplanned outages that limited output in several producing and exporting countries. The resulting market tightening was further exacerbated by a drop in Russian supply to Europe in spite of available production and transport capacity. We anticipate global gas production growth being slightly negative in 2022, as the expected drop in Russian production resulting from lower demand and higher import diversification in Europe offsets increases from other regions. It is followed by limited increases in the subsequent years, principally from North America and the Middle East.

Gas production in **North America** grew by 2.1% in 2021 in spite of limited spending in the US upstream sector, supported by increasing domestic and export demand. In this forecast, North America leads medium-term global growth in natural gas supply with about 85 bcm added between 2021 and 2025. The region accounts for about 40% of the net increase in production capacity and over half of global net production growth between 2021 and 2025. The United States continues to lead the trend, with average growth of 2% supported by limited domestic and LNG export development and primarily supplied by the Appalachian Basin, complemented by contributions from other dry shale gas plays and associated gas from tight oil basins. Canadian production grows at a slower pace and principally towards the end of the forecast period to provide feedgas for the LNG Canada project, while Mexico continues its declining trend.

Eurasia's gas production rebounded by over 10% in 2021, accounting for over half of incremental global gas supply. Strong recovery in domestic demand together with higher exports (primarily towards Asia) supported this strong growth. Gas production is expected to decline by over 12% in 2022 on lower domestic demand and Russia's rapidly declining pipeline supplies to Europe. Russia's rapidly deteriorating export prospects in Europe are expected to weigh on the region's production outlook. Gas production is expected to recover by 1% per year between 2022 and 2025, but total output would remain 10% below 2021 levels by the end of the forecast.

The **Middle East** is a major contributor to global gas supply growth, adding nearly 70 bcm of production between 2021 and 2025, which represents a 10% increase on the region's gas output. This is driven by a handful of large-scale projects currently under development, including various phases of South Pars in Iran, Hawiyah in Saudi Arabia, Barzan in Qatar and Karish in Israel.

Gas production in the **Asia Pacific** region is set to increase by 4% between 2021 and 2025 and approach 680 bcm by the end of the forecast period. Most of the region's growth is in China, which could see its domestic production increase by 12% (or 25 bcm) from 2021 levels to reach 230 bcm in 2025. India's domestic production revival is also expected to continue, boosting output by close to 9 bcm (27%) between 2021 and 2025. Australia's gas supply stabilises at around 150 bcm per year, while most of the other producers in the region (including Indonesia, Malaysia, Thailand, Viet Nam, Pakistan and Bangladesh) are set to experience production declines over the forecast horizon.

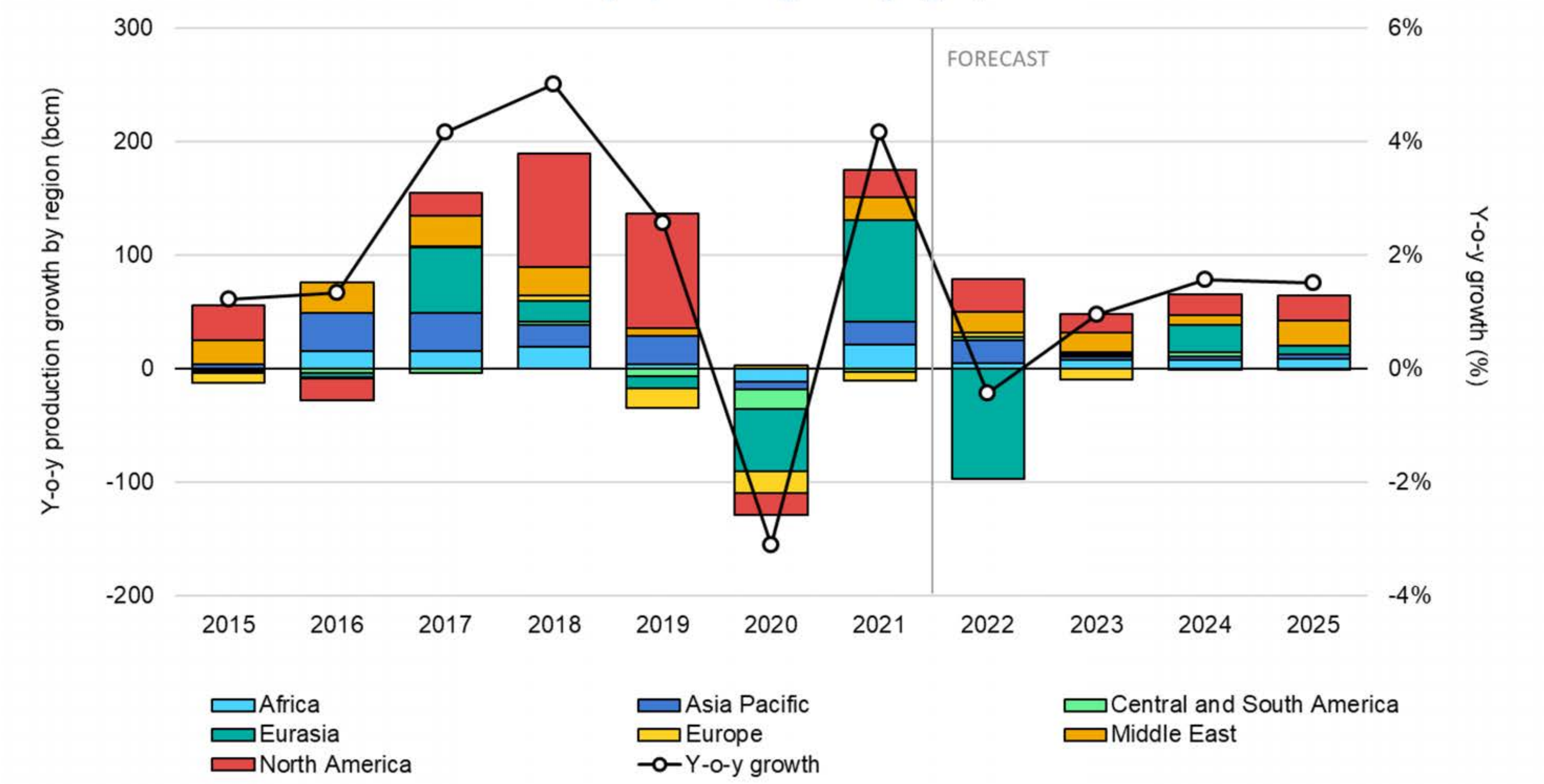
Africa's production of natural gas reaches over 290 bcm by 2025, increasing at an average of 2.7% per year over the forecast period, less than half its pre-pandemic rate (averaging 6.1% during the 2015 to 2019 period). This results from a combination of limited additional upstream and LNG export capacity due to be commissioned up to 2025, and more modest domestic growth as mature North African markets start to plateau while demand in emerging African markets is hampered by high import prices and limited availability of local resources. This modest growth is almost equally balanced between increases in domestic consumption and exports.

Gas production in **Central and South America**, which experienced two years of decline in 2020 and 2021, is expected to partly recover and reach 156 bcm by 2025, above its 2020 level (150 bcm) but still significantly below its 2019 level (167 bcm). This is led by Argentina's gradual ramp-up of pipeline capacity to debottleneck its Vaca Muerta shale gas deliveries, while Peru sees some increase with the recovery of its LNG export capacity and additional domestic growth. Brazil's output almost stagnates to 2025. Legacy exporters Bolivia and Trinidad and Tobago see some capacity being developed, but this is not sufficient to return to past production levels, while Venezuela's production continues its decline.

Europe's gas production declined by 3.5% in 2021, driven by lower output from the Netherlands, Norway and the United Kingdom. Production is expected to recover by almost 3% in 2022 on lower maintenance in Norway and the United Kingdom, leading to higher output. Overall gas production is set to decline by close to 1.5% per year between 2021 and 2025. Output is expected to remain broadly flat in Norway and Ukraine, while UK and EU output drops by 20% by 2025 compared to 2021 levels. In the Republic of Türkiye, the Sakaryia field is set to deliver first gas in 2023 and ramp up during 2024-2025.

Gas production growth to 2025 remains limited and geographically concentrated

Global natural gas production growth by region, 2019-2025



A bleak outlook for Russian gas production and upstream development

Russia's invasion of Ukraine rapidly impaired the outlook for Russian gas production and upstream projects. Sanctions limiting access to major capital markets and key energy technologies, together with the European Union's decision to phase out Russian gas as soon as possible, cast a long shadow over Russia's upstream development. This year's forecast foresees a cumulative production loss of over 480 bcm compared with our previous medium-term outlook for the 2022-2025 period. An accelerated phase-out of Russian gas would lead to a production loss close to 550 bcm. Upstream developments in western Siberia and the Yamal Peninsula are expected to be the most affected, while the production outlook for east Siberian fields is set to be more resilient.

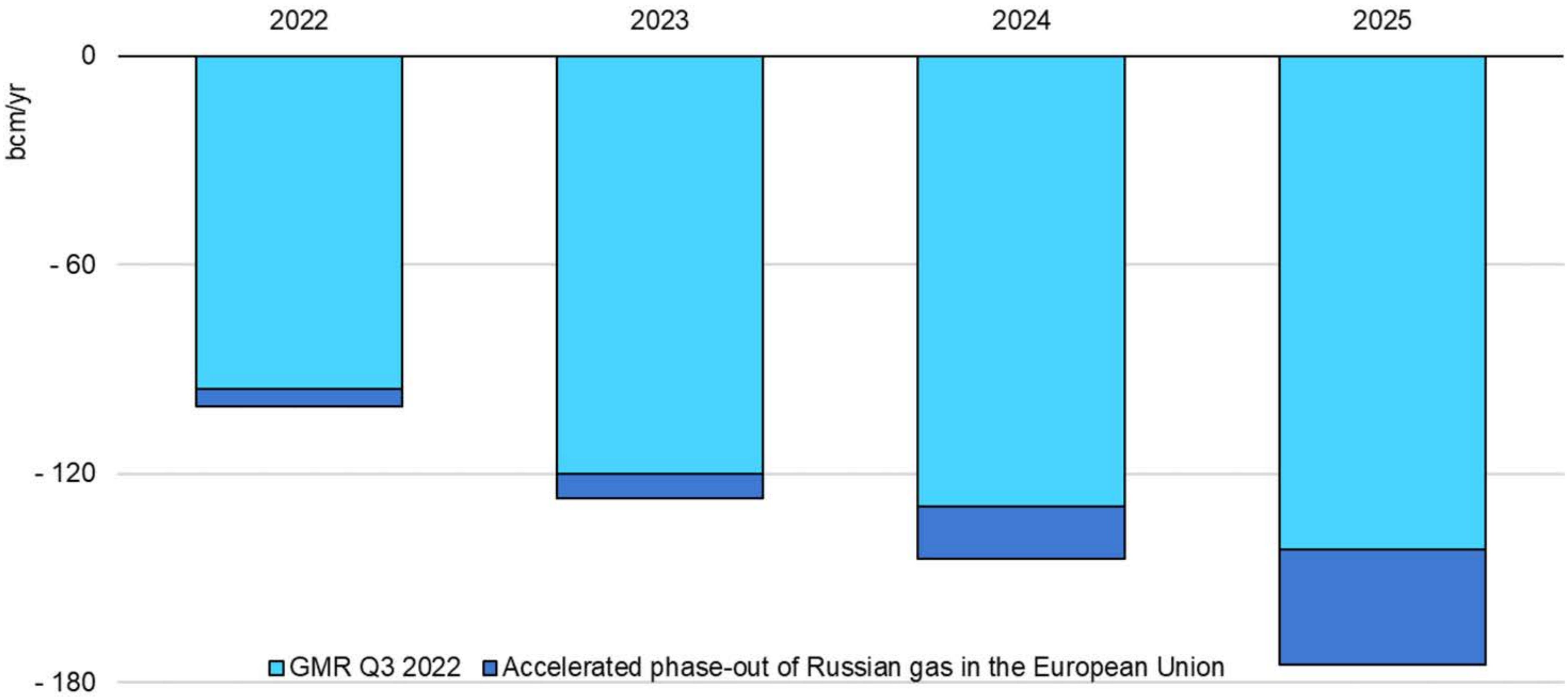
The prospects for the Arctic LNG 2 project (with a capacity of 27 bcm/yr) have worsened significantly, both in terms of financing and access to technology. Novatek, the project's developer, noted at the end of April 2022 that the development of the project is strained and the company is not in a position to confirm the previously adopted project timelines. Considering that train 1 was 78% completed by the end of 2021, this forecast assumes that it will be commissioned in 2023. Trains 2 and 3 are not expected to come online in the forecast period. This will ultimately weigh on the development and production outlook of the Utrenneye field, reducing its projected output by around 20 bcm/yr to just 10 bcm/yr by 2025.

The EU decision to phase out Russian gas as soon as possible and the abandonment of Nord Stream 2 leave the Kharasavey field and the Bovanenkovo expansion project without offtake export markets. The Kharasavey field (32 bcm/yr nameplate capacity) is due to start production in 2023. No cancellation or delay has been officially announced, although the field's ramp-up period could be prolonged amid the worsening export outlook. Considering current sanctions, this forecast does not include the 18 bcm/yr Baltic LNG project, the commission of which was previously announced for 2023-2024. This in turn might delay the start of the supergiant Tambey field, previously expected by 2026.

In east Siberia the Chayandinskoye field is set to reach its nameplate capacity of 25 bcm/y by 2024, enabling the ramp-up of gas supplies to China via the Power of Siberia pipeline. The Kovyktinskoye field is expected to be connected to the Power of Siberia pipeline system by the beginning of 2023 and ramp up to its nameplate capacity of 15 bcm/yr during the forecast period. The Amur gas processing plant is expected to reach its 42 bcm/yr design capacity by 2025. Gazprom and CNPC signed a 10 bcm/yr long-term supply contract in February 2022; a potential resource base could be the Yuzhno-Kirinskoye field, with a design capacity of 21 bcm/yr. The field is expected to be commissioned between 2023-2025 and could enable gas deliveries to China via the Far Eastern route.

Russia's deteriorating export prospects lead to a steep downward revision to its production outlook

Natural gas production in Russia, 2022-2025
(change in forecast between Gas 2021 and Gas 2022)



Prospects for US gas production growth are caught between short-term caution on spending and longer-term optimism on export growth potential

US natural gas production rebounded in 2021 with a 2% annual increase, offsetting its previous 1.6% drop in 2020, thanks to operational optimisation and higher completion rates. The current tight LNG market and high price environment has revived talks of further investment, but the industry remains cautious. This forecast expects an average annual growth rate of 2% for the 2021-2025 period, driven by the current timeline of LNG export projects under development.

High domestic prices

The spot price on the US benchmark Henry Hub has soared since the beginning of 2022, reaching an average of USD 7.50/MBtu in the second quarter, its highest since 2008, at a time of the year when gas prices usually decline between the end of the heating season and the start of the summer cooling season. Being a net exporter of gas, the United States is not directly exposed to LNG market tightness, but a combination of domestic supply and demand fundamentals has led to this price rally.

Temperature-sensitive consumption is one of these factors: the United States experienced colder than average temperature episodes in the Northeast and Midcontinent in April and early May, which sustained natural gas demand for space heating and were simultaneous with early heatwaves in the Gulf of Mexico and Pacific Southwest that triggered additional cooling demand from the power generation sector. In addition to these weather-related fluctuations, gas for power demand has remained elevated in spite of high prices throughout the winter and spring, due to coal supply constraints and power plants' low coal stocks, which reduced coal-to-gas switching ability.

Daily average domestic natural gas production was 3.7% higher y-o-y during the first half of 2022, but 0.6% lower than during the fourth quarter of 2021. Meanwhile, demand from LNG export terminals kept growing, reaching an average of 12.5 bcf/d in the period from January to early June 2022[2] against 11.1 bcf/d during Q4 2021. This reflected LNG capacity expansion and Europe's supply needs. The result was higher pipeline imports from Canada and strong storage withdrawals to provide additional supply.

[2] Until the shutdown of the Freeport export terminal, which brought LNG export demand down to an average of 10.6 bcf/d for the rest of the month of June.

Upstream spending remains cautious in spite of a tight international market

The high energy price environment and tight international supply situation resulting from Russia's invasion of Ukraine have yielded mixed responses from US gas companies in their first quarter financial communications, highlighting some growing interest in potential investment opportunities while remaining cautious on their spending guidance in the face of longer-term market uncertainty.

Several leading shale gas producers, such as EQT and Chesapeake Energy, have expressed interest in taking stakes in LNG projects in order to capture strong export margins. Pipeline developers and operators like Kinder Morgan have also expressed optimism in midstream development potential to serve additional LNG export capacity, while LNG project developers have reported a strong increase in long-term contracting activity over recent months, which would support future investment decisions.

Industry players have nonetheless so far reaffirmed their low spending guidance and the priority given to shareholder returns through dividends and share buy-backs. Caution is also motivated by longer-term market uncertainty, especially for Europe's LNG needs in the framework of its decarbonisation objectives.

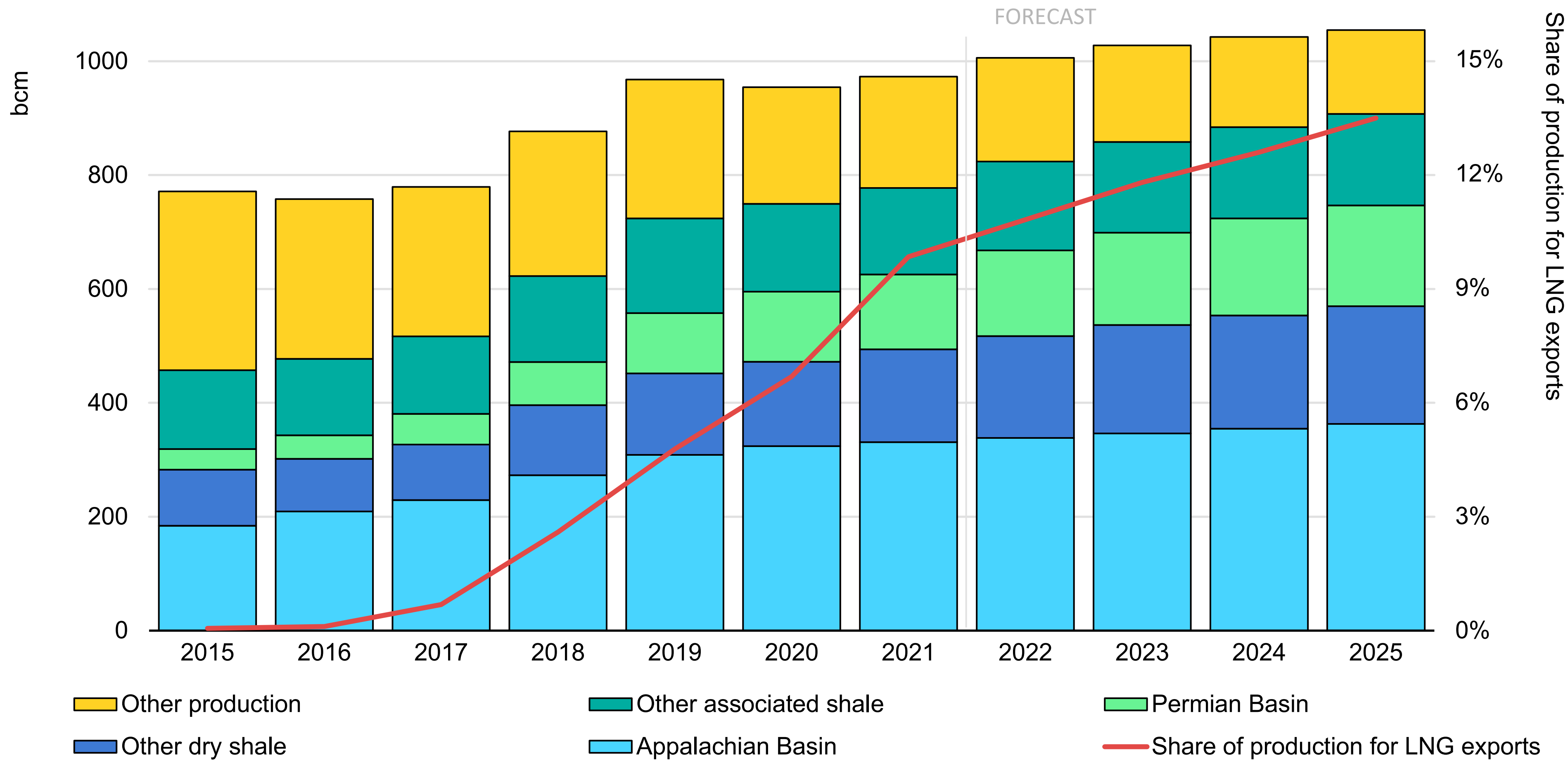
Additional production should mainly support export growth

In the absence of a significant increase in domestic consumption, medium-term US gas production growth is expected to be driven by LNG export needs, which should account for above 13% of total production volumes compared to 10% in 2021. However, the pace of LNG export capacity additions slows during the forecast period, as no new commissioning is scheduled until at least late 2024 among the projects currently under construction.

Our forecast expects US dry gas production to reach 1 055 bcm in 2025, a limited 8% increase compared with 2021. The north-eastern Appalachian Basin remains the main driver of US output increase, albeit at a slower growth rate relative to past years. Other dry shale gas plays are also expected to contribute to this modest medium-term growth, as well as associated gas from light tight oil production basins, led by the Permian, principally over the shorter term. Production from conventional natural gas fields continues to decline until 2025.

LNG export growth drives medium-term US gas production development

Dry gas production by main source in the United States, 2015-2025



South American gas production struggles to grow between limited domestic demand development and depletion in legacy producing countries

The South American gas market as a whole is close to self-sufficiency, but its two largest markets, Argentina and Brazil, rely on LNG imports to balance their seasonal needs. This leads to greater exposure to high international gas prices and triggers investment to increase access to domestic production and pipeline imports.

The development of **Argentina**'s large domestic natural gas resources, principally located in the Vaca Muerta shale play of the Neuquén Basin, has been hampered by delays in production and infrastructure investment, which resulted in the need for imports from Bolivia and the LNG market (together about 18% of supply in 2021), especially during the southern winter. The government launched the country's Fourth Gas Plan in late 2020, which provides production incentives in the form of supply contracts that upstream companies bid for in an auction process. This has resulted in domestic production growth since the second half of 2021, leading to a modest 0.5% annual increase in 2021 after the sharp decline observed in 2020 (down by close to 9% y-o-y). Against the backdrop of surging LNG costs, the government decided to fast-track the resolution of capacity bottlenecks with the development of exit pipeline capacity from the Néuquen Basin. President Fernández launched the Néstor Kirchner gas pipeline project in late April 2022. The project has an ambitious target of starting operations by mid-2023 in an initial phase for up to 22 mcm/d, thus increasing the Néuquen's exit capacity by about 30%. This first phase of the project is principally financed by the National Treasury. Our forecast expects a gradual ramp-up in use of the new pipeline capacity from late 2023, enabling it to further support production development and resulting in an average annual growth rate of production of 3.6% during the 2021-2025 period.

The vast majority of **Brazil**'s natural gas production comes from oilfields, with an increasing share in recent years: associated gas accounted for 85% of total production in 2021 compared with 73% in 2015. About half of this associated gas production is reinjected in order to maintain oil reservoir pressure, which explains how annual marketed gas production growth has been almost flat since 2015 despite an average 6% increase in gross production. Domestic production accounts for about two-thirds of the country's supply in normal years, down to about half in dry years like 2015 and 2021 when gas demand from the power sector surges to compensate for lower hydroelectric output. The continued development of offshore oil and gas resources, especially in the pre-salt layer, is expected to remain the principal driver of Brazil's hydrocarbon production for the coming years; however, as a significant proportion of pre-salt associated gas is to be used for reinjection, the net gas production increase will be limited – our forecast expects an average 0.3% increase per year.

Bolivia's natural gas production has been on a declining trend since its peak in 2014, due to the depletion of legacy fields and low investment in new exploration and production. Gross output declined from a peak above 22 bcm to about 16.5 bcm in 2021. Pipeline exports to neighbouring Argentina and Brazil accounted for close to 75% of the country's gas production in 2021. Bolivia's long-term export contracts are currently due to expire in 2026, but the decline in production and domestic market needs create uncertainty on the country's ability to maintain sufficient supply levels. The recent discovery in the Margarita field, announced in February 2022, has potential reserves estimated at up to 10 bcm and is expected to help balance the country's declining production; the Margarita-10 well started production in early June 2022 and is expected to deliver up to 3 mcm/d. This volume would help Bolivia meet its export agreements, but would not be sufficient to reverse the trend. State-owned YPFB announced in March 2022 an investment target of USD 1.4 billion in 21 exploration prospects, with the objective of discovering 5 Tcf of gas. In the absence of further additional short-term developments, our forecast expects Bolivia's gas production to decline at an average annual rate of 1.4% for the 2021-2025 period.

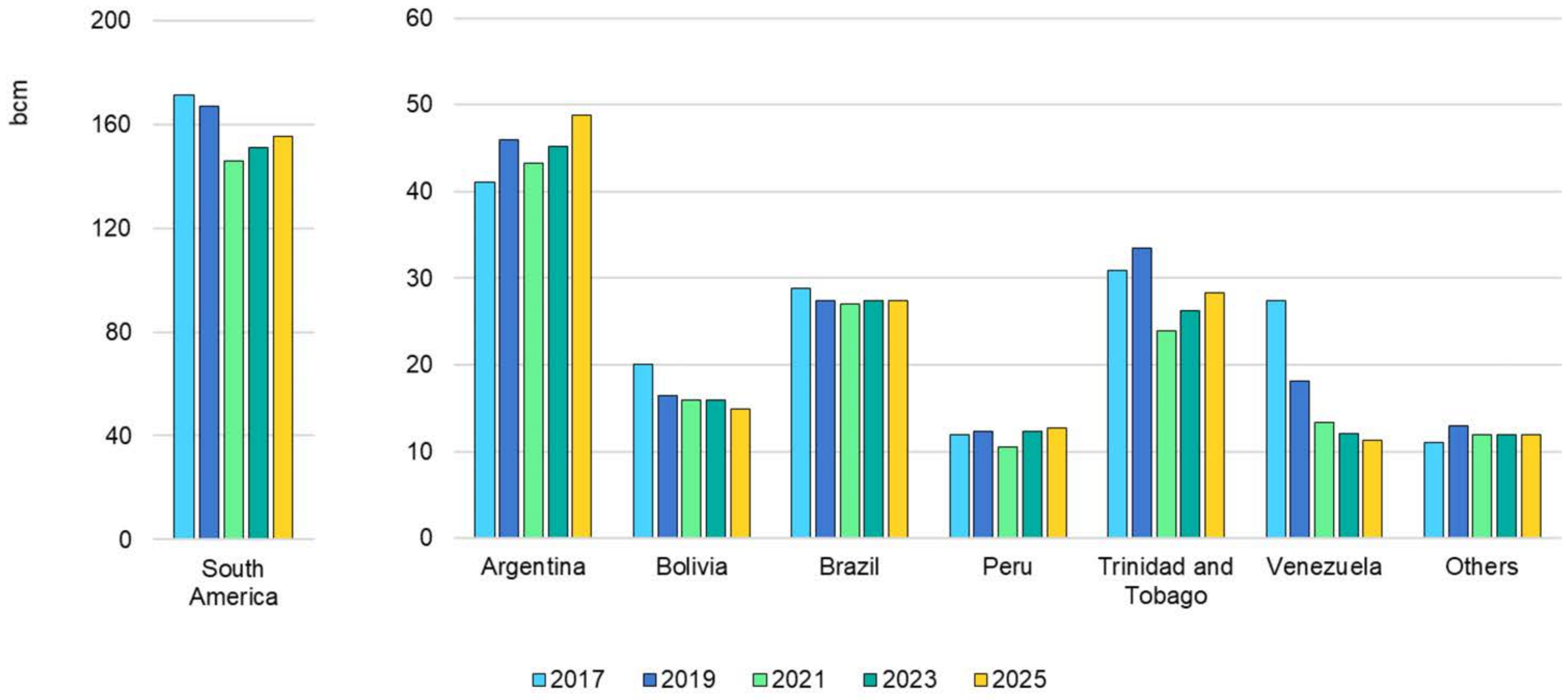
Natural gas production in **Peru** principally comes from the Camisea field (over 80% of total supply) and serves both the domestic (about 70% of output in 2021) and LNG export markets. Production declined by close to 6% in 2021 due to LNG export capacity outages, but had returned to its previous monthly levels by the end of the year and grew by 22% y-o-y in the first four months of 2022. The government is planning the development of a southern extension to the integrated gas transmission system (SIT-GAS project), which would open up new sources of demand for power generation and industry from 2024. This would result in accelerated development of the current proven reserves in the Camisea field (expected production growth at an average rate of 4.7% during the 2021-2025 period) and further development beyond 2025 to sustain longer-term production growth.

Trinidad and Tobago's gas output declined by close to 30% between 2019 and 2021 due to technical issues, which hampered its export capacity and led to the mothballing of one of the four liquefaction trains at the Atlantic LNG export plant. New offshore production capacity has been commissioned recently, including Barracuda in July 2021 (220 MMcf/d at peak), Matapal in September 2021 (up to 350 MMcf/d) and Colibri in March 2022 (250 MMcf/d at peak), but it is not sufficient to compensate for the previous decline. Further developments and exploration are planned, but their timing to deliver production remains uncertain, leading to anticipated average annual growth of 4.2% for 2021 to 2025, providing a partial return to previous production levels.

Gas production in **Venezuela** has been on a steep declining trend since 2018 due to lack of investment; this trend is expected to persist during the forecast period, with an average 4% annual drop.

South American gas production is expected to increase to 2025, but to remain below its pre-pandemic levels

Natural gas production in South America, 2017-2025



Spotlight on low-carbon gases

Clean gas policies pave the way for the deployment of low-carbon gases

Low-carbon gases are today at the intersection of energy supply security and decarbonisation efforts: besides contributing to lower-emission pathways, domestically produced low-carbon gases enhance market resilience and can reduce significantly reliance on fossil fuel imports. Effective policy initiatives, targeted sector-specific regulations and enhanced international co-operation can fast-track their production and deployment in the short to medium term.

The European Commission published its [Hydrogen and Decarbonised Gas Market Package] in December 2021, including proposed amendments to the regulation on natural gas transmission networks and revision of the directive on common rules for the internal market for natural gas. The package lays down the foundations for the integration of low-carbon gases, including hydrogen, into the broader European gas system. The proposed regulation provides guidelines on the gradual implementation of non-discriminatory third-party access to hydrogen networks, blending limits, tariffs, network codes and operational transparency. To facilitate the initial integration of low-carbon and renewable gases, the proposed regulation foresees abolishing cross-border tariffs and reducing injection costs by 75%. The tariff exemptions would remain in place until 1 January 2031. In addition, a 5% cap on hydrogen blends would be introduced by 1 October 2025 at interconnection points between member states to avoid cross-border flow restrictions due to differences in gas quality. To ensure the optimal management of an EU-wide hydrogen network and facilitate cross-border trade, a European Network of Network Operators for Hydrogen (ENNOH) would be established. Notably, ENNOH would publish non-binding, EU-wide, ten-year network development plans for hydrogen. Starting on 1 January 2031, hydrogen network operators would be organised under entry–exit systems and should allow non-discriminatory third-party access. Capacity allocation mechanisms, balancing rules and tariffs should also be set in a non-discriminatory manner. As part of the European Union's legislative process, the proposed Hydrogen and Decarbonised Gas Market Package is currently subject to consultation with national parliaments.

Low-carbon gases are set to play a pivotal role in the European Union's efforts to phase out Russian natural gas well before 2030. The European Commission's [REPowerEU Plan] foresees biomethane production ramping up to 35 bcm/yr by 2030 – a more than tenfold increase from today's levels. As for low-emission hydrogen, REPowerEU foresees annual renewable hydrogen supply of 20 Mt by 2030, of which 10 Mt would be imported from diverse sources. Depending on the end-use sector, the rapid scale-up of low-emission hydrogen could replace 34-68 bcm/yr of natural gas by 2030.

Ukraine's parliament adopted a law on biomethane production in October 2021. The law defines biomethane, provides for non-discriminatory access to gas networks (both transmission and distribution level), lays down the legislative grounds for the establishment of a biomethane registry and introduces the concept of "guarantee of origin". Considering Ukraine's substantial biomethane and hydrogen production potential, low-carbon gases could play a significant future role in reducing the country's gas import requirements and could potentially enable exports to the rest of Europe.

Japan's 6th Strategic Energy Plan, approved in October 2021, sets a target to introduce a 5% share of carbon-neutral gas into existing networks by 2030, including 1% synthetic methane. Under the plan, hydrogen and ammonia would account for 1% of Japan's power mix by 2030. The share of synthetic methane would rise to 90% of city gas supply by 2050.

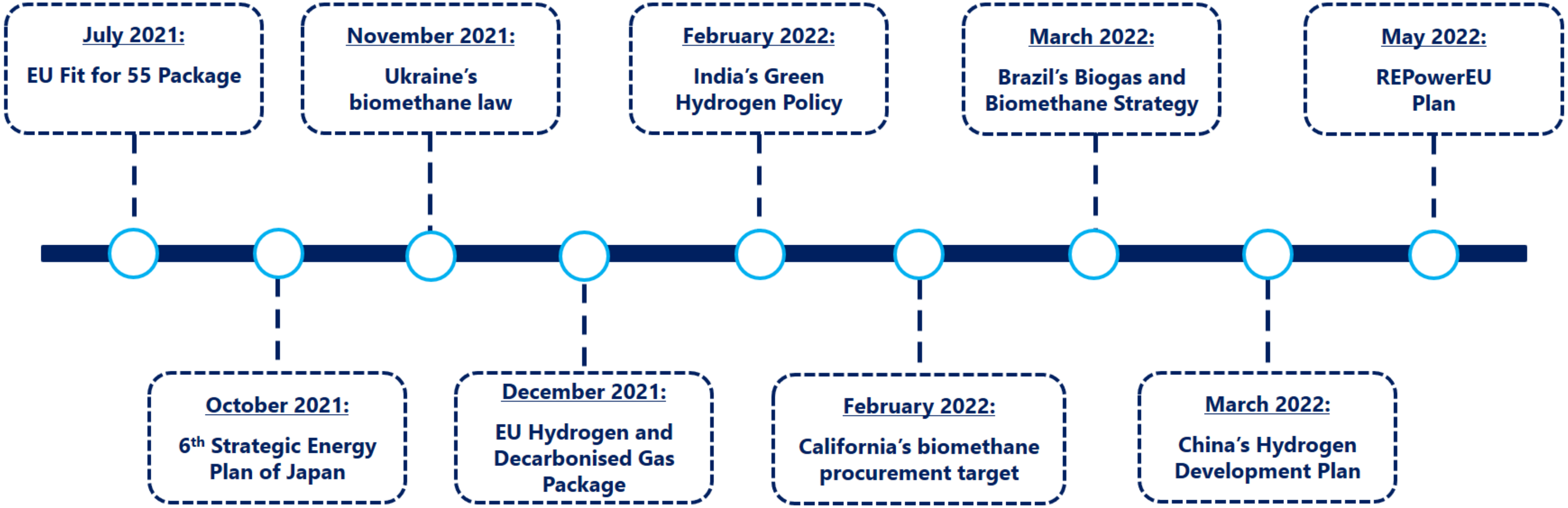
China's 14th Five-Year Plan for a Modern Energy System expects hydrogen to develop on a large scale and drive fundamental changes in the energy system. The National Development and Reform Commission published China's first medium-term plan for a clean and green hydrogen industry in March 2022: the Medium and Long-term Plan for the Development of Hydrogen Industry (2021 to 2035) set a production target of 0.1-0.2 Mt/yr of hydrogen from renewable energy by 2025 (translating into 1-2 Mt/yr of carbon emission savings).

India released an interim hydrogen/ammonia policy in February 2022, with the aim of producing 5 Mt/yr of renewable hydrogen by 2030. According to the policy initiative, projects commissioned before June 2025 will not have to pay interstate transmission charges for 25 years and will be granted priority when seeking connection to the grid. A more detailed policy document is expected, potentially including hydrogen purchase obligations on carbon-emitting sectors.

California's Public Utilities Commission in February 2022 set biomethane procurement targets for utilities to reduce short-lived climate pollutant emissions. The short-term 2025 biomethane procurement target was set at 0.5 bcm, increasing to over 2 bcm by 2030.

Brazil launched the Federal Strategy to Incentivise the Sustainable Use of Biogas and Biomethane in March 2022. Besides providing a definition of biogas and biomethane, the decree includes guidelines on the development of biomethane supply chains, promotion of biomethane consumption and measures to reduce methane emissions. The total anticipated investment amounts to USD 1.4 billion with the plan to build 25 new facilities across six states.

Key clean gas policies and initiatives adopted since mid-2021



Sources: IEA analysis based on various policy documents.

Europe and the United States continue to lead biomethane production growth

Global biomethane production grew by an estimated 16% in 2021 to over 5.5 bcm. This has been largely supported by strong growth in the United States and the European Union, primarily Denmark and France.

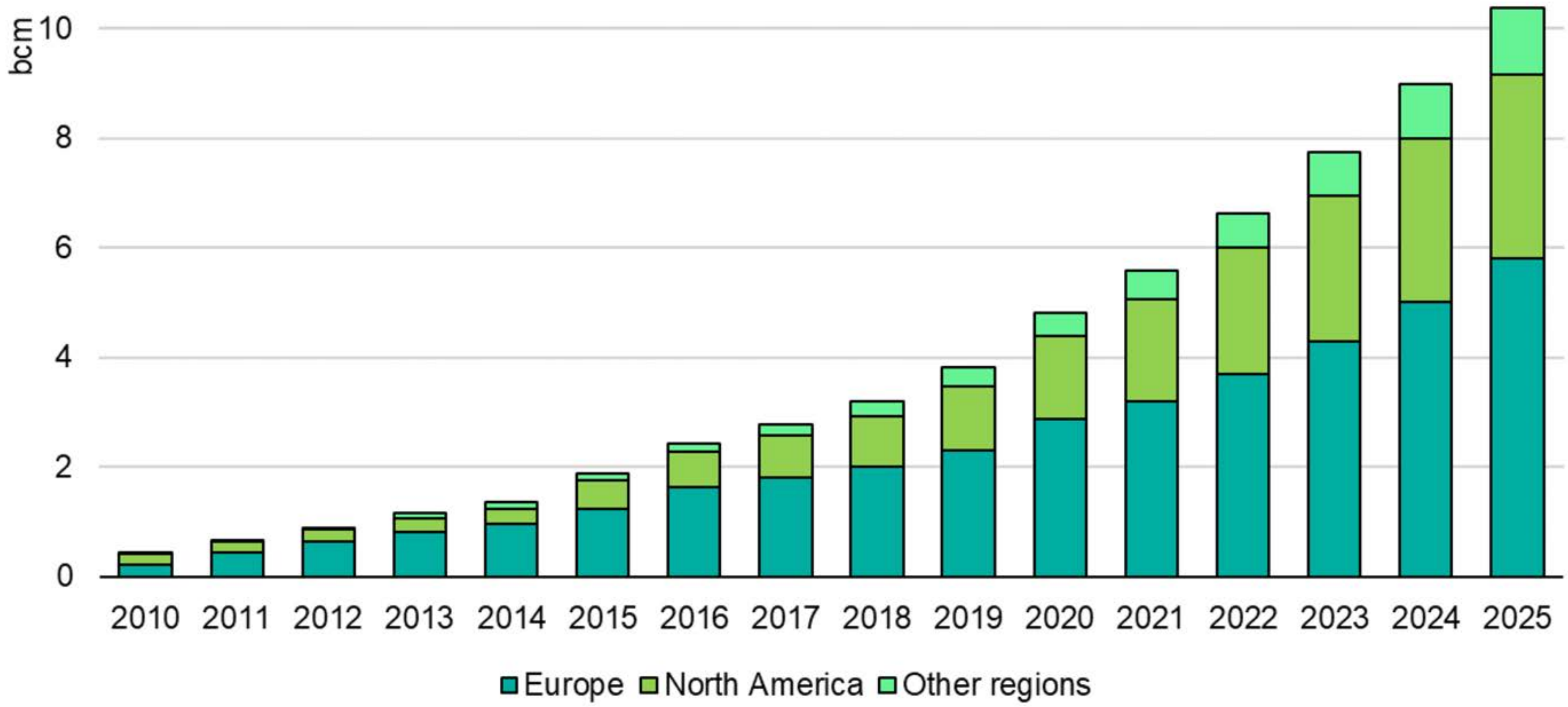
In the last two years the United States has solidified its position as the world's largest biomethane producer. The number of operational biomethane production facilities has more than doubled since 2019, while the country's biomethane production capacity rose by over 60% to reach 1.7 bcm/yr in 2021. Landfill gas remains the dominant feedstock, associated with over 70% of biomethane production capacity, followed by agricultural waste (20%), food waste (5%) and wastewater (3%). Around 90% of biomethane production facilities have grid injection capability, with the remaining 10% dedicated to on-site use. In the United States over 80% of biomethane is used as a transport fuel and only around 10% for power generation. Biomethane use in the transport sector almost tripled between 2016 and 2020 to account for over half of all on-road fuel used in natural gas vehicles.

Biomethane production in Europe rose by a record 0.6 bcm in 2020 to reach 2.9 bcm. This has been largely driven by Denmark and France, which together accounted for almost half of incremental biomethane supply. **Germany** remains Europe's largest biomethane producer with over 1 bcm output in 2020. It is estimated that over 90% of its biomethane plants have grid injection capability, most of them connected to distribution networks. Preliminary data indicate that biomethane production continued to grow strongly in some of Europe's key markets. In **Denmark** biomethane output rose by 36% to reach over 0.5 bcm in 2021. As such, biomethane met over 20% of Denmark's total gas demand in 2021 – the highest share in any European country. The share of biomethane reached a daily record of over 50% in September 2021. In **France** biomethane output grew by an impressive 90% to reach almost 0.3 bcm in 2021.

Global biomethane production is expected to double in the medium term to reach over 10 bcm/yr in 2025. This growth is largely driven by Europe and North America, where biomethane is supported through a variety of subsidy schemes and benefits from well-developed and interconnected gas grids. Biomethane production in the **United States** is foreseen to increase at an average rate of 17% per year during the forecast period to reach over 3 bcm by 2025. Production in **Europe** is expected to continue to grow at a similarly strong rate of 16% per year to reach over 5.5 bcm by 2025. The right set of policy measures and enhanced subsidy mechanisms could enable stronger growth in Europe, with the potential of reaching over 10 bcm by 2025.

Global biomethane production is expected to reach 10 bcm by 2025

Biomethane production by region, 2010-2025



Sources: IEA analysis based on Argonne National Laboratory (2020), Database of Renewable Natural Gas (RNG) Projects: 2020 Update; Biogas Partner (2021), Biogaspartner Einspeiseatlas Deutschland; Cedigaz (2021), Global Biomethane Database; Energinet (2021), Energi Data Service; GRDF (2021), Production annuelle de biométhane par site d'injection.

Low-emission hydrogen continues to gain traction

Low-emission hydrogen can play a significant role in decarbonising existing gas and energy systems. Besides its environmental benefits, domestically produced low-emission hydrogen can reduce reliance on fossil fuel imports and enhance the resilience of energy markets.

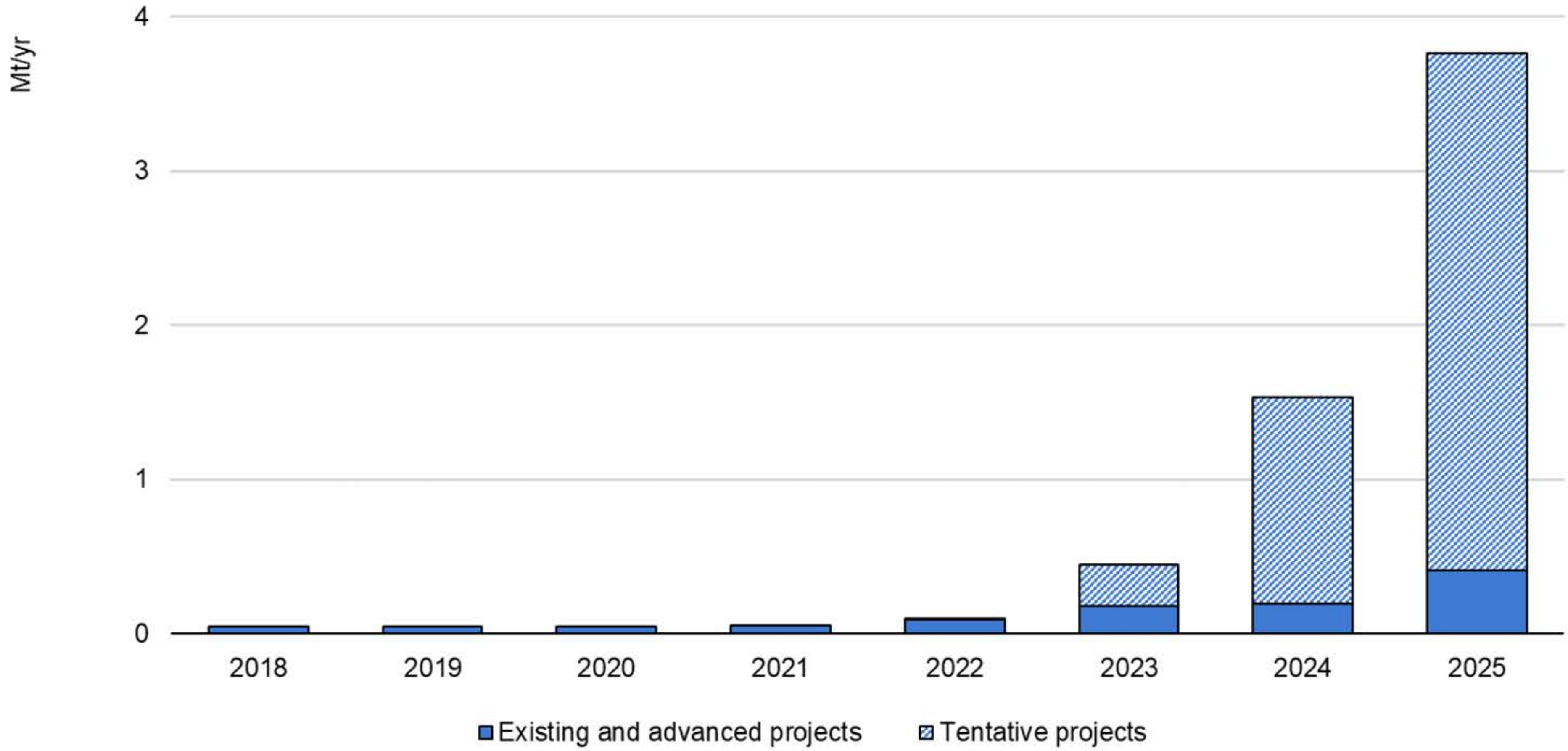
The European Union and its member states recently set more ambitious hydrogen production capacity targets for the medium term. The European Commission's REPowerEU Plan foresees 20 Mt of renewable hydrogen supply by 2030, of which 10 Mt would be produced domestically and 10 Mt imported. According to initial estimates, 20 Mt of low-emission hydrogen could reduce natural gas demand by 34-68 bcm, depending on the end-use sector. Germany announced at the start of 2022 the doubling of its hydrogen electrolyser capacity target to 10 GW by 2030. Ruling parties in the Netherlands proposed doubling the country's 4 GW target to 8 GW by 2030. Denmark announced its Power-to-X Strategy in March 2022, targeting 4-6 GW of electrolyser capacity by 2030. The United Kingdom similarly aims to double its hydrogen production target to 10 GW by 2030, with at least half of it from electrolytic hydrogen. Achieving these targets would require an increase in electrolyser manufacturing capacity. The major electrolyser manufacturers in Europe have already agreed to deliver capacity of 17.5 GW/yr by 2025.

The IEA Hydrogen Projects Database indicates that Europe continues to lead on low-emission hydrogen developments. Based on advanced projects (either under construction or having reached FID), Europe alone would contribute over 55% of global incremental production capacity by 2025. However, reaching its ambitious production targets by 2030 would necessitate the more rapid implementation of projects. European hydrogen production capacity is set to increase more than sevenfold by 2025 to 0.4 Mt/yr, falling short of the announced targets. If tentative projects (either conceptual or subject to feasibility studies) are considered, Europe's low-emission hydrogen production capacity would soar by almost 70 times to over 3.5 Mt/yr by 2025.

Accelerating the deployment of low-emission hydrogen will require stronger policy support, to "pull" investment along the entire value chain of hydrogen supply. Public funding programmes and state-backed risk-sharing mechanisms can help to de-risk investment and improve the economic feasibility of low-emission hydrogen projects. Demand creation should be a key instrument to stimulate investment, including via quotas and public procurement rules. The IEA's forthcoming Global Hydrogen Review will provide in-depth analysis of recent low-emission hydrogen developments.

Reaching Europe's hydrogen ambitions will require stronger policy support

Low-emission hydrogen production capacity in Europe, 2018-2025



Source: Analysis based on IEA (2022), Hydrogen Projects Database.

Synthetic methane: The next frontier for low-carbon gases?

Synthetic methane is produced by combining low-emission hydrogen and a carbon source. The production process presents substantial efficiency losses. Approximately half of the primary energy supplied is lost during the two-step conversion process from electricity to hydrogen and from hydrogen and the carbon source to synthetic methane. Moreover, its production requires the development of a separate carbon value chain and emission accounting system (to ensure its carbon neutrality). Consequently, the production cost of synthetic methane remains elevated, estimated at USD 50/MBtu. Hence, further technological development and policy support will be required.

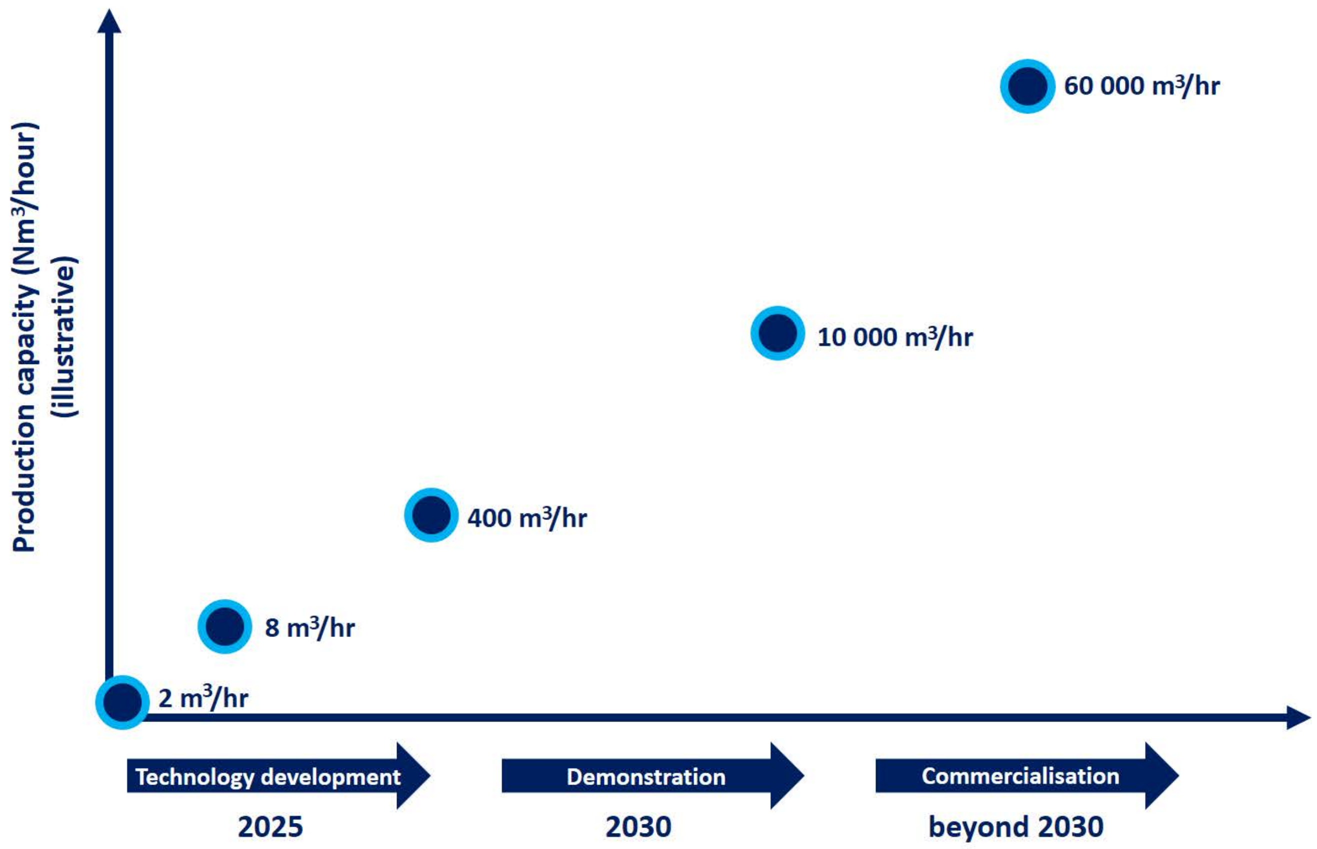
Synthetic methane could play a significant role in decarbonising existing gas networks without retrofitting, while enhancing the seasonal and short-term flexibility of future energy systems. Synthetic methane is perfectly interchangeable with natural gas due to their almost identical chemical and physical properties. As such it is suitable for use in existing gas networks without requiring any substantial repurposing as in the case of pure hydrogen. Synthetic methane could also be stored in porous formations in gaseous form (an option still being investigated for pure hydrogen) and in LNG storage tanks (an option that is unlikely to be available for pure hydrogen). The availability of widespread storage options would allow synthetic methane to play a key role in meeting seasonal or short-term energy demand swings. In addition, synthetic methane would enable the coupling of methane and hydrogen networks, i.e. surplus hydrogen could be converted into synthetic methane before being injected into the methane system.

Recognising the benefits of synthetic methane, Japan is considering methanation as a key component of its strategy to decarbonise gas supply. The country's 6th Strategic Energy Plan set a target for synthetic methane to comprise 1% of the gas supply in existing networks by 2030, increasing to 90% by 2050. A number of pilot projects are currently being implemented or designed. Tokyo Gas started a small-scale demonstration project in Yokohama in March 2022. The company has a target of producing 80 million m^3/yr of synthetic methane by 2030. INPEX and Osaka Gas are set to launch the world's largest-scale synthetic methanation plant in Nagaoka by the second half of FY 2024/25. Production is expected to ramp up to 400 m^3/hr by FY 2025/26. Osaka Gas has a target of producing 60 million m^3/yr of synthetic methane by 2030. In addition to their domestic projects, some Japanese utilities and trading houses started jointly exploring the feasibility of a synthetic methane supply chain in LNG exporting countries.

Several pilot projects are being developed/tested in Europe, including Jupiter 1000 in France and in Falkenhagen in Germany.

Japan foresees a key role for synthetic methane in decarbonising gas supply

Japan's roadmap for methanation scale-up



Sources: IEA analysis based on Mr Taichi NODA (Director of the Gas Market Office, Japan's Ministry of Economy, Trade and Industry [METI]) presentation on Low-carbon gases in Japan's Strategy reaching Net Zero by 2050.

Looking for a purpose: Adapting existing gas infrastructure for a low-carbon future

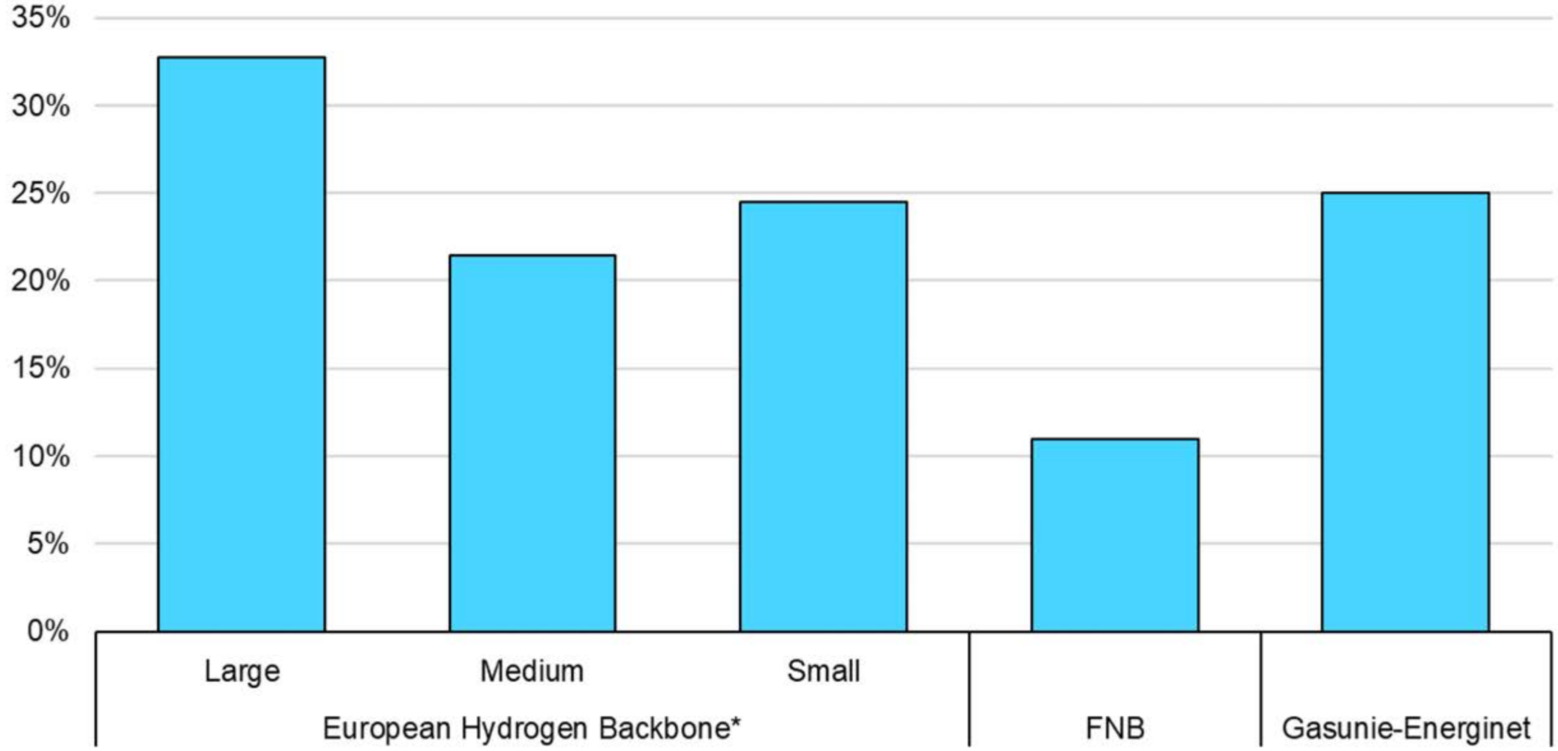
The existing natural gas infrastructure can fast-track the deployment of low-carbon gases, although large-scale transition would require the reconfiguration and adaptation of the gas system.

Biomethane and synthetic methane are well-suited to the existing gas infrastructure as they have almost identical physical and chemical characteristics to natural gas. Nevertheless, scaling them up in the future might necessitate a gradual reconfiguration of the broader gas system. Given the decentralised form of its production the majority of biomethane is fed into local distribution grids. The high penetration of low-carbon gases at the distribution level would require closer integration between transmission and distribution networks. This would include the introduction of reverse-flow stations or bidirectional compressors to enable reverse flows from distribution to the transmission network. Reverse flows would also facilitate biomethane's access to underground storage sites, which are typically connected to the transmission grid. There are currently over 15 reverse flow stations in operation in the European Union and around 25 are under construction. In France, one of the most dynamic markets for biomethane development, 100 reverse flow projects are planned by 2030.

In the case of hydrogen, blending into methane can provide a transitional solution, although reaching the more ambitious medium-term targets will require the development of dedicated hydrogen networks. Converting existing methane pipelines to hydrogen can result in substantial cost savings and shorter lead times when compared with new-build hydrogen networks. Various studies estimate repurposing costs to be just 10-35% of the cost of constructing new hydrogen pipelines. The first gas-to-hydrogen pipeline conversion project took place in the Netherlands in 2018. A number of pilot projects are currently being implemented, including in Australia, France and Germany. **Germany**'s Ten-Year Network Development Plan (2020-2030) foresees 452 km of additional hydrogen pipelines by 2025, of which 85% would be repurposed natural gas pipelines. In the **Netherlands** Gasunie announced in June 2021 its intention to roll out a national hydrogen transport infrastructure by 2027. The hydrogen network would have a throughput of 10 GW and would consist of around 85% repurposed natural gas pipes. In the **United Kingdom** National Grid expects to create a 2 000 km hydrogen backbone by repurposing around 25% of the existing gas network by 2030. Besides pipelines, other parts of the gas infrastructure could be potentially converted to serve hydrogen. In Germany Uniper plans to convert the former Krummhörn salt cavern storage facility to serve hydrogen with a storage volume up to 250 000 m^3. The project is expected to start commercial operations in 2024, with investment costs estimated at EUR 10 million.

Gas-to-hydrogen pipeline conversions can result in substantial cost savings

Cost of repurposing natural gas pipeline for hydrogen as a percentage of building new hydrogen pipeline



* Including compressor station CAPEX costs.

Notes: FNB = FNB Gas (the association of supra-regional gas transmission companies in Germany).

Sources: IEA analysis based on FNB (2020), Netzentwicklungsplan 2020; Gas For Climate (2022), European Hydrogen Backbone 2022; Gasunie-Energinet (2021), Pre-feasibility Study for a Danish-German Hydrogen Network.

Trade

Global gas trade growth is expected to slow significantly in the medium term

Global gas trade – including both LNG and long-distance pipeline[3] – grew by over 9% in 2021, equivalent to 85 bcm. This was its strongest growth on record. However, lower liquefaction capacity additions, together with the reduction in Europe's piped imports from Russia, are set to significantly slow global gas trade growth in the medium term. It is expected to grow at an average rate of 1.2% per year during the forecast period, compared with an average of 4.3% per year between 2017 and 2021. An accelerated phase-out of Russian gas imports by the European Union would further reduce global gas trade growth to below 0.5% per year over the forecast period.

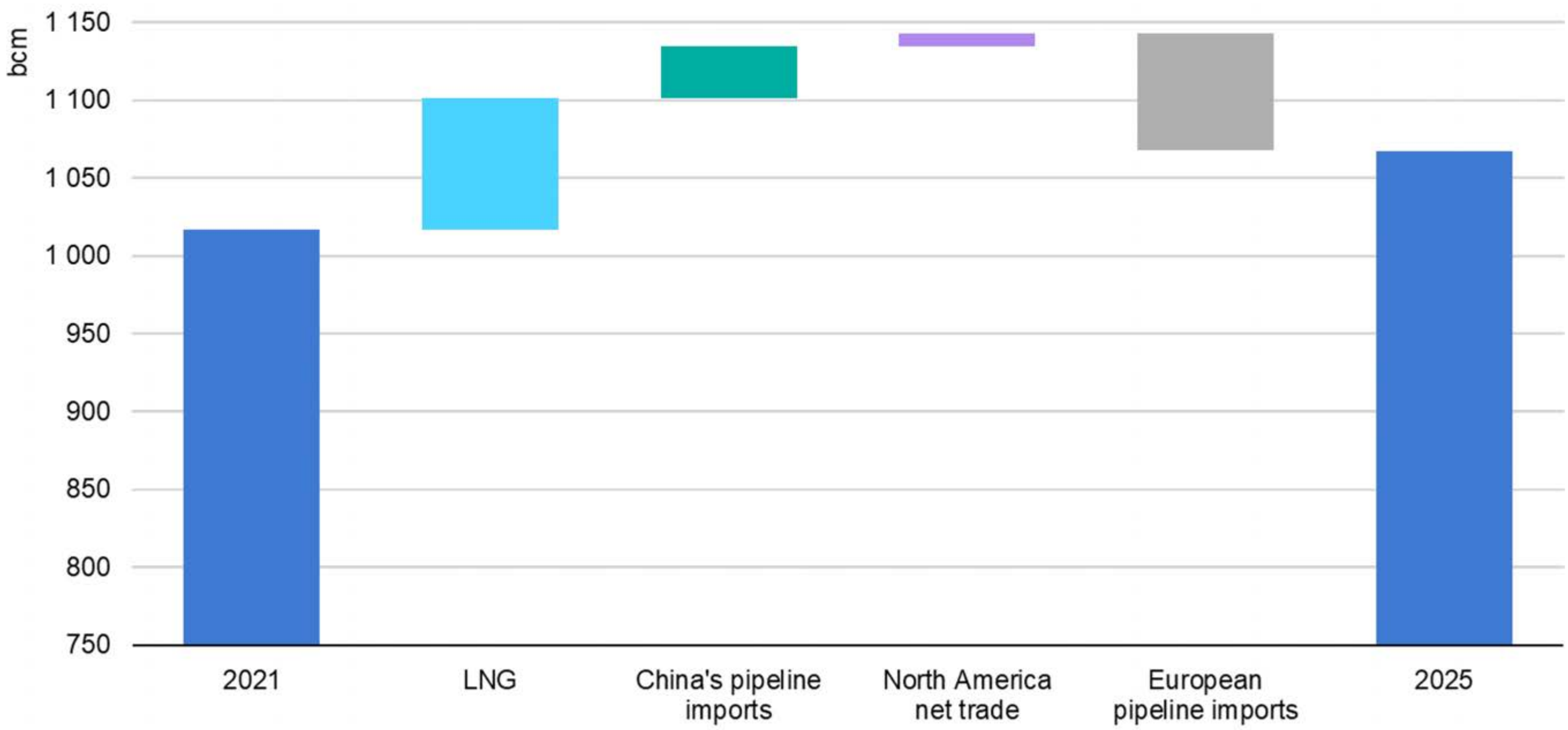
LNG trade is expected to expand by close to 17% (or 85 bcm/yr) between 2021 and 2025, accounting for virtually all net growth in global gas trade through the forecast. Liquefaction capacity additions are set to average just over 20 bcm/yr between 2021 and 2025, around half of the 40 bcm/yr average between 2017 and 2020. The annual 4% growth in global LNG trade in the forecast period is a far cry from the 7% experienced between 2017 and 2021. Limited liquefaction capacity additions, together with strong LNG demand from Europe and lower Russian piped imports, indicate that the current tight market conditions may linger into the medium term.

Long-distance pipeline trade is expected to decline by 1.9% per year between 2021 and 2025. This is largely driven by Europe's lower pipeline imports from Russia in the aftermath of its invasion of Ukraine. Russian pipeline exports to OECD Europe are expected to halve by the end of the forecast period compared to their 2021 levels. A complete cut of Russian pipeline supplies to the European Union cannot be excluded, which would overwrite the current outlook. Alternative pipeline imports into Europe are expected to increase only marginally, not sufficient to offset the steep drop in Russian gas imports. China's extra-regional piped imports (excluding Myanmar) are expected to increase by almost 60% by 2025 compared with their 2021 levels. This growth is largely dominated by the ramp-up of Russian export flows via the Power of Siberia pipeline, which are set to reach 38 bcm/yr by 2025. In North America net pipeline trade is expected to gradually increase thanks to higher US flows to Mexico.

[3] For the purpose of this analysis, long-distance pipeline trade includes Europe's pipeline imports (including deliveries from Norway), North American net pipeline trade and China's pipeline imports.

LNG remains the main driver of global gas trade during the forecast period

Main drivers of global gas trade growth, 2021-2025



Global LNG trade growth is led by European demand and North American supply in 2021-2025

Global LNG trade is projected to reach 594 bcm by 2025, a 17% (85 bcm) increase from 2021 levels. This corresponds to an annual average growth rate of just under 4% during the 2021-2025 period, lower than the nearly 6% increase recorded in 2021 and well below the 7% annual average increase registered between 2017 and 2021.

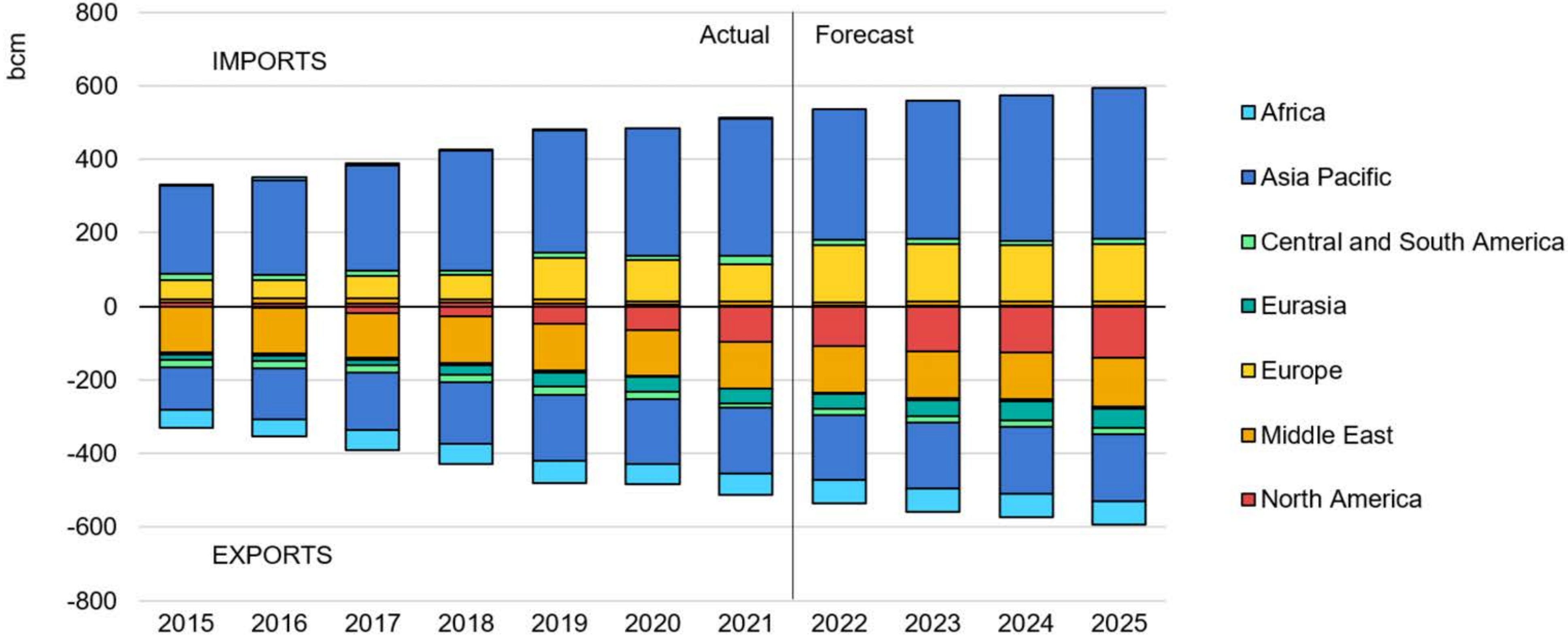
LNG import growth is led by Europe, which is projected to boost its LNG intake by 51% (53 bcm) between 2021 and 2025 as the continent tries to wean itself off Russian pipeline gas imports. As a result, Europe is set to account for more than 60% of the net global growth in LNG imports during the forecast period. The Asia Pacific region remains a strong secondary driver of import growth, registering an 11% (39 bcm) increase in the same period. However, in absolute terms this is less than half the growth Asian importers achieved in the previous four-year period of 2017-2021. Following last year's droughts – and record-breaking LNG inflows – in Central and South America, the region is expected to return to just below the 2015-2020 average level of imports in the 2022-2025 period. LNG imports into the Middle East (led by Kuwait) register small increases, while Africa and North America see further small declines.

LNG export growth is dominated by North America, which is on course to increase LNG output by 46% (44 bcm) in the 2021-2025 period. Altogether the region accounts for 54% of LNG export growth globally. This expansion is fuelled by the continuing ramp-up of production in the United States – both from recently commissioned projects (Sabine Pass train 6, Calcasieu Pass) and new plants currently under construction (Golden Pass). Energía Costa Azul on the west coast of Mexico and LNG Canada in British Columbia also contribute to North America's production surge from 2024 and 2025, respectively. Russia is the number two driver of LNG export growth with a projected increase of 28% (11 bcm) between 2021 and 2025. This is due to the launch of the small-scale Portovaya LNG project and the start-up of the first train of Arctic LNG 2. However, the completion of the second and third trains of Arctic LNG 2 is no longer expected within our forecast period due to Western sanctions.

Growing exports from Africa (up by 13% or 7 bcm) are fuelled by new projects in Mozambique (Coral South FLNG), Nigeria (NLNG train 7) and Senegal (Tortue). Output from the Middle East is solely driven by Qatar's expansion project, which is scheduled to start ramping up in the second half of 2025. Export growth in Europe and South America results from recovering output at existing plants, while production in the Asia Pacific region is projected to remain flat in the 2021-2025 period.

Global LNG trade volume is on course to approach 600 bcm by 2025

World LNG imports and exports by region, 2015-2025



LNG investment: On the verge of a new FID cycle?

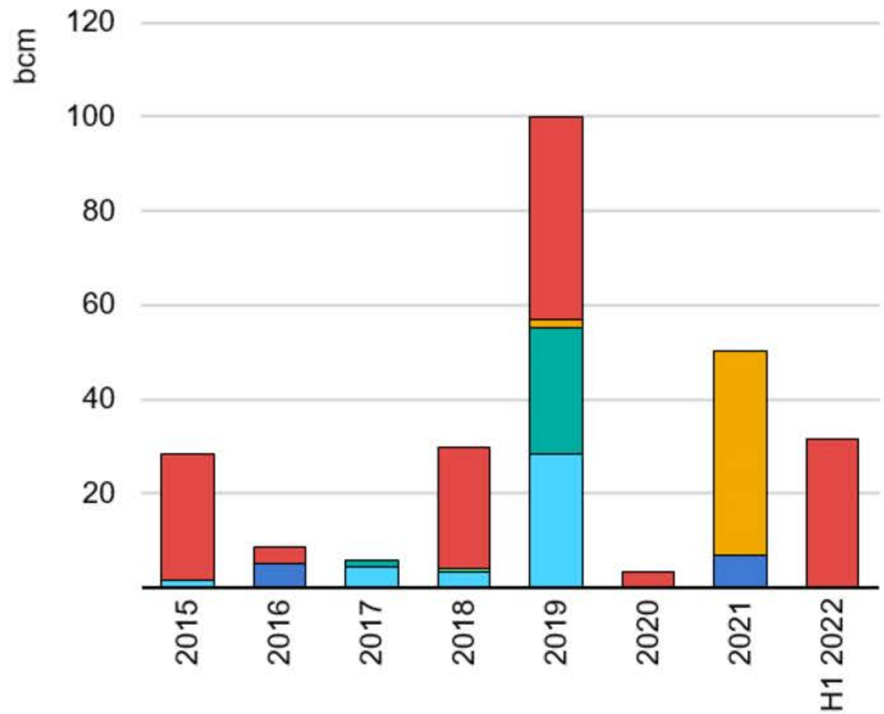
After a record year in 2019, when project developers approved close to 100 bcm of new capacity, FIDs on LNG projects saw a near-complete collapse in 2020 with only one small project (the Energía Costa Azul plant in Mexico) taking FID as falling oil and gas prices in the wake of the Covid-19 crisis put the brakes on investment. Project sanctioning saw a tentative recovery in 2021 with the approval of Qatar's 44 bcm North Field East expansion (the largest FID ever taken) and Pluto LNG train 2 in Australia, continuing with the launch of the 18 bcm first phase of the Plaquemines project and the 14 bcm Corpus Christi Stage 3 development on the US Gulf Coast in 2022.

Annual capital spending on already approved liquefaction projects rebounded sharply from a low point of USD 14 billion in 2020 to more than USD 23 billion in 2021, and based on projects already sanctioned it is expected to average USD 24 billion over the 2021-2025 period, 10% higher than the annual average between 2017 and 2021. Half of the total spend in 2021-2025 is projected to take place in North America, where more than 100 bcm of new capacity has been sanctioned since 2018. Golden Pass, Plaquemines and Corpus Christi Stage 3 in the United States and LNG Canada in western Canada are the biggest drivers of spending in this region over the forecast horizon. Projected spending levels in Africa have been lowered due to the suspension of work on the Mozambique LNG project in 2021 amid insurgent attacks in the vicinity of the construction site. Uncertainty around the completion of the second and third trains of the Arctic LNG 2 project in Russia amid western sanctions has also compressed the spending profile in Eurasia to 2025.

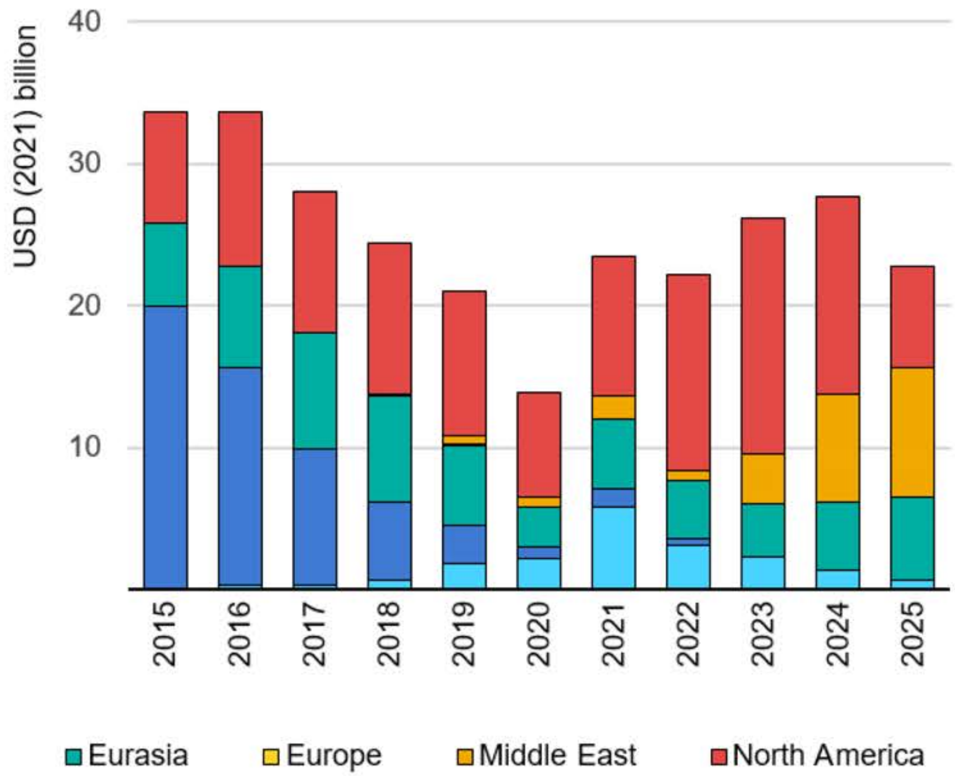
High and volatile spot LNG prices, forward curves that position both oil-linked and Henry Hub-linked LNG significantly below spot prices for several years into the future, and a renewed focus on gas supply security in both Europe and Asia create a favourable environment for additional FIDs. Contracting activity has seen a sharp rise since the beginning of 2021, with 92 bcm of firm LNG contracts signed in 2021 (a 60% rise from 2020) and a further 42 bcm concluded in the first half of 2022. Of the combined volume signed since the beginning of 2021, close to 90% is for long-term (10 years or longer) durations and more than 45% relates to projects that had not reached FID at the time of signing, thereby helping to underpin new liquefaction capacity. However, these favourable market conditions and the flurry of contracting activity have yet to translate into project approvals, with only two FIDs announced so far in 2022. The continuing rise of uncontracted portfolio volumes, the expiry of nearly 170 bcm of active LNG contracts by the end of 2025, and the reluctance of European buyers to sign long-term LNG contracts (despite rising short-term requirements) complicate – but certainly do not foreclose – the path to a new wave of FIDs in the current investment cycle.

LNG investment: Tentative recovery underway since 2021

FIDs for new LNG liquefaction capacity, 2015-2022



Investment in new LNG liquefaction capacity, 2015-2025

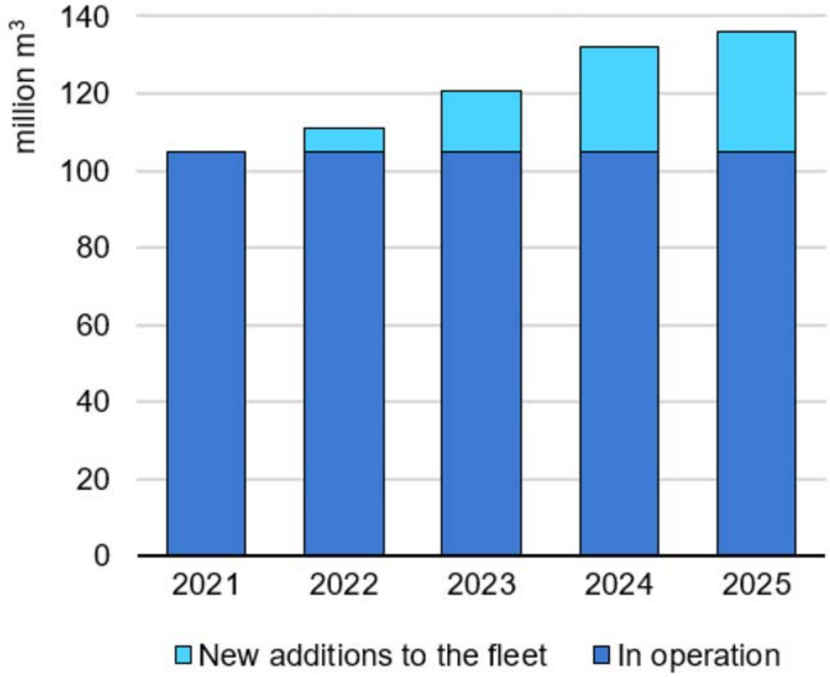


LNG shipping capacity is on course to expand by 30% between 2021 and 2025

The LNG shipping market has experienced substantial volatility and periods of seasonal tightness in recent years, including in 2021. Daily spot LNG vessel charter rates (as assessed by reporting agencies) reached a new all-time high of USD 270 000 in December 2021 as low spot vessel availability coincided with a cold start to the winter in Northeast Asia and a sharp rise in LNG demand in Europe. The previous record (USD 210 000) was set during the Northeast Asian energy crisis in January 2021, when rising tonne-mile demand and congestion on the Panama Canal seized up LNG shipping.

High spot charter rates (averaging USD 100 000 in 2021), the re-acceleration of liquefaction capacity additions from 2024 and the prospects of new LNG FIDs this year have prompted fleet operators to maintain a strong order book for LNG vessels. In 2021 more than 50 conventional LNG carriers (excluding FSRUs and small-scale vessels) were delivered and more than 90 such vessels were added to the order book. At the end of 2021 close to 180 LNG vessels were on order, which is equivalent to about 28% of the active fleet. Conventional LNG shipping capacity is expected to grow by 30% between 2021 and 2025, faster than forecasts for global LNG trade (17%) and global LNG shipping demand (23%) over the same period. Absent retirements, the projected fleet expansion should provide sufficient capacity to maintain fleet utilisation rates at comfortable levels through to 2025.

Conventional LNG shipping capacity, 2021-2025



Notes: Conventional LNG shipping capacity excludes FSRUs, small LNG carriers (under 50 000 m^3) and LNG bunkering vessels. Capacity on order excludes the majority of Qatar Energy's reservation for nearly 120 new build vessels at Chinese and Korean shipyards, which are mainly intended to serve Qatar's North Field East LNG expansion project and are expected to be progressively converted into orders over our forecast horizon. As of June 2022, only four of these vessels have been converted to firm orders, which are included in the forecast above.

Source: IEA analysis based on ICIS (2022), ICIS LNG Edge.

FSRU outlook: Surge of interest in Europe runs into fleet capacity constraints

The size of the global FSRU fleet has grown rapidly in recent years and more than doubled since 2015. At the end of 2021 the total fleet consisted of 48 vessels. However, after a period of rapid deployment of FSRU-based import facilities between 2015 and 2018, the adoption of floating regasification terminals has since slowed, and at the end of 2021 about a quarter of the fleet was either idle or employed in the less lucrative LNG carrier business instead of serving as receiving terminals. Waning interest by fleet operators led to a gradual erosion of the FSRU order book from a peak of 12 outstanding orders in 2017 to only five at the end of 2021.

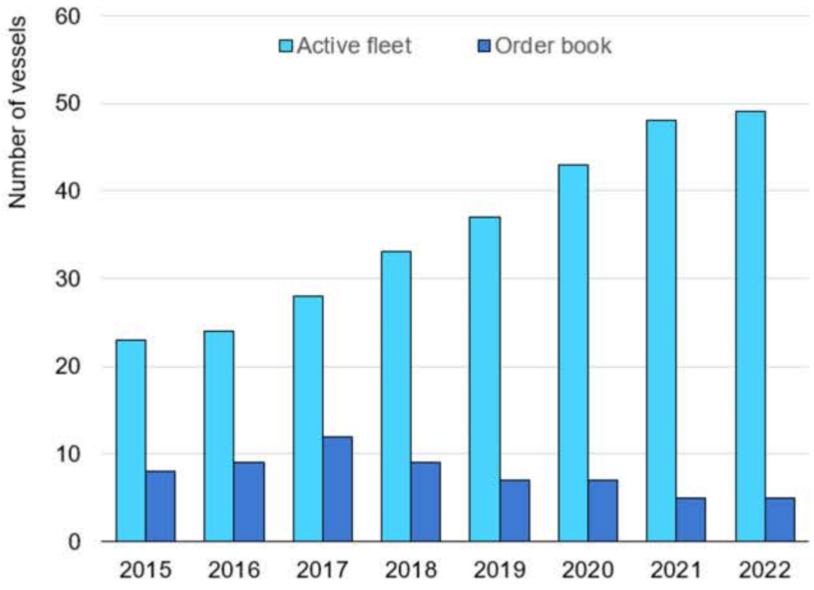
However, the Russian invasion of Ukraine – and the rapid increase in LNG demand in Europe to replace shrinking Russian pipeline gas supplies – has led to a resurgence of interest in FSRU-based terminal projects, which have considerably shorter lead times than land-based terminal infrastructure. With port facilities and pipeline connections readily available, and the FSRU chartered from the existing fleet, a floating regasification terminal can start importing LNG within less than 12 months after project approval (though such conditions are far from universal), whereas a land-based terminal takes 3 to 5 years to complete.

The renewed appetite of European governments and utilities for FSRU vessels has quickly run into the capacity constraints of the existing and under-construction fleet. As of mid-2022 European importers had secured as many as 12 FSRU vessels for newly proposed and revived regasification projects, comprising Germany (4), the Netherlands (2), Italy (2), Finland (1), Greece (1), Cyprus (1) and Albania (1). At least six additional European FSRU projects have been announced, in Greece (3), Poland (1), France (1) and the United Kingdom (1). Another five active and under-construction units were committed to projects outside Europe, bringing the total call on FSRUs to at least 23 vessels within our forecast horizon.

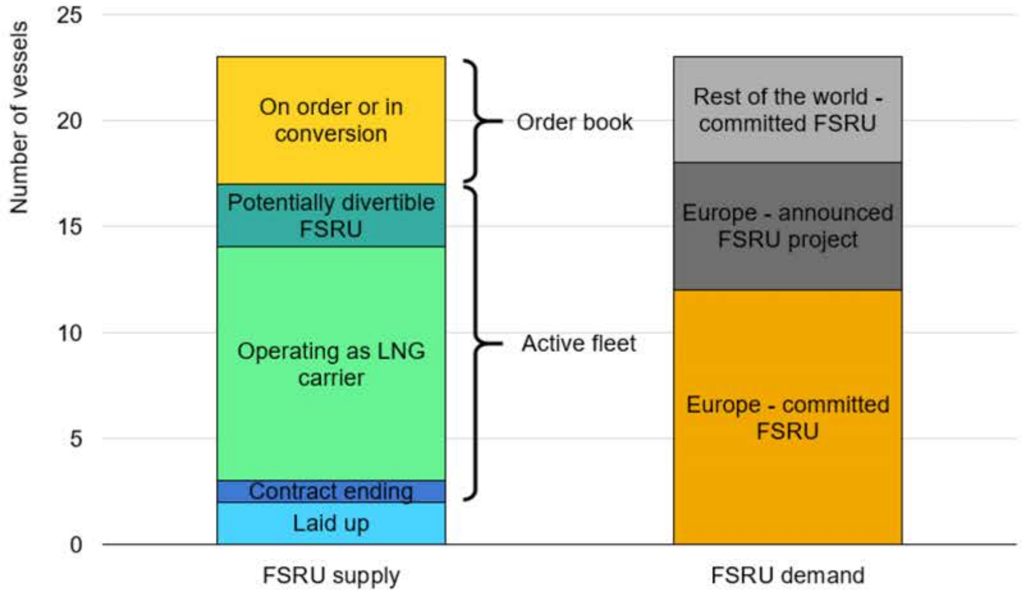
To accommodate this requirement, as of mid-2022 the existing fleet had 11 vessels operating as LNG carriers, two vessels laid up but redeployable as FSRUs and one unit (currently operating in Israel) subject to contract expiry at the end of 2022. A further six vessels were under construction or in the process of being converted from conventional LNG carriers to FSRUs at the time of writing, bringing the total fleet available to meet requirements in the medium term to 20. To bridge the gap between supply and demand, additional FSRU vessels may have to be redirected to planned European projects from other regions, with the most likely such candidates reportedly being in India (2) and Ghana (1).

FSRU outlook: Despite rapid fleet growth, European demand could quickly erode spare capacity

FSRU fleet and order book at year end, 2015-2021



FSRU supply and demand as of mid-2022



Sources: IEA analysis based on ICIS (2022), ICIS LNG Edge; GIIGNL (2022), Annual Report.

Long-distance pipeline trade is expected to decline over the medium term…

Following a steep decline in 2020, long-distance pipeline trade grew by a strong 12% (or 55 bcm) in 2021, largely supported by the recovery in European pipeline imports. However, long-distance pipeline trade is expected to decline by 1.9% per year between 2021 and 2025, driven by Europe's lower Russian gas imports in the aftermath of Russia's invasion of Ukraine.

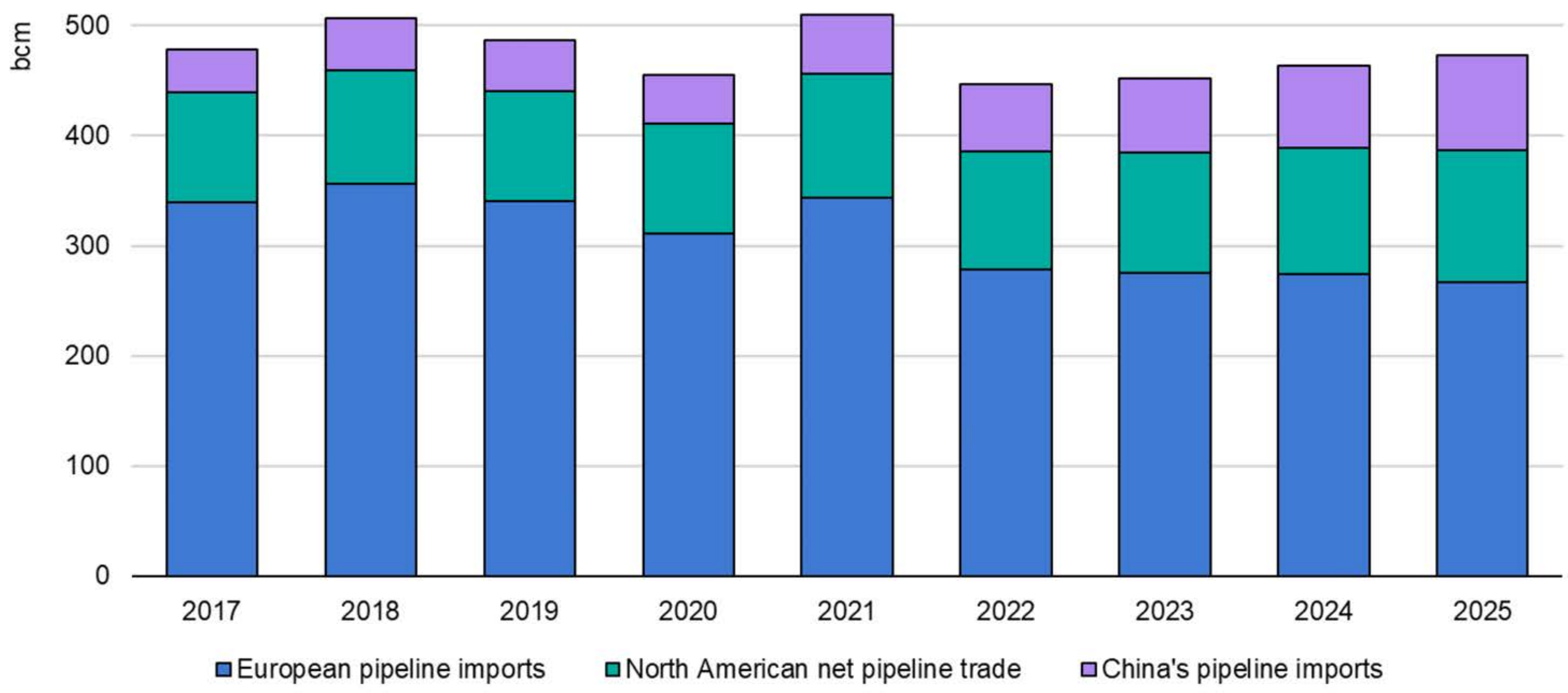
Russia's pipeline gas exports to Europe stood at 167 bcm in 2021 and fell by 25% y-o-y in the first half of 2022. They are expected to halve by 2025 relative to their 2021 levels. This forecast is based on the gradual expiry of Gazprom's long-term supply contracts and on the assumption that no extension or new contract will be signed. It also assumes that the sanctions imposed by Russia will make it impossible to use the YAMAL–Europe pipeline (33 bcm/yr) and prevent gas deliveries to Gazprom Germania over the medium term. An accelerated phase-out of Russian gas would reduce Russian pipeline inflows to the European Union by close to 80% by 2025 compared to their 2021 levels. This would be consistent with the European Union's ambition to phase out its dependence on Russian gas by 2027. The current forecast is subject to unusually large uncertainty, due to Russia's unpredictable behaviour. A complete cut of Russian pipeline supplies to the European Union cannot be excluded, which would overwrite the current outlook.

China's pipeline imports rose by 25% (or 11 bcm) in 2021, supported by the recovery in Central Asian supplies and the gradual ramp-up of the Power of Siberia pipeline (flows reached over 10 bcm in 2021). In the medium term, China's extra-regional pipeline imports are expected to expand by almost 60% to 85 bcm/yr by 2025. This is largely driven by incremental supplies via the Power of Siberia pipeline, with flows reaching 38 bcm/yr by 2025. The construction of the southern section of the China–Russia East Gas Pipeline (the continuation of the Power of Siberia) started in January 2021 and is set to be put into commercial operation by 2025. Pipeline supplies via the Far Eastern route from Sakhalin Island are expected to start in 2024/25 and gradually ramp up to 10 bcm/yr in the second half of the decade. Pipeline flows from Central Asia are expected to average around 45 bcm/yr.

In North America net gas trade rose by 12% to 112 bcm in 2021, largely supported by rising US exports to Mexico and a sharp recovery in US imports from Canada. North America's net gas trade rose by over 10% y-o-y in the first four months of 2022, again supported by stronger US imports from Canada, whose net exports are expected to oscillate around 50-55 bcm/yr during the forecast period and play a key role in meeting seasonal demand swings. United States exports to Mexico are expected to grow at an annual average rate of 4% during the forecast period, slowing from a previous 8% in 2017-2021.

…driven by Europe's lower pipeline imports from Russia

Long-distance pipeline trade by key importing regions, 2017-2025



Sources: IEA analysis based on China Customs Office (2021), Customs Statistics; EIA (2021), Natural Gas Data, Imports/Exports; ENTSOG (2021), Transparency Platform; Eurostat (2021), Imports of Natural Gas by Partner Country – Monthly Data.

Russia's pivot to the east: A long and bumpy road for Russian gas towards Asia

The phase-out of Russian gas from the EU market is expected to intensify Russia's efforts to reconfigure its gas and LNG exports towards Asia. Our analysis indicates that in a best-case scenario for Russia it would take at least a decade to ramp up its gas supplies to Asian markets to a level close to its 2021 exports to the European Union (155 bcm). It would also necessitate the development of new gas export infrastructure and require significant capital investment at a time when Russia's access to capital markets and energy technologies is restricted by the various sanction regimes imposed after its invasion of Ukraine.

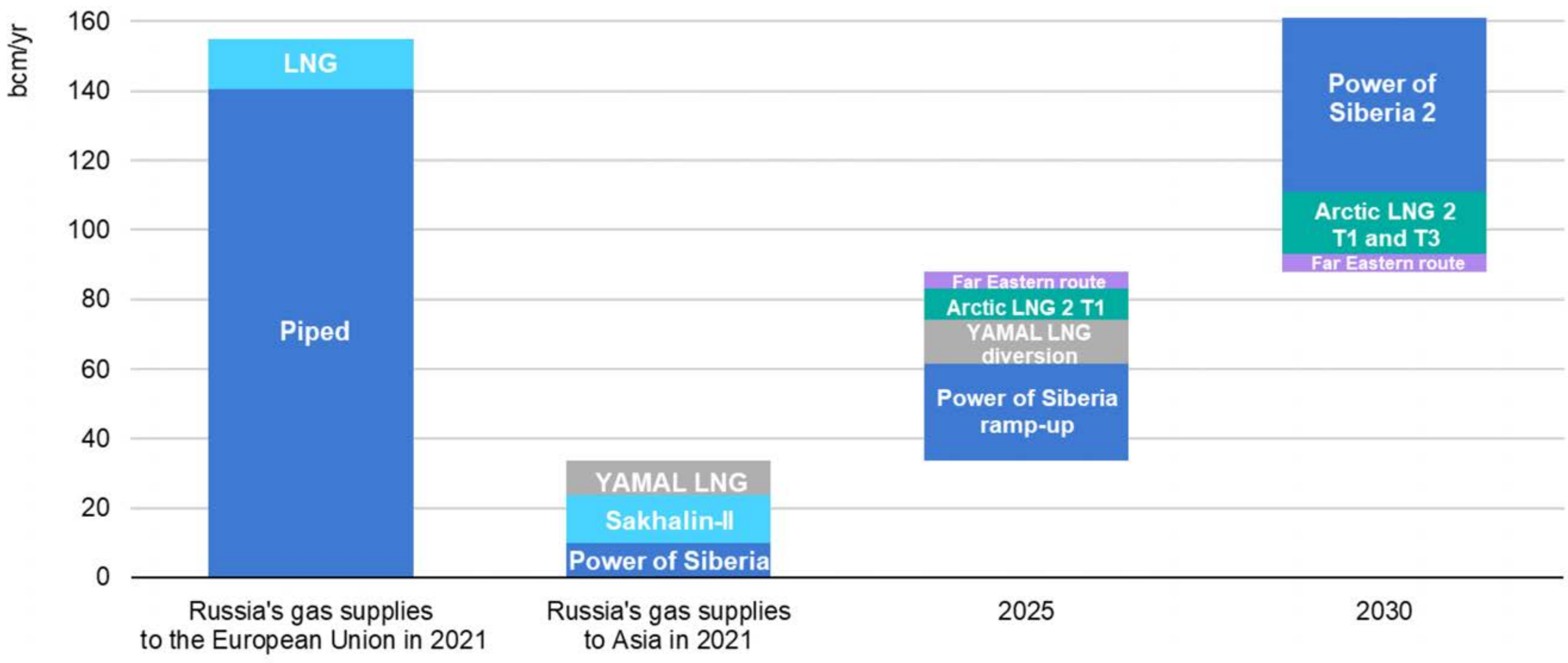
Russia's natural gas exports to Asia totalled 32 bcm in 2021, of which 10 bcm were exported via the Power of Siberia pipeline to China and the remainder via LNG from the Sakhalin-II and YAMAL LNG plants to various Asian markets. China is by far Russia's largest market in Asia (17 bcm), followed by Japan (9 bcm) and Korea (4 bcm).

Russia's gas deliveries to Asian markets could increase by 40 bcm/yr to reach just over 70 bcm/yr by 2025. Under the long-term contract underpinning gas supplies via the Power of Siberia pipeline, Russia's gas exports to China are set to increase to 15 bcm in 2022 and gradually ramp up to 38 bcm/yr by 2025. Russia can divert over 10 bcm of LNG passing through the YAMAL LNG plant from Europe to Asian markets. Rerouting all the LNG flows from Europe to Asia would significantly increase shipping costs, especially during the December to June period when navigation on the Northern Sea Route is limited due to ice and weather conditions. Our forecast assumes that Arctic LNG train 1 will be commissioned, which could increase LNG supplies to Asian markets by 9 bcm/yr, although they would face similar constraints as cargoes from YAMAL LNG. In February 2022 Gazprom and CNPC signed a 10 bcm/yr long-term contract for gas deliveries via the Far Eastern pipeline route (according to non-official sources, for a duration of 25 years). The expected resource base for the gas deliveries, the Yuzhno-Kirinskoye field, could start production in 2023-2025, meaning that supplies could ramp up to 10 bcm/yr in the second half of the decade.

The current sanctions put at risk the development of Arctic trains 2 and 3, which are assumed to be delayed beyond 2025 in our current forecast. Once operational, they could supply an additional 18 bcm/yr to Asian markets. The planned 50 bcm/yr Power of Siberia two pipeline is designed to connect the western Siberian fields to China's gas market through Mongolia. According to Gazprom's own estimates, the pipeline could be constructed by 2027/28. Notably, no legally binding supply contract has been agreed for this route and negotiations between Gazprom and its counterparts in China may last for several years, possibly delaying its start-up to beyond 2030.

It would take Russia at least a decade to ramp up gas supplies to Asian markets to a level close to its 2021 exports to the European Union

Russia's natural gas deliveries and potential export capacity to Asian markets, 2021-2030

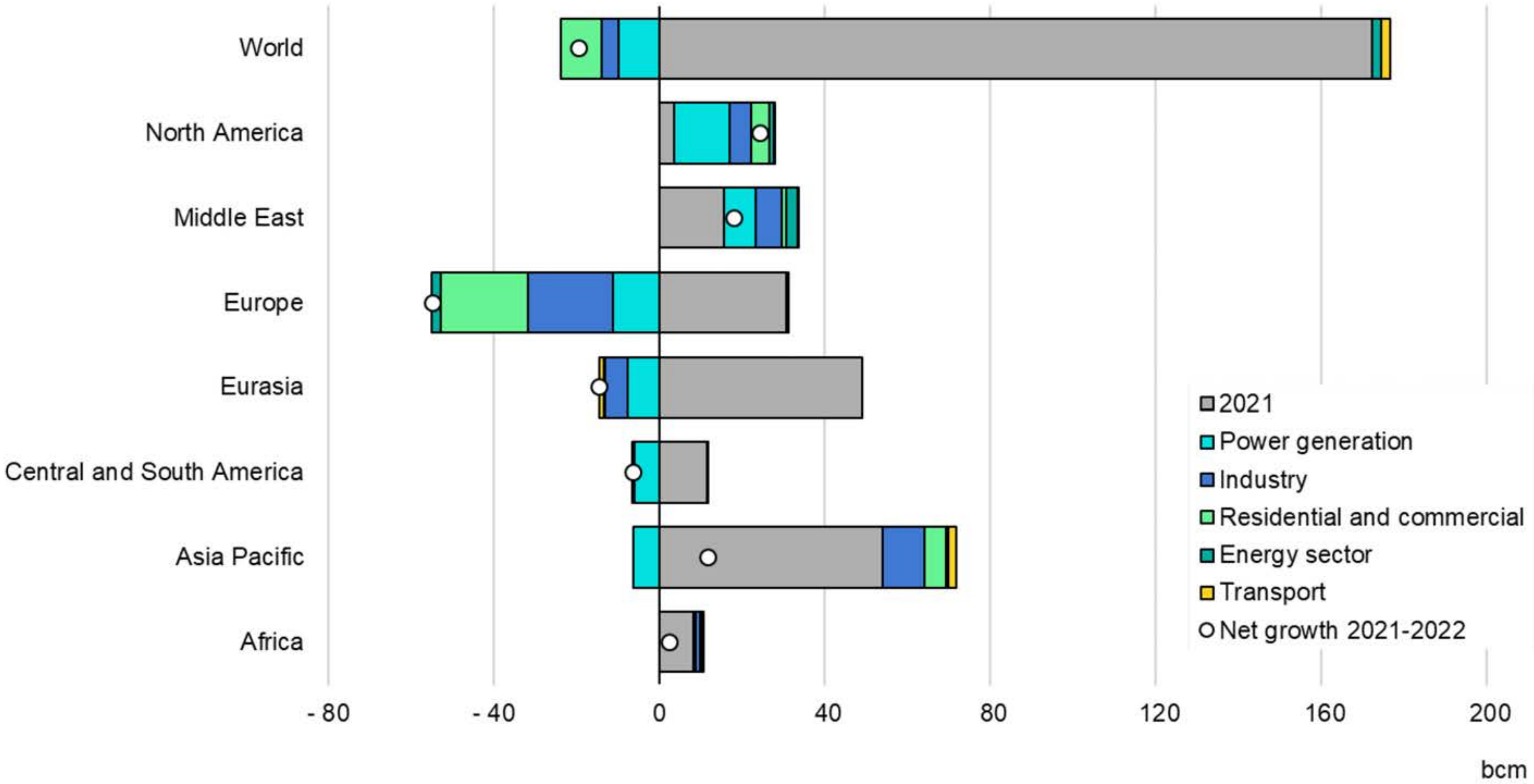


Sources: IEA analysis based on General Administration of Customs of People's Republic of China (2022), Customs Statistics; ICIS (2022), ICIS LNG Edge; and various company reports.

Gas market update

A slight contraction in global gas consumption is expected in 2022 after an extraordinary 2021

Change in natural gas consumption by region, 2021-2022



North American gas demand continues its growth despite rising prices

Natural gas consumption in the **United States** increased by close to 5% y-o-y during the first half of 2022. Weather conditions provided some support to heating demand, with colder than average temperatures in January and early February, followed by late cold spells that lasted until early May in the northern regions of the country. This resulted in an estimated 2.2% y-o-y increase in gas consumption by the residential and commercial sector during the first half of the year.

Colder temperatures also affected electricity demand, resulting in record January gas demand for power generation at close to 32 bcf/d, the highest average level on record for a winter month. Electricity use was also spurred by demand for cooling in the second quarter due to early hot and dry weather conditions in several southern and central regions. Gas use for power generation increased by over 8% y-o-y in January through to June 2022, in spite of significantly higher natural gas fuel costs compared to 2021; gas-to-coal switching ability has been muted by the retirement of coal-fired capacity as well as significant constraints on coal delivery and on-site stock levels for the remaining active fleet.

Natural gas consumption in the industrial sector increased by close to 6% y-o-y in the first quarter of 2022, but then experienced a decline in the second quarter on increasing prices, resulting in an estimated 4.8% y-o-y increase for the first half of 2022.

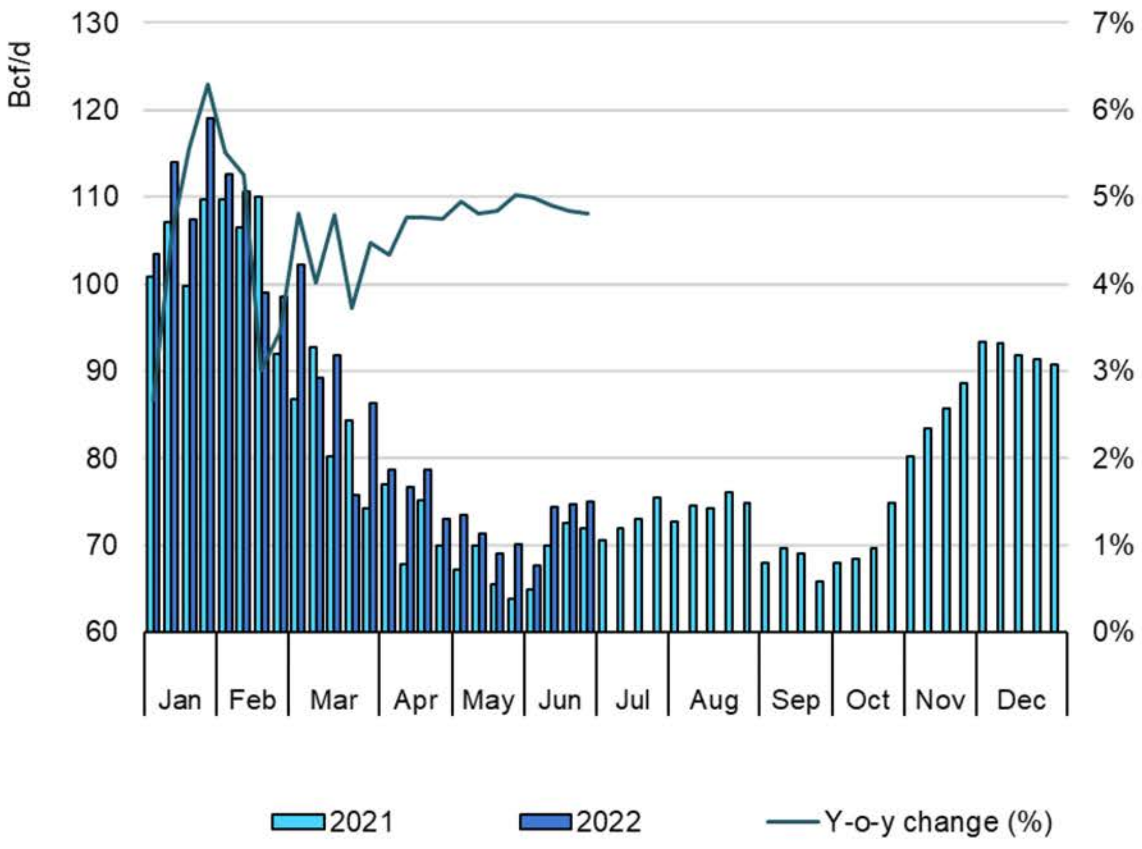
Canada's natural gas consumption is estimated to have increased by close to 8% y-o-y during the first three months of 2022. This strong increase was primarily supported by coal-to-gas switching in the power sector on the accelerated coal phase-out in the province of Alberta, as well as by higher retail demand from residential and commercial customers. Pipeline deliveries to the neighbouring US market increased by almost 9% in January through to June 2022.

Mexico's apparent natural gas consumption followed a slight y-o-y decline during the first quarter of 2022, as the limited increase in pipeline imports appeared insufficient to offset lower domestic production and LNG deliveries. US pipeline deliveries in April through to June showed a close to 7% y-o-y decline, indicating a further potential slowdown in Mexican gas demand.

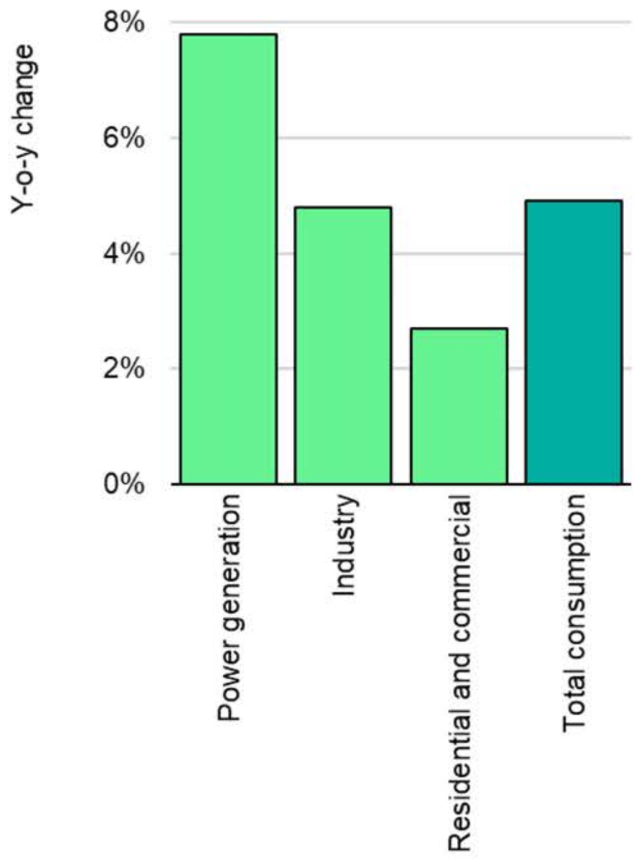
Our forecast expects North American gas demand growth to slow over the second half of 2022 to reach 2.3% for the full year, as high prices continue to negatively affect industrial customers and limit gas use in power generation. The outlook for electricity demand remains uncertain, especially for the peak summer months; NERC highlighted in its 2022 Summer Reliability Assessment that warnings of seasonal drought and above-normal temperatures put several North American electricity markets under risk of capacity shortfall in situations of strong demand peaks.

US gas consumption is up by close to 5% y-o-y in the first half of 2022

Weekly natural gas consumption in the United States, 2021-2022



Gas consumption by sector in the United States, H1 2022 relative to H1 2021



Sources: IEA analysis based on EIA (2022), Natural Gas Consumption; Natural Gas Weekly Update.

Central and South American gas demand is expected to decline in 2022 on improved hydro generation, high import prices and limited industrial growth

Brazil's natural gas demand declined by about 8% y-o-y during the first quarter of 2022 as the country's hydro conditions recover from last year's exceptional droughts. Data from the Electricity Sector Monitoring Committee show that hydroelectricity generation was up by an average of 2.8 TWh (or 7% y-o-y) during the first quarter, resulting in an average 2 TWh drop in thermal generation, which mainly affected gas-fired generation (down by close to 1.4 TWh). This led to a sharp 28% y-o-y decline in gas use for power generation. The industrial sector, which experienced strong growth of almost 18% in 2021, has slowed to 1% on rising gas prices. The residential, commercial and transport sectors maintained robust 15% growth, but account for a limited share of the country's gas demand (less than 10%). Gas use in the energy sector remained stable over the first quarter. According to Petrobras, Bolivia's YPFB lowered its exports to Brazil by 30% in May.

Total gas consumption in **Argentina** was flat y-o-y in the first quarter of 2022 due to higher demand from the energy sector (up 13%), residential sector (up 11%) and industrial sector (up 4%) offsetting a 10% drop in gas use for power generation. Argentina signed an agreement with Bolivia in April that guarantees a minimum pipeline supply of 14 mcm/d during the southern winter months, with the possibility of extra volumes if Bolivia is able to deliver any excess capacity. This would help to reduce seasonal LNG imports and associated costs, as the agreed price of USD 12.18/MBtu was around one-third of spot LNG prices at the time the contract was signed. Another agreement was signed with Brazil for seasonal electricity imports to reduce the call on gas from the power sector during the winter. The Argentinian government also launched fast-track development of the Néstor Kirchner gas pipeline project in April 2022, which should debottleneck domestic gas production capacity from mid-2023.

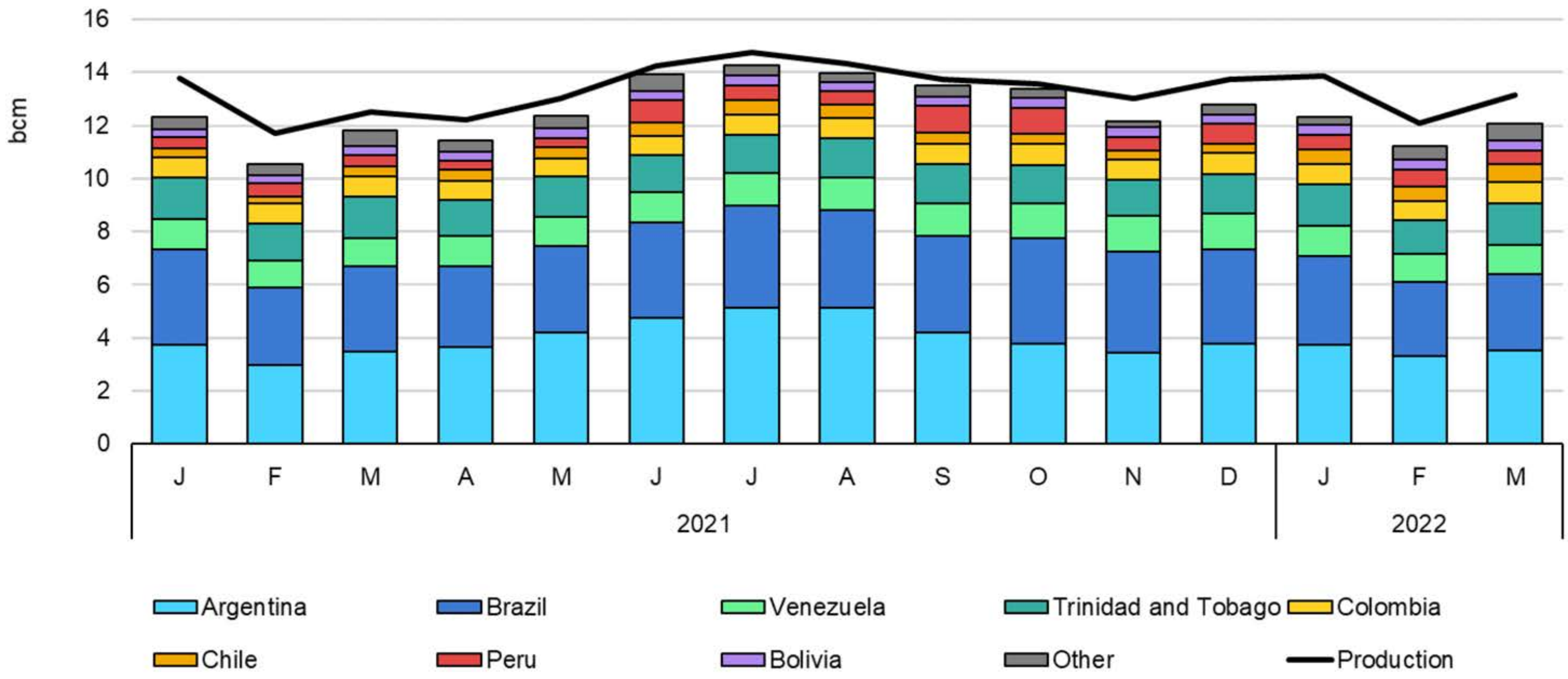
Apparent gas consumption in **Central America** and the **Caribbean** increased by 15% y-o-y during the four first months of 2022, prompted by a near doubling of imports in Panama and a notable increase in Jamaica. El Salvador received its first LNG cargo from its newly commissioned floating regasification unit in April 2022.

Consumption increased in **Columbia** by close to 9% in January through to May 2022 on higher use for power generation and in the industrial sector. Gas deliveries in **Peru** reportedly soared over the same period, with a 47% increase as production recovered.

Our forecast expects a further decline in gas consumption in Central and South America for 2022 with a close to 4% y-o-y drop, resulting from further improvement in hydro conditions in Brazil and lower demand from industrial customers faced with high gas prices and slower activity growth.

South America prepares for the southern winter amid a tight global LNG market

Monthly natural gas demand and production, Central and South America, 2021-2022



Sources: IEA analysis based on ANP (2022), Boletim Mensal da Produção de Petróleo e Gás Natural; BMC (2022), Informes Mensuales; Central Bank of Trinidad and Tobago (2022), Statistics; CNE (2022), Generación bruta SEN; ENARGAS (2022), Datos Abiertos; ICIS (2022), ICIS LNG Edge; IEA (2022), Monthly Gas Data Service; JODI (2022), Gas Database; MME (2022), Boletim Mensal de Acompanhamento da Industria de Gás Natural; OSINERG (2022), Reporte diario de la operación de los sistemas de transporte de gas natural.

European gas demand is set to fall below its 2020 levels on ongoing demand destruction

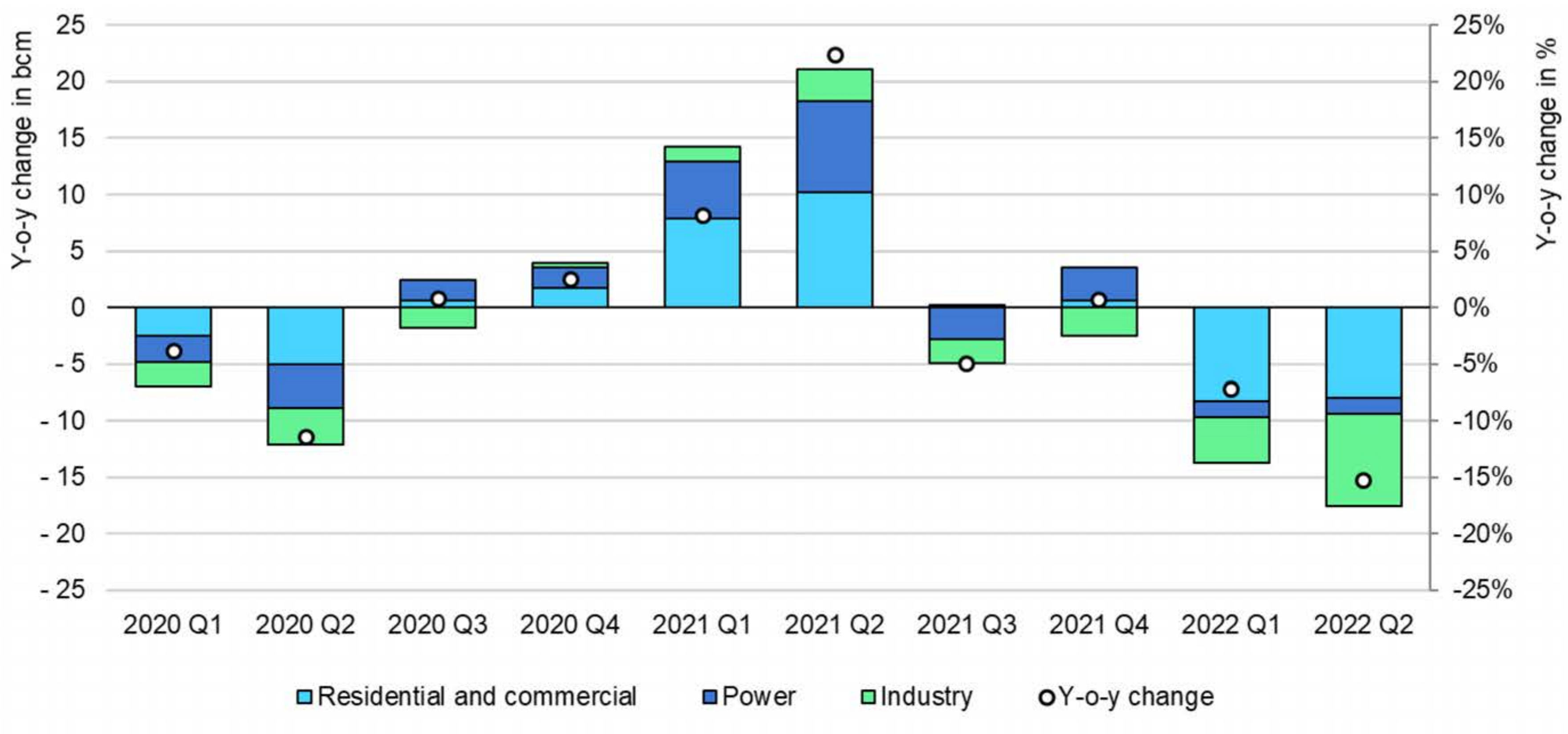
Natural gas demand in OECD Europe fell by over 10% y-o-y in the first half of 2022. This has been driven by milder temperatures and record high gas prices weighing on gas use in both the industrial and power sectors.

Distribution network-related demand, most of which is associated with the residential and commercial sectors, fell by over 13% y-o-y in the first half of 2022. Milder winter and spring temperatures reduced space heating requirements and gas demand. The decline was particularly steep in Q2, when distribution-network related demand fell by over 20%. In contrast with 2021, when Europe faced a particularly cold April and May, this year's temperatures were above their historical averages, putting an early end to the European heating season. Gas demand in industry fell by an estimated 10% y-o-y in the first half of 2022. The drop has been particularly pronounced in Italy (down 9%), France (down 11%) and Spain (down 10% in the first five months of the year). Record high gas prices have led to production curtailments in the most energy- and gas-intensive industries. In contrast with the industrial sector, gas burn in the power sector remained more resilient and declined by an estimated 3% y-o-y in the first half of 2022. The steep drop in hydropower output in Southern European markets, where remaining coal-fired capacity is limited, supported higher gas-fired generation, which increased both in Iberia (up 36%) and Italy (up 10%) despite the record high gas prices. In addition, lower nuclear output in France (down 15%) provided additional market space for gas-fired power plants. In Northwest Europe, and Central and Eastern Europe (where considerable gas-to-coal switching potential remains), coal-fired generation rose by 11%, while output from gas-fired power plants fell by 7% y-o-y in the first half of 2022. In the Republic of Türkiye the strong recovery in hydropower output weighed on gas-fired generation, which fell by 25% y-o-y.

OECD Europe's natural gas demand is forecasted to decline by close to 9% in 2022, falling below its 2020 levels. This represents a further downward revision compared with the previous forecast in Q2 2022, amid the expectation of higher gas prices following Russia's invasion of Ukraine. The rapid expansion of renewables is set to weigh on thermal power generation, while the continuing high gas price environment is set to put gas-fired power plants at a disadvantage vis-à-vis coal-fired plants. Gas demand for power generation is expected to decline by close to 5%. High gas prices are also set to weigh on industrial gas demand, which is expected to fall below its 2020 levels. Assuming average weather conditions for the rest of the year, space heating requirements in the residential and commercial sectors are expected to be lower than in 2021. Potential further disruptions to the supply of Russian gas provide further downside risk to the current outlook.

European gas consumption fell by 10% y-o-y in the first half of 2022

Estimated quarterly change in gas demand, OECD Europe, 2020-2022



Sources: IEA analysis based on Enagas (2022), Natural Gas Demand; ENTSOG (2022), Transparency Platform; EPIAS (2022), Transparency Platform; Trading Hub Europe (2022), Aggregated consumption.

Asia's gas demand growth is on course to decelerate markedly in 2022

Asia's gas consumption growth has continued to decelerate as high spot LNG prices, mild temperatures and Covid-related disruptions in China have put the brakes on natural gas demand so far this year. In 2022 Asia's total consumption is expected to increase by only 1% (vs 7% in 2021), with high prices and tight LNG supplies continuing to weigh on demand growth throughout the year. Despite its weaker growth prospects in 2022, China still accounts for virtually all net demand growth in Asia. Emerging Asia is expected to see a modest increase, India is projected to remain flat, while gas demand in Japan and Korea is set to decline this year.

China's gas consumption increased by less than 3% y-o-y in the first five months of 2022. Slowing economic growth, price-driven demand destruction, mild winter temperatures and factory closures to improve air quality ahead of the Beijing Winter Olympics in February all contributed to slowing natural gas use in Q1 2022. Strict lockdowns following Covid-19 outbreaks in major economic hubs, including Shanghai, have tipped y-o-y growth rates into negative territory since March. In 2022 total gas consumption is expected to increase by 3% (vs 12% in 2021), which would be the lowest annual growth rate since 2015. The industrial sector accounts for 65% of China's net gas demand expansion in 2022. Residential and commercial users and the transport sector also contribute to China's consumption growth in 2022 with both categories increasing by about 6% this year. Growth in these sectors is primarily driven by slow – but still rising – economic activity, new grid connections and expanding natural gas vehicle fleets, respectively. Gas use in the power generation sector is now projected to drop by 5% amid high import prices and rapidly growing renewable generation. Our outlook rests on the assumption that Covid-related restrictions on economic activity are gradually lifted by mid-2022. Continuing lockdowns under China's "zero Covid policy" in the second half of the year present further downside risks to demand.

Growth in **India**'s gas consumption continued to decelerate, shrinking by an estimated 2.7% y-o-y in the first five months of 2022 (vs an expansion of 0.4% in Q4 2021 and 4% in 2021 overall). Sustained high LNG prices curtailed gas use most extensively in the power, refining and petrochemical sectors during the January to May period, although a heat wave combined with domestic coal shortages prompted a temporary uptick in power sector gas burn in May (using expensive spot LNG). Demand in the fertiliser sector, the city gas segment and other end uses (including agriculture, upstream operations and other industries) increased in 5M 2022, despite the challenging price environment. India's LNG imports dropped by 16% y-o-y in 5M 2022 as a combined result of rising domestic production (up by 9% y-o-y over the same period) and fuel switching away from LNG amid continuing high import prices. India is now on course to register two consecutive years of decreasing

LNG demand in 2021-2022, the first multi-year drop since the country started importing LNG in 2004. Total gas consumption in 2022 is set to remain flat. Modest growth in the city gas segment is supported by the continuing expansion of India's domestic gas infrastructure. However, high and volatile imported LNG prices as well as rising domestic gas prices are likely to keep overall demand growth in check, and continue to suppress gas use in the power generation, refining and petrochemical sectors in particular.

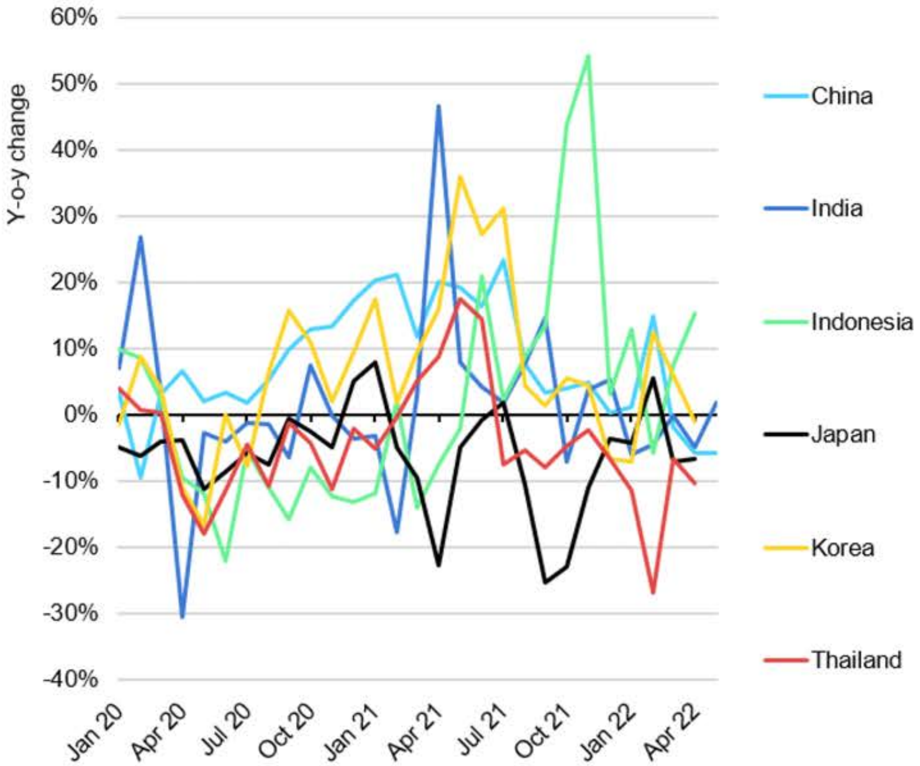
Korea's total gas consumption increased by 1% y-o-y in Q1 2022, while LNG imports declined by nearly 3% as the country drew down LNG stocks at a rapid rate, especially in the first two months of the year. Gas demand for power and district heating was down by 8% y-o-y in the first two months due to high prices and switching to coal and nuclear generation. Meanwhile, city gas and industrial users increased their combined natural gas consumption by 6% y-o-y amid colder than average winter temperatures and rising industrial production in Q1 2022. In 2022 as a whole, Korea's gas demand is expected to decrease by 4% due to the addition of the 1.4 GW Shin Hanul-1 nuclear block and another 1.04 GW of new coal-fired capacity, both scheduled for the second half of 2022.

Japan's gas consumption decreased by 3% y-o-y in the first four months of 2022. Gas demand for power generation normalised after a sharp spike seen during the cold spell in Q1 2021, while the residential, commercial and industrial sectors registered flat y-o-y demand growth in the first quarter. Gas consumption in the industrial sector remained strong, despite the prolonged restrictions due to Covid-19. Overall gas consumption in 2022 is expected to remain flat as growing solar generation and the planned start-up of several new coal-fired units could fully offset the gas demand boost from the planned shutdown of several nuclear reactors for inspection. Recent discussions on nuclear restarts to ensure electricity security and reduce LNG imports could reduce gas demand, but no concrete steps have been announced to date.

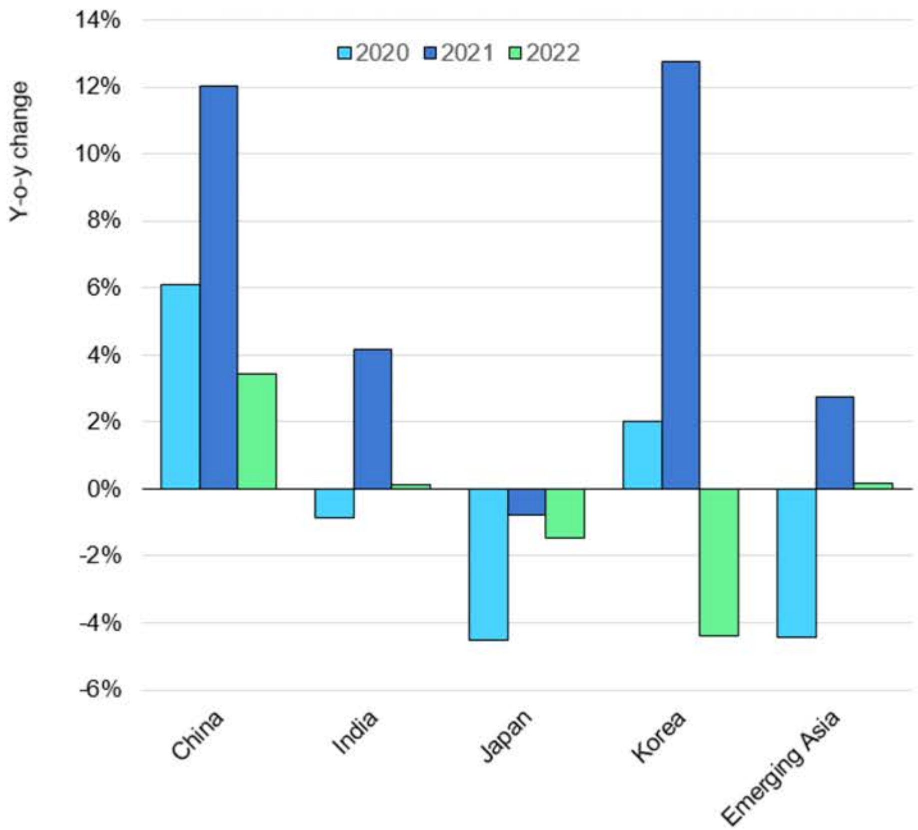
Emerging Asia's gas demand recovery has been slow and uneven in the first four months of 2022. Thailand, the region's largest gas-consuming country, registered a sharp 14% y-o-y decline in 4M 2022, as high LNG prices cut gas use for power generation and falling domestic production reduced the energy sector's own consumption for gas processing. Indonesia, the second-largest gas market in emerging Asia, registered a 7% y-o-y increase in gas consumption over the same period amid low coal stocks and rising power demand. Preliminary shipping data indicate declining LNG inflows to both Pakistan (down 10% y-o-y) and Bangladesh (down by less than 1% y-o-y) during the first six months of 2022, as high LNG prices contributed to fuel shortages and fuel switching away from gas. Total gas consumption in emerging Asia is expected to remain flat in 2022 – a marked slowdown from the already modest 3% expansion in 2021 – as tight LNG supply and high prices continue to squeeze demand throughout the year.

Asia's gas demand recovery was weak and uneven in Q1 2022 and remains so throughout 2022

Monthly gas demand in selected Asian countries, 2020-2022



Gas demand in selected Asian countries, 2020-2022



Sources: IEA analysis based on ICIS (2022), ICIS LNG Edge; CQPGX (2022), Nanbin Observation; JODI (2022), Gas World Database; PPAC (2022), Gas Consumption; EPPO (2022), Energy Statistics.

US natural gas production and drilling activity increase despite cautious spending guidance

US dry gas production grew by an estimated 3.8% y-o-y in the first half of 2022, to reach an average of 96 bcf/d in the second quarter. It rebounded from its initial drop in the first quarter of 94.6 bcf/d, but remains below the all-time record of 97 bcf/d set in December 2021. Output from the oil-driven Permian Basin leads growth with a 20% y-o-y increase in January through to April, while Appalachian Basin production grew by about 2% over the same period and remains below its December 2021 highs.

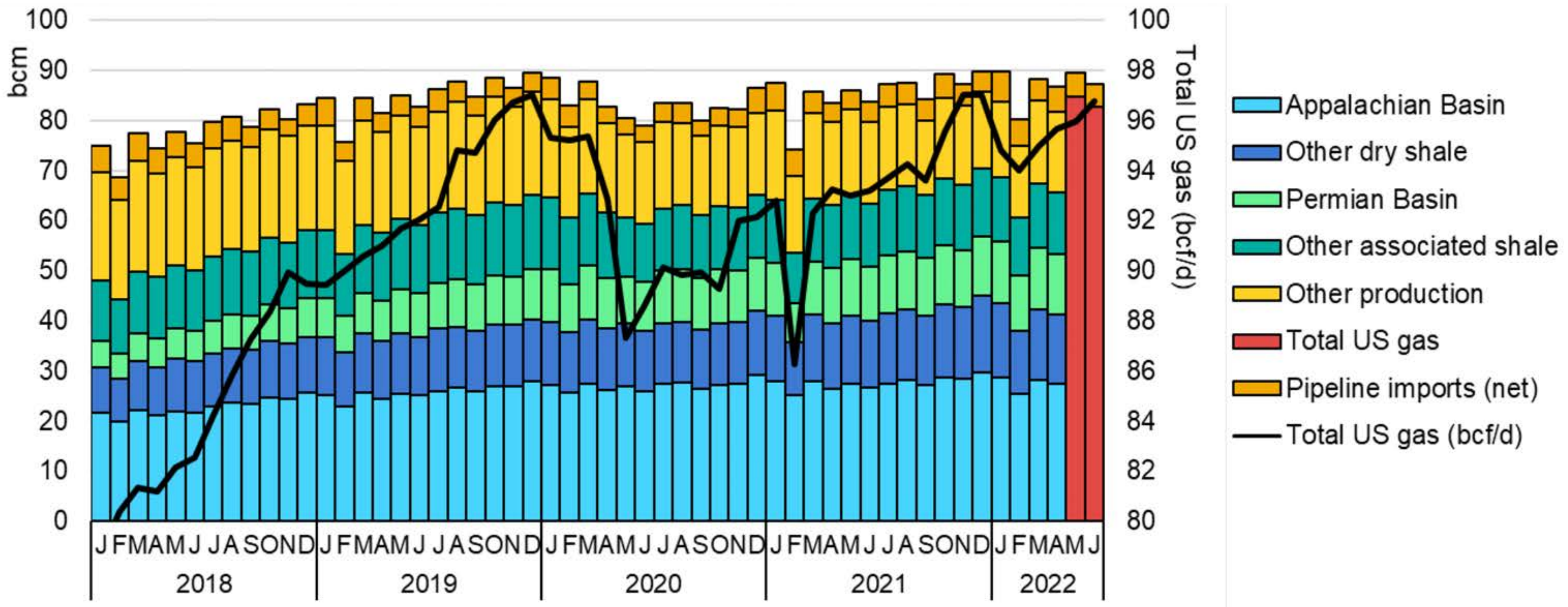
Drilling activity continues to grow, with close to 160 active gas rigs as of the end of June, 60% higher than a year ago and 48% above the early January number. Completion rates are also increasing, with an average 96 wells completed per month in the Appalachian since the beginning of 2022, compared with 74 for the same period in 2021. This results in a further drop in the inventory of DUC wells, for both oil- and gas-driven shale basins; in the Appalachian the inventory dropped by 25% y-o-y to reach less than 500 units in May 2022, while in the Permian the DUC count plunged by 44% to around 1 260 units over the same period. Several listed US oil and gas producing companies began to adjust their communication on spending in their Q1 2022 earnings presentations, encouraged by rising profits from the high energy price environment. Some leading gas producers mentioned their interest in potential downstream integration by investing in future LNG export capacity, while others expressed optimism in pipeline development potential. The general financial guidance remains cautious, however, with priority given to short-term returns to shareholders, and lingering uncertainty regarding longer-term export market growth prospects.

New pipelines providing about 430 MMcf/d of transport capacity entered service in the initial months of 2022. The bulk of this increase is an additional 245 MMcf/d of takeaway capacity from the core production area of the oil-driven Bakken Formation, which contributes to monetising associated gas and further reduce flaring. FERC has recently approved new capacity expansion projects, including further debottlenecking in the eastern Appalachian Basin and connections to future LNG export projects in the Gulf Coast and in Southern California. Two further projects are progressing in the Permian Basin, including the 2.5 bcf/d Matterhorn Express Pipeline, which reached FID in mid-May 2022.

US natural gas production is expected to increase by 3.4% in 2022, primarily from associated production in the Permian and other oil-driven basins, and to a lesser extent in the Appalachian Basin. FERC highlighted in its Summer Assessment 2022 the risk of a tight domestic gas balance during the summer as total demand growth (including LNG exports) could outpace supply growth.

US natural gas production rebounds since March on higher associated gas output

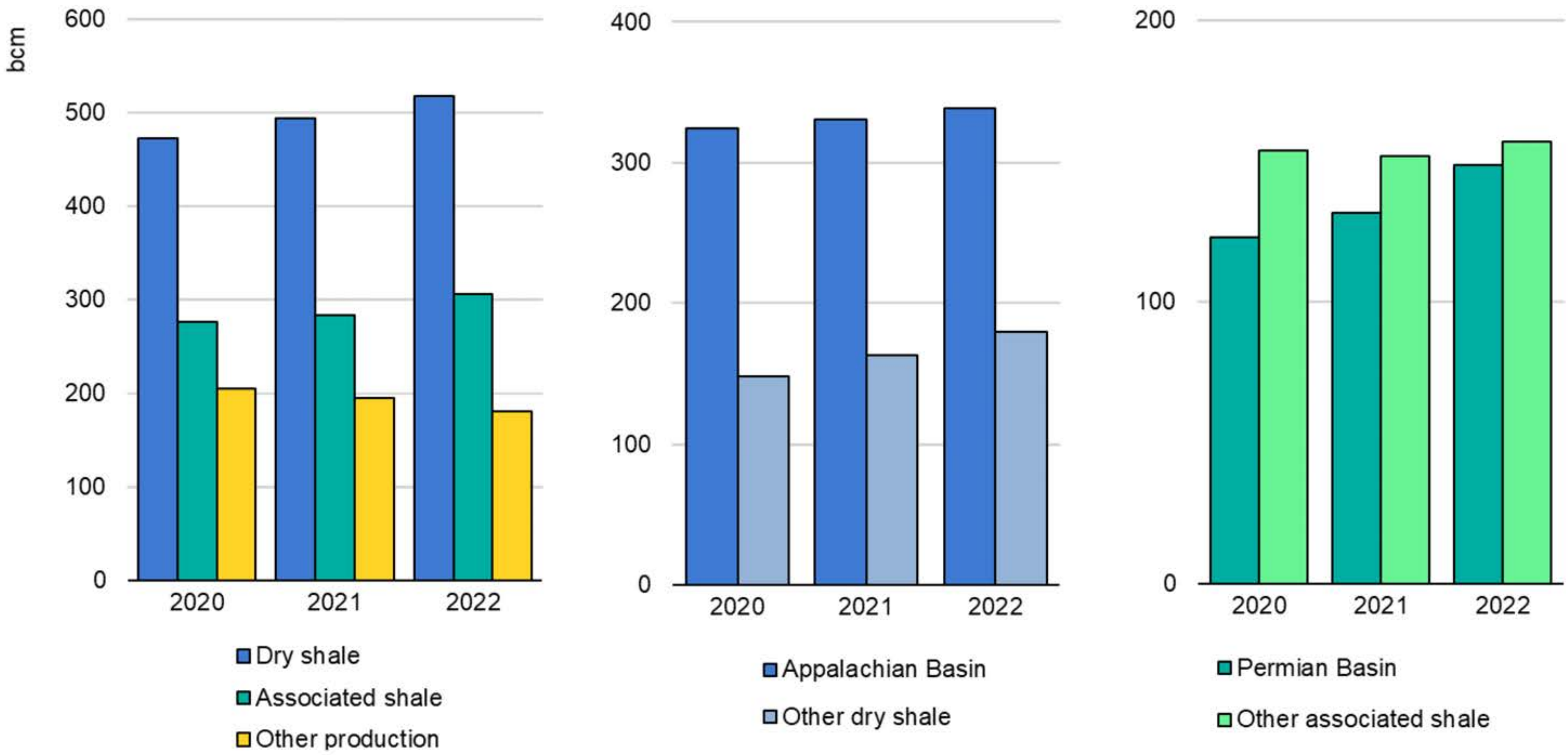
Gas production by type in the United States, 2018-2022



Sources: IEA analysis based on EIA (2022), Natural Gas Data; Natural Gas Weekly Update.

US production is expected to increase by 3.4% in 2022, driven by higher supply from the Permian while growth from the Appalachian slows

Dry gas production by main source in the United States, 2020-2022



Sources: IEA analysis based on EIA (2022), Natural Gas Data; Natural Gas Weekly Update.

Fast and flexible: Record LNG inflow to Europe offsets the steep drop in Russian gas deliveries

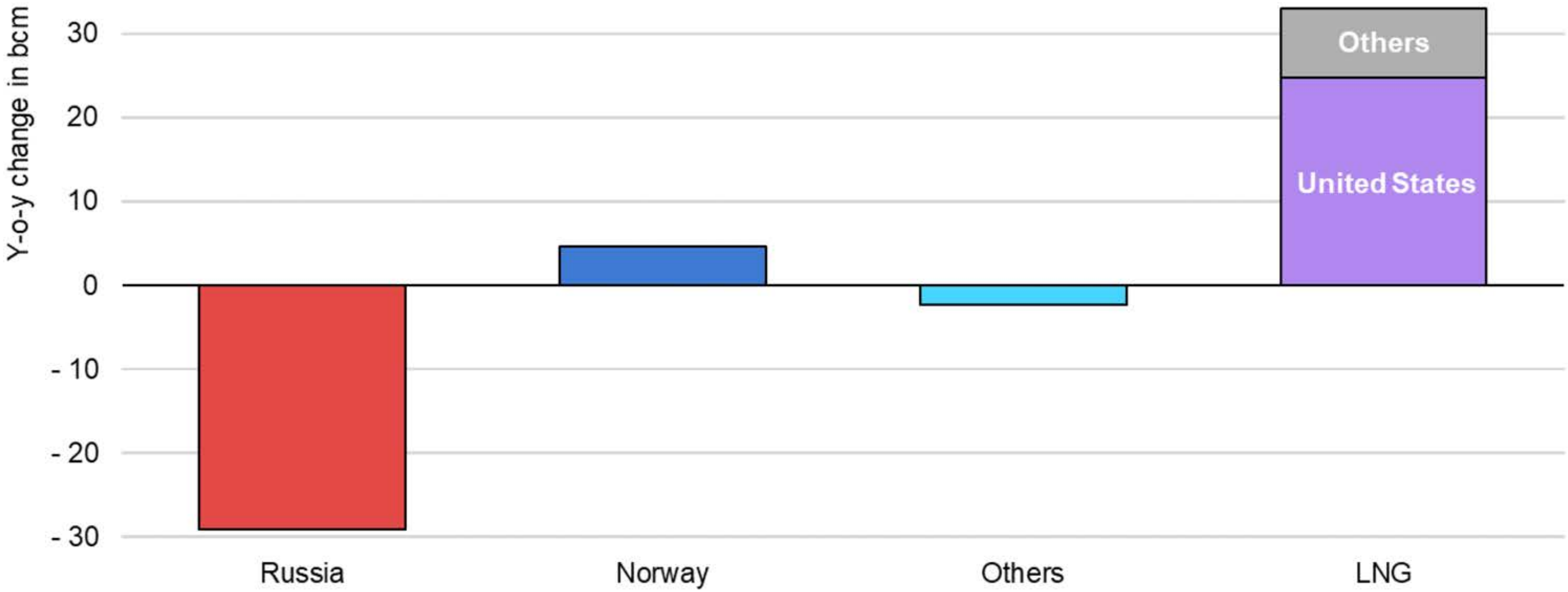
Russian gas supplies to Europe continued their sharp decline in the first half of 2022, further tightening the European gas and global LNG markets. Flexible LNG inflow to Europe hit an all-time high, offsetting the lower gas deliveries from Russia.

Russia's piped exports to OECD Europe fell by an estimated 33% y-o-y in the first six months of 2022. While deliveries to the Republic of Türkiye dropped by 8% in the first five months, gas supplies to the European Union fell by 38% y-o-y in H1. End of March 2022 Russia issued a decree introducing a new rouble-based payment system for Russian piped gas. Gazprom unilaterally cut gas supplies to Bulgaria, Poland, Finland, Denmark and the Netherlands following their refusal to adhere to the new payment system. Russia imposed a range of sanctions on European companies on 11 May, following which Gazprom announced that it would cease to use the Yamal–Europe pipeline, a key supply route to Poland and Germany. Gas transit via Ukraine to the rest of Europe remained stable despite the Russian invasion. On 10 May Ukraine's gas transmission systems operator declared force majeure at a key compressor station Ukraine, following illegal actions and unauthorised gas offtakes by occupying forces. According to Ukraine's Gas TSO, flows can be temporarily rerouted, although Gazprom refused to accommodate this option. Transit gas volumes via Ukraine to the European Union have dropped by 60% since then. Gazprom reduced further gas supplies via Nord Stream, with deliveries falling from an average 158 mcm/d to 63 mcm/d by 18 June. According to Gazprom this is due to lower compressor power at the Portovaya compressor station. Supplies were steeply reduced to Austria, the Czech Republic, France, Germany, Italy and Slovakia. Lower flows from Russia and declining domestic production were compensated by higher pipeline deliveries from alternative sources and record volumes of LNG inflow. Pipeline supplies from Norway rose by over 8% in the first half of 2022, while gas deliveries from Azerbaijan via the TAP pipeline surged by over 70% y-o-y. North African gas supplies declined by 15% due to the non-availability of the Maghreb–Europe pipeline and lower Libyan flows. LNG imports rose by 60% y-o-y to over 80 bcm in H1 2022 – their highest-ever level for this period of the year. The United States supplied 75% of incremental LNG, solidifying its position as Europe's largest LNG supplier.

OECD Europe's domestic gas production is expected to increase by 3% in 2022, driven by higher output in Norway and the United Kingdom. Higher storage injection needs are set to provide strong support for imports in H2. Considering available capacities and assuming that Nord Stream flows will remain at 63 mcm/d, Russian piped gas flows are expected to fall by 40% y-o-y in 2022, largely compensated by higher LNG inflows, up by over 45%. The current forecast is subject to unusually large uncertainty, due to Russia's unpredictable behaviour.

Europe's LNG imports are set to hit an all-time high in 2022

Y-o-y change in European natural gas imports and deliveries from Norway, H1 2022 vs H1 2021



Sources: IEA analysis based on ENTSOG (2022), Transparency Platform; Eurostat (2022), Energy Statistics; Gas Transmission System Operator of Ukraine (2022), Transparency Platform; ICIS LNG Edge; JODI (2022), Gas World Database.

Global LNG trade growth is fuelled by European demand and US supply in 2022

In the first six months of 2022 global LNG trade (net of reloads) grew by 5% according to preliminary shipping data. Europe remained the dominant driver of LNG trade flows on the demand side. Between January and June 2022 European LNG imports were up by 55% (30 bcm) y-o-y as the continent relied primarily on waterborne shipments to compensate for lower pipeline flows from Russia. The Asia Pacific region, which – uncharacteristically – has become the balancing market for LNG, registered a 7% (14 bcm) y-o-y decline in net LNG imports in the first six months. China (down 21%), India (down 14%), Japan (down 3%) and Korea (down 3%) saw the biggest y-o-y declines in volume terms. Combined LNG imports into Central and South America and North America also decreased by 30% (4 bcm) y-o-y, while imports into the Middle East, Africa and Eurasia were marginally up (1 bcm).

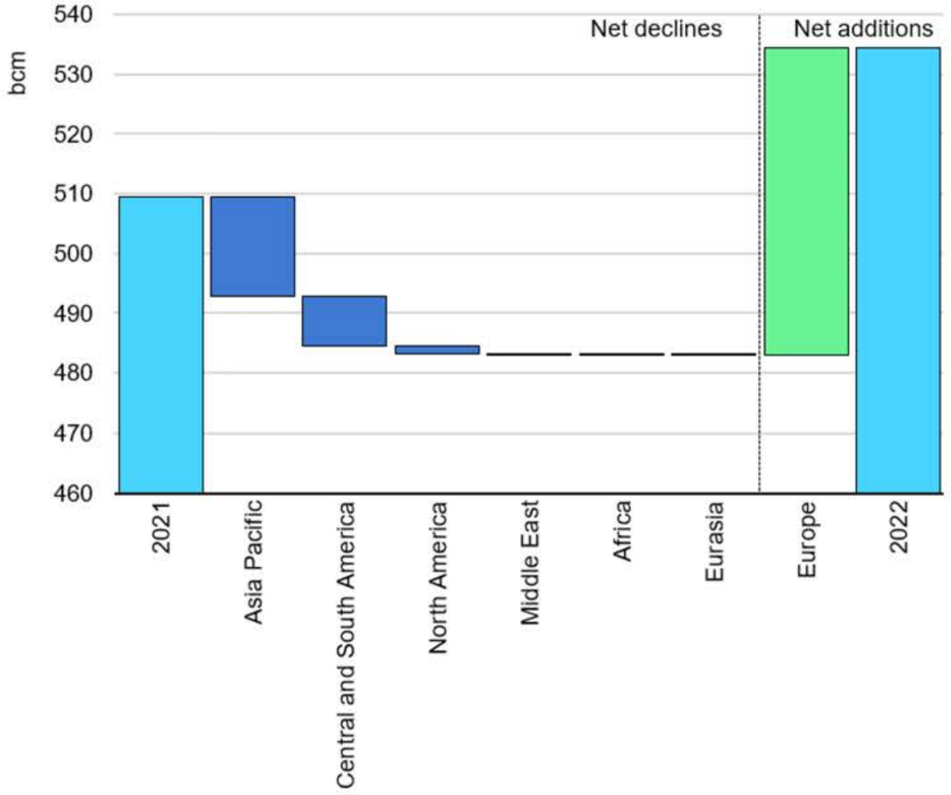
Global LNG exports increased by 5% y-o-y in the January to June 2022 period. This was mainly driven by the United States, which boosted LNG exports by 19% y-o-y thanks to the ramp-up of production from Sabine Pass train 6 and the commercial start-up of the Calcasieu Pass LNG terminal in Louisiana. Russian LNG exports were also up by 10% due to higher output at the Yamal LNG terminal in particular. Africa and the Asia Pacific region saw relatively minor y-o-y export declines, which were partly offset by small increases in South American and Middle Eastern exports.

In 2022 global LNG trade is on course to increase by 5%, slightly below the growth rate observed in 2021. Europe remains the premium market for LNG thanks to a sustained TTF premium over Asian spot LNG prices throughout the year. European LNG imports are set to increase by 50% (51 bcm) in 2022 and surpass all previous records by a wide margin. The Asia Pacific region is now expected to see total LNG imports decrease by 4% (17 bcm) in 2022, with China, India and Korea registering the biggest declines. LNG imports to Central and South America could decrease by 36% (8 bcm) with the normalisation of hydro generation levels in Brazil following last year's historic droughts. LNG demand in the rest of the world is expected to decrease marginally in 2022.

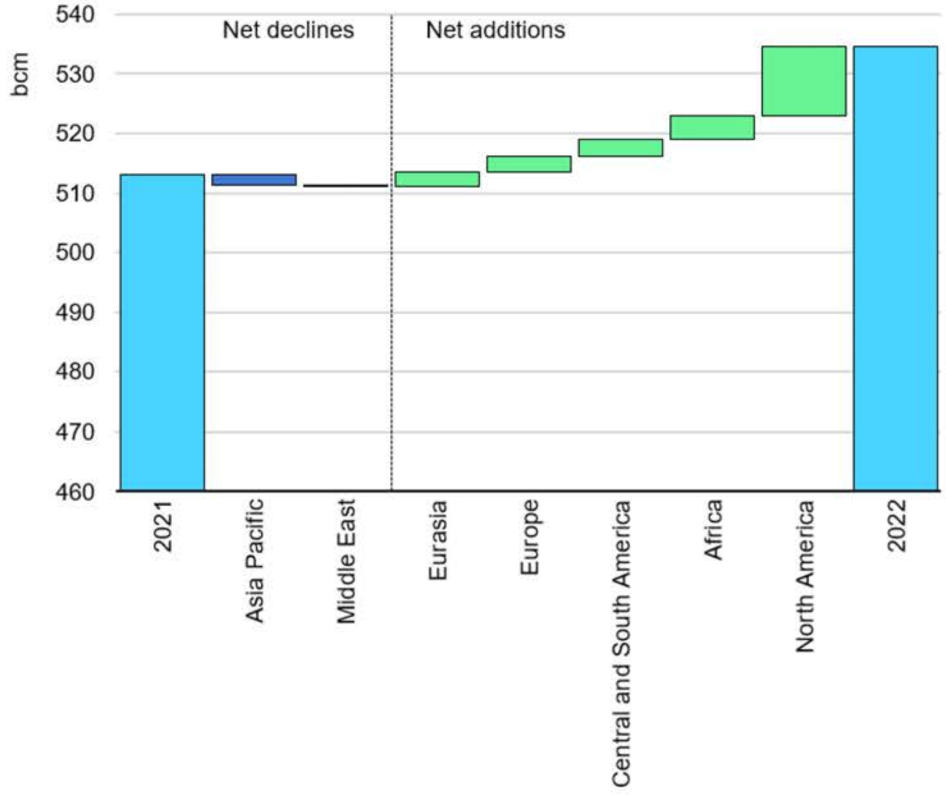
North America retains its role as the primary engine on the supply side, accounting for more than half of global LNG export growth in 2022. LNG output in the United States is projected to increase by 12% (12 bcm) thanks to the addition of new liquefaction capacity. This is a lower increase than projected in our previous forecast as the ongoing outage at the Freeport LNG facility since early June is now expected cut US LNG exports by about 7 bcm in 2022. The remaining LNG supply growth comes from Africa (thanks to higher exports from Egypt and the start-up of Coral South FLNG in Mozambique) and Europe (thanks to the restart of the Hammerfest terminal in Norway), as well as from Central and South America and Eurasia.

Europe's newfound appetite for LNG sets the pace for global LNG trade in 2022

LNG import growth in 2022



LNG export growth in 2022



Source: IEA analysis based on ICIS (2022), ICIS LNG Edge.

Tight supply conditions kept European and Asian prices at seasonal records in Q2 2022

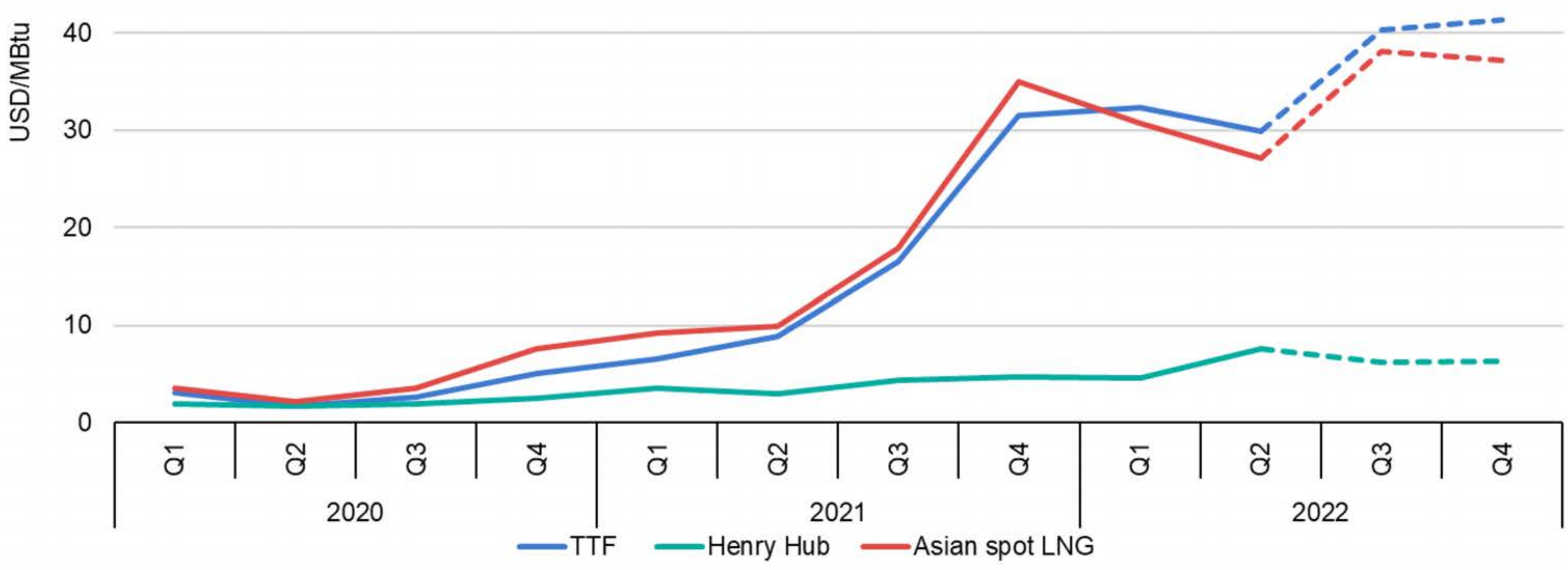
European and Asian gas prices moderated from their winter highs in Q2. Nevertheless, tight supply and ongoing uncertainty around Russian gas deliveries continued to provide strong upward pressure on European hub prices, and indirectly on Asian spot LNG, keeping them at seasonal records in Q2. In the United States tight supply–demand fundamentals, together with low storage levels, drove Q2 prices to their highest level since the shale revolution.

In Europe TTF prices averaged over USD 30/MBtu in Q2 – more than 5 times their five-year average for this period of the year. Gas prices spiked to an all-time high of EUR 207/MWh (USD 54/MBtu) on 7 March, following Russia's invasion of Ukraine. Russia's decision to introduce a new payment scheme for gas supplies and its subsequent unilateral supply cuts to several EU member states fuelled further market uncertainty and price volatility over the course of April and May. Strong LNG inflow and sharply declining consumption moderated gas prices from the second half of May. Gazprom's supply cuts via Nord Stream, together with the extended outage at Freeport LNG, provided renewed pressure on gas prices in the second half of June, with TTF averaging USD 39/MBtu. Record high LNG imports led to a reconfiguration of gas flows across Europe, while emerging pipeline bottlenecks reduced price correlation across key European gas hubs in Q2. Markets with remaining spare regasification capacity displayed significant discounts compared to TTF. In contrast, Central and Eastern Europe markets, which have limited access to LNG supply, further extended their premium compared to TTF. Asian spot LNG fell from an average of USD 31/MBtu in Q1 to USD 28/MBtu in Q2 2022, an all-time high for this period of the year. Weaker demand amid China's widespread lockdowns and demand destruction in price-sensitive end-use sectors provided downward pressure on spot LNG prices. Supply cuts via Nord Stream and extended outages put strong upward pressure on Asian LNG spot prices from the second half of June. The wide TTF–Asian spot LNG premium enabled a record inflow of LNG into Europe. In the United States, Henry Hub prices averaged USD 7.5/MBtu in Q2, their highest level since 2008. Strong weather-related gas demand and higher gas burn in the power sector (amid a sharp increase in coal prices) coincided with strong growth in LNG exports and a weak supply response from US producers. The extended Freeport outage moderated Henry Hub prices from the second half of June.

The high gas price environment is set to linger through the rest of 2022. Forward curves as of the end of June 2022 indicate that TTF is set to average at USD 35/MBtu, Asian spot LNG at USD 33/MBtu and Henry Hub at USD 6/MBtu in 2022. Uncertainties surrounding Russian gas supply and high restocking needs in all key gas regions are set to provide strong support to gas prices in 2022. TTF is expected to trade at a premium of USD 3/MBtu above Asian spot LNG in H2 2022, enabling strong LNG inflow into Europe.

TTF is expected to display a strong premium over Asian spot LNG prices in H2 2022

Main spot and forward natural gas prices, 2020-2022



Sources: IEA analysis based on CME (2022), Henry Hub Natural Gas Futures Quotes, Dutch TTF Natural Gas Month Futures Settlements; CME Group (2022), LNG Japan/Korea Marker (Platts) Futures Settlements; EIA (2022), Henry Hub Natural Gas Spot Price; ICIS (2021), ICIS LNG Edge; Powernext (2022), Spot Market Data.

Gas storage dynamics varied across key regions in Q2 2022

Natural gas storage in the European Union and the United States ended the 2021/22 heating season with inventory levels well below the five-year average. Storage injections displayed a varied pattern in Q2 2022: the European Union experienced a strong storage build-up, while injections in the United States remained below their five-year average.

In the European Union gas storage sites stood 25% (or 8.5 bcm) below their five-year average at the beginning of April, which marks the end of the European heating season. The European Union adopted a new storage regulation according to which storage sites have to be filled to at least 80% of their capacity before the winter of 2022/23, and to 90% ahead of the following winter periods. The EU will strive collectively to fill 85% of their underground gas storage capacity in 2022. Notably, the filling obligation will be limited to a volume equal to 35% of the annual gas consumption of each member state over the past five years. Several EU members states have adopted fill targets at 90% of working storage capacity ahead of the 2022/23 heating season. The strong inflow of LNG, together with lower consumption, enabled a strong storage build-up in Q2. Storage injections stood 20% above their five-year average and totalled close to 30 bcm. Consequently, the storage deficit of the European Union decreased significantly, inventory levels standing just 3% (or 2 bcm) below their five-year average at end of June. However, reduced gas supplies via Nord Stream weighed on storage injections in the second half of June and are putting at risk the EU ambition to fill storage sites to 80% of capacity by 1 November. Inventory levels reached over 57% of their working storage capacity at the end of Q2. In Ukraine gas storage levels were critically low by the end of June, standing at just 20% of their working storage capacity according to data from Gas Infrastructure Europe. Arranging timely gas supplies to Ukraine in Q3 will be crucial to refill storage sites to adequate levels by the beginning of the heating season.

In the United States storage sites closed the 2021/22 heating season 17% (or 8 bcm) below their five-year average. Tight supply–demand fundamentals limited the build-up of storage during Q2, when injections fell 4% (or 1 bcm) below their five-year average. Consequently, storage levels stood 12.5% (or 9 bcm) below their five-year average at the end of June. Inventory levels reached over 50% of their working storage capacity by the end of Q2. If injections return to their five-year average, storage will be 78% full by the beginning of November, which typically marks the start of the heating season in the United States.

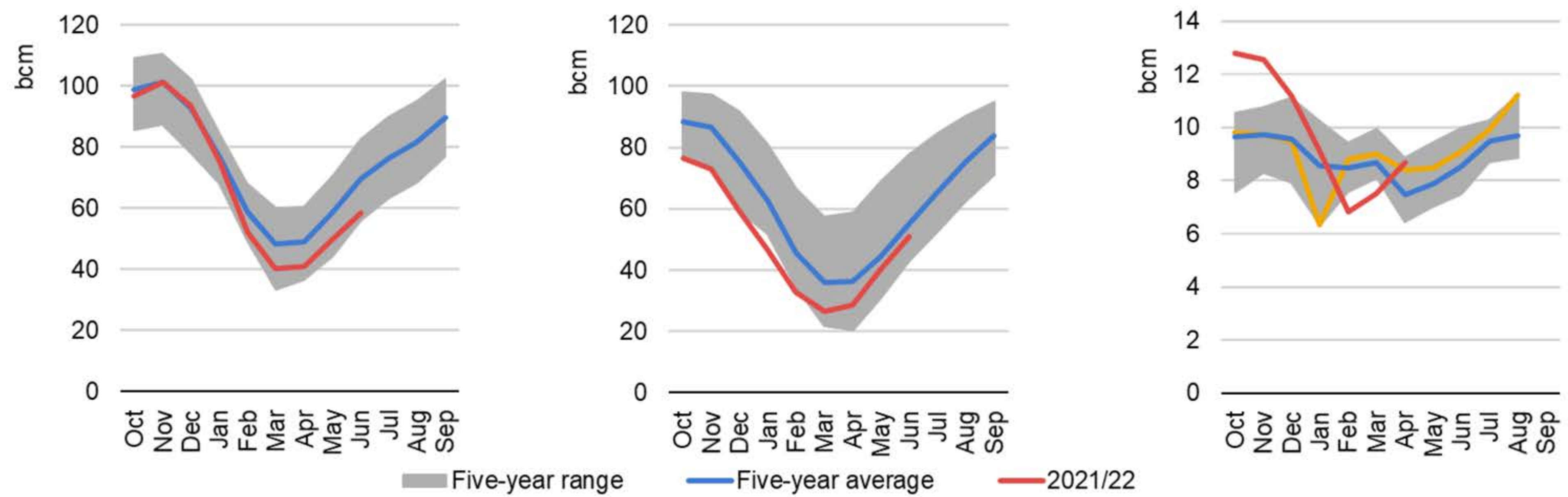
In Japan and Korea LNG closing stocks stood 15% above their five-year average in April 2022. The LNG stocks of Japan's largest power generation companies stood at 2.15 Mt (or 2.9 bcm) at the end of June 2022, 6% above their five-year average.

The European Union had almost entirely eradicated its storage deficit by the end of Q2 2022

US underground storage inventory

EU underground storage inventory

Japan and Korea LNG stock inventory



Sources: IEA analysis based on EIA (2022), Weekly Working Gas In Underground Storage; GIE (2022), AGSI+ Database; IEA (2022), Monthly Gas Data Service.

Annex

Summary tables (1/2)

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

	2019	2020	2021	2022	2023	2024	2025
Africa	164	161	169	172	177	183	188
Asia Pacific	835	841	895	907	935	962	990
of which China	*306*	*325*	*364*	*377*	*395*	*416*	*438*
Central and South America	155	142	153	147	148	150	153
Eurasia	608	584	634	619	614	624	632
of which Russia	*482*	*460*	*501*	*484*	*479*	*487*	*492*
Europe	586	573	604	549	556	545	536
Middle East	545	548	564	582	596	609	627
North America	1 106	1 080	1 084	1 108	1 101	1 105	1 116
of which United States	*888*	*869*	*867*	*887*	*878*	*880*	*889*
World	**3 999**	**3 930**	**4 103**	**4 083**	**4 127**	**4 178**	**4 243**

Summary tables (2/2)

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

	2019	2020	2021	2022	2023	2024	2025
Africa	252	241	262	267	275	283	292
Asia Pacific	637	630	651	670	674	676	679
of which China	*174*	*189*	*205*	*214*	*220*	*225*	*230*
Central and South America	167	150	147	150	152	156	156
Eurasia	921	866	955	858	859	883	891
of which Russia	*738*	*692*	*762*	*668*	*665*	*684*	*688*
Europe	249	230	223	227	218	217	216
Middle East	671	674	694	712	729	739	761
North America	1 174	1 154	1 178	1 208	1 223	1 241	1 263
of which United States	968	954	973	1 006	1 028	1 042	1 055
World	**4 071**	**3 945**	**4 110**	**4 092**	**4 132**	**4 195**	**4 259**

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 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 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 countries and territories.[4]

Eurasia – Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Russian Federation, Tajikistan, Turkmenistan and Uzbekistan.

Europe – Albania, Austria, Belarus, 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, the Republic of Moldova, Montenegro, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Republic of Türkiye, Ukraine 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, St Lucia, St. Vincent and the Grenadines, Suriname and Turks and Caicos Islands.

[5] Note by the Republic of Türkiye
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. The Republic of Türkiye recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, The Republic of Türkiye 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 Türkiye. 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

ANP	National Petroleum Agency (Brazil)
CAPEX	capital expenditure
CME	Chicago Mercantile Exchange (United States)
CNE	National Energy Commission (Chile)
CNG	compressed natural gas
CNY	Chinese yuan
CQPGX	Chongqing Petroleum Exchange (China)
EIA	Energy Information Administration (United States)
ENARGAS	National Gas Regulatory Entity (Argentina)
ENTSOE	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
EPIAS	Enerji Piyasaları İşletme A.Ş (the Republic of Türkiye)
EPPO	Energy Policy and Planning Office (Thailand)
FID	final investment decision
GIE	Gas Infrastructure Europe
HH	Henry Hub
IEA	International Energy Agency
ICIS	Independent Chemical Information Services
JODI	Joint Oil Data Initiative
LNG	liquefied natural gas
MME	Ministry of Mines and Eergy (Brazil)
m-o-m	month-on-month
NBP	National Balancing Point (United Kingdom)
OPEC	Organisation of the Petroleum Exporting Countries
OSINERG	Energy Regulatory Commission (Peru)
PPAC	Petroleum Planning and Analysis Cell (India)
SENER	Secretariat of Energy (Mexico)
TAP	Trans Adriatic Pipeline
TTF	Title Transfer Facility (the Netherlands)
USD	United States dollar
w-o-w	week-on-week
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
mb/d	million barrels per day
MBtu	million British thermal units
mcm/d	million cubic metres per day
MMcf/d	million cubic feet per day
tcm	trillion cubic metres
TWh	terawatt hour

Acknowledgements, contributors and credits

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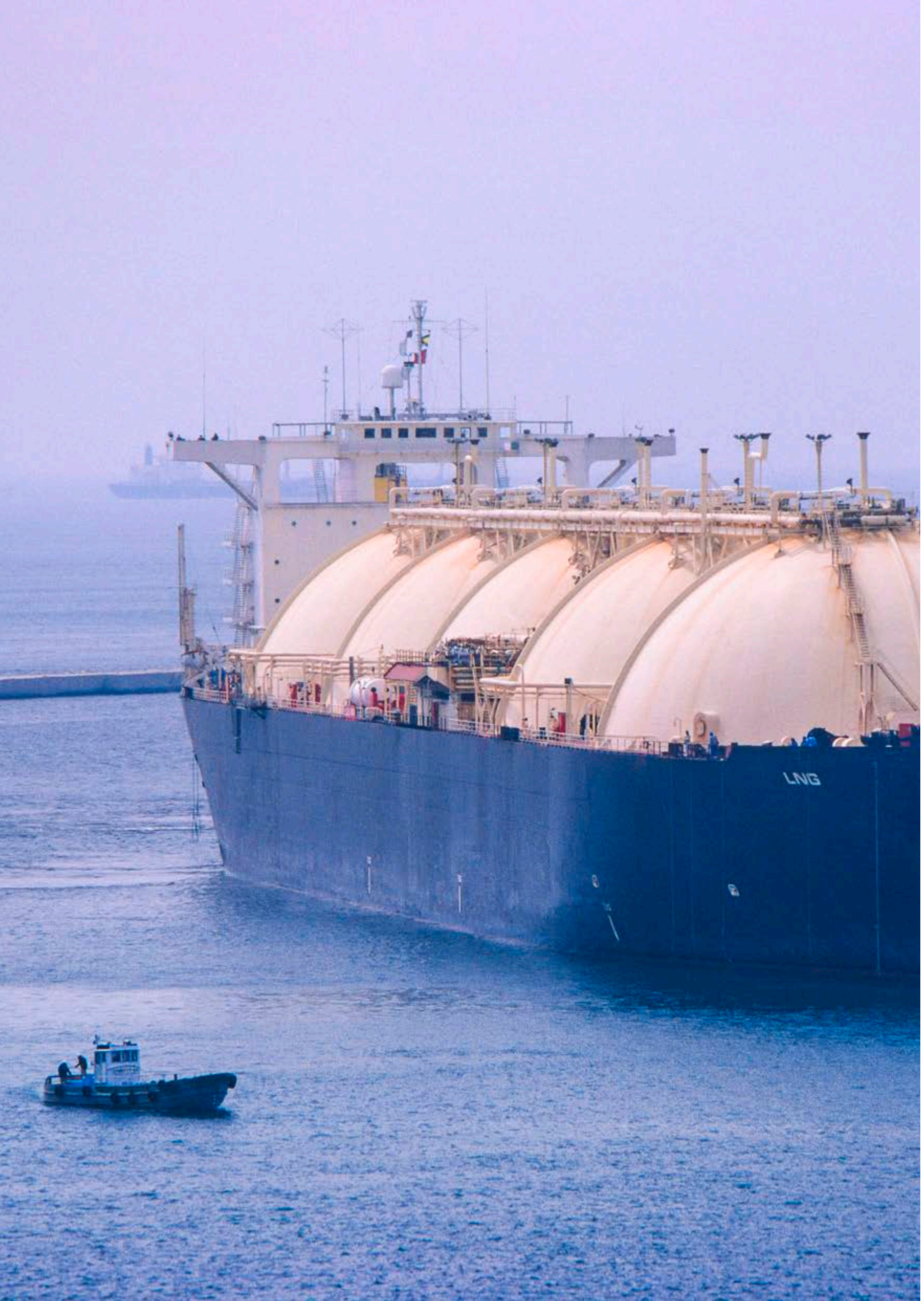
LNG