Medium-Term Gas Report 2023

Including the Gas Market Report, Q4-2023

INTERNATIONAL ENERGY AGENCY

The IEA examines the full spectrum of energy issues including oil, gas and coal supply and demand, renewable energy technologies, electricity markets, energy efficiency, access to energy, demand side management and much more. Through its work, the IEA advocates policies that will enhance the reliability, affordability and sustainability of energy in its 31 member countries, 13 association countries and beyond.

Source: IEA.
International Energy Agency
Website: www.iea.org

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

The European Commission also participates in the work of the IEA

IEA association countries:

Argentina
Brazil
China
Egypt
India
Indonesia
Kenya
Morocco
Senegal
Singapore
South Africa
Thailand
Ukraine

Abstract

The energy crisis triggered by Russia's invasion of Ukraine marked a turning point for global natural gas markets. Growth in global gas demand is set to slow down significantly over the medium term (2022-2026). This follows a decade of strong expansion in which gas contributed around 40% of the growth in primary energy supply worldwide.

While market tensions eased in the first three quarters of 2023, gas supplies remain relatively tight and prices continue to experience strong volatility, reflecting a fragile balance in global gas markets. High storage levels in the European Union allow for cautious optimism ahead of the 2023-24 heating season. However, a range of risk factors could easily renew market tensions. Northwest Europe will have no access this winter to two sources that used to be the backbone of its gas supply: Russian piped gas and the Groningen field in the Netherlands.

The gas supply shock of 2022 reinforced the structural trends that are weighing on the longer-term prospects for global gas demand. Overall gas consumption across the mature markets of Asia Pacific, Europe and North America peaked in 2021 and is set to decline over the medium term as a result of the rapid deployment of renewables and improved energy efficiency standards. Demand growth is almost entirely concentrated in fast-growing Asian markets and gas-rich countries in Africa and the Middle East. Strong LNG supply at the end of the forecast period is set to ease market fundamentals and unlock price sensitive demand in emerging markets in Asia.

The International Energy Agency's (IEA) *Gas 2023 Medium-Term Market Report* provides an outlook on the development of global gas demand and supply until 2026. This year's report includes a special spotlight on Africa and the potential for gas to contribute to regional economic growth and improved energy access. Beyond the medium-term outlook, the report provides a thorough review of recent market developments ahead of the 2023-24 winter season in the Northern Hemisphere. As part of the IEA's Low-Emission Gases Work Programme, this year's report includes a section on the medium-term outlook for biomethane, low-emissions hydrogen and e-methane. In addition, a special focus is provided on the developments in emerging markets.

Table of contents

Executive summary and key assumptions

Beyond the Golden Age of Gas: Slower growth, higher volatility and greater uncertainty

The period between 2011 and 2021 marked the Golden Decade of Gas: During this period, natural gas consumption worldwide expanded by close to 25% and accounted for 40% of the growth in primary energy supply worldwide – more than any other fuel. This rapid growth was underpinned by a number of factors including the availability of relatively cheap and cost-competitive gas supply, clean air policies in the fast growing markets of the Asia Pacific region, and the scaling up of shale production in the United States.

The energy crisis triggered by Russia's invasion of Ukraine marked a turning point for global gas markets. While markets moved towards a gradual rebalancing in the first three quarters (Q1-3) of 2023, structurally higher gas prices pave the way for a slower and more uncertain demand trajectory, with growth almost entirely concentrated in Asia and the gas-rich markets of Africa and the Middle East. A strong increase in liquefied natural gas (LNG) production capacity towards the end of our forecast horizon is expected to loosen market fundamentals and ease gas supply security concerns in the second half of the decade.

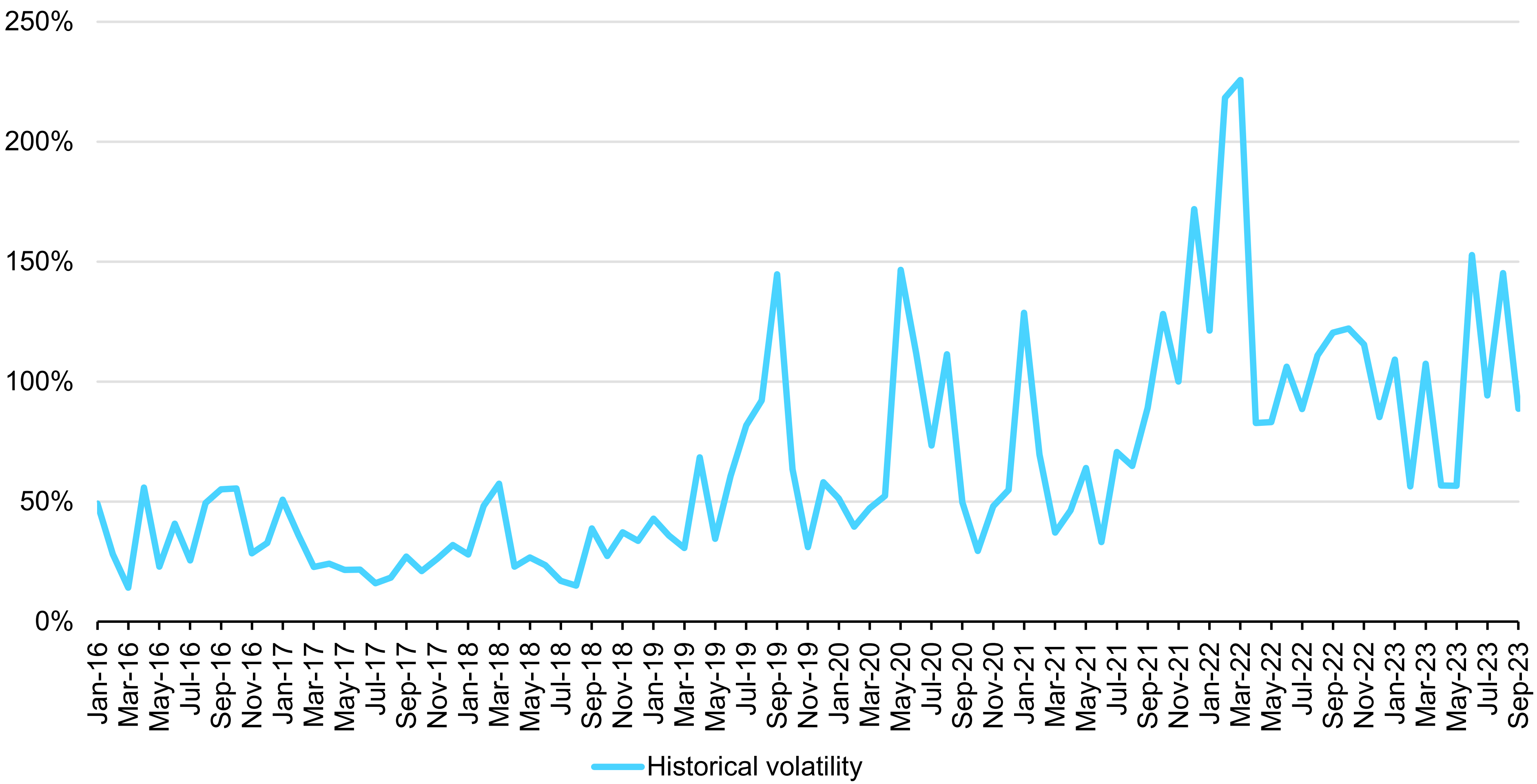
Despite the gradual rebalancing of gas markets, risks and uncertainties weigh on the outlook for the 2023-24 winter. The steep demand reductions in European and mature Asian markets in 2023 have eased market fundamentals and put downward pressure on prices. In the first three quarters of the year, European hub and Asian spot LNG prices averaged 70% and 60% below their 2022 levels, respectively. However, they have remained well above their historical averages.

The supply side remained tight in the first three quarters of 2023, as the additional LNG supply (+11 bcm) was insufficient to offset the steep decline in Russian piped gas deliveries to the European Union (-38 bcm). In this context, **markets remained sensitive and continued to display strong price volatility**. In August 2023, volatility on the European benchmark (TTF month-ahead contract) reached its highest level since Russia's invasion of Ukraine, as strike risks in Australia and unplanned outages in Norway weighed on the near-term gas supply outlook.

In the European Union, storage sites opened the 2023-24 heating season at 96% of full capacity and 10 bcm above their five-year average. Nevertheless, **full storage sites are no guarantee against winter volatility**. As highlighted in the *Global Gas Security Review 2023*, a cold winter together with lower LNG availability and a further decline in Russian piped gas deliveries could renew market tensions, especially towards the end of the 2023-24 winter. The **risks associated with this near term outlook** are reflected in the summer-winter spread, which averaged USD 5/MBtu on TTF in Q2-Q3 2023.

European gas prices remained highly volatile in Q3 2023 amid tight supply conditions

Historical monthly price volatility on the TTF month-ahead contract (annualised), 2016 - 2023



Sources: IEA analysis based on Bloomberg (2023).

Gas markets are set for slower growth over the medium-term, following a peak in gas demand in mature markets in 2021

The supply shock triggered by Russia cast a long shadow over gas markets. Higher gas prices are reducing its competitiveness vis-à-vis other fuels, while Russia's steep supply cuts and the lack of LNG availability in South Asian markets damaged the image of natural gas as a "reliable" fuel.

Gas demand growth is projected to slow by almost a third, from an average rate of 2.5% per year during 2017-2021 to 1.6% in the 2022-2026 period. Natural gas consumption is expected to **remain broadly flat in 2023** as demand gains in Asia Pacific and the Middle East are almost entirely offset by the drops in demand in Europe, Central America and South America. Global gas demand is expected to **return to moderate growth in 2024**, primarily driven by Asia Pacific and the Middle East. **Demand growth is expected to be more robust in 2025-26**, supported by higher LNG liquefaction capacity additions than the historical average.

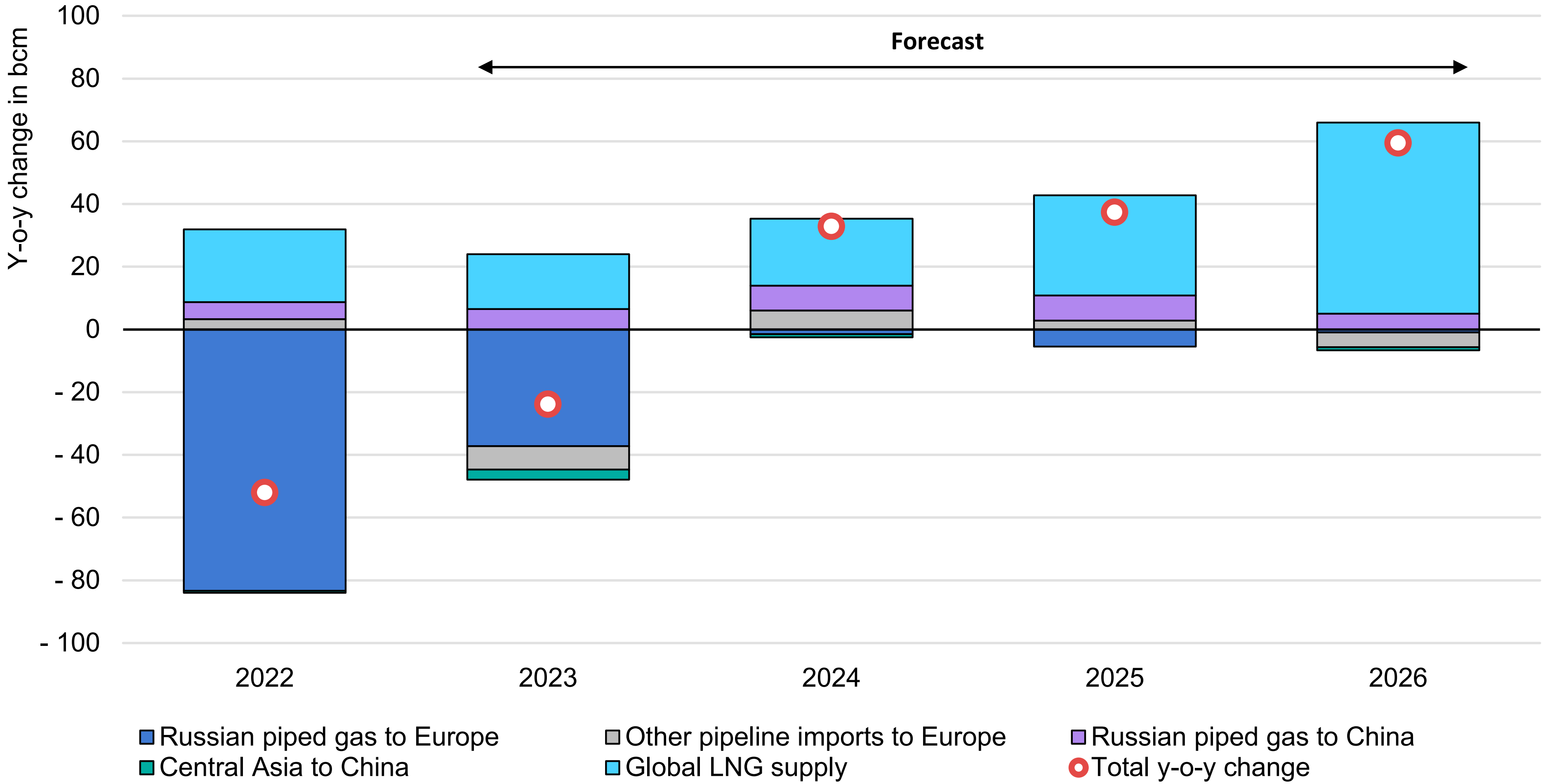
The combined gas consumption of mature markets in Asia Pacific[1], Europe and North America peaked in 2021 and is expected to decline at a rate of 1% per year between 2022 and 2026. In **Europe**, the gas crisis reinforced the structural drivers accelerating the decline in gas demand over the medium term. An accelerated deployment of renewables, higher energy efficiency standards and growing electrification in areas such as space heating are set to weigh on gas consumption. In **mature Asia Pacific markets**, improving nuclear availability together with the continued expansion of renewables is expected to reduce the call on gas-fired power plants and drive down overall gas demand. In **North America**, higher output from renewable energy is forecast to reduce gas usage in power generation, while improved energy efficiency standards and a gradual electrification of heating are set to shrink the role of gas in residential and commercial sectors.

Faster-growing Asia Pacific markets and gas-rich countries in Africa and the Middle East are set to drive growth in gas demand. **China alone accounts for almost half of the increase in global gas demand** over the forecast period, with the power sector, industrial production and city gas networks the major consumers. Strong LNG supply at the end of the forecast period is set to ease market fundamentals and unlock some price sensitive demand in developing Asian markets that have the infrastructure in place. In the Middle East, **production growth in Iran, Israel and Saudi Arabia** is expected to support the expansion of gas-intensive industries and higher gas burn in the power sector. Africa's gas demand growth is driven by its rapidly rising population, improving energy access and economic growth. Eurasian natural gas demand trends towards stagnation, with the region's gas demand standing 2% above its 2021 level by 2026.

[1] Australia, Japan, Korea, New Zealand and Singapore.

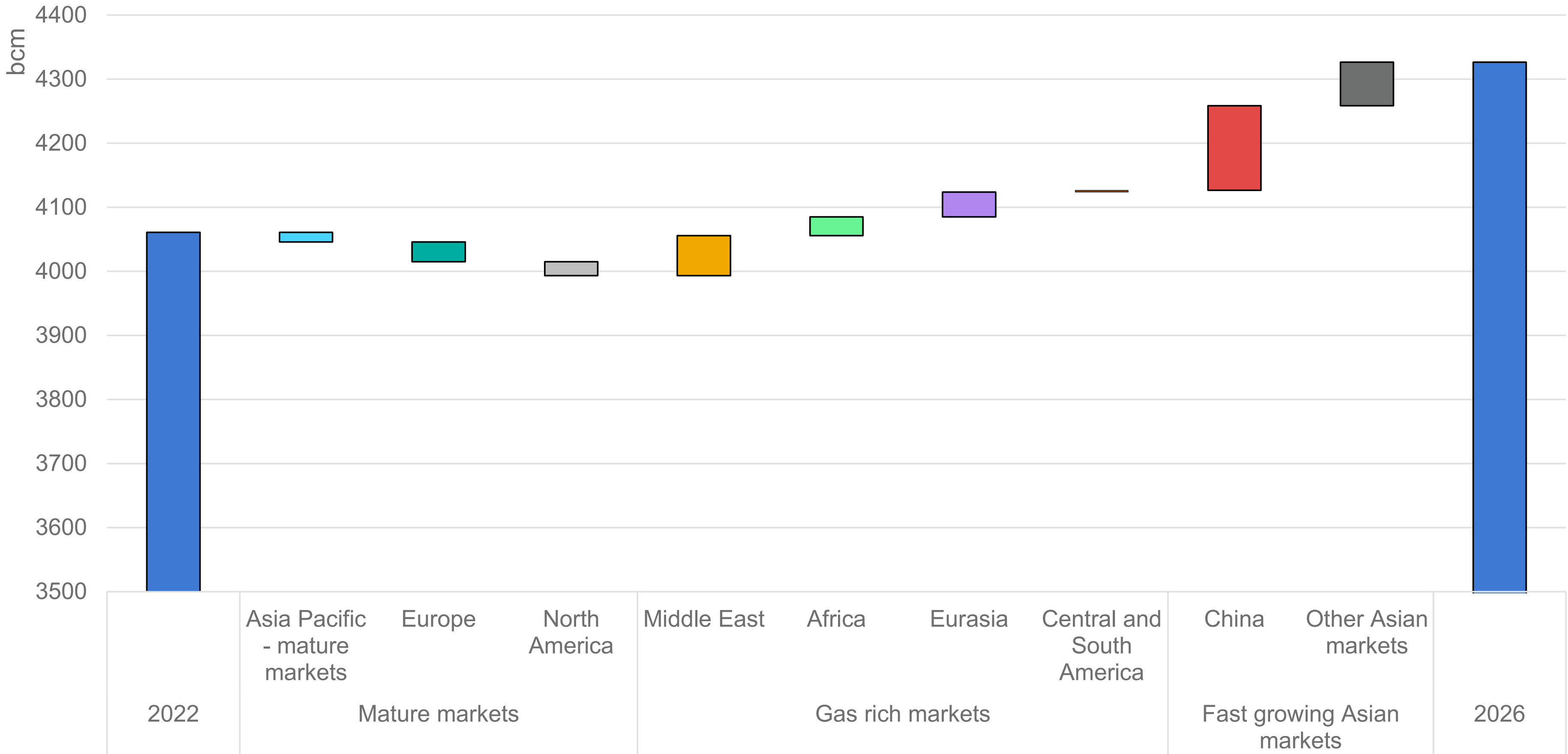
The strong increase in LNG supply in 2026 is expected to ease market fundamentals

Year-on-year change in key piped natural gas trade and global LNG supply, 2022 – 2026



Natural gas demand peaked in mature markets in 2021, with growth prospects increasingly concentrated in the Asia Pacific region and the Middle East

Forecasted change in natural gas demand by key regions, 2022 – 2026



LNG supply growth is expected to drive an increasingly interconnected and globalised gas market

Global LNG supply is expected to expand by 25% (or 130 bcm a year) between 2022 and 2026, with 70% of the supply increase concentrated in 2025-26. In this context, LNG export projects will be a key driver of upstream developments, as supply requirements for LNG feedgas account for around 55% of the net increase in global gas output in the forecast period.

The United States alone is set to contribute for around half of incremental LNG supply, reinforcing its position as the world's largest LNG exporter. Consequently, the share of the United States in global LNG supply is set to increase from 20% in 2022 to over 25% by 2026. Considering the contractual terms underpinning US LNG supply (hub-indexed pricing mechanisms and destination-free shipping arrangements), the liquidity and the flexibility of global LNG trade is set to increase over the medium-term.

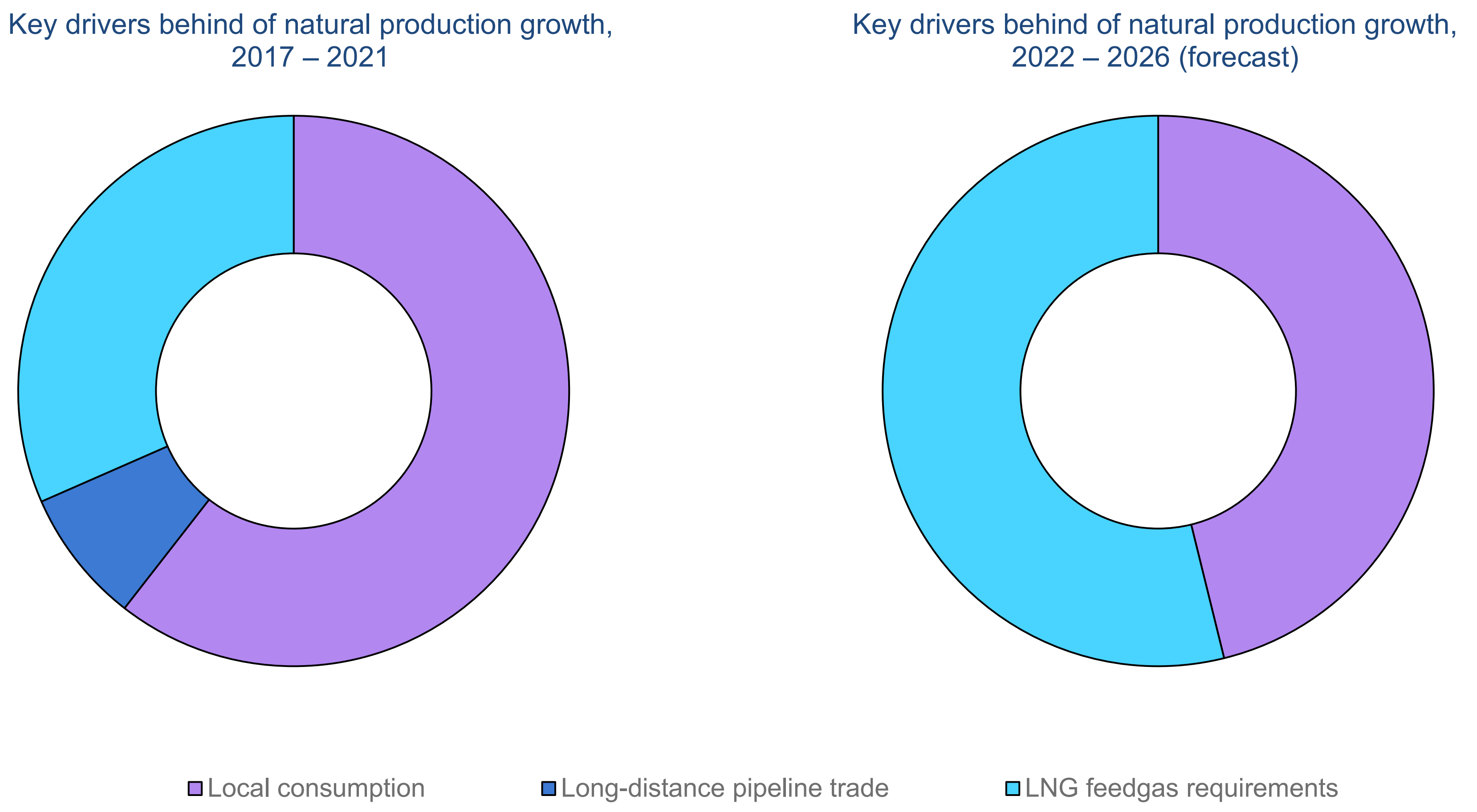
Liquidity in the LNG market will allow for a more effective response to short-term supply and/or demand shocks, resulting in a more resilent global gas market. **Regional markets are set to become increasingly interdepedent**. Liquidity in the LNG market can ease market tensions in regions facing tight supply-demand fundamentals. However, this also means that events that induce price volatility in one region could impact price fluctuations and supply-demand dynamics in geographically distant markets. An **increasingly globalised market** will reinforce the need for enhanced dialogue between producers and consumers on security of supply issues. The IEA's Task Force on Gas and Clean Fuels Market Monitoring and Supply Security has provided such a platform since October 2022.

Low-emissions gases are set to expand rapidly

The supply of low-emissions gases is expected to more than double over the medium term, resulting in an increase of over 8 bcm in absolute terms. Europe and North America are set to drive this expansion and to contribute for 70% of the overall growth. The development of low-emissions gases in these markets benefits from a wide range of policies, increasingly sophisticated subsidy schemes and well-developed, interconnected gas networks. Nevertheless, further efforts will be required to reach the ambitious targets set for biomethane and low-emissions hydrogen. Besides Europe and North America, a number of emerging low-emissions gas producers are expected to scale up their output.

Biomethane production is expected to expand by over 65% (or 4.5 bcm) between 2022 and 2026, accounting for almost 55% of the total increase in low-emissions gases during this period. **Low-emissions hydrogen** is projected to grow at an average rate of close to 25% per year between 2022 and 2026, translating into almost 4 bcm equivalent of additional supply by 2026. In contrast, **e-methane** struggles to take off over the forecast period, requiring a concentrated effort between emerging producers and consumers to establish viable supply chains and effective support mechanisms.

LNG feedgas supply requirements account for around 55% of the net increase in global gas output in the forecast period



Key assumptions behind the medium-term forecast

The global energy crisis triggered by Russia's invasion of Ukraine led to a profound reconfiguration of the global gas market. This medium-term forecast is subject to an unusually wide range of uncertainties stemming from the broader geopolitical and macroeconomic environment.

Macroeconomic outlook: Towards slower growth

Following a drop of 3.1% in 2020, global real GDP grew by 6.4% in 2021. This strong performance was partly supported by the recovery in commercial and industrial activity after the Covid-induced lockdowns, when governments and central banks launched major fiscal and monetary stimulus packages. **Global GDP growth slowed to 3.3% in 2022** amid the unfolding global energy crisis, soaring commodity prices and rapidly rising consumer prices. In response to the inflationary pressures, central banks adopted **tighter monetary policies** by raising their interest rates. This in turn increased the cost of borrowing and is set to weigh on economic activity during 2023 and 2024. **Global GDP growth is set to fall below 3% in 2023 and to 2.6% in 2024** – its lowest annual rate since the 2007-2008 global financial crisis, with the exception of the 2020 pandemic period. Improving economic performance and monetary easing is expected to translate into **stronger GDP growth in the second half of the forecast** period and average 3.4% between 2025 and 2026.

Short-term indicators are confirming this general slowdown in economic growth. In the **United States**, the Manufacturing Purchasing Managers' Index (PMI) averaged 47 during Q1-Q3 2023, indicating a contraction in manufacturing activity. Real GDP growth in the United States is expected to slow to an average of 1.5% per year between 2023 and 2026. In the **Euro area**, the Manufacturing PMI stood at 45 during Q1-Q3 2023 and dropped to 42.7 in July – its lowest level in three years. Real GDP growth in the European Union is forecast to average 1.4% per year between 2023 and 2026. In **China**, manufacturing activity and consumption rebounded at the start of 2023 when authorities eased their strict lockdown policies. Nevertheless, weak export demand together with the ongoing real estate downturn is weighing on economic performance. China's Manufacturing PMI stood at 50 in Q1-Q3 2023 and the country's GDP growth is expected to average just below 4.5% between 2023 and 2026 – well below the 6.6% average growth rate experienced between 2016 and 2019.

Natural gas prices are expected to remain above their historical averages

This forecast relies on external energy price assumptions **based on the futures' market prices** observed at the end of September 2023. **European hub and Asian spot LNG prices** rose to all-time highs in 2022 amid the supply shock triggered by Russia. In

Europe, TTF spot prices stood at USD 37/MBtu in 2022, more than seven times their average between 2016 and 2020. In Asia, JKM prices followed a similar trajectory and averaged close to USD 34/MBtu. Gas markets have moved towards **a gradual rebalancing since the start of 2023** due to timely policy action, effectively working market forces and favourable weather conditions. Natural **gas prices could strengthen again in 2024** amid tighter supply–demand fundamentals. Forward curves indicate that TTF and JKM prices are expected to increase by around 10% and oscillate in a range between USD 14-15/MBtu in 2024. However, the start-up of new LNG liquefaction terminals and improving supply fundamentals are set to provide **downward pressure on TTF and Asian spot LNG** prices during **the second half of the forecast period** to average USD 13/MBtu in 2025 and 2026. This would still be more than double the average price levels seen between 2016 and 2020. **Oil-indexed LNG prices** are assumed to display a less volatile pattern over the forecast period and average USD 12/MBtu between 2023 and 2026 – 30% above their levels between 2016 and 2020. In the United States, Henry Hub prices rose to over USD 6/MBtu in 2022, their highest level since 2008. Forward curves indicate that **Henry Hub** prices are expected to hover at around USD 2.7/MBtu in 2023 and strenghten to an average close to USD 4/MBtu during 2024-2026 – 40% above the levels experienced between 2016 and 2020.

Natural gas prices trending above their historical average are expected to weigh on natural gas demand growth over the medium term, especially in sectors where gas is facing stiff competition from other fuels, such as power generation and road transport.

Russian piped gas flows to the European Union

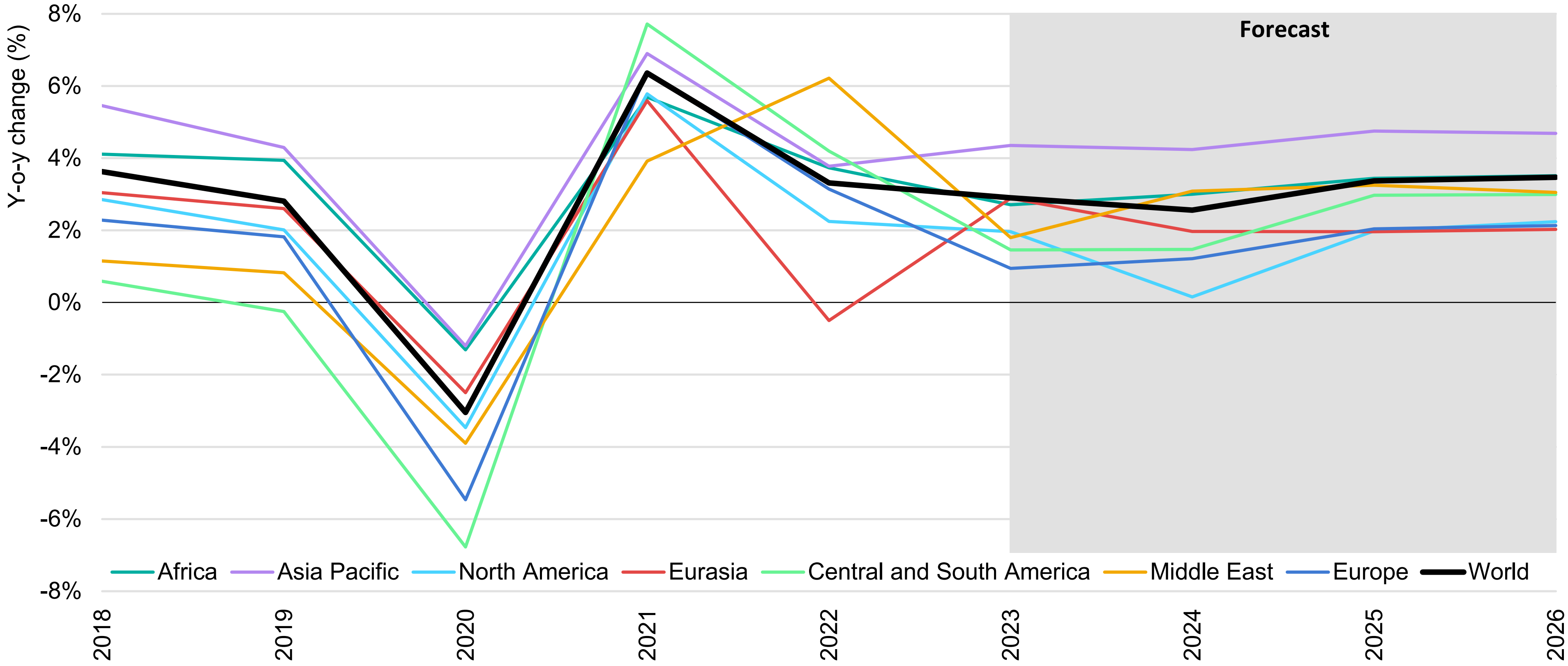
The future of Russian piped gas deliveries to the Europe Union is a key uncertainty in our forecast. They more than halved in 2022, dropping from almost 140 bcm in 2021 to just above 60 bcm. Considering current flow profiles, Russian piped gas deliveries are set to decline by around 65% in 2023 to within a range of 20-25 bcm. Russia's gas transit contract with Ukraine is set to expire at the end of 2024. Ukraine's energy minister has ruled out the possibility of extending the contract, following Russia's invasion of the country. Hence, this forecast assumes that only TurkStream string 2 (15.75 bcm/yr) will supply Russian piped gas to the European Union starting from 2025. While short-term capacity booking options might continue to be available along the Ukrainian transit route for European importers of Russian piped gas, this upside potential is not included in our baseline forecast.

Weather

Natural gas consumption is particularly sensitive to the weather, notably temperature; this forecast is based on the assumption of average winter conditions (typically based on rolling five-year averages) for the forthcoming heating seasons.

Global GDP growth is expected to slow over the forecast period

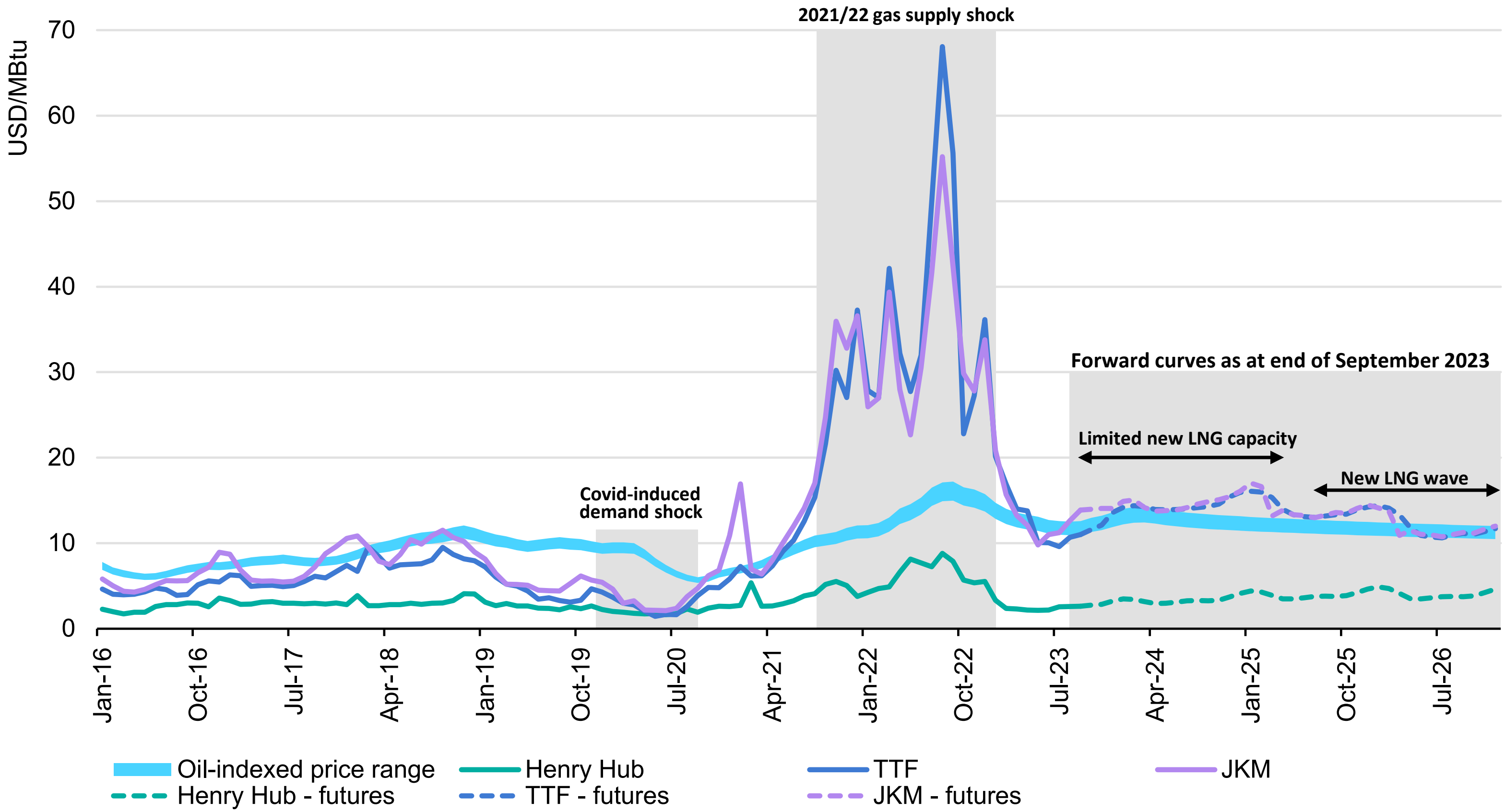
GDP growth, global and regional, 2018-2026



Sources: IEA, IMF and Oxford Economics.

Forward curves suggest that natural gas prices will remain above their historical averages in the medium term

Natural gas price assumptions across key regions, 2016-2026



Note: Future prices are based on forward curves as of the end of September 2023 and do not represent a price forecast.

Sources: IEA analysis based on CME (2023), Henry Hub Natural Gas Futures Quotes, Dutch TTF Natural Gas Month Futures Settlements, LNG Japan/Korea Marker (Platts) Futures Settlements; EIA (2023), Henry Hub Natural Gas Spot Price; Powernext (2023), Spot Market Data; S&P Global (2023), Platts Connect.

Gas market update

Natural gas demand returned to moderate growth in Q2-Q3 in Asia and North America…

Global gas consumption contracted by an estimated 1.5% y-o-y (or 65 bcm) in 2022 – comparable to demand drops seen in 2009 in the aftermath of the financial crisis, or during the global Covid-19 pandemic in 2020. First data indicate that **this downward trend continued in Q1 2023**, when gas consumption declined in all key markets due to the continued impact of high prices on gas use in the industrial and power sectors and unseasonably mild weather conditions. **Natural gas demand returned to moderate growth in Q2-Q3** in North America and the rapidly growing markets of the Asia Pacific, while consumption continued to decline in Europe.

OECD Europe recorded a drop of 9% (or 33 bcm) y-o-y in Q1-Q3 2023. This was primarily driven by lower residential and commercial demand in Q1 and a steep decline in gas burn in the power sector during Q2 and Q3. The power sector emerged as the most important driver behind Europe's gas demand reduction, accounting for over 55% of Europe's total gas demand decline in Q1-Q3 2023. Preliminary data indicate that gas use in industry continued to decline during H1 2023, starting to recover in Q3 – albeit remaining well below its pre-crisis levels.

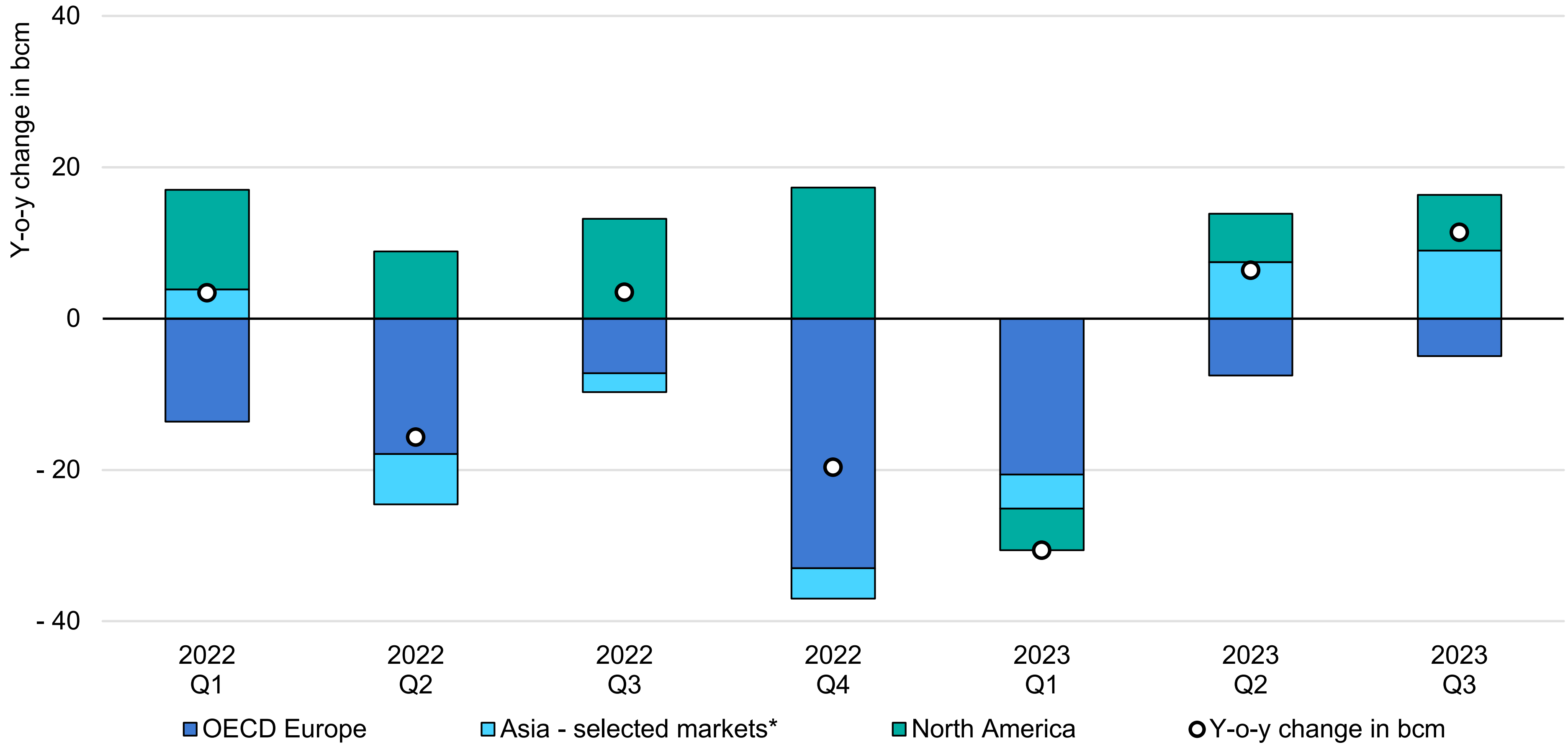
Natural gas demand in the **Asia Pacific region** increased by an estimated 2.5% (or 12 bcm) in the first eight months of 2023, as the declines recorded in Q1 were more than offset by rising consumption during Q2-Q3. Demand growth is largely concentrated in China. Preliminary data indicate that the country's estimated gas consumption rose by around 7% y-o-y in Q1-Q3 2023, supported by the industrial and power sectors. The country's LNG imports rose by close to 15% over the same period. In contrast, gas demand continued to decline in the region's mature gas markets (Japan and Korea) amid depressed electricity consumption and improving nuclear availability.

In **North America**, natural gas demand increased by a mere 1% (or 8 bcm) in Q1-Q3 2023. While residential and commercial demand declined amid an unseasonably mild Q1, gas use in the power sector continued to grow strongly on continued coal-to-gas switching dynamics. In **Central and South America** natural gas demand dropped by 4% (or 3 bcm) in H1 2023 amid lower gas burn in the power sector.

Global gas supply is set to remain tight in 2023, as incremental LNG supply (18 bcm) will not be sufficient to offset the expected drop in Russia's piped gas deliveries to the Europe Union (a decline of over 35 bcm). Considering the tight gas supply picture in 2023, **global gas demand is expected to remain broadly flat in 2023**. Most of the demand growth is projected to be driven by the Asia Pacific region and the Middle East; however, this growth is almost entirely offset by the demand drops in Europe and Central and South America. This short-term forecast is subject to an **unusually wide range of uncertainties**, stemming from the broader geopolitical and macro-economic environment.

…while European gas consumption remains depressed

Quarterly change in natural gas demand in key regions, 2022-2023



* China, India, Japan and Korea.

North American gas demand growth is set to slow and peak in 2023 before declining in 2024

Natural gas consumption in North America increased by an estimated 1% (or 8 bcm) y-o-y in Q1-Q3 2023, primarily supported by higher gas burn in the power sector.

In the **United States**, natural gas demand rose by an estimated 0.8% (or 5 bcm) in Q1-Q3 2023, with growth entirely driven by the power sector. Preliminary data indicate that gas-to-power demand expanded by 6% (or 16 bcm) in Q1-Q3 amid lower hydro output and at the expense of coal-fired generation (down almost 20% y-o-y). Consequently, the share of natural gas in the power generation mix rose from 34% in January 2021 to more than 45% in August 2023 – its highest monthly average on record. By the end of the year, a total of 16 gas-fired power plants are expected to come online, amounting to 8.4 GW of additional capacity.

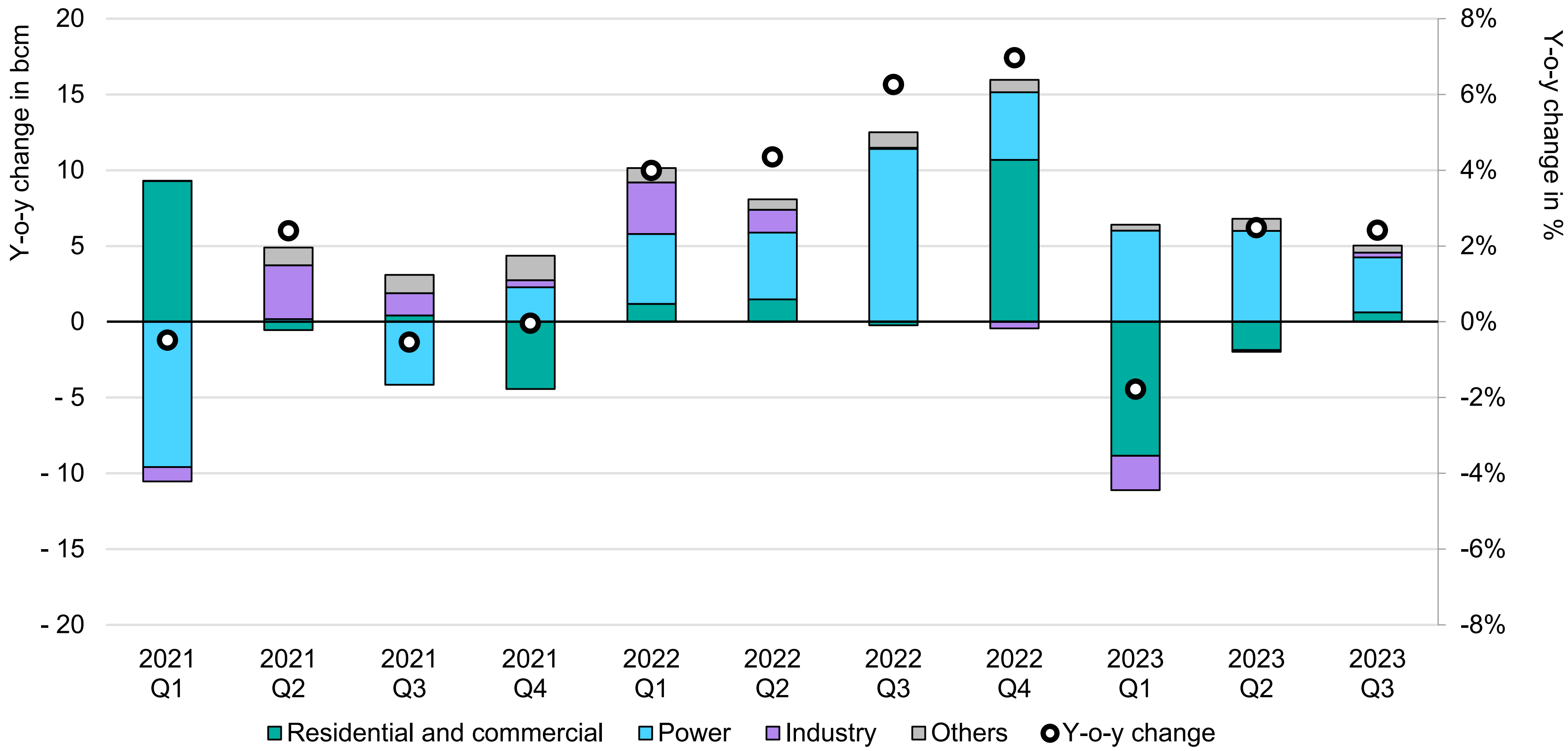
In contrast, natural gas consumption in the residential and commercial sector contracted by more than 6% (or 10 bcm) y-o-y in Q1-Q3 2023 amid unseasonably mild weather in January-April. Natural gas demand in industry declined by 1% (or 2 bcm) y-o-y in Q1-Q3 2023 due to subdued economic activity. The US Manufacturing Purchasing Managers' Index (PMI) averaged 47 in Q1-3, indicating a contraction in manufacturing activity.

Natural gas consumption in **Canada** increased by an estimated 2% (or 1.5 bcm) y-o-y in Q1-3 2023. Natural gas demand in the power and industrial sectors grew by 5% y-o-y in H1 2023 due to coal-to-gas switching in the power sector. This increase was almost entirely offset by a 9% y-o-y decline in residential and commercial gas demand. **Mexico**'s estimated natural gas consumption increased by 2% (or 1 bcm) y-o-y in the first eight months of 2023.

In this **forecast**, North American growth in natural gas demand is expected to experience a slowdown and to peak in 2023 with growth close to 1%, followed by a decline in 2024 triggered by the contraction of gas demand for power generation in the United States.

US gas consumption increased by 0.8% y-o-y in Q1-Q3 2023

Estimated quarterly change in gas demand, United States, 2021-2023



Sources: IEA analysis based on EIA (2023), Natural Gas Consumption; Natural Gas Weekly Update.

Lower gas burn in the power sector continued to weigh on natural gas demand in Central and South America

Following a 3% decline in 2022, natural gas consumption remained depressed in Central and South America in H1 2023. First estimates indicate that the region's gas demand fell by 4% (or 3 bcm) y-o-y in H1 2023 amid lower gas burn in the power sector.

In **Argentina**, the region's largest gas market, gas demand fell by 2% (or 0.5 bcm) y-o-y in the first seven months 2023 according to preliminary data. This decline was almost entirely driven the residential and commercial sectors, where gas use dropped by over 12% (or 0.9 bcm) y-o-y amid milder weather conditions. In contrast, gas demand in industry grew by 5% y-o-y, while gas burn in the power sector increased by close to 2% y-o-y.

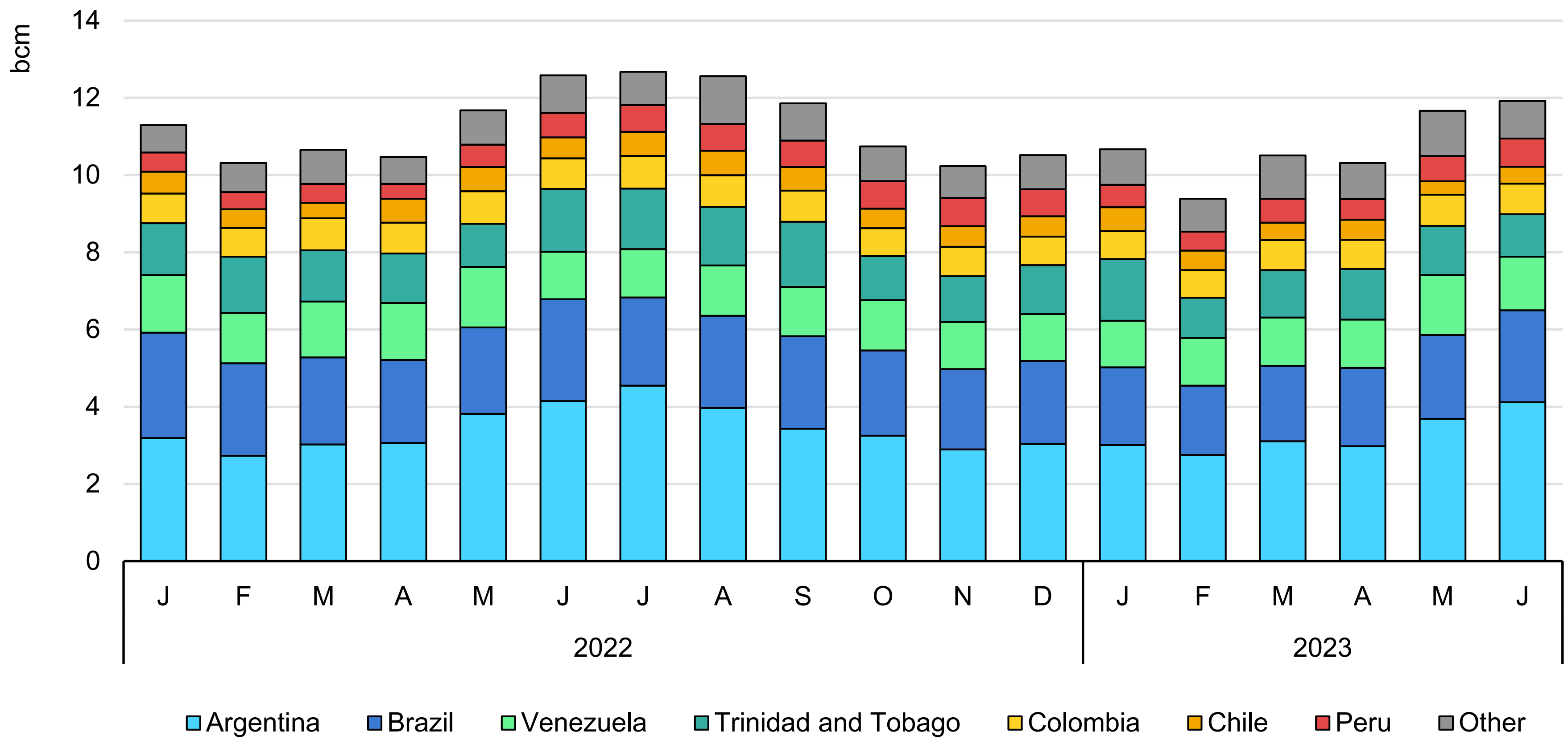
In **Brazil**, gas consumption continued to decline steeply and dropped by over 10% (or 2.2 bcm) y-o-y in the first eight months of 2023, primarily driven by lower gas burn in the power sector. This decreased by 30% (or 5 TWh) y-o-y in the first eight months of 2023. The decline was almost entirely concentrated in Q1 2023, when gas-to-power demand plummeted by close to 60% y-o-y amid higher hydro availability. Gas-fired generation returned to growth in Q2 amid lower hydro output. Gas burn in the power sector increased by 10% (or 0.7 TWh) y-o-y during the April-August period. As a consequence of lower gas demand, Brazil reduced its piped gas imports from Bolivia by 15% (or 0.2 bcm) y-o-y, while its LNG inflows dropped by 80% (or 2 bcm) y-o-y in the first half of 2023.

Several other countries in the region experienced similar declines. In **Trinidad and Tobago** natural gas production remained broadly flat in H1 2023 compared with the same period in 2022. The country's LNG exports rose by close to 10% y-o-y, suggesting that domestic gas consumption declined by over 5% (or 0.4 bcm) y-o-y during H1 2023. In **Venezuela** observed gas consumption decreased by 7% (or 0.6 bcm) y-o-y in H1 2023. In **Colombia** gas demand declined by 3% (or 0.22 bcm) y-o-y in the first eight months of 2023, primarily driven by lower gas burn in the power sector (down by 17% y-o-y). Gas demand in industry declined by 5% y-o-y, largely offset by higher gas use in refining (up by 10%). Gas consumption in the residential and commercial sectors increased by 2% y-o-y. The region's smaller markets displayed varied demand patterns over the first eight months 2023, not sufficient to offset the declines recorded in the five largest gas markets.

Taking into account the declines in H1 and assuming average weather conditions for the remainder of the year, this forecast expects natural gas demand in Central and South America to decline by close to 2% in 2023 amid depressed gas burn in the power sector and a slowdown in economic growth.

Natural gas demand declined by 4% in Central and South America in H1 2023

Monthly natural gas consumption, Central and South America, 2022 and H1 2023



Sources: IEA analysis based on ANP (2023), Boletim Mensal da Produção de Petróleo e Gás Natural; BMC (2023), Informes Mensuales; Central Bank of Trinidad and Tobago (2023), Statistics; CNE (2023), Generación bruta SEN; ENARGAS (2023), Datos Abiertos; ICIS (2023), ICIS LNG Edge; IEA (2023), Monthly Gas Data Service; JODI (2023), Gas Database; MME (2023), Boletim Mensal de Acompanhamento da Industria de Gás Natural; OSINERG (2023), Reporte diario de la operación de los sistemas de transporte de gas natural.

Asian gas demand returned to moderate growth in Q2-Q3 2023…

Following a 2% decline in 2022, natural gas demand in the Asia Pacific region **returned to moderate growth** during Q2-Q3 2023. While gas consumption in China and certain emerging Asian markets has been on the rise, demand remains depressed in the region's mature markets amid improving nuclear availability. For the full year of 2023 Asian gas demand is projected to increase by 3%, supported by the power and industrial sectors.

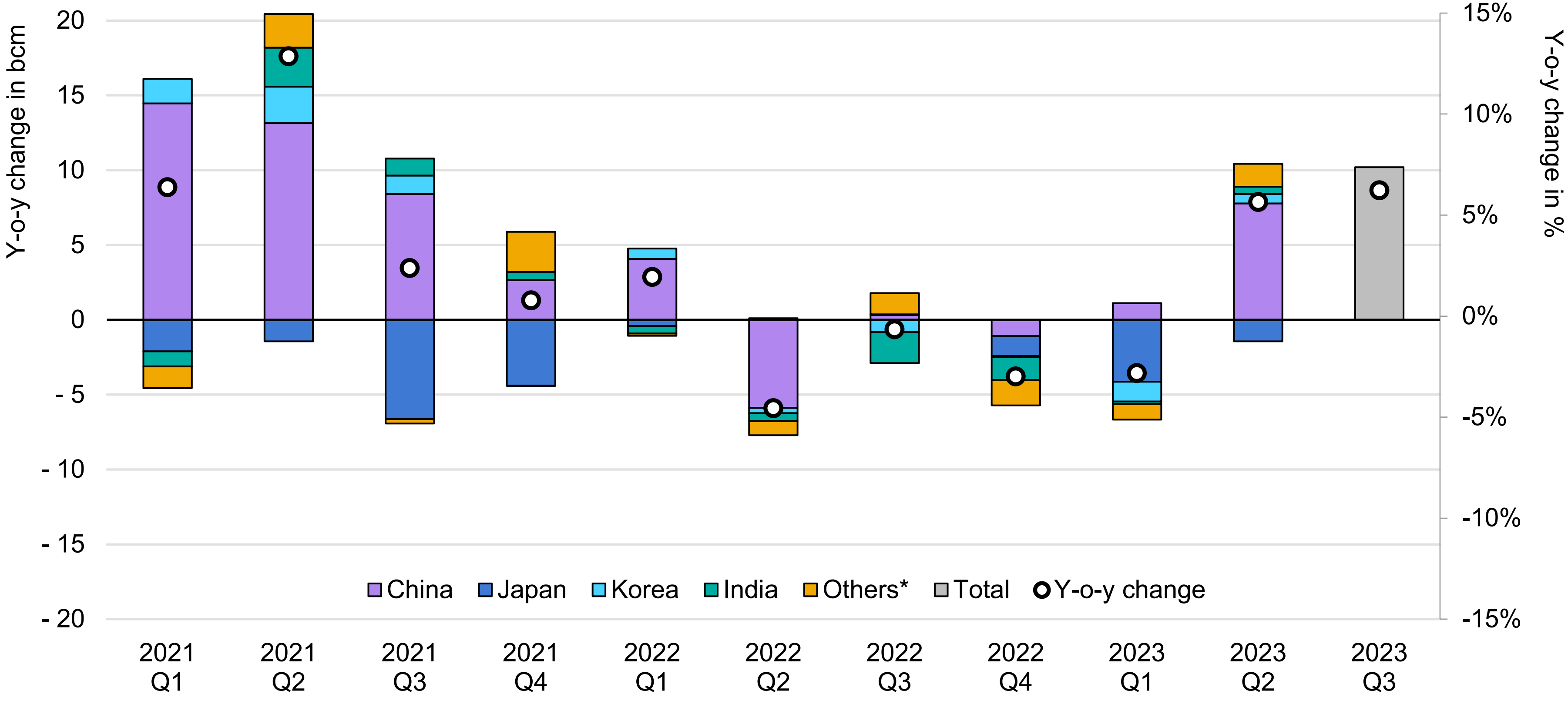
Following its first demand drop in four decades in 2022, **China**'s natural gas consumption returned to growth in Q1 2023. Preliminary data indicate that the country's estimated gas consumption rose by around 7% (or 18 bcm) y-o-y in Q1-Q3 2023. Industrial gas demand rose by over 3% y-o-y in H1 2023, supported by a recovery in economic activity. Gas-to-power demand surged by more than 10% y-o-y, as higher electricity demand together with lower hydro output increased the call on gas-fired power plants. The city gas segment rose by around 7% y-o-y due to growing gas penetration. For the full year of 2023, China's gas demand is projected to increase by over 7%, led by the industrial and power sectors.

Japan's gas consumption decreased by 11% (or 7 bcm) in the first seven months of 2023. Gas-to-power demand declined by 16% (or about 3 bcm) y-o-y in the first four months of 2023. This was primarily driven by lower electricity consumption (down by 5% y-o-y) and improving nuclear availability. Japan's nuclear power output rose by 53% (or 18 TWh) y-o-y in the first eight months of 2023. In addition, city gas sales to commercial and industrial consumers decreased by 2% and 11% y-o-y respectively in the first seven months of 2023. For the full year of 2023 Japan's gas demand is forecast to decrease by 6% compared with last year. This decline is mainly driven by the power sector, reflecting higher nuclear power generation. **Korea**'s gas consumption fell by 1% y-o-y in the first seven months of 2023 amid lower gas use in the power sector and city gas segments. For the full year of 2023, Korea's gas demand is expected to decrease by 2% due to higher nuclear power output.

India's primary gas supply rose by 2% in the first eight months of 2023, according to the Petroleum Planning & Analysis Cell. Demand growth is primarily supported by the power, petrochemical and fertiliser sectors. For the full year of 2023, India's natural gas demand is expected to increase by 4%, driven by the industrial and power sectors. **Emerging Asia**'s gas consumption increased by an estimated 2% y-o-y in the first seven months of 2023, amid lower LNG spot prices. **Thailand** recorded 4% y-o-y growth in the first seven months of 2023, primarily driven by higher gas burn in the power sector. **Bangladesh and Pakistan** increased their LNG imports by 14% and 6% y-o-y in Q1-Q3 2023, respectively. This indicates a gradual recovery in the two countries' gas demand, driven by higher gas use in industry and the power sector. In 2023 gas demand in emerging Asia is projected to increase by a modest 3%, supported by growing economic activity and power demand.

…primarily driven by China and emerging Asia

Estimated quarterly change in gas demand, selected Asian markets, 2021-2023



*Others comprise Indonesia, Malaysia, the Philippines, Singapore and Thailand.

Sources: IEA analysis based on ICIS (2023), ICIS LNG Edge; CQPGX (2023), Nanbin Observation; JODI (2023), Gas World Database; PPAC (2023), Gas Consumption; EPPO (2023), Energy Statistics; Korea Energy Economics Institute (2023), Monthly Energy Statistics; Ministry of Economy, Trade and Industry of Japan (2023), METI Statistics.

The power sector drives down European gas demand in 2023

Natural gas consumption in OECD Europe fell by over 9% (or 33 bcm) y-o-y during Q1-Q3 2023. Over 60% of this demand reduction occurred in Q1 when European gas consumption fell by 12% (or 21 bcm) y-o-y, primarily driven by lower gas use in the residential and commercial sectors. The pace of demand reduction moderated to a 7% (or 12 bcm) y-o-y decline in Q2-Q3 2023. Lower gas burn in the power sector accounted for the entire gas demand reduction during this period, amid lower electricity consumption and stronger renewable power output.

Distribution network-related demand fell by an estimated 9% (or 12 bcm) y-o-y in Q1-Q3 2023, with over 80% of the contraction concentrated in Q1. Despite a colder spring, gas demand in the residential and commercial sectors continued to decline in Q2, driven by non-weather-related factors. They include efficiency gains, administrated gas-saving measures, fuel switching, deployment of heat pumps, behavioural changes and rising affordability issues. Preliminary data indicate that distribution network-related demand rose by 4% (or over 0.5 bcm) in Q3, driven by the commercial and service sectors.

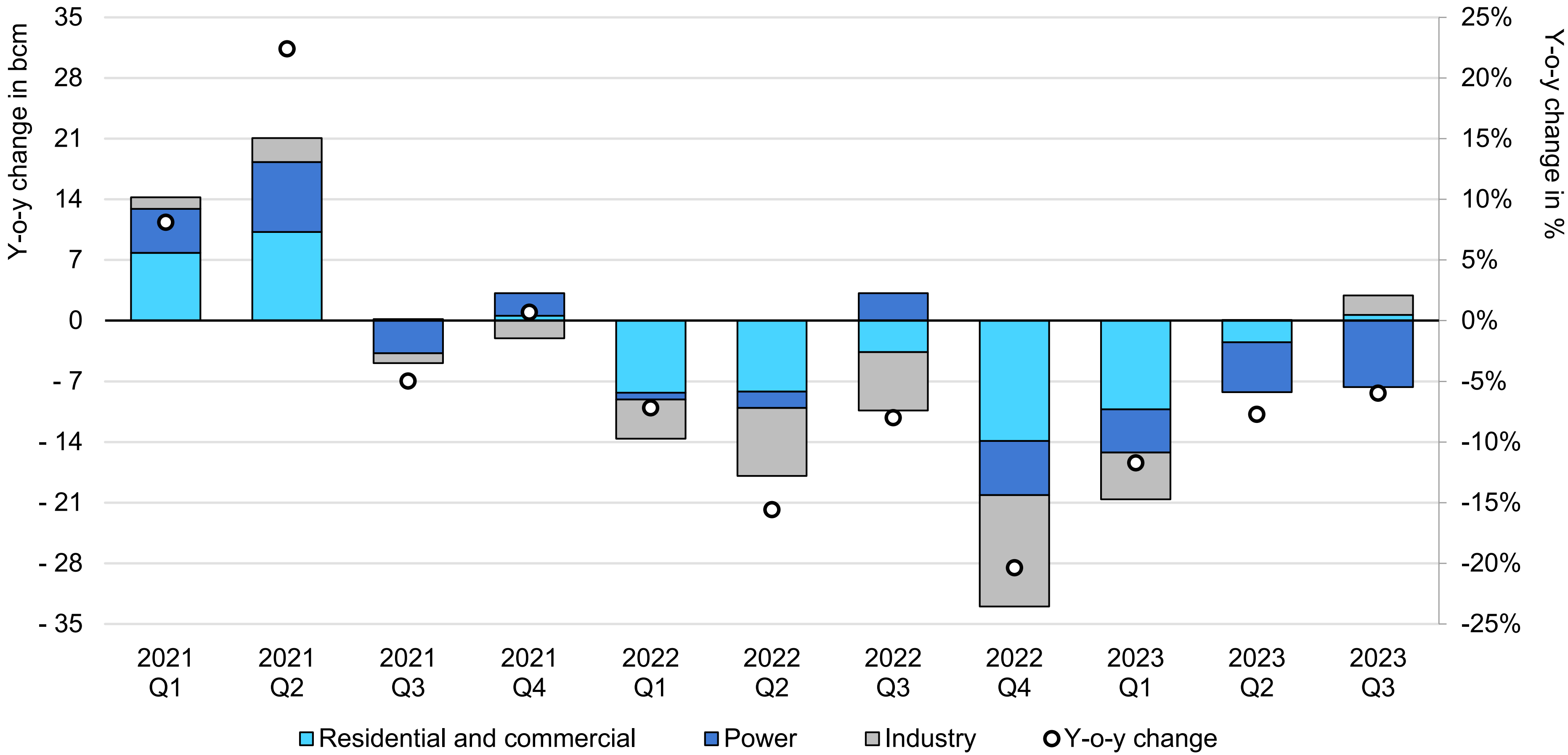
Gas-to-power demand dropped by an estimated 16% (or 18 bcm) y-o-y in Q1-Q3 2023 and accounted for over 55% of Europe's total gas demand reduction over this period. Gas burn in the power sector dropped by close to 20% (or 17 bcm) y-o-y in Q2-Q3 2023.

This steep decline was driven by a combination of factors. Subdued activity in energy-intensive industries together with continued improvements in energy efficiency and behavioural changes depressed electricity consumption, which fell by an estimated 5% (or 58 TWh) y-o-y in Q2-Q3. In addition, stronger renewable power output (up by 8%) and improving nuclear availability in France (up by 25%) further reduced the call on gas-fired power plants. **Gas demand in industry** declined by an estimated 3% (or 3 bcm) in Q1-Q3. First data indicate that following the steep reductions recorded in Q1, industrial gas consumption stayed close to last year's levels in Q2 and increased by 10% y-o-y in Q3. While lower gas prices support gradually improving activity in gas-intensive industries, industrial gas demand remains 15% below its Q3 2021 levels.

For the full year of 2023, OECD Europe's gas demand is forecast to decline by 7%. This is primarily driven by lower gas burn in the power sector, which is expected to decline by 15% amid rapidly expanding renewables and lower electricity consumption. Gas use in industry is projected to remain close to last year's levels, as lower prices enable demand recovery in H2 2023. Considering the declines in the year to date, demand in the residential and commercial sectors is expected to fall by 3% in 2023. **In 2024** European gas demand is forecast to grow by a moderate 2%, as the expected decline in gas-to-power demand is offset by higher gas use in the residential, commercial and industrial sectors.

European gas consumption dropped by over 9% in Q1-Q3 2023

Estimated quarterly change in gas demand, OECD Europe, 2021-2023



Sources: IEA analysis based on Enagas (2023), Natural Gas Demand; ENTSOG (2023), Transparency Platform; EPIAS (2023), Transparency Platform; Trading Hub Europe (2023), Aggregated consumption.

US natural gas production increased by close to 6% in Q1-Q3 2023

Dry natural gas production in the United States increased by an estimated 5% y-o-y (about 32 bcm) in the first nine months of 2023. On average, daily output remained above the 100 Bcf threshold (or 2.8 bcm/d). Natural gas production growth slowed from a 5% y-o-y increase in Q1-2 to 2% in Q3 2023.

The significant growth in natural gas production was primarily due to an increase in the output of associated gas production from oil-driven shale plays. The Permian Basin, the largest source of associated natural gas, grew its output by 10% y-o-y during January to July 2023, when it reached an all-time high of 17.1 Bcf/d (or 0.48 bcm/d). The Permian Basin alone accounted for 30% of incremental natural gas production in the United States over the first eight months of 2023. This expansion is the result of sustained drilling activity in the region, with 466 wells drilled on average per month in 2023, or 8.3% more y-o-y than in July 2022. Additionally, other plays such as the Eagle Ford, the Woodford and the Bakken plays contributed to the development of associated gas output. The debottlenecking of the Permian Basin will be crucial to further expansion of sales gas production. In 2023 several pipeline expansion projects are expected to be completed. The Permian Highway Pipeline, the Whistler Pipeline and the Gulf Coast Express could add 17 bcm/yr of takeaway capacity by the end of 2023.

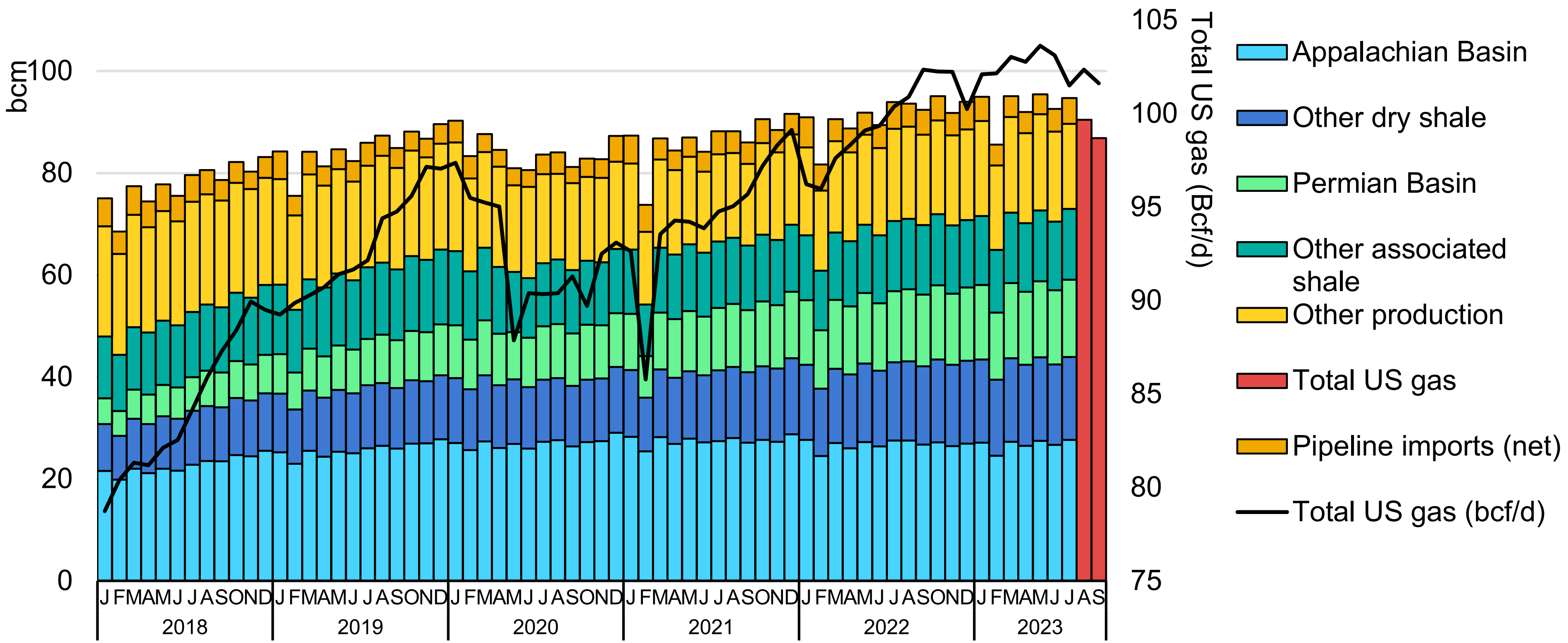
In Northeast Texas and Louisiana, the Haynesville pure gas shale play provided further support to US gas production growth with a 13% y-o-y increase in the first eight months of 2023. While drilling activity showed a contraction of 5% in August 2023 compared with the previous year, wells completed increased by close to 30% y-o-y. In May 2023 the completion of the Acadian Haynesville Extension pipeline added 400 Mcf/d (or 4 bcm/yr) of takeaway capacity to meet the growing need for feedgas in Louisiana.

Gas production from the Appalachian Basin recovered from an initial contraction in the first half of the year, and displaying 0.5% y-o-y growth in July 2023. Appalachia alone accounted for almost 30% of total US production in Q1-Q3 2023. Additional takeaway capacity is expected to ease midstream pipeline constraints. The Mountain Valley Pipeline is expected to be commissioned by the end of 2023/early 2024 and would add 20 bcm/yr of transmission capacity from northwestern West Virginia to southern Virginia. The first phase of the Regional Energy Access Project (0.83 Bcf/d or 8.5 bcm/yr) is foreseen to enter commercial service in Q4 2023.

We forecast growth in US natural gas production to slow during the remainder of the year due to the relatively high storage levels and an expected decline in domestic demand. For the full year of 2023, US natural gas output is forecast to grow by around 2%.

The Permian Basin accounted for 30% of incremental US gas production in Q1-Q3 2023

Gas production by type, United States, 2018-2023



Sources: IEA analysis based on EIA (2023), Natural Gas Data; Natural Gas Weekly Update.

Europe's primary natural gas supply tightened further in Q1-Q3 2023

Europe's total gas supply dropped by an estimated 13% (or 54 bcm) y-o-y in Q1-Q3 2023. Lower pipeline flows from Russia, together with the ongoing decline in domestic output and higher maintenance in Norway, depressed the availability of primary gas supply. LNG inflows increased by 2.5% y-o-y in Q1-Q3 2023 and accounted for almost 40% of Europe's total gas consumption, a share similar to that of Russia's piped gas before its invasion of Ukraine.

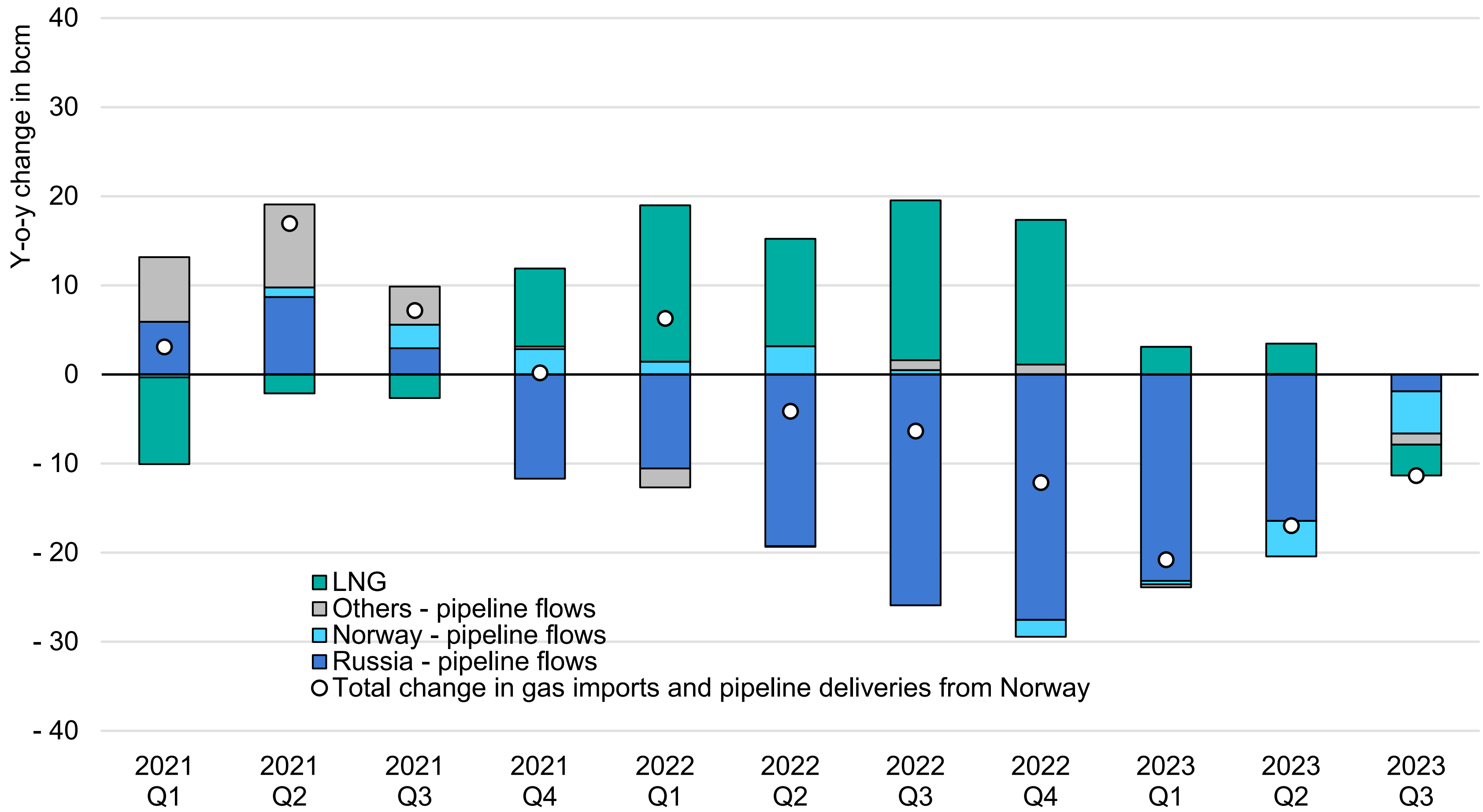
Russian piped gas exports to OECD Europe fell by an estimated 60% (or 42 bcm) y-o-y during Q1-Q3 2023. Piped deliveries to the European Union dropped by almost 70% (or 38 bcm) y-o-y to a total of 17 bcm in Q1-Q3 2023. The Ukrainian transit route accounted for around half of the volumes supplied to the European Union. Russian piped gas deliveries to the European Union increased by 2-20% (or 1.2 bcm) in Q3 compared with Q2, amid stronger flows via TurkStream. Exports to Türkiye declined by 20% y-o-y in the first eight months of 2023. Russian piped gas met less than 10% of OECD Europe's gas demand in Q1-Q3 2023. Norway's piped gas supplies to the rest of Europe declined by 11% (or 9 bcm) y-o-y in Q1-Q3 2023 amid a higher level of planned maintenance and unplanned outages. Norwegian pipeline deliveries to the European Union fell by 6%, while exports to the United Kingdom plummeted by 25% (or 5 bcm). Non-Norwegian domestic production fell by an estimated 10% (or 5.5 bcm) y-o-y in the first seven months of 2023. The steepest declines were recorded in the Netherlands, with the phase-out of the Groningen field. Pipeline gas deliveries from North Africa declined by 2% (or 0.5 bcm) y-o-y, with flows to Iberia falling by 14% (or 1 bcm) and those to Italy rising by 3% (or 0.5 bcm). Gas flows from Azerbaijan via the Trans Adriatic pipeline rose by 2% (or 0.2 bcm) y-o-y during Q1-Q3 2023.

Europe's LNG imports increased by 8% (or 7 bcm) y-o-y in H1 2023. Continued demand reductions together with high storage levels weighed on European LNG imports in Q3, leading to a reduction of 9 (or over 3 bcm), the first decline since Russia's invasion of Ukraine. LNG flows from the United States increased by 6% (or 3.5 bcm). This further reinforced the position of the United States as Europe's leading LNG supplier, with a 46% share of total LNG imports. Russia's LNG exports to Europe remained broadly flat. According to shipping data, 80% of Europe's total LNG imports from Russia in Q1-Q3 2023 were delivered to Belgium, France and Spain.

The volume of Russian piped gas supplies remains a major uncertainty for Q4 2023. Assuming that flows to the European Union continue at their current levels, Russian piped gas deliveries to OECD Europe would drop by around 50% (or 40 bcm) in 2023. LNG imports are expected to remain broadly flat in 2023 compared with last year amid high storage levels. A colder than average Q4 could lead to higher LNG import needs.

Europe's LNG imports switched from growth to decline in Q3 2023 amid high storage levels

Estimated quarterly change in European natural gas imports and deliveries from Norway, Q1 2021-Q3 2023



Sources: IEA analysis based on ENTSOG (2023), Transparency Platform; Eurostat (2023), Energy Statistics; Gas Transmission System Operator of Ukraine (2023), Transparency Platform; ICIS LNG Edge; JODI (2023), Gas World Database.

Global LNG trade grew by 3% in Q1-Q3 2023, primarily supported by US exports

Global LNG supply expanded by 3% y-o-y (or 11 bcm) in Q1-Q3 2023, measured on an import basis. This growth was primarily supported by the United States and Algeria, together accounting for 85% of the incremental global LNG supply. The Asia Pacific region and Europe led LNG demand growth, increasing their LNG inflows by 2.7% and 2.5% respectively.

From a supply perspective, North America accounted for more than half of incremental LNG exports, while growth from Algeria, Mozambique and Norway also drove increased trade. The **United States** saw a remarkable 8% (or 6.1 bcm in absolute terms) y-o-y increase in its LNG output in the year to date, primarily driven by the continued ramp-up of Calcasieu Pass and the return of the Freeport LNG export terminal to full service after a fire-induced outage in June 2022. **Algeria**'s LNG exports increased by 30% (or 2.8 bcm) in Q1-Q3 2023. OECD Europe have benefited from this growth, absorbing more than 90% of the total LNG volumes exported from Algeria so far this year. **Mozambique**'s LNG exports contributed 2.3 bcm to global incremental supply, with the continued ramp-up of Coral South FLNG. Additional y-o-y growth in LNG supply was driven by **Norway** (up 2.3 bcm yoy), **Indonesia** (up 1.4 bcm yoy) and **Qatar** (up 1 bcm yoy).

From a demand perspective, Europe's LNG imports continued to grow in H1 2023, reversing to a y-o-y decline in Q3 amid continued gas demand reduction and high storage levels. Europe's net LNG imports rose by 2.7% y-o-y (or 3.2 bcm) in Q1-Q3 2023, largely driven by higher LNG inflows to the Netherlands, Germany and Italy. In contrast, LNG flows to France dropped by 16% (or 4 bcm) in Q1-Q3 2023 amid widespread strike action in April and May. The commercial start-up of several new floating storage and regasification units (FSRUs) facilitated European LNG import growth. Altogether, 30 bcm/yr of regasification capacity has been added in Germany, Italy, Finland, the Netherlands and Türkiye since Russia's invasion of Ukraine. This incremental regasification capacity allows for a more optimal inflow of LNG into the European market and lowered the utilisation rate of the existing LNG import terminals. Overall, Europe's LNG regasification terminals saw a 64% utilisation rate in Q1-Q3 2023, compared with a rate of 75% during the same period in 2022.

LNG imports into the **Asia Pacific** region increased by 2.6% y-o-y (or 6.3 bcm in absolute terms) in Q1-Q3 2023. This was primarily driven by **China**. After more than 13 months of year-on-year declines, China's net LNG imports started to recover in March 2023 and grew by 13% y-o-y (or 7.8 bcm) in Q1-Q3 2023. Three new LNG import terminals have been commissioned so far this year, namely Caofeidian Xintian LNG terminal in Tangshan city (6.8 bcm/yr), Wenzhou LNG in Zheijang (4 bcm/yr), and Nansha LNG in Guangzhou city (1.4 bcm/yr). China has now 27 LNG import terminals, with a total regasification capacity of 156 bcm/yr.

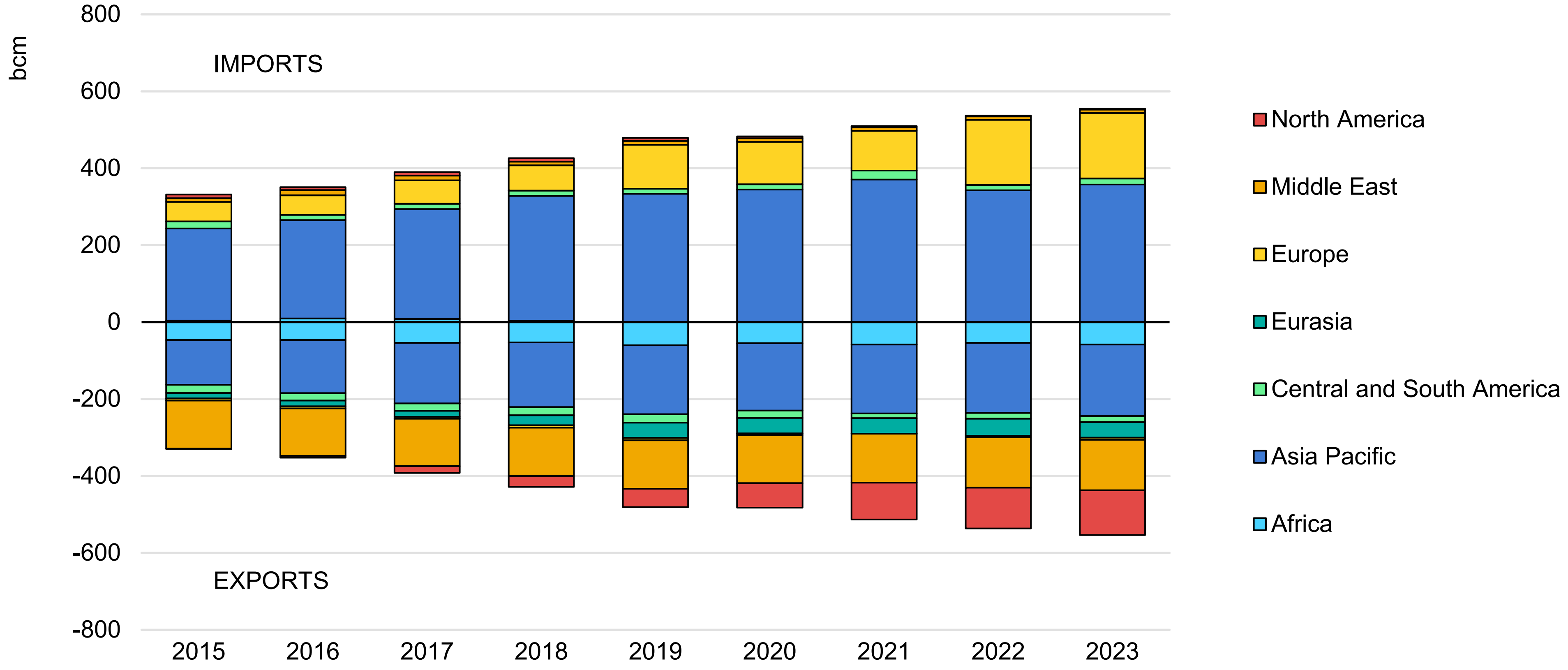
In contrast, **Japan**'s LNG imports declined by 9% (or 6.6 bcm) in Q1-Q3 2023, as improving nuclear availability and lower electricity demand weighed on gas-fired power generation. Japan's LNG imports fell to their lowest in more than 20 years in May at 5.5 bcm (down by 19% y-o-y), as efforts to save energy and boost nuclear power reduced gas demand. **Korea**'s LNG imports slightly decreased in Q1-Q3 2023 (down 3.8% or 1.7 bcm y-o-y) due to lower gas demand, supporting high LNG inventory levels. In contrast, **Thailand**'s LNG imports grew by a strong 33% y-o-y (or 3.1 bcm), largely supported by the country's declining domestic production. **Singapore**'s LNG imports increased by 33% (or 1.3 bcm) y-o-y in Q1-Q3 2023, supported by stable gas demand and lower pipeline supplies from Indonesia and Malaysia. **India**'s LNG imports increased by 8% (up by 1.4 bcm) compared with Q1-Q3 2022. Lower spot LNG prices since Q2 (below the USD 15/MBtu threshold) spurred a positive demand response from industry and the power sector. In April the country commissioned the Dhamra LNG import terminal (7 bcm/yr), which adds more than 10% to India's existing regasification capacity. This is India's seventh LNG import facility and the second on the east coast, along with Ennore. According to data from PPAC, demand for regasified LNG in the fertiliser sector almost tripled in the first 8 months of 2023 compared with the same period in 2022, largely thanks to government subsidies and improved connectivity for fertiliser plants in southern India. JKM prices moderated significantly from the levels seen at the beginning of 2023, and South Asian buyers returned to the spot markets via tenders, especially as demand for electricity in the region increased with the heat waves in spring and summer 2023. **Bangladesh** and **Pakistan** saw their LNG imports increase by 12% and 9% respectively (or 0.6 bcm for both) y-o-y in Q1-Q3 2023.

LNG imports in **Central and South America** slightly increased by 1.5% (or 0.2 bcm) y-o-y in Q1-Q3 2023. **Brazil**'s LNG imports dropped by 67% (or 1.8 bcm) y-o-y in Q1-Q3 amid healthy hydro availability and a lower gas burn in the power sector.

For the full year of 2023 we forecast global LNG trade to increase by 3% (or 18 bcm). The United States alone is expected to contribute more than half of the incremental LNG supply and become the world's largest LNG exporter. Additional supply is expected from improved feed gas availability in Algeria, the start-up of Tangguh Train 3 in Indonesia and the continued ramp-up of Coral South FLNG in Mozambique. Demand growth is set to be largely driven by Asia. China's LNG imports are expected to increase by 16% over 2022 levels. While China's LNG inflows are forecast to remain below their record levels of 2021, the country is set to regain its position as the world's largest LNG importer. Europe's LNG imports are expected to remain close to last year's levels.

LNG demand growth is largely driven by the Asia Pacific region in 2023

LNG imports and exports by region, 2015-2023



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

European natural gas prices continued to weaken in Q3 2023, while Asian and US spot prices strengthened compared with Q2

Subdued demand, together with high storage levels, weighed on spot gas prices in Europe in Q3. In Asia, emerging buying interest and supply uncertainty strengthened JKM prices compared with Q2. In the United States, Henry Hub prices rose amid tighter supply–demand fundamentals and a gradually eroding storage surplus.

In **Europe**, TTF spot prices declined by 8% on the quarter to an average of just over USD 10/MBtu in Q3 2023, standing 80% below last year's levels. Continued demand reduction and high inventory levels put downward pressure on European hub prices in Q3. Despite lower price levels, volatility remained elevated. Outages in Norway and the risk of strikes at LNG plants in Australia fuelled strong price volatility during August and September. Historic volatility in TTF month-ahead prices averaged 140% in Q3 2023 – its highest level since Q1 2022, when Russia's invasion of Ukraine drove price volatility to all-time highs. TTF's premium over NBP narrowed to USD 0.1/MBtu in Q3 2023 from over USD 18/MBtu during the same period last year. The expansion of LNG regasification capacity in Northwest Europe and lower storage injection needs eased congestion along the EU–UK interconnectors, which in turn tightened the TTF–NBP price spread. NBP traded at a premium compared with TTF in September, as lower Norwegian pipeline deliveries supported stronger price gains on the British gas hub.

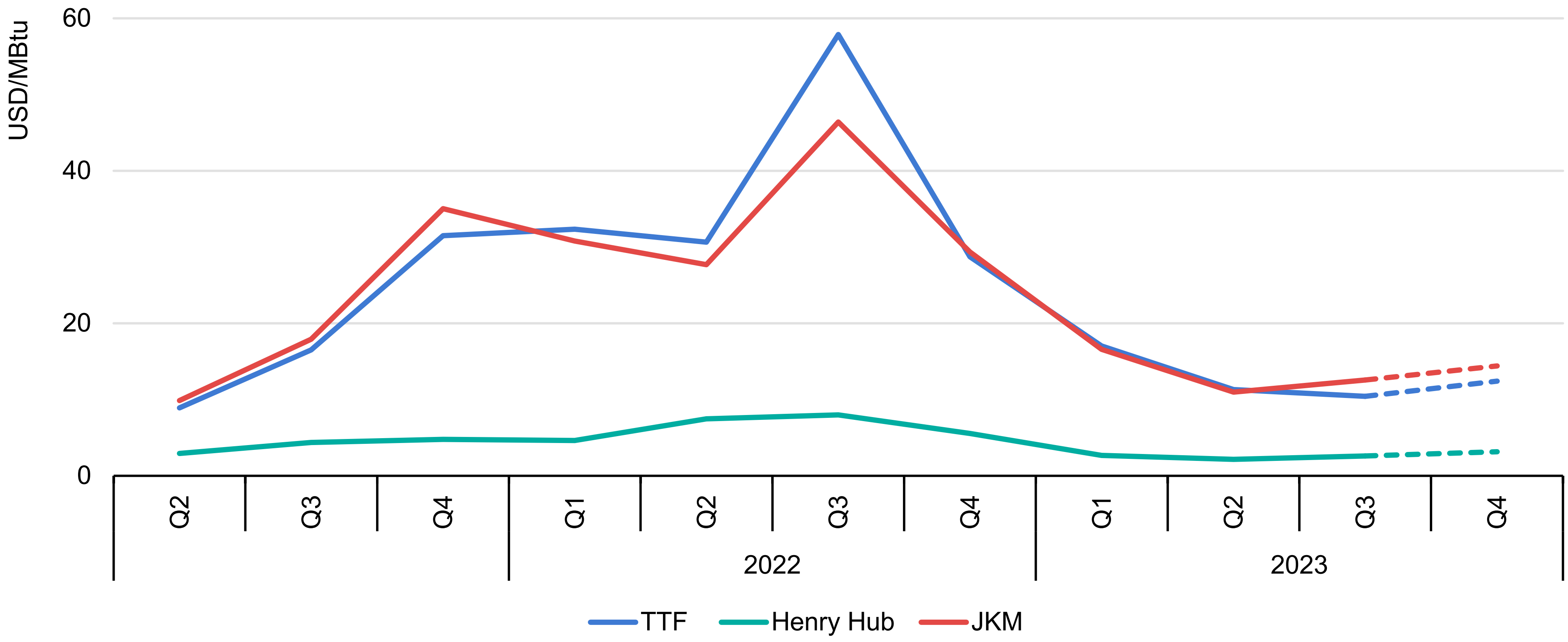
In **Asia**, JKM prices increased by 15% on the quarter to an average of USD 12.5/MBtu in Q3 2023, albeit 70% lower than the same period last year. Emerging buying interest together with supply uncertainty surrounding Australian LNG provided upward support to JKM prices in Q3. Asian spot LNG prices recovered their premium over European hub prices at the end of May 2023. JKM averaged USD 2/MBtu above TTF month-ahead prices in Q3 2023. The re-emergence of the JKM premium above TTF drove LNG cargos away from Europe. While Asia's LNG imports grew by 6% y-o-y in Q3, Europe's declined by 9%.

In the **United States**, Henry Hub prices increased by 20% on the quarter to an average of USD 2.6/MBtu in Q2 2023, albeit down by 65% compared with last year's levels. Slower domestic production growth combined with robust gas burn in the power sector and higher LNG exports drove the quarter-on-quarter increase in gas prices.

According to **forward curves** as of the end of September 2023, TTF is set to average just below USD 13/MBtu in 2023, with JKM slightly above USD 13.5/MBtu and Henry Hub at USD 2.7/MBtu. JKM prices are expected to have an average of USD 2/MBtu above TTF in Q4 2023.

Asian spot LNG prices are expected to trade above TTF in Q4 2023

Main spot and forward natural gas prices, 2020-2023



Note: Future prices are based on forward curves as of the end of September 2023 and do not represent a price forecast.
Sources: IEA analysis based on CME Group (2023), Henry Hub Natural Gas Futures Quotes, Dutch TTF Natural Gas Month Futures Settlements, LNG Japan/Korea Marker (Platts) Futures Settlements; EIA (2023), Henry Hub Natural Gas Spot Price; Powernext (2023), Spot Market Data; S&P Global (2023), Platts Connect.

Storage injections in the European Union and the United States slowed in Q3 2023

Despite slower injections in Q3, **storage sites in the European Union and the United States** opened the 2023/24 heating season[2] with inventory levels standing **well above their historic averages**. This is largely due to the above-average inventory levels inherited from the 2022/23 winter season, and in the case of the United States strong storage build-up over Q2.

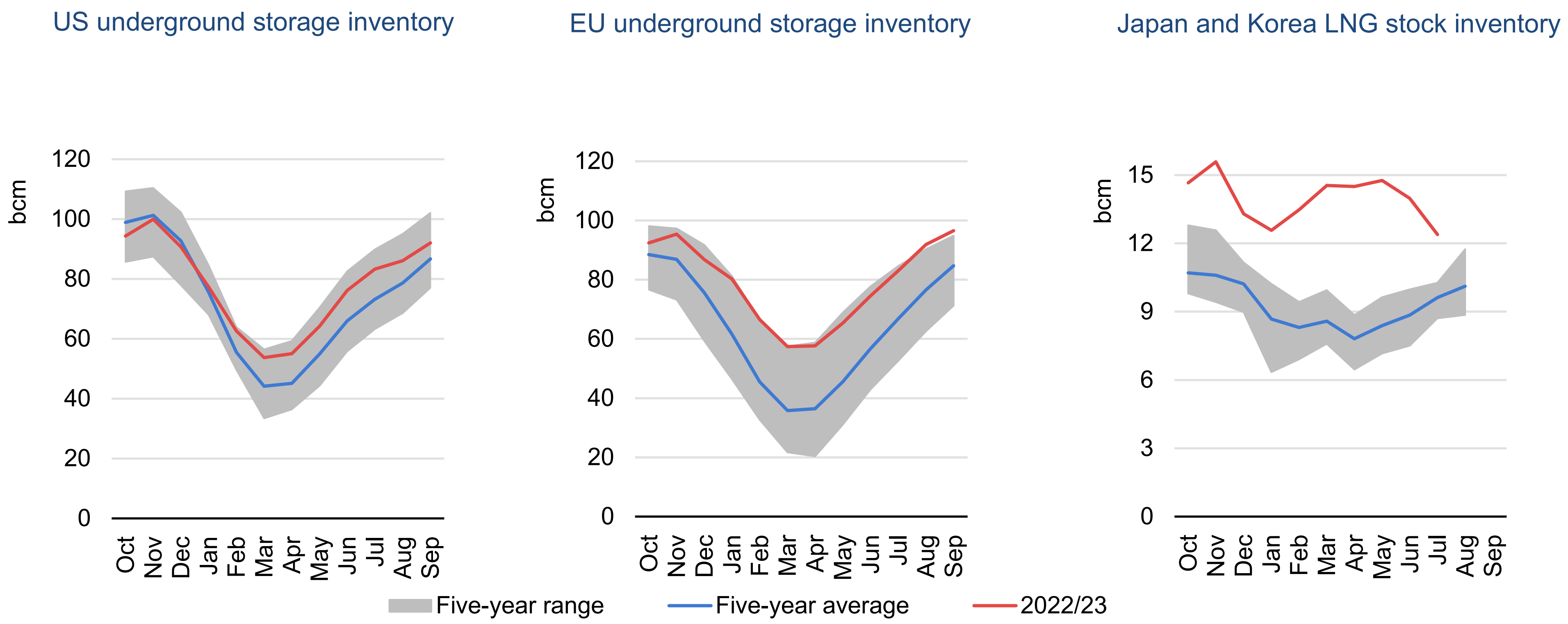
In the **European Union**, storage sites closed the 2022/23 heating season with inventory levels standing 67% (or 23 bcm) above their five-year average as a consequence of below-average net withdrawals during the winter. Lower primary gas supply (domestic production and imports) led to a slower storage build-up during the gas summer. Net injections fell 22% (or 12 bcm) below their five-year average to a total of 42 bcm in Q2 and Q3 2023. While slower injection rates moderated the EU storage surplus, inventory levels still stood 12% (or 10 bcm) above their five-year average on 1 October 2023. Consequently, EU inventory levels reached 96% of their working storage capacity by the start of the 2023/24 heating season, 6% above the EU storage target. In **Ukraine**, gas inventory levels at the end of March 2023 were estimated at 9 bcm and rose to 15 bcm by the end of Q3. As EU storage sites reached 90% of their working storage capacity by the beginning of August, injections increasingly shifted to Ukraine. The country alone accounted for over 25% of total European storage injections during August and September. EU traders injected 2 bcm of natural gas into Ukraine's gas storage facilities before the start of the 2023/24 winter season.

In the **United States,** storage sites opened the 2023 injection season 43% full, standing almost 20% (or 8 bcm) above their five-year average. Strong growth in domestic gas production supported above-average net injections in Q2; they were 7% (or 2 bcm) above their five-year average at 29 bcm. The slowdown in production growth, together with high gas-to-power demand and rising LNG exports, depressed storage injections in Q3, which were 25% (or 5.5 bcm) below their five-year average at 16 bcm. While slower injections moderated the US storage surplus, inventory levels still stood 5% (or 5 bcm) above their five-year average at the end of September, reaching a fill level of 81%.

In **Japan and Korea**, closing LNG stocks stood 29% (or 2.8 bcm) above their five-year average in July 2023. Lower LNG imports weighed on the LNG stocks of Japan's largest power generation companies, which declined by 20% between early August and the end of September to 1.62 Mt (2.2 bcm), standing 19% below their five-year average.

[2] The heating season (or gas winter) in the markets of the Northern Hemisphere refers to the period between 1 October and 31 March. The injection season (or gas summer) in the markets of the Northern Hemisphere refers to the period between 1 April and 30 September.

EU and US storage sites opened the 2023/24 heating season with inventories well above their five-year average



Sources: IEA analysis based on EIA (2023), Weekly Working Gas In Underground Storage; GIE (2023), AGSI+ Database; IEA (2023), Monthly Gas Data Service.

Medium-term market outlook

Global gas demand: Towards a slower growth trajectory

Global gas demand expanded by over 10% (or 380 bcm) **between 2017 and 2021**, making it the fastest-growing source of energy supply. The global gas crisis triggered by Russia, together with a weaker macroeconomic outlook, is weighing on the prospects for natural gas. **Global gas demand growth is forecast to slow down significantly,** from an average rate of 2.5% per year during 2017-2021 to 1.6% during 2022-2026. **Industry alone is expected to account for almost 60% of incremental gas demand**, primarily concentrated in the fast-growing markets of Asia Pacific and the gas-rich countries of the Middle East. **Gas-to-power demand growth is expected to decelerate** from an average of 2.4% between 2017 and 2021 to 0.5%. While gas-fired power generation is still expanding in emerging markets, this growth is almost entirely offset by demand reduction in the mature markets of Europe, North America and Northeast Asia.

Natural gas demand in North America – the world's largest gas market – is set for a slow decline. Gas demand expanded by 12% (or over 115 bcm) between 2017 and 2021, primarily driven by coal-to-gas switching dynamics in the United States and Canda. In contrast with other regions, North American gas demand continued to grow in 2022, rising by close to 5% (or 53 bcm) compared with 2021. This increase was largely due to the power generation sector and the residential and commercial sectors . Gas demand is expected to remain broadly flat in 2023, as higher gas-to-power demand is offset by demand reductions in the industrial, commercial and residential sectors. Gas demand for power generation declines in 2024 and beyond. As a result, overall North American gas demand is forecast to decline at an average rate of 0.5% per year during 2022-2026, primarily due to lower gas burn in the power sector amid the continued expansion of renewables. Gas use in the industrial sector is forecast to increase at a rate of 0.5% per year, primarily due to the expansion of gas-intensive industrial subsectors, including fertilisers. Gas demand in the residential and commercial sectors is set for a gradual decline amid energy efficiency gains enabled by retrofits.

The Asia Pacific region is set to remain the driving force behind natural gas demand growth globally, accounting for almost 70% of incremental gas demand over the medium term. The region's demand for gas grew at a rate of 4% per year between 2017 and 2021, supported by economic expansion, China's mandated coal-to-gas switching policy and its gasification programme. Asia's gas consumption decreased by an estimated 2% in 2022 due to all-time high LNG prices, Covid-induced lockdowns in China and mild weather during most of the year in Northeast Asia. China's natural gas consumption declined for the first time in four decades. The Asia Pacific region's gas demand is expected to recover in 2023 by close to 3%, primarily supported by China. The region's demand is expected to expand by 20% by 2026 compared with 2022. Demand growth is primarily concentrated in China, India and emerging Asia, while gas demand is set to decline in the region's mature markets (Japan and Korea) on improving nuclear availability and a growing share of renewables in the power sector.

Eurasian natural gas demand trends towards stagnation. The region's natural gas consumption rose by 13% (or 72 bcm) between 2017 and 2021, led by Russia and primarily supported by demand growth in the industrial and power sectors. In 2022 natural gas consumption fell by 4% amid economic contraction in Russia and milder winter weather conditions. Natural gas demand growth is forecast to slow from an average of 3% between 2017 and 2021 to 1.9% between 2023 and 2026. This moderate recovery from 2022 allows the region's gas demand to stand just 2% above its 2021 level by 2026. Weaker economic growth in Russia and upstream supply issues in Uzbekistan, the region's second-largest gas market, are limiting the prospects of gas demand growth in Eurasia.

Natural gas demand in Europe is set for structural decline over the medium term. OECD Europe's natural gas consumption remained broadly flat between 2017 and 2021. The 2022 gas crisis triggered by Russia deeply transformed the European market: consumption fell by 13% (or 72 bcm), its steepest drop on record. Lower gas use in the residential and commercial sectors, together with plummeting industrial gas demand, accounted for the bulk of this reduction. Natural gas consumption is set to decline further in 2023, primarily due to lower gas burn in the power sector amid lower electricity demand and the continued expansion of renewables. OECD Europe's natural gas demand is forecast to decline by 8% (or over 35 bcm) during 2022-2026 and by 2026 to stand almost 20% (or 110 bcm) below the level reached in 2021. This decline is driven by structural factors, including more rapid deployment of renewables and heat pumps, and energy efficiency gains. This forecast assumes that over half of the industrial gas demand lost in 2022 will not be recovered by 2026.

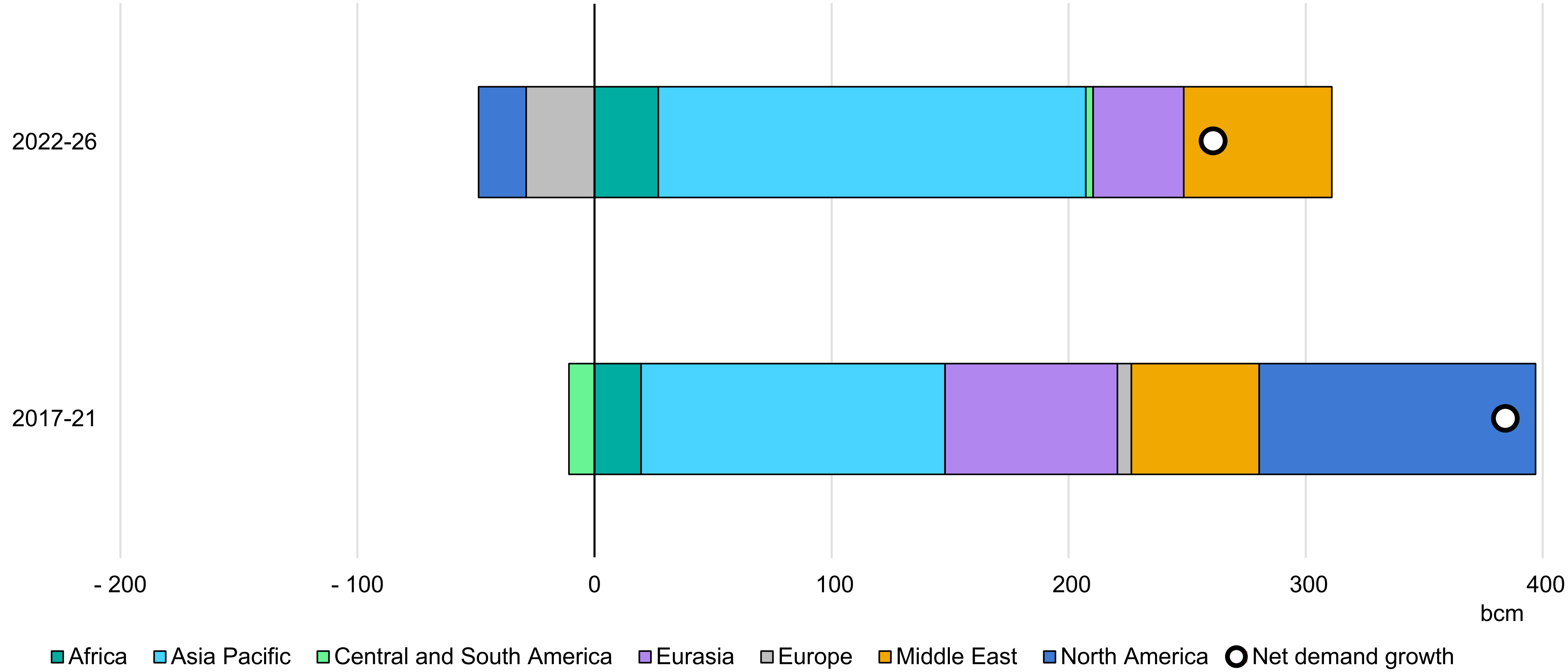
Natural gas demand in the Middle East is set to continue its rapid expansion, at an average rate of 2.6% between 2022 and 2026. Iran and Saudi Arabia are expected to account for around 75% of the incremental gas demand. The expansion of gas-intensive industries, together with the gradual phase-out of oil products from the power sector, is set to support this growth.

Africa's gas demand growth is driven by its rapidly rising population, improving energy access and economic growth. The region's gas demand growth is forecast to accelerate from 3% between 2017 and 2021 to close to 4% between 2022 and 2026. Higher gas burn in the power sector is expected to account for almost 70% of incremental gas demand.

Natural gas demand in **Central and South America** is set for a moderate growth, primarily driven by industry. This growth is supported by improving natural gas production prospects in Argentina and Brazil.

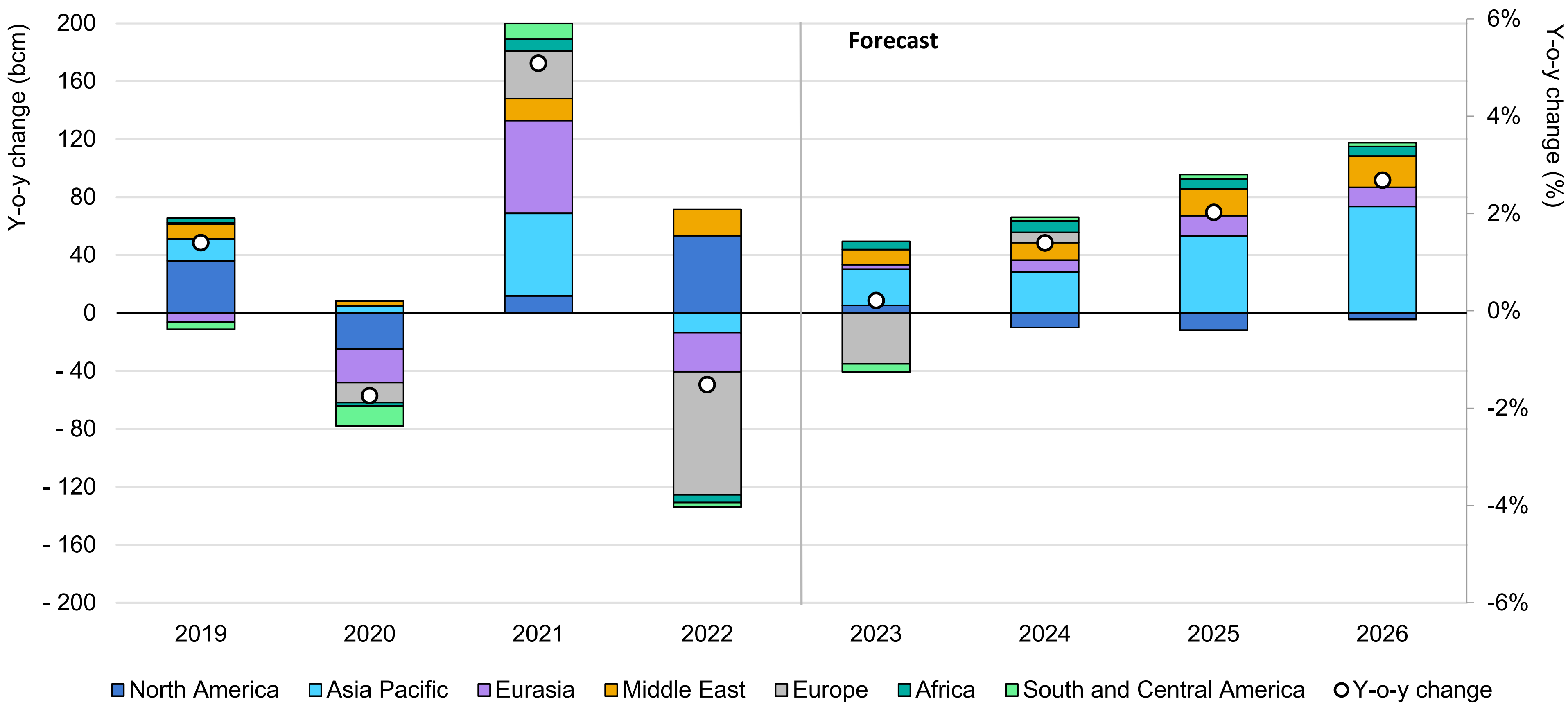
Global gas demand growth is set to slow by one-third over the forecast period

The evolution of natural gas demand by region, 2017-2021 vs 2022-2026



Asia Pacific is expected to account for 70% of incremental gas demand over the medium term

Year-on-year change in natural gas production by region, 2020-2026



European natural gas demand: Structural decline

The gas supply shock triggered by Russia in 2022 reinforced the **structural drivers** accelerating the decline in European gas demand over the medium term. **Natural gas demand in OECD Europe is expected to decline by 8% (or 35 bcm) between 2022 and 2026** and stand almost 20% (or 110 bcm) below the 2021 level by 2026. A **relatively high gas price environment** is set to weigh on demand recovery in industry, while **a more rapid deployment of renewables** is expected to reduce the call on gas-fired power plants. In the residential and commercial sectors, **energy efficiency gains** together with more rapid installation of **heat pumps** are set to reduce gas use during the forecast period. Nevertheless, the **flexibility provided by natural gas** will remain crucial to ensure security of energy and electricity supply in the medium term.

Residential and commercial sectors

European gas consumption fell by 13% (or 72 bcm) in 2022, its steepest drop on record. Lower gas use in the residential and commercial sectors (down by 15% compared with 2021) accounted for almost half of this decline. Milder weather conditions explain just over 40% of the gas demand reduction in the residential and commercial sectors. Non-weather-related factors were a major driver behind this lower gas use. Gas-saving measures enacted in public buildings, fuel-switching in households with the option, the installation of heat pumps, efficiency gains and behavioural changes all played a critical role in reducing distribution network-related demand. In addition, rising affordability issues contributed to lower natural gas use in households. The share of households unable to keep their homes adequately warm rose from 6.9% in 2021 to 9.3% in 2022 – its highest level since 2015.

Natural gas demand in the residential and commercial sectors is set for a moderate reduction over the medium term. Accounting for the declines this year to date, distribution network-related demand is expected to drop by 4% in 2023. A return to average temperatures would alone increase residential and commercial demand during 2024-2026, although more **structural changes** are set to offset this impact and weigh on natural gas use. In the European Union, the Renovation Wave is set to improve the **energy efficiency** standards of the building stock. Considering the renovation rates targeted by the European Union, direct natural gas savings from improved energy efficiency could amount to over 0.8 bcm/yr in the period 2023-2026. **Electrification of heat** through the deployment of heat pumps is expected to further moderate natural gas use in the residential and commercial sectors. This forecast assumes that heat pumps could reduce natural gas demand by over 3 bcm by 2026 compared with 2022 levels. Considering the temperature sensitivity of these sectors, significant demand variations can occur depending on weather conditions, which would alter the current forecast.

Power sector

Despite record high gas prices, **European gas-to-power demand remained relatively resilient in 2022**, declining by just 4% (or 6 bcm). While **decade-low hydro and nuclear generation** increased the call on gas-fired power plants in certain markets, lower electricity demand together with **gas-to-coal switching** and stronger **wind and solar** power output weighed on the overall gas burn in the power sector.

Gas-to-power demand is forecast to decline by over 25% (or close to 50 bcm) in the period 2022-2026, primarily driven by **accelerated deployment of renewables** and improving **nuclear availability**. Gas-fired power generation is expected to drop by over 15% (or 25 bcm) in 2023 due to lower electricity demand, stronger nuclear and hydro output and the continued expansion of wind and solar power generation. The decline in gas-to-power demand is projected to slow to a rate of below 5% per year during 2024-2026 amid the expected recovery in electricity demand and the continued **coal phase-out**. Coal-fired power generation capacity is set to decline by close to 25% (or over 30 GW) between 2022 and 2026, with around 85% of the plant closures concentrated in northern and southwestern Europe. This in turn reinforces the role of gas-fired power plants in providing flexible power supply and ensuring electricity supply security in an increasingly variable renewables-dominated power system.

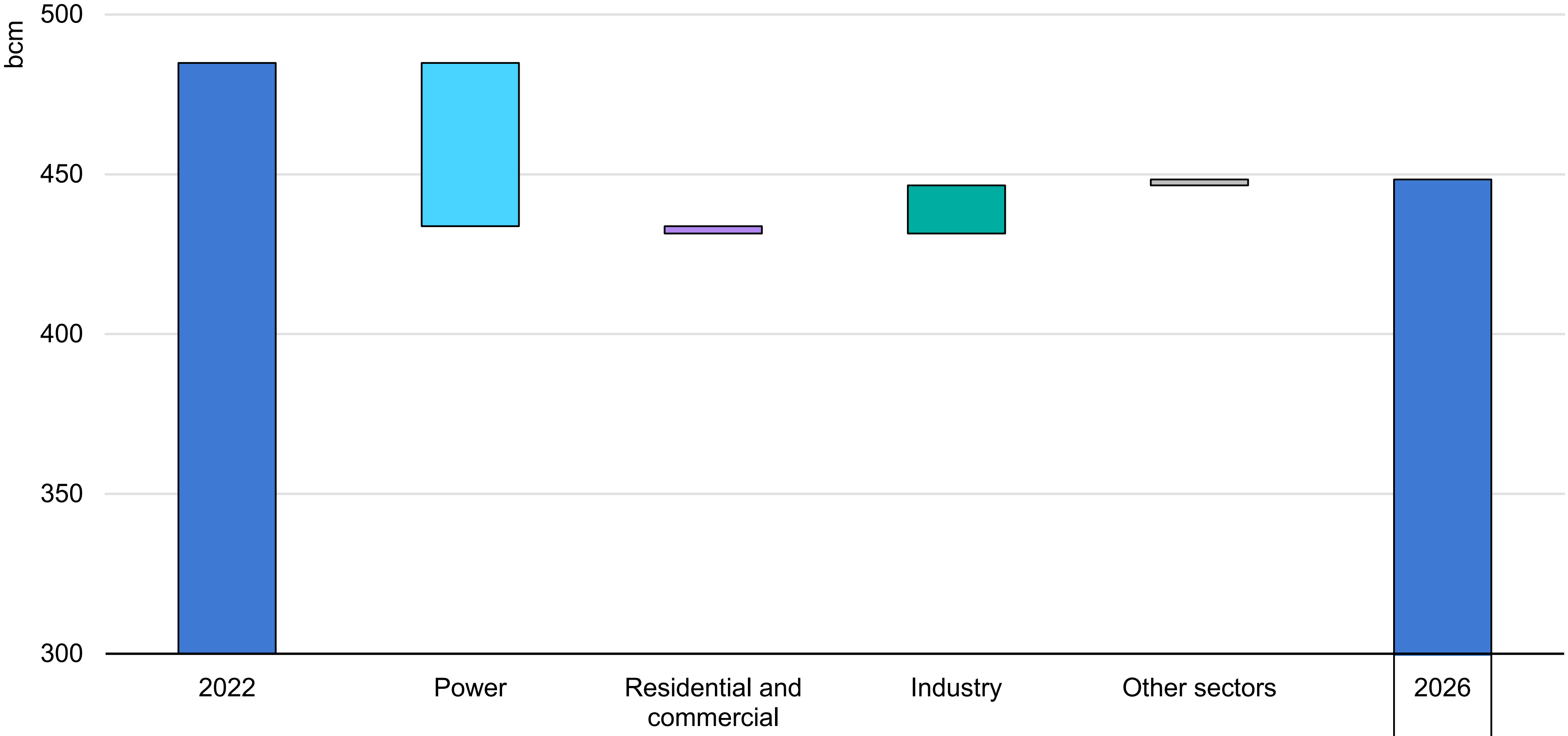
Industry

Natural gas demand in industry dropped by around 20% (or 30 bcm) in 2022, with all-time high gas prices driving **fuel-switching** and leading to **reduced production rates** across the most gas- and energy-intensive industries. In the European Union, production curtailments accounted for around half of the decline in industrial gas use, with **chemicals and fertilisers being the most-affected** sectors. For instance, ammonia production dropped by close to 25%, methanol output by 23% and urea by almost 20%.

Our forecast assumes that more than half of the industrial gas demand lost in 2022 will not be recovered over the medium term, as the relatively high gas price environment weighs on the prospects of gas-intensive European industries. In 2023 gas use in industry is expected to stay close to last year's levels, with demand recovery in the second half of the year offsetting the losses in H1. Industrial sector gas use is expected to marginally recover during 2024-2026 amid an improving macroeconomic environment and healthier supply availability. The relocation of European industries to other regions – with a structurally lower cost of gas supply – remains a major downside risk to industrial gas demand in Europe. As hightlighted in a recent survey, almost a third of Germany's industrial companies are relocating capacity abroad or restricting production at home, or are planning to do so, in light of the impacts of the 2022 energy crisis.

The expansion of renewables is set to reduce Europe's gas demand over the medium term

Expected change in natural gas demand by sector, OECD Europe, 2022-2026



Russian natural gas demand: Trending towards stagnation

Russia’s invasion of Ukraine and the subsequent sanctions regime have negatively affected the outlook for Russian gas demand over the medium term. Following a steep decline in 2022, Russia’s natural gas demand is expected to grow at an average rate of 1.5% per year during the forecast period, largely supported by the industrial and power sectors.

Recent demand trends

Russia’s natural gas demand rose by a strong 12% (or 55 bcm) in 2021 to reach an all-time high of 516 bcm. This particularly strong growth was supported by a number of factors. **Colder weather** conditions during the heating season led to higher gas use in the residential and commercial sectors, including indirectly via the country’s vast district heating system. **Recovery in economic activity** (GDP grew by 5.6%) following the Covid-related lockdowns of 2020 supported stronger demand from the country’s energy- and gas-intensive industries. Gas burn in the **power sector** increased by over 10% in 2021, reflecting economic growth, colder weather conditions and lower hydro availability in the country’s western regions (where most of the gas-fired power fleet is located).

Following strong growth in 2021, Russia’s natural gas demand dropped by over 5.5% (or almost 30 bcm) in 2022. This partly reflected the country’s deteriorating commercial and industrial activity. Russia’s GDP declined by 2.1% in 2022 amid the sanctions imposed following its invasion of Ukraine. Initial estimates indicate that natural **gas use in industry** fell by over 7% (or more than 6 bcm) amid lower demand from the more energy-intensive and export-oriented industrial sectors. For instance, Russia’s ammonia production dropped by 15% (or 3 Mt) in 2022, that alone translating into a reduction in gas demand of around 3 bcm. Gas use in the **residential and commercial sectors** dropped by over 5% as milder winter weather conditions lowered space heating requirements. Gas burn in the **electricity and heat generation sector** declined by an estimated 4% (or over 10 bcm) primarily due to lower district heating demand. The steep decline in Russia’s gas production (down by 12%) together with the halving of piped gas exports to Europe weighed on natural gas use as a fuel for compressor stations in the country’s vast transmission system. Consequently, **gas used for transport** dropped by an estimated 10% (or 4 bcm) in 2022.

Medium-term forecast

Russia’s natural gas demand is expected to remain broadly flat in 2023, as higher gas burn in the power sector is offset by the continued reduction in gas use in the industrial and transport sectors. Gas demand is projected to return to growth in 2024 and expand by 6% (or close to 30 bcm) between 2022 and 2026, largely supported by the industrial and power sectors.

Industry

Natural gas demand in industry is forecast to expand by 10% (or more than 10 bcm) in the period 2022-2026, accounting for one-third of overall demand growth. However, around 60% of industrial demand growth is associated with the recovery following the steep decline in 2022. Incremental gas demand is set to be driven by rising **fertiliser** production, primarily higher ammonia output. Russia has set ambitious plans to develop its gas-based chemicals industry, including a ramp-up in **methanol** production. Three projects are under advanced development, with the potential to add 4.5 Mt/yr of production capacity by 2026, which could translate into more than 4 bcm/yr of gas demand. However, these projects are facing increasingly uncertain timelines and could be delayed beyond our forecast horizon, amid sanctions limiting access to capital markets and key energy technologies.

Power sector

Natural gas demand in Russia's power sector (including heat generation) is expected to increase at an average rate of less than 1% per year during 2022-2026, assuming average weather conditions. This meagre growth will be partly supported by a continued **increase in Russia's electricity demand** amid gradually improving commercial and industrial activity in the country. **Nuclear plant closures** totalling 2.8 GW during 2024-2026 are expected to provide additional market space for gas-fired power plants.

Residential and commercial sectors

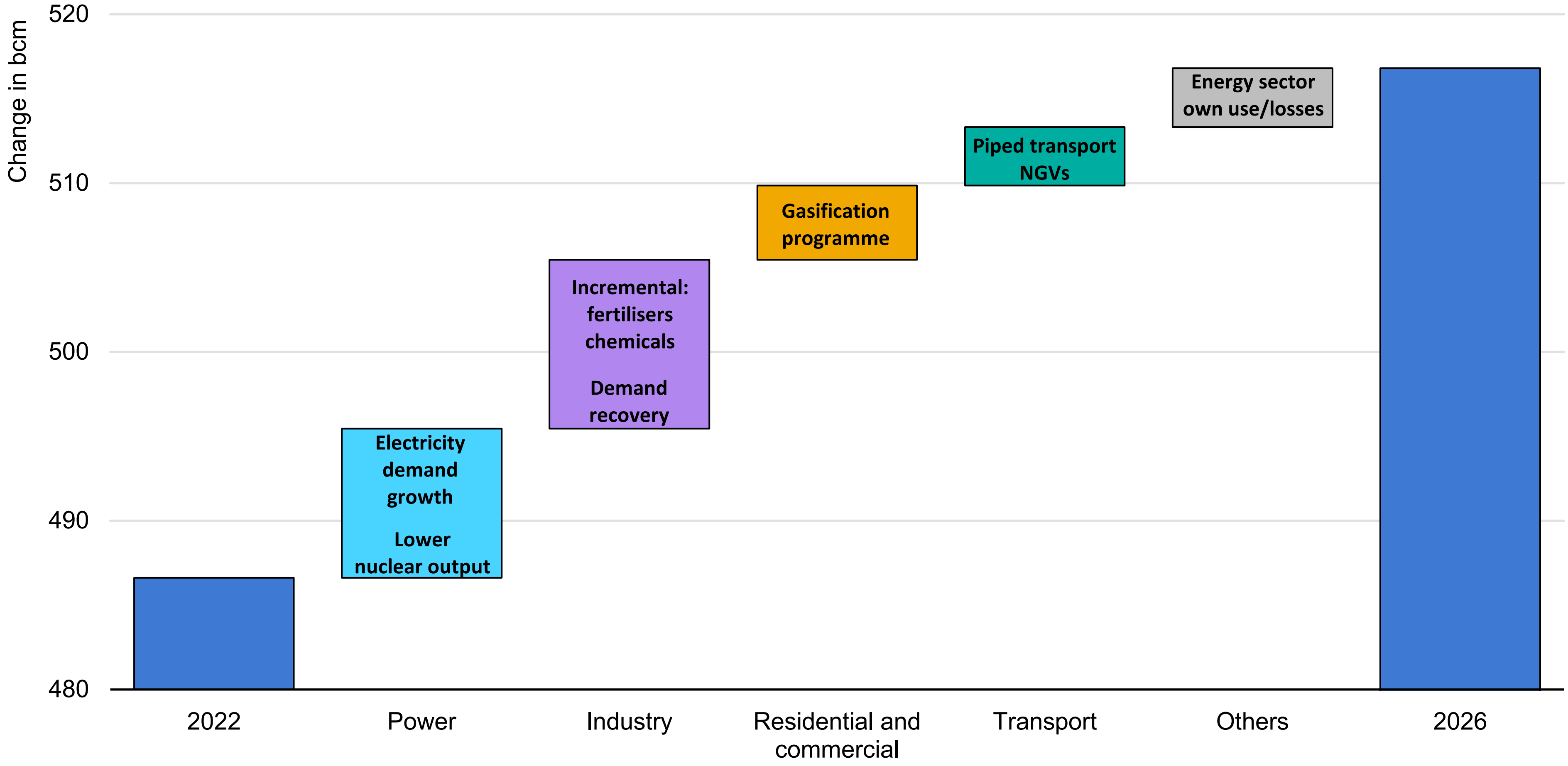
Direct gas use in the residential and commercial sectors is projected to increase at an average of 1.5% per year during 2022-2026. Given the temperature sensitivity of these sectors, significant demand variations can occur depending on weather conditions. Demand growth in these sectors is largely supported by Russia's **gasification programme** carried out by Gazprom. Natural gas penetration in Russia has risen significantly in recent years, from 53% in 2006 to 73% by the end of 2022. Under the current gasification scheme more than 530 000 new households will be connected to the gas grid in 2021-2025, with an investment of over RUB 520 billion (or USD 5.5 billion). The gasification level is expected to increase to 75% by 2024 and to 83% by 2030.

Transport

Natural gas use in transport is expected to expand by close to 10% (or 3.5 bcm) during 2022-2026. This is largely supported by higher demand from the **transmission system** amid the gradual recovery in Russia's natural gas production and the ramp-up of piped gas exports to China via the Power of Siberia pipeline system. In addition, Russia is set to increase the use of natural gas as a road fuel. Gas demand for **natural gas vehicles** rose from 1 bcm in 2020 to 1.72 bcm by 2022 and is expected to expand by close to 70% to reach over 3 bcm by 2026.

Russia’s gas demand recovery is primarily led by the industrial and power sectors

Expected change in natural gas demand by sector, Russia, 2022-2026



Improving nuclear availability and rising renewable power output is expected to reduce gas demand in Japan and Korea

Combined gas demand in Japan and Korea is forecast to decline by 8% (or 13 bcm) between 2022 and 2026, primarily due to improving nuclear availability and the continued expansion of renewable power generation. Improving energy efficiency standards are expected to further weigh on gas use in the residential and commercial sectors. This in turn could help ease prevailing market tensions and enhance global gas supply security in the coming years.

Japan

Natural gas demand in Japan declined by 1% (or 1 bcm) in 2022. While commercial and industrial city gas sales increased by 7% and 3% respectively, the decline in total gas demand was driven by significantly lower gas consumption in the power sector.

In 2023 Japan's natural gas demand is expected to drop by 6% (or 6 bcm) compared with 2022. This decline is primarily driven by lower gas burn in the power sector amid improving nuclear availability. Slower economic growth is expected to weigh on gas demand in industry, while an unseasonably mild Q1 reduced gas use in the residential and commercial sectors, weighing on the outlook for the full year of 2023. Japan's gas demand is projected to decline by 11% (or 11 bcm) by 2026 compared with 2022. Lower gas burn in the power sector alone accounts for around 80% of the overall demand reduction in the forecast period, as higher nuclear and renewable energy generation weighs on gas-fired power output.

Japan's nuclear power output is set to increase in the medium term. Takahama 1 restarted full-scale operations at the end of August 2023. In addition, Takahama 2 is scheduled to restart full-scale operations in October. Including the restart of these two reactors, 12 reactors (about 11.6 GW in total) will be in operation in October. Based on the latest publicly available information, it can be assumed that the number of restarts will gradually increase after 2023. Total operating nuclear capacity could increase to over 15 GW by 2026, weighing on coal- and gas-fired power generation, but with high uncertainty regarding restarts and operating capacity growth. At the same time, other factors affecting gas consumption in the power generation sector include a decrease in electricity demand due to energy conservation and an increase in renewable power generation. Consequently, gas-fired generation in Japan is forecast to decline by 14% between 2022 and 2026.

In particular, renewable energy has shown significant growth in recent years and can be assumed to continue its rise. According to Japan's 6th Strategic Energy Plan published in 2021, the share of renewable energy in the power supply mix in FY2030 should be 36-38% and the amount of electricity generated 336-353 TWh/yr, an increase of approximately 60% from FY 2021. Energy efficiency gains and progress in energy saving in the industrial, residential and commercial sectors all contribute to a reduction in gas consumption.

Korea

Natural gas demand in Korea declined by about 1% (or 0.7 bcm) in 2022. Gas consumption for power generation fell by about 3%, lowering overall gas demand. The industrial and city gas segments increased, but not enough to compensate for the reduction in power generation.

Korea's gas demand in 2023 is expected to decrease by about 2% compared with 2022. This is mainly due to a decline in power generation as nuclear and renewable generation increase, but also due to lower gas use in city gas segments.

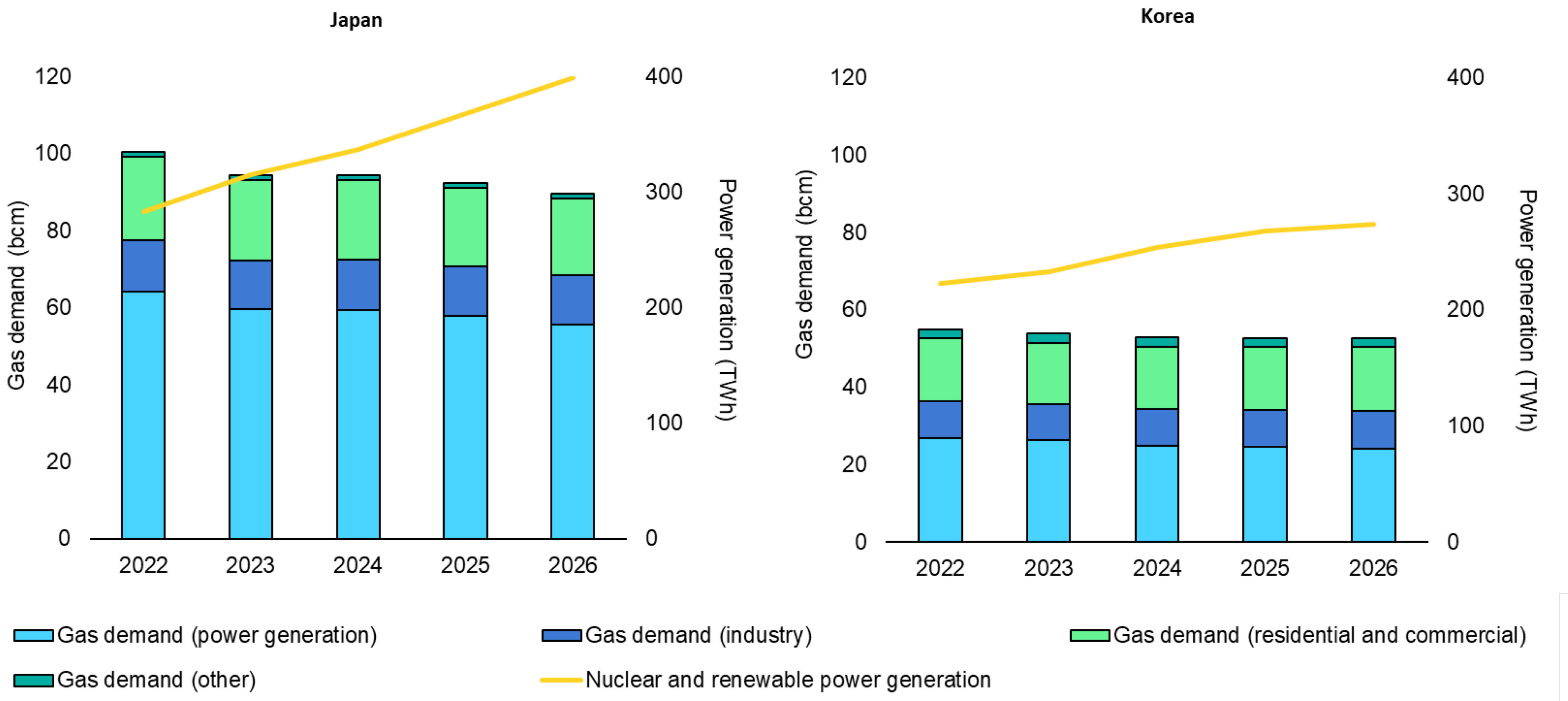
Korea's gas demand is projected to decline by 4% (or 2 bcm) by 2026 compared with 2022. Nuclear power and renewable energy output are expected to continue growing, which will reduce the call on coal- and gas-fired power plants.

In January 2023 Korea announced plans to increase nuclear power generation through the 10th Basic Energy Plan. According to the plan, in 2030 nuclear power capacity is expected to reach approximately 29 GW, accounting for 32% of all electricity generation. Shin Hanul 1 started commercial operation in December 2022, and currently 25 reactors are in operation with a total capacity of approximately 25 GW. Shin Hanul 2 is scheduled to start full operations in Q1 2024. In addition, Saeul 3 and Saeul 4 are expected to become operational, and total operating nuclear capacity could increase to close to 29 GW by 2026.

At the same time, the amount of renewable power generation is also expected to increase significantly over the medium term. Consequently, gas-fired power generation in Korea is forecast to decline by about 10% between 2022 and 2026. According to the 10th Basic Energy Plan, the share of renewable power output in total power generation should increase to about 22% in 2030, with the share of gas-fired power supply at approximately 23%. It is assumed that the consumption of city gas segments will increase slightly towards 2026. However, this will not be enough to compensate for the decline in power generation.

Combined natural gas demand in Japan and Korea is expected to decline by 8% over the medium term

Natural gas demand, and nuclear and renewable power generation, Japan and Korea, 2022-2026



China is expected to account for nearly half of medium-term global gas demand growth

China is set to remain the key driving force behind global gas demand growth over the medium term, accounting for 48% of incremental gas demand during 2022-2026.

Following its **first decline in four decades in 2022**, China's natural gas demand returned to a **clear path of recovery** over the first eight months of 2023. **Demand growth is expected to remain** strong at an average of 8% per year during 2022-2026, although below the 11% growth rate experienced between 2017 and 2021. Slower economic expansion, together with relatively high gas price levels and accelerated deployment of renewables, is set to moderate China's natural gas demand growth over the short to medium term.

Industry

The industrial sector has been the **longstanding driver of demand** in the Chinese gas market, accounting for nearly 40% of overall gas demand in recent years and almost **half of total demand growth** during 2017-2021.

In 2022 gas demand in industry was hampered by a combination of factors. Strict Covid restrictions remained in place until December, acting as a brake on overall economic activity. All-time-high gas prices further softened industrial output and spurred fuel switching away from gas. As a result, while Chinese economic growth slowed to a rate of approximately 3%, the **industrial sector's gas demand fell by approximately 2%**. However, with Covid-related lockdowns easing and price pressures softening since late 2022, **industry's gas demand is back on track** and expected to grow by 8% in 2023, accounting for half of this year's demand growth.

Industry is set to continue its multi-year trend as the primary driver of natural gas demand growth in China, **accounting for 40% of its incremental gas demand from 2022 to 2026**. A slowing of GDP growth compared with recent years has led to a downward revision in the demand outlook, but continued economic recovery is expected to drive industrial sector gas demand which is expected to expand by 40% by 2026 compared with 2022. However, the sector's gas demand outlook remains uncertain as a state-led policy push aiming to replace coal with natural gas in industry is met by the reality of price uncertainty and a focus on ensuring "reliable energy supplies".

Power sector

Power generation is only **the third-largest gas demand sector** in China, but accounted for close to one-fifth of incremental demand during 2017-2021. Growth of over 40% in installed gas-fired capacity over this period facilitated average annual growth of 9% in power sector gas burn. Still, the share of natural gas in the power mix has grown more slowly than renewables, reaching only 3% of China's total power production in 2022, far behind the more than 60% share held by coal.

In **2022 gas use for electricity generation fell by 10%**, squeezed by high gas prices and record renewable capacity additions. However, recovery in electricity demand and restricted hydro output due to historic heatwaves in the spring have led China's power sector gas demand to register **strong growth in the first eight months of 2023**. Improved gas plant economics – thanks to a steep decline in gas prices compared with 2022 – are also expected to lead to power sector gas burn growth of 12% (or 8 bcm) for the full year of 2023.

Growth in gas-fired power generation is expected to average at over 12% per year between 2022-2026. Wind and solar capacity additions are expected keep the share of renewables in the power mix on a strong growth path, partially conditioning the upside to gas for power generation.

In the context of slower economic expansion and a high gas price environment, potential downside risk remains as an emphasis on ensuring energy security and stabilising economic growth could outweigh government policy on coal-to-gas switching, which was among the key factors behind gas market dynamism in past years. However, loosening global gas market fundamentals as a wave of LNG supply capacity comes online in 2026 could spur growth in price-responsive demand segments, notably in the power sector.

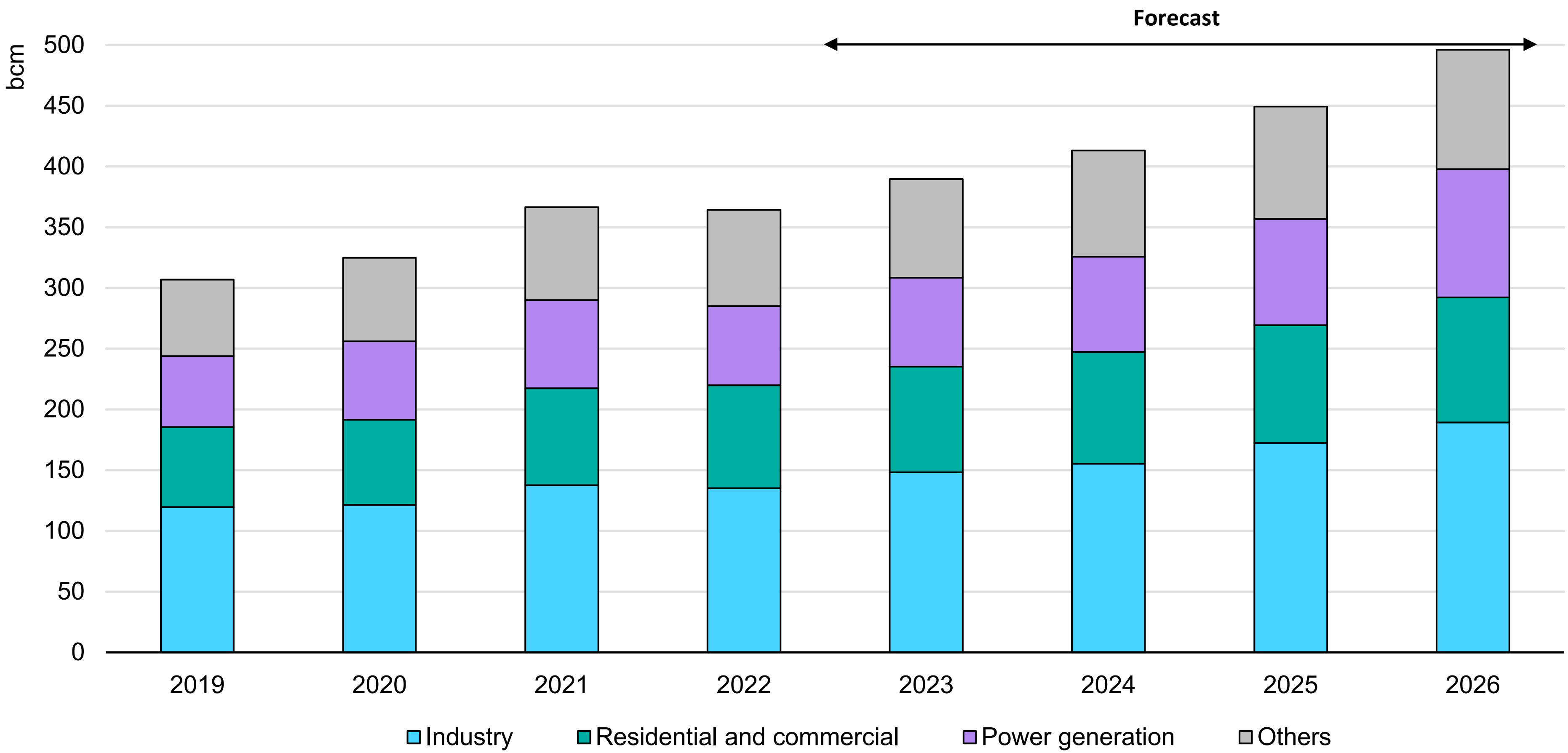
Residential and commercial, and transport

Gas use in the residential and commercial sectors grew strongly during the 2017 to 2021 period, boosted by the long-standing policy to replace domestic coal-fired boilers – notably across China's northern provinces – as part of an action plan to improve air quality through reduced pollution. However, as the share of coal in domestic applications falls and cost considerations weigh on targeted subsidies aimed at favouring gas, **growth in residential and commercial gas demand is expected to slow in the short to medium term**, averaging 5% during 2022-2026. Still, incremental demand in the sector reaches 18 bcm, supported by the continued expansion of gas transmission and distribution systems.

Transport sector gas demand is set to grow by an average of 6% per year, buoyed by **gas transmission network use** and **road transport**. Taken together, transport, residential and commercial demand are expected to account for 22% of total Chinese gas demand growth over the 2022-2026 period.

China's natural gas demand growth is set to slow over the forecast period

Natural gas demand by sector, China, 2019-2026



India and emerging Asian gas markets: Price-sensitive growth

Adverse gas market conditions in 2022 drove a contraction in gas demand in India and emerging Asian markets[3] – down by 6% and 4% respectively – as all-time-high gas prices particularly hit gas consumption in the power and industrial sectors. While a recovery in overall demand is already underway in 2023, thanks in part to lower LNG import prices, diverging factors will drive the recovery in the short to medium term across these markets.

India

Following a steep decline in 2022, India's natural gas demand is forecast to return to a growth trajectory, supported by a positive economic outlook, improving gas supply availability and continued gas market opening reforms. The Petroleum and Natural Gas Regulatory Board (PNGRB), the downstream regulator, set a levelised **unified tariff** for domestic natural gas pipelines starting from 1 April 2023. The new tariff system will benefit consumers located far from domestic gas supply sources and/or LNG terminals.

The Indian natural gas market is **heavily skewed toward industrial demand**, which accounted for over 70% of net incremental gas demand during 2017 to 2021 and represented over half of annual demand in 2022. Gas demand for power generation, although notably smaller than industrial demand, also remains a key driver of price-responsive demand in India.

Total demand fell by 6% in 2022 as a tight global gas market reduced power sector gas burn by nearly a quarter and abruptly slowed industrial demand growth to just 2%. In 2023 gas demand has started to recover, driven by gains in both the industrial and power sectors as lower prices have eased pressure on price-sensitive segments of the economy. Natural gas demand is expected to grow by 4% in 2023.

India's natural gas demand is set to grow by an average annual rate of over 8% in the 2022-2026 period, adding over 20 bcm of incremental demand. Industry is set to remain the largest contributor to this growth, accounting for close to 40% of the total increase. A positive economic outlook (GDP growth is expected to average close to 7% per year during 2023-2026) and priority allocation for certain industrial segments will help the largest gas-consuming sectors rebound from lacklustre growth in 2022-2023. The fertiliser sector is set to be a key driver behind India's growing industrial gas demand, as the country aims to phase out urea imports by the end of 2025. India's conventional urea production

[3] Bangladesh, Indonesia, Malaysia, Myanmar, Pakistan, Philippines, Thailand and Viet Nam.

capacity is expected to increase by over 6 Mtpa by 2025, which could translate into almost 5 bcm of incremental gas demand.

Following its steep decline in 2022, **gas-to-power demand** is expected to recover during the forecast period. Preliminary data indicate that gas burn in the power sector rose by to 20% y-o-y in the first eight months of 2023 amid more favourable natural gas price levels. Despite continuing renewable capacity additions, gas-to-power demand is expected to grow at an average of 15% per year between 2022 and 2026 as capacity factors improve at existing gas plants in response to growing power demand.

Development of the distribution network and a continued push to favour gas in **household applications** are expected to drive average annual growth of 7% in residential and commercial gas use during 2024-2026.

Emerging Asia

Natural gas demand across emerging Asian markets remained broadly stable in the period 2017 to 2021. The power sector accounted for approximately half of total gas demand in this period, while the industrial sector has been the one to counter the trend of stagnating demand. **In 2022 high gas prices hit the power sector**, trimming gas demand for electricity generation by 6%. A more favourable price environment is expected to support a 3% rebound in 2023, a precursor to the growth expected in the medium term.

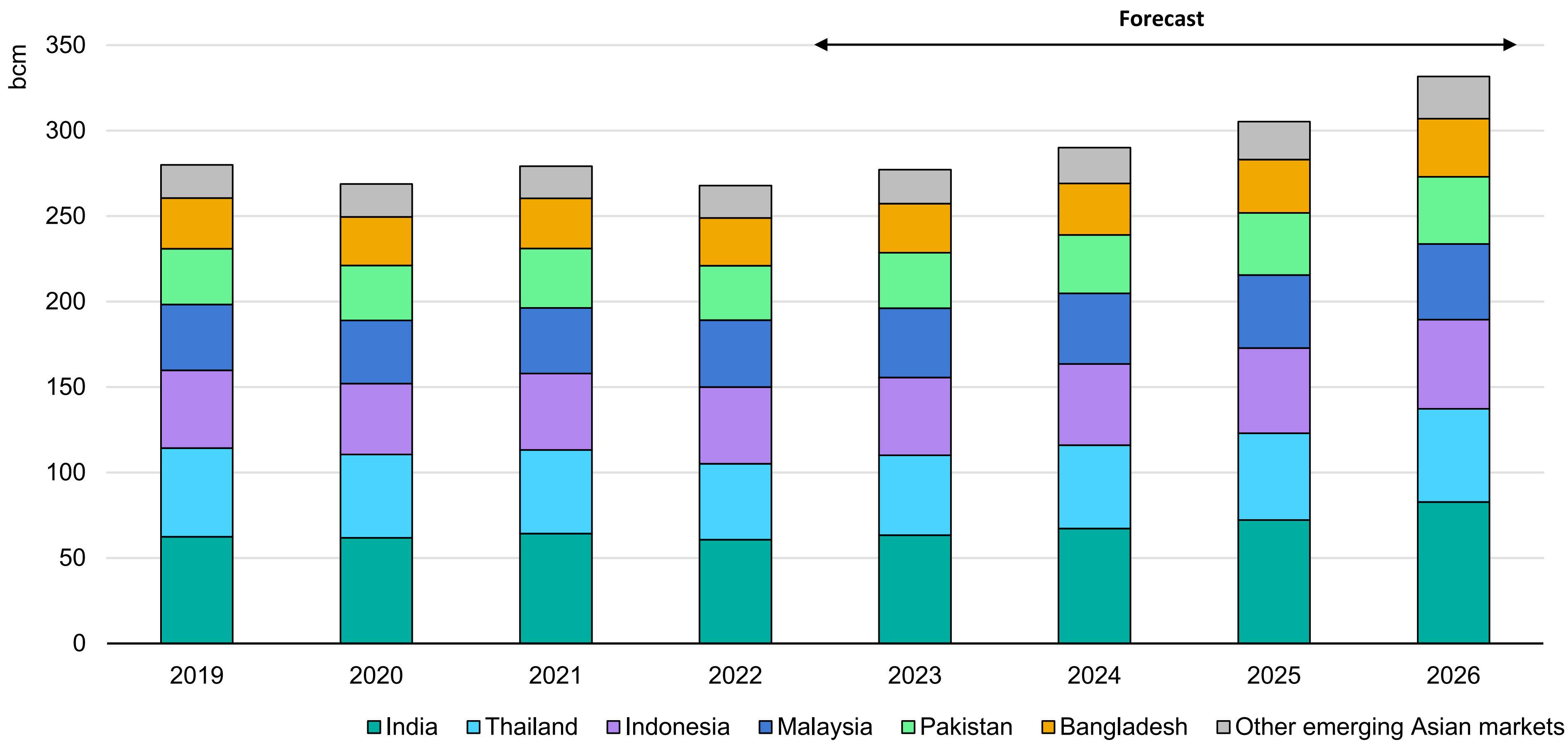
Dynamic economic drivers and population growth point to robust short-term demand fundamentals in emerging Asia. **Natural gas demand is forecast to grow at an average rate of 5% per year between 2022 and 2026**, with over 50% of incremental demand concentrated in Bangladesh, Pakistan and Thailand. This comes on the back of a severe demand contraction in Bangladesh and Pakistan in 2022 given their strong sensitivity to imported gas prices.

Growing electricity requirements across the region and policy support in key markets to limit greenhouse gas emissions should lead to increased gas penetration in electricity production, even as renewable power investments progress, placing the power sector as the primary driver of gas demand growth. **Gas use for power generation** accounts for nearly 60% of incremental consumption over the forecast period, and nearly 70% of this power sector uptick is concentrated in Thailand, Pakistan, Indonesia and Malaysia.

Industrial demand – led by fertilisers and light industry – makes up the bulk of the remaining gas demand growth in the outlook period, with the biggest increments expected in Bangladesh, Indonesia, Malaysia, Pakistan and Thailand. **Residential and commercial demand**, along with **transport** applications, make relatively minor gains.

Natural gas demand in India and emerging Asia is set to expand by over 20% during 2022-2026

Natural gas demand, India and emerging Asia, 2022-2026



Global gas production growth is set to slow in the medium term

Natural gas production is expected to expand by close to 6% (or 240 bcm) by 2026 from 2022. North America and the Middle East are forecast to account for almost 80% of the net increase in global gas output during this period, while Russia's natural gas production is set to remain well below the record levels reached in 2021. The feedgas supply requirements of LNG export projects are foreseen to account for over 55% of the net increase in global gas output in the forecast period, reflecting strong growth in LNG trade and an increasingly globalised gas market.

In **North America**, natural gas production rose by 4% (or close to 50 bcm) in 2022, driven by strong domestic demand growth and the continued ramp-up of of LNG exports from the United States. Shale gas output in the United States grew by an impressive 5% (or 40 bcm), driving up overall US gas production to over 1 tcm for the first time in the nation's history. This strong growth continued during Q1-Q3 2023, when North America's gas output increased by an estimated 4% (or 30 bcm) y-o-y, primarily supported by expanding upstream activity in the vast shale plays of the United States. **Natural gas production growth in North America is expected to slow during the forecast period** to 1.8% per year during 2023-2026. This moderate growth trajectory is reflective of declining domestic gas demand in Canada and the United States. The bulk of incremental gas supply is set to feed North America's rapidly expanding LNG liquefaction fleet, with the region's LNG exports expected to increase by 50% (or 55 bcm) 2023 and 2026.

In **Eurasia**, natural gas production fell by 10% (or over 90 bcm) in 2022 due to the steep drop in Russia's piped gas supplies to Europe and continued declines in Kazakh and Uzbek gas production. The downward trend continued in the first eight months of 2023, with Russia's gas output down by 10% (or almost 45 bcm) y-o-y and Uzbekistan recording a similar 10% decline (3 bcm) amid deteriorating upstream activity in the country. Eurasian gas production is expected to recover from its 2023 lows and grow at an average rate of 2.5% per year in 2023-2026, primarily driven by export-oriented projects in Russia and Turkmenistan aimed at China. Despite the gradual recovery in Russian production, output is expected to remain 11% (or 85 bcm) below 2021's record levels.

In the **Middle East**, natural gas output rose by an estimated 3% (or 20 bcm) in 2022, primarily driven by expanding gas demand in the industrial and power sectors of Iran and Saudi Arabia. **The region's gas production is expected to expand by close to 15%** (or 100 bcm) by 2026 compared with 2022. This strong growth is largely supported by the growing domestic demand in Iran and Saudi Arabia, as well as export projects in Israel and Qatar. The **North Field East expansion in Qatar** is set to increase the country's LNG export capacity by over 40%, requiring almost

50 bcm/yr of additional feedgas supply by 2026-27. In **Iran**, the bulk of incremental supply is set to be met by the rising output from the giant South Pars field. **Phase 11 of the South Pars field** started producing gas in August 2023, with initial output estimated at 4-5.5 bcm/yr and the potential to ramp up production close to 20 bcm/yr in the coming years. In **Saudi Arabia**, production is supported by the ramp-up of the North Arabia field, the expansion of South Ghawar and the start-up of the Jafurah field towards the end of the forecast period. In **Israel**, the expansion of the **Leviathan and Tamar** fields, together with the start-up of the **Karish field,** are expected to add over 15 bcm/yr of gas supply by 2026. This will allow Israel to further increase its piped gas deliveries to neighbouring markets, including Egypt and Lebanon.

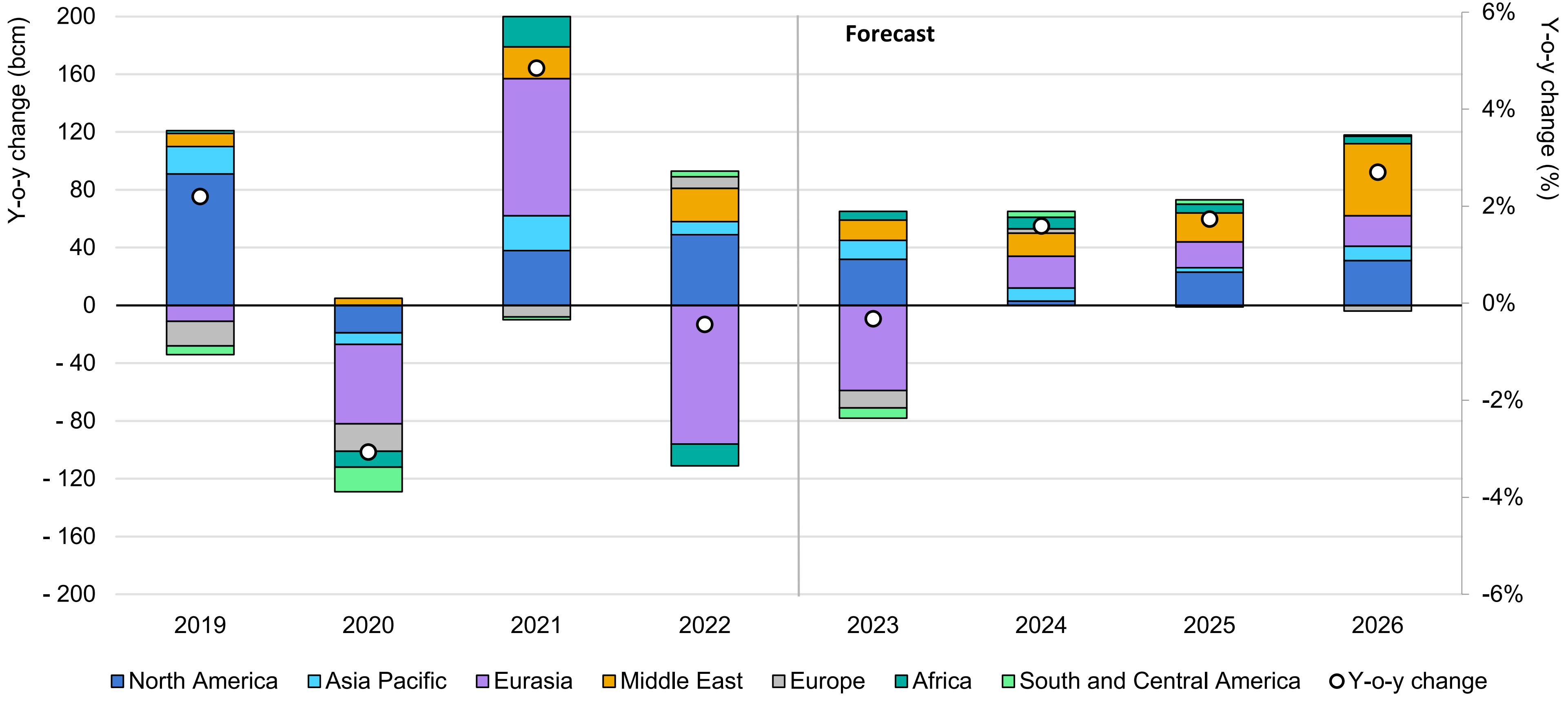
Natural gas production in the **Asia Pacific region** rose by a mere 1% in 2022 and is expected to expand by 5% (or 35 bcm) by 2026 compared with 2022. Most of the region's growth is concentrated in China, where domestic production is projected to increase by more than 15% from 2022 levels to reach 250 bcm in 2025. India's natural gas production is foreseen to grow at a rate of 4% per year over the forecast period, adding over 10 bcm of gas supply by 2026. Australia's gas production is expected to remain broadly flat, averaging 150 bcm/yr over the medium term. Most other producers in the region are set to experience production declines over the forecast horizon, paving the way for higher LNG import needs.

Following a 4% increase in 2022, **Europe's** natural gas production is set to resume its decline over the medium term and drop by 7% (or close to 15 bcm/yr) by 2026 compared with 2022, as the increase in natural gas output in Eastern European markets (Romania and Türkiye) proves insufficient to offset the declines projected in Northwestern Europe. **Africa**'s natural gas production dropped by close to 6% in 2022 amid lower output in Algeria, Egypt and Nigera. Production is set to expand by 10% (or 25 bcm/yr) by 2026, primarily driven by Algeria, Congo, Egypt, Mozambique and Nigeria. Around 60% of this additional supply is expected to feed Africa's expanding LNG liquefaction fleet, which is set to grow by 25% by 2026.

In **Central and South America** natural gas output grew by 3% in 2022, supported by Argentina, Peru and Trinidad and Tobago. Gas output is projected to remain broadly flat over the forecast period. Production growth will be supported by Argentina, where the debottlenecking of the Vaca Muerta shale play should allow output to expand by 20% (or 10 bcm) by 2026. Pre-salt developments in Brazil will support moderate growth in sales gas production, while reinjection is set to expand further to stimulate oil production over the forecast period. In Trinidad and Tobago, gas output is projected to remain broadly stable. Additional supply from the ramp-up of the Colibri and Matapal fields, and the start-up of the Cypre field in 2025, are expected to be largely offset by declines in the country's ageing fields. The region's other large producers, including Bolivia, are set to further reduce their gas output over the medium term.

North America and the Middle East drive global gas supply expansion over the medium term

Year-on-year change in natural gas production by region, 2019-2026



Upstream developments in the United States: Export-oriented growth

US natural gas production is expected to expand by 7% (or over 70 bcm) by 2026 compared with 2022, largely driven by the ramp-up of LNG exports into the global gas market and higher piped gas deliveries to Mexico. Incremental supply is principally met by associated shale gas production, led by the Permian Basin. In contrast, conventional gas production is set to continue to decline over the forecast period. Shale gas is expected to account for nearly 80% of total US gas production by 2026.

US gas production continued to expand strongly in 2023

Following the setback caused by the pandemic in 2020, natural gas production in the United States has been steadily increasing from its 2019 level of 970 bcm and surpassed 1 tcm in 2022 to end at 1 020 bcm. While the Appalachian Basin remains the largest source of supply, with a share of 30% of total production, the lack of additional takeaway pipeline capacity in 2022 resulted in a production slowdown and flat production rates during Q1-Q3 2023. In contrast, associated gas production rose by over 10% (or 9 bcm) in the Permian Basin and increased by close to 13% (or 10 bcm) in the Haynesville Shale. Altogether, US gas production is expected to increase by 5% (or 35 bcm) in 2023. This growth is largely driven by the continued expansion of LNG exports, stronger piped gas deliveries to Mexico and higher gas burn in the power sector.

Export-oriented projects drive US production growth

US natural gas production growth is set to slow in the medium term from an average growth rate of 4% per year between 2018 and 2022 to 1.5% per year between 2022 and 2026. This slower growth is reflective of declining US domestic gas consumption and is entirely driven by a combination of the country's rapidly expanding LNG exports and the continued ramp-up of piped gas deliveries to Mexico.

Domestic demand for natural gas in the United States is expected to drop by 2% (or 20 bcm) during 2022-2026. Natural gas use in the **residential and commercial sectors** is projected to decline at a rate of 1% per year amid efficiency gains and the gradual deployment of heat pumps. Natural gas demand in **industry** is expected to grow at an average rate of almost 1% per year, supported by the expansion of gas-intensive industries. Following strong growth in recent years, gas burn in the **power sector** is forecast to decline by 8% (or over 25 bcm) during 2022-2026, amid the rapid expansion of renewable electricity sources. Consequently, gas-fired power generation is projected to lose its position as the largest source of electricity supply to renewables towards the end of the forecast period.

While US domestic demand is expected to decline, natural gas exports are set to increase strongly over the medium term. US LNG exports are expected to increase by 60% (or 65 bcm/yr) by 2026 compared with 2022. This strong growth will be supported by the build-up of new LNG liquefaction capacity, primarily in Louisiana and Texas. This includes the Plaquemines LNG Phases 1 and 2 (27 bcm/yr), Golden Pass LNG (21 bcm/yr) and the Corpus Christi Liquefaction Stage 3 (13.7 bcm/yr) projects. In addition, piped gas deliveries to Mexico are set to expand by 20% during 2022-2026, partly driven by new LNG export terminals in Mexico relying on US feedgas supplies, including the Energía Costa Azul LNG project (4.4 bcm/yr) and Altamira FLNG (5.5 bcm/yr). Incremental piped gas deliveries to Mexico should be supported by the North Baja Xpress expansion project in 2023 (5 bcm/yr) and the Southwest Gateway pipeline (13.5 bcm/yr) expected to come online in 2025. Imports from Canada are set to decline over the medium term, although they will remain key to meeting seasonal demand swings.

Additional takeway capacity from the Appalachian and Permian Basins will be key to production growth over the medium term

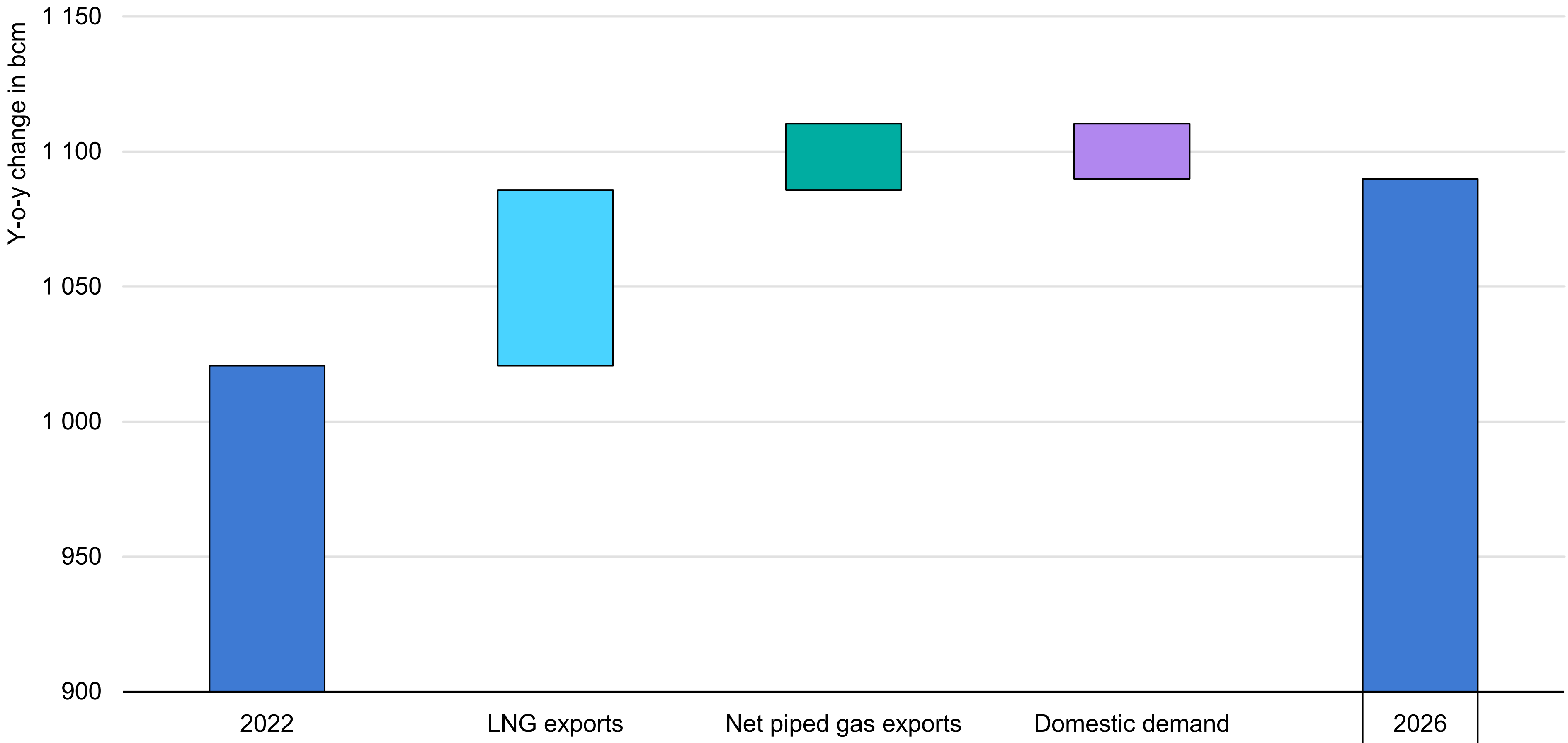
Natural gas production growth is primarily enabled by upstream developments in the country's vast shale plays, and in particular by the ramp-up of associated petroleum gas. The Permian Basin is expected to be the largest source of incremental supply, with its natural gas production expected to expand by 20% (or 30 bcm) between 2022 and 2026. This strong growth will be supported by the continuing light tight oil developments and improving gas-to-oil ratios. Additional takeaway capacity will be key to debottlenecking the Permian Basin. Expansions to the Gulf Coast Express, Permian Highway and Whistler pipelines are set to add 17 bcm/yr of takeaway capacity by the end of 2023. The Matterhorn Express pipeline project (26 bcm/yr) is expected to enter service in 2024. Natural gas ouput in the Appalachian Basin is projected to increase by 6% (or 20 bcm) between 2022 and 2026, enabled by the start-up of the Mountain Valley Pipeline (21 bcm/yr), which is expected to start operations in 2024. Other shale gas production is projected to increase by close to 15% (or 50 bcm) during 2022-2026. In contrast, conventional natural gas production is forecast to decline by over 15% (or 30 bcm) during the forecast period. Consequently, the share of shale gas in total US gas output is expected to increase from 80% in 2022 to over 85% by 2026.

The rise of certified natural gas

A rising proportion of US natural gas output is receiving **third-party certification**. According to industry surveys, close to 30% of US gas production in 2022 was certified for its performance against certain environmental, social and governance metrics. This share is expected to rise over the medium term, with several US producers setting ambitious targets to reduce the **emissions intensity** of their operations. EQT Corporation – the largest US gas producer – aims to reach net zero emissions for Scope 1 and 2 in its production segment by 2025.

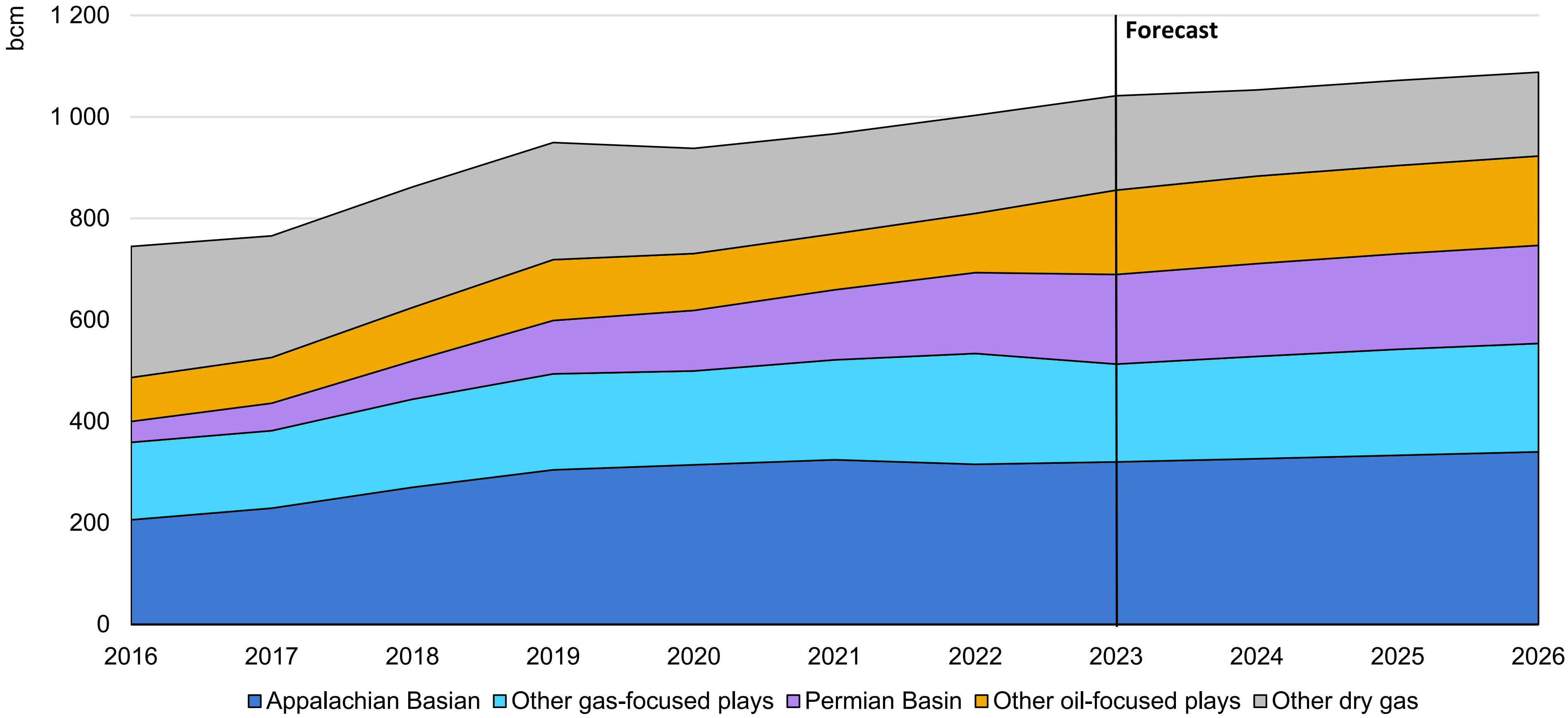
Strong growth in LNG exports and piped gas supplies to Mexico drive US natural gas production over the medium term

Key drivers of natural gas production growth, United States, 2022-2026



The Appalachian and Permian Basins are set to support the expansion of US natural gas production

Dry natural gas production by main source, United States, 2016-2026



Sources of historical data: IEA analysis based on EIA (2023), Natural gas production.

Under pressure: Russia’s natural gas production has collapsed since its invasion of Ukraine

Russia’s invasion of Ukraine and the consequent break-up of its decade-long ties with the European market are having profound implications for its gas production and upstream developments over the medium term. The country’s natural gas output in 2023 is expected to drop to its lowest level since 2009, putting pressure on upstream operations and potentially leading to production shut-ins at ageing, vulnerable fields. Russia’s gas production is expected to expand by 9% by 2026 and to remain 11% (or 85 bcm) below the record levels reached in 2021. This reflects Russia’s limited options for finding new export outlets over the medium term to replace the volumes once sent to the European market. Altogether, this year’s forecast foresees a cumulative production loss of over 600 bcm for the 2023-2026 period compared with our pre-war medium-term outlook.

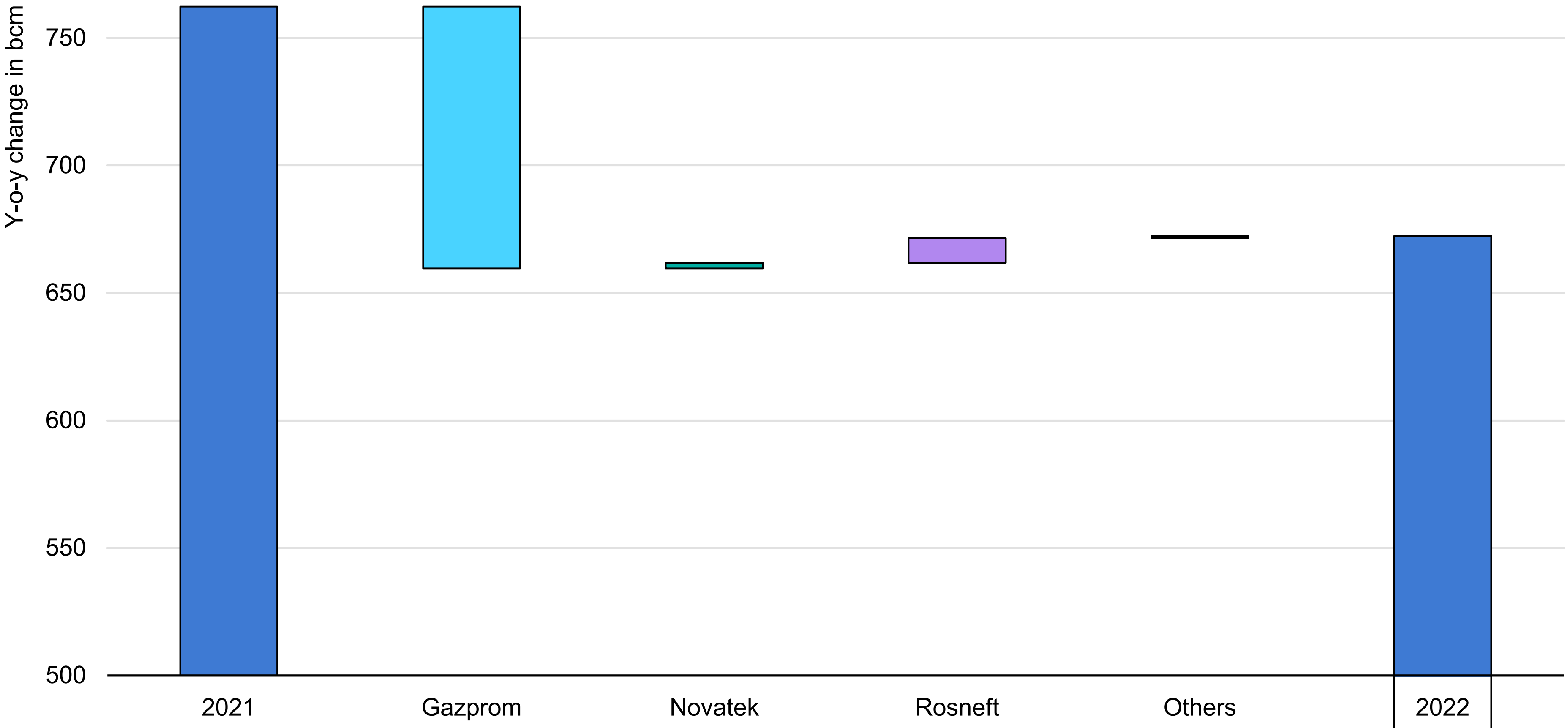
Russia’s natural gas production dropped by 12% (or 90 bcm) in 2022 – its steepest decline in history. This was primarily driven by the **sharp reduction in piped gas exports** to Europe (down by over 80 bcm) and lower domestic demand (down by 30 bcm) amid the country’s worsening macroeconomic performance. **Gazprom bore the brunt of the decline**, recording a drop of 20% (or over 100 bcm) in its natural gas output. Gazprom’s giant, flexible swing fields located in Western Siberia and the Yamal peninsula (including Zapolyarnoe, Urengoyskoe, Yamburgskoe and Bovanenkovo) contributed to the bulk of the downward flexibility displayed in 2022. In contrast with Gazprom, Novatek – Russia’s second-largest gas producer – increased its gas production by close to 3% amid higher LNG exports. As Russia’s third-largest gas producer, Rosneft saw its natural gas production grow by an estimated 15% as the company continued to ramp up new upstream projects and expand its sales to Russian end consumers (primarily industrial players).

Russia’s natural gas production fell by close to 10% (or almost 45 bcm) in the first eight months of 2023 amid deteriorating piped gas exports to Europe. Gazprom accounted for virtually all the decline, with its natural gas output dropping by 22% (or 65 bcm), while both Novatek and Rosneft countinued to increase their production. As a consequence, Gazprom’s share of Russia’s total gas production fell from 68% in 2021 to 55% in the first eight months of 2023.

For the full year of 2023, the country’s natural gas output is expected to decline by 8% (or over 50 bcm) to its lowest level since 2009. This will naturally require further downward flexibility from Russia’s upstream activities, including at the more vulnerable, ageing fields in the Nadym Pur Taz (NPT) region, which could potentially face production shut-ins.

Gazprom bore the brunt of the Russia’s gas production decline in 2022

Year-on-year change in natural gas production by key companies, Russia, 2021-2022



Sources: IEA analysis based on various company reports.

No relief: Russia's upstream gas sector faces a bleak medium-term outlook

Russia's natural gas production is forecast to grow at a rate of close to 3% per year between 2023 and 2026, primarily supported by the continued expansion of piped gas deliveries to China, higher LNG exports and a gradual recovery in domestic gas demand. The ramp-up of gas fields in Eastern Siberia and the Far East is expected to account for close to 40% of Russia's net production growth over the forecast period.

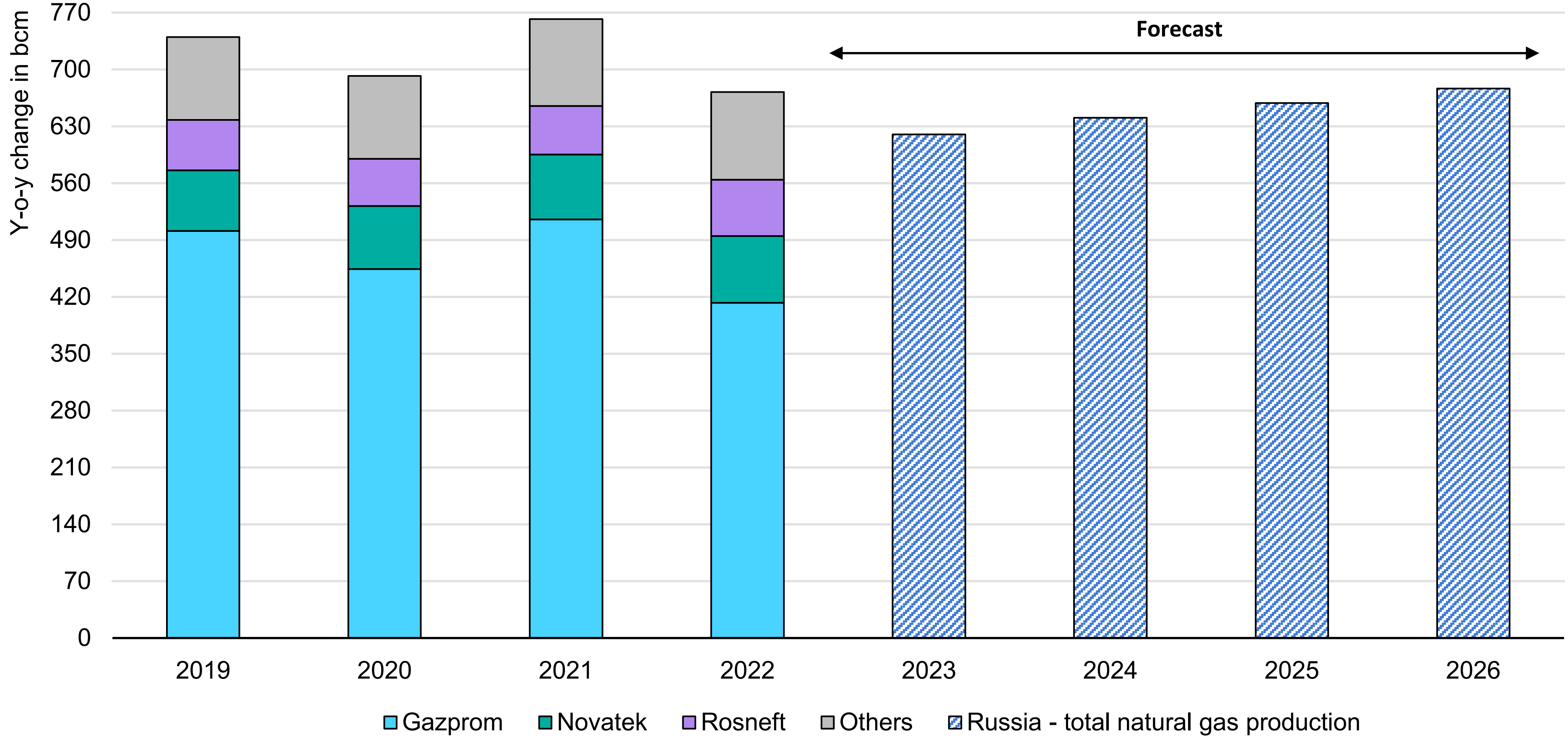
The European Union's decision to phase out Russian gas imports as soon as possible primarily affects upstream developments in **Western Siberia and the Yamal peninsula**. This is reflected in Gazprom's amended ten-year strategy for the period 2024-2033, which no longer considers Europe to be a strategic market. The start-up of the **Kharasavey field** (32 bcm/yr nameplate capacity) was delayed from 2023 to 2024 while the ramp-up of production rates remains uncertain. The planned expansion of the giant **Bovanenkovo field** from its current 115 bcm/yr nameplate capacity to 140 bcm/yr faces an uncertain future amid the lack of export outlets and is expected to be delayed beyond our forecast horizon. Similarly, the supergiant **Tambey field** – previously planned to start up in 2026 – is foreseen to be delayed. The field was expected to feed the planned Baltic LNG project (18 bcm/yr), which is stalled following the withdrawal of western engineering and construction service providers.

This forecast takes a conservative view on Russia's LNG project developments, considering the financial and technological uncertainties due to the sanctions imposed on Russia following its invasion of Ukraine. Arctic LNG Train 1 (8.9 bcm/yr) is expected to start up at the end of 2023, although uncertainties remain around its ramp-up schedule and initial utilisation rates. The start-up of Train 2 is expected to be delayed to 2025, with production ramping up during 2025-2026. The commissioning of Train 3 is assumed to be delayed beyond our forecast horizon.

In Eastern Siberia, the **Chayandinskoye field** is set to reach its nameplate capacity of 25 bcm/yr by 2024, enabling the ramp-up of gas supplies to China via the Power of Siberia pipeline. The **Kovyktinskoye field** was officially commissioned and connected to the Power of Siberia pipeline system at the end of 2022. The continued ramp-up of the two fields will allow Russia to increase its piped gas exports to China to 38 bcm/yr by 2025 via Power of Siberia. In addition, Gazprom signed a 25-year agreement with China's CNPC to supply 10 bcm/yr of piped gas via the "Far Eastern route". The expected resource base is the **Yuzhno-Kirinskoye** field, which has a design capacity of 21 bcm/yr. The field is set to be commissioned by 2025 and produce an initial 5 bcm/yr. The **Power of Siberia 2** project (50 bcm/yr) is not expected to be commissioned over the forecast period due to the lack of a long-term offtake agreement with Chinese buyers.

Russia's natural gas production is expected to remain 85 bcm below its 2021 levels by 2026

Natural gas production, Russia, 2019-2026



Sources of historical data: IEA analysis based on various company reports.

Europe's natural gas production is set to continue to decline over the medium term

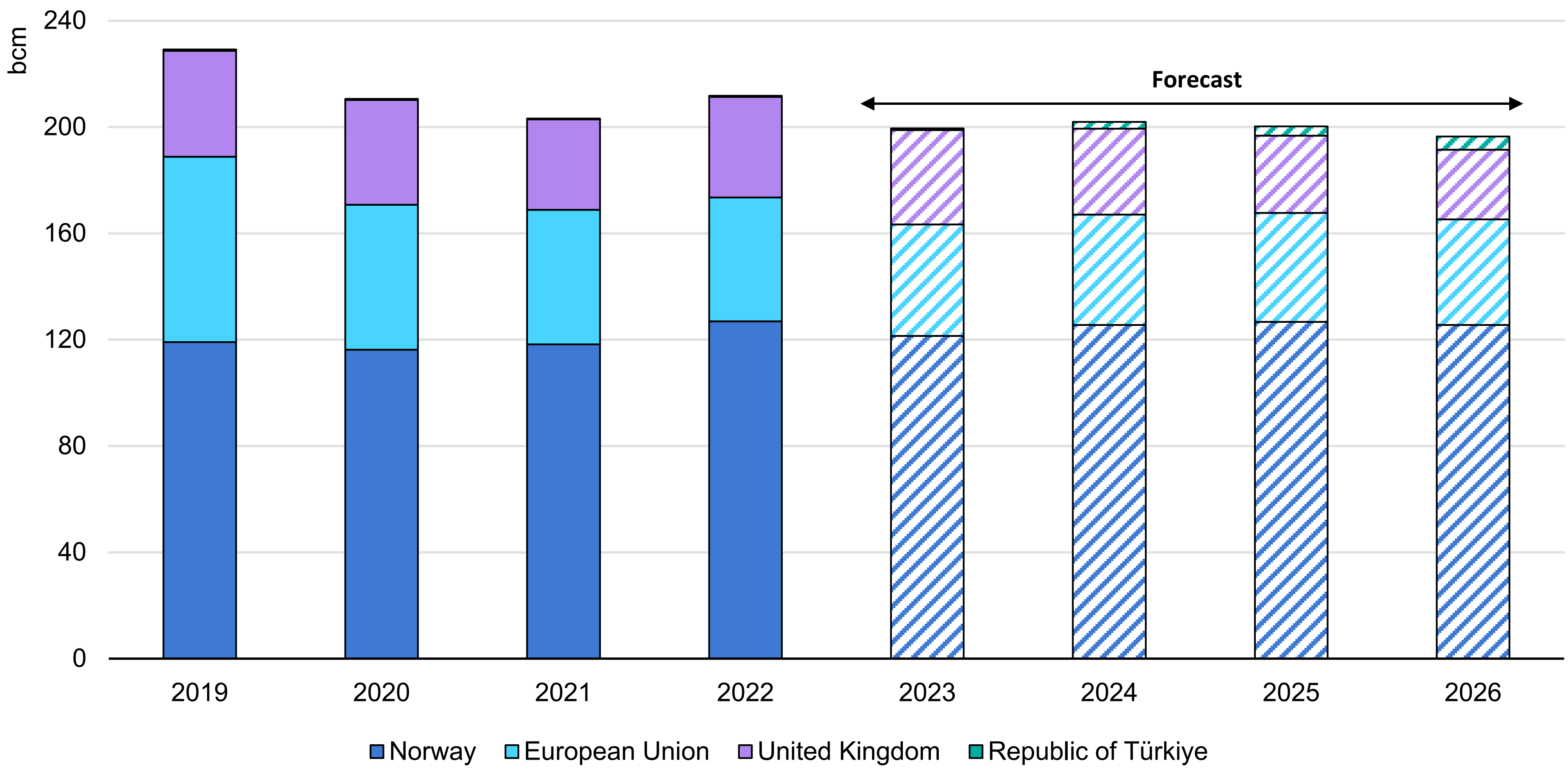
Europe's natural gas production is expected to continue to decline over the medium term, despite renewed interest in upstream developments in some key markets after Russia's invasion of Ukraine. OECD Europe's natural gas production has dropped by 33% (or 90 bcm/yr) since 2010, leading to a higher reliance on imports, including (initially) from Russia. The Netherlands and the United Kingdom accounted for over 90% of the net decline. This downward trend was temporarily reversed in 2022, when European gas production rose by 4% (or 6 bcm) amid the gas crisis triggered by Russia. European gas output returned to its downward trajectory in 2023, with production down by 4% (or 3.5 bcm) in the first eight months of the year on higher maintenance in Norway and lower UK and Dutch output.

Europe's natural gas production is forecast to drop by 7% (or close to 15 bcm/yr) by 2026 compared with 2022, as the increase in natural gas output in Eastern European markets is not sufficient to offset the declines projected in Northwestern Europe. **Norway is set to remain the backbone of European gas production**, with the country's natural gas output expected to remain broadly flat and average 125 bcm/yr between 2023 and 2026. In the **United Kingdom**, ageing gas fields in the North Sea are expected to reduce the country's natural gas output by over 30% (or more than 10 bcm) by 2026 compared with 2022. The government's plan announced in July 2023 to grant more than 100 new licences for oil and gas production in the North Sea could provide upside potential to the current forecast. In **the Netherlands**, the giant **Groningen field** ceased production on 1 October 2023, marking the end of its phase-out which started in 2018 due to earthquakes caused by production from the field. Production from small fields is expected to continue to decline over the forecast period, leading to an overall decrease of over 40% (almost 10 bcm) in Dutch natural gas output by 2026 compared with 2022.

In **Denmark**, the **Tyra gas field** has been under redevelopment since September 2019 and is expected to restart production in the 2023/24 heating season, with a capacity of 2.8 bcm/yr. In **Romania**, the Midia Gas Development Project started producton in 2022 and is set to ramp up gas supplies to 1 bcm/yr during 2023-2026. Project partners took FID in June 2023 on the development of the **Neptun Deep** offshore gas field in the Black Sea. First gas is expected in 2027, beyond our forecast horizon, and production could reach 8 bcm/yr at plateau. According to industry estimates, **Italy** could potentially double its 3.4 bcm/yr gas output by 2025 by optimising production at existing fields and by accelerating the developments of already licensed projects. In **Türkiye**, the giant **Sakarya gas field** was commissioned in April 2023. Natural gas production is expected to ramp up to 3.6 bcm/yr during the first phase in 2023-2025, and then to close to 15 bcm/yr during the second phase after 2026.

Europe’s natural gas production is expected to decline by 7% by 2026 compared with 2023

Natural gas production, OECD Europe, 2019-2026



Sources of historical data: IEA analysis based on Eurostat (2023), Energy statistics.

Waking the Dead Cow: Vaca Muerta is set to drive Argentina's gas production growth

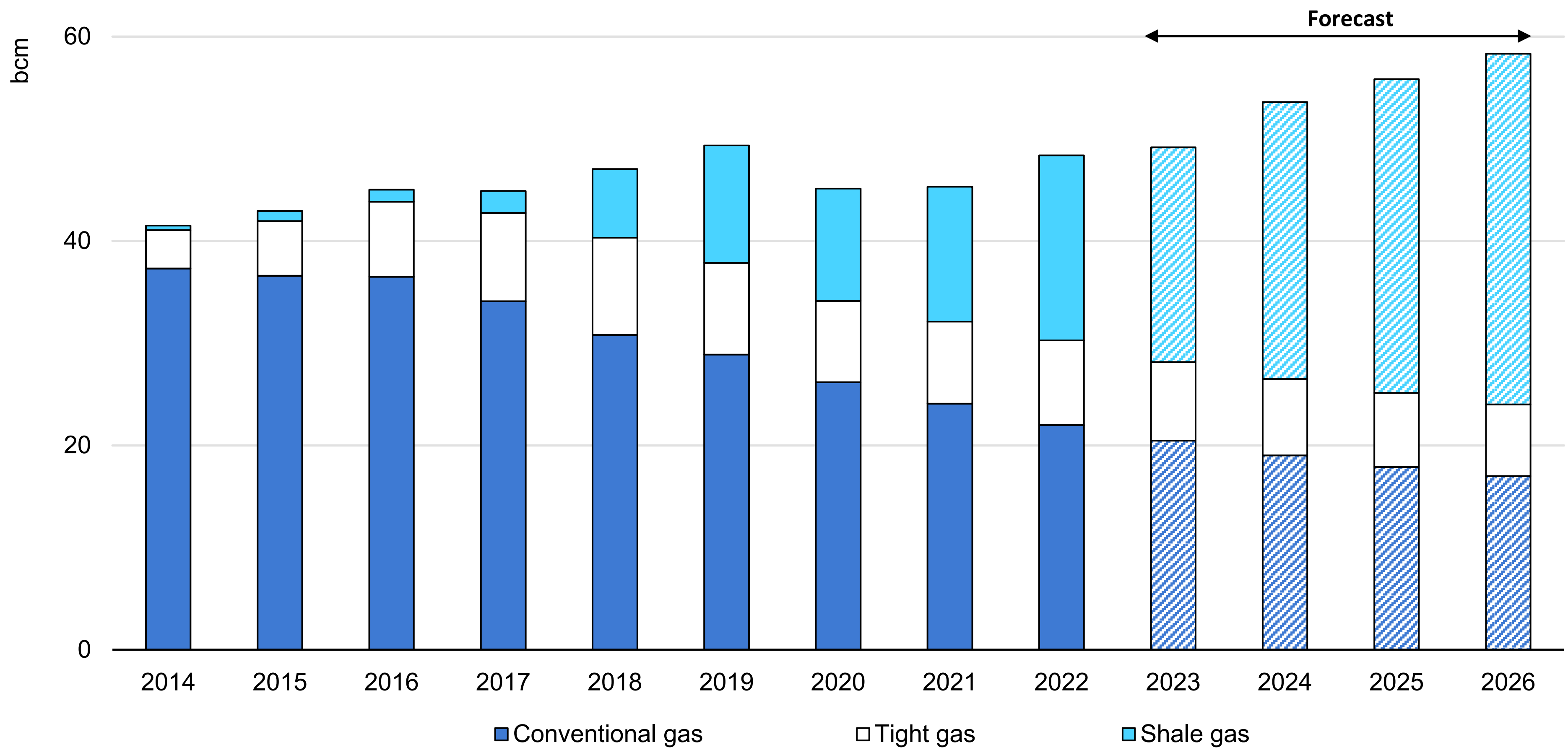
Argentina's natural gas production is expected to expand by over 20% (or 10 bcm) between 2022 and 2026 as the continued decline in convential gas production is more than offset by the country's rapidly growing shale gas output. This growth is primarily supported by the debottlenecking of the Vaca Muerta shale play and will allow Argentina to reduce its natural gas import requirements over the medium term.

Argentina's domestic gas supply has undergone a profound transformation since 2012, when the first development activity started in Vaca Muerta, the world's second-largest shale gas deposit. Argentina's **conventional natural gas production** declined by over 40% (or 15 bcm/yr) between 2014 and 2022 amid declining output from ageing fields. This decline was more than offset by the country's rapidly growing **unconventional gas** production, leading to an increase of 2% per year in the country's total gas output between 2014 and 2022. **Shale gas supply** – primarily from Vaca Muerta – expanded from almost zero in 2014 to 18 bcm in 2022. In addition, **tight gas production** more than doubled during the same period, expanding by close to 5 bcm. As a consequence, the share of shale gas in Argentina's total gas production rose from just 1% in 2014 to 37% in 2022. This trend continued over the first eight months of 2023, with convential gas production declining by 6% (or 1 bcm) y-o-y, while shale gas output rose by over 16% (or 2 bcm). For the full year of 2023, the shale gas share is expected to rise to close to 45% of Argentina's total gas output.

The strong increase in natural gas production in the Vaca Muerta shale play has led to takeaway constraints in recent years, necessitating the building of new pipeline systems. The first phase of the **Néstor Kirchner Gas pipeline** was commissioned in July 2023, stretching 573 km from Vaca Muerta to Buenos Aires. The pipeline's initial capacity is 4 bcm/yr, to be expanded to 8 bcm/yr by the end of 2023 through the addition of compressor stations. The **second phase** will allow gas deliveries to reach San Jeronimo in Santa Fe province, while the overall transmission capacity of the pipeline system will be expanded to around 16 bcm/yr. The higher deliveries to the coastal area, made possible by the pipeline, are set to reduce Argentina's LNG import requirements in the coming years. The financing for the construction of the second phase was secured by the end of 2022 and commissioning is expected in the first half of 2024. In addition, Argentina plans to reverse flows through the **Northern Gas Pipeline** to replace imports from Bolivia (standing at around 3 bcm in 2023) and potentially export natural gas to Chile, and to southern and central Brazil via Bolivia. As a consequence of the debottlenecking of Vaca Muerta, the share of shale gas in Argentina's total gas production is set to increase from 37% in 2022 to around 60% by 2026.

Argentina's natural gas production is set to expand by 20% by 2026

Natural gas production, Argentina, 2014-2026



Sources of historical data: IEA analysis based on Argentine Ministry of Economy (2023), Producción de gas convencional y no convencional.

Global LNG supply is expected to expand by 25% by 2026

Global LNG trade is forecast to expand by nearly 25% (or just over 130 bcm) by 2026 compared with 2022, primarily driven by LNG liquefaction capacity additions in North America and Qatar. The overall investment value of new LNG export capacity coming online during the forecast period is estimated at close to USD 130 billion. Over 70% of this incremental supply is expected to arrive on the market in 2025 or 2026, although project delays and varying ramp-up rates could alter this forecast. The strong growth in LNG supply could potentially alleviate market tensions and moderate gas supply security risks in the second half of the decade.

Global LNG supply grew at 4% in 2022 and at 3% in Q1-Q3 2023. This modest growth is reflective of limited liquefaction capacity additions, outages at major export facilities and declining feedgas supply at LNG plants fed by ageing fields. Altogether, LNG supply is set to increase by just over 40 bcm during 2022-2023, not sufficient to offset the decline in Russian piped gas deliveries to Europe (down by 122 bcm in 2023 compared with 2021) and hence contributing to tighter market conditions. **The United States** alone accounted for almost half of the total incremental LNG supply since the start of 2022 and **is set to become the world's largest LNG exporter in 2023**, ahead of Qatar and Australia. **The gas supply shock caused by Russia led to reconfigured LNG trade flows**, with Europe increasing its LNG imports by 60% to almost 170 bcm in 2022, while deliveries to Asia dropped by 7%. For the full year of 2023, Europe's LNG inflows are expected to remain close to their record 2022 levels, while Asian LNG demand is forecast to return to growth and rise by 5%. This is primarily driven by the recovery in China's LNG demand. The country's LNG imports grew by an impressive 13% y-o-y in Q1-Q3 2023 and are expected to increase by 14% for the full year of 2023, albeit remaining below the record levels reached in 2021.

North America and Qatar are set to drive the expansion of LNG exports over the medium term, together accounting for over 80% of incremental LNG supply between 2022 and 2026. In the United States, LNG exports are expected to expand by over 60% (or 65 bcm) by 2026 compared with 2022. Hence, the **United States** alone is set to contribute for around half of incremental LNG supply, reinforcing its position as the world's leading LNG exporter. Consequently, the US share of global LNG supply is projected to increase from 20% in 2022 to 25% by 2026. This strong growth is primarily supported by the commissioning of three large LNG export projects in Lousiana and Texas. At the **Golden Pass LNG** export facility (21 bcm/yr), Train 1 is expected to start operations in Q1 2024, while Trains 2 and 3 are set to ramp up production during 2025 and 2026. The first phase of the **Plaquemines LNG** project is set to start operations in the second half of 2024, followed by the ramp-up of the second phase in 2025-2026, adding a total liquefaction capacity of 20 bcm/yr. The **Corpus**

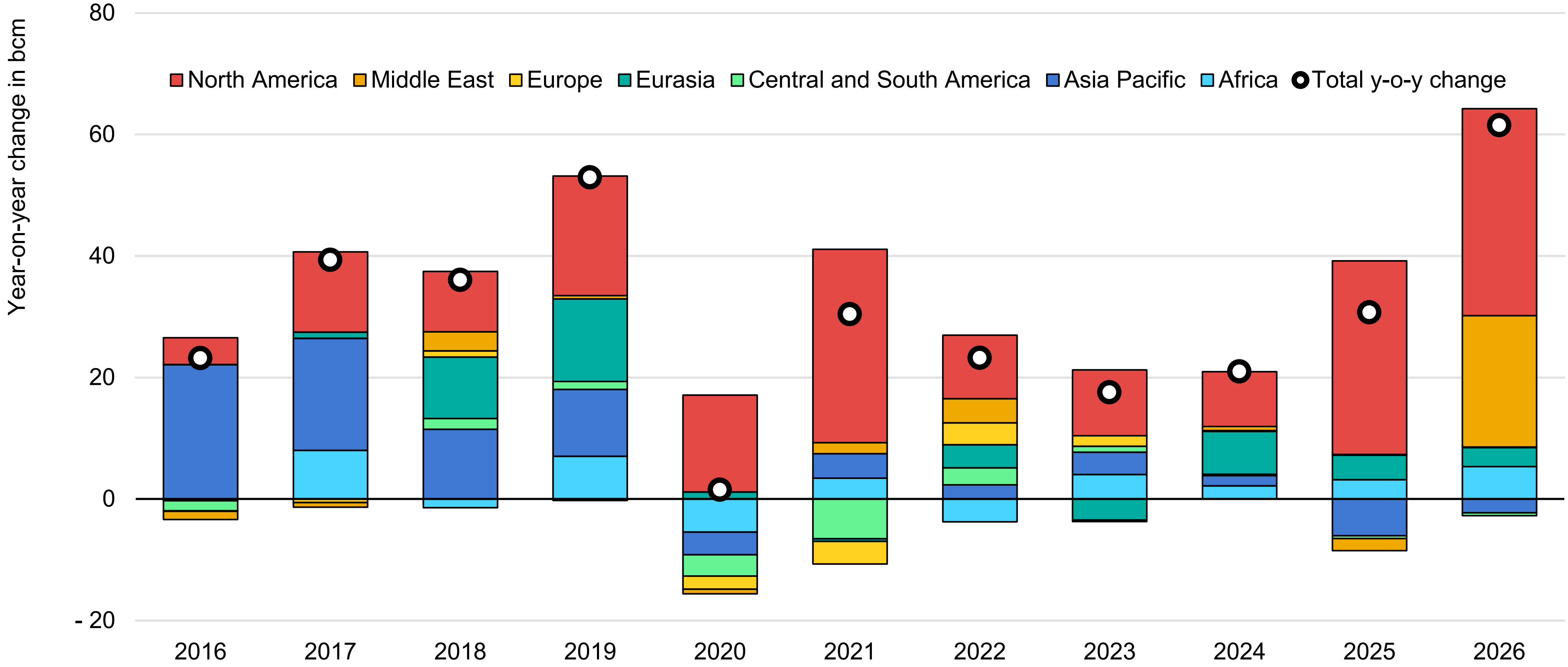
Christi Stage 3 expansion project (over 13.6 bcm/yr) is expected to start operations by the end of 2025 and ramp up production during 2026. In British Columbia, on Canada's west coast, the **LNG Canada Phase 1** project is set to ramp up deliveries in 2025 and 2026 with an overall capacity of 19 bcm/yr. In Mexico, the first phase of the **Energía Costa Azul LNG project** (4.4 bcm/yr) is expected to start producing first LNG by the end of 2024 and ramp up exports in 2025. While located on the west coast of Mexico, the LNG plant will be fed by the Rosarito pipeline with natural gas sourced from West Texas and the Rocky Mountain region. In addition, offshore at **Altamira** in Mexico, an initial **floating LNG (FLNG) production unit** is set to be deployed from October 2023 with a capacity of 1.9 bcm/yr. According to the project developer, additional FLNG units are to be installed during 2024, scaling total liquefaction capacity up to 5.5 bcm/yr over the forecast period.

Qatar took FID on the **North Field East expansion project** in 2021 – the largest FID in the history of LNG with a capacity of 45 bcm/yr. The project consists of four liquefaction trains and is expected to ramp up exports during 2026-27. In **Russia**, first train of **Arctic LNG 2** is expected to start operations by the end of 2023 with a capacity of 8.9 bcm/yr. The start-up of Train 2 is expected to be delayed until 2025, with production ramping up during 2025-2026. The commissioning of Train 3 is assumed to be delayed beyond our forecast horizon. Considering the sanctions imposed on Russia, significant uncertainties remain around the ramp-up schedule and initial utilisation rates of the project. In **Africa**, the ramp-up of Coral South FLNG in Mozambique, together with the start-up of Tortue FLNG and Congo FLNG, are set to add over 12 bcm/yr of liquefaction capacity. The Nigeria LNG Train 7 (9.5 bcm/yr) is expected to begin operations in 2026 and ramp up to full capacity beyond our forecast horizon. In the **Asia Pacific** region, Australia and Indonesia are set to lead the expansion of LNG liquefaction capacity. The **Tangguh LNG Train 3** (5.2 bcm/yr) in Indonesia is set to begin production in H2 2023 and ramp up LNG supplies during 2024. In Australia, **Pluto LNG Train 2** is expected to produce first LNG in 2026 and ramp up operations to full capacity in 2027. **Reduced feedgas supply** to LNG projects linked to ageing fields is expected to reduce LNG output by around 7 bcm/yr by 2026 in the Asia Pacific region.

From a demand-side perspective, the **Asia Pacific region** is expected to absorb the equivalent of total incremental LNG supply during the 2023-2026 period, largely driven by China's renewed appetite. China's LNG imports are set to double by 2026 compared with 2022, partly enabled by the country's portfolio of long-term contracts. **Europe**'s LNG imports are set to average just over 165 bcm/yr between 2023 and 2026, slightly lower than in 2022. A further reduction in Russian piped gas supplies could increase EU LNG import requirements by an additional 20 bcm/yr.

North America and Qatar account for 80% of incremental LNG supply during 2023-2026

Year-on-year change in LNG supply by key export region, 2016-2026



Sources of historical data: IEA analysis based on ICIS (2023), LNG Edge.

Spotlight on Africa

Has Africa reached a turning point for natural gas?

With almost one-fifth of the world's inhabitants, Africa is the continent with the youngest and fastest-growing population and also the lowest level of energy access. Despite holding over 9% of the world's proven reserves and a vast potential for green energy, Africa remains the most energy-poor continent. According to the IEA [Africa Energy Outlook 2022](), nearly 600 million people, or 43% of the total population, have no access to electricity. Its significant natural gas reserves could turn Africa into a key player in the global gas market, while improving energy access for its rapidly growing population.

African countries produced around 6% of the world's natural gas in 2022, a proportion that has doubled since 2000 and roughly tripled since 1990. The main producing countries are Algeria, Egypt and Nigeria, together accounting for over 80% of the continent's production in 2022. In the medium term, up to 2026, we forecast 6% growth in Africa's gas production, a rate that could have been higher without upstream concerns on legacy projects and had projects under development not experienced delays due to security and soaring costs.

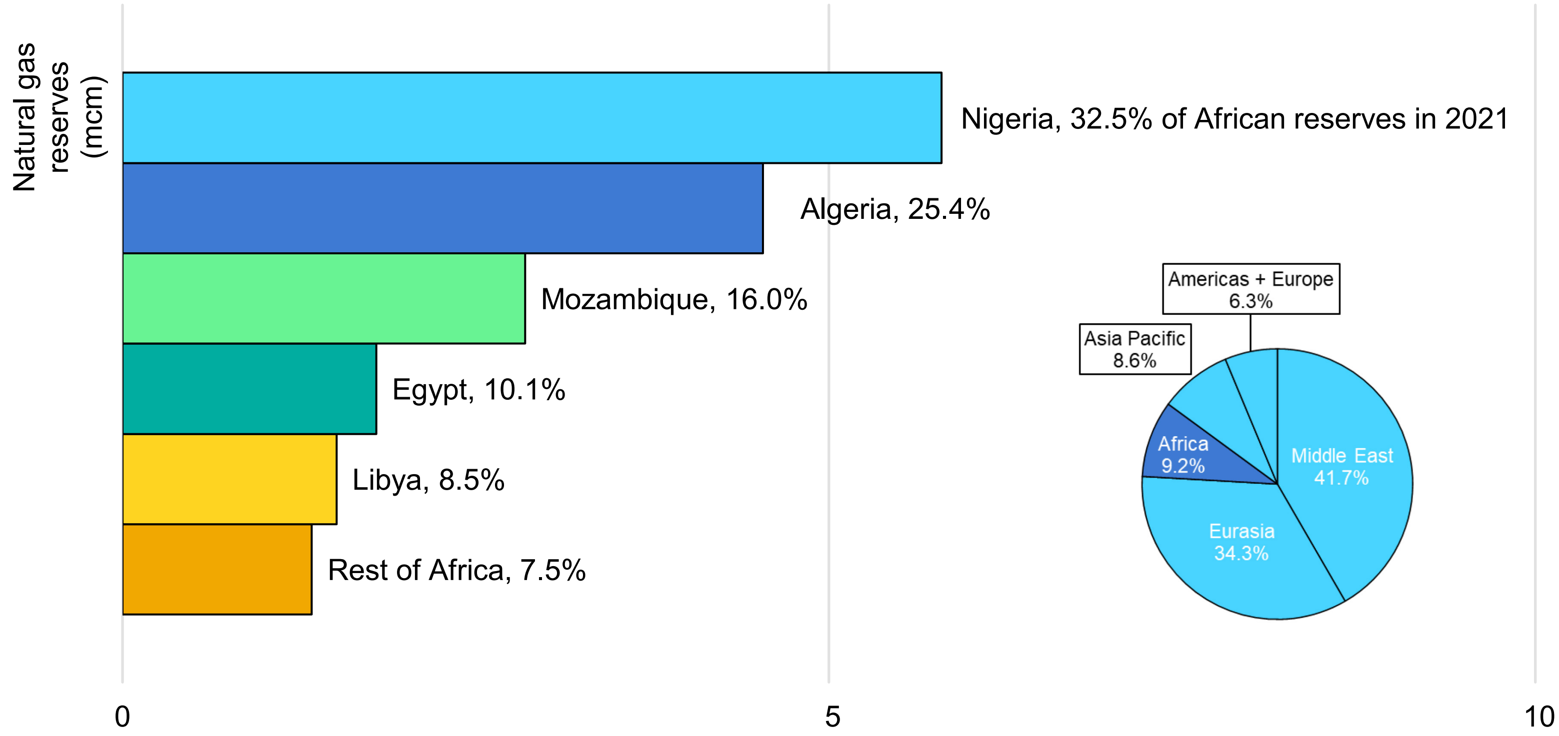
African countries expect to benefit from the development of gas projects to meet their growing energy needs in the medium term. Gas demand in Africa is concentrated in the major producing countries – Egypt, Algeria and Nigeria – mainly to produce power for air conditioning. We forecast Africa's annual gas consumption to increase by an annual average of 3% during 2022-2026.

The use of domestic natural gas production makes sense for African consumer countries, offering the considerable advantage of lower energy costs compared with fuel imports. Large-scale gas projects promise new opportunities for export revenues, although they are not evenly spread, since the distribution of resources shows regional inequalities. Although African leaders are embracing the transition to clean energy, and the region has enormous renewable energy resources, they also claim that they need to be able to develop their fossil fuel resources to meet their development needs and provide access to modern energy for their populations. Governments expect tangible economic gains for society, such as job creation and skills development.

The climate and environmental impacts of natural gas projects and the risk of stranded assets should not be put aside. The lack of existing midstream infrastructure to allow domestic access to gas is an issue and financing these projects will become increasingly complicated. Nevertheless, natural gas can be part of the solution for building resilient and sustainable energy systems that can help Africa reduce its GHG emissions.

Domestic gas remains underdeveloped in Africa, despite significant reserves

Top five African countries by natural gas reserves in 2021



Sources: IEA analysis based on EIA (2023), [US Energy Information Administration](https://www.eia.gov).

Wide regional disparities exist in Africa's gas production forecast

Africa accounted for nearly 40% of new natural gas discoveries globally in the past decade, mainly in Mozambique, Mauritania, Senegal and Tanzania. However, socio-political instability and security issues make Africa a high-risk environment for the gas industry. This results in a gap between the potential and the actual gas production projects under development. The delays experienced by the Mozambique LNG project are a good illustration: originally scheduled to deliver its first LNG cargo in 2024, and with plans to produce up to 60 bcm/yr, the project now sees LNG production starting in 2028 at the earliest.

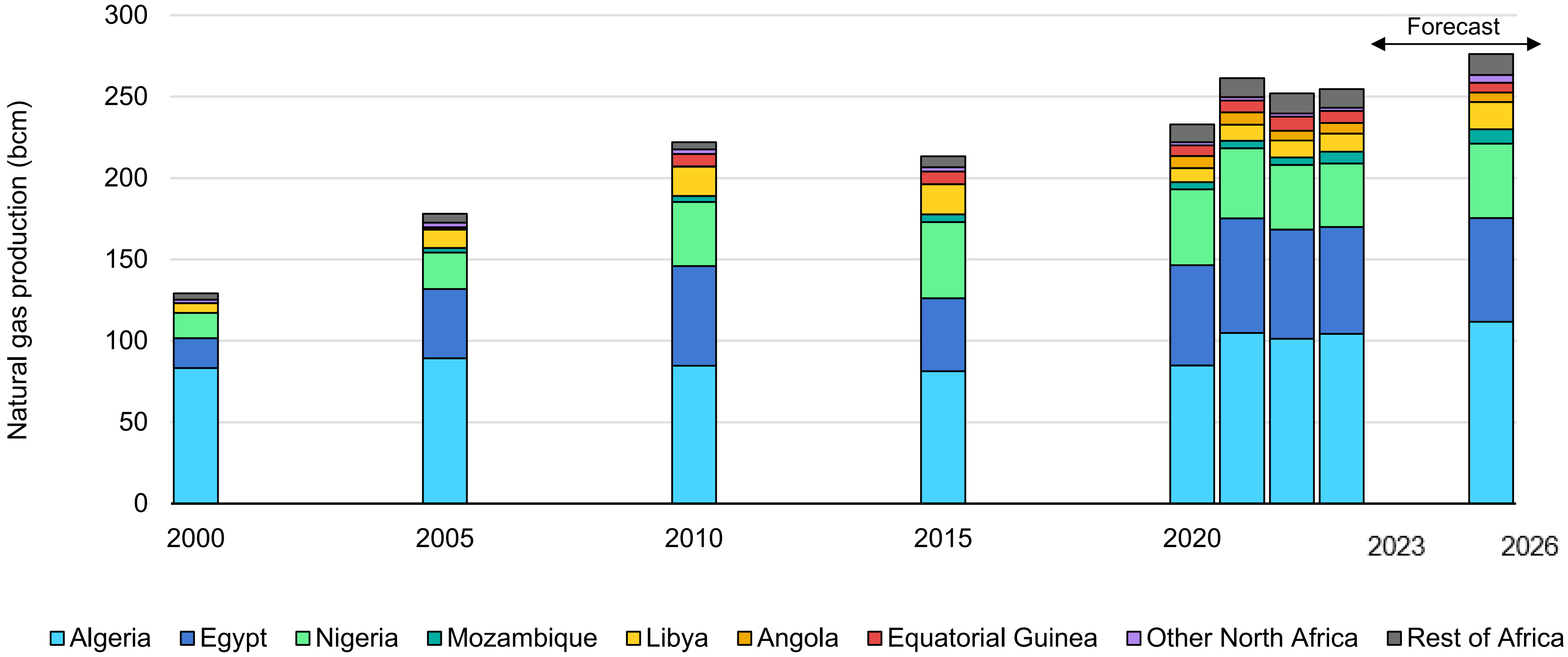
Gas production in Africa has increased by an average of 2.5% per year between 2011 and 2021, above the world average of 2.2%. It reached 246 bcm in 2022, representing just over 6% of global production. Africa has the potential to become a much more important source of global supply. Of the natural gas produced in 2022, 36% was exported, of which 61% was in the form of LNG. The main destinations are Europe (60% of total volumes exported in 2022, by pipeline and in the form of LNG) and Asia (less than 10% of total volumes exported in 2022, representing half of what was exported to Asia in 2021 in absolute terms).

North Africa remains the biggest contributor to gas production on the continent, with Algeria (101 bcm in 2022) and Egypt (67 bcm) among the top three gas-producing countries, along with Nigeria (40 bcm). As a result of the energy crisis triggered in 2022, some European companies showed renewed interest in agreements with North African states already connected to Southern Europe via pipelines. For example, Algeria, which is linked by pipeline to Italy and Spain, has increased its exports to its main customers in Southern Europe over the past year, as Eni added gas assets to its Algerian portfolio. Gas production from **Algeria** is expected to grow by 10% over the forecast period 2022-2026. **Egypt**'s supply is estimated to decline by 7% due to a lack of major discoveries coming online and a natural decline from producing fields. **Nigeria**'s gas production is estimated to gradually increase by 15%, thanks to higher feedgas availability. Overall, we anticipate a slight increase in the continent's gas production to 255 bcm in 2023. This will be primarily driven by sustained production in Algeria and full production realisation from the Eni-operated Coral South Floating LNG (FLNG) project in Mozambique, which was brought online in late 2022.

In our medium-term outlook, we forecast gas production growth of 10% during the 2022 to 2026 period, taking into consideration gradually increasing production in Algeria and Nigeria, and production starting in Senegal, Mauritania, Congo and Gabon.

Natural gas production in Africa is expected to grow by 10% by 2026, driven mainly by new projects in Nigeria, Senegal, Mauritania and Congo

Natural gas production by country, Africa, 2000-2026



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

African gas consumption has almost tripled since 2000, and the main consumers are also the major producing or transit countries of North Africa plus Nigeria. In absolute terms, natural gas demand in Africa reached 172 bcm in 2022, comparable to the annual consumption of Central and South America and representing only 4% of global natural gas demand, or a tenth of the annual consumption of North America. Overall, we forecast annual gas consumption to increase by an annual average of 3% in Africa as a whole, over the period 2022-2026.

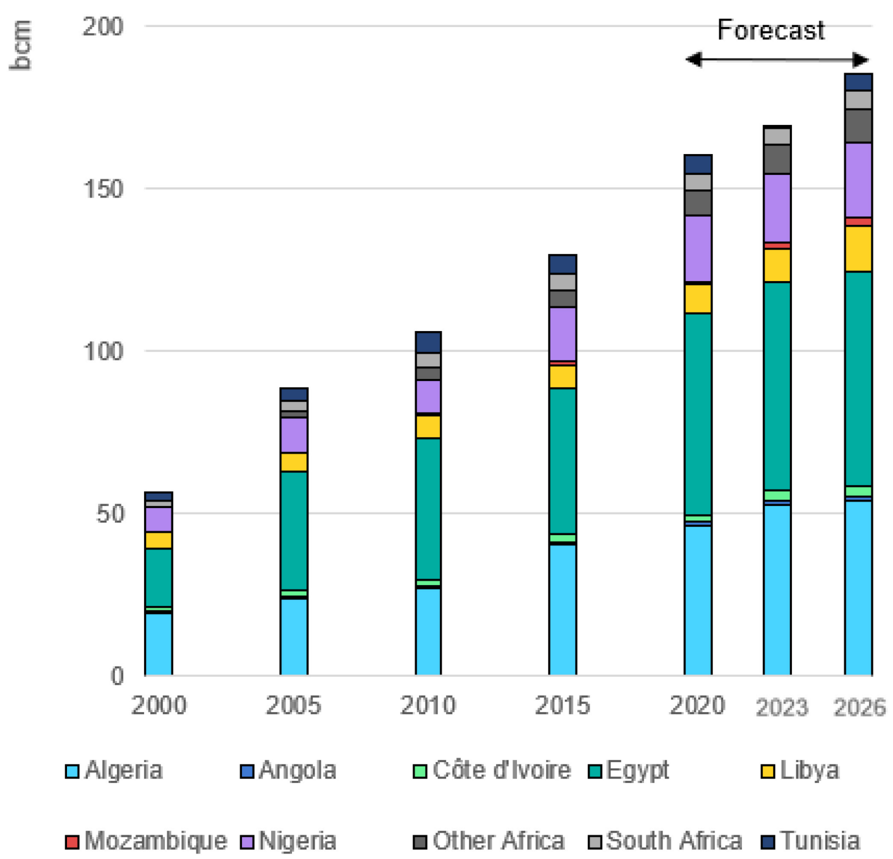
New natural gas markets are emerging, mainly for power generation, as in Ghana, South Africa and Senegal, to meet growing electricity needs and replace liquid fuels. These new markets are supported by the development of production as well as the commissioning of new import infrastructure. The current environment of high prices and tight supply is particularly challenging for these price-sensitive emerging African markets and is likely to have a negative impact on the growth outlook for natural gas consumption.

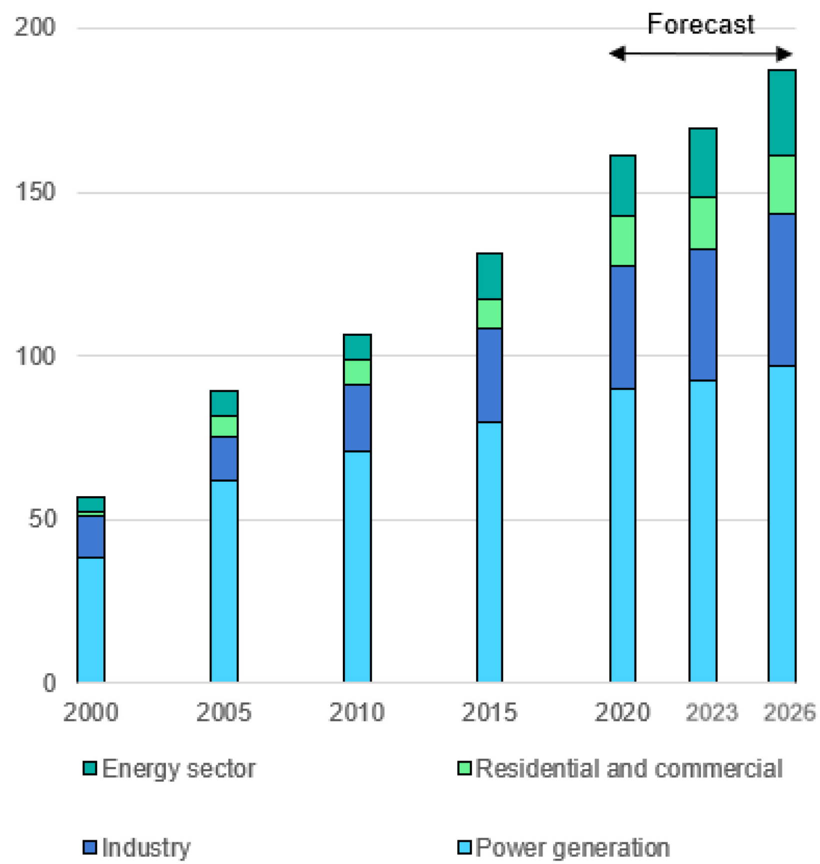
North Africa currently accounts for about three-quarters of the continent's natural gas consumption, which remains concentrated in **Egypt** and **Algeria,** Together, they account for nearly 70% of total natural gas consumption on the African continent, at 117 bcm in 2022. These two markets have developed strong export industries while simultaneously succeeding in boosting domestic gas penetration, mainly in the form of gas-fired power generation to meet the rising cooling demand. Gas-to-power accounts for close to 40% of total natural gas consumption in Algeria and 55% in Egypt. Industry is the second sector, accounting for 23% of total natural gas consumption in Algeria (driven by petrochemicals production) and 18% in Egypt (driven by fertiliser and urea production). Our forecast expects modest growth in gas demand in Algeria, at an average of 1.9% per year until 2026, due to gas supply constraints and a downgraded economic environment, and growth revised downwards to an average of 3.6% per year in Egypt. This increase in domestic gas demand threatens Egypt's LNG export ambitions and highlights the need to import gas by pipeline from Israel.

Although natural gas has great potential in the region, the share of natural gas in the energy mix in **sub-Saharan Africa** remains limited. **Nigeria** is the largest natural gas market in sub-Saharan Africa, with an estimated 21 bcm consumed in 2022. The power generation sector in Nigeria 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. Our forecast anticipates average annual gas consumption growth of 2.8% during the 2023 to 2026 period, taking into consideration uncertainties regarding access to investment.

Sub-Saharan Africa accounts for more than half of the continent's gas consumption growth to 2026, driven by the power sector and industry

Natural gas consumption by country and by use, Africa, 2000-2026





LNG focus: Key projects

In 2022 around a quarter of the natural gas produced in Africa, or 62 bcm, was shipped to international markets in the form of LNG, largely driven by **Nigeria** (accounting for 41% of LNG production in Africa), followed by **Algeria** (23%) and **Egypt** (16%). LNG production from Africa accounted for 11% of the worldwide LNG supply.

Africa’s LNG export capacity is currently just over 100 bcm/yr. During the past decade and until recently, over a dozen new LNG export projects were planned and proposed in Africa. In the late 2010s FIDs were taken for Coral South FLNG in Mozambique and the Greater Tortue Ahmeyim (GTA) LNG project on the maritime border of Mauritania and Senegal, followed by larger projects such as Mozambique LNG and Nigeria Train 7. Additional projects have been proposed, including GTA Phase 2, Rovuma LNG in Mozambique, Cameroon Phase 2 and Nigeria Floating LNG (FLNG), without reaching FID to date. In total, new projects in sub-Saharan Africa could add some 90 bcm of annual LNG capacity by 2030. Within the forecast horizon, only 17 bcm of additional LNG production capacity is expected to be commissioned by 2026, corresponding to projects already under construction or not suspended for security reasons.

The recent surge in offshore FLNG production suggests that more African gas could reach the global market over the next decade. Four FLNG units for the region are currently under construction or reactivation. The first of these is the Golar Gimi FLNG unit allocated to BP's GTA project, scheduled to come on stream in 2024 at the earliest.

However, Africa’s track record for LNG exporting projects is not encouraging. The Mozambique LNG project has been halted since 2021 following the declaration of force majeure due to security risks. The GTA LNG project is encountering problems with cost overruns, environmental concerns and cost inflation. These problems are weighing on the prospects for investment decisions for other African LNG projects.

Since the beginning of the energy crisis in 2022, some international oil companies and EU member states have focused on LNG projects to secure supplies in a tight global gas market. Existing LNG contracts have been renegotiated to export more LNG to Europe. Italy should certainly benefit from Eni's efforts in this respect. Over the past year, the company signed agreements with Egypt, Algeria and Angola, while launching LNG exports from the Coral field in offshore Mozambique and concluding an agreement with the Republic of Congo on its FLNG project for the Marine XII fields. Similarly, British giant BP announced earlier this year that it planned to take FID on Phase 1 of the Yakaar-Teranga LNG project, off the coast of Senegal, before the end of this year. Meanwhile, Shell and Norway's Equinor revealed in mid-May that they had completed negotiations on the Tanzania LNG project and expected to sign a host government agreement and a production sharing agreement soon.

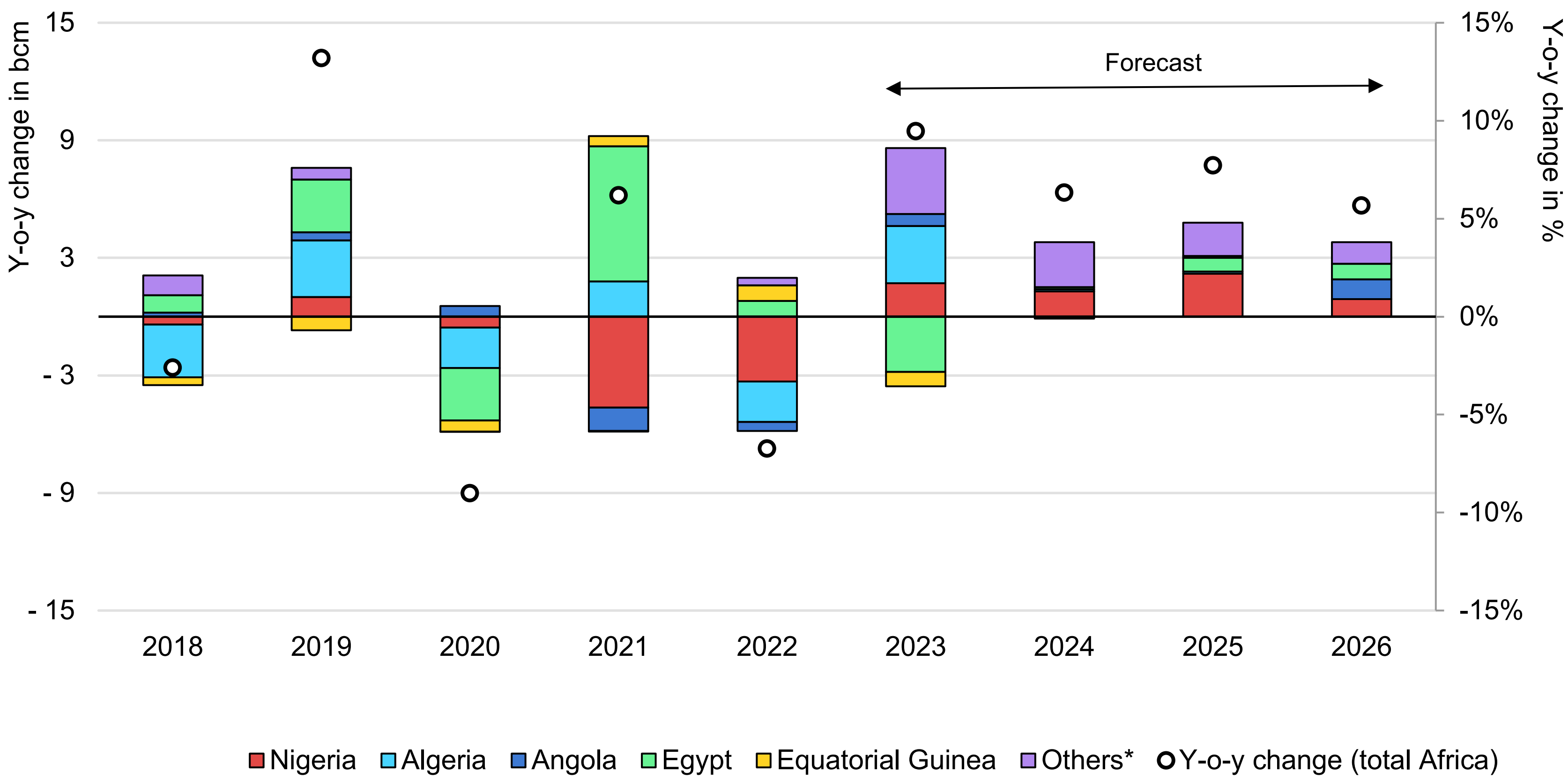
Yet, considering the long lead times of LNG projects, these commitments are not going to change the game for African LNG in the immediate future. For the time being, the continent's LNG activities will continue to be dominated by established players: Egypt, Algeria and Nigeria (and, to a lesser extent, Equatorial Guinea and Angola). Algeria and Egypt are likely to maintain their current annual LNG capacity of around 40 bcm and 17 bcm respectively.

In our medium-term forecast, Africa's share of global LNG supply is expected to remain broadly flat during 2022-2026. Security issues and poor governance are weighing on project development despite the vast reserve base and relatively low cost of supply.

The window of opportunity to monetise the region's significant gas resources could be limited, with US and Qatari projects expected to start delivering significant volumes by 2027, and the potential for LNG demand to fall from 2030 onwards, driven by decarbonisation targets.

LNG production in Africa is expected to grow by 25 to 30% by 2026, mainly driven by Nigeria and new exporting countries

Y-o-y change in Africa's natural gas LNG exports by key countries, 2018-2026



* Cameroon, Congo, Mozambique, Mauritania and Senegal.
Source: IEA analysis based on ICIS (2023), ICIS LNG Edge.

A concerted effort to limit flaring and methane emissions in Africa could make 35 bcm of natural gas available

Substantial quantities of gas currently produced in Africa do not make it to market because they are flared or emitted directly into the atmosphere. In 2022 close to 30 bcm of natural gas was flared and nearly 15 bcm was lost, together representing almost 20% of actual gas production. Reducing flaring, venting and methane leaks can bring a double dividend: a boost in natural gas sales and reduced greenhouse gas emissions. Reducing methane emissions, the main component of natural gas, is one of the best opportunities available for limiting the near-term effects of climate change. Reducing flaring would also lower local air pollution.

A concerted effort to limit flaring and methane emissions in Africa could make around 35 bcm of natural gas available to markets. The IEA estimates that it is technically possible to avoid around 80% of methane emissions from oil and gas operations in Africa and nearly 95% of flared volumes. Around half of the 35 bcm could be avoided at no net cost because the outlays for the abatement measures are less than the market value of the additional gas that can be captured and sold.

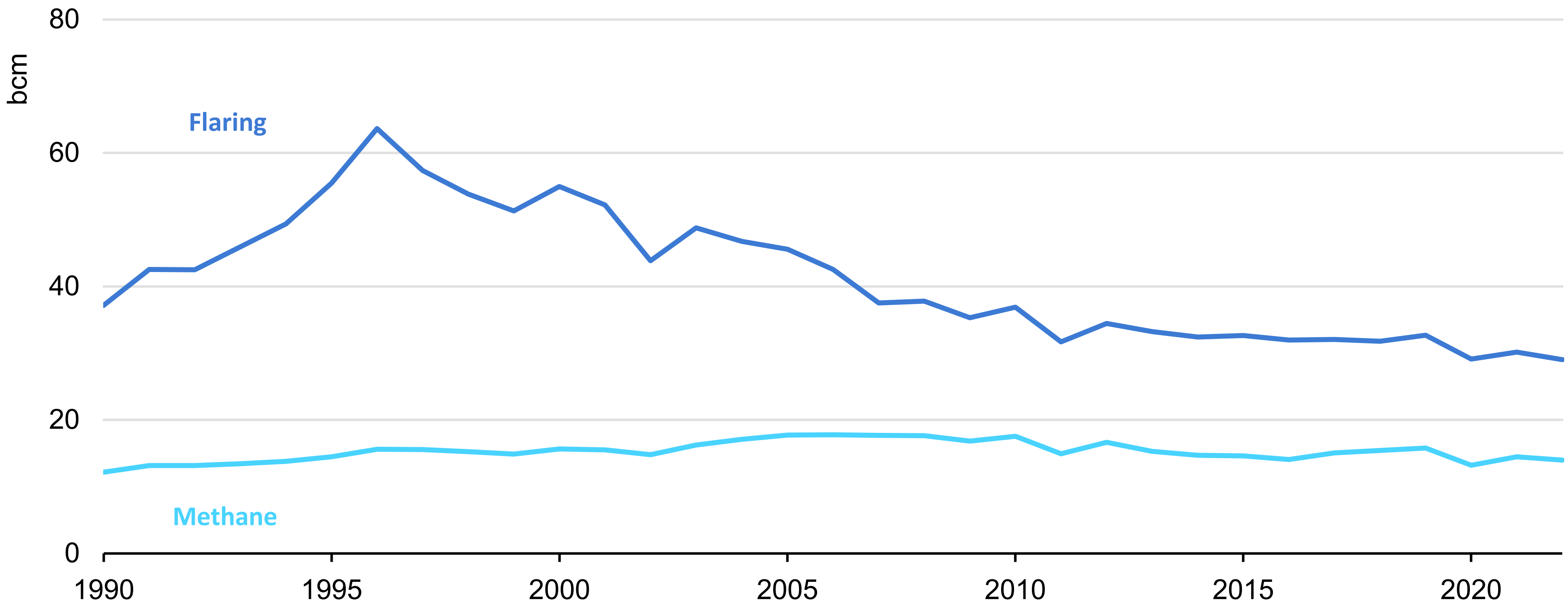
The ways to limit flaring and methane emissions from oil and gas operations are well known. Methane abatement measures include installing emission control devices, conducting regular leak detection and repair campaigns, and replacing components and devices that emit methane during normal operations. Gas that would be flared can be captured and injected into pipelines, turned into other useable products, or converted into electrical power that can be used on site or sold back to the electricity grid. Portable CNG or mini-LNG facilities are available to treat gas on site and enable its use in nearby facilities.

In parallel with industry action, new policies and regulations will be needed to ensure that companies have the incentive to act. Many African countries participate in the Global Methane Pledge, thereby committing to collectively reduce global methane emissions by at least 30% below 2020 levels by 2030 and to move towards the highest-tier IPCC inventory methodologies. Several countries, including Nigeria and Egypt, also endorse the World Bank's Zero Routine Flaring by 2030 Initiative, and are taking action to curtail methane emissions and flaring. In 2022 Nigeria issued guidelines for emissions management in the upstream oil and gas sector to support the elimination of routine gas flaring by 2030, and a 60% reduction in fugitive methane emissions by 2031.

International support is available to support such efforts. For example, the EU external energy engagement strategy includes assistance for partners to deploy methane abatement technologies through "You collect, we buy" schemes.

Africa has reduced flared volumes by more than 50% from their peak in the mid 1990s, but made little progress on tackling methane emissions

Methane emissions and natural gas flaring in Africa, 1990-2022



Source: IEA analysis based on flaring data from the World Bank's Global Gas Flaring Reduction Partnership (2023), Global Gas Flaring Data.

Medium-term outlook for low-emission gases

The supply of low-emission gases is set to double by 2026, but further efforts are required to unleash their full potential

Low-emission gases (including biomethane, low-emission hydrogen[4] and e-methane[5]) can play a crucial role in decarbonising gas supply chains and the broader energy system. Recognising their growing importance, the International Energy Agency has developed a **Low-emission Gases Work Programme** to track closely market developments in this sphere and facilitate dialogue between emerging producers and consumers. This section provides a medium-term outlook for low-emission gases, with a particular focus on emerging producers.

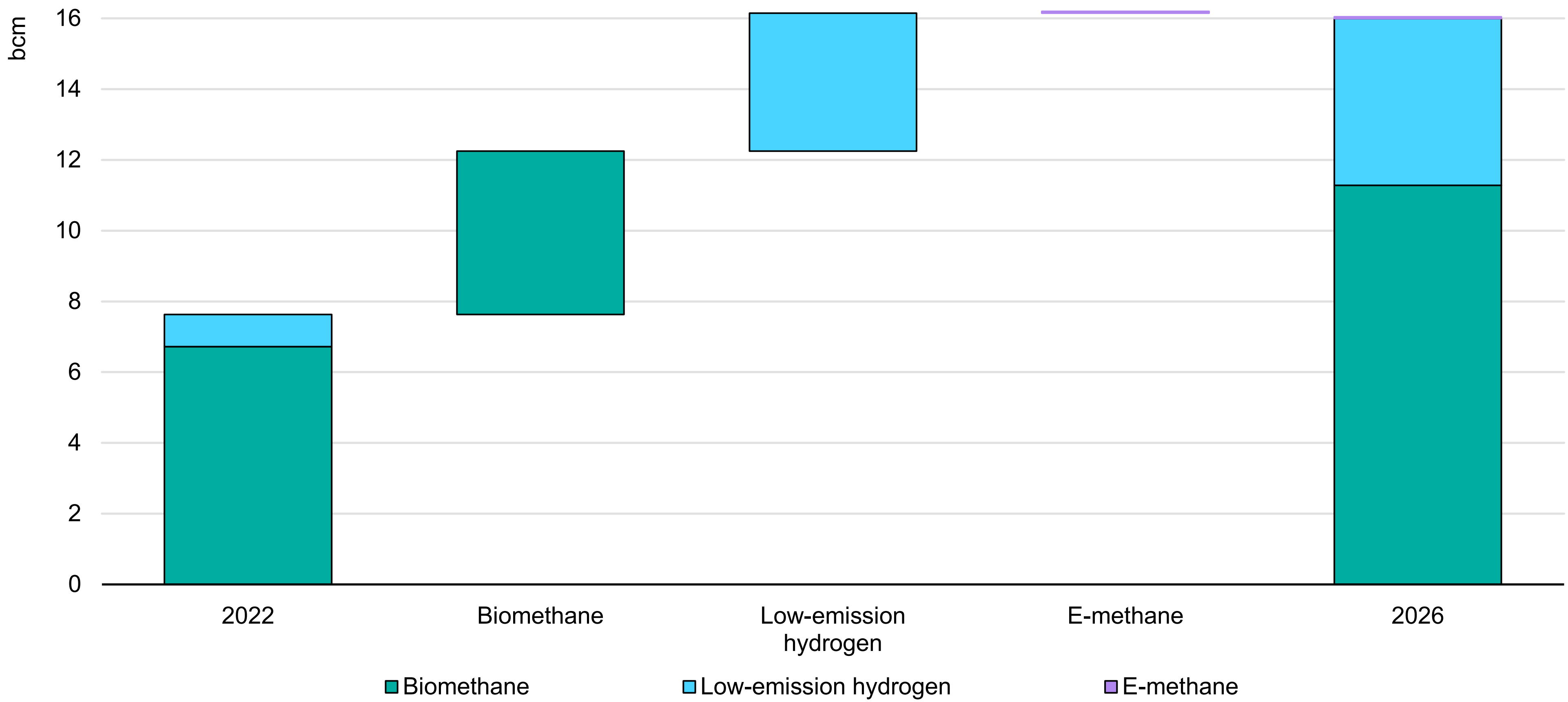
The deployment of low-emission gases is expected to accelerate over the medium term. The current forecast projects a doubling of the supply of low-emission gases by 2026, translating into an increase of over 8 bcm in absolute terms. Europe and North America are set to drive this expansion and to contribute over 70% of the overall growth. The development of low-emission gases in these markets benefits from a wide range of policies, increasingly sophisticated subsidy schemes and well-developed, interconnected gas networks. **Nevertheless, further efforts will be required** to reach the ambitious targets set both for biomethane and low-emission hydrogen. Besides Europe and North America, a number of emerging low-emission gas producers are expected to scale up their output, including Brazil, China, India and Oman.

Biomethane production is expected to expand by over 65% (or 4.5 bcm) between 2022 and 2026, and to account for almost 55% of the total increase in low-emission gases during this period. Europe and North America are set to remain the key drivers of this growth, scaling up their biomethane output by close 60% (or 3.6 bcm) over the period. Brazil is expected to emerge as one of the fastest-growing biomethane producers over the medium term, as the country is forecast to quadruple its renewable natural gas output by 2026. **Low-emission hydrogen** is projected to grow at an average rate of almost 25% per year between 2022 and 2026, translating into an incremental 3.9 bcm_{eq} of supply by 2026. Similarly to biomethane, Europe and North America are set to drive this growth, accounting for close to 60% of the total increase. In contrast, **e-methane** struggles to take off over the forecast period, requiring a concentrated effort between emerging producers and consumers to establish viable supply chains and effective support mechanisms.

[4] Low-emission hydrogen includes hydrogen produced via electrolysis where the electricity is generated from a low-emission source (renewables or nuclear), biomass or fossil fuels with CCUS.
[5] E-methane refers to synthetic methane produced from electrolytic hydrogen. The definition of low-emission synthetic methane used by the IEA for analytical purposes in its reports considers that any carbon inputs, e.g. from CO_2, are not from fossil fuels or process emissions. Beyond this definition, a commercial proposition for carbon-neutral e-methane could consider the use of CO_2 captured at industrial or power plants and offset through carbon credits (similar to the commercial offers of carbon-neutral LNG).

Biomethane is expected to dominate low-emission gas supply over the medium term

Estimated low-emission gas supply in 2022 and expected increase in production to 2026



In the fast lane: Biomethane is set for strong growth over the medium term…

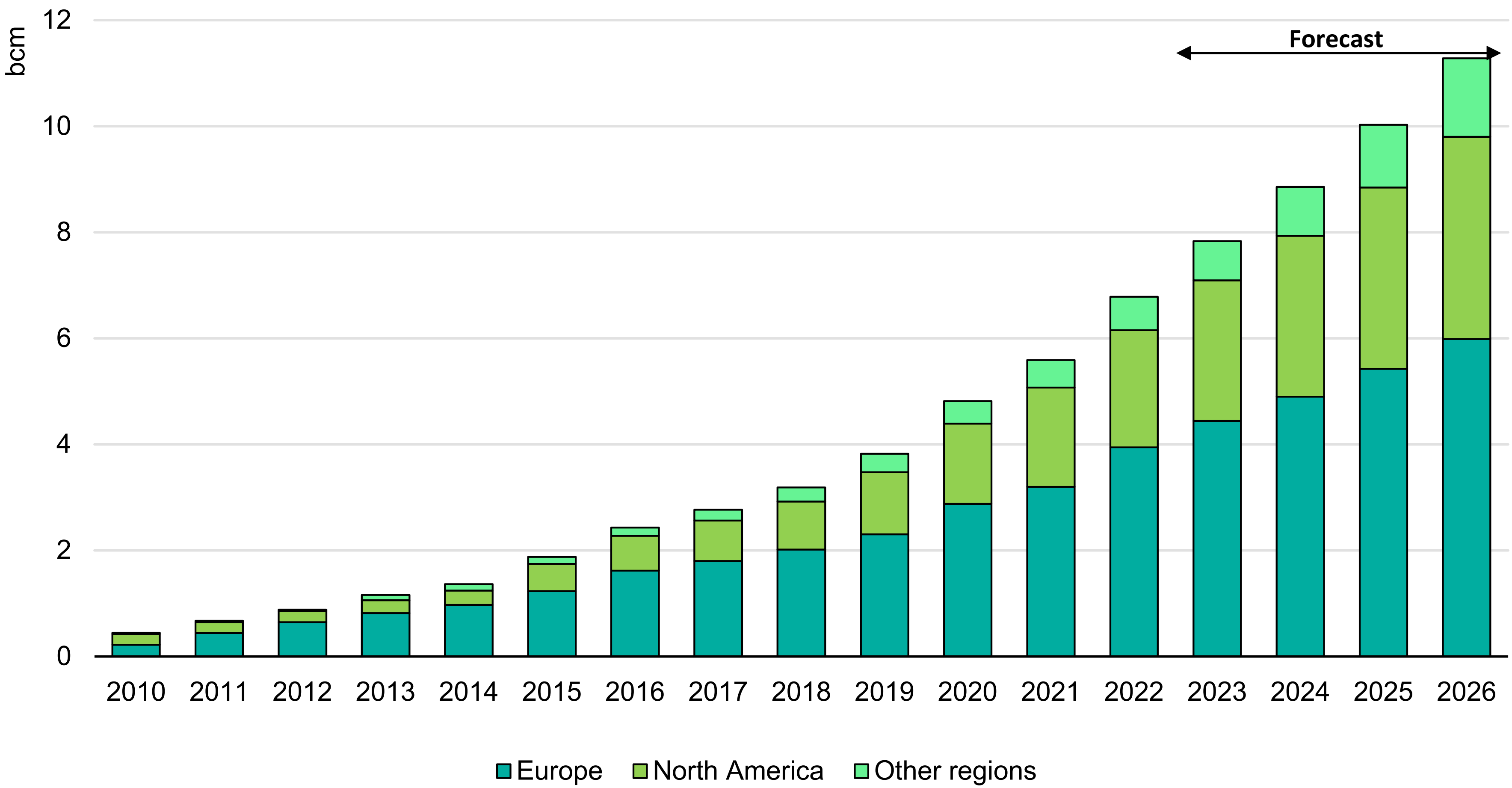
Global biomethane (or renewable natural gas) production more than doubled between 2018 and 2022, largely driven by Europe and North America. Latest estimates indicate that global biomethane output grew by 17% (or 1 bcm) in 2022 to reach close to 7 bcm. Europe and North America accounted for around 90% of this growth. **Biomethane production is expected to expand by over 65%** (or 4.5 bcm) between 2022 and 2026, primarily supported by projects undertaken in Europe, North America and Brazil.

The **United States** retained its position as the world's largest biomethane producer. Latest data indicate that biomethane output grew by around 20% (or 0.35 bcm) to reach almost 2 bcm in 2022. This strong growth is largely supported by the **transport sector**, where the use of biomethane more than doubled during 2018-2022. In 2022 renewable natural gas met almost 70% of all on-road fuel used in natural gas vehicles. In turn, the transport sector accounts for nearly 90% of total biomethane use in the United States. **Feedstock supply** remains largely dominated by municipal solid waste, accounting for 72% of the feedstock mix, followed by agricultural and food waste (23%) and wastewater (5%). Renewable natural gas in North America is set to benefit from the Inflation Reduction Act and expand by 70% to reach almost 4 bcm by 2026.

In **Europe**, biomethane output grew by an estimated 15% (or 0.5 bcm) to reach almost 4 bcm in 2022. Latest surveys indicate that around **80% of biomethane plants have grid injection capability**, with close to 60% of them connected to a gas distribution grid. In terms of **feedstock supply**, the landscape is increasingly dominated by agricultural residues, accounting for over 35% of the feedstock mix, followed by energy crops (30%) and organic waste (24%). Biomethane production in **Germany** – Europe's largest biomethane producer – remained broadly flat at just over 1 bcm in 2022, while Denmark and France together contributed over 70% of the incremental biomethane supply amid effective policy support. Growth has been particularly strong in **France**, where biomethane output increased by more than 60% compared with 2021 to reach 0.7 bcm. In the first half of 2023, France's biomethane output rose by over 30%, putting it on track to become Europe's second-largest producer this year. In **Denmark**, biomethane output rose by an estimated 15% in 2022 to almost 0.7 bcm. Initial data indicate that biomethane production rose by 20% y-o-y in Q1-Q3 2023. As such, biomethane met over 40% of Denmark's natural gas demand during this period. Europe's biomethane production is **projected** to increase at an average rate of over 10% per year over the forecast period and reach 6 bcm by 2026, albeit insufficient to put the European Union on track to reach its target of 35 bcm/yr biomethane output by 2030. **Outside Europe and North America**, biomethane production growth is expected to be supported by project developments in Brazil, China and India.

…primarily supported by project developments in Europe and North America

Biomethane production by region, 2010-2026



Sources: IEA analysis based on Argonne National Laboratory (2022), Renewable Natural Gas Database; Biogas Partner (2023), Biogaspartner Einspeiseatlas Deutschland; Cedigaz (2023), Global Biomethane Database; Energinet (2023), Energi Data Service; ODRE (2023), Production Quotidienne Consolidée de Biométhane sur le réseau de transport et de distribution par Opérateur.

Awakening green giant: Biomethane developments in Brazil

Brazil is expected to emerge as a key biomethane producer over the forecast period. The country's renewable natural gas output is projected to quadruple between 2022 and 2026, accounting for over 10% of incremental global biomethane supply.

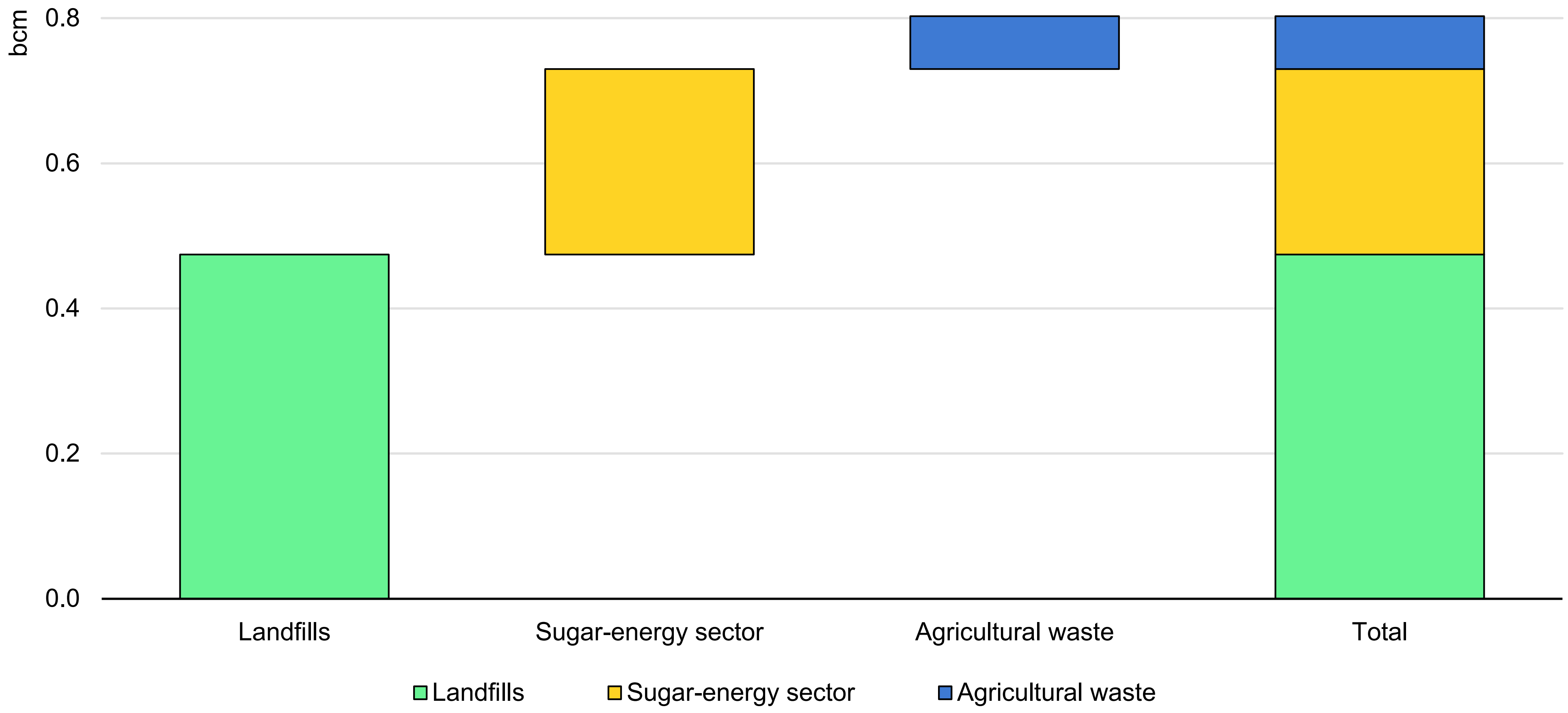
Considering Brazil's **vast agricultural sector**, the country has significant biogas and biomethane production potential. Brazil's Biogas Association (ABiogás) estimates the country's **biogas** potential at over 43 bcm/yr. Assuming that biogas contains 60% methane on average, the country's biomethane potential is estimated at around 25 bcm/yr. Brazil's biogas output has grown strongly in recent years and more than doubled between 2017 and 2021. In 2021 Brazil had 755 biogas plants in operation with an overall output of 2.3 bcm. Over 70% of the biogas produced was used for power generation and around 20% was upgraded into biomethane. According to latest data, Brazil's biogas output grew by more than 20% in 2022 to reach 2.8 bcm.

In contrast with biogas, biomethane is still in its infancy in Brazil. In March 2022 Brazil launched the Federal Strategy to Incentivise the Sustainable Use of Biogas and Biomethane. Besides providing a definition of biogas and biomethane, the decree includes guidelines on the development of biomethane supply chains, the promotion of biomethane consumption and measures to reduce methane emissions. Biomethane was also included in the Special Incentive Scheme for Infrastructure Development, under which new projects benefit from tax exemptions for the acquisition of machinery, construction materials and equipment.

According to the latest industry data, there are currently ten **biomethane plants** in Brazil with a total production capacity of 0.16 bcm/yr. As of July 2023, only six of them have been authorised to produce and inject biomethane into the country's gas network. Eleven biomethane plants (with a total capacity of 0.12 bcm/yr) are in the process of seeking regulatory approval from the National Agency of Petroleum, Natural Gas and Biofuels (ANP). According to a survey carried out by ABiogás and the Brazilian Association of Pipeline Gas Distributors (Abegás), there are currently 27 biomethane projects in Brazil at various stages of development. **Renewable natural gas output is expected to more than quadruple from current levels**, rising to 0.8 bcm/yr by 2027 and making Brazil the fifth-largest biomethane producer in the world. Landfills are foreseen to account for nearly 60% of the feedstock supply mix, followed by the sugar-energy sector (32%) and agricultural waste (8%). To foster production, several **certification schemes** are being developed in Brazil. In 2022 the country's first Gas-RECs – renewable energy certificates for biogas – were issued by an agricultural conglomerate producing biogas. ABiogás is currently developing its own biomethane certification programme.

Brazil's biomethane output is expected to more than quadruple by 2027

Biomethane production prospects by feedstock supply, Brazil, 2023-2027



Source: IEA analysis based on EPBR (2022), Brasil tem 27 novas plantas de biometano previstas para os próximos anos.

Biomethane developments in India: Driven by the transport sector

Biomethane production in India rose by over 20% y-o-y during the 2022/23 financial year to reach close to 20 mcm. Supported by government policies, biomethane output **is expected to increase more than tenfold** over the forecast period, with demand concentrated in the transport and industrial sectors.

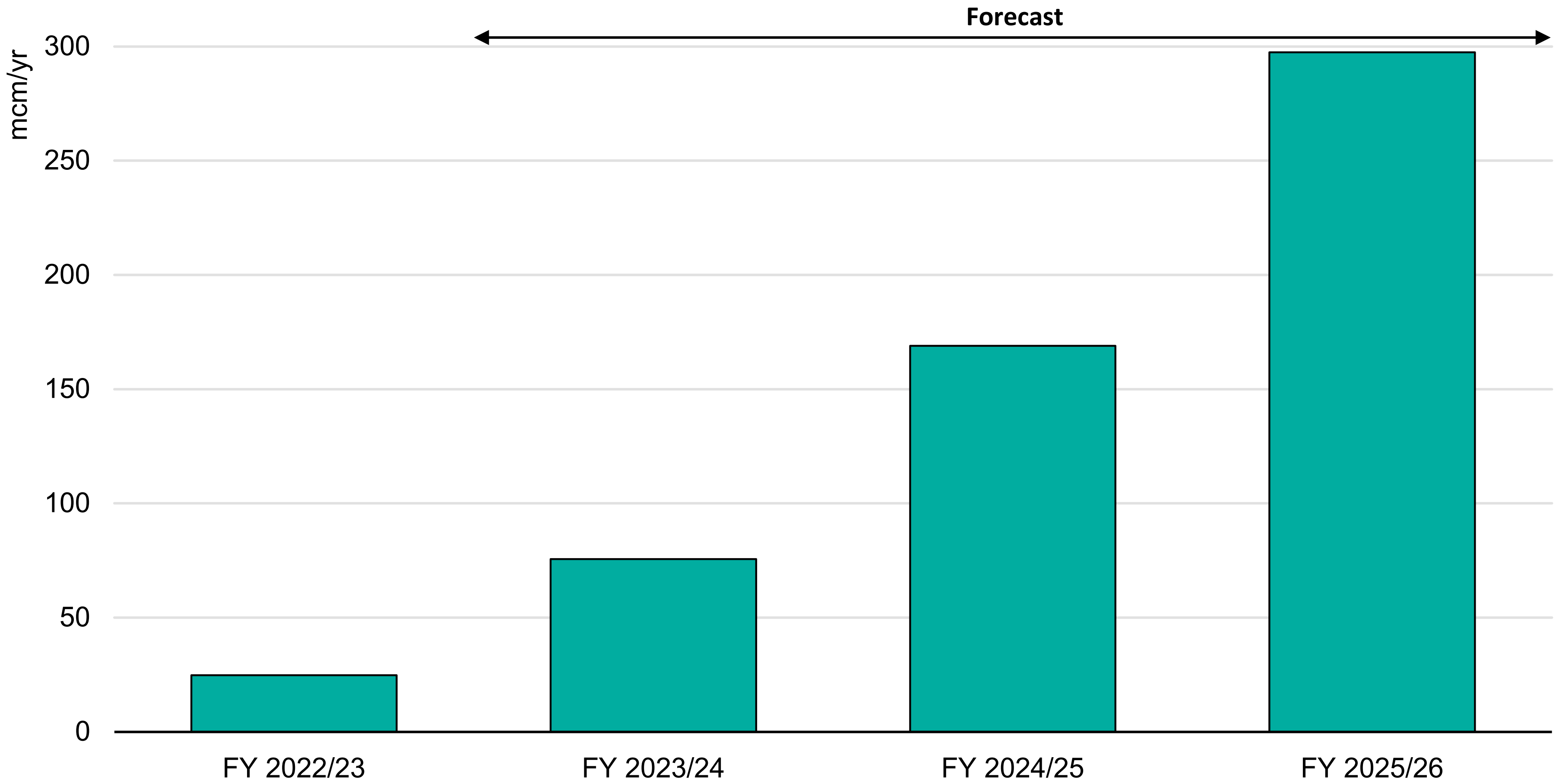
India's biomethane sector has **strong potential** due to a combination of local resource availability and supportive government policies. Historically, captive **feedstock supply** (such as pressmud and bagasse in the sugar industry, distillery by-products, and sewage treatment plants) have been the preferred option for biomethane production. However, technological advancements and improvements in feedstock supply chain management are expected to enable larger biomethane projects that rely on agricultural waste, municipal solid waste (MSW) and napier grass.

The government of India and the Ministry of Petroleum and Natural Gas introduced a number of **policies to accelerate the deployment of biomethane and compressed biogas** (**CBG**). This includes the SATAT (Sustainable Alternative Towards Affordable Transportation) scheme launched in October 2018, which envisaged production of 15 Mt of CBG from 5 000 plants by financial year 2024. Under the scheme, oil and gas marketing companies have been inviting expressions of interest from potential investors and entrepreneurs to procure CBG. In addition, the government has recently introduced the GOBAR-DHAN scheme to promote the conversion of biowaste to biogas/biomethane in rural areas. As of August 2023, a total of 56 plants with a rated **capacity of 160 mcm/yr have been commissioned**. Agricultural waste accounts for 34% of the feedstock supply mix, followed by pressmud (27%), MSW (17%) and animal wastes (16%).

Currently over 110 CBG/biomethane plants are **under construction** and more than 200 plants are in the early phases of development. Based on plants currently under construction, India's biomethane output could increase more than tenfold and **reach close to 300 mcm/yr** by 2026. Agricultural waste, MSW and napier grass feedstocks are expected to support this strong expansion. In the longer term, India aims to increase the share of CBG/biomethane in its priority segments of the city gas distribution sector (CNG for transport and piped natural gas for domestic use) to 10%. This would require annual CBG/biomethane output to increase to over 1.5 bcm. Despite India's strong potential, several **key challenges** remain ahead of the development of biomethane/CBG. This includes the lack of stable, long-term prices for feedstock supply, and the limited scope of support schemes. In this context, project financing remains difficult due to the relatively thin profit margins and the risks related to marketing biomethane.

Biomethane production in India is expected to expand more than tenfold by 2026

Biomethane production, India, FY 2022/23-FY 2025/26



* The Financial Year in India starts on 1 April and ends on 31 March.
Source: IEA analysis based on data provided by the Indian Gas Exchange.

Low-emission hydrogen production is expected to more than triple over the medium term

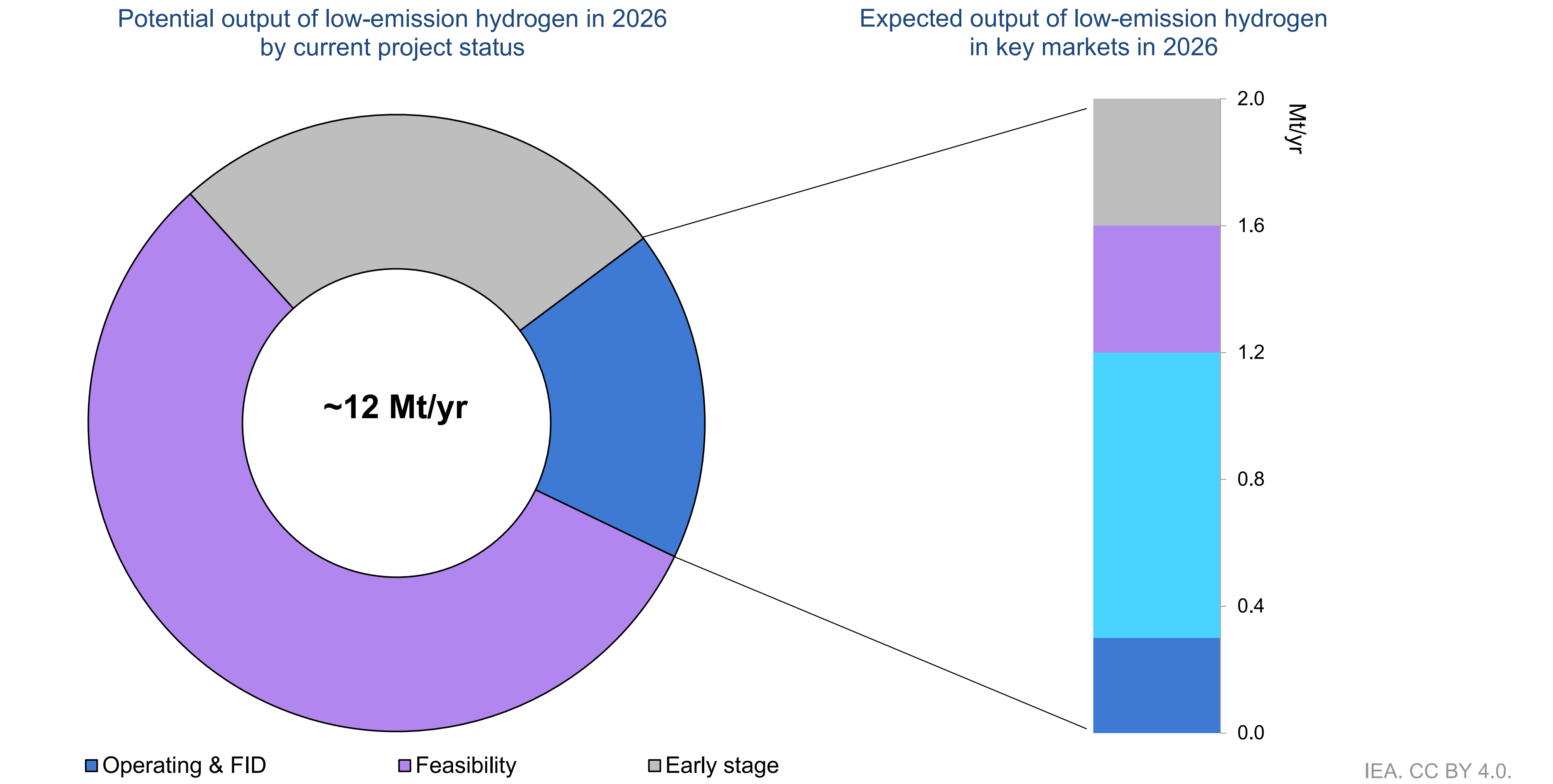
Low-emission hydrogen production is set to triple over the medium term, primarily supported by project developments in China, Europe and North America. Despite this rapid growth, the current pace of project development may be insufficient to reach the ambitious targets set in certain regions.

Low-emission hydrogen production remained broadly flat in 2022, with output estimated at 0.7 Mt and equating to just 0.7% of total hydrogen output. The majority of low-emission hydrogen was produced from **fossil fuels with CCUS**. Around 15 large-scale hydrogen facilities around the world are equipped with CCUS, capturing around 11 Mt CO_2 per year. Natural gas with CCUS accounted for just over half of global low-emission hydrogen output. Low-emission hydrogen production via **water electrolysis** grew by around 35% in 2022, although it continued to be small, with output estimated at less than 100 000 t H_2. From a regional perspective, low-emission hydrogen production remains dominated by **North America**, accounting for around two-thirds of global output.

According to the IEA Hydrogen Projects Database, projects at various stages of development could increase global low-emission hydrogen production up to 12 Mt (or 36 bcm_{eq}) by 2026. Projects relying on water electrolysis would account for around 75% of this potential growth. However, the majority of these projects are either undertaking feasibility studies or at the concept phase, and fewer than 20% of them are in mature phases of development (either operational, under construction or having reached FID).

Considering projects in mature phases of development, low-emission hydrogen output more than triples and reaches 2 Mt/yr (or 6 bcm_{eq}) by 2026. From a regional perspective, production growth will be largely supported by North America, with a share of incremental supply of more than 40% over the forecast period, followed by China (20%) and Europe (17%). **Water electrolysis** is expected to contribute 50% of incremental low-emission hydrogen supply by 2026. Electrolyser capacity is projected to reach around 14 GW by 2026, with China alone accounting for 40% of total installed capacity, followed by Europe (25%), the Middle East (20%) and North America (less than 10%). Under the current state of project development, electrolytic hydrogen production in the European Union would reach 0.25 Mt by 2026, leaving a significant gap to reach the 10 Mt/yr target by 2030. Low-emission hydrogen produced from **fossil fuels with CCUS** is expected to grow at a slower pace, although is projected to account for 50% of incremental supply in the forecast period. Hence, the share of low-emission hydrogen produced from fossil fuels with CCUS is set to decline from today's 90% to just 50% by 2026. CCUS-based hydrogen projects are expected to be almost entirely concentrated in North America, benefiting from the region's abundant and relatively cheap natural gas supply.

The majority of low-emission hydrogen projects remain in the early stages of development



* "Operating & FID" includes projects that are operating and that have reached at least FID, therefore projects under construction are also included; "Feasibility" includes projects undergoing a feasibility study; "Early stage" includes projects at very early stages, such as those in which only a co-operation agreement among stakeholders has been announced

Source: IEA Hydrogen Projects Database (2023).

Oman: Transitioning from an oil and gas producer to a hydrogen exporter

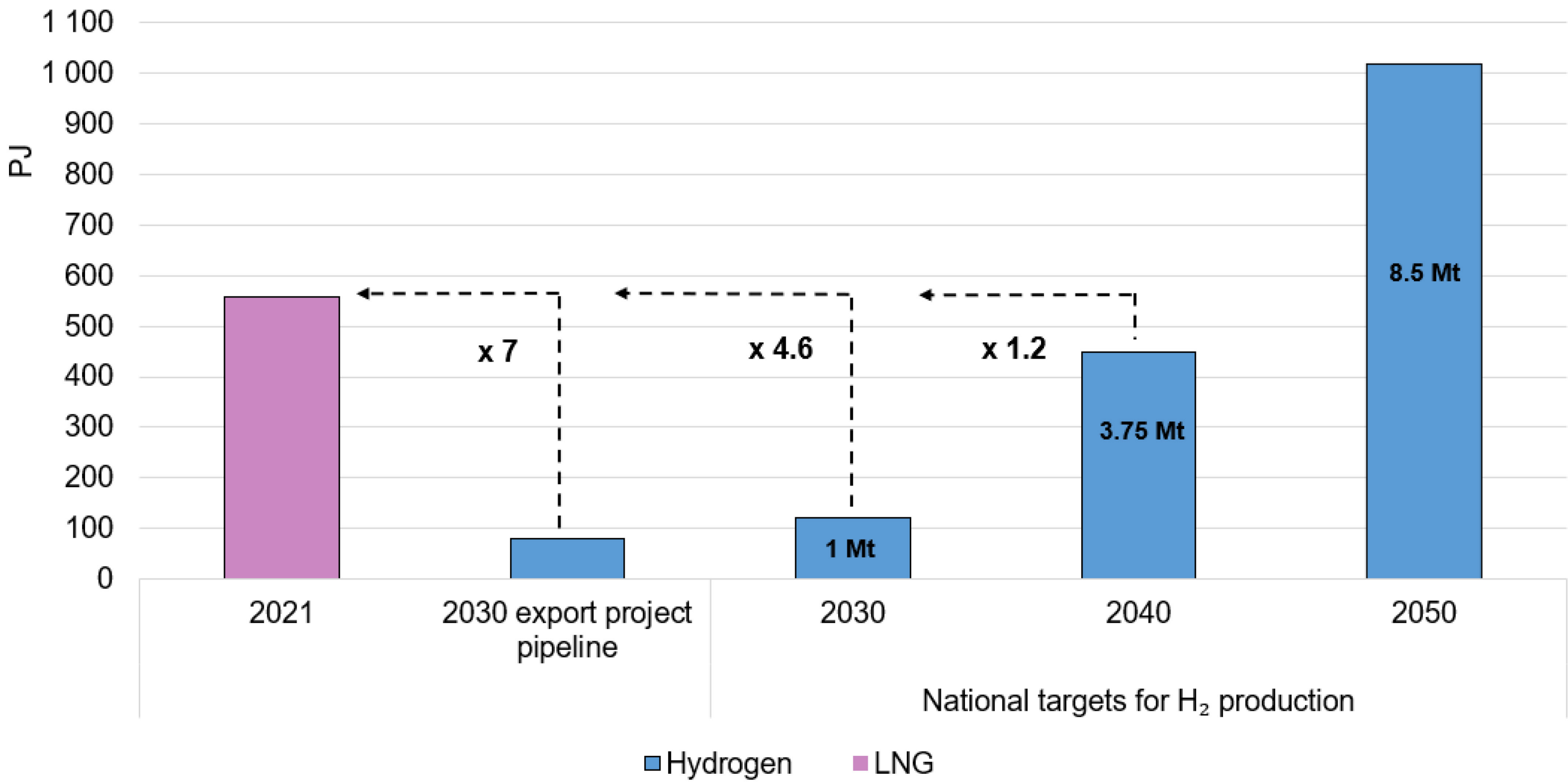
Oman is a producer economy with a clear long-term vision and strong net zero ambitions. Today, oil and gas represent around 60% of Oman's export income, and domestic natural gas accounts for over 95% of the country's electricity generation. In 2022 Oman announced a target to become net zero by 2050 and it aims to significantly ramp up domestic production of hydrogen from renewable electricity. Beyond fossil fuels, Oman is **abundantly endowed with significant renewable resources**. Building on its potential in solar and wind, the country aims to produce at least 1 Mt of renewable hydrogen a year by 2030, up to 3.75 Mt by 2040 and up to 8.5 Mt by 2050. These targets would make hydrogen exports twice as large as the size of Oman's current LNG exports in energy-equivalent terms.

Oman has already taken steps to lay the groundwork for achieving its 2030 targets, demonstrating its commitment and providing the certainty that investment and industry stakeholders need to support the development of the sector. In 2022 the government established an independent entity, Hydrogen Oman (HYDROM), to oversee and lead its national hydrogen strategy and manage the project auction process. The geographical area earmarked for the hydrogen projects to meet the 2030 target stretches over 1 500 km^2 and is intended to supply a total of 15 GW of electrolyser capacity. The agreements are for a period of 47 years, which includes 7 years for development and construction and 40 years of operation. The **first round of auctions** for the allocation of land blocks for hydrogen projects was completed in June 2023 and resulted in a total of five projects awarded grants worth a combined USD 30 billion. The second round of auctions is currently active with plans to award up to three land blocks in the Dhofar region by the end of Q1 2024.

While international demand develops, Oman can already develop a **domestic market for renewable hydrogen** to strengthen its position and mitigate uncertainties. Domestic demand could start with the refining sector, which uses around 0.35 Mt of fossil hydrogen annually that could be replaced by renewable hydrogen at a production cost of USD 1.6/kg by 2030. This would reduce Oman's emissions by more than 3 Mt CO_2/yr, as well as save around 1.5 bcm of natural gas by 2030. Total **natural gas savings** could increase to a total of 3 bcm if Oman successfully meets its 2030 target of replacing 20% of natural gas in power generation with renewables. These savings would be equivalent to roughly 20% of the country's 2021 LNG exports. Depending on LNG demand and supply trends in the coming years, Oman may consider expanding its LNG infrastructure to increase export volumes.

Oman's long-term H_2 targets exceed the size of its current LNG exports

Oman's LNG exports vs renewable hydrogen export project pipeline and production targets



Namibia: A frontrunner in unleashing sub-Saharan Africa's low-emission hydrogen potential

Namibia aims to start exporting low-emission hydrogen derivatives (primarily ammonia) by 2026. Enhanced international co-operation with future importing markets will be critical to unleash the hydrogen potential of sub-Saharan Africa over the medium term.

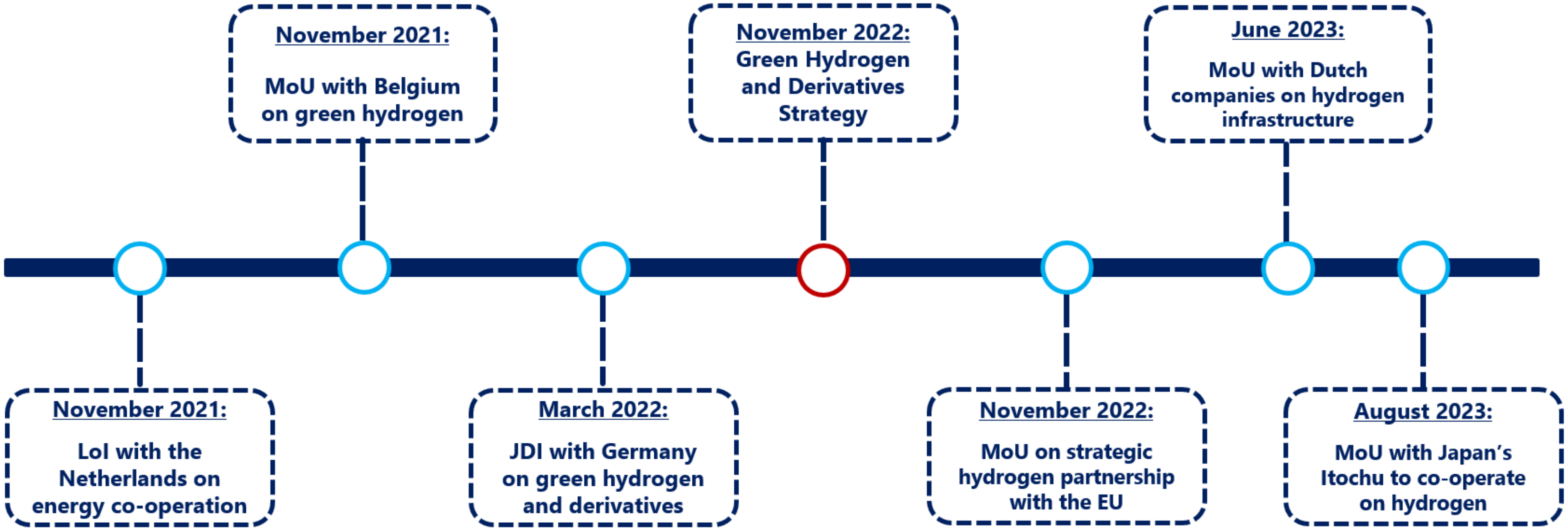
Namibia's world-class **wind and solar power potential** could translate into the cost-competive supply of low-emission hydrogen and its derivatives. According to the country's Hydrogen Strategy, the **levelised cost of electrolytic hydrogen** produced in Namibia could decline to just USD 1.5-1.6/kg by 2030 at 95% hydrogen purity, as required for the production of hydrogen derivatives such as ammonia. Thiswould make Namibia's hydrogen competitive on an international scale. . Namibia published its **Green Hydrogen and Derivatives Strategy** in November 2022. The country expects to start the production of electrolytic hydrogen and its derivatives in 2026 and gradually ramp up output to 1-2 Mt/yr by 2030, 5-7 Mt/yr by 2040 and 10-15 Mt/yr by 2050. Namibia plans to develop **three hydrogen valleys**: the Southern region is expected to produce 5 Mt/yr of hydrogen equivalent by 2050, the Central region around 3 Mt/yr and the Northern region 5 Mt/yr.

Namibia has actively engaged in the development of **strategic partnerships with future importing markets** to facilitate the technology transfer and investment flows required to scale up its hydrogen economy. At COP26 in November 2021 Namibia and **the Netherlands** agreed to sign a letter of intent on collaboration in the field of energy, in particular green hydrogen. A similar agreement during the same COP was signed with **Belgium**. In March 2022 Namibia and **Germany** signed a joint declaration of intent to co-operate on the production, application and transport of green hydrogen and synthetic fuels. At COP27 in November 2022 Namibia and the **European Union** signed a memorandum of understanding (MoU) to develop a secure and sustainable supply of raw and refined materials and renewable hydrogen. In June 2023 Dutch and Namibian companies signed an MoU to develop hydrogen-related infrastructure to support trade between Namibia and the Netherlands. In August 2023 **Japan**'s Itochu signed an agreement with Namibia to co-operate on the development of low-emission ammonia value chains.

Namibia's **Hyphen Hydrogen Energy project** has a target to begin hydrogen production by the end of 2026 and ramp up output to 0.3 Mt/yr by 2030. Ammonia production would reach 2 Mt/yr. The project has not reached FID yet, although there is a signed MoU for the potential offtake of 1 Mt/yr of ammonia. In December 2021 an MoU was signed between the Hyphen Hydrogen Energy Project and Germany's RWE Supply and Trading (0.3 Mt/yr), while in February 2023, Korea's Approtium and an undisclosed chemical company signed an MoU for the offtake of 0.75 Mt/yr. Such **long-term offtake agreements** will be necessary to derisk investment and enable FID.

Namibia is building up international partnerships to develop its hydrogen economy

Timeline of key agreements and strategy documents related to hydrogen developments in Namibia



Notes: JDI = joint declaration of intent; LoI = letter of intent; MoU = memorandum of understanding.
Sources: IEA analysis based on various news reports.

E-methane: The next generation of low-emission gases

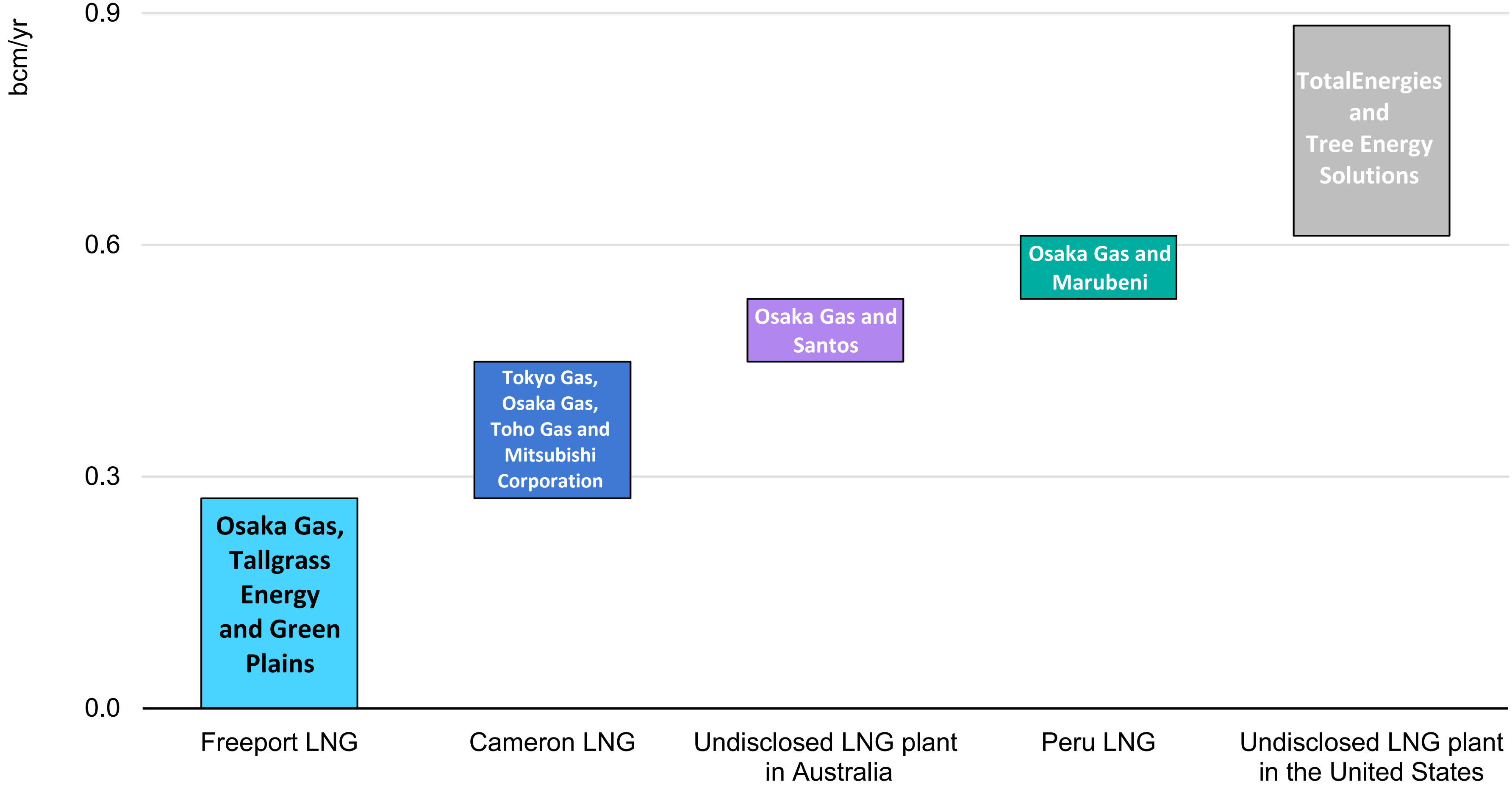
E-methane is produced by combining low-emission hydrogen and a carbon source. As recognised by the G7 Climate, Energy and Environment Ministers' Communiqué, e-methane could play a significant role in **decarbonising existing gas networks** without the need for retrofitting. In contrast with biomethane and low-emission hydrogen, e-methane is not expected to expand significantly over the forecast period considering the complexity of the underlying value chains and the high production costs. Nevertheless, various companies in Japan and Europe are investigating project development options. Further technological development, coupled with policy support could lead to a take-off in e-methane production in the second half of the decade. In addition, proper emissions accounting rules will be required to ensure that e-methane contributes to carbon neutrality.

Japan is a first mover in the e-methane space. The country's Strategic Energy Plan aims to ramp up annual e-methane supply to 0.28 Mt (or 0.38 bcm/yr) by 2030 and 25 Mt (or 34 bcm/yr) by 2050. The country's Basic Hydrogen Strategy, published in June 2023, recognises the potential contribution of e-methane to energy supply security and the need to develop international partnerships with producing economies. Japanese utilities and trading houses have started jointly exploring the feasibility of developing **e-methane supply chains with LNG exporting countries**. While no binding agreements have been reached yet, these recent project proposals could potentially enable 0.45 Mt/yr (or 0.6 bcm/yr) of e-methane imports into Japan by 2030. A comprehensive overview of Japan's domestic and international e-methane projects is provided in the IEA's Quarterly Gas Report – Q2 2023. Japan Gas Association (JGA) is set to establish a clean gas certification scheme for e-methane and biogas producers during the 2024/25 fiscal year.

In **Europe**, the European Network of Transmission System Operators for Gas (ENTSOG) expects e-methane production to reach 0.2 bcm/yr by 2030 and increase to a range of 2-4 bcm/yr by 2050. The French Gas Association sees a stronger potential for e-methane production in France: 0.3 bcm/yr by 2030 and 5.4 bcm/yr by 2050. Besides several **pilot projects** undertaken in recent years (mainly in France and Germany), European companies are considering the development of **international supply chains** for e-methane. TotalEnergies and Tree Energy Solutions are considering developing a large-scale e-methane production unit in the United States with an output in the range of 0.15-0.3 bcm/yr. The liquefied e-methane could be sold into the global LNG market. The project is expected to benefit from the tax credits under the Inflation Reduction Act, with the companies aiming to take FID in 2024.

Japanese and European companies are targeting international e-methane supply chains

Key planned e-methane import projects led by European and Japanese companies



Sources: IEA analysis based on various news reports and company announcements.

Annex

Summary tables (1/2)

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

	2020	2021	2022	2023	2024	2025	2026
Africa	161	169	164	170	178	184	191
Asia Pacific	834	891	877	904	939	990	1062
of which China	*325*	*367*	*364*	*390*	*413*	*449*	*496*
Central and South America	142	153	150	144	147	150	153
Eurasia	585	649	622	625	633	647	660
of which Russia	*461*	*516*	*487*	*490*	*495*	*506*	*517*
Europe	576	609	524	489	496	495	493
Middle East	546	562	580	590	602	621	642
North America	1079	1091	1144	1149	1139	1128	1124
of which United States	*868*	*874*	*919*	*922*	*912*	*901*	*899*
World	**3924**	**4124**	**4061**	**4071**	**4135**	**4214**	**4325**

Summary tables (2/2)

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

	2020	2021	2022	2023	2024	2025	2026
Africa	239	260	245	251	259	265	270
Asia Pacific	622	646	655	668	677	680	690
of which China	*189*	*205*	*216*	*227*	*234*	*242*	*250*
Central and South America	150	148	152	145	149	152	153
Eurasia	866	961	865	806	828	846	867
of which Russia	*692*	*762*	*672*	*620*	*641*	*659*	*677*
Europe	230	222	230	218	221	220	216
Middle East	670	692	715	729	745	765	815
North America	1145	1183	1232	1264	1267	1290	1314
of which United States	*954*	*984*	*1021*	*1046*	*1050*	*1070*	*1091*
World	**3922**	**4112**	**4094**	**4081**	**4146**	**4218**	**4325**

Regional and country groupings

Africa – Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of the 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, the Russian Federation, Tajikistan, Turkmenistan and Uzbekistan.

Europe – Albania, Austria, Belarus, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,[5,6] the 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, the Netherlands, Norway, Poland, Portugal, Romania, Serbia, the Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Republic of Türkiye, Ukraine and the United Kingdom.

European Union – Austria, Belgium, Bulgaria, Croatia, Cyprus,[5,6] the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, the 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, the 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)
BMC	Colombian Mercantile Exchange (Colombia)
CBG	compressed biogas
CCUS	Carbon Capture, Utilisation and Storage
CII	Carbon Intensity Indicator
CME	Chicago Mercantile Exchange (United States)
CNE	National Energy Commission (Chile)
CNPC	China National Petroleum Coporation
CQPGX	Chongqing Petroleum Exchange (the People’s Republic of China)
EEXI	Energy Efficiency eXisting ship Index
EIA	Energy Information Administration (United States)
ENARGAS	National Gas Regulatory Entity (Argentina)
ENTSOG	European Network of Transmission System Operators for Gas
EPIAS	Energy Markets Operations Inc. (Republic of Türkiye)
EPPO	Energy Policy and Planning Office (Thailand)
EU	European Union
EUR	Euro
FID	final investment decision
FLNG	floating LNG
FSRU	floating storage and regasification unit
FY	fiscal year
GDP	gross domestic product
GHGs	greenhouse gases
GIE	Gas Infrastructure Europe
GX	Green Transformation programme (Japan)
HH	Henry Hub
HoA	Head of Agreement
IEA	International Energy Agency
ICE	Intercontinental Exchange
ICIS	Independent Chemical Information Services
IEA	International Energy Agency
IMO	International Maritime Organization
JGA	Japan Gas Association
JKM	Japan Korea Marker
JODI	Joint Oil Data Initiative
JPY	Japanese yen
LBG	liquefied biomethane
LEGWP	Low-Emission Gases Work Programme
LNG	liquefied natural gas
METI	Ministry of Economy, Trade and Industry (Japan)
MoU	Memorandum of Understanding
MME	Ministry of Mines and Energy (Brazil)
MSW	municipal solid waste
NBP	National Balancing Point (United Kingdom)
NDRC	National Development and Reform Commission (the People’s Republic of China)
NPT	Nadym Pur Taz (Russia)
OECD	Organisation for Economic Co-operation and Development
ONS	National Electric System Operator (Brazil)
OSINERG	Energy Regulatory Commission (Peru)
PMI	Manufacturing Purchasing Managers’ Index

PNGRB	Petroleum and Natural Gas Regulatory Board (India)
PPAC	Petroleum Planning and Analysis Cell (India)
REC	renewable energy certificate
RFO	Residual Fuel Oil
SBL	Strategic Buffer LNG
SMR	steam methane reforming
SPA	Sales and Purchase Agreement
TFFS	Task Force on Gas and Clean Fuels Market Monitoring and Supply and Security
TTF	Title Transfer Facility (the Netherlands)
UGS	underground storage
USD	United States dollar
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_{eq}	billion cubic metre equivalent
bcm/yr	billion cubic metres per year
GJ	gigajoule
GW	gigawatt
kWh	kilowatt hour
MBtu	million British thermal units
Mt	million tonnes
Mt/yr	million tonnes per year
m^3/hr	cubic metres per hour
m^3/yr	cubic metres per year
Nm^3	normal cubic metre
TWh	terawatt hour
t/yr	tonnes per year

Acknowledgements, contributors and credits

This publication has been prepared by the Gas, Coal and Power Markets Division (GCP) of the International Energy Agency (IEA). The analysis was led and co-ordinated by Gergely Molnár. Louis Chambeau, Carole Etienne, Gergely Molnár, Takeshi Furukawa and Frederick Ritter are the main authors.

Keisuke Sadamori, Director of the IEA Energy Markets and Security (EMS) Directorate and Dennis Hesseling, Head of Gas, Coal and Power Markets Division, provided expert guidance and advice. The Report benefitted from the review of senior management, including Tim Gould, Chief Energy Economist.

The development of this report benefitted from contributions provided by the following IEA colleagues: Elisa Asmelash (hydrogen developments in Oman), Tomás de Oliveira Bredariol (methane emissions Africa). Jose Miguel Bermudez Menendez (HAF), Francesco Pavan (HAF) and Amalia Pizarro (HAF) provided guidance on hydrogen.

Eren Cam (GCP) and Carlos Fernandez Alvarez (GCP) provided support on power modelling. Alexander Bressers (OIM) and Jacob Messing (OIM) provided valuable comments on oil market dynamics. Hiroyasu Sakaguchi provided support.

Ravi Kumar Singh (Indian Gas Exchange) provided invaluable insights and data on biogas/biomethane developments in India.

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

The IEA Communication and Digital Office (CDO) provided production and launch support. Particular thanks go to Jethro Mullen and his team: Poeli Bojorquez, Astrid Dumond, Grace Gordon, Julia Horowitz, Oliver Joy, Isabelle Nonain-Semelin, Oscar Padula, Charner Ramsey, Clara Vallois and Therese Walsh.

Justin French-Brooks edited the report.

The report was made possible by assistance from Tokyo Gas.

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

For questions and comments, please contact GCP (gcp@iea.org) or Gergely Molnár (Gergely.Molnar@iea.org).

IEA Publications

International Energy Agency

Website: www.iea.org

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

Typeset in France by the IEA – October 2023

Cover design: IEA

Photo credits: © Shutterstock