Gas 2025

Analysis and forecasts to 2030

INTERNATIONAL ENERGY AGENCY

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Abstract

Global gas markets are set to undergo major changes by the end of the decade, with the coming wave of liquefied natural gas (LNG) production capacity set to profoundly transform market dynamics. The unprecedented scaling up of LNG supply is expected to improve gas supply security and make natural gas more affordable – including in emerging, price-sensitive import markets. However, to account for these shifts, LNG producers and suppliers may need to adapt their medium-term strategies.

The *Gas 2025* medium-term report from the International Energy Agency (IEA) examines this coming transformation and its consequences, offering a comprehensive overview of potential supply, demand and trade trends in global natural gas markets for the coming years. It provides a thorough review of recent market developments ahead of the 2025-26 winter season in the Northern Hemisphere – and includes forecasts for how supply and demand could evolve to 2030.

The report also includes the IEA's detailed annual assessment of gas supply security, including the implications of LNG contracting trends, and features a special spotlight on the potential to deploy carbon capture technologies along LNG value chains to reduce the emissions intensity of supply. Additionally, as part of the IEA's Low-Emission Gases Work Programme, it includes a section on the medium-term outlook for biomethane, low-emissions hydrogen and e-methane.

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Executive summary

The coming LNG wave is set to profoundly transform the global gas market

Following the supply shock of 2022/23, natural gas markets moved towards a gradual rebalancing in 2024 and 2025. During this period, supply fundamentals remained tight and prices stayed well above their historic levels. This limited demand growth, especially in price-sensitive Asian markets.

Around 300 billion cubic metres per year of new liquefied natural gas (LNG) export capacity is expected to be added worldwide by 2030, primarily supported by liquefaction capacity expansions in the United States and Qatar. This wave of new LNG production capacity is set to profoundly transform global gas market dynamics. The scaling up of LNG supply will play a key role in enhancing supply security and improving the affordability of natural gas – including in price-sensitive emerging import markets.

The analytical framework underpinning the medium-term outlook in this report is structured around a base case, which is complemented by a high case that explores the potential for greater demand response to possible price changes. The base case reflects current project plans, policy settings and economic growth projections, as well as prices informed by the current forward curve. The high case assumes that LNG import prices move closer towards the short-run marginal cost of US LNG supply and unlock additional gas demand, especially in price-sensitive Asian markets. However, a weaker macroeconomic environment, together with a slower build-out of natural gas infrastructure and contractual rigidities, might limit the scope of the price-adjusted demand response.

A prolonged period of lower LNG prices could reduce the incentive for project developers to invest in LNG liquefaction projects and in upstream and midstream infrastructure. This, in turn, could lead to a potential tightening of global gas markets post-2030, especially if demand growth follows a higher trajectory.

Global gas demand growth slowed in 2025 amid macroeconomic uncertainty and tight supply fundamentals

Following a relatively strong increase in 2024, natural gas demand growth slowed significantly in the first nine months of 2025. Preliminary data indicate that natural gas consumption increased by just around 0.5% year-on-year during this period in major markets[1]. This growth was almost entirely driven by Europe and North America, while demand remained subdued in Asia and declined in Eurasia.

Tighter market fundamentals have contributed to higher gas prices in key import markets, weighing on natural gas consumption, especially in price-sensitive Asian markets. While

[1] Asia Pacific, Central and South America, Eurasia, Europe and North America.

global LNG supply increased by more than 5% year-on-year in the first nine months of 2025, this growth was partially offset by lower piped gas supplies to Europe from Russia and Norway. Stronger storage injection needs in Europe further tightened markets.

For the full year of 2025, global gas demand growth is forecast to slow from 2.8% in 2024 to below 1% in 2025. Demand in the Asia Pacific region is expected to expand by less than 1% from 2024, the weakest growth since 2022.

Final investment decisions in US LNG projects reached an all-time high in the first nine months of 2025

Despite macroeconomic uncertainty, 2025 has seen the second highest amount of LNG liquefaction capacity reaching final investment decision (FID) in a single year. More than 90 billion cubic metres per year (bcm/yr) of additional capacity has been sanctioned so far in 2025.

Over 80 bcm/yr of liquefaction capacity has been approved year-to-date in the United States, an all-time high for the US LNG sector. The projects include Louisiana LNG, Corpus Christi Train 8&9, CP2 phase 1, Rio Grande LNG Train 4 & 5 and Port Arthur phase 2.

The amount of LNG projects reaching FID highlights the industry's confidence that demand for LNG will continue to expand strongly, reflecting the supportive policy environment in the United States for natural gas projects. This new wave of LNG projects is set to further solidify the United States' position as the world's largest LNG exporter. By the end of the decade, the United States could provide around one-third of global LNG supply, up from around 20% in 2024.

The coming LNG wave is set to enhance energy supply security and could spur additional demand in some markets

The United States and Qatar together account for 70% of the roughly 300 bcm/yr of new LNG liquefaction capacity that is expected to come online globally by 2030. This is based on the official timelines of projects that have reached FID or are under construction. The scaling up of LNG supply is playing a key role in rebalancing global gas markets, enhancing supply security and making natural gas more affordable for importing countries.

The unprecedented expansion in LNG capacity could translate into a net increase of 250 bcm in global LNG supply by 2030. This takes into account declining LNG output from certain legacy producers, as well as the ramp-up rates and utilisation factors of new liquefaction plants. To put this number into perspective, this increase in LNG supply is equivalent to around 7% of Asia's thermal coal demand. In contrast, long-distance piped gas trade is expected to decline by almost 55 bcm between 2024 and 2030, primarily due to lower piped gas deliveries to Europe.

When considering price trajectories informed by current forward curves, global LNG demand growth is not expected to absorb all incremental LNG supply over the 2024-30 period in the base case. This could result in around 65 bcm of surplus supply. If European hub and Asian spot LNG prices start to gradually move closer to the short-run marginal cost of US LNG supply between 2027 and 2030, this could spur additional gas demand, especially in price-sensitive Asian markets. This could absorb additional LNG supply and limit the risk of production shut-ins at liquefaction plants. However, a weaker macroeconomic environment – together with a slower build-out of natural gas infrastructure in South and Southeast Asia and contractual rigidities – might limit the scope of the price-adjusted demand response. If existing infrastructure in Southeast Asia and other emerging LNG-importing regions is not expanded, about one-quarter of the demand response may be at risk of not materializing.

Global gas demand grows by around 9% by 2030 in our base case, largely driven by Asia and the Middle East

Our base case expects global natural gas demand (excluding bunkers) to increase at an average annual rate of nearly 1.5% between 2024 and 2030. This translates into an increase of 380 bcm by 2030. Global gas demand grows at a somewhat faster rate, around 1.7% per year, and expands by more than 10% by 2030 in our price-driven high case. This would translate into an additional increase of over 65 bcm compared with the base case. The Asia Pacific region accounts for almost 80% of this additional demand.

In the base case, the Asia Pacific region is expected to be the primary driver of global gas demand growth, representing around half of the increase through 2030. China alone is projected to account for a quarter of global demand growth due to abundant supply, lower spot LNG prices and expanding import infrastructure. The Middle East, Eurasia and North America are also expected to see meaningful demand growth during this period. Demand is expected to rise more modestly in Africa and Latin America. This increase is expected to be more than offset by an 8% decline in European gas demand over the forecast period.

In terms of sectors, industry and energy (including refining) together account for about 45% of expected global gas demand growth between 2024 and 2030 in the base case.The power sector is the second largest contributor to global demand growth over the forecast period, accounting for over a third of the net increase. The Asia Pacific region accounts for more than half of power sector demand growth. Rising electricity demand in the Middle East also plays a significant role, adding more than 50 bcm/yr of demand between 2024 and 2030, primarily due to large-scale oil-to-gas switching initiatives, led by Saudi Arabia. Natural gas demand in the residential and commercial sector is expected to increase by close to 50 bcm/yr by 2030, driven by Asia, Eurasia and the Middle East.

Gas demand from the transport sector is expected to grow more modestly than other sectors, rising by almost 35 bcm/yr. This growth is largely driven by road transport in China, with a smaller contribution from India. In addition to inland consumption, LNG use in the marine transport sector, which includes both LNG carriers and commercial vessels powered by LNG, is expected to increase by 15 bcm/yr to 2030. This is driven by fleet expansion, the build-out of LNG bunkering infrastructure and favourable economics compared with other alternative fuels.

The global LNG market is poised to see greater liquidity and pricing diversity

The role of long-term LNG contracts remains crucial as an effective risk-sharing mechanism between sellers and buyers. Long-term agreements, or those with a duration of ten years or more, accounted for 75% of the volumes contracted since 2022, reflecting sellers' and buyers' preference for demand and supply security, respectively.

The IEA's database of LNG contracts indicates that they are evolving towards greater flexibility and pricing diversity. The share of destination-free contracts is expected to account for just over half of total LNG volumes contracted by 2030. Meanwhile, pricing terms are becoming more diverse, with hub indexation and hybrid pricing formulae gaining traction at the expense of oil indexation.

Based on existing active contracts, the share of oil-indexed LNG contracts is expected to fall to around half of contracted volumes by 2030. The role of portfolio players in LNG trade is growing, providing greater optionality to end-buyers. The growing flexibility and liquidity of the LNG market is becoming increasingly important in responding to gas supply and demand shocks, helping to ensure supply security.

Carbon capture, utilisation and storage (CCUS) can reduce the emissions intensity of LNG supply

LNG supply operations have a sizeable greenhouse gas footprint. This comes primarily from associated carbon dioxide (CO_2) emissions, but also from methane leaks, with Scope 1 and 2 emissions distributed across upstream operations, gas processing and transmission, and liquefaction. By capturing and storing CO_2 in both upstream and liquefaction operations, LNG producers could reduce part of their emissions while maintaining energy security and flexibility.

Momentum behind CCUS is building among major producers. In Australia, the Gorgon LNG project started CO_2 reinjection in 2019. In Qatar, a major CO_2 recovery and sequestration facility at Ras Laffan was commissioned in 2019 and is currently being expanded. In Southeast Asia, both Indonesia and Malaysia are developing CCUS projects, which could reduce the emissions intensity of their LNG exports. In the United States, several LNG project developers announced plans to integrate CCUS-based solutions into existing or future LNG liquefaction plants.

CCUS is shifting from demonstration to deployment in the LNG sector. The projects now underway suggest that by 2030, CCUS could become an increasingly important feature of new LNG supply, influencing access to finance and long-term contracts in markets where carbon intensity is scrutinised.

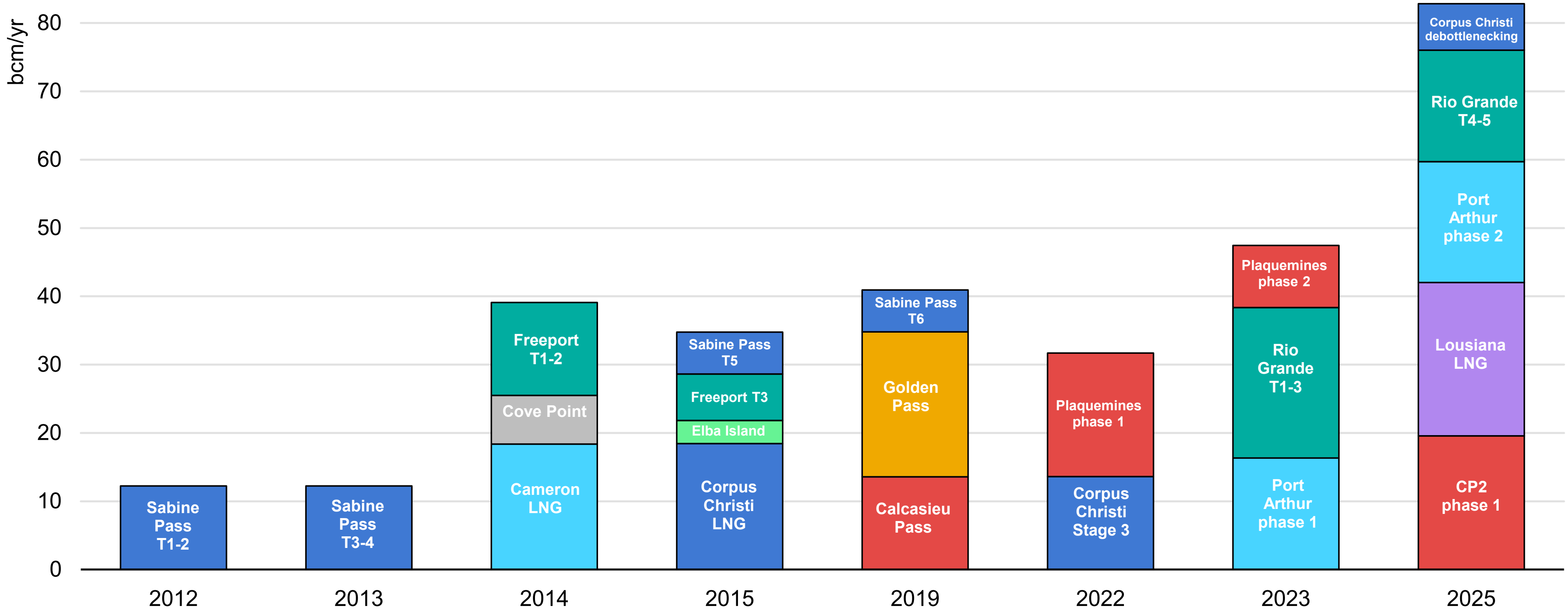
Low-emissions gases are set for a rapid expansion to 2030, driven by biomethane and hydrogen

The deployment of low-emissions gases is expected to continue at a strong pace over the medium term. In our outlook, the supply of low-emissions gases is expected to increase by two-and-half times by 2030. This translates to a rise of over 20 billion cubic meters-equivalent (bcm-eq) . Despite this growth, the impact of low-emissions gases on the global gas balance is set to remain limited through 2030. They are expected to account for less than 1% of global gaseous fuels supply at the end of this decade.

Biomethane production is expected to more than double between 2024 and 2030, contributing over 50% of the total increase in low-emissions gases during this period. Low-emissions hydrogen is projected to grow at an average rate of 33% per year between 2024 and 2030 from a very low base. 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, effective support mechanisms and cost efficiency.

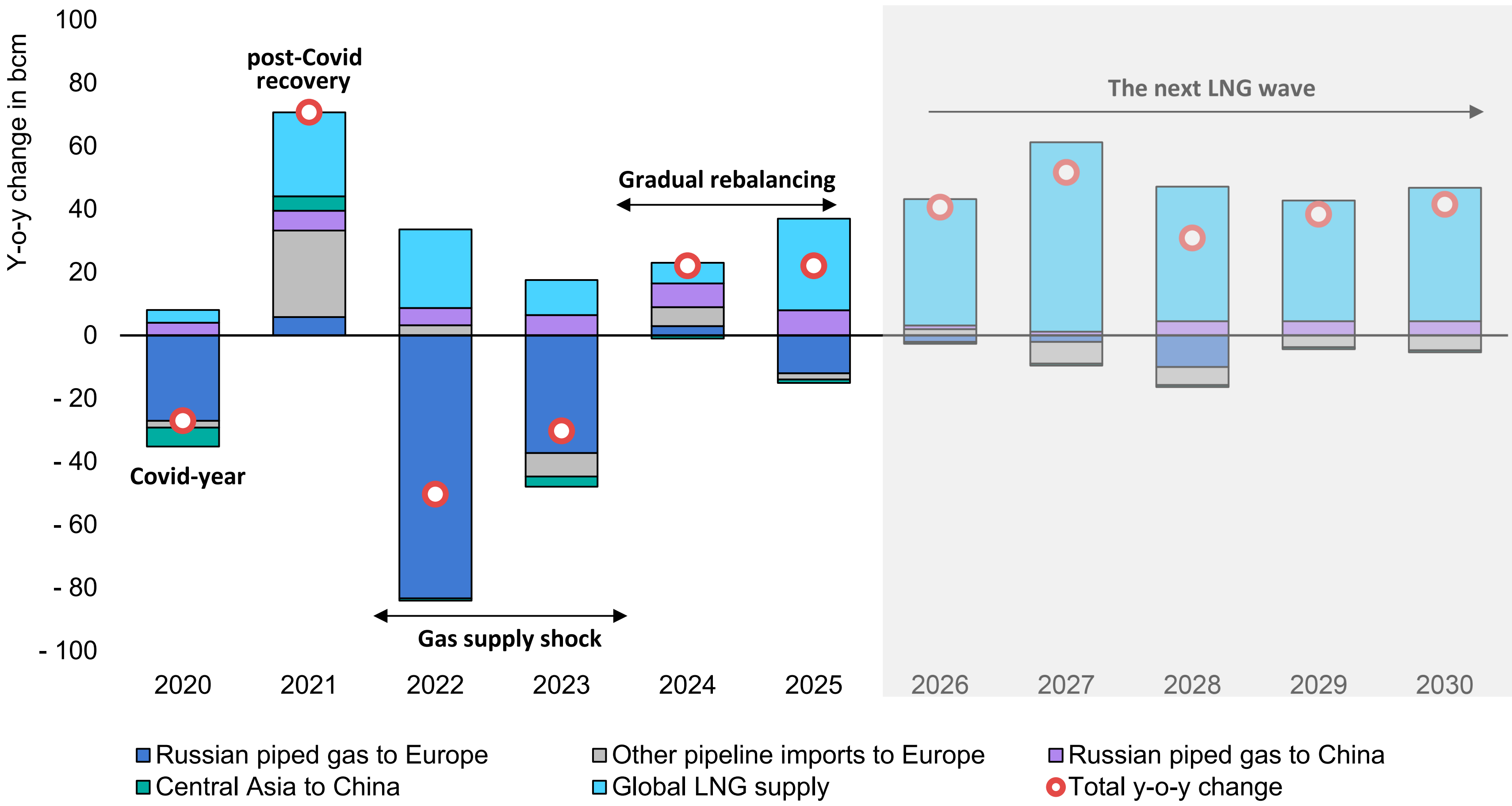
Final investment decisions in US LNG reached an all-time high in 2025

Final investment decisions in the United States by project, 2014-2025



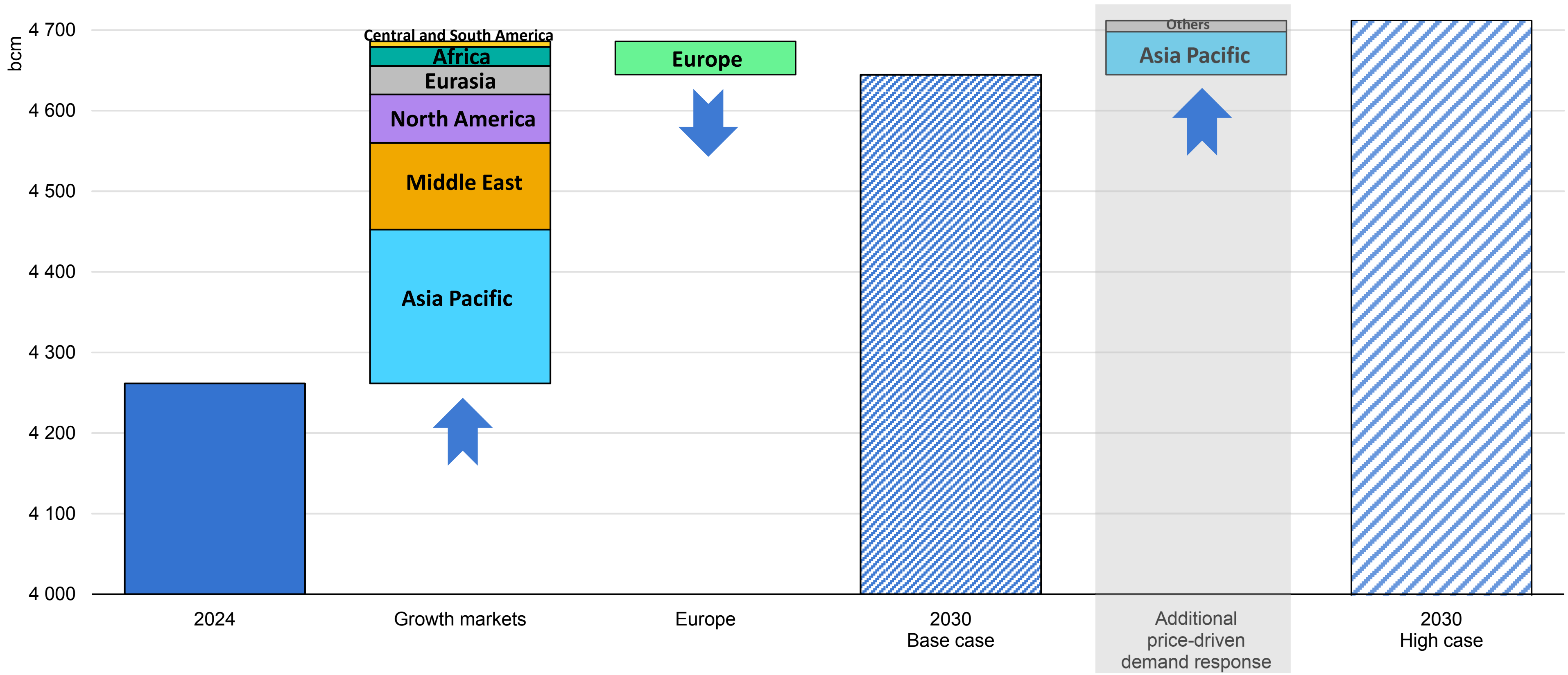
The coming LNG production wave is set to enhance energy supply security and affordability

Year-on-year change in key piped natural gas trade and potential global LNG supply, 2020-2030



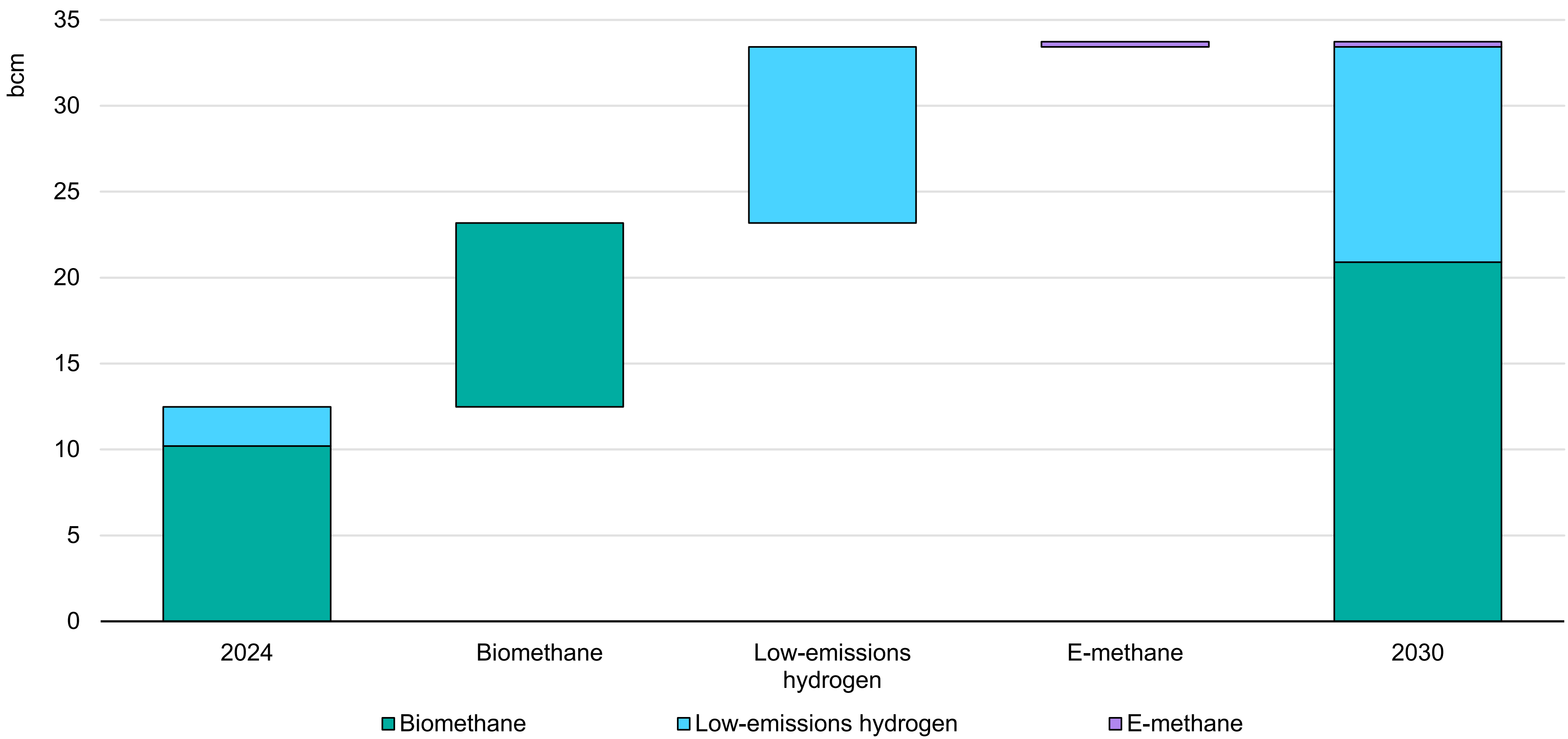
Improved LNG availability could stimulate additional gas demand

Global gas demand growth by case and regions, 2024-2030



The supply of low-emissions gases is expected to double by 2030

Expected increase in production of low-emissions gases, 2024-2030



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Gas market update

Natural gas demand growth has slowed significantly in 2025

Following a relatively strong increase in 2024, **global gas demand growth slowed markedly** in Q1-Q3 2025. Higher natural gas prices together with heightened macroeconomic uncertainty and tight supply fundamentals weighed on natural gas consumption. In contrast with previous years, demand **growth was largely concentrated in Europe**, while in Asia natural gas consumption remained broadly flat compared with the same period in 2024.

Preliminary data suggest that **natural gas demand increased by just 0.5%** (or around 10 bcm) y-o-y in Q1-Q3 2025 in the markets covered by this market update,[2] primarily driven by Europe and North America. **Supply fundamentals remained tight.** While global LNG supply increased by around 5% (or nearly 20 bcm) y-o-y in Q1-Q3 2025, this was partially offset by lower Russian and Norwegian piped gas deliveries to Europe. Strong storage injections in the European Union further tightened market fundamentals.

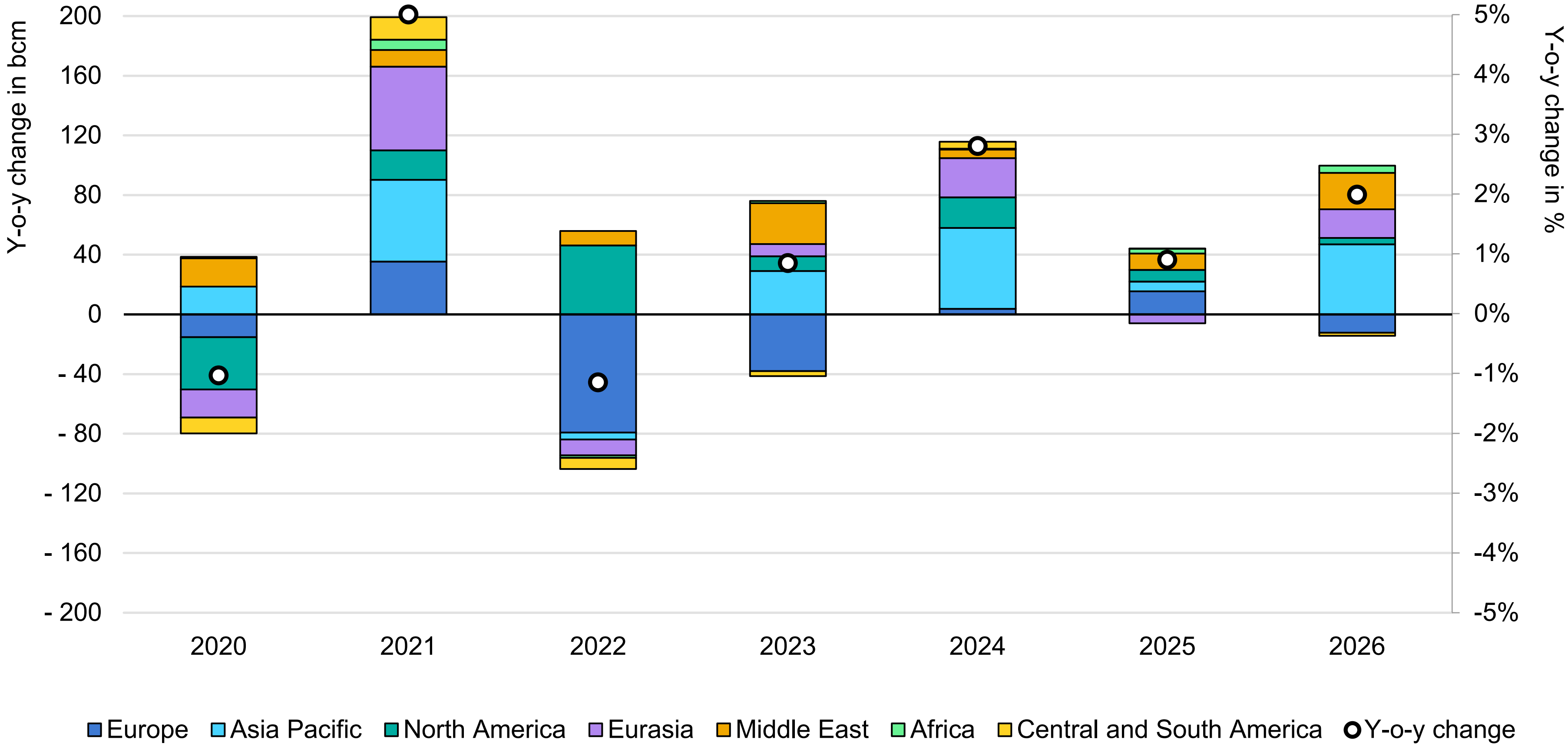
For the full year of 2025, global gas demand growth is expected to increase by less than 1% – assuming average weather conditions in Q4. Natural gas demand in the **Asia Pacific region** is expected to expand by less than 1% compared with 2024, its weakest growth since 2022. Following a cold Q1, the year's natural gas demand in **North America** is projected to increase by around 0.5% compared with 2024 and remain broadly flat in **Central and South America**. In **Europe** natural gas demand is expected to increase by 3%. **Eurasian** gas demand is projected to decline by 1.5%. Combined gas demand in **Africa and the Middle East** is forecast to increase by 2% amid higher demand in industry and the power sectors.

Global gas consumption is expected to reach a new all-time high in 2026, with demand growth accelerating to 2%. **Global LNG supply** is forecast to increase by a strong 7% (or 40 bcm), primarily driven by the United States, Canada and Qatar. Improving supply fundamentals are expected to support stronger demand, especially in fast-growing and price-sensitive Asian markets. Natural gas demand in the **Asia Pacific region** is expected to increase by nearly 5% in 2026, accounting for around half of global gas demand growth. In **North America**, natural gas demand is projected to increase by around 0.5% in 2026 primarily driven by the power sector. In contrast, natural gas use is projected to decline by almost 1.5% in **Central and South America** amid higher renewables output. In **Europe**, the continued expansion of renewables is expected to reduce gas demand by 2%. In **Eurasia**, gas consumption is forecast to increase by more than 3% assuming a return to average weather conditions. Combined demand in **Africa and the Middle East** is projected to increase by 3% amid higher gas use in industry and the power sector.

[2] Asia Pacific, Central and South America, Eurasia, Europe and North America.

Global gas demand growth is expected to accelerate in 2026 amid improving LNG supply

Year-on-year change in natural gas demand in key regions, 2020-2026



Higher natural gas prices weigh on gas-fired power generation in the United States…

Natural gas consumption in North America increased by an estimated 0.5% (or less than 5 bcm) y-o-y in Q1-Q3 2025. This growth was primarily concentrated in Q1, when colder temperatures increased space heating requirements across Canada and the United States. In contrast, natural gas consumption declined in both Q2 and Q3 as higher natural gas prices weighed on gas-fired power generation. Natural gas use in industry increased marginally compared with 2024 levels.

In the **United States**, natural gas consumption increased by less than 0.5% (or around 3 bcm) y-o-y during Q1-Q3 2025. This growth was largely supported by colder winter and spring temperatures, which increased space heating requirements across the **residential and commercial sectors**. Heating degree days were up by 10% y-o-y in the first five months of 2025, which drove up natural gas use in the buildings sector by around 10% y-o-y during the same period. Demand growth in the buildings sector continued throughout the summer months, largely driven by commercial entities.

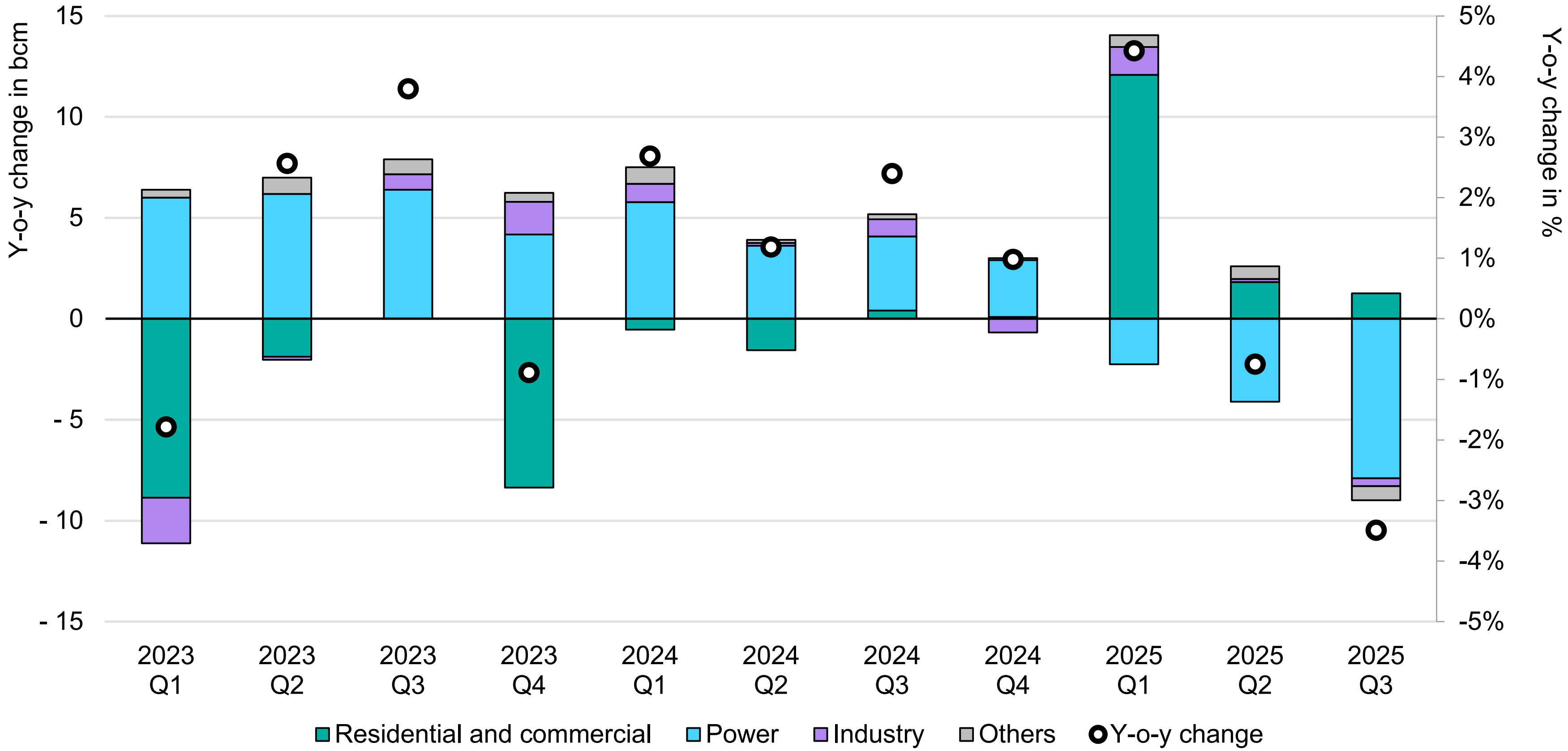
In contrast, **gas-to-power demand** in the United States declined by an estimated 4% (or 14 bcm) y-o-y in Q1-Q3 2025 amid stronger renewable power output and price-driven gas-to-coal switching. Tighter market fundamentals drove up natural gas prices, with Henry Hub prices averaging almost 65% above 2024 levels in Q1-Q3 2025. This strong increase in natural gas prices eroded the cost-competitiveness of gas-fired power generation vis-à-vis coal-fired power plants, which increased their output by around 11% y-o-y. Consequently, the share of natural gas in power generation declined from 42% in Q1-Q3 2024 to below 40% in Q1-Q3 2025. Natural gas demand in **industry and the energy sector** increased by an estimated 1% (or almost 2 bcm) y-o-y, partly supported by stronger gas use by the country’s growing LNG liquefaction fleet.

In **Canada**, natural gas demand rose by 4.5% (or 3.3 bcm) y-o-y in the first seven months of 2025. Colder weather conditions prompted higher gas use in the residential and commercial sectors, which increased by more than 10% y-o-y in the first five months of 2025. Combined gas demand in the industrial and power sectors rose by 2.5% y-o-y in the first seven months of 2025, largely supported by stronger gas-fired power generation. In **Mexico**, natural gas consumption declined by an estimated 2.5% (or 2 bcm) y-o-y in Q1-Q3 2025, primarily driven by lower gas-fired power generation.

Natural gas demand in North America is forecast to increase by around 0.5% in 2025. Gas use in the residential and commercial sectors is expected to increase, assuming average weather conditions for the rest of the year. This growth is expected to be largely offset by lower gas burn in the power sector amid stronger renewable power output and gas-to-coal switching dynamics. This forecast anticipates natural gas demand in North America increasing by 0.5% in 2026 amid stronger gas use in the power, industrial and energy sectors.

…driving down gas demand during Q2-Q3 2025

Estimated year-on-year change in quarterly natural gas demand by sector in the United States, 2023-2025



Sources: IEA analysis based on EIA (2024), Natural Gas Consumption; Natural Gas Weekly Update.

Gas demand in Central and South America increased marginally in Q1-Q3 2025…

Following a relatively strong increase in 2024, natural gas consumption in Central and South America increased by an estimated 1% y-o-y in Q1-Q3 2025. Incremental demand was largely met by higher domestic production, while the region's LNG imports declined by 8% y-o-y in Q1-Q3 2025.

Argentina's natural gas demand decreased by a modest **0.5%** y-o-y in the first seven months of 2025. The declines in the residential and commercial sectors (down 2.5%) and industrial sector (down 2%) were almost fully compensated by increases in gas-to-power demand (up 5%). On the production side, the Vaca Muerta formation continues to show strong performance. Argentina's shale gas production grew by an impressive 5% (or 0.9 bcm) y-o-y in the first eight months of 2025, largely offsetting the declines recorded in tight gas output (down by 3% or 0.7 bcm y-o-y).

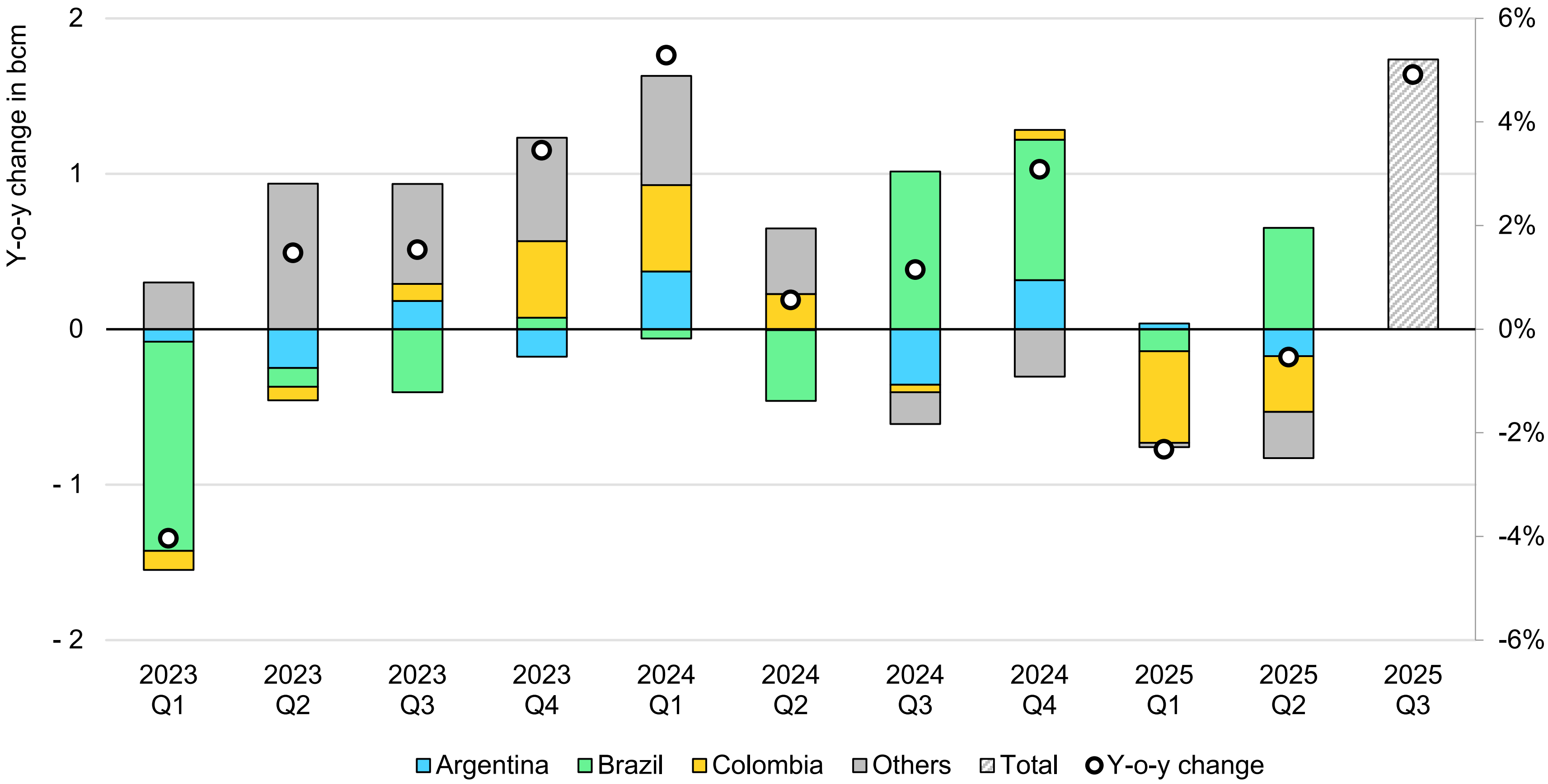
In **Brazil**, primary gas supply grew by more than 10% y-o-y in Q1-Q3 2025. This strong growth was largely supported by the country's rapidly expanding domestic gas production, which increased by almost 20% y-o-y in the first eight months of 2025. This upward trend is partly supported by the Rota 3 pipeline (6.5 bcm/yr), which began operations in September 2024 to allow greater takeaway from the offshore Santos Basin. Lower hydropower output (down by 5.5% y-o-y) supported stronger gas burn in the power sector, rising by around 10% y-o-y in Q1-Q3 2025.

Venezuela reported a moderate decrease of 3.5% y-o-y in natural gas use in the first seven months of 2025. In **Trinidad and Tobago**, natural gas consumption declined by 1% y-o-y in the first half of 2025. Gas-to-power demand fell by 0.6%, while gas use in industry and the energy sector declined by around 1%. In **Columbia**, gas consumption plummeted by 15% y-o-y in the first eight months of 2025. This steep decline was largely driven by the power sector, where gas burn fell by over 40% y-o-y amid the recovery in hydropower generation. **Chile** saw a robust 8% y-o-y demand increase in the first seven months of 2025, partly supported by stronger gas use in industry and the power sector. In **Peru**, natural gas consumption declined by 2.5% y-o-y in Q1-Q3 2025. **Bolivian** gas consumption grew by almost 2.5% y-o-y in the first seven months of 2025, supported by stronger gas use in the residential and commercial sectors (up by 6% y-o-y), as well as higher gas demand in industry (up by 2% y-o-y). Natural gas demand continued to expand in **Central America and the Caribbean** markets, where combined LNG imports increased by 7% y-o-y in Q1-Q3 2025.

For 2025 as a whole, Central and South America's natural gas demand is projected to remain close to last year's levels. **In 2026**, a modest decline in natural gas consumption is expected despite continued industrial growth as renewable output accelerates the displacement of natural gas use in electricity generation.

…with demand growth largely concentrated in Q3 2025

Estimated year-on-year change in quarterly natural gas demand in Central and South America, 2023-2025



Sources: IEA analysis based on ANP (2025), Boletim Mensal da Produção de Petróleo e Gás Natural; BMC (2025), Informes Mensuales; Central Bank of Trinidad and Tobago (2025), Statistics; MEEI (2025), Monthly bulletins; CNE (2025), Generación bruta SEN; ENARGAS (2025), Datos Abiertos; ICIS (2025), ICIS LNG Edge; IEA (2025), Monthly Gas Data Service; JODI (2025), Gas Database; OSINERG (2024), Reporte diario de la operación de los sistemas de transporte de gas natural.

Asia's natural gas demand growth remained subdued during Q1-Q3 2025

Following strong growth of 5.5% in 2024, natural gas demand growth in Asia declined by an estimated 0.5% in Q1-Q3 2025. This decline was largely concentrated in the first half of the year and was driven by weaker macroeconomic conditions, relatively high spot LNG prices, mild weather conditions in northeast China, as well as lower gas use in the power sector. For 2025 as a whole, Asia's gas demand is expected to expand by less than 1%, largely supported by a modest recovery in power sector gas use during the remainder of the year. In 2026, total consumption in Asia is projected to grow significantly more rapidly, by more than 4%, driven by rebounding industrial demand due to improved LNG availability and – to a lesser extent – by modest increases in demand from the power, residential and commercial sectors.

China's natural gas demand remained broadly flat y-o-y in Q1-Q3 2025. The country's natural gas consumption declined by almost 1% y-o-y the first half of the year, primarily due to lower gas use in industry and below-average heating demand in Q1. Preliminary data suggest that China's natural gas demand grew by around 3% y-o-y in Q3 2025, largely offsetting the declines recorded in H1 2025. Stronger gas use in industry and the power sector supported this recovery. China's relatively weak demand coincided with a strong growth in domestic production (up by 6% y-o-y in the first eight months of 2025) and the continued ramp-up of Russia's piped gas deliveries via the Power of Siberia pipeline system (up by an estimated 25% y-o-y in Q1-Q3 2025). This led to a steep decline in China's LNG import requirements, plummeting by 17% y-o-y in Q1-Q3 2025.

Full-year demand for 2025 is expected to increase by around 1% from 2024 levels. In 2026, Chinese demand growth is expected to recover from the 2025 slowdown, reaching close to 6% as easing economic headwinds drive industrial activity and accelerating global LNG liquefaction capacity additions provide supply-side support to Chinese buyers.

Japan's natural gas consumption decreased by 1.7% y-o-y in H1 2025, mainly due to stronger gas use in the industrial and residential and commercial sectors. The demand for LNG-fired power did not increase because of the restart of Onagawa nuclear power plant last year and increased renewable power generation (up by an estimated 20% y-o-y). Total gas consumption in 2025 is expected to decrease by 1.1%, driven by reduced gas use for power generation amid improving nuclear availability and higher renewable output. In 2026, Japan's gas demand is expected to decline by close to 2.5%, mainly driven by lower gas use in power generation amid nuclear restarts and robust renewable generation growth.

Korea's natural gas demand increased by 1.5% y-o-y in H1 2025, supported by strong demand in the power generation sector, as well as in industry and energy sector own use. In 2025, total gas demand is expected to rise by 1.3% y-o-y, mainly driven by the power sector, along with more modest increases in the residential and commercial sectors and in industry. Despite the addition of new nuclear capacity, gas demand in 2026 is projected to remain flat, as declining coal use in the power generation sector and modest increases in industrial, residential and commercial consumption of gas fully offset the headwinds from nuclear.

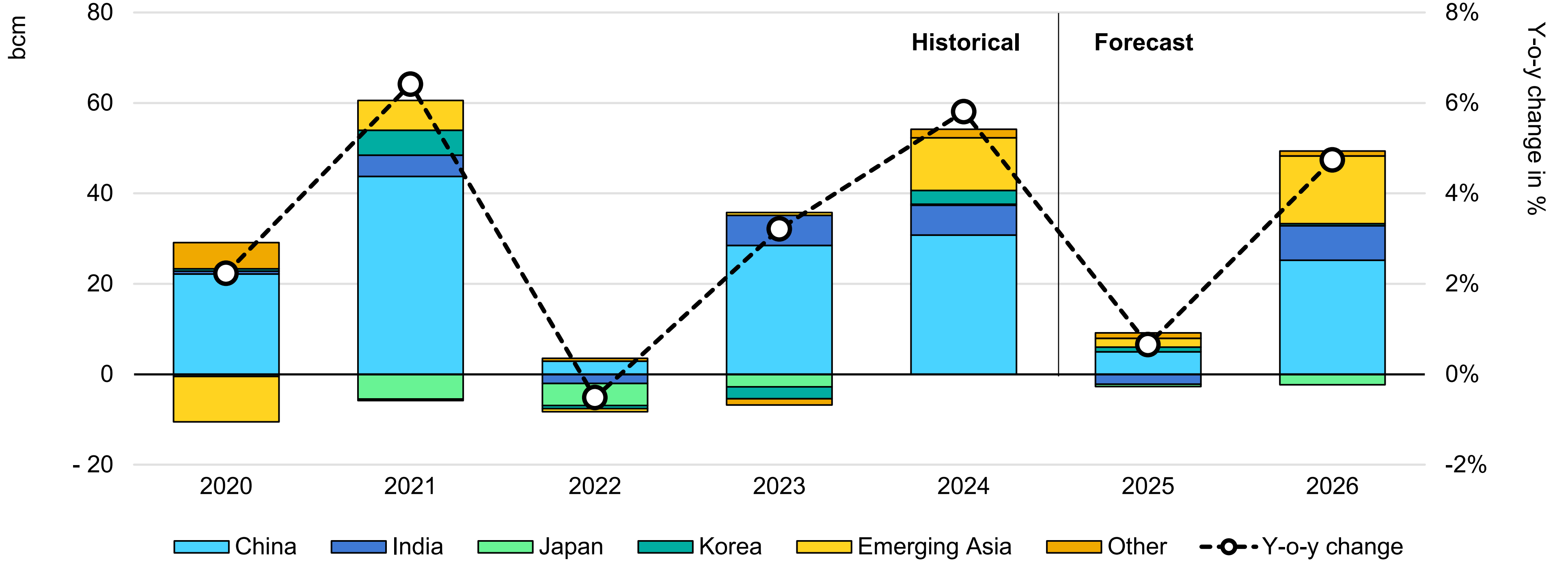
India's total gas consumption fell by 6% y-o-y in the first eight months of 2025, based on preliminary data. This decline was mainly driven by the power generation and oil refining sectors (both down 20% y-o-y), as well as lower gas use in fertiliser production. In contrast, city gas distribution demand increased by almost 9% y-o-y amid the continued expansion of the gas network to new commercial and residential buildings. India's natural gas production fell by 3% y-o-y in the first eight months of the year. As demand declined more steeply than domestic gas output, the country's LNG imports declined by almost 10% y-o-y in the first eight months of 2025. For the full year of 2025, India's natural gas demand is expected to decline by 3%, a notable shift from the 10% growth seen in 2024. In 2026 India's gas consumption growth is forecast to reach 7%, driven by the ongoing expansion of India's city gas distribution and CNG filling station networks, expanding industrial gas use and rising electricity needs.

Emerging Asia's gas consumption remained close to last year's levels in Q1-Q3 2025. The region's net LNG imports grew by around 1% y-o-y in Q1-Q3 2025, partially offsetting the production declines recorded in some of the region's producers. **Thailand**'s natural gas consumption fell by 5% y-o-y in the first eight months of 2025, primarily driven by steep declines in power sector gas use (down 10%). **Indonesia**'s total consumption rose by 2% y-o-y in the first seven months of 2025, supported by industry and the power sector. **Malaysia**'s gas demand remained close to the previous year's levels in Q1-Q3 2025. **Pakistan**'s total consumption is estimated to have declined by around 5% y-o-y in Q1-Q3 2025 amid weaker gas use in the power sector. LNG imports were similarly subdued (down 7%) in Q1-Q3 2025. **Bangladesh**'s natural gas demand rose by an estimated 6% y-o-y in Q1-Q3 2025, primarily supported by industry. The country's LNG imports increased by 40% y-o-y in Q1-Q3 2025, amid stronger demand and a continued decline in domestic natural gas output, which fell by 7.5% y-o-y in the first half of 2025.

For 2025 as a whole, gas demand growth in Emerging Asia is projected to slow from around 5% in 2024 to approximately 1% in 2025, as relatively high LNG prices and macroeconomic headwinds weigh on natural gas use. **In 2026**, Emerging Asia's gas consumption growth is expected to accelerate to around 6%, driven by recovering gas use in both the power and industrial sectors amid rising overall energy needs, moderating prices and improving macroeconomic conditions.

Natural gas demand in Asia is expected to return to stronger growth in 2026

Year-on-year change in natural gas demand in Asia Pacific, 2020-2026



Note: Emerging Asia comprises Bangladesh, Indonesia, Malaysia, Myanmar, Pakistan, the Philippines, Singapore, Thailand and Viet Nam.

European natural gas consumption grew by nearly 5% in Q1-Q3 2025

Natural gas consumption in OECD Europe rose by almost 5% (or 15 bcm) y-o-y in Q1-Q3 2025. Growth was **primarily concentrated** in Q1, when cold weather and lower renewable power output drove up natural gas demand by 9% y-o-y. Demand growth continued during Q2-Q3, albeit slowing to just below 1% y-o-y. The **power sector was the most important driver** behind higher gas use and alone accounted for around 80% of the incremental gas demand in Q1-Q3 2025 amid lower wind and hydro power output. In contrast, higher natural gas prices weighed on natural gas use in industry during the first three quarters of the year.

Distribution network-related demand rose by an estimated 4% (or 4.5 bcm) y-o-y in Q1-Q3 2025, with growth entirely concentrated in Q1. Heating degree days increased by more than 10% y-o-y in Q1, which naturally drove up space heating requirements across households and commercial entities. First data suggest that natural gas consumption via the distribution network fell by 3% y-o-y during Q2-Q3 2025, partially due to warmer temperatures in April and potentially reflecting efficiency improvements in commercial entities.

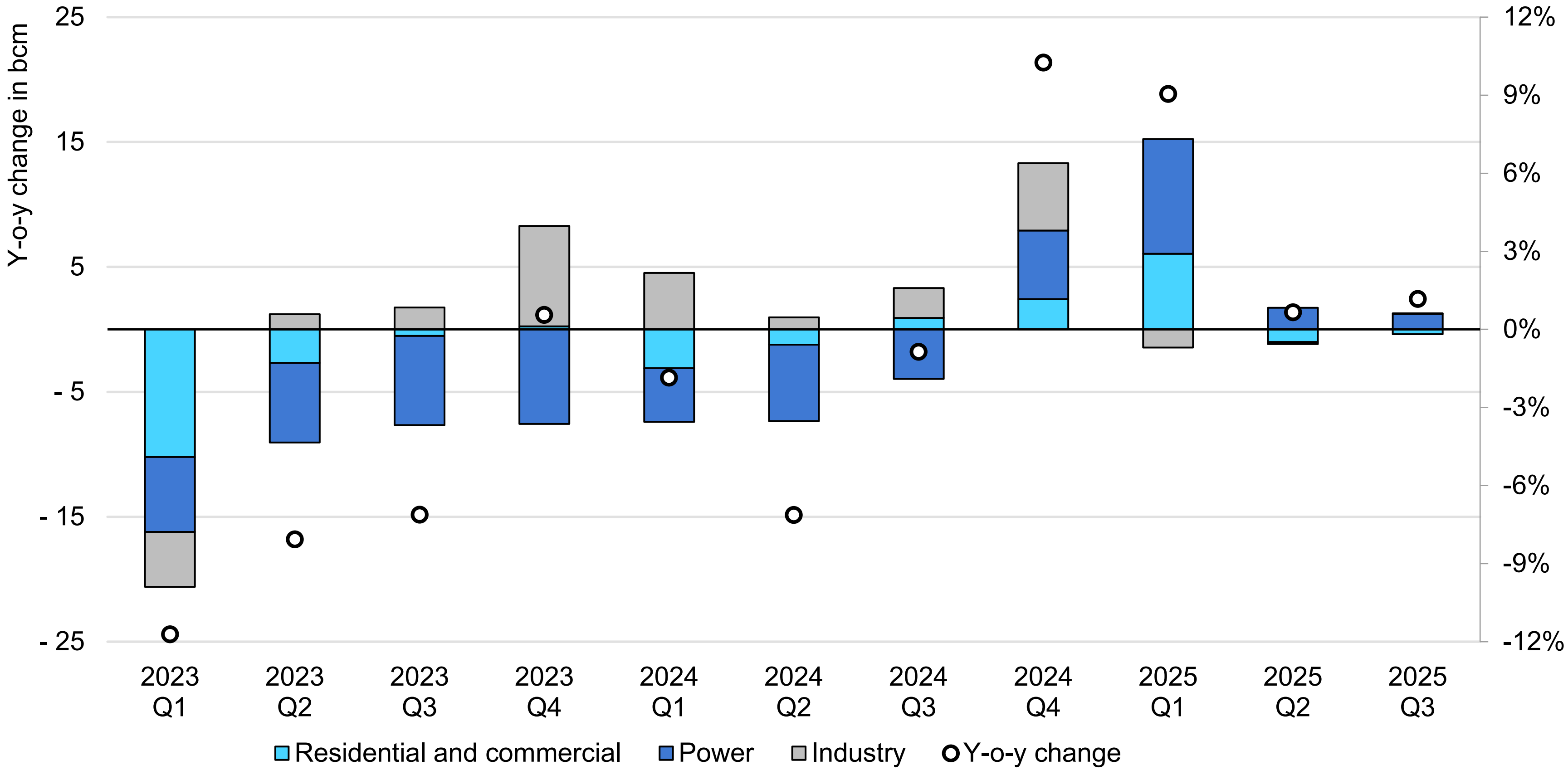
Gas-to-power demand rose by 15% (or 12 bcm) y-o-y in Q1-Q3 2025. This steep increase was primarily supported by lower renewable power generation (down by an estimated 3% y-o-y) and stronger electricity consumption. While solar power generation rose by almost 20% y-o-y, this was more than offset by lower wind and hydro generation. Wind power output recorded a 5% y-o-y decline amid slower wind speeds across Northwestern Europe, while hydropower generation fell by 12%, primarily due to lower hydro availability in Southern Europe.

Natural gas consumption in industry declined by an estimated 2% y-o-y in Q1-Q3 2025 amid higher natural gas prices. This decline was primarily concentrated in H1 2025, while first data suggest that gas use in industry remained close to the previous year's level in Q3 2025. In Q1-Q3 2025, industrial gas consumption decreased by an estimated 2.5% y-o-y in Belgium, by 7% in France, by more than 10% in the Netherlands and by 6% in Spain. First data suggest that this decline was primarily driven by the refining and fertiliser sectors.

For the full year of 2025, this **forecast** expects natural gas demand in OECD Europe to increase by nearly 3%. Gas-to-power demand is projected to increase by almost 10% as the recovery and continued expansion of renewables are expected to partially offset the strong gains recorded in Q1-Q3 2025. Natural gas demand in the buildings sector is expected to increase, assuming average winter weather conditions in Q4. Gas use in industry is forecast to decline by 1.5% in 2025 amid the higher gas price environment. This forecast expects Europe's natural gas demand to decline by 2% in 2026, as the continued expansion of renewables weighs on gas burn in the power sector.

The power sector emerged as the strongest driver of Europe's gas demand in Q1-Q3 2025

Estimated year-on-year change in semi-annual natural gas demand in OECD Europe, 2023-2025



Sources: IEA analysis based on Enagas (2025), Natural Gas Demand; ENTSOG (2025), Transparency Platform; EPIAS (2025), Transparency Platform; Trading Hub Europe (2025), Aggregated consumption.

LNG supply growth continues to accelerate despite underperformance at certain legacy plants

Global LNG trade grew by about 4.7% y-o-y (or 19 bcm) in the first nine months of 2025, with supply progressively accelerating into the third quarter. The ramp-up of new liquefaction projects (notably in North America) was key to this growth, but European gas market dynamics also drove a strong demand-side pull, absorbing the equivalent of more than total supply growth. Following lacklustre growth in 2023 and 2024, more incremental LNG supply is set to reach the market in 2025 than in any single year since 2019.

The United States provided the largest LNG export upside (up nearly 21 bcm) over the first three quarters of the year. This came from both the ramp-up of new projects (Plaquemines LNG and Corpus Christi Stage 3 expansion) and the effects of debottlenecking and a return to normal operations at Freeport LNG (after two years of sub-par output).

Qatar was the second-largest growth contributor, squeezing out more cargoes from its existing liquefaction trains. Mexico and Canada also drove the upside, although at a much smaller scale.

However, a number of legacy producers put downside pressure on the market over this period, most notably Russia, Norway, Algeria and Australia. Russian exports fell by 11% y-o-y (or 3.5 bcm) in this period as two sanctions-hit plants remained offline. Arctic LNG 2, also under sanctions, still managed to export 6 cargoes to China from June to September, but these totalled less than 1 bcm.

Planned maintenance and a delayed restart at Norway's Hammerfest LNG lowered output by 44% y-o-y in the Q1-Q3 period. Algerian exports, which have trended below prior-year levels since the second quarter of 2024, were down by 22% y-o-y. In Australia, exports were down 3% y-o-y, impacted notably by ongoing decline at the North West Shelf Australia LNG project and a month-long maintenance shut-in at Ichthys LNG. In all, production declines from these projects and others totalled over 13 bcm.

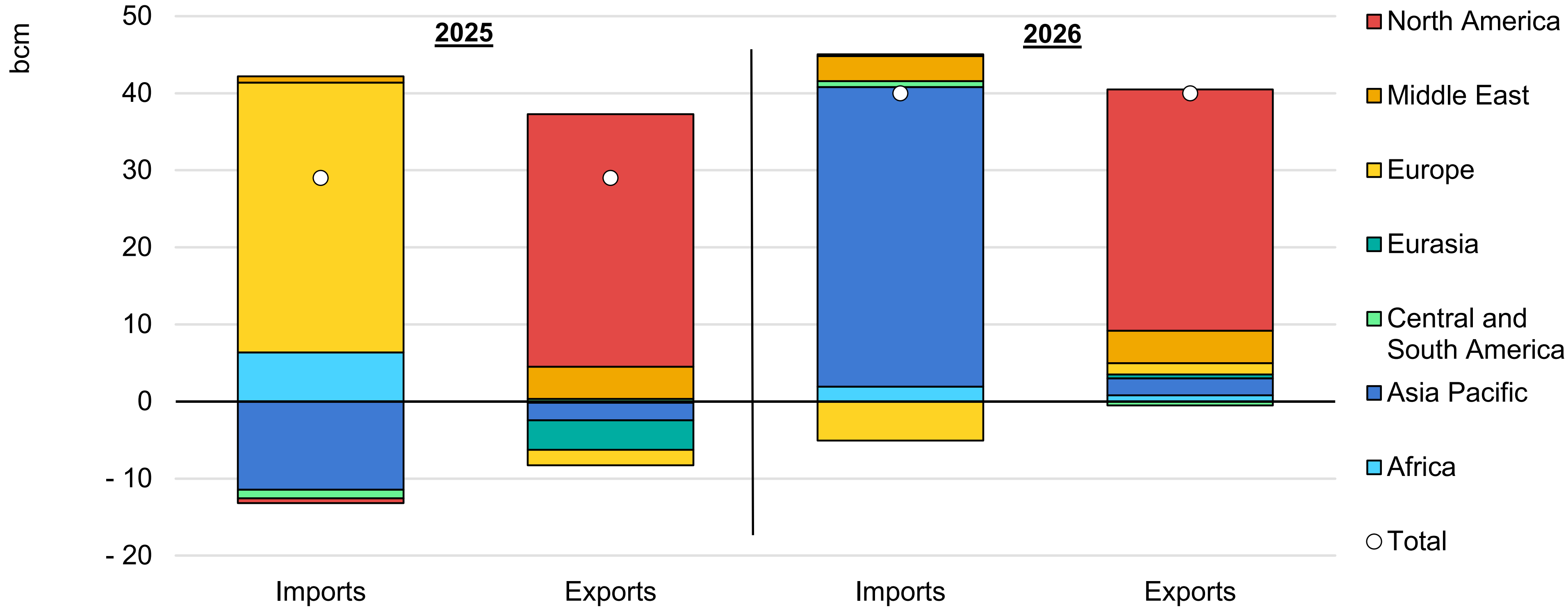
As a result of tightening pipeline supply dynamics, Europe's LNG imports grew by 28% y-o-y (or 27 bcm), outpacing global net incremental LNG supply since the start of 2025. Simultaneously, imports into Asia fell by nearly 5% y-o-y (13 bcm), notably as Chinese LNG buying significantly trailed the previous year's levels in most months. Cumulative Chinese LNG imports remained down 17% y-o-y (or nearly 14 bcm) by September.

Outside Europe and Asia, Egypt also drove shifting trade flows. The addition of an extra floating storage and regasification unit allowed Egyptian LNG imports to skyrocket in Q3 2025. Total imports in the first nine months of the year were up 350% y-o-y (or 6 bcm).

Thanks to the continuing ramp-up of new liquefaction projects, we expect LNG trade to grow by over 5% y-o-y, or 29 bcm, in 2025. In 2026, growth is expected to continue accelerating to about 7% y-o-y, or 40 bcm, notably allowing Asia as a whole to return to import growth.

North America leads LNG supply growth in 2025 and 2026

Year-on-year change in LNG imports and exports by region, 2025 and 2026



Source: IEA analysis based on ICIS (2025), LNGEdge.

US gas production growth continues to follow incremental LNG export requirements

US dry natural gas production is estimated to have grown by 3.3% y-o-y in the first nine months of 2025. Despite an easing of the growth dynamics from the second to the third quarter, Q3 production was still up 4.6% y-o-y. This growth is underpinned by rising LNG feedgas requirements and a stronger gas price environment than in 2024, compensating for relatively subdued domestic oil market dynamics and broader economic uncertainty.

In the midst of weak US oil market fundamentals and a declining rig count, average Permian Basin associated gas production growth in Q1-Q3 2025 (9.2% y-o-y) stood about 4 percentage points lower than in full-year 2024. Nevertheless, improved well productivity and increasing gas-to-oil ratios for both existing and new plays helped prop up third-quarter production growth at 7.7% y-o-y, maintaining the Permian Region as the primary contributor to US output growth this year. These trends are set to extend into 2026 as weak oil market fundamentals persist.

Improving gas price dynamics continue to support a recovery in non-associated Haynesville shale. Despite a downward trajectory since the start of the year, Henry Hub prices averaged USD 3.11/MBtu in second and third quarters of 2025, about 50% above the same period in 2024. This helped reverse a year-long period of production decline in the higher-cost Haynesville Basin by the start of Q2 2025, with production growth accelerating through the summer months. While we expect Haynesville production to continue recovering into 2026, output is likely to remain sensitive to the domestic gas price environment.

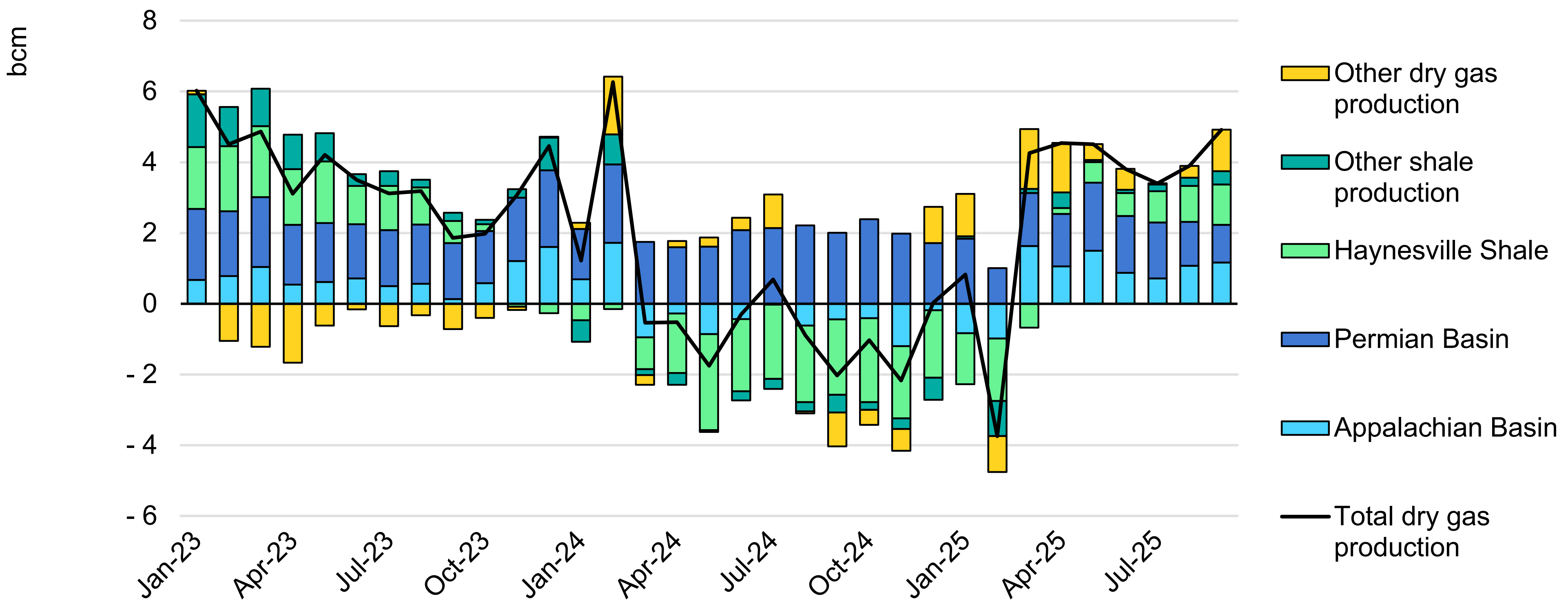
Appalachian gas production had switched back to sustained growth by March 2025 as drilling activity (particularly in the Utica play) has risen through much of 2025. By Q2 and Q3 2025, monthly Appalachian output had recovered to (and even surpassed) pre-2024 levels, supported in part by in-basin demand dynamics and by additional takeaway capacity from the Mountain Valley Pipeline, which came into service in mid-2024. Despite abundant low-cost natural gas reserves in the region, takeaway pipeline capacity constraints are expected to act as a limit on production growth in the short term.

US domestic consumption is set to remain largely flat during 2026. However, feedgas demand from new liquefaction projects is set to drive production growth. Feedgas requirements for LNG exports already added over 20 bcm of incremental pull to the US market in Q1-Q3 2025 and are set to continue growing in 2026. Much of this growth is set to be driven by Plaquemines LNG and the Corpus Christi Stage 3 expansion (which started ramping up in 2025), with Golden Pass LNG expected to add further demand in 2026.

Despite the scale of liquefaction capacity additions, the US market is expected to remain well supplied, with dry gas production growing by 3% in 2025 and about 2% in 2026, reaching new record highs in both years.

Rising LNG exports drive natural gas production growth through Q3

Year-on-year change in monthly dry natural gas production in the United States, 2024-2025



Note: August and September include estimated data.
Source: Energy Information Administration (2025), Natural Gas.

Europe’s LNG imports rose to an all-time high in Q1-Q3 2025

OECD Europe’s primary natural gas supply increased by an estimated 6.5% (or 19 bcm) y-o-y in Q1-Q3 2025. The strong increase in LNG imports, together with higher non-Norwegian gas production, offset the declines recorded in piped gas imports.

Europe’s **LNG imports** rose by 28% (or almost 28 bcm) y-o-y and reached an all-time high of 127 bcm in Q1-Q3 2025. Stronger domestic demand, together with lower piped gas imports and higher storage injections since April, kept European LNG netback prices at a premium compared with key Asian markets. This in turn incentivised flexible LNG cargoes to flow towards Europe. Consequently, the share of LNG in Europe’s primary natural gas supply rose from 35% in Q1-Q3 2024 to 42% in Q1-Q3 2025. The United States increased its LNG deliveries to Europe by 60% y-o-y in Q1-Q3 2025 and alone accounted for almost all incremental LNG supply to Europe during this period. This reinforced the United States’ position as Europe’s largest LNG supplier, accounting for almost 60% of Europe’s LNG imports in Q1-Q3 2025. **Russian LNG** inflows fell by 10% (or 1.8 bcm) y-o-y, although Russia remained Europe’s second-largest LNG supplier. Belgium, France and Spain accounted for over 85% of Europe’s total LNG imports from Russia in Q1-Q3 2025.

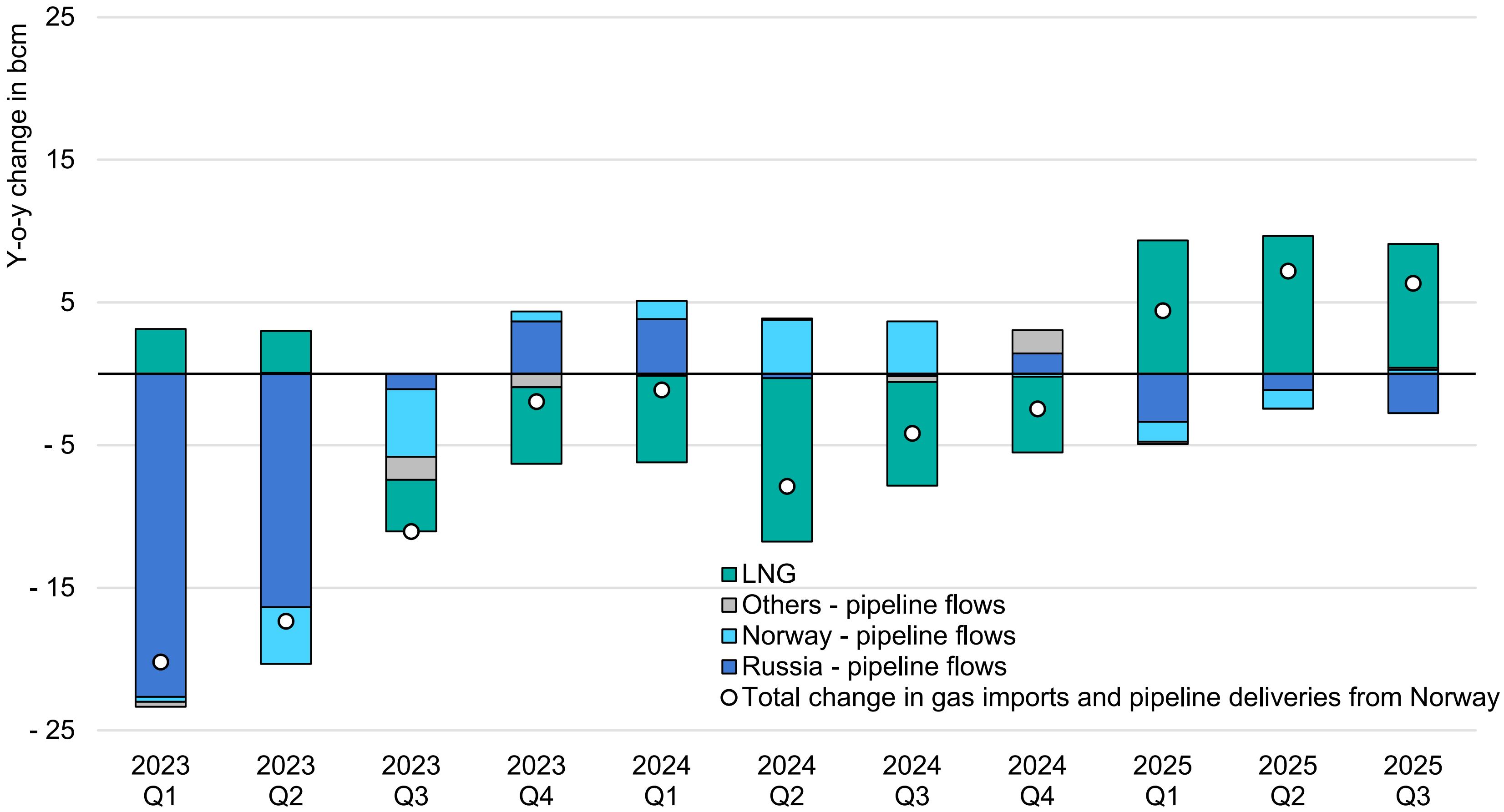
Norway’s piped gas deliveries to the rest of Europe declined by 2.8% (or almost 2.5 bcm) y-o-y in Q1-Q3 2025 amid unplanned outages and higher maintenance works. Deliveries to the United Kingdom dropped by 9% (or 1.7 bcm) and declined by 1% (or 0.7 bcm) to the rest of Europe. **Non-Norwegian domestic production** grew by 4% (or 0.7 bcm) y-o-y in the first seven months of 2025. This increase was primarily supported by the strong production growth recorded in Denmark, Italy and Türkiye. In Denmark, domestic production grew by 80% (or 0.7 bcm) y-o-y on the back of the redeveloped Tyra field. In Türkiye, natural gas output grew by 60% (or 0.7 bcm) y-o-y, with growth driven by the Sakarya field.

Russia’s piped gas supplies to the European Union fell by 45% (or 10 bcm) y-o-y in Q1-Q3 2025 amid the halt of gas transit via Ukraine. Exports to Türkiye rose by more than 20% (or almost 2.5 bcm) y-o-y in the first seven months of 2025. The share of Russian piped gas in Europe’s gas demand is estimated at below 10% in Q1-Q3 2025. Piped gas supplies from **North Africa** remained broadly flat, while **Azeri flows** via the TAP fell by 2% (or 0.2 bcm) in Q1-Q3 2025.

Lower Russian and Norwegian piped gas supplies, together with higher gas consumption and stronger storage injection requirements, are expected to increase Europe’s LNG imports by more than 20% in 2025 to reach a new record. We expect Europe’s LNG imports to decline by almost 5% in 2026 amid lower demand and higher piped gas deliveries from Norway.

Strong US LNG supply is offsetting the decline in piped gas deliveries to Europe

Year-on-year change in quarterly European natural gas imports and deliveries from Norway, Q1 2023-Q3 2025



Sources: IEA analysis based on Enagas (2025), Natural Gas Demand; ENTSOG (2025), Transparency Platform; EPIAS (2025), Transparency Platform; Trading Hub Europe (2025), Aggregated consumption.

Asian and European gas prices moderated to below last year's levels in Q3 2025

Natural gas prices moderated across all key markets in Q3 2025 compared with the previous quarter and fell below their 2024 levels in Asia and Europe. In contrast, tighter market fundamentals in the United States kept Henry Hub prices well above their 2024 levels.

In **Europe**, TTF spot prices fell by 4% compared with Q2 to an average of USD 11.3/MBtu in Q3 2025, standing 1% below Q3 2024 levels. The strong inflow of LNG (up by more than 30% y-o-y), together with improving renewable power output, provided downward pressure on European hub prices. Short-term price variability softened as well. The volatility on TTF month-ahead declined from 50% in Q2 to 28% in Q3 – its lowest quarterly average since Q3 2018. Improved global LNG supply availability and the absence of unforeseen supply and demand patterns limited short-term price variability on the European market.

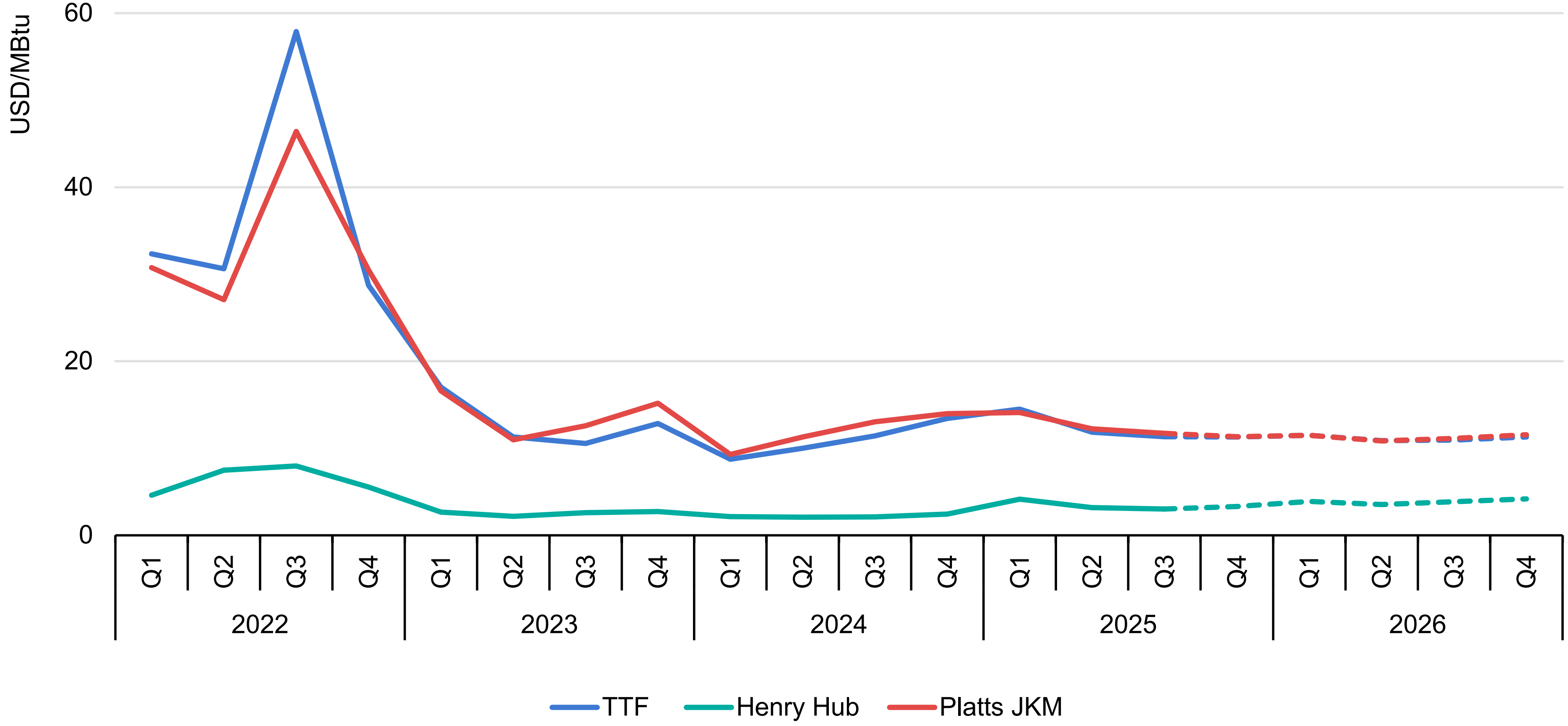
In **Asia**, Platts JKM prices followed a similar trajectory and declined by 4% on the quarter to an average of USD 11.7/MBtu in Q3 2025 – standing 10% below last year's Q3 levels. Weak regional demand, together with improving LNG supply availability and the ramp-up of Russian piped gas deliveries to China, weighed on regional price levels. In China, the nationwide ex-factory LNG price declined by 7% on the quarter to an average of RMB 4 360/tonne (around USD 10/MBtu). Oil-indexed LNG prices traded in an estimated range of USD 11-12/MBtu, incentivising Asian buyers to reduce their spot LNG procurements and nominate higher volumes through long-term contracts.

In the **United States**, Henry Hub prices fell by 5% on the quarter to an average of USD 3/MBtu in Q3 2025, albeit trading 40% above Q3 2024 levels. Relatively low storage levels following the 2024/25 winter and higher injection needs provided upward pressure on Henry Hub prices.

Forward curves as of the end of September suggest that TTF prices could increase by 12% in 2025 compared with 2024 and average at just over USD 12/MBtu. Higher storage injections through the summer, together with lower piped gas imports and continued competition for flexible LNG cargoes, support higher gas prices. Forward curves indicate that JKM prices could increase by 4% in 2025 to an average of nearly USD 12.5/MBtu. A tight TTF-JKM spread is expected to continue to incentivise healthy LNG flows towards Europe in Q4. Based on forward curves, Henry Hub prices in the United States are expected to increase by over 55% to average USD 3.4/MBtu amid tighter market fundamentals. Forward curves suggest that Asian and European gas prices could soften in 2026. Both TTF and JKM prices could decline by around 10% to an annual average of just below USD 11/MBtu, amid improving LNG availability. Forward curves suggest that Henry Hub prices could increase by more than 10% to an average near USD 4/MBtu, supported by tighter market fundamentals in the United States.

Improving LNG supply is expected to weigh on Asian and European spot prices in 2026

Main spot and forward natural gas prices, 2022-2026



Note: Future prices are based on forward curves as of the end of September and do not represent a price forecast.
Sources: IEA analysis based on CME Group (2025), Henry Hub Natural Gas Futures Quotes, Dutch TTF Natural Gas Month Futures Settlements, LNG Japan/Korea Marker (Platts) Futures Settlements; EIA (2025), Henry Hub Natural Gas Spot Price; Powernext (2025), Spot Market Data; S&P Global (2025), Platts Connect.

Strong summer recovery in EU and US inventories provides optimism for winter 2025/26

EU and US underground gas storage inventories ended winter 2024/25 in a relatively weak position. However, above-average summer injections have set storage dynamics back on track to help balance the global market through the winter.

EU underground gas storage fill followed a steady recovery over the second and third quarters of 2025, largely compensating for below-average inventories at the start of the filling season. However, despite this trajectory, EU storage levels are likely to fall short of the 90% fill target before the start of winter 2025/26.

EU storage levels ended the 2024/25 winter at a 42% (or 26 bcm) deficit to the previous year's levels following an above-average seasonal drawdown. However, the switch to net injections occurred in line with the early-April norm and injection rates remained broadly above the five-year average for much of the filling season. As a result, the year-on-year storage deficit had fallen to just 13% (or 13 bcm) by the start of October.

Reaching the European Union's 90% fill target from the levels in store in early October (83%) would require injections of about 8 bcm – more than double the five-year average in October injections and about 15% more than the volume injected over the same month in 2022. EU-level political agreement to extend the target deadline to 1 December instead of 1 November grants flexibility around the storage obligation, but continued net injections through November would require a clear market signal to boost injection rates from their early October levels. As such, EU underground gas storage fill is likely to remain below the 90% target ahead of winter 2025/26.

In Ukraine, storage injection rates in the 2025 filling season were significantly stronger than in 2024, with approximately 50% more gas injected into storage to the end of September than in the same period last year. This helped storage levels recover to 2024-equivalent levels by mid-September (up from an 80% deficit at the end of the 2024/25 winter) and stretch 5% ahead of 2024 levels by the start of October. Nevertheless, this remains 28% below levels on the same date in 2023.

An earlier than average start to the filling season and faster than average injections helped US storage levels recover from a year-on-year deficit of 27% (or 18 bcm) in early March and end September about 1% (or 1 bcm) above 2024 levels. Despite the backdrop of growing LNG feedgas demand, the US gas market remained well supplied throughout the second and third quarters of 2025, freeing up gas for greater injections than in recent years.

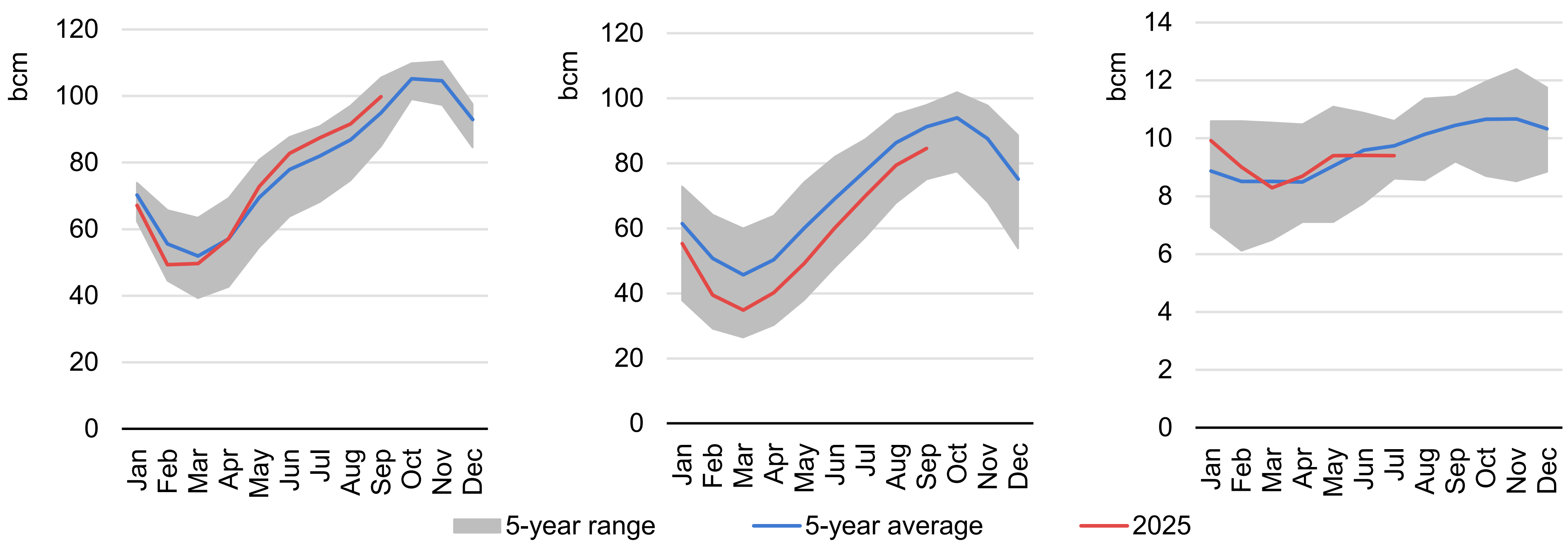
Strong weather-linked power sector gas burn in Korea contributed to a widening deficit against the five-year average in LNG inventories in the first half of 2025. By June, stocks were rising, but July levels remained 31% below their 2024 levels. Despite similar demand dynamics in Japan, LNG stocks broadly tracked 2024 levels over the same period. Their combined inventories trended slightly above the five-year average in the first half of 2025.

US pre-winter inventories are above the five-year average, European levels remain below

US underground storage inventories inventories

EU underground storage inventories

Japan and Korea LNG



Source: IEA analysis based on EIA (2025), Weekly Working Gas in Underground Storage; GIE (2025), AGSI+ Database; JODI (2025), World Gas Database.

Medium-term market outlook

Key assumptions behind the medium-term forecast

Natural gas markets are becoming increasingly complex and difficult to predict in a rapidly changing geopolitical context and trade environment. This section provides an overview of the key assumptions behind the medium-term gas market forecast.

Macroeconomic outlook: Towards slower growth

Global GDP growth is expected to average 3% per year during the forecast period (2024-2030), less than the pre-pandemic historical average of 3.7%. Following an increase of 3.3% in 2024, global GDP growth is forecast to slow to 3% in 2025 and to 2.9% in 2026 – its lowest annual rate since the 2007-2008 global financial crisis, with the exception of the 2020 pandemic period. Global GDP growth is expected to continue to average around 3% during 2027-2030. A **more complex trade environment** is weighing on economic performance, while tariff policies remain a key uncertainty for the current forecast. **Asian markets are expected to account for almost 60% of global GDP growth** during the forecast period, followed by North America (12%) and the European Union (7%).

Global LNG supply: The next LNG wave

The outlook for global LNG supply is driven by the **official timelines of LNG projects** that have reached final investment decision (FID) and/or are under construction. Assumptions on ramp-up rates and utilisation factors are applied based on historic profiles of LNG export plants. **This forecast expects global LNG liquefaction capacity to expand by around 300 bcm/yr by 2030** compared with 2024. This unprecedented growth is largely driven by **Qatar and the United States**, with the two countries accounting for more than 70% of the liquefaction capacity additions during the outlook period. This strong increase in LNG liquefaction capacity is partially offset by the continued **feedgas supply issues** at certain legacy LNG producers amid declining upstream deliverability and/or a strong increase in domestic demand. We assume that feedgas supply issues could reduce LNG production by nearly 20 bcm/yr by 2030. Together with the assumed ramp-up rates and utilisation factors, this forecast expects **global LNG supply to increase by around 250 bcm/yr by 2030**.

Russia's Arctic LNG 2 project remains under international sanctions and hence is not considered as a source of firm supply in the outlook. Sporadic LNG exports from the two-train plant cannot be excluded, which adds further upside potential to the global LNG supply during the forecast period.

Russian natural gas exports

This forecast assumes that Russia's **LNG deliveries** to the European Union will halt by 1 January 2027, while **piped gas supplies** will be phased out by 1 January 2028 in line with the European Commission's proposed regulation. This would reduce Russian piped gas deliveries to the European Union by around 12 bcm compared with 2025 (and by nearly 30 bcm compared with 2024). Notably, these volumes cannot be redirected to other markets and hence would result in a loss to the overall global gas supply. Russia's LNG exports to the European Union stood at around 21 bcm in 2024 and are expected to be gradually redirected to other markets (primarily Asia) in 2026. **Russia's piped gas exports to China** are assumed to continue to increase via the Power of Siberia pipeline system, from 30 bcm/yr in 2024 to 44 bcm/yr by 2030. In addition, Russia's Far East Pipeline is assumed to start operations in 2027 and ramp up to a range of 10-12 bcm/yr by 2030. These assumptions reflect the latest agreements signed between Gazprom and CNPC on the potential to increase Russian piped gas deliveries to China.

Natural gas prices in Europe and Asia are expected to converge close to the short-run marginal cost of US LNG

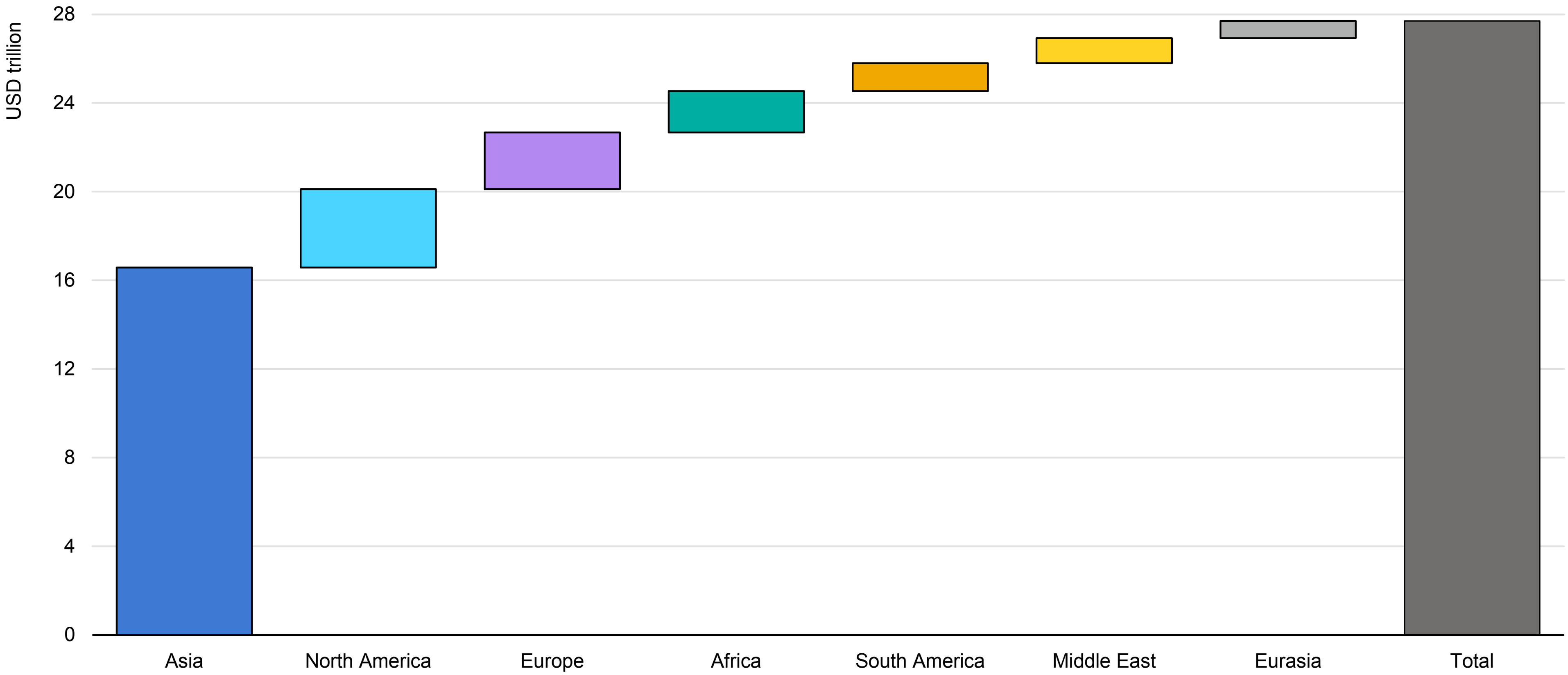
This forecast partially relies on external energy price assumptions, informed by forward curves observed at the end of September 2025. **In the United States**, Henry Hub prices collapsed to USD 2.2/MBtu in 2024 – their lowest level since 1998, with the exception of the 2020 pandemic period. Prices recovered to USD 3.5/MBtu in Q1-Q3 2025. Forward curves indicate that **Henry Hub** prices in the United States are expected to average USD 3.7/MBtu during 2025-2030, almost 15% above the levels experienced between 2019 and 2024. In **Europe**, natural gas prices on TTF moderated from their 2022-2023 highs and averaged just below USD 11/MBtu in 2024. TTF prices rose to an average of USD 12.5/MBtu in Q1-Q3 2025 amid tighter market fundamentals. In **Asia**, Platts JKM prices followed a similar trajectory. Following the easing in 2024, JKM prices rose to an average of USD 12.7/MBtu in Q1-Q3 2025. Considering the strong increase in LNG supply, both **European hub and Asian spot LNG prices could start to gradually converge towards the short-run marginal cost of US LNG** between 2027 and 2030. Under these assumptions, European hub and Asian spot LNG prices are expected to average USD 8/MBtu and USD 8.5/MBtu in the 2025-2030 period, respectively, around 40% below the levels experienced between 2019 and 2024. Natural gas prices trending below their historic averages are expected to unlock additional demand, especially in the price-sensitive Asian markets. Based on current forward curves, **oil-indexed LNG prices** are assumed to average USD 10/MBtu between 2025 and 2030, almost 10% below their levels between 2019 and 2024.

Power sector and weather-related assumptions

Natural gas consumption is particularly sensitive to the weather. This forecast is based on the assumption of average winter conditions for the forthcoming heating seasons (using a five-year rolling average). Renewable power generation capacity additions are based on the IEA Renewables 2025 report. This forecast assumes average hydro availability and average wind speeds. Assumptions on nuclear power capacity are detailed through the relevant sections of the report.

Asia alone is expected to account for almost 60% of global GDP growth in the medium term

Forecast GDP growth across key regions, 2024-2030



Source: IEA analysis based on Oxford Economics.

Finding a balance: How will the global gas market absorb the next LNG wave?

Global LNG supply is expected to expand by almost 50% by 2030. This unprecedented growth in LNG supply is set to profoundly transform the global gas market, unlock additional natural gas demand and drive new marketing strategies.

The upcoming LNG wave will play a crucial role in ensuring gas supply security and affordability over the medium term

Global LNG liquefaction capacity is set to increase by 300 bcm/yr by 2030 compared with 2024, based on the official timelines of projects that have reached FID and/or are under construction. More than 230 bcm/yr of LNG liquefaction capacity was sanctioned and/or started construction after Russia's full-scale invasion of Ukraine. Russia's piped gas supplies to Europe fell by 120 bcm during 2022-2023, equating to around one-fifth of global LNG trade at the time. The scale-up of LNG supply is **playing a key role in rebalancing the global gas market**, enhancing supply security and improving the affordability of natural gas, including in emerging, price-sensitive import markets.

The United States and Qatar are leading the next LNG wave, together accounting for more than 70% of the incremental liquefaction capacity expected to come online by 2030. This strong increase in LNG liquefaction capacity coincides with mounting feedgas supply issues at certain legacy LNG producers, which often face the double challenge of declining upstream deliverability and growing domestic natural gas demand. Feedgas supply issues at legacy producers could reduce LNG production by nearly 20 bcm/yr by 2030. This includes lower LNG export capability at legacy plants in Africa and Southeast Asia. Taking this into account together with assumed ramp-up rates and utilisation factors, this forecast expects **global LNG supply to increase by around 250 bcm/yr by 2030** – equating to nearly half of the current global LNG trade. This strong increase is comparable to around 7% of Asia's thermal coal demand.

Domestic production is expected to display varying patterns across key LNG import markets

Domestic gas production is expected to increase by more than 55 bcm/yr across key LNG importing countries. This growth is largely concentrated in **China**, where domestic gas output is forecast to expand by over 20% (or about 55 bcm/yr) by 2030. However, other key LNG import markets in Asia are expected to face declining production rates, including Bangladesh and Pakistan.

In **Europe**, non-Norwegian domestic natural gas production is expected to increase marginally over the forecast period, as production declines in Northwestern Europe are more than offset by the ramp-up of the Sakarya field in Türkiye and the start-up of the Neptun Deep field in Romania. The deteriorating upstream deliverability of ageing North Sea fields in the UK Continental Shelf is a key driver behind this trend. In **Central and South America**, the ramp-up of Vaca Muerta production in Argentina and the development of pre-salt fields in Brazil are set to have an easing effect on the region's LNG import needs over the medium term.

Piped gas trade is expected to decline in the medium term

Europe's piped gas imports (including from Norway) are expected to decline by more than 25% (or 60 bcm) between 2024 and 2030. This forecast assumes that Russia's piped gas to the European Union will halt by 1 January 2028, in line with the European Commission's proposal. This would reduce Russian piped gas deliveries to the European Union by nearly 30 bcm compared with 2024. Notably, these volumes cannot be redirected to other markets and hence would result in a loss for overall global gas supply. In addition, Europe's piped gas imports from North Africa are expected to decline amid lower piped gas export availability in the region (due to a strong increase in domestic demand) and the expiry of key long-term contracts. This forecast expects lower piped gas deliveries from Norway amid lower gas production in the country (in line with the projections of the Norwegian Offshore Directorate).

In contrast, **China**'s piped gas imports from Russia are expected to expand by 75% (or almost 25 bcm) through the forecast period. This is largely driven by the ramp-up of deliveries via the Power of Siberia pipeline system and the start-up of the Far East Pipeline in 2027. This forecast also includes a 6 bcm upside potential in line with the latest agreements concluded between Gazprom and CNPC. The continued increase in Russia's piped gas deliveries to China is partially offset by lower exports from Central Asia amid the mounting upstream deliverability issues in Uzbekistan.

Piped gas supplies between **Iran** and **Iraq** are assumed to come to a halt over the medium term amid tightening sanctions, necessitating the scale-up of LNG importing capabilities in Iraq (potentially through the lease of a floating storage and regasification unit). In contrast, piped gas exports from **Israel** to **Egypt** are expected to continue to expand during the forecast period (including through the 6 bcm/yr Nitzana pipeline). In South America, piped gas exports from **Bolivia** to **Brazil** are expected to come to a halt amid the expiry of the supply contract and declining production rates in Bolivia.

Asian markets are expected to drive LNG import growth

Natural gas demand across key LNG import markets is expected to expand by almost 11% (or 175 bcm) up to 2030. This demand trajectory reflects current price forward curves for Asian spot LNG and European hub prices (averaging at USD 10/MBtu for 2025-2030 as of end September 2025). Taking into account domestic production and piped gas trade trends, their combined **LNG import requirements would increase by around 170 bcm by 2030** compared with 2024.

This increase is largely concentrated in **Asia**, with the region's net LNG import requirements rising by close to 140 bcm by 2030. China and India together account for about 40% of this growth. In contrast,

Europe's LNG import requirements are expected to remain broadly flat over the forecast period comared with the elevated levels expected in 2025, as lower piped gas imports are largely offset by the continued decline in natural gas demand. **Central and South America** is projected to transition from a small net LNG importer to a small net exporter over the forecast period amid rising domestic production in Argentina and Brazil.

LNG use as a marine fuel is projected to expand by 15 bcm between 2024 and 2030. This is driven partly by the rapid expansion of the LNG carrier fleet, which is expected to increase by more than 40% in terms of capacity by 2030 and uses boil-off gas as propulsion fuel. In addition, the number of LNG-fuelled vessels could more than double by 2030 amid tightening emissions regulations.

The next LNG wave is expected to unlock additional demand

When considering price trajectories informed by current forward curves, **LNG demand growth in importing markets** would not absorb all the incremental LNG supply over the medium term, leaving around 65 bcm of LNG surplus by 2030. Considering the strong increase in LNG supply, both **European hub and Asian spot LNG prices could start to gradually converge towards the range of the short-run marginal cost of US LNG starting from 2027. This would translate into an** average USD 8/MBtu and USD 8.5/MBtu in the 2025-2030 period, respectively. These lower price levels would unlock additional demand, especially in the price-sensitive Asian markets, helping absorb LNG supply and limiting the risk of production shut-ins at liquefaction plants. **Price-elastic demand** across the power sector, gas-intensive industry and the transport sector – together with storage operations – could absorb an additional 65 bcm of LNG by 2030. This will require the continued expansion of natural gas infrastructure, especially in South and Southeast Asia.

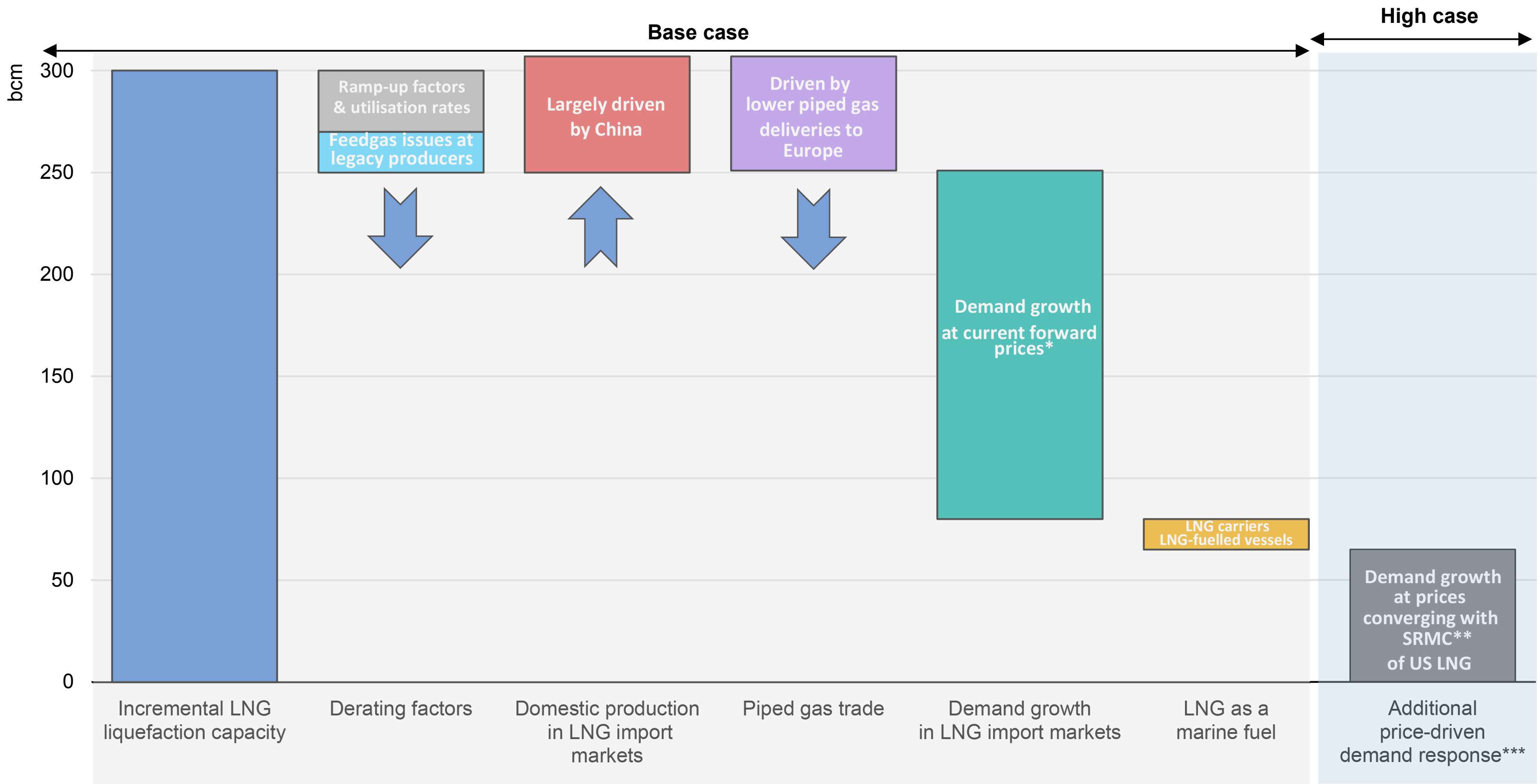
Marketing strategies will need to evolve

LNG producers and suppliers will need to adapt their marketing strategies over the medium term to ensure that the LNG wave has long-lasting benefits to the development of the global gas market.

Pricing terms in long-term supply contracts are already moving towards a better reflection of underlying market fundamentals: by 2030, the share of hub-indexed LNG contracts is set to increase to around half of overall LNG volumes contracted. Hub-based pricing ensures a better demand response across price-sensitive end-use sectors and could play a key role in unlocking additional demand. LNG suppliers will also need to actively develop their **short-term trading capabilities** to meet the more volatile gas demand patterns emerging in import markets (and partly driven by the growing variability in gas-fired power generation). In addition, **greater downstream integration** and investment by LNG suppliers in natural gas infrastructure in key emerging markets could unlock and scale up additional LNG demand over the medium term.

The next LNG wave is expected to unlock additional demand in price-sensitive markets

Forecast global LNG balance including price-driven high case, 2030 vs 2024



* TTF and Platts JKM forward curves as of the end of September 2025.
** SRMC = short-run marginal cost. For additional details, please refer to the main assumptions section of this report.
*** Including storage operations.

Global LNG growth by 2030 equates to around 7% of Asia’s thermal coal demand

Forecast global LNG demand growth in 2024-2030 vs Asia’s thermal coal consumption in 2024

The United States and Qatar are set to lead the next wave of LNG supply

Between 2024 and 2030, a total of around 300 bcm/yr of new LNG export capacity is expected to come online from projects that have already reached FID and/or are under construction. This represents the largest liquefaction capacity wave in any comparable period in the history of LNG markets.

While the LNG market is set to tip into a phase of accelerated growth thanks to the burgeoning liquefaction wave, feedgas issues at existing projects and growing domestic gas demand are increasingly likely to emerge as constraining factors on some legacy LNG exporters, particularly in the Pacific Basin. Nonetheless, potential LNG supply is expected to grow by around 250 bcm by 2030 compared with 2024 levels. This equates to almost half of the current global LNG trade.

On the demand side, while mature markets such as Europe, Japan and Korea are set to remain important pillars of the global LNG trade, their share of the market is set to continue to decrease as import growth increasingly comes from newer markets, particularly in Asia.

LNG supply growth supported by record FID streak

Between 2019 and October 2025, about 390 bcm/yr of LNG export capacity reached FID.[3] This is more than double the liquefaction capacity sanctioned during the 2014-2018 period.

With a traditional construction period of four to five years, the majority of these projects are set to come online in the second half of this decade, driving a new wave of LNG supply growth. While projects have already started coming online in 2025 and additions are set to accelerate in 2026, the peak in capacity additions this decade is expected to occur in 2027 and 2028.

Over 70% of liquefaction capacity additions to 2030 are set to come from the United States and Qatar, further concentrating global supply in today's top two exporting markets. Canada is set to account for a further 9% of capacity growth on its own due to its first two liquefaction projects coming online. African projects – led by Nigeria LNG train 7 – are expected to cover about 6% of global capacity growth to 2030.

However, not all projects having reached FID over this period are expected to contribute to global LNG supply upside this decade: Mozambique LNG (18 bcm/yr) and Russia's Arctic LNG 2 project

[3] For a closer look at liquefaction project FIDs and capacity additions, please see the IEA's Global LNG Capacity Tracker.

(27 bcm/yr), both of which reached FID in 2019, are not included in our liquefaction capacity outlook. Construction was halted in 2021 at the former following a declaration of force majeure in relation to security concerns in the country. At the latter project, the first two trains were reported operational in December 2023 and May 2025, but, being under international sanctions, the project is not considered as a source of firm supply in this outlook. However, while Arctic LNG 2 did not export cargoes until June 2025, from June 2025 to September 2025, it loaded eight cargoes from train 1 that were exported to one regasification terminal in China. Hence, sporadic LNG exports from the two-train plant cannot be excluded, which adds further upside potential to the global LNG supply during the forecast period.

Ageing upstream resources and domestic gas demand growth raise headwinds for some legacy exporters

While new liquefaction projects drive global LNG trade to new highs out to 2030, exports from existing projects across certain markets – notably in the Pacific Basin – are expected to face growing headwinds as a result of declining feedgas availability and growing domestic gas demand.

The Asia Pacific region accounted for as much as about 40% of global LNG supply in the 2016-2018 period as a result of the rapid expansion of Australian liquefaction projects, production kicking off in Papua New Guinea and relatively stable output from legacy producers Indonesia and Brunei. However, with few new projects or FIDs in the region since 2019 and ageing resource basins tied to historical liquefaction projects, medium-term production dynamics face a degree of uncertainty.

Australia, the region's largest LNG producer and the world's third largest, saw only one recent FID for a new liquefaction project (Pluto LNG train 2; 6.8 bcm/yr), taken in 2021. While industry players have been developing long-term backfill plans for existing projects whose legacy production fields have entered declining phases – notably for the Darwin LNG, North West Shelf Australia LNG, Gorgon LNG and Prelude FLNG projects – timing around the delivery of some of these new upstream assets and the growth in domestic gas demand could dampen Australian LNG export growth potential through to 2030.

Indonesia is another market where both upstream dynamics and domestic demand are set to affect the availability of LNG for export to the global market. Indonesian LNG loadings trended downward from 2010 to 2021 as legacy gas fields have progressively been depleted and limited new developments have come online to backfill liquefaction projects. While Tangguh LNG's three trains successively came online from 2009 to late 2023, only two of the original eight trains from the country's legacy Bontang LNG project remain online today due to declining feedgas availability.

Indonesian LNG loadings have started to recover since 2022 and upstream discoveries and investments have been announced in recent years. However, domestic gas demand has also absorbed a growing share of these loadings, rising from an average of 17% in 2016-2020 to about one-third in the first nine months of 2025. The speed at which new upstream assets can be unlocked will therefore be key to servicing both domestic demand growth and contractual export obligations in the medium term.

Ongoing upstream investments in Malaysia are set to keep the country's medium-term exports broadly in line with recent years' loadings, although the varying quality of new gas finds could slow backfill efforts. Domestic demand is also expected to grow, but is not expected to significantly affect the availability of Malaysian LNG on the global market.

Overall, we expect exports from countries in the Asia Pacific region to slowly trend downward to 2030, with the risk that delays to backfill projects (in both FIDs and project execution) lead to steeper declines in the latter part of the outlook.

LNG demand growth hinging on developing markets

While today's largest LNG exporters are set to increase their share of supply in the coming years, the LNG import landscape is set to evolve more significantly, with an increasing share of the demand being driven by newer markets, particularly in Asia.

The world's more mature LNG importers are set to remain important pillars of global LNG trade through to 2030, but they are not expected to act as key drivers of demand growth. The share of markets like Europe, Japan and Korea as a proportion of global imports has fallen over the past decade and is set to remain on this trajectory to 2030. In Europe, LNG imports are set to increase significantly in 2025 as a gas market balancing lever amid declining pipeline imports from Russia. However, the medium-term trend is for only marginal incremental imports from that point as demand continues to soften and pipeline imports stabilise.

Continued nuclear restarts in Japan are set to limit the potential upside in the country's LNG imports through to 2030. In Korea, however, LNG imports are set to grow more strongly during the outlook period as alternative electricity generation capacity makes less of a dent in power sector gas burn dynamics amid rising electricity demand.

Despite remaining upside potential in mature LNG importing markets, most LNG demand growth is set to be driven by newer LNG markets, notably in Asia. As the world's largest LNG importer in 2024, China is first among these. Although LNG is set to continue acting as a balancing lever for the Chinese gas market – complementing domestic production growth and growing pipeline imports from Russia in the latter part of the outlook – it remains a key pillar of supply for in the country. Despite a significant drop in LNG imports expected in 2025 (in contrast to the increase in Europe), China's LNG imports could grow by more than 20% in the base case and nearly 50% in the high case from 2024 levels by 2030.

Smaller, more price-sensitive markets with less long-term contract coverage are also expected to grow their LNG imports through to 2030. The next wave of LNG supply is expected to soften the cross-basin competition for LNG cargoes that has intensified in recent years. As such, Asian importers that have intermittently been priced out of the market by high spot LNG prices are expected to import more LNG. By 2030, gross LNG imports into these other Asian markets could grow by nearly 150% in the high case (or by more than 125% in the base case) compared with 2024 levels.[4]

However, LNG import growth in South and Southeast Asia will hinge on important gas infrastructure and network developments as well as on continued policy support. Governments' assessment of the affordability and accessibility of LNG in ensuring energy security will be key in accelerating its uptake, particularly following the drastic LNG market and price movements experienced in recent years.

While incremental global LNG supply is set to underpin emerging market LNG import growth, a highly interconnected and flexible LNG market remains a key balancing lever in the face of potential shocks – both demand- or supply-driven, regional or global. As illustrated in the 2022/23 energy crisis, LNG flows remain susceptible to drastic reshuffling in response to market shocks.

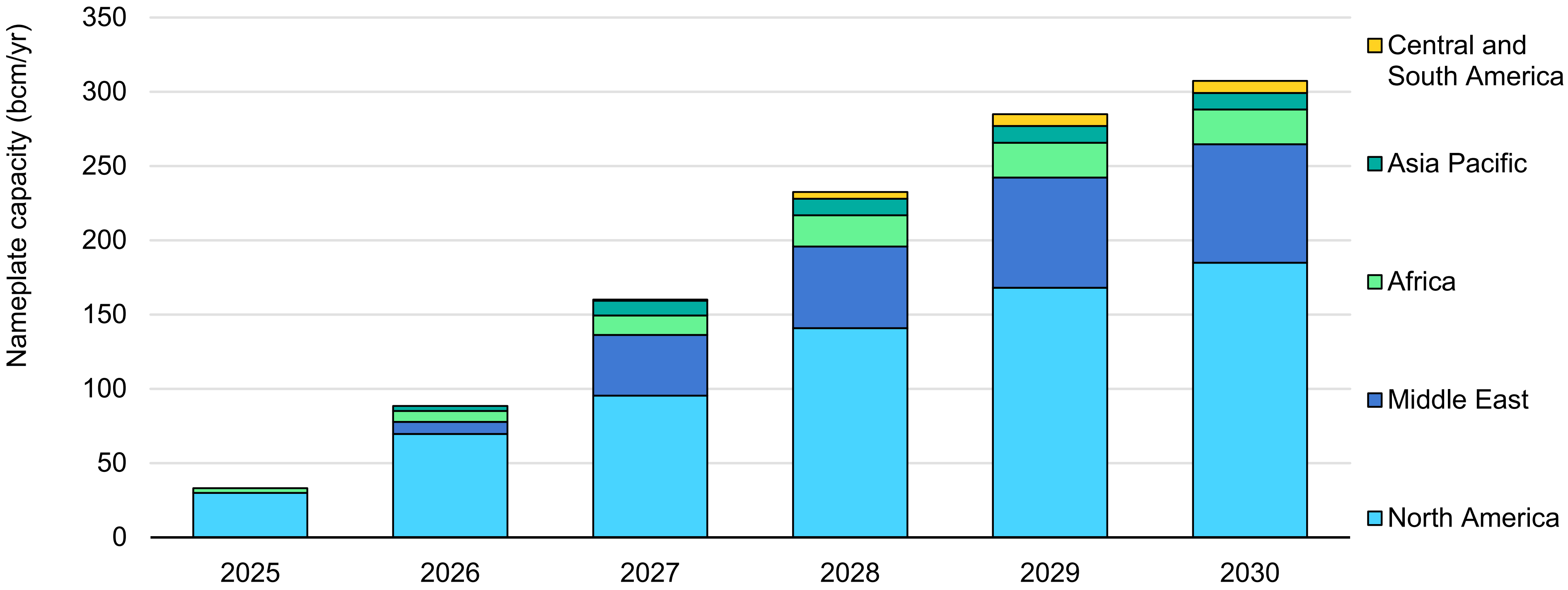
A period of low prices could undermine LNG investments

While the global gas market is expected to be preoccupied with absorbing the next wave of LNG supply in the medium term, a prolonged period of lower LNG prices could reduce the incentive for project developers to invest in LNG liquefaction projects and in upstream and midstream infrastructure. Considering the long lead times of LNG liquefaction projects, this could lead to a potential tightening of global gas markets post-2030, especially if demand growth follows a higher trajectory.

[4] Including Bangladesh, Indonesia, Malaysia, Pakistan, the Philippines, Thailand and Viet Nam.

Annual liquefaction capacity additions accelerate midway through the outlook period

Cumulative liquefaction capacity additions from post-FID projects by region, 2025-2030



Note: Outlook includes post-FID projects as of 24 October 2025.

Global LNG carrier capacity is set to grow by around 40% by 2030

As of early 2025, the global LNG carrier fleet comprised over 830 vessels in total. This figure includes large-scale carriers as well as 52 floating storage and regasification units (FSRUs) and 79 small-scale and bunkering vessels. Together, these vessels provide an aggregate operational transport capacity of over 120 million cubic metres of LNG. By 2030, the fleet is expected to approach 1 100 units, representing an increase of about 30%. Meanwhile, the overall LNG shipping capacity is projected to expand by nearly 40% (assuming that the average rate of LNG vessel retirements observed in recent years continues), driven by the shift towards larger and more efficient carriers. More than 350 additional vessels are on order for delivery by the end of the decade, driven by long-term supply contracts. While the global LNG fleet is set to expand strongly over the medium term, the rapid growth in global LNG trade could lead to a tighter shipping market post-2028. The current outlook for global LNG trade suggests that further expansion of the order book for the new LNG carriers would need to expand further to avoid logistical bottlenecks and allow for smooth global LNG flows.

This expansion is not solely a function of volume. New vessels are increasingly being designed to enhance efficiency and environmental compliance. The latest generation of LNG carriers integrates air lubrication systems, high-efficiency cargo containment with reduced boil-off rates, hybrid shaft generator systems, and advanced dual-fuel engines designed to minimise methane slip. These features are essential for alignment with international decarbonisation objectives and regulatory frameworks, including those established by the International Maritime Organization (IMO), helping reduce the lifecycle GHG emissions of LNG shipping.

Smaller-scale and modular carriers are opening new markets but add complexity to shipping logistics

Asia remains the dominant market for LNG imports, with China and increasingly India driving growth. These rising import needs are prompting a parallel expansion of LNG shipping fleets, both in size and range. While utilities historically invested directly in vessels, most have shifted to long-term charters over the past two decades. However, several Asian utilities and trading houses continue to invest directly to secure capacity and reduce market exposure, similar to practices in LNG-exporting countries in the Middle East. Europe's pivot to LNG following disruption to pipeline gas deliveries from Russia has also increased near-term demand for spot cargoes and FSRUs, reinforcing the need for flexibility in LNG shipping. Although spot charter rates have remained low throughout much of 2024 and 2025 due to fleet overcapacity and seasonal demand patterns, structural shifts in trade flows and voyage distances continue to test the responsiveness of the global LNG carrier fleet. This transition underscores the importance of an agile and adaptable LNG shipping sector, capable of supporting both long-haul and regional deliveries.

In emerging markets across Southeast Asia, Africa and Latin America, smaller-scale LNG carriers and modular shipping solutions are being considered to service remote or distributed import terminals. In Indonesia, for example, a USD 1.5 billion small-scale LNG project led by PLN EPI[5] aims to replace diesel power plants across six regional clusters, using a hub-based supply chain with feeder vessels that deliver LNG to satellite or remote terminals. The diversification of vessel sizes and functions is expected to accelerate through to 2030, driven by design standardisation, evolving market needs and improved deployment flexibility, even as rising material and construction costs place upward pressure on overall capital expenditure.

Shipyard constraints and decarbonisation targets are testing the pace of fleet renewal

Despite favourable demand trends, several headwinds could constrain the development of LNG carrier capacity. Supply chain bottlenecks, particularly in specialised shipyards in South Korea and China, have led to cost escalation and delivery delays. At the same time, the industry faces rising uncertainty regarding the long-term role of gas in a decarbonising the global energy system. This uncertainty may limit investment in shipping assets with lifespans extending beyond 2040.

From a regulatory standpoint, compliance with the IMO's Carbon Intensity Indicator (CII) and Energy Efficiency Existing Ship Index (EEXI) is already influencing operational and investment decisions, including speed reduction[6] and fleet retrofitting, while also driving the adoption of new technologies to reduce GHG emissions. As emissions benchmarks tighten beyond 2030, regulatory pressures are expected to drive accelerated fleet renewal, with investments shifting toward more efficient, compliant vessels.

Balancing energy security with climate goals

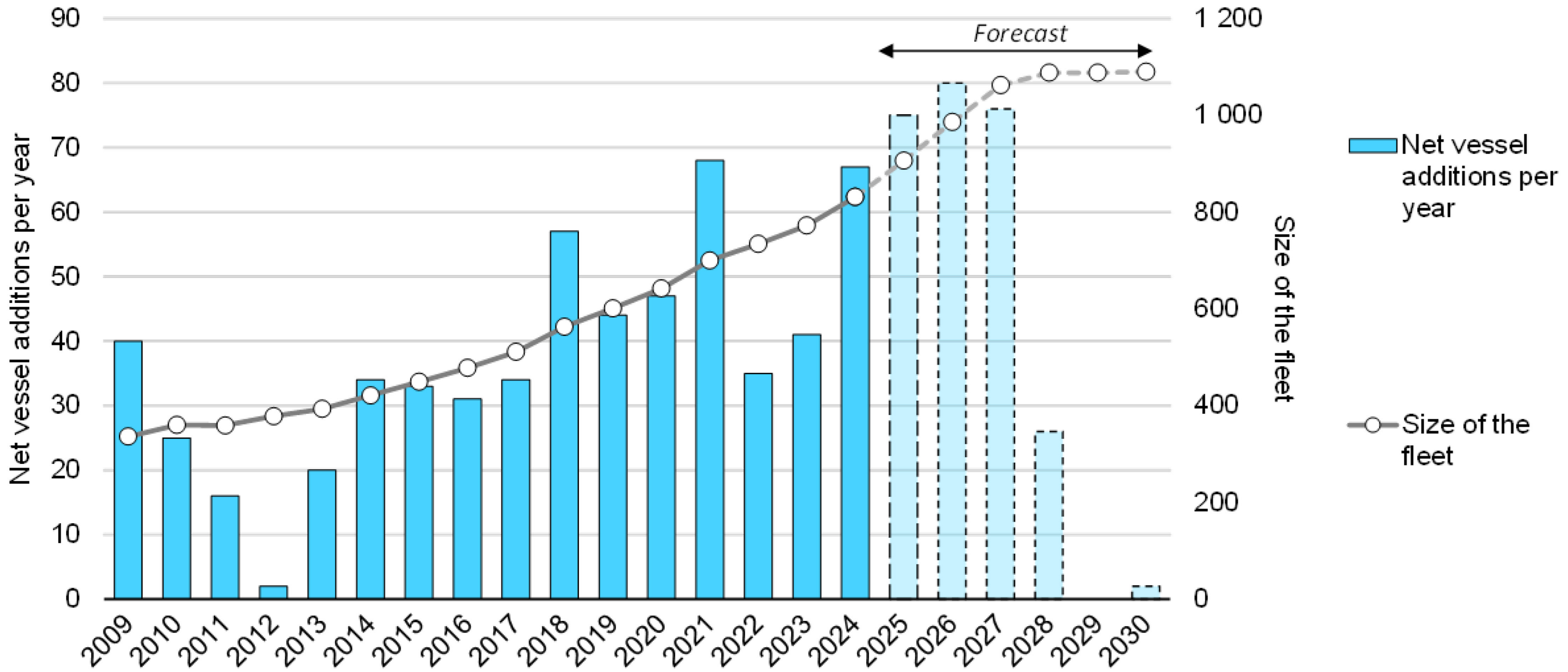
The global LNG carrier fleet is expanding steadily to support new liquefaction projects and flexible trade patterns. However, new orders could peak by the late 2020s as decarbonisation efforts accelerate and low-emissions alternatives gain market traction. A resilient LNG carrier market through to 2030 will require not only adequate shipbuilding capacity, but also coordinated planning between producers, importers and shipowners. Strategic investments in digital vessel optimisation, energy efficiency technologies and low-emissions propulsion, including LNG dual-fuel engines and potentially designs adaptable to hydrogen and its derivative fuels, will be essential to align operational performance with evolving climate objectives. The LNG shipping sector stands at a pivotal juncture: critical for supporting energy security, yet increasingly under pressure to adapt its fleet to reduce emissions amid tightening regulatory frameworks.

[5] A subsidiary of the state-owned electricity company Perusahaan Listrik Negara (PLN), specialising in energy infrastructure development.

[6] Speed reduction helps lower emissions because fuel consumption – and therefore CO_2 output – increases exponentially with ship speed.

Following strong deliveries in 2024, 2025 is expected to set a new record for LNG vessel additions

Growth of the global LNG fleet and annual vessel additions, 2009-2030



Notes: Net vessel additions represent the number of new LNG vessels added to the global fleet each year, minus those that are retired or scrapped. Data are based on the LNG carrier order book as of September 2025; vessels ordered after this date are not included, which may cause net additions to appear lower after 2025.

Sources: GIIGNL (2025), GIIGNL; GTT (2025), Order book; ICIS (2025), LNG Edge.

US gas production poised for rapid growth, driven by growing demand and LNG exports

After a brief slowdown in 2024, US natural gas production is set to return to steady growth, supported by surging LNG exports, growing consumption, upstream productivity gains and expanded pipeline takeaway capacity in key shale-producing basins. Between 2024 and 2030, US gas production could grow by up to 20% (210 bcm/yr) in our high case, reaching 1 280 bcm/yr by the end of the decade and cementing the United States' position as the world's largest gas producer. This corresponds to an annual growth rate of 3%, slower than the nearly 4% average growth during the decade to 2024, but in line with the pace observed in the past three years. Virtually all production growth comes from shale and tight oil plays, while conventional producing areas register moderate declines.

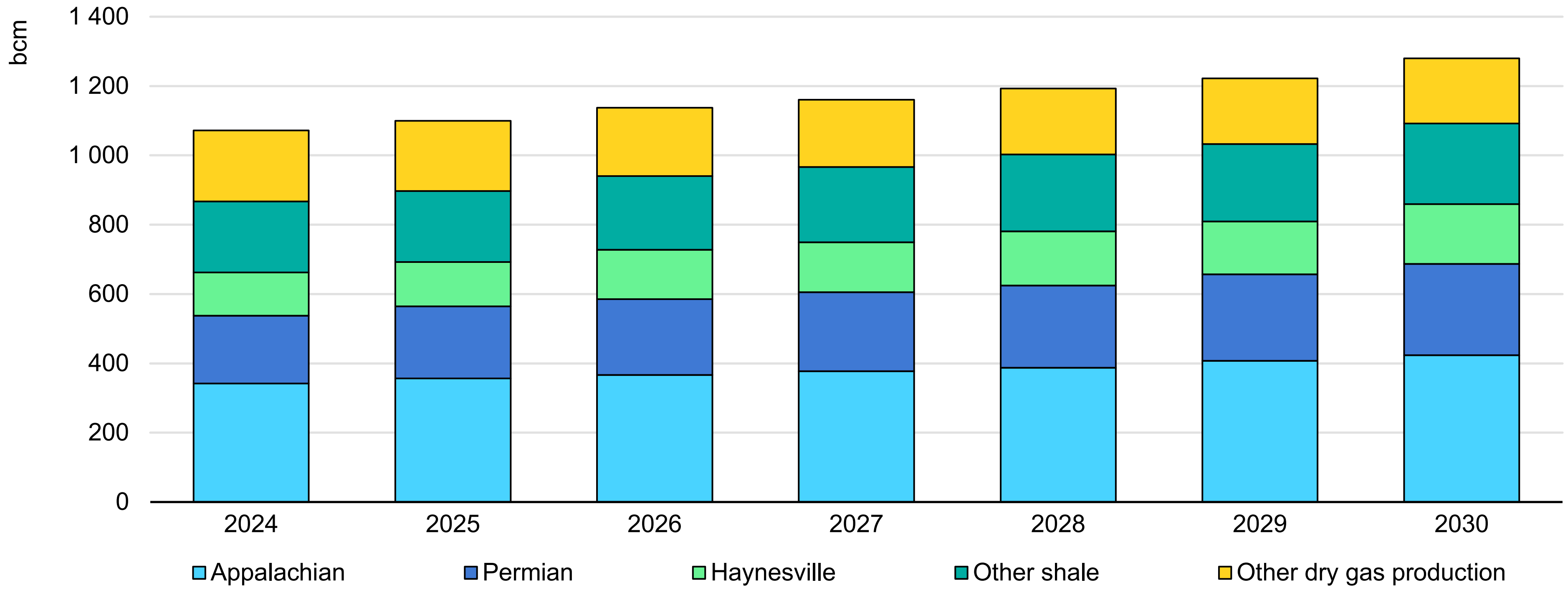
The Appalachian Basin is expected to see the largest increase, adding around 80 bcm/yr of supply between 2024 and 2030. This growth is supported by pipeline takeaway capacity additions such as the recently completed Mountain Valley Pipeline (21 bcm/yr), and several expansion projects along the Transco pipeline system. Rising demand in the eastern part of the United States, coupled with declining pipeline gas imports from Canada, further supports the basin's expansion. The Permian Basin also remains a key driver of production growth, mainly through associated gas from oil-directed wells. With forward oil prices supportive of sustained upstream activity, Permian gas output is expected to increase by nearly 70 bcm/yr over the forecast period. Several major pipeline projects are expected to relieve bottlenecks by adding takeaway capacity from the Permian to the US Gulf Coast, including Apex (21 bcm/yr), Blackcomb (26 bcm/yr), Saguaro Connector (29 bcm/yr) and Eiger Express (26 bcm/yr).

Haynesville, a higher-cost dry gas play with close proximity and abundant pipeline connections to Gulf Coast LNG terminals, is also expected to contribute significantly, adding nearly 50 bcm/yr by 2030. This increase is driven by robust consumption and LNG export growth, which are expected to keep domestic gas prices at sufficient levels to support expanded Haynesville production. Other shale plays collectively add more than 25 bcm/yr over the projection period. Marginal technological improvements, such as simultaneous fracking, and increasing oil-to-gas ratios in associated gas plays are also expected to support the robust rise in US gas production.

If supply- and demand-side adjustments in price-sensitive markets around the world fail to materialise due to infrastructure constraints, policy obstacles or market distortions, US natural gas production could turn out to be lower in our base case compared to the high case.

US production could grow by up to 210 bcm with support from price-responsive LNG demand

Natural gas production in the United States, 2024-2030



Note: Production levels shown on the graph are associated with the high case.

Middle Eastern natural gas production is expected to expand by more than 20% by 2030

Natural gas production in the Middle East increased by 20% (or almost 125 bcm) between 2018 and 2024. This strong growth was largely supported by upstream developments in Iran, Israel, Qatar and Saudi Arabia. Higher production was primarily driven by the region's growing gas demand, while extra-regional exports contributed just 13% to the overall production growth.

This forecast expects Middle Eastern gas production to expand by more than 20% (or 165 bcm) between 2024 and 2030. Qatar alone is expected to account for almost 45% of this growth. In contrast with the 2018-2024 period, natural gas exports (both LNG and piped) are expected to contribute around 40% of the overall production growth in the forecast, largely supported by price-responsive LNG demand.

Qatar: Strong LNG export growth is set to drive upstream developments over the medium term

Qatar's natural gas production grew by 2% between 2018 and 2024, mainly to support stronger domestic demand, while the country's LNG exports and piped gas supplies to Oman and the United Arab Emirates remained broadly flat.

Qatar's natural gas production is **forecast to increase by nearly 45% (or almost 75 bcm) between 2024 and 2030**, primarily driven by the expansion of the country's **LNG exports**, which are expected to increase by more than 55% (or over 60 bcm/yr) by 2030 and solidify Qatar's position as the world's second-largest LNG exporter. Natural gas deliveries via the Dolphin pipeline system to Oman and the United Arab Emirates are expected to remain flat at around 20 bcm/yr in the forecast period. **Domestic demand** – including natural gas used for LNG production – is forecast to increase by 25% (or nearly 15 bcm) between 2024 and 2030.

This strong supply growth will be almost entirely underpinned by the **expansion projects at the giant North Field**. The drilling campaign for the **North Field East** expansion project started in March 2020 and consists of eight wellhead platforms and 80 development wells. The feedgas will supply four new LNG trains with a combined capacity of almost 45 bcm. The upstream part of **North Field South** project consists of five platforms and 50 development wells. The feedgas will supply two liquefaction trains with a combined capacity of around 22 bcm.

Saudi Arabia: Continued production growth is set to support the growing role of natural gas in power generation

Saudi Arabia's natural gas production increased by more than 10% (or 11 bcm) between 2018 and 2024. This growth was largely supported by associated natural gas and the country's rapidly expanding gas processing capabilities, rising from just 2 bcf/d (20 bcm/yr) in 2000 to over 19.1 bcf/d (195 bcm/yr) by the end of

2024. Incremental gas supplies primarily serve the country's rapidly rising natural gas demand in the industrial and power sectors. Saudi Arabia has no LNG or piped gas export capacity.

Saudi Aramco has an ambitious natural gas development strategy. The company aims to increase its gas production by more than 50% compared with its 2021 production levels by 2030. This forecast expects **Saudi Arabia's natural gas output to expand by almost 40 bcm** between 2024 and 2030. This strong growth will be partly supported by the Jafurah and South Gawar unconventional gas fields. **Jafurah**'s production is anticipated to ramp up and deliver around 2 bcf/d (or 20 bcm/yr) of sales gas by 2030. **South Gawar** started operations in 2023 and the field's output is expected to ramp up from around 3 bcm/yr to 7.6 bcm/yr in the forecast period. Incremental domestic gas production is expected to drive Saudi Arabia's **oil-to-gas switching** strategy in the power sector and support the country's expanding **industrial activity**. Gas-to-power demand is forecast to increase by more than 40% by 2030.

Iran's natural gas demand growth is set to slow

Iran's natural gas production grew by an impressive 30% (or almost 70 bcm) between 2018 and 2024, solidifying the country's position as the Middle East's largest gas producer. This strong growth was primarily driven by the continued development of the South Pars field and supported both oil-to-gas switching in the power sector and the expansion of gas-intensive industries (including fertilisers and chemicals).

Following this strong increase, Iran's gas demand growth is expected to slow to an average rate of just 1% per year between 2024 and 2030. This would translate into an increase of less than 15 bcm/yr by 2030 and would primarily serve the country's domestic market. Growth will be primarily supported by South Pars phase 11, which was inaugurated in 2023, and production is expected to ramp up to over 18 bcm/yr in the forecast period.

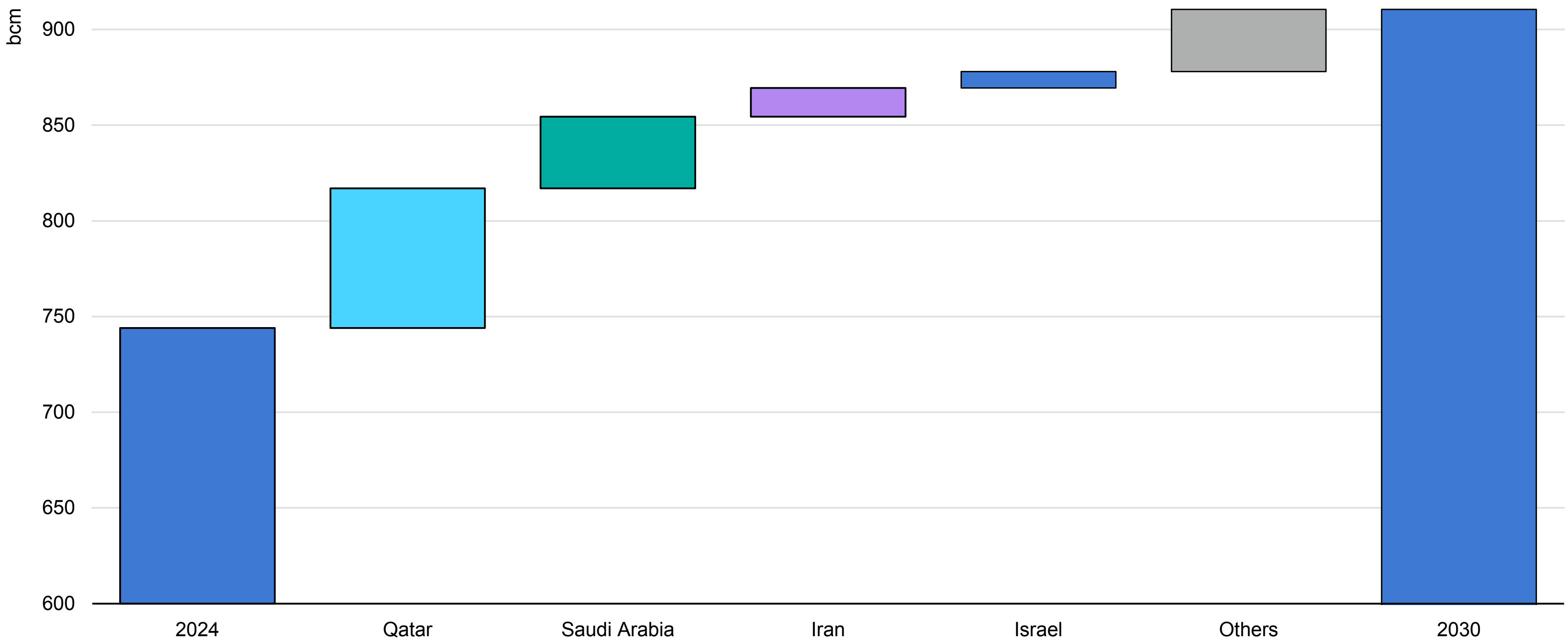
Israel's role as a key regional piped gas supplier is set to further strengthen over the medium term

Israel has significantly expanded its natural gas production during the past decade to become a key regional piped gas supplier, including to Egypt and Jordan. The country's natural gas output has risen more than tenfold since 2009 to reach around 27 bcm in 2024. This strong growth was primarily driven by the development of the Tamar (2013), Leviathan (2019) and Karish (2022) offshore gas fields. In 2024, Israel exported around 10 bcm of natural gas to Egypt through the EMG Pipeline and the Arab Gas Pipeline, and around 3 bcm to Jordan.

Israel's natural gas output is expected to expand by 30% (or more than 8 bcm) between 2024 and 2030, primarily from the expansion of the Tamar and Leviathan fields. This growth will support Israel's rising piped gas exports to Egypt, including through the 6 bcm/yr Nitzana pipeline.

Qatar is set to drive natural gas supply growth in the Middle East

Forecast change in natural gas production in the Middle East key markets, 2030 vs 2024



Note: Production levels shown on the graph are associated with the high case.

Russia's upstream sector struggles to recover to pre-invasion levels by 2030

The break-up of Russia's decades-long ties with the European market have profoundly changed the prospects for the country's upstream sector. Russia's natural gas output plummeted by 20% between 2021 and 2023. While the country's gas production is forecast to increase over the medium term, it is expected to remain almost 7% below its 2021 levels in 2030.

Recent trends

Russia's natural gas production rose by 20% between 2015 and 2021 to reach an all-time high of 762 bcm. This strong increase was largely driven by the country's growing exports (both via pipeline and LNG) and to a lesser extent by the expansion of domestic demand. The steep decline in Russia's piped gas exports to the European Union led to a sharp drop in natural gas output, plummeting by more than 15% (or 125 bcm) between 2021 and 2023 to its lowest level since 2015. Gazprom bore the brunt of the decline, recording a drop of 30% (or over 155 bcm) in its natural gas output in just two years. Gazprom's giant, flexible swing fields located in Western Siberia and the Yamal Peninsula contributed to the bulk of the downward flexibility displayed in 2022 and 2023.

Russia's natural gas production grew by 7% (or 45 bcm) in 2024. Stronger exports, both via pipeline and in the form of LNG, supported this growth. Russia's piped gas exports to China via Power of Siberia increased by almost 40% y-o-y (or 8.4 bcm). Piped gas deliveries to Europe rose by 10% (or 5 bcm) y-o-y. In addition, Russia ramped up its piped gas exports to Uzbekistan from 1.3 bcm in 2023 to 5.6 bcm in 2024. Russia's LNG output increased by close to 6% (or 2 bcm) y-o-y, with Asia accounting for around half of total Russian LNG exports. Gas deliveries to the domestic market grew by 5% (or just over 25 bcm) in 2024, supported by colder-than-average winter weather, stronger thermal power generation and higher gas use in industry.

Preliminary data suggest that Russia's natural gas production declined by nealy 4% (or 17 bcm) y-o-y in the first eight months of 2025, driven both by lower domestic demand and reduced gas exports. Gas deliveries to the domestic market fell by an estimated 4% (or 10 bcm) y-o-y in the first eight months of the year. The decline was largely concentrated in Q1, when unseasonably mild weather conditions depressed space heating requirements and weighed on natural gas used in district heating. Russia's piped gas exports to the European Union plummeted by 45% (or 10 bcm) y-o-y in Q1-Q3 2025 amid the halt of transit flows via Ukraine at the beginning of the year. In addition, the country's LNG exports fell by 11% (or 3.5 bcm) y-o-y in Q1-Q3 2025, partly amid the sanctions imposed on the mid-scale Portovaya and Vysotsk LNG plants. These declines were only partially offset by the higher piped gas exports to China (up by an estimated 25% y-o-y), Türkiye (up by 23% y-o-y in the first seven months of 2025) and Uzbekistan (up by an estimated 33% y-o-y).

Medium-term outlook

This forecast expects Russia's natural gas output to expand by nearly 4% (or just over 25 bcm) between 2024 and 2030, partially driven by stronger domestic demand and the continued ramp-up of piped gas exports to China and Uzbekistan. While natural gas production is projected to increase over the medium term, it is expected to remain almost 7% (or 50 bcm) below its 2021 levels in 2030.

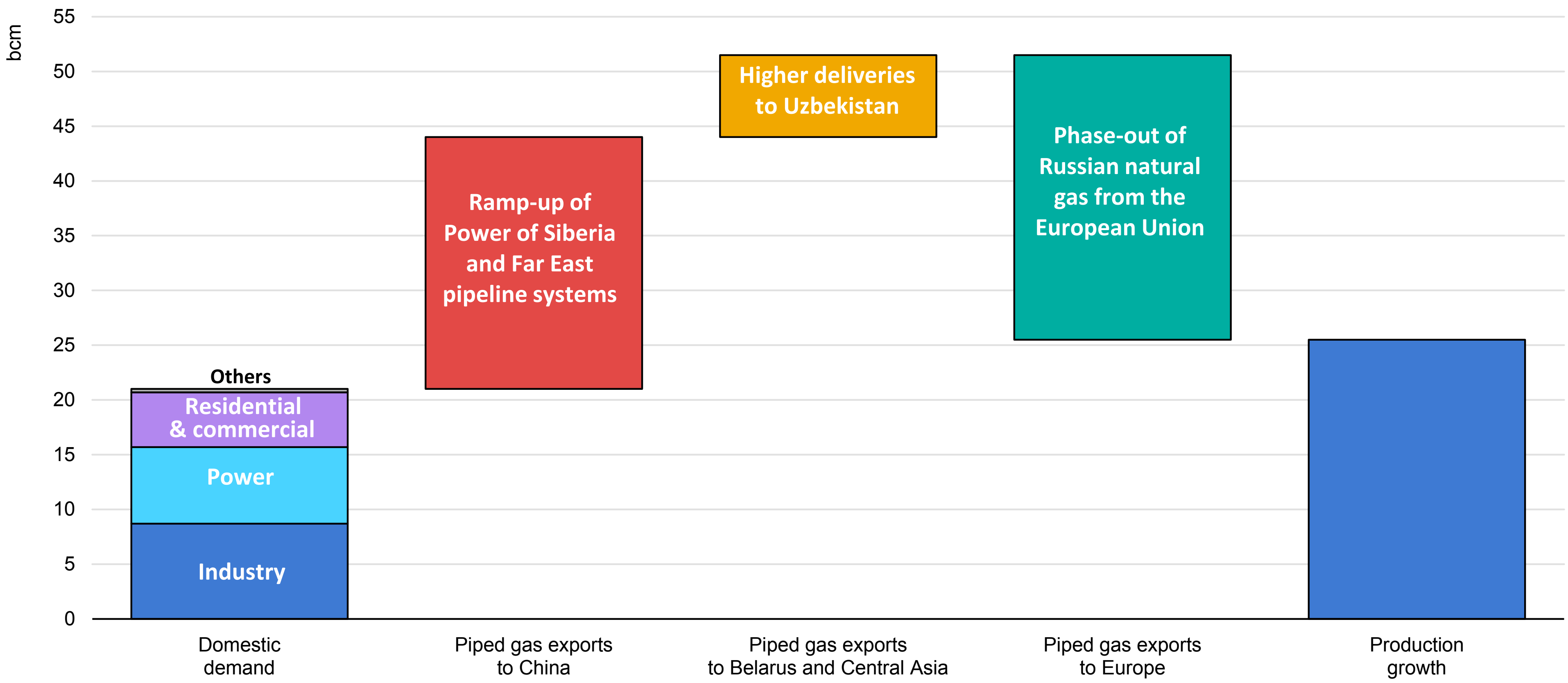
Russia's domestic natural gas demand is forecast to expand by 4% (or just over 20 bcm) between 2024 and 2030. This is partly supported by the **gasification programme** launched by the country's government and implemented by Gazprom. Under the programme, the level of gasification in Russia increases from around 75% in 2024 to around 83% by 2030 and over 1.6 million households would be newly connected to the gas distribution network. In addition, **industrial gas demand** is expected to expand by almost 10% over the forecast period. This growth is largely driven by fertiliser and gas-based chemical production (including methanol). Gas-to-power demand is projected to increase at an average rate of 0.5% per year during 2024-2030, supported by higher electricity demand.

Russia's natural gas exports are expected to increase only marginally over the medium term. This forecast assumes that Russia's LNG deliveries to the European Union will halt on 1 January 2027, while piped gas supplies will be be phased out by 1 January 2028 in line with the European Commission's proposal. This would reduce Russian piped gas deliveries by 26 bcm compared with 2024. Notably, these volumes cannot be redirected to other markets and hence would result in a loss for the overall global gas supply. Russia's LNG exports to the European Union (around 21 bcm in 2024) are expected to be gradually redirected to other markets (primarily Asia) in 2026. The loss of the European export market is set to weigh on the upstream developments in Western Siberia and the Yamal Peninsula. Russia's piped gas exports to Uzbekistan are expected to increase from 5.6 bcm in 2024 to around 11 bcm by 2030. Russia's LNG exports are assumed to remain broadly flat, amid the international sanctions environment.

In Eastern Siberia, the **Chayandinskoye field** reached its nameplate capacity of 25 bcm/yr in 2024, enabling the ramp-up of gas supplies to China via the Power of Siberia pipeline. The **Kovyktinskoye field** was officially commissioned at the end of 2022. The field has a nameplate capacity of 27 bcm/yr. The continued ramp-up of the two fields will allow Russia to increase its piped gas exports to China to 38 bcm/yr in 2025 via Power of Siberia and to around 44 bcm/yr by the end of the forecast. Gazprom signed a 25-year long-term agreement with China's CNPC to supply 10 bcm/yr of piped gas via the "Far Eastern route", with first deliveries set to start in 2027. The expected resource base is the **Yuzhno-Kirinskoye field**, which has a design capacity of 21 bcm/yr.

Russia's natural gas production is expected to increase by a less than 4% by 2030

Key drivers behind Russia's natural gas production growth, 2024-2030



Note: Production levels shown on the graph are associated with the high case.

Global gas demand to 2030: Well-supplied market conditions to support continued growth

After years of turbulence and the worst energy crisis since the oil shocks of the 1970s, the global gas market is set to transition from a period of tightness to a period of abundant supply between 2024 and 2030. This shift to more balanced market conditions is expected to support continued growth in global gas demand throughout the forecast period.

Fundamental drivers alone, including existing projects, policies, projections of economic activity and prices corresponding to the current forward curve, can support a 9% (380 bcm) increase in global gas demand during the 2024-2030 period in our base case. This is equivalent to an annual average growth rate of nearly 1.5%.

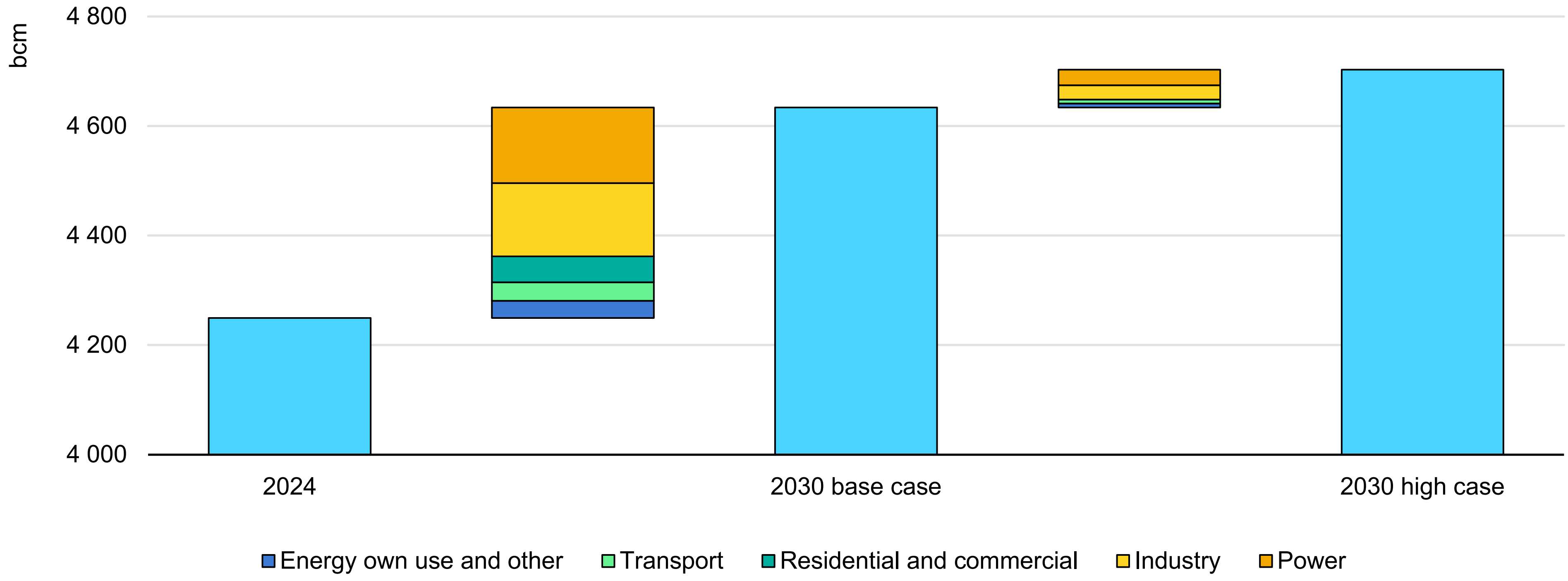
However, this demand growth under the base case is not sufficient to absorb the coming wave of LNG supply and would result in an imbalance in the global LNG market. Under such conditions, spot LNG prices are likely to come under pressure and could fall towards the short-run marginal cost of US LNG supply, which remains well below current forward price levels. Depressed spot LNG prices, in turn, could incentivise additional price-sensitive demand in regions and sectors with significant fuel-switching potential or a track record of responding to major price movements. Based on historical sensitivities and detailed sector-by-sector analysis, such price-responsive demand is most likely to emerge in power generation, industry, petroleum refining, and LNG use in road transport.

This additional price-sensitive demand could push total gas consumption growth to more than 450 bcm/yr over the 2024-2030 period in the high case, corresponding to an average annual growth rate of 1.7%.

Coal-to-gas switching in power generation could add approximately 29 bcm/yr of gas demand by 2030 in addition to the demand trajectory in the base case. The vast majority of this increase is expected to occur in Asia, with only a modest increment in Europe. More than two-thirds of the industrial sector’s demand response (totalling 26 bcm/yr) by 2030 is also concentrated in Asia, with the remaining upside split between Europe and the rest of the world. The refining sector offers a more modest potential increase of around 3.5 bcm/yr, primarily in Asia and, to a lesser extent, in Europe. Incremental LNG use in medium- and heavy-duty transport (estimated at 7 bcm/yr) is expected to occur predominantly in China, with a smaller contribution in India, which would also require policy support and new infrastructure in addition to lower prices. Beyond price-responsive demand, these additional levers are projected to increase global LNG trade by around 65 bcm/yr by 2030 relative to the base case. This increase is estimated to add another 7 bcm/yr of gas consumption for LNG liquefaction and regasification operations within the energy sector.

Fundamentals and price elastic demand can drive up global gas demand by over 10% by 2030

Projected global gas consumption growth by sector, 2024 and 2030



Regional and sectoral outlook to 2030: Asia Pacific and industry remain in the driver's seat

Global gas consumption is expected to grow at an average annual rate of nearly 1.5% between 2024 and 2030 in our base case, increasing by more than 380 bcm/yr to around 4 630 bcm by 2030. In the high case, which accounts for the demand response triggered by lower LNG prices, the average growth rate could increase to 1.7% per year, corresponding to an increase of more than 450 bcm/yr to just over 4 700 bcm.

The Asia Pacific region is expected to be the primary driver of this expansion, accounting for around half of the total increase in both the base and high cases. China alone is projected to contribute half of Asia's net growth (and a quarter of the global increase) in both cases, as a period of abundant supply, expanding import infrastructure and – in the high case – low spot LNG prices help accelerate gas demand in the second half of the decade.

The remainder of the regional growth is split between Emerging Asia, which could add 55 to 66 bcm/yr, India, contributing 27 to 35 bcm/yr, and the mature markets of Japan, Korea and Chinese Taipei, adding 10 to 17 bcm/yr in the base and high cases, respectively. The Middle East, Eurasia and North America also see meaningful growth, accounting for 28%, 9% and 16% of the global increase in the base case (and 24%, 8% and 13% in the high case), respectively, with rising indigenous production supporting demand in each region.

In contrast, Africa and Central and South America are expected to record more modest gains, which are largely offset by declining gas demand in Europe in both cases.

From a sectoral perspective, industry and the energy sector (which includes refining and upstream operations) together account for about 45% of incremental gas consumption growth between 2024 and 2030 in both demand trajectories.

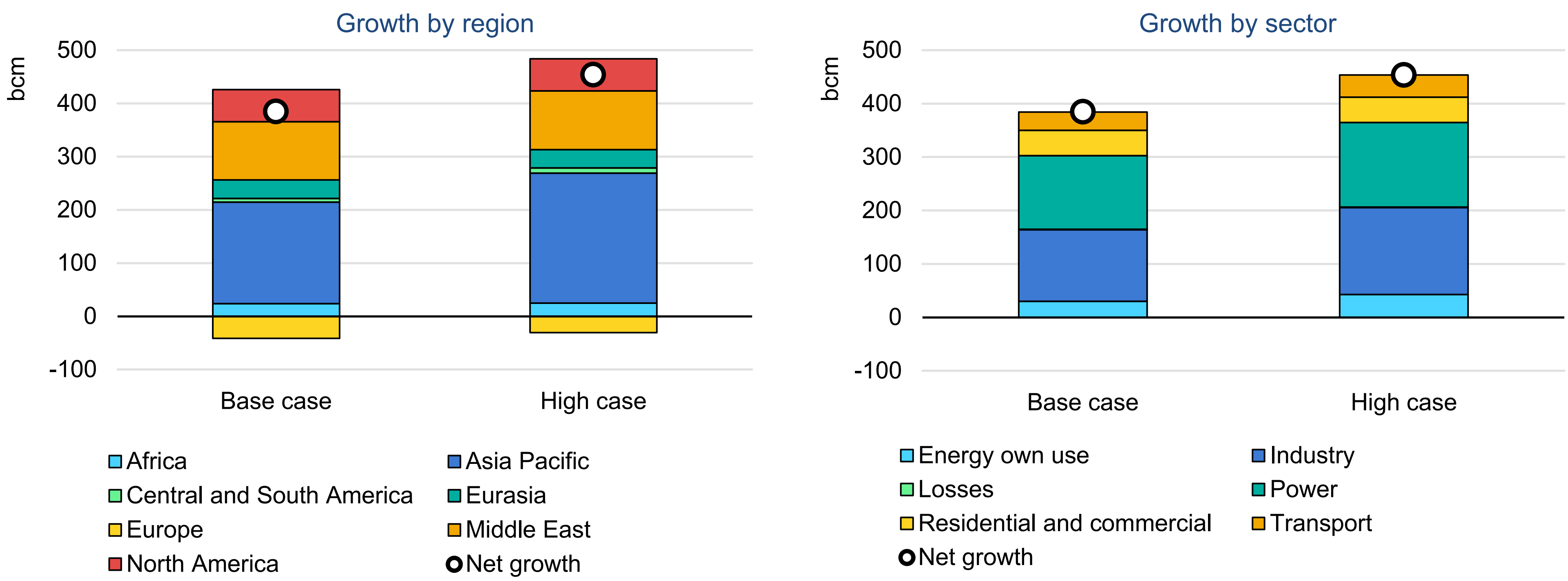
The power sector is the second-largest contributor to global demand growth over the forecast period, responsible for about 35% of the net increase in both cases. The Asia Pacific region accounts for up to two-thirds of this growth, with China alone contributing 25% of the global increase in power sector gas use in the high case. In the base case, the shares for Asia and China are closer to 50% and 20%, respectively. The Middle East also plays a significant role, adding more than 50 bcm of demand between 2024 and 2030, primarily due to large-scale oil-to-gas switching initiatives led by Saudi Arabia.

The residential and commercial sector experiences more balanced growth, with Asia, Eurasia and the Middle East each making meaningful contributions. The sector's total increase reaches nearly 50 bcm/yr by 2030 in both cases.

Transport sector demand grows by 34 to 41 bcm/yr across the base and high cases through 2030, with nearly two-thirds of this increase coming from road transport in China alone.

Global gas demand growth between 2024 and 2030 is driven by Asia Pacific and industry

Projected global natural gas consumption growth by region and by sector, 2024 vs 2030



New frontiers in global demand to 2030: Trucks, ships, city gas and data centres

Four distinct drivers of global gas and LNG demand stand out for their individual impact: LNG-fuelled trucks in China, city gas distribution in India, data centre-driven electricity demand in the United States, and LNG use in domestic and international shipping. Together, these four segments are projected to add more than 70 bcm to annual global natural gas consumption – roughly equivalent to India's total gas use in 2024, or about a sixth of the projected global demand growth between 2024 and 2030.

LNG-fuelled medium- and heavy-duty vehicles have developed a unique ecosystem in China over the past decade, supported by widespread domestic liquefaction, truck loading and distribution infrastructure, well-established markets with competitive pricing, and a large number of local truck and bus manufacturers offering LNG-powered models. By 2024, the size of China's LNG-fuelled truck and bus fleet had approached one million vehicles, consuming an estimated 25 bcm of natural gas. By 2030, demand in this segment could rise to nearly 48 bcm in the base case. However, lower domestic LNG prices relative to diesel have historically supported higher LNG truck sales, and further declines in spot LNG prices towards the end of the forecast period could incentivise an additional 5 bcm of demand, bringing the sector's total consumption to nearly 53 bcm/yr in the high case, more than double the 2024 level.

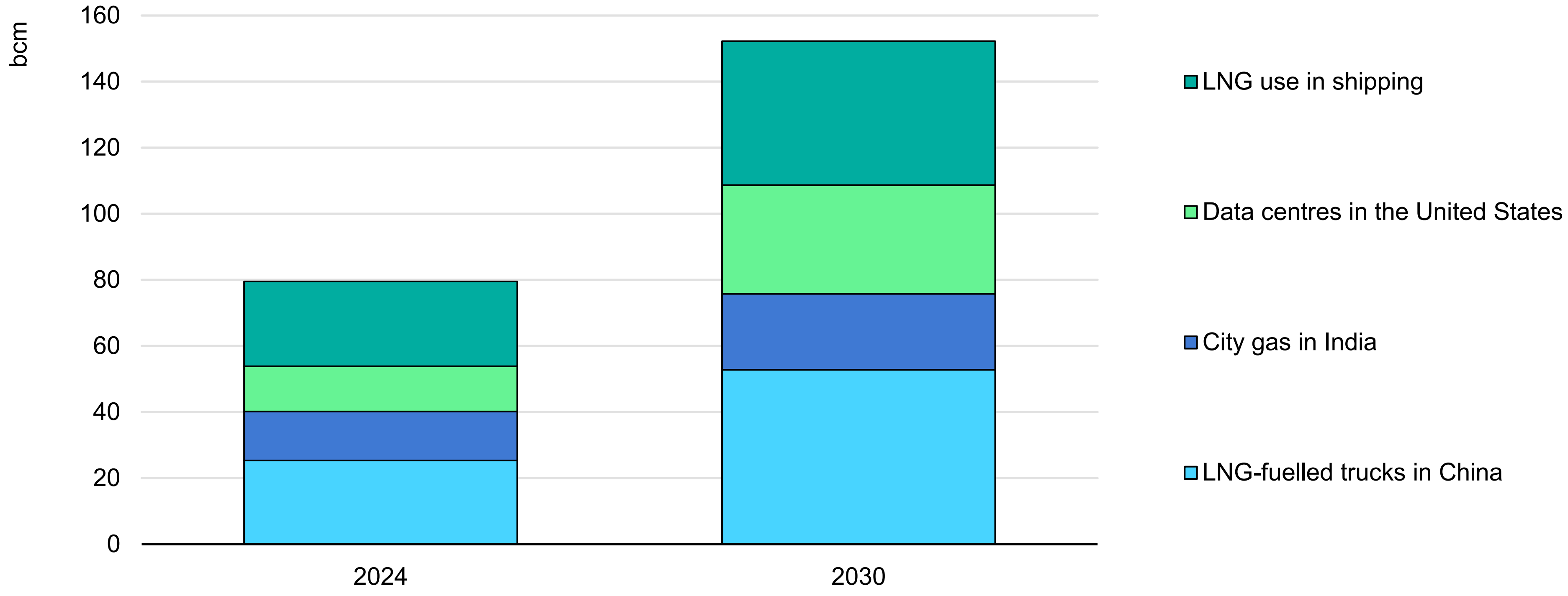
India's city gas distribution infrastructure, which serves residential and commercial users, small industry, and CNG and LNG filling stations, is undergoing the largest expansion of its kind anywhere in the world, driven by supportive government policies and private sector investment. Government targets envisage 120 million pipeline gas connections and 17 500 compressed natural gas (CNG) stations by 2030, representing a tenfold and threefold increase from 2024 levels, respectively. While these targets are highly ambitious, even partial achievement could drive significant gas demand growth. We estimate that India's city gas sector alone could add around 8 bcm/yr to global gas demand between 2024 and 2030.

The United States is already the world's largest consumer of electricity for data centres, and power demand in this segment is expected to grow by around 250 TWh between 2024 and 2030. With just over 40% of data centre electricity currently generated from natural gas, this growth could translate into nearly 20 bcm of additional annual gas demand by 2030.

LNG use in the marine transport sector is expected to increase by 70% and reach nearly 44 bcm/yr by 2030. International maritime shipping, which includes both LNG carriers and commercial vessels powered by LNG, accounts for most of the increase, adding an estimated 15 bcm/yr between 2024 and 2030. Growth is driven by fleet expansion, the build-out of LNG bunkering infrastructure, IMO regulations and favourable economics compared with other alternative fuels. Another 3 bcm/yr increase could come from domestic LNG shipping, including inland waterway barges, ferries and offshore supply vessels.

Four key drivers alone could add over 70 bcm to annual gas use by 2030

Forecasted natural gas demand in selected countries and sub-sectors, 2024 and 2030



Asia is expected to account for half of global gas demand growth to 2030

Following a brief period of weakness, the Asia Pacific region is expected to regain its role as the dominant driver of global gas demand through to 2030. Natural gas consumption in the Asia Pacific region is expected to expand by about 20% (or 190 bcm/yr) between 2024 and 2030 in the base case. When accounting for the demand response triggered by lower LNG prices in the high case, the region's demand could expand by 25% (or nearly 245 bcm/yr). Under this higher trajectory, China (up 125 bcm/yr), Emerging Asia (up 66 bcm/yr) and India (up 35 bcm/yr) are the three main pillars of Asian demand growth while the rest of the region sees more modest increases, led by Korea, Chinese Taipei and Japan.

China's gas demand could grow by up to 30% by 2030

China is set to maintain its role as the largest driver of global gas demand growth in our outlook period. In our base case, the country's total consumption grows by close to 100 bcm/yr (or 22%) between 2024 and 2030. In the high case – accounting for price-responsive demand – Chinese gas use could increase by as much as 125 bcm (29%), contributing about one-quarter of incremental global gas demand through 2030. Industrial activity, power generation and transport are expected to drive this growth. However, continued electrification and the deployment of renewables are expected to slow the overall uptake of gas, which is projected to grow at a compound annual rate of 4.3% to 2030, well below the average rate of more than 7% observed during the 2019-2024 period.

The industrial sector – the largest gas-consuming sector in China – is also expected to remain the country's largest contributor to demand growth in the medium term. However, rising competition from the electrification of industrial processes and a more cautious policy approach to coal-to-gas switching are set to reduce industry's role to only about one-third of total incremental demand, compared with more than half in the 2019-2024 period.

Power sector gas burn is expected to act as the second-largest demand driver in the forecast period, despite competition from both renewables and coal. China is expected to continue adding significant renewable power capacity in the coming years, leading to a near-doubling of renewable power generation by 2030. However, strong (albeit tapering) electricity demand growth is set to provide sufficient space for gas-fired power generation growth. Despite coal remaining a low-cost fuel source for the sector, varying regional market dynamics and policy support are set to increase gas use in the sector as a cleaner-burning and dispatchable fuel.

The transport sector is also expected to benefit from easing global gas market dynamics, helping LNG make greater inroads in the heavy goods transport segment. Residential and commercial demand growth, linked to the continued build-out of gas distribution infrastructure, is expected to taper.

While overall Chinese gas demand growth rates are expected to remain well below those of the past ten years, expanding global LNG supply is expected to make natural gas a more accessible option to Chinese buyers, spurring demand response in periods of looser global gas market dynamics.

Domestic gas production is expected to increase by close to 25%, reaching more than 300 bcm by 2030, as both conventional and unconventional sources continue to act as a lever of supply security for the country. Increased pipeline imports from Russia through the existing Power of Siberia pipeline and the anticipated Far East route are expected to materialise in the latter part of the outlook period but are set to remain the smallest contributor to incremental supply. LNG is expected to bridge the supply gap, with imports rising to more than 130 bcm in the base caset and to nearly 160 bcm in the high case by 2030.

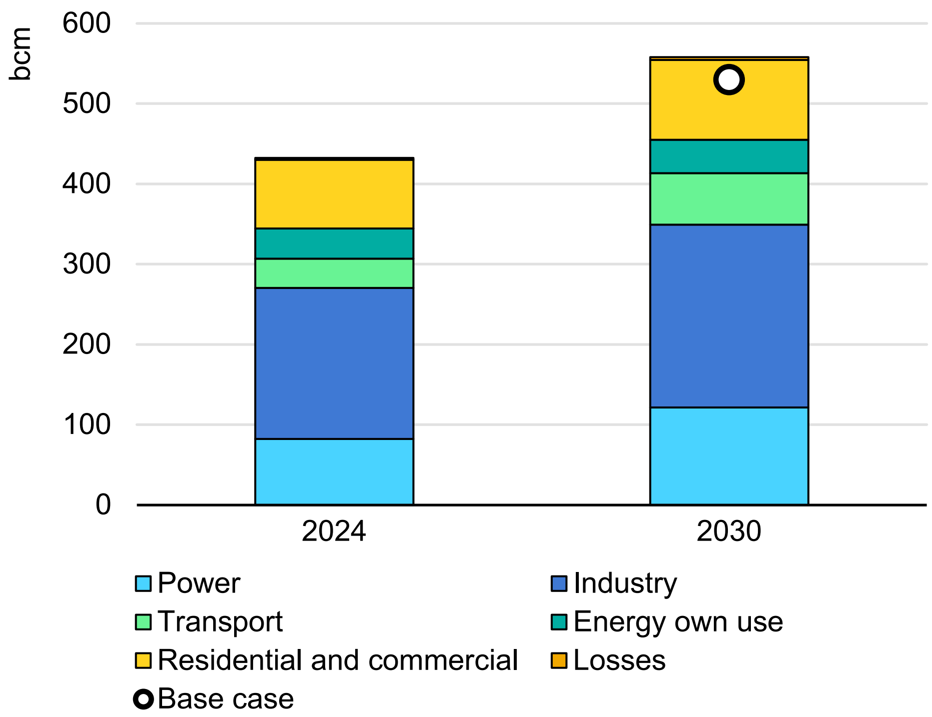
Japan and Korea

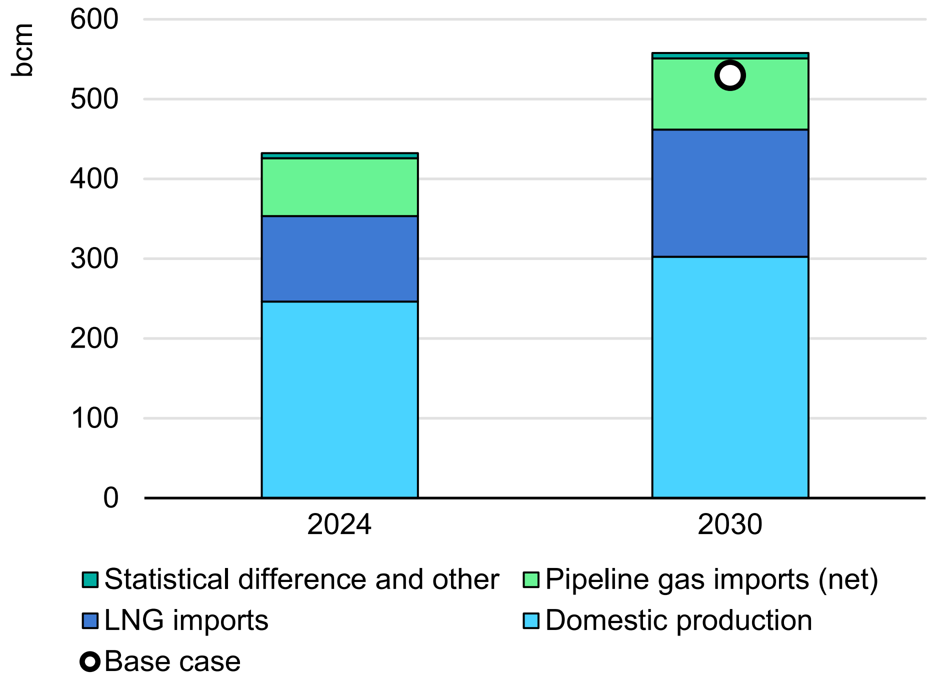
Japan's natural gas demand has been gradually declining over the last decade. The primary drivers of this decline were the restart of nuclear power plants and the growing adoption of renewable energy, both of which contributed to a reduction in the demand for gas-fired power generation. This downward trend is expected to slow down or even reverse in the medium term. Total gas demand in 2030 is projected to be only around 1% lower than 2024 levels under our base case. Additional demand in response to low spot LNG prices in the high case could lift Japan's total gas consumption to around 2% above 2024 levels, reaching nearly 94 bcm by 2030. This reversal of the historical decline is due to higher expected electricity demand growth, driven in part by data centres, as well as greater coal-to-gas switching and some delays in nuclear restarts over the forecast horizon.

South Korea's natural gas demand is projected to increase by 13% (8 bcm/yr) between 2024 and 2030 in the base case. Additional demand in response to lower spot LNG prices in the high case could lift this growth to 16% (10 bcm/yr) over the forecast period. Growing gas use is driven by rising electricity demand met through natural gas-fired power generation. According to the 11th Basic Plan for Long-term Electricity Supply and Demand, released in February 2025, South Korea's electricity demand is expected to continue growing steadily well into the 2030s. Although two new nuclear reactors (Shin Hanul 3 and 4) are scheduled to begin operation in 2026, the country also plans to phase down coal-fired power generation, which will further increase reliance on natural gas for electricity. As a result, natural gas demand for power generation in South Korea could grow by up to 23% by 2030 in our high case, accounting for about 80% of the overall increase in gas demand over the forecast period.

Industry, power and transport could boost China's annual demand by up to 125 bcm by 2030

Natural gas demand and supply in China, 2024-2030





Note: The sectoral demand and detailed supply breakdowns shown for 2030 correspond to the high case.

India's gas demand shifts to a higher gear through to 2030

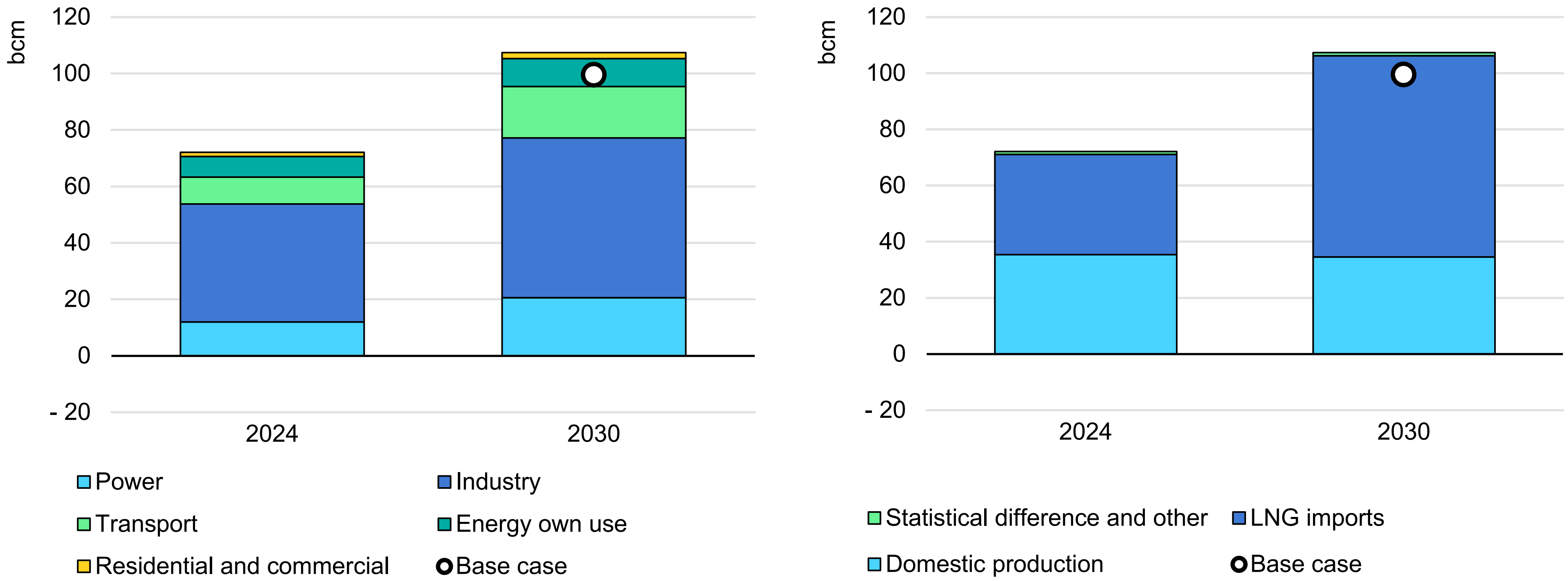
India's natural gas market has undergone a notable transformation over the past five years. Between 2019 and 2024, demand rebounded after a prolonged period of stagnation, with growth exceeding 10% annually in both 2023 and 2024. This recovery was driven by the rapid expansion of city gas infrastructure, with the number of CNG stations quadrupling and residential connections more than doubling between 2019 and 2024, as well as by a temporary resurgence in domestic production. Industrial demand also strengthened, especially in iron and steel, while gas use in oil refining increased as more facilities connected to the grid. In 2025, gas demand growth is expected to slow temporarily, with a projected decline of 3%. Two factors are driving this short-term slowdown. First, milder summer temperatures reduced the need for gas-fired electricity generation, in stark contrast to the exceptionally hot summer of 2024. Second, higher spot LNG prices prompted fuel switching in the industrial and oil refining sectors, where price sensitivity remains high. These developments underscore the responsiveness of India's gas demand to both weather-related and global market fluctuations.

India's natural gas consumption is projected to grow by nearly 40% from 2024 levels in the base case, reaching 99 bcm by 2030. With additional demand triggered by low spot LNG prices in the high case, total gas consumption could rise to around 107 bcm by the end of the decade, a nearly 50% increase compared with 2024. Growth under this higher trajectory is led by the industrial sector, which is projected to expand by more than 35% (15 bcm/yr) between 2024 and 2030. This expansion is driven by growing industrial activity and price-responsive demand, particularly in the small and manufacturing industries, as well as by operational efficiencies and environmental considerations as industries seek to reduce their emissions by finding alternatives to coal and oil. In contrast, growth in petrochemicals and fertilisers is expected to remain limited, with no major new gas-based capacity additions foreseen. The transport sector could add up to 9 bcm/yr of incremental gas consumption over the forecast horizon, supported by the continuing rollout of CNG infrastructure, the growing competitiveness of gas relative to liquid fuels and additional demand from LNG trucks, incentivised by lower LNG prices. Gas use in power generation is also expected to recover, contributing up to an additional 9 bcm/yr by 2030. This reflects a rebound in large-scale gas-fired generation and growing use of captive power in commercial and industrial settings. The energy sector – led by refining – is projected to add less than 3 bcm, supported by better grid connections and gas use in new and upgraded facilities.

Meanwhile, domestic gas production is projected to rise in the near term but fall back to around the 2024 level of 35 bcm/yr by 2030 under pressure from low prices, covering only about a third of total demand at the end of the decade. The remainder will be met by LNG imports, which could double to nearly 72 bcm/yr in the high case. Of this, close to 8 bcm could be triggered by low spot LNG prices.

India's gas demand could increase by 50% by 2030, led by industry and fuelled by LNG imports

Natural gas demand and supply in India, 2024-2030



Note: The sectoral demand and detailed supply breakdowns shown for 2030 correspond to the high case.

Emerging Asia could once again become a significant growth driver for global LNG demand

Emerging Asian economies represent the third major driver of growing gas consumption in Asia, where a combination of strong economic growth, rising energy demand, declining domestic gas production and lower spot LNG prices could lead to a significant increase in LNG imports. However, the region currently has only about three-quarters of the regasification capacity needed to meet projected imports, meaning that Emerging Asia's ability to play a leading role in absorbing the global LNG surplus through to 2030 and beyond depends on the development of additional infrastructure.

The region's combined natural gas consumption is projected to increase by more than 20% (55 bcm) between 2024 and 2030 in the base case, corresponding to an average annual growth rate of 3.4%. Depressed spot LNG prices toward the end of the forecast period could unlock an additional 10 bcm of demand across the region in the high case, equivalent to an annual expansion of just over 4%. This marks a sharp acceleration compared with the previous five years, when growth averaged well under 1% as the Covid-19 pandemic, followed by a period of high LNG prices, suppressed demand.

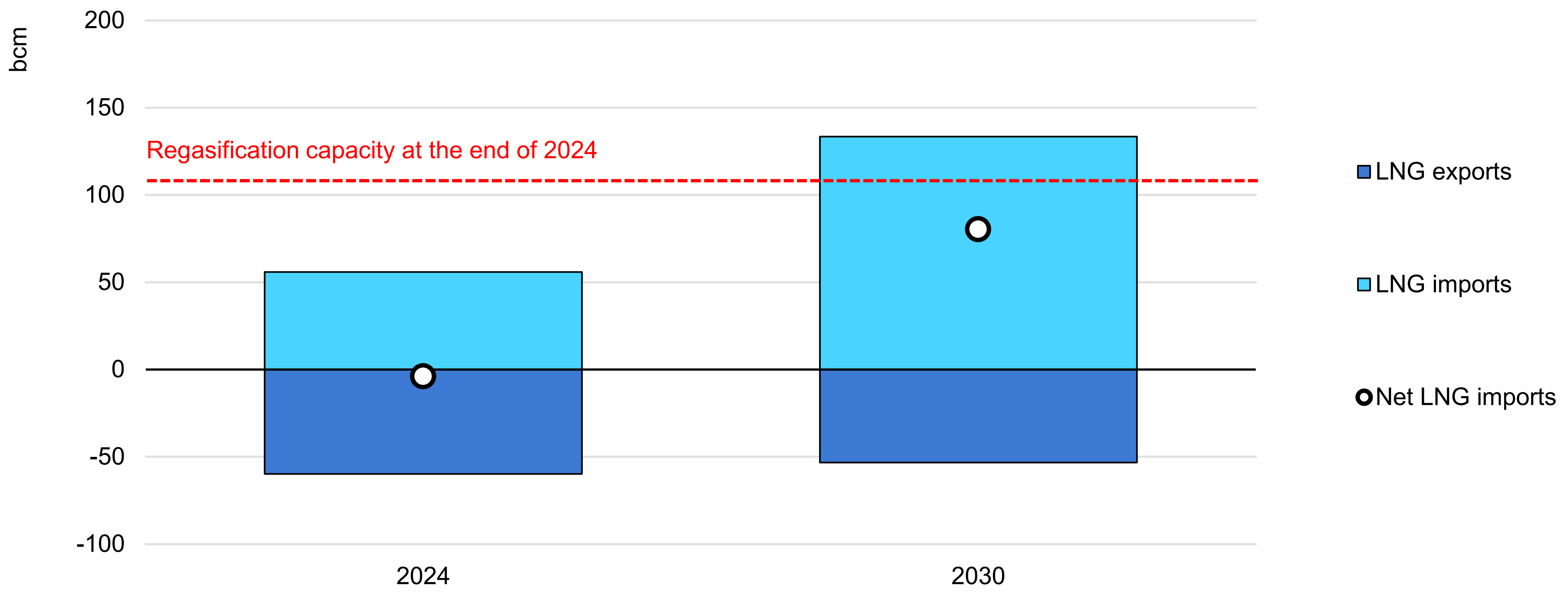
Under the price-adjusted demand trajectory in the high case, Indonesia accounts for the largest share of demand growth between 2024 and 2030, contributing one-third of the total, followed by Malaysia (22%), Viet Nam (12%) and Bangladesh (12%). By sector, power generation is expected to be the primary driver, accounting for about 60% of the region's demand increase in both the base and the high cases. Most of the remaining 40% of growth comes from the industrial sector in both cases.

Indigenous production in Emerging Asia is projected to drop by about 6% (14 bcm/yr) between 2024 and 2030, with the steepest declines concentrated in Bangladesh, Pakistan, Myanmar and Thailand. These are only partially offset by moderate increases in Indonesia, where Geng North and a handful of smaller development projects are expected to ramp up towards the end of the forecast. The region's already modest intra-regional pipeline gas trade is set to diminish further as Singapore's imports from Malaysia and Indonesia drop from around 6 bcm/yr in 2024 to just 1 bcm/yr by 2030.

As a result of growing demand, declining domestic production and shrinking pipeline gas trade, the region's LNG imports are projected to rise sharply, from around 55 bcm/yr in 2024 to nearly 125 bcm/yr in the base case and more than 130 bcm/yr in the high case by 2030. This shift would transform the region from a modest net exporter to a significant net importer of LNG by the end of the decade. However, the region's aggregate LNG import capacity stood at only around 105 bcm/yr at the end of 2024, indicating that additional investment in LNG import terminals, as well as downstream gas and power infrastructure, will be necessary to unlock its full price-sensitive demand potential over the next five years.

Emerging Asia transforms from a net LNG exporter to a significant net importer by 2030

LNG trade balance in Emerging Asia, 2024 and 2030



Source: IEA analysis based on ICIS (2025), LNG Edge, GIIGNL (2025), GIIGNL.
Note: LNG import and export levels in 2030 are associated with the high case.

North American natural gas demand growth tapers, but key incremental demand drivers remain

Gas demand growth in North America is set to taper across all sectors in our forecast period, as improving end-use efficiency and the continued roll-out of renewables influence the demand pathway of one of the world's largest and most mature gas markets. Nevertheless, key growth drivers remain, pushing 2030 demand up by more than 5% (60 bcm/yr) from 2024 levels in both the base and high cases.

Power sector

Power sector gas burn – North America's largest gas-consuming sector and its largest source of electricity generation – is set to remain the primary demand-side driver, accounting for over 45% of the continent's natural gas demand growth in the coming years. However, this is down from nearly 80% of total incremental gas demand over the past decade, a period over which the emergence of an abundance of relatively cheap gas from the US shale boom drove rapid uptake of gas and a steep economics-led decline in coal-fired power generation.

In the coming years, renewable power generation is set to replace gas as the primary source of power generation growth, with continued wind and solar PV capacity additions, despite the repeal of the Inflation Reduction Act dampening the uptake and delivery of projects in the United States. Overall, this is expected to reduce the relative role for fossil fuels in the power mix. However, strong electricity demand growth and the continued cost-led marginalisation of coal-fired plants in the merit order mean that gas demand still has space to grow in the power sector to 2030, albeit at just one-quarter the rates of the 2019-2024 period.

Energy sector own use

Energy sector own use of natural gas is set to play an increasing role in North American gas demand dynamics, accounting for around 25% of incremental demand to 2030, up from about 17% over the previous decade.

Demand growth from this sector accelerated nearly a decade ago under the combined effect of expanding oil and gas production and the start of the first US LNG export projects along the US Gulf Coast. Looking ahead to 2030, continued growth in the sector is expected to be driven foremost by liquefaction plant activity as a slew of new LNG export projects ramp up in Canada, Mexico and the United States. Growing oil and gas upstream activity, although key in sustaining overall domestic demand growth and continued fossil fuel exports from North America, is set to contribute a smaller share to incremental gas demand than in the recent past. Still the subsector is expected to make up more than half of total energy own use demand for natural gas in 2030.

Industry

Industrial sector consumption of natural gas in North America dipped sharply in 2020 as a result of the slowdown in economic activity linked to the Covid-19 pandemic. While demand has since embarked on a recovery, it remained almost 2% below the pre-pandemic peak by 2024, notably as Mexico has struggled to overcome more structural headwinds that had emerged prior to the pandemic.

In the decade before the pandemic, industrial demand for natural gas grew at an average annual rate of close to 2.5% in North America, led by robust US activity. Between 2024 and 2030, we expect industrial demand to continue growing (again, led by the United States), although at a compound rate of less than 1%. This means that the sector is set to account for just over one-fifth of incremental demand through to the end of the decade. By the end of the outlook period, industry remains the third-largest demand sector for the continent, approaching similar consumption levels as residential and commercial demand.

Residential and commercial

During the 2010s, residential and commercial demand for natural gas made modest gains but remained largely stable, before easing in the early 2020s in both the United States and Canada, while accounting for only small volumes in Mexico. In the coming period, continued efficiency improvements in buildings and in boiler systems, as well as progress in the electrification of space and water heating, are expected to lower the demand trajectory during the outlook. Nevertheless, gas use in buildings is expected to end the decade about 2% above 2024 levels thanks to sustained growth in the commercial segment in particular.

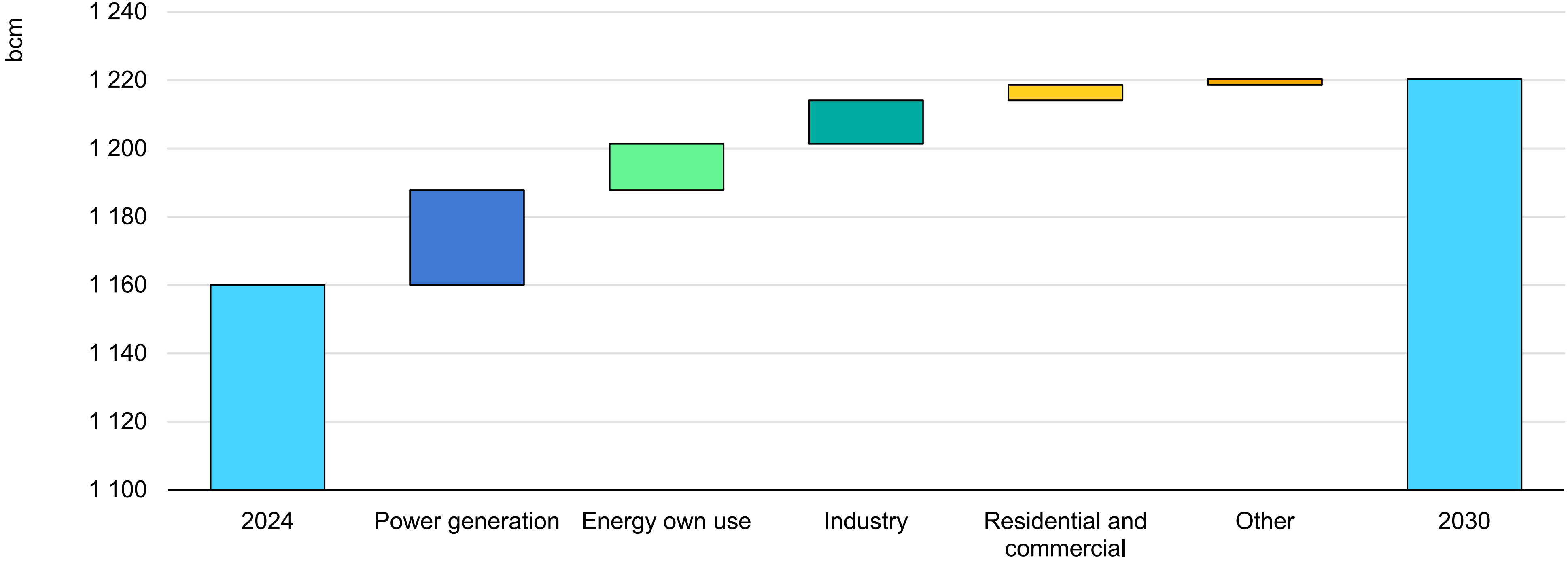
Overall demand trends

Despite expectations of a marked slowdown in total natural gas demand in North America over the second half of the decade, underlying growth drivers remain. A relatively robust economic outlook points to activity-based growth in both gas and power demand, the latter driving the largest share of the demand upside to 2030. However, with such a large share of gas demand growth hinging on power generation, the outlook remains dependent on several variables somewhat exogenous to strictly gas-market fundamentals. The power demand trajectory will depend on burgeoning segments of demand, notably related to data centres and AI applications. On the supply side, the pace of renewable capacity additions will also be a critical variable.

In total, North American natural gas demand is expected to grow by less than 1% per year, reaching over 1 220 bcm by 2030, compared with an average growth rate of just over 2% per year in the previous decade.

Power generation continues to drive North American gas demand, despite rising renewables

Incremental natural gas demand by sector in North America, 2024-2030



European gas demand: A continuing downward trend

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 declined by nearly 20% (or over 100 bcm) between 2021 and 2023 due to a combination of lower gas use in buildings, industry and the power sector. Natural gas consumption increased by less than 1% in 2024, partly supported by higher industrial gas demand. Preliminary data suggest that Europe's gas demand grew by nearly 5% in Q1-Q3 2025, largely driven by stronger gas-to-power demand amid lower hydro and wind power generation.

Natural gas demand in OECD Europe is expected to decline by 10% (or almost 45 bcm) between 2024 and 2030 in the base case and stand 26% below the 2021 level by 2030. When considering the demand response coming from lower LNG prices in the high case, the region's demand decline moderates to 8% (or nearly 35 bcm) between 2024 and 2030 and remains almost 25% below the 2021 level by 2030. Under this demand trajectory, the **power sector** alone is expected to account for around 85% of the net decline amid the continued expansion of renewables. Nevertheless, the flexibility provided by natural gas will remain crucial to ensure electricity supply security in the medium term. In the **residential and commercial sectors**, energy efficiency gains together with the deployment of heat pumps are set to reduce gas use during the forecast period. In industry, the lower gas price environment is expected to support a gradual recovery, although the sector's gas use is expected to remain 10% below its 2021 levels.

The decline in European gas demand is forecast to be primarily driven by Northwest European markets. In contrast, gas use in Eastern European markets is expected to marginally increase amid the phase-out of coal- and lignite-fired power plants.

Residential and commercial sectors

Residential and commercial gas demand declined by almost 20% (or 40 bcm) between 2021 and 2023. 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 available to them, the installation of heat pumps, efficiency gains and behavioural changes all played a critical role in reducing distribution network-related demand. Residential and commercial gas demand remained broadly flat in 2024 and increased by 4% y-o-y in the first nine months of 2025 amid colder weather in Q1.

Our analysis indicates that the heating intensity (gas use per heating degree day) of the residential and commercial sectors declined by 15% between 2020 and 2023 and has remained well below its pre-crisis levels since then. This indicates that gas-saving measures implemented since the 2022/23 gas crisis, along with the electrification of space heating, are reducing the temperature sensitivity of direct natural gas use in buildings.

Natural gas demand in the residential and commercial sectors is expected to decline at a rate of 1% per year between 2024 and 2030 both in the base and high case. In the European Union, the Renovation Wave is set to improve the energy efficiency standards of the building stock, while the electrification of heat through the deployment of heat pumps is expected to further moderate natural gas use in the residential and commercial sectors. Considering the temperature sensitivity of these sectors, significant demand variations can occur depending on weather conditions, which would alter the current forecast.

Power sector

Gas-to-power demand fell by more than 15% (or over 25 bcm) during 2021-2023, with the decline largely concentrated in 2023. The downward trend continued in 2024, when gas burn in the power sector dropped by a further 10%. In contrast, gas use in the power sector grew by 15% in Q1-Q3 2025, driven by lower hydro and wind power output and higher electricity consumption.

Gas-to-power demand is expected to decline by around 25% (or more than 30 bcm) between 2024 and 2030, even when the effect of lower LNG prices is considered. This is largely driven by the rapid expansion of renewable power output, which is forecast to increase by more than 40% by 2030. The decline in gas-to-power demand is moderated by the gradual phase-out of coal-fired power plants. Coal-fired power generation capacity is set to decline by more than 50% between 2024 and 2030. By 2030, coal-fired power generation will virtually disappear in Northern and Southwestern Europe (with the exception of Germany). 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.

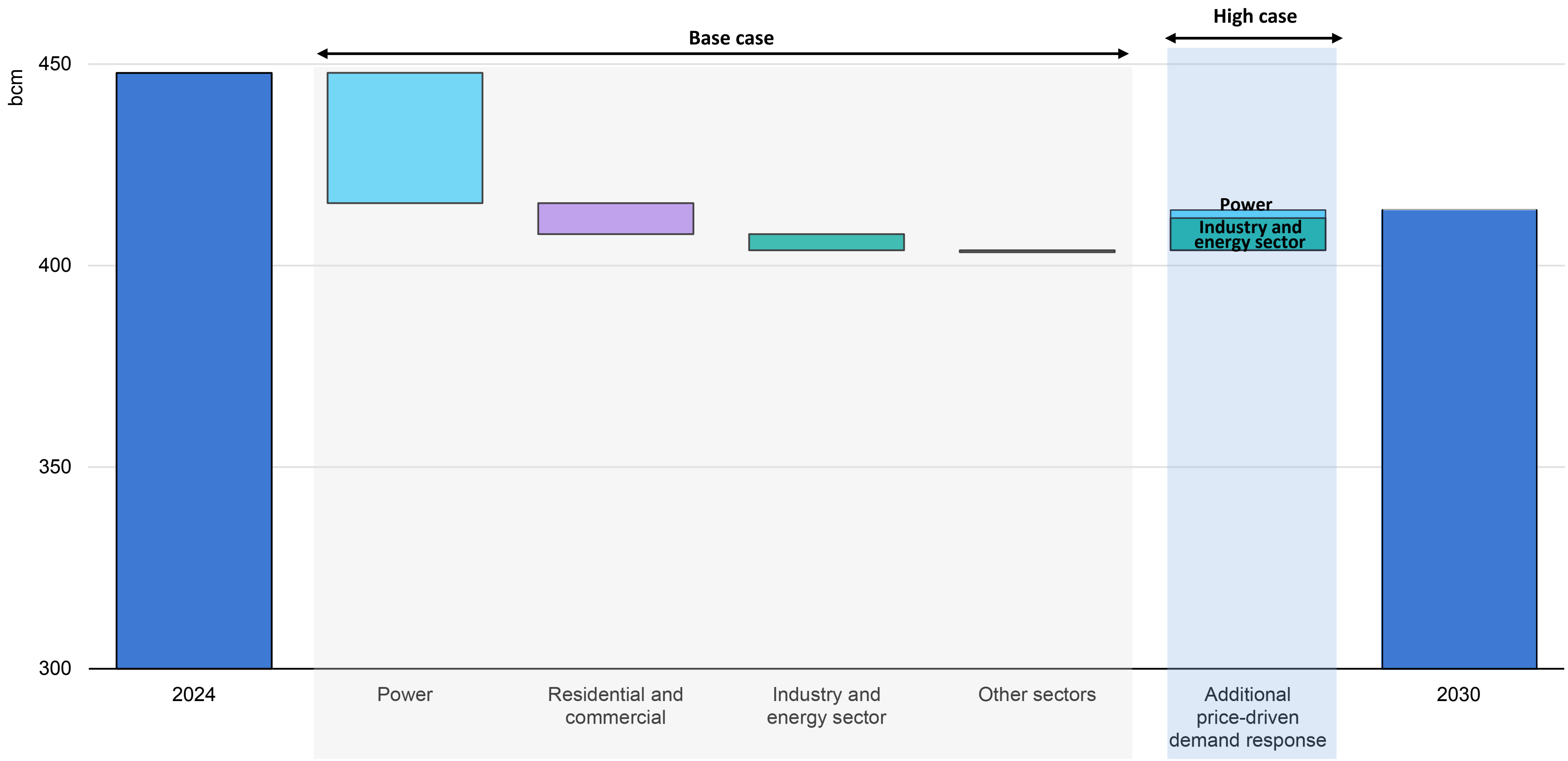
Industry and energy sector

Natural gas demand in industry and the energy sector dropped by around 20% (or 35 bcm) between 2021 and 2022, with all-time high gas prices driving fuel-switching and leading to reduced production rates across the most gas- and energy-intensive industries. Industrial gas use remained broadly flat in 2023 and grew by an estimated 9% in 2024 amid lower price levels. Preliminary data suggest that gas use in industry and the energy sector fell by 2% y-o-y in Q1-Q3 2025.

In the base case, gas use in industry and energy sector declines by 3% during 2024-2030. When considering the demand response coming from lower LNG prices, natural gas use in industry and the energy sector is expected to marginally increase during 2024-2030, amid an improving macroeconomic environment, healthier supply availability and lower price levels. Despite this gradual recovery, gas use for these activities is forecast to remain 10% below its 2021 levels by 2030. This means that around half of the industrial gas demand lost during 2022-2023 is not expected to recover due a combination of permanent plant closures and energy efficiency gains. 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.

The continued expansion of renewables is set to reduce Europe's natural gas demand

Incremental natural gas demand by sector in OECD Europe, 2024-2030



LNG contracting and flexibility update

Update on LNG contracting trends

This section provides an overview of the most recent LNG contracting trends, analysing LNG supply availability and the evolution of destination flexibility in LNG contracts. The analysis is based on the contractual positions of exporters and importers and their actual traded volumes, using **the IEA internal LNG contract database**. Unless otherwise stated, only firm supply contracts are considered. These include LNG sale and purchase agreements (SPAs), equity entitlements and tolling agreements linked to an LNG supply project that is either operational or under construction, or has reached a final investment decision (FID).

Since the first issue of the Global Gas Security Review in 2016, the **LNG market has gained in depth and liquidity**. Total traded volumes expanded by 60% between 2016 and 2024, while both buyers and sellers are displaying a greater diversity in their commercial preferences and flexibility requirements. The share of **destination-free contracts** rose from 29% in 2016 to 45% in 2024, largely driven by the expansion of US LNG supplies. Destination-fixed agreements have regained traction and accounted for more than 60% of volumes contracted since 2024. However, by 2030 many existing destination-fixed contracts will expire, causing the share of destination-flexible contracts to rise to 52% again.

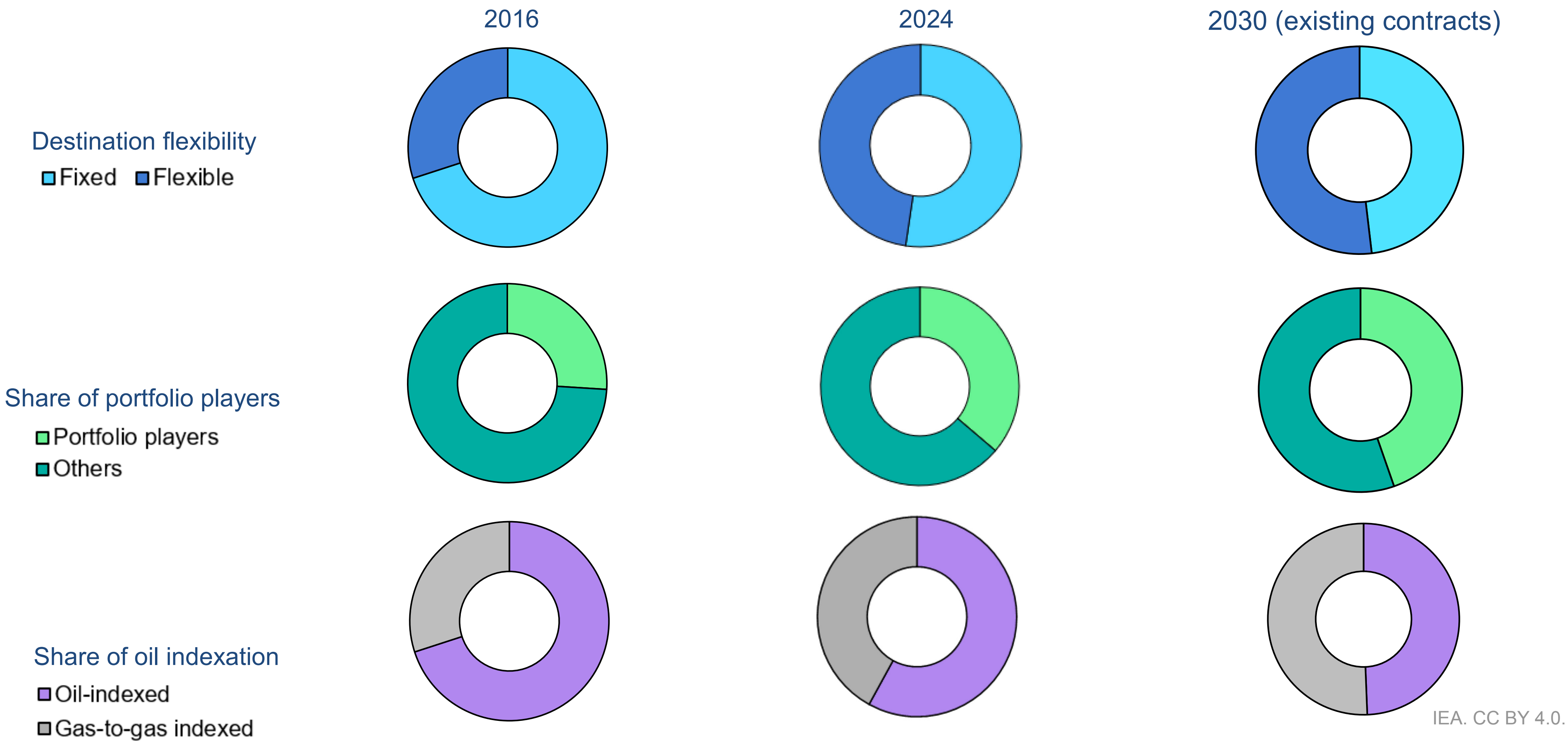
Pricing terms are becoming more diverse, with the share of oil-indexed LNG export contracts declining from over 70% in 2016 to 61% in 2024, replaced by hub indexation and hybrid pricing formulae. Based on existing active contracts, the share of oil-indexed LNG contracts is expected to decline further, falling to 50% by 2030 as new US LNG projects linked to Henry Hub come online.

In addition to traditional buyers, the role of **portfolio players** in LNG trade has increased significantly in recent years: their procurement contracts' share of all LNG contracts in force rose from 26% in 2016 to over 38% in 2024. Based on existing contracts, this share is expected to increase to nearly 44% by 2030.

Although the global LNG market is becoming more flexible and liquid, **the role of long-term contracts remains crucial** as an effective risk-sharing mechanism between sellers and buyers. Long-term agreements (with a duration of ten years or more) accounted for 75% of the volumes contracted since 2022, reflecting sellers' and buyers' preference for demand and supply security, respectively.

The **growing flexibility and liquidity of the LNG market** is becoming increasingly important in responding to gas supply and demand shocks to **ensure energy supply security**. This was highlighted during the 2022-2023 gas supply and demand shock, when flexible LNG partially offset the steep decline in Russian piped gas deliveries in the European gas market.

The global LNG market continues to gain liquidity and pricing diversity



Notes: Destination flexibility is only for indicative purposes, assumed in the absence of a clear source of information. Destination-flexible contracts are typically underpinned by FOB shipping arrangements.
Source: IEA analysis based on ICIS (2025), ICIS LNG Edge.

The strong momentum behind LNG project development continued in 2025…

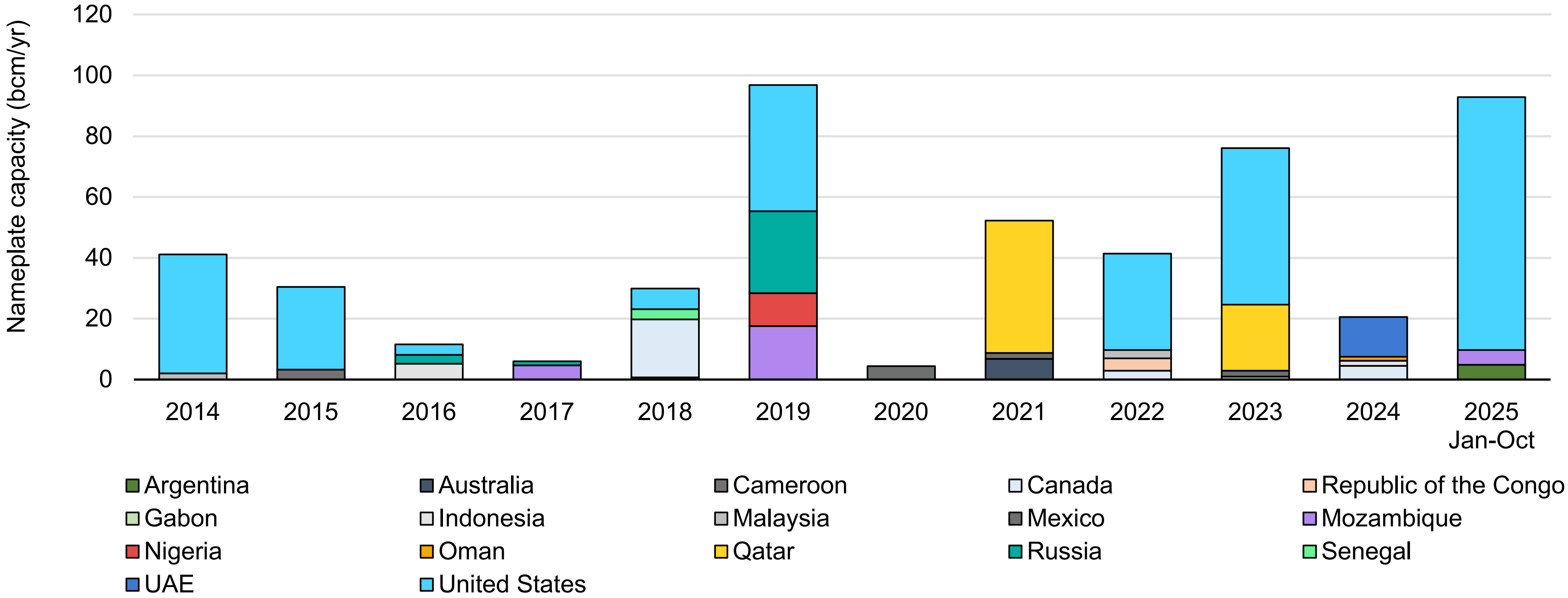
Since Russia's full-scale invasion of Ukraine in February 2022, **more than 230 bcm/yr of LNG liquefaction capacity has been approved**, including **Qatar**'s North Field South expansion project. The **United States** alone accounted for about 60% of the liquefaction capacity sanctioned between 2022 and 2024.

In January 2025, the United States lifted the freeze on LNG export permits that had been in place since the previous year. **This policy shift has accelerated LNG investment in the country**, with more than 80 bcm/yr of LNG capacity sanctioned in the first ten months of 2025 (until 20 October 2025) -, a new all-time high for the US LNG industry. The **Louisiana LNG project phase 1** took FID in April 2025 and is expected to start operations by mid-2029. The project will consist of three trains with a combined capacity of 22.4 bcm/yr. In June 2025, an FID was also made for **the Corpus Christi Midscale Trains 8-9 plus Debottlenecking**. This expansion is expected to increase annual production capacity by 6.8 bcm, bringing total capacity to 41 bcm/yr by 2029.In July 2025, **Venture Global's CP2 project Phase 1 reached FID**. This project proceeded with engineering, procurement and construction activities even prior to the FID, reflecting the accelerating momentum in US LNG investments. Phase 1 is expected to have annual production capacity of 20 bcm and aims to begin operations in 2027. In early September, NextDecade Corporation reached FID on Rio Grande LNG Train 4. Train 4 is expected to have a production capacity of over 8 bcm/yr and operations are anticipated to start in H2 2030. In the second half of September 2025, **Sempra announced FID for Phase 2 of its Port Arthur LNG project.** The Phase 2 expansion is expected to add an additional 18.36 bcm/yr of liquefaction capacity. Phase 2 will consist of two liquefaction trains: Train 3 is scheduled to begin commercial operations in 2030, followed by Train 4 in 2031. In October 2025, NextDecade reached FID on Rio Grande LNG Train 5 (8 bcm/yr). The start of operations is anticipated in the first half of 2031. The strong momentum behind US LNG projects shows the confidence of the industry that demand for LNG will continue to expand strongly and reflects the supportive policy environment for natural gas projects in the United States.

LNG project development is gaining momentum in **South America**. Until now, only Trinidad and Tobago and Peru have had large-scale LNG liquefaction projects in the region. In May and August 2025, the first and second phases of **Southern Energy FLNG project in Argentina reached FID,** with a combined annual production capacity of 8 bcm and scheduled production starts in 2027 and 2028, respectively. In early October 2025, ENI and its partners took FID on the Coral North FLNG export project offshore Mozambique. The project will have a production capacity of 4.9 bcm/yr and is expected to start operations in 2028.

…primarily supported by the United States

FIDs for new LNG liquefaction capacity, 2015-2025



Note: Includes Qatar's North Field South expansion project.
Sources: IEA analysis based on various public statements.

The Middle East and North America led new LNG contracts on the export side in 2024

Contract volumes concluded with post-FID projects in 2024 totalled 68 bcm/yr, representing a 25% increase compared with 2023, when they totalled 54 bcm/yr. Including contracts with pre-FID projects, contracted volumes in 2024 stood at 77 bcm/yr, short of the volume concluded in 2022 (119 bcm/yr) and 7% lower than the volume signed in 2023 (83 bcm/yr). Combined volumes from North America and the Middle East, both pre- and post-FID, accounted for over 60% of the contracted volumes signed in 2024, showing a pattern similar to 2023.

On the export side, the Middle East alone accounted for 58% (or 37 bcm/yr) of the volumes contracted with post-FID projects in 2024, surpassing North America as the largest source of supply contracts for the second consecutive year. Qatar accounted for about 35% (or 26 bcm/yr) of concluded volumes in 2024 and was the largest source by country, supported by the North Field East and North Field South expansion projects. Portfolio players were the second-largest source of supply in 2024, accounting for 30% (or 20 bcm/yr) of the contracted volumes signed with post-FID projects in 2024. North America and the Asia Pacific region accounted for 3% (or 1.7 bcm/yr) and 3% (or 1.6 bcm/yr) respectively of the total post-FID contracted volumes signed in 2024.

When including pre-FID projects, contracted volumes in 2024 with North America as the source of supply amounted to 14 bcm/yr, following the contracted volumes sourced from portfolio players. Numerous pre-FID LNG projects are progressing in the region, and buyers are signing many new contracts with them. Therefore, including or excluding pre-FID projects significantly affects the reported volume of LNG contracts in the region.

On the import side, Asian countries accounted for the largest share of contracted volumes concluded with post-FID projects in 2024 (60%, or 38 bcm/yr). By country, India accounted for 23% (or 15 bcm/yr), overtaking China to become the largest purchaser in 2024. Portfolio players took the next largest share, accounting for 18% (or 12 bcm/yr) of the contracted volumes signed in 2024. The volume contracted by portfolio players was their second largest after 2023. Europe accounted for 15% (or 10 bcm/yr) of the contracted volumes concluded in 2024.

When including pre-FID projects, Asia, Europe and portfolio players accounted for 50% (or 40 bcm/yr), 13% (or 10 bcm/yr) and 30% (or 23 bcm/yr) respectively of the total contracted volumes concluded in 2024. The volume that portfolio players contracted as buyers in 2024 had a high proportion of contracts sourced from North America (62%). Given that the contracted volumes sourced from North America include a number of pre-FID projects, it suggests that portfolio players play an important role in project developers achieving the longer-term offtake contracts required for project FID.

The volume of contracts signed with post-FID projects in the first nine months of 2025 was 99 bcm/yr, representing a 90% increase compared with the same period in 2024. Buyers in Asian countries accounted for 22% of the volumes contracted, with India signing the highest proportion (44%) by country. When pre-FID projects are included, 110 bcm/yr of contracts were signed in the first nine months of 2025, an increase of 63% compared with the same period in 2024. The strong expansion of LNG liquefaction capacity (expected to increase by approximately 300 bcm/yr by 2030) is offering additional contracting opportunities.

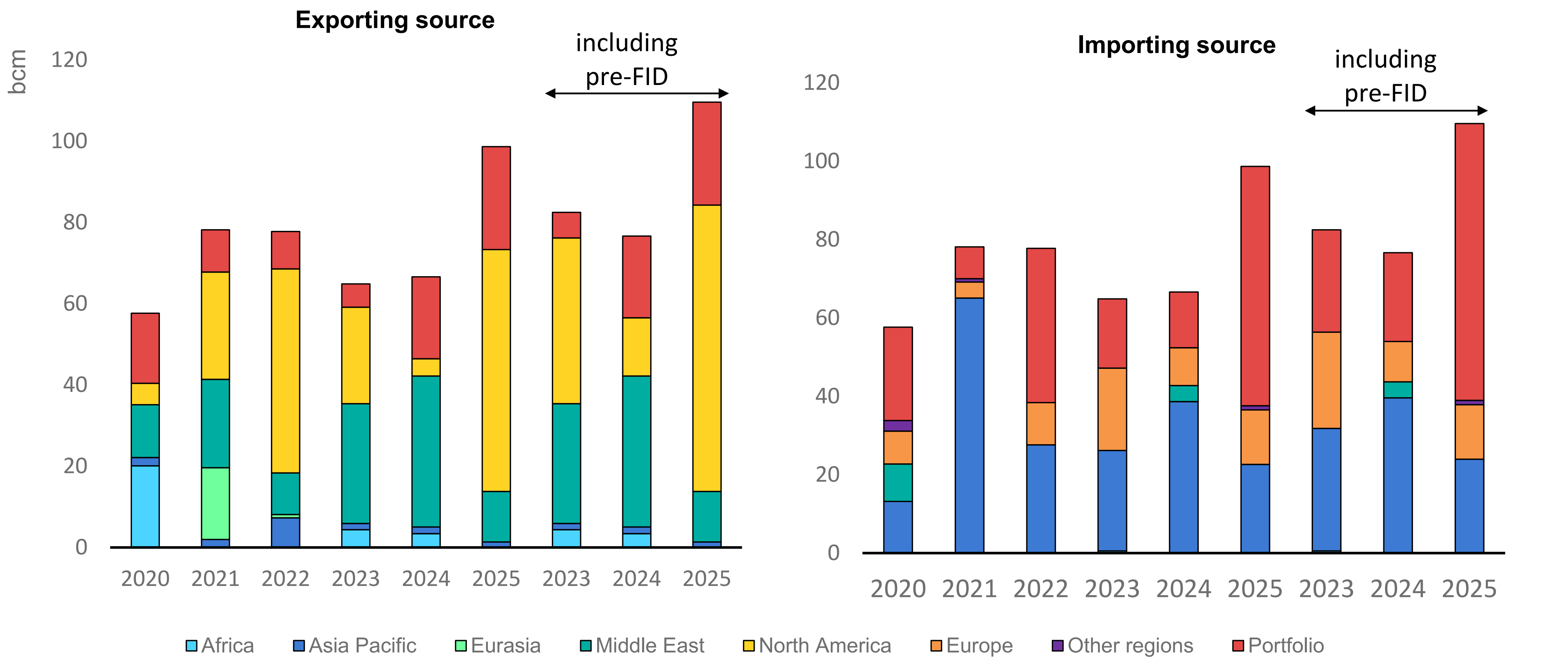
On the export side, North America accounted for the highest share of contract volumes signed in the first nine months of 2025 (64% or 60 bcm/yr); indeed, new contracts in North America surpassed the Middle East in contrast with the same period in 2024. By country, the United States commanded the highest share (59% or 55bcm/yr). Portfolio players accounted for 23% (or 22 bcm/yr) and Middle East 12% (or 12 bcm/yr). The contract volumes sourced from the Middle East increased by around 25% compared with the same period in 2024. When pre-FID projects are included, 60 bcm/yr of export contracts with North America were signed in the first nine months of 2025, compared with 26 bcm/yr in the same period in 2024, also representing a similar upward trend.

On the import side, portfolio players accounted for the highest share of contract volumes signed in the first nine months in 2025 (64% or 60 bcm/yr) surpassing Asia. **Portfolio players have notably increased their LNG procurement activities, with a particular focus on offtake from new US LNG projects offering destination flexibility**. In June 2025, Japan's JERA announced the purchase of a total of 5.5 Mtpa of LNG from several new LNG projects in the United States. JERA plans not only to supply this LNG to the Japanese market, but also to distribute it to a broader range of destinations across Asia, reflecting the prevailing uncertainties surrounding Japan's gas demand and its strategic shift toward regional diversification and flexible supply management.

Again on the import side, Türkiye accounted for a high proportion (10% or 9 bcm/yr), representing the largest share contracted by country. China accounted for 7 bcm/yr, increasing by around 550% compared with the same period in 2024. India accounted for 7 bcm/yr, increasing by 75% compared with same period in 2024. Europe (including Türkiye) accounted for 12% (12 bcm/yr), representing higher volumes than the same period in 2024.

Asian buyers and portfolio players continue to drive new LNG purchase contracts

Volume of contracts concluded in each year split by exporting and importing source, 2020-2025



Notes: Contracted volumes used for the analysis are associated with confirmed export projects. 2025 represents volumes signed by the end of September 2025. “Portfolio” volumes are contracted by a market player who may source product from one or multiple regions to fulfil contractual obligations.
Source: IEA analysis based on ICIS (2025), ICIS LNG Edge.

Long-term agreements have dominated contracting activity since 2018

Contracts concluded in 2024 showed a high share of long-term agreements (with a duration of ten years or more) and small volume contracts (under 2 bcm/yr). The trend for a high share of long-term agreements has continued since 2018.

Long-term agreements dominated contracted volumes in 2024, accounting for 83%, a slight increase from 81% in 2023. Asian buyers were the driving force behind long-term agreements, accounting for 65% of them by volume. On the supply side, the Middle East led long-term contracting. Agreements with a medium duration (five years and over, but under ten years) and with a short duration (under five years) accounted for 10% and 5% of the total contracted volume, respectively.

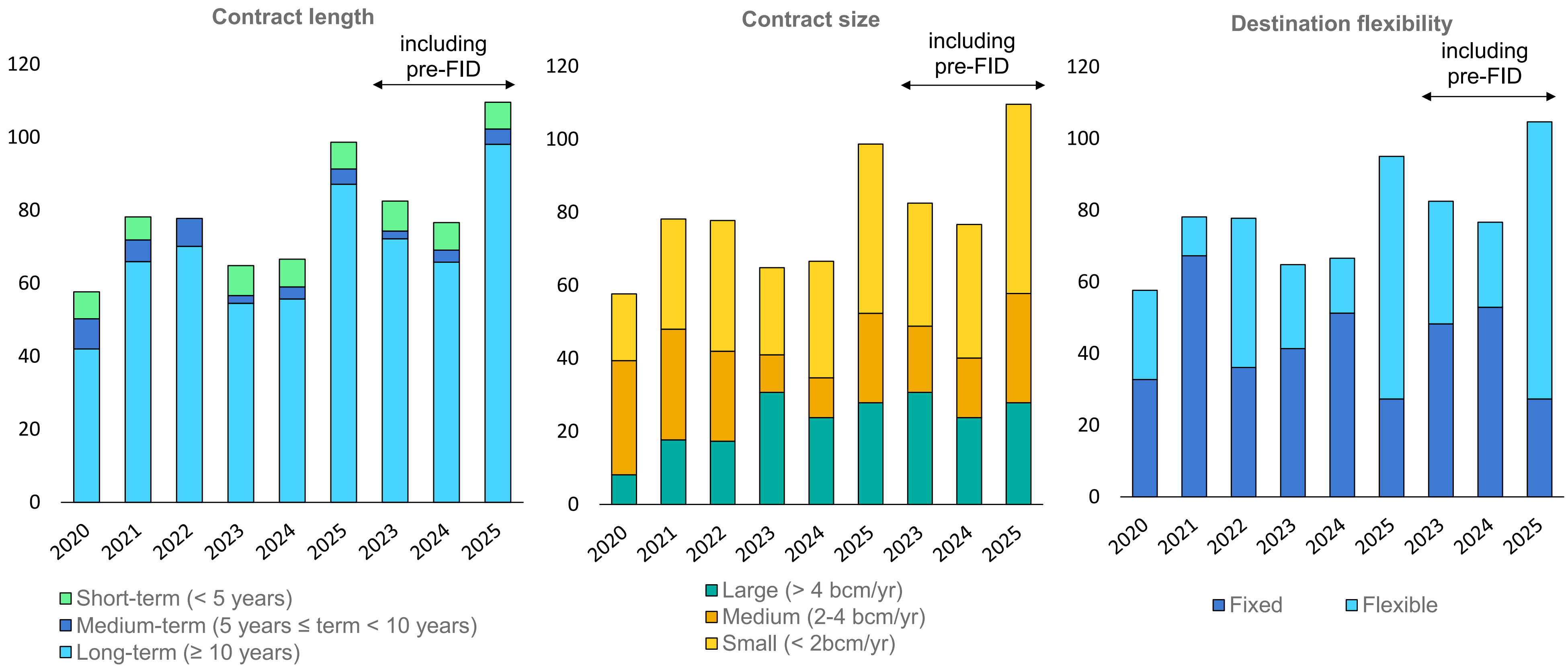
Long-term agreements also dominated during the first nine months of 2025, accounting for 78%. In this period, Asian buyers signed long-term agreements accounting for more than 49% of the total newly contracted long-term volume. Of the total contracted volumes signed since 2018, long-term agreements have accounted for more than 80%, of which Asian buyers accounted for about 40%. Notably, China and India accounted for over 20%, leading the volume of long-term agreements.

Large contracts (over 4 bcm/yr) accounted for 37% of contracted volumes in 2024. Qatar accounted for all the large contract volumes, signing four contracts with a volume exceeding 4 bcm/yr. Medium-sized contracts (2-4 bcm/yr) accounted for 13%, while contracts for small volumes (less than 2 bcm/yr) accounted for 50%. In the first nine months of 2025 no large contracts were signed. Large contracts as a share of all contracts concluded since 2022 are close to 30%, and Asian buyers accounted for a high proportion of these (48%).

Destination-fixed contracts account for around 75% of all volumes contracted since 2024. This has mainly been driven by Asian buyers, which account for more than 60% of total contracted volumes with a fixed destination. Conversely, the share of destination-free contracts decreased from around 50% in 2022 to around 20% in 2023 and 2024, increasing again to about 50% in 2025. The decrease in destination-flexible contracted volumes sourced from North America in 2023 and 2024, compared with 2022, is likely to be one of the reasons for the decline in the share of destination flexibility since 2023. Destination-flexible volumes from North America rose again in 2025. Although the share of contracts concluded in 2023 and 2024 with a fixed destination was high, the overall trend is for total active contracts increasingly to have a flexible destination – their share was 45% in 2024 and is assumed to reach about 52% in 2030. This is due to the expiry of existing contracts with a fixed destination.

Destination-fixed contracts accounted for 60% of the firm volumes contracted since 2024

Volume of contracts concluded in each year split by contractual element, 2020-2025



Notes: 2025 represents volumes signed by the end of September 2025. Destination flexibility is only for indicative purposes, assumed in the absence of a clear source of information.
Source: IEA analysis based on ICIS (2025), ICIS LNG Edge.

Portfolio players have a growing role in providing LNG supply flexibility

Portfolio players have an important role in meeting buyers' growing need for volume and supply source flexibility. They procure a mix of LNG supplies from various origins and resell to customers to meet their requirements through term and spot contracts. The role of portfolio players has increased significantly in recent years.

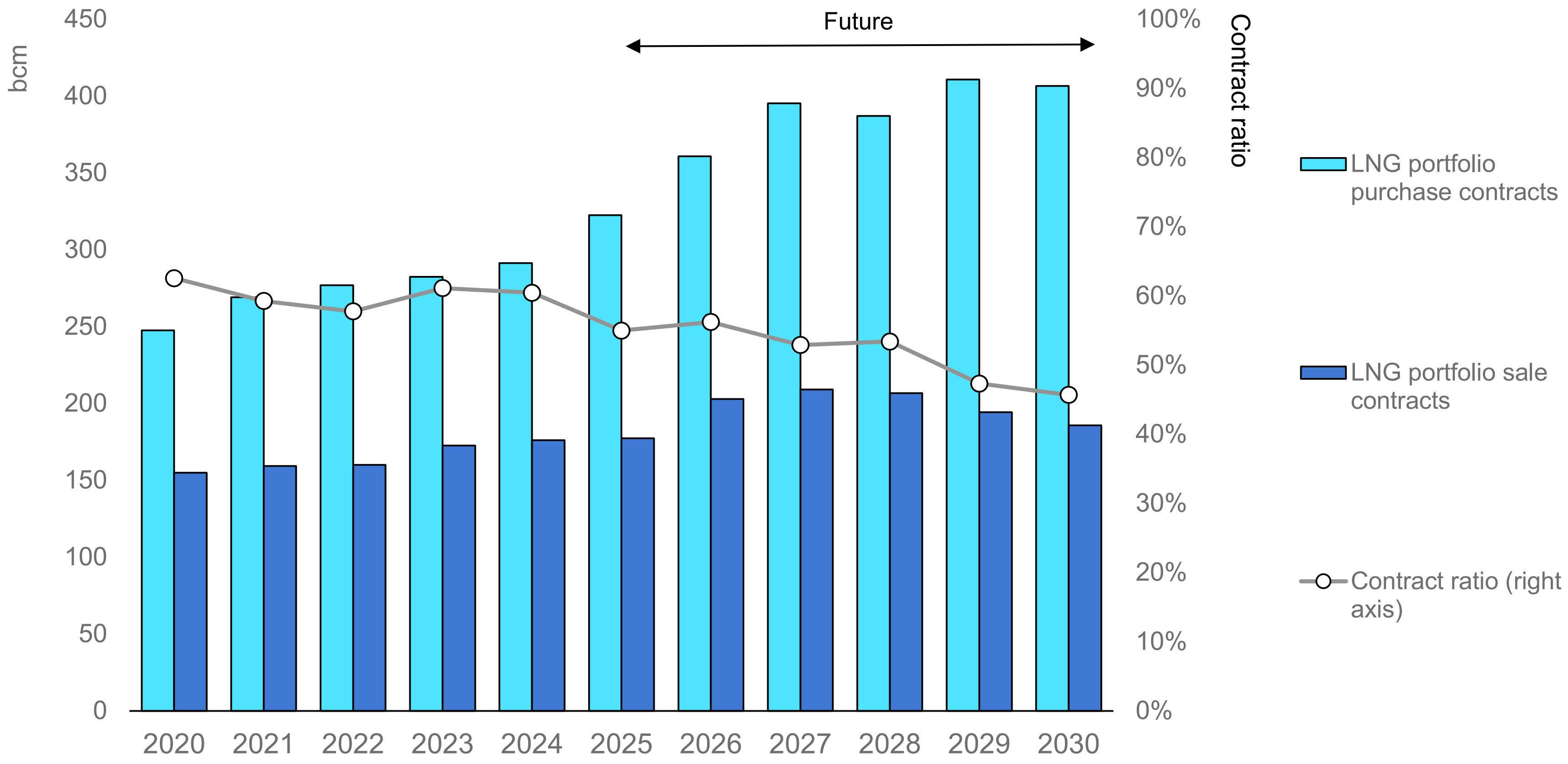
The share of contract volumes procured by portfolio players is steadily increasing. In 2025 their procurement volume as a share of total LNG contracts stands at 42%, up from 26% in 2016. Between 2020 and 2024 portfolio players concluded 37% of total contracted volumes in this period, raising the share of their procurement volume among all active LNG contracts. The average contract duration for newly contracted volumes procured by portfolio players in 2016 and 2017 was less than ten years. However, for contracts signed in 2024 and 2025, the average duration rose to approximately 15 years. By contrast, the average duration of contracts signed by portfolio players for the sale of LNG in 2024 and 2025 was less than 11 years. Portfolio players' share of contracts for the sale of LNG was approximately 50% of total contracted volumes signed in 2016 and 2017. However, their share of contracted volumes concluded since 2022 stands at just 15%. The trend for portfolio players' decreasing share of long-term contract sales might reflect their preference under the market conditions prevailing since 2022 (elevated prices following the 2022-23 supply shock) to sell their LNG volumes on the spot market, as well as buyers' reluctance to enter into long-term contracts, stemming from uncertainty around long-term demand and the potential issue of stranded costs.

Portfolio players' contract ratios – sales offtake as a percentage of purchase obligations, a metric of relative exposure to certain types of market risk – declined to 56% in 2024 from 71% in 2017. This means that the share of their purchase obligations not covered by term sales contracts – or their net open position – increased from 29% to 40% between 2017 and 2024. Based on existing contracts, their net open position is set to increase to an average of close to 54% between 2025 and 2030. The growing net open position of portfolio players could contribute to market stabilisation by providing increased trading flexibility on contract duration and volume.

With approximately 300 bcm/yr of new LNG liquefaction capacity expected to be added by the end of 2030, the additional LNG supply could reduce gas market prices compared to the current situation. But equally, some buyers may be attracted to long-term contracts to ensure future energy security and avoid future price volatility risks. Given this complex outlook, portfolio players are expected to continue to play an important role in providing flexibility to the global LNG market.

A wider net open position among portfolio players can add flexibility to the global LNG market

LNG portfolio players' contractual position and contract ratio, 2020-2030



Note: This graph represents the volumes signed by the end of September 2025.
Source: IEA analysis based on ICIS (2025), ICIS LNG Edge.

North America is set to drive additional LNG supply volume over the medium term

The volume of active contracts (including portfolio players) by 2030 is expected to increase by about 21% compared with 2024 levels. This is set to be driven notably by the start-up of new liquefaction plants in North America, although contract expirations start to impact growth in contracted volumes in the latter part of the outlook.

On the export side, the volume of supply contracts from North America is expected to approximately double between 2024 and 2030 as new liquefaction plants across the United States, Canada and Mexico come online and drive global LNG supply growth over this period. North America's share of total existing contracts is set to increase from 15% in 2024 to 36% by 2030.

Over the same period, the volume of supply contracts from the Middle East is set to increase by about 15%, primarily supported by Qatar's expansion projects. In contrast, during the same period, existing contracted volumes from Africa and Central and South America are set to decrease by 53% and 100% respectively as existing contracts expire.

On the import side, the Asia Pacific region's share of total import contract volumes is set to reach around 45% in 2030. The volume contracted by Asian buyers is expected to increase by 11% between 2024 and 2030. China's existing contracted volume is set to grow by 35% over this period, increasing the country's share of existing contracts to around 30% by 2030. India is assumed to increase its existing contracted volume by 36% over the same period.

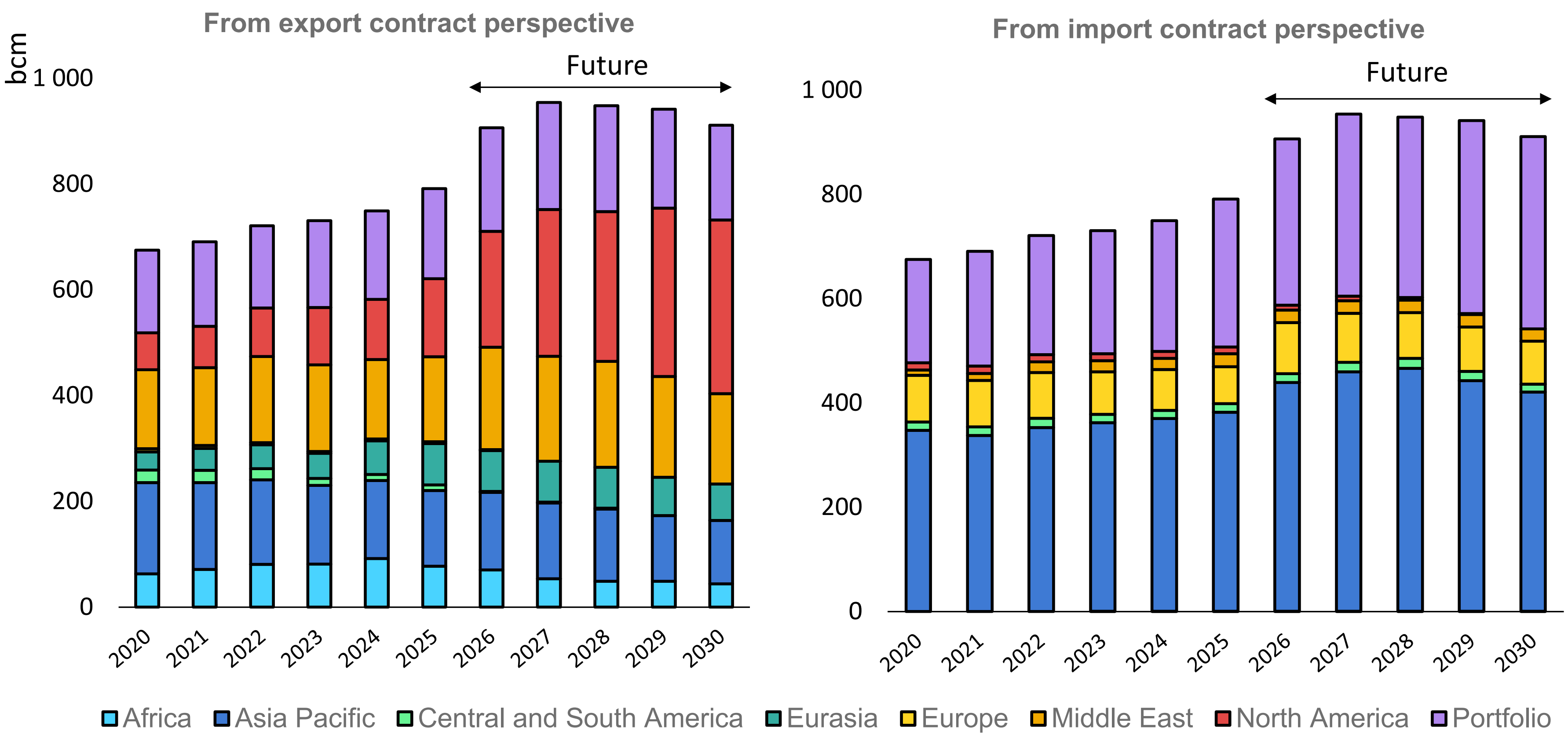
Based on existing contracts, the proportion of destination-flexible contract volumes as a share of primary[7] LNG export contracts is set to grow to 59% by 2030, up from 55% in 2023. With several new LNG liquefaction plants expected to start operation by 2027, **the total volume of uncontracted capacity and contracts with a flexible destination is set to increase over the medium term**.

Destination-flexible contracts are more prevalent on the export side (35%) than on the import side (22%), suggesting that portfolio players tend to purchase under flexible terms that allow destination changes, but sell under fixed contracts with predetermined destinations.

[7] Sourced directly from export project owners, as opposed to secondary volumes sold by portfolio players.

Active LNG contracted volume is expected to expand over the medium term

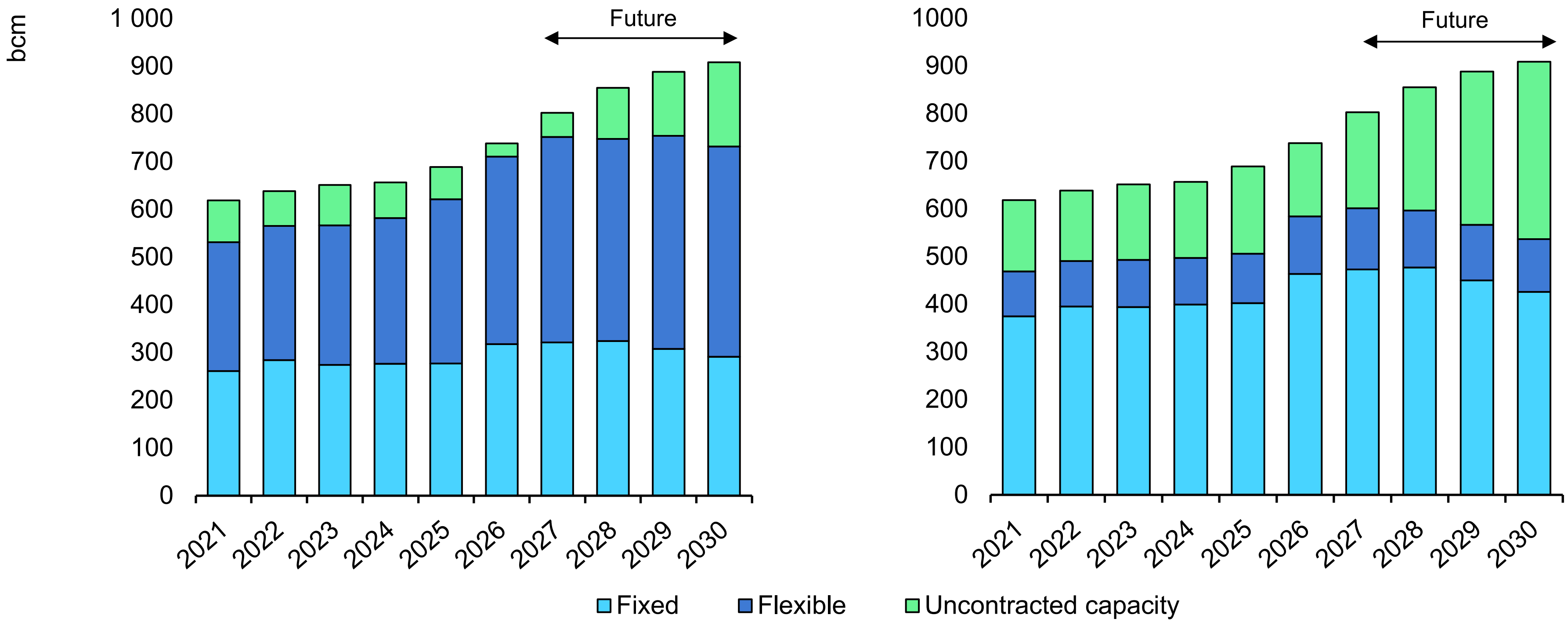
Total active LNG contract volumes, 2020-2030



Source: IEA analysis based on ICIS (2025), ICIS LNG Edge.

Destination-flexible contracts and uncontracted capacity are set to improve market flexibility

LNG supply volumes by destination flexibility (excluding portfolio contracts), 2020-2030



Source: IEA analysis based on ICIS (2025), [ICIS LNG Edge](#).

Expiring contract volumes are set to increase

Based on existing contracts, it is assumed that about 220 bcm/yr of active LNG contracts are set to expire between 2025 and 2030. These expiring contract volumes are expected to create new contracting opportunities in the medium term.

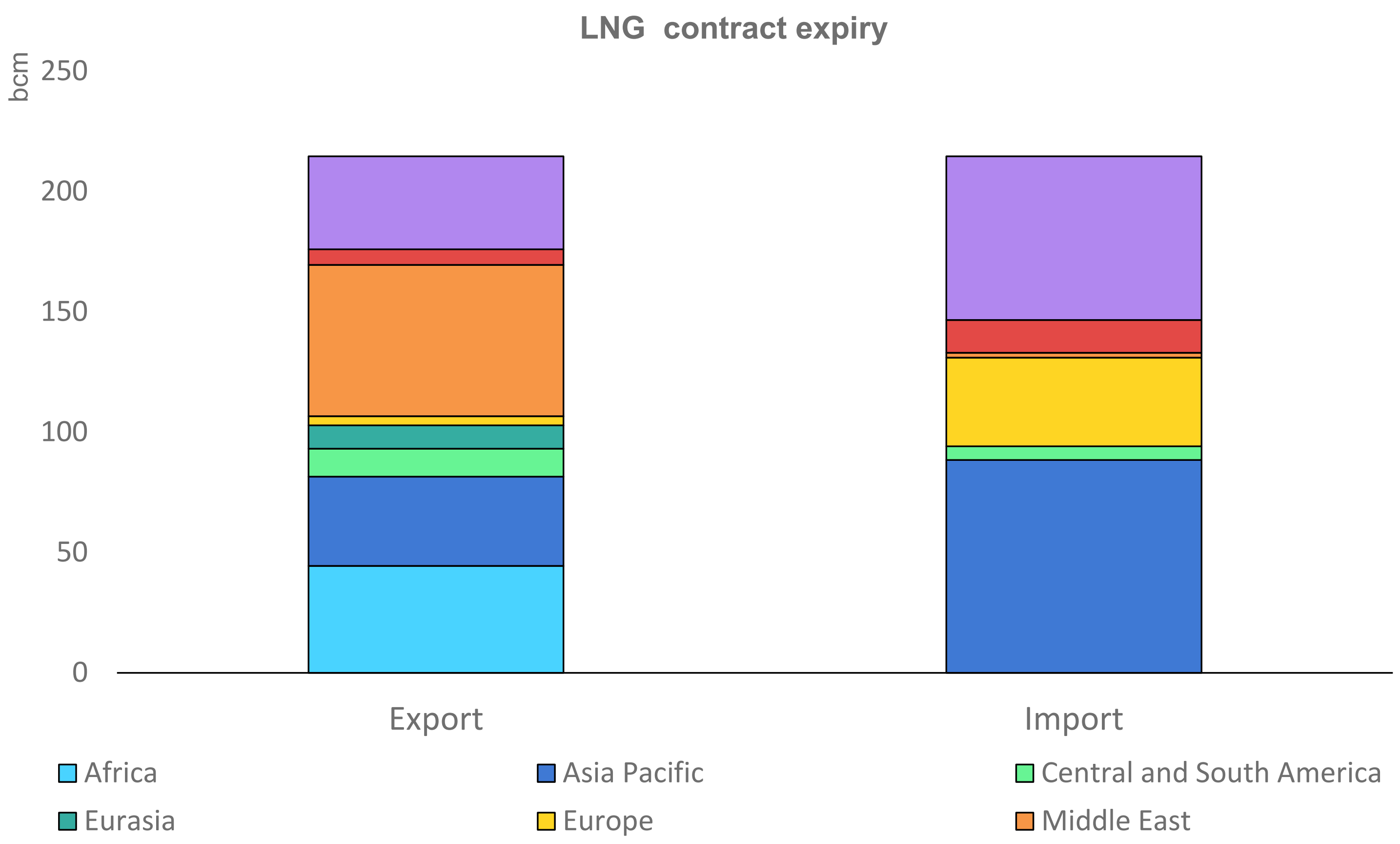
On the seller side, the Middle East accounts for the highest share of expiring contract volumes in the period 2025-2030, with about 29% (or 63 bcm/yr). Africa has the next highest share, accounting for 21% (or 44 bcm/yr), while Asia and portfolio players are set to see expiring volumes of 37 bcm/yr (or 17% of the total expiring volume) and 39 bcm/yr (or 18% of the total), respectively.

On the buyer side, Asia, portfolio players and Europe account for 41% (or 88 bcm/yr), 31% (or 68 bcm/yr) and 17% (or 37 bcm/yr) of the total expiring volumes between 2025 and 2030, respectively. In Asia, new contracts compensate for contract expiries, leading to growth in active contracts.

LNG contracting has historically been dominated by oil indexation. Based on available information, the share of oil-indexed volumes in total active LNG export contracts was approximately 70% in 2016, but fell to about 57% in 2024 and is assumed to continue declining to about 52% in 2030. By contrast, the share of gas-to-gas indexation in LNG export contracts has increased from about 30% in 2016 to 38% in 2024 and is assumed to reach about 48% in 2030. In addition to contracts with oil indexation and Henry Hub formulae, contracts with JKM, TTF and hybrid formulae were signed recently. This trend would indicate that pricing mechanisms underpinning long-term LNG contracts are becoming more diverse. Gas market prices spiked during the gas supply shock in 2022-2023, leading to a sharp increase in LNG trading prices under contracts with gas-to-gas indexation. Conversely, trading prices under oil indexation increased more modestly. Securing long-term LNG contracts with some form of oil indexation can be one way to moderate exposure to gas price volatility.

About 145 bcm of LNG contracts are expiring by 2030, mainly from Africa and the Middle East

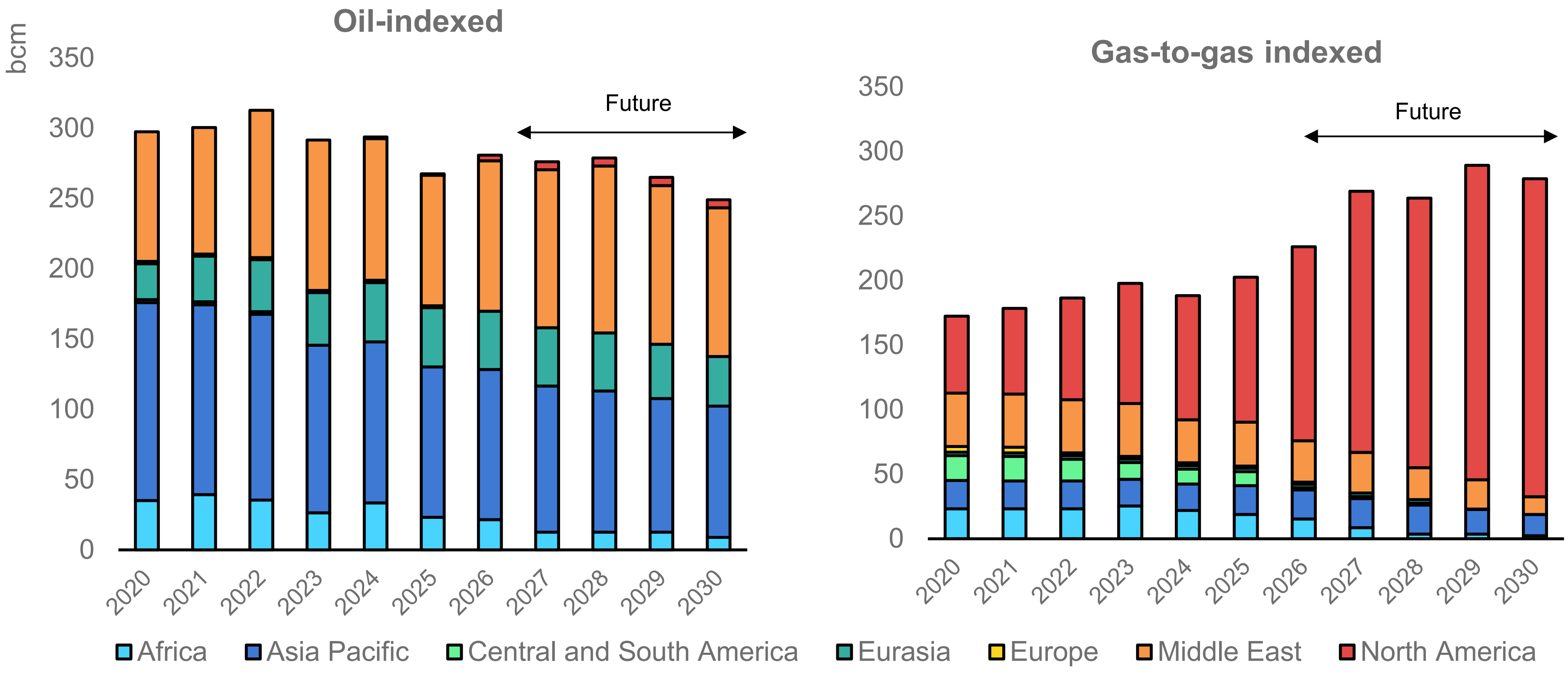
Expiring import and export volumes under active LNG contracts, 2024-2030



Source: IEA analysis based on ICIS (2025), ICIS LNG Edge.

LNG export volumes with gas-to-gas indexation are set to expand, driven by North America

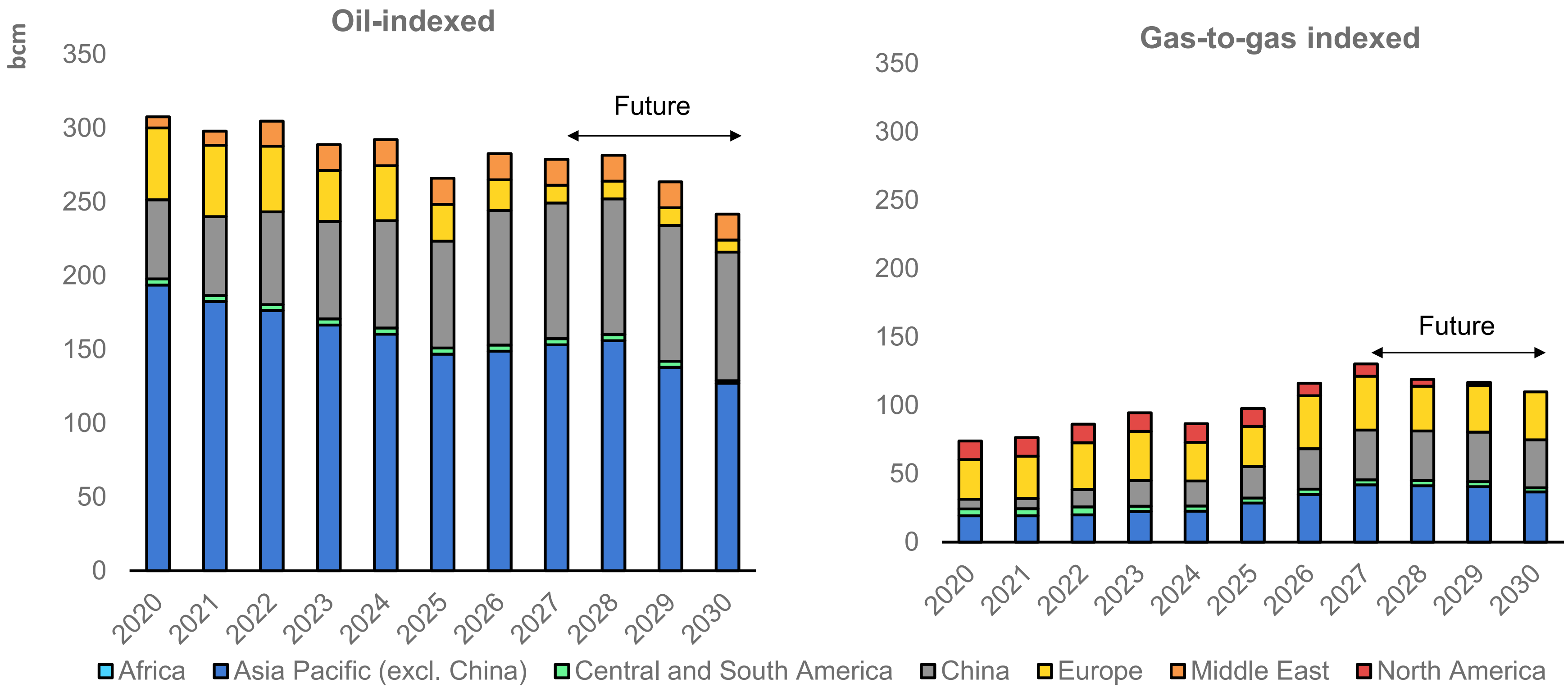
LNG export contract volumes with oil-indexed and gas-to-gas pricing by region and country, 2020-2030



Note: Contracts not linked to a specific origin or destination have been excluded from the analysis.
Source: IEA analysis based on ICIS (2025), ICIS LNG Edge.

Although oil-linked pricing is decreasing, it remains dominant in import contracts

LNG import contract volumes with oil-indexed and gas-to-gas pricing by region and country, 2020-2030



Note: Contracts not linked to a specific origin or destination have been excluded from the analysis.
Source: IEA analysis based on ICIS (2025), ICIS LNG Edge.

CCUS applications along LNG value chains

Reducing emissions across the LNG supply chain with carbon capture, utilisation and storage (CCUS)

Natural gas, and LNG in particular, is an important component of the global energy system, providing supply security, flexibility and a relatively lower-carbon alternative to coal and oil in many regions. Yet LNG also has a sizeable greenhouse gas (GHG) footprint, primarily CO_2 emissions, but also methane leaks, with scope 1 and 2 emissions distributed across upstream operations, gas processing and transmission, and liquefaction. Meeting climate objectives requires reducing these emissions systematically along the value chain. While the majority of LNG's lifecycle emissions occur at the point of combustion (scope 3), this section focuses on scope 1 and 2 emissions within the production and liquefaction chain, where CCUS can play a direct role.

In LNG production, CCUS remains one of the few scalable options for addressing process emissions that cannot otherwise be abated. CCUS is also one of the options to tackle combustion emissions from the LNG plant, delivering deeper emission reductions, albeit at a higher cost. Alongside CCUS, tackling methane leakage, minimising flaring, adopting electrification and making efficiency improvements remain essential to lowering LNG's overall climate footprint.

CCUS in the upstream segment

The upstream segment (covering production, gathering, processing and transmission to liquefaction) accounts for the largest share of LNG's supply chain GHG emissions, encompassing both CO_2 and methane. A key source of emissions lies in the removal of naturally occurring CO_2 from raw gas streams to meet pipeline and LNG specifications. Traditionally vented to the atmosphere, this CO_2 can instead be reinjected into geological formations.

Several projects have demonstrated this pathway. Snøhvit LNG (Norway) has reinjected separated CO_2 since start-up in 2007, while Gorgon LNG (Australia) has one of the largest dedicated carbon capture facilities and has stored 11 Mt of CO_2-eq to date via reinjection into a saline aquifer. These projects demonstrate the technical feasibility of large-scale upstream CCUS, although Gorgon's CO_2 storage operation has operated at reduced capacity due to subsurface pressure management challenges, with works ongoing to increase rates back to design specification.

Momentum is building among major producers. In Qatar, a CO_2 recovery and sequestration facility at Ras Laffan, commissioned in 2019 with a capacity of 2.1 Mtpa, marks the first step in building a wider CCUS hub. This hub is designed to support the North Field East LNG expansion, one of the first large LNG projects to integrate CCUS from the design stage. QatarEnergy has set a target to capture more than 7 Mtpa of CO_2 by 2030, making this the latest LNG-linked CCUS programme in the Middle East.

In Indonesia, BP and its partners have approved the USD 7 billion Tangguh Ubadari CCUS Compression project (UCC). This project will combine carbon capture with the development of the Ubadari field, with the potential to reduce Tangguh LNG's operational emissions. It is Indonesia's first at-scale enhanced gas recovery with CCUS, aiming to sequester around 15 Mt CO_2 in its initial phase and with potential for further storage given the large CO_2 capacity of the basin. These initiatives illustrate growing recognition that CCUS can play an important role in upstream LNG development strategies, particularly when combined with efforts to cut methane emissions and flaring.

CCUS in LNG liquefaction plants

The liquefaction process accounts for the next-largest share of LNG's supply chain GHG emissions, primarily CO_2 from the combustion of natural gas to power refrigeration compressors. Multiple pathways exist to lower this footprint: electrification of plant operations using renewable or low-carbon power, efficiency improvements and CCUS.

LNG Canada sources hydropower for its auxiliary needs (around one-fifth of total electricity demand in a liquefaction plant). Freeport LNG in the United States, by contrast, secured a grid connection to supply 675 MW of power capacity to drive its compressors. This reduced site combustion CO_2 emissions by around 90% and increased net LNG production by 6.5% relative to a design based on gas turbines. QatarEnergy is investing in more than 4 GW of solar capacity to supply electricity to its LNG facilities, including the North Field expansion. Such measures significantly reduce indirect emissions.

Direct application of CCUS at liquefaction plants is also gaining traction. Venture Global LNG has announced plans to integrate CCUS at Calcasieu Pass and future facilities. Details on whether capture will focus on turbine exhaust or other process streams remain limited, and implementation timelines have not yet been confirmed. In Norway, Equinor has explored linking LNG operations to the Northern Lights CO_2 transport and storage network, which started injecting CO_2 captured from a cement plant in Norway earlier this year, and has signed offtake agreements with several other industrial sites in Europe.

These initiatives highlight the potential for CCUS to alter the carbon profile of liquefaction plants. When deployed alongside renewable electrification and operational efficiency improvements, CCUS can substantially reduce CO_2 emissions from liquefaction, resulting in LNG with lower upstream emissions that could become increasingly attractive to buyers.

Strategic benefits of CCUS in LNG

Deploying CCUS across both upstream and liquefaction segments delivers several potential benefits:

- **Market differentiation**: Buyers in Europe, Japan, Korea and other markets are beginning to place greater emphasis on the carbon intensity of LNG. CCUS can help producers demonstrate lower upstream emissions, positioning their cargoes more competitively as transparency and carbon-related requirements expand.
- **Licence to operate**: CCUS helps companies meet national and corporate emissions targets, while ensuring alignment with evolving environmental, social and governance (ESG) expectations from investors and regulators.

- **Policy alignment**: CCUS supports compliance with emerging climate policies and carbon border adjustment mechanisms, which are likely to increasingly shape LNG trade.
- **Infrastructure and technology synergies**: LNG companies can leverage their existing expertise in subsurface engineering, project management and offshore operations to develop adjacent CCUS projects, often drawing on storage data from their own fields. By oversizing the storage component, facilities can also provide spare capacity for third-party emitters, enabling the emergence of shared CO_2 transport and storage hubs such as Ras Laffan in Qatar, the US Gulf Coast and Northern Lights in Norway. This reduces costs through economies of scale.
- **Technology leadership**: Early movers in CCUS-integrated LNG projects position themselves at the forefront of innovation, shaping standards and accessing premium markets.

Regulatory landscape

The regulatory landscape for CCUS varies significantly across regions. In Europe and North America, frameworks are relatively well-established. The EU Directive 2009/31/EC, also transposed into UK law after Brexit, provides a comprehensive basis for storage regulation, setting requirements for site selection, permitting, monitoring, closure and long-term liability, while Canada and the United States have mature permitting regimes. The focus in these regions has shifted to commercial models and public support mechanisms, such as viability gap funding, to accelerate deployment.

In contrast, regulatory frameworks in Asia Pacific remain nascent. Australia has developed a patchwork of federal and state rules, but among ASEAN countries only Indonesia and Malaysia have passed enabling CCUS legislation, and of these, only Indonesia has adopted detailed implementing regulations. This limits the ability of commercial parties to structure and finance CCUS projects. Transboundary CO_2 storage, critical for land-constrained countries such as Singapore as well as for Japan and Korea, remains an open issue. The European Union has not yet created a unified regime for cross-border CO_2 transport and storage. While bilateral agreements between member states are emerging and the European Union is working on common standards and a co-ordinated pan-European network, there remains a lack of global guidance on what should be included in such agreements. ASEAN has yet to establish comparable arrangements, and both Malaysia and Indonesia allow CO_2 imports for storage. Effective deployment will require bilateral agreements between emitter and host states addressing issues such as the London Protocol (the international treaty governing the prevention of marine pollution, which was amended in 2009 to allow for cross-border CO_2 transport and storage, but is not yet fully ratified globally), transboundary liability, funding of ongoing monitoring, verification and reporting, avoidance of double counting under carbon accounting rules, the impact on nationally determined contributions (NDCs), and long-term financial responsibilities.

Costs of CCUS deployment

The cost of CCUS in LNG operations varies significantly depending on the source stream and proximity to storage. For concentrated CO_2 removed from feedgas, capture costs are typically in the range of USD 20–50/t CO_2, adding around USD 0.1-0.2 per MBtu to delivered LNG costs. Post-combustion capture from liquefaction plant exhaust is more complex and costly, averaging USD 110-140/t CO_2 avoided, equivalent to an additional USD 0.7-0.9 per MBtu.

Transport and storage costs add further variation: USD 15-30/t CO_2 when storage sites are located nearby, but USD 75-150/t CO_2 when offshore transport and infrastructure are required. While costs remain high relative to current CO_2 prices in most jurisdictions, economies of scale, shared infrastructure hubs, technological learning and stronger carbon pricing mechanisms could bring costs down over time.

For comparison, EU ETS carbon prices have recently fluctuated in the range of USD 60-80/t CO_2, well below the cost of post-combustion capture but broadly aligned with feedgas capture costs, underlining the importance of policy support and shared infrastructure in enabling projects.

Outlook

CCUS continues to have challenges. Costs remain high, storage capacity must be secured and regulatory frameworks need to mature to support investment. Nevertheless, CCUS is becoming a more visible part of LNG development strategies. With multiple large projects announced and a growing number of feasibility studies underway, CCUS (together with efforts to reduce methane leakage and flaring) could help LNG continue supplying global markets with improved climate compatibility.

By capturing and storing CO_2 in both upstream and liquefaction operations, LNG producers can reduce part of their emissions footprint while maintaining energy security and flexibility. As global competition for LNG with lower emissions grows, CCUS may become an important factor in shaping access to long-term contracts and financing, particularly in markets where carbon intensity is increasingly scrutinised.

Overall, CCUS is shifting from demonstration to deployment in the LNG sector. The projects now under way suggest that by 2030, CCUS could become an increasingly important feature of new LNG supply, influencing access to finance and long-term contracts in markets where carbon intensity is scrutinised.

CCUS capacity in LNG is expanding, with a few large projects under way, although timelines, costs and regulatory hurdles suggest most additional capacity will materialise around 2030

Key developments on CCS/CCUS projects tied to domestic gas and LNG production (by order of maturity)

Name	Country	Status	Announced CO_2 capture capacity	Developments
Ras Laffan Carbon Hub	Qatar	Operational and expanding	7-9 Mtpa	• Commissioned in 2019 with 2.1 Mtpa capacity; integrated into a broader CCS hub strategy linked to the North Field LNG expansion. • Part of QatarEnergy's target to capture more than 7 Mtpa by 2030, making it the largest LNG-linked CCS program in the Middle East.
Gorgon CCS	Australia	Operational	3.4-4 Mtpa	• Gorgon LNG features one of the earliest large-scale gas-linked CCS operations. CO_2 is separated during gas processing and injected underground; initially expected to store 3.4-4 Mtpa. The project has stored 11 Mt CO_2 to date. • Injection started in 2019, but performance has faced issues. As of late 2023, only about one-third of the emissions produced were actually stored, due to subsurface pressure management challenges.
Moomba CCS	Australia	Operational	1.7 Mtpa	• In Australia, for domestic gas, Santos' Moomba CCS project, which reached FID in 2021 and began injection in 2024, is now operational and by mid-2025 had stored over 1 Mt CO_2. It is the world's largest CCS project in a depleted gas reservoir, with a capacity of up to 1.7 Mtpa.
Kasawari CCS	Malaysia	Under construction	~3.3 Mtpa (up to 76 Mtpa total)	• Kasawari is Malaysia's flagship gas-linked CCS project. It achieved FID in October 2022, aiming to cut flaring emissions by 3.3 Mt CO_2-eq per year, making it among the world's largest offshore CCS initiatives. • However, recent reporting indicates that while gas production began in 2024, CO_2 injection is being delayed, with the first injection now targeted for late 2029 or early 2030, pending alignment with emitters and client readiness, as well as finalising the regulatory regime between the Malaysian Federal Government and the State of Sarawak. • Petronas is also developing a broader CCS infrastructure network, with additional storage sites in Peninsular Malaysia (e.g. near the Malaysia-China Kuantan Industrial Park). Progress is being enabled by Malaysia's new CCUS Bill (passed in 2025), which establishes a regulatory framework for permitting and monitoring storage projects and their long-term liability.

Name	Country	Status	Announced CO_2 capture capacity	Developments
Tangguh UCC	Indonesia	Under construction	~15 Mtpa initial phase	• BP's Ubadari gas project, tied to the Tangguh LNG facility, achieved FID in November 2024. It will incorporate CCUS to capture associated CO_2 and reinject it to maintain reservoir pressure. This is BP's first such gas-linked CCUS project, with production expected to begin around 2028. • The scale is significant: the CCUS system is anticipated to potentially sequester around 15 Mt CO_2, unlocking substantial additional gas reserves.
Arthit CCS	Thailand	Under construction	1 Mtpa	• Thailand's first carbon capture and storage (CCS) project, located at the Arthit gas field operated by PTTEP. • Reached Final Investment Decision (FID) in September 2025, with operations expected to begin in 2028. • Recognised as a Flagship Project under Thailand's Nationally Determined Contribution (NDC) Action Plan on Mitigation 2021–2030
Bonaparte CCS Project	Australia	Pre-FEED	10 Mtpa	• The Bonaparte CCS Joint Venture (Inpex, TotalEnergies and Woodside) has moved into the pre-FEED stage, following extensive appraisal activities. It has received Major Project Status from the Australian government, marking it as the first offshore CCS initiative to receive such recognition. • The project is expected to support CO_2 injection by around 2030, with a potential capacity exceeding 10 Mtpa, serving as a large-scale, multi-user CCS hub, with the Ichthys LNG Joint Venture expected as anchor customer.
Bayu-Undan CCS	Timor-Leste	Planned	10 Mtpa	• The Bayu-Undan CCS hub is under FEED studies offshore from Timor-Leste, potentially storing up to 10 Mtpa CO_2, serving as a regional storage facility.
Perenco Offshore CCS	United Kingdom	Pre-FEED	TBD	• Perenco, in collaboration with Carbon Catalyst, has licences to develop offshore CCS at the Leman gas field, as well as the West Sole and Amethyst fields east of the Yorkshire coast. These involve injecting CO_2 into depleted reservoirs or saline aquifers.
Other Southeast Asia initiatives	Indonesia	Planned	TBD	In Southeast Asia, co-ordinated efforts under Japan-led networks are encouraging CCS deployment: • Exploration of CCUS at the Sukowati and Jatibarang oil/gas fields in Indonesia, in collaboration with Japanese companies. • Expansion of CCS storage assignments for Japan, including the Kasawari gas field as a storage destination.

Medium-term outlook for low-emissions gases

The supply of low-emissions gases is expected to increase by two-and-half times by 2030…

Low-emissions gases (including biomethane, low-emissions hydrogen and e-methane[8]) 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 report provides a medium-term outlook for low-emissions gases.

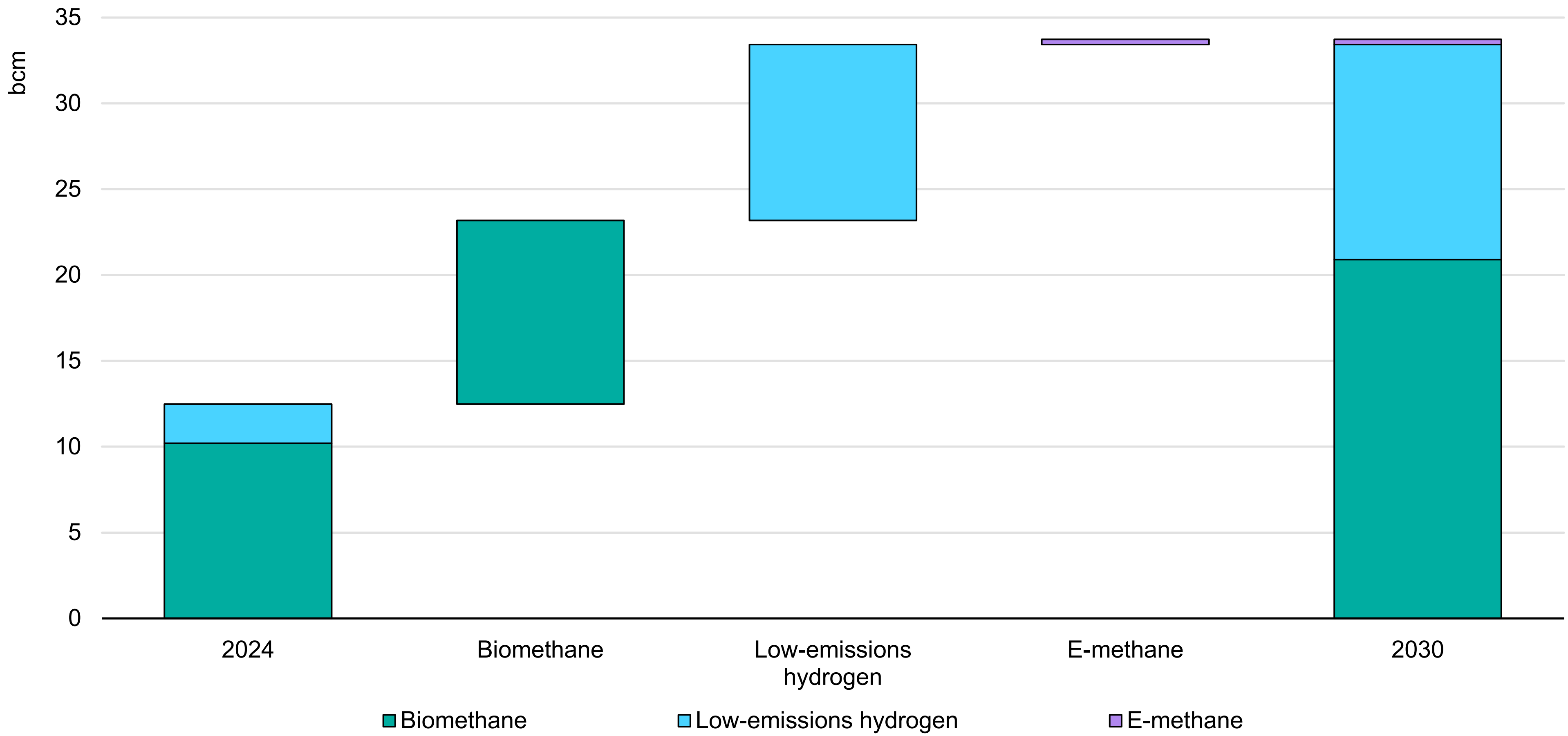
The deployment of low-emissions gases is expected to continue at a strong pace over the medium term. The current forecast projects that the supply of low-emissions gases is set to increase by two-and-half times by 2030, translating into an increase of over 20 bcm-eq in absolute terms. Despite this impressive growth, **the impact of low-emissions gases on the overall global balance is set to remain limited**: they are expected to account for less than 1% of global gaseous fuels supply. **Europe and North America are expected to drive the expansion** and to contribute around 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. Besides Europe and North America, a number of emerging low-emissions gas producers are expected to scale up their output over the medium term, including Brazil, China and India.

Biomethane production is expected to more than double between 2024 and 2030 (an increase of 11 bcm in absolute terms) and to contribute over 50% of the total increase in low-emissions gases during this period. Europe and North America are set to remain the key drivers of this growth, accounting for over 85% of incremental biomethane supply. In addition, Brazil and India are expected to emerge as fast-growing biomethane producers over the medium term, supported by new policies in recent years. **Low-emissions hydrogen** is projected to grow at an average rate of 33% per year between 2024 and 2030, translating into over 10 bcm-eq of incremental supply by 2030. Similarly to biomethane, Europe and North America are expected to drive this growth, accounting for over half of the total increase in low-emissions hydrogen supply. China also emerges as a key producer, accounting for 34% of incremental supply. 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.

[8] E-methane refers to synthetic methane produced from electrolytic hydrogen. The definition of low-emissions 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).

…primarily supported by biomethane and low-emissions hydrogen

Expected increase in production of low-emissions gases, 2024-2030



The momentum behind biomethane is growing

Global biomethane (or renewable natural gas) production almost tripled between 2018 and 2024, largely driven by Europe and North America. Latest estimates indicate that global biomethane output grew by more than 15% in 2024 to reach around 10 bcm. **Biomethane production is expected to more than double** between 2024 and 2030, primarily supported by projects undertaken in Europe, North America, Brazil and India.

Europe

Europe is the world's largest biomethane market, alone accounting for around half of global production. The region's biomethane output has more than doubled since 2018, reaching around 5 bcm in 2024. Latest surveys indicate that Europe has near 1 700 operational biomethane plants, and more than 85% of them have grid injection capability, either to the transmission system or to distribution networks. 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%).

European biomethane production was largely dominated by **Germany** during the 2010s, with the country's biomethane output reaching around 1 bcm by 2018. Production growth in Germany has slowed significantly since 2018 amid the shift away from feed-in-tariffs towards other incentive mechanisms (such as auctions and transport quota fuel requirements). Since 2018, European biomethane production growth has primarily been driven by Denmark and France, together accounting for 55% of incremental biomethane supply during 2018-2024. Generous feed-in-tariffs and regulations facilitating grid injection supported this rapid scale-up.

Growth has been particularly strong in **France**, where biomethane output increased at an average rate of 55% per year during 2018-2024 to reach over 1 bcm. In the first three quarters of 2025, France's biomethane output rose by over 15% y-o-y, putting it on track to become Europe's largest producer. In **Denmark**, biomethane output almost quadrupled during 2018-2024 to just over 0.8 bcm. First data indicate that biomethane production rose by 5% y-o-y during Q1-Q3 2025. Biomethane met near 44% of Denmark's gas demand during this period.

Momentum is growing behind biomethane investment. According to the European Biogas Association's Biomethane Investment Outlook, industry players have committed over EUR 25 billion to biomethane up to 2030. This could translate into an additional 6.5 bcm/yr of biomethane production capacity by the end of the decade. Europe's biomethane production is **projected** to increase at an average rate of over 10% per year over the forecast period and reach 10 bcm by 2030, although this is nowhere near sufficient to put the European Union on track to reach its non-binding target of 35 bcm/yr biomethane output by 2030.

United States

Renewable natural gas production in the United States has quadrupled since 2018 and the country became **the world's largest biomethane producer** in 2019. Latest data indicate that biomethane output grew by around 20% in the first eight months of 2025 and is expected to reach over 4 bcm for the full year. As of June 2025, the United States had more than 410 operational biomethane plants. The rapid scale-up is largely supported by the **transport sector**, where the use of biomethane more than doubled during 2018-2023, primarily due to clean fuel standards. In 2023, renewable natural gas met almost 80% of all on-road fuel used in natural gas vehicles (up from 53% in 2018). 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 69% of the feedstock mix, followed by agricultural and food waste (27%) and wastewater (4%).

This forecast expects biomethane production in the United States to more than double by 2030 compared to 2024. As of June 2025, over 150 biomethane plants were under construction in North America – the majority of them located in the United States. The One Big Beautiful Bill Act legislation extended the Clean Fuel Production Tax Credit (Section 45Z) by moving the sunset date from 31 December 2027 to 31 December 2029. The tax credit is expected to play a crucial role in directing investment towards low-carbon fuels, including biomethane. The transport sector is expected to remain the single most important driver behind biomethane growth, supported by clean fuel standards.

Brazil

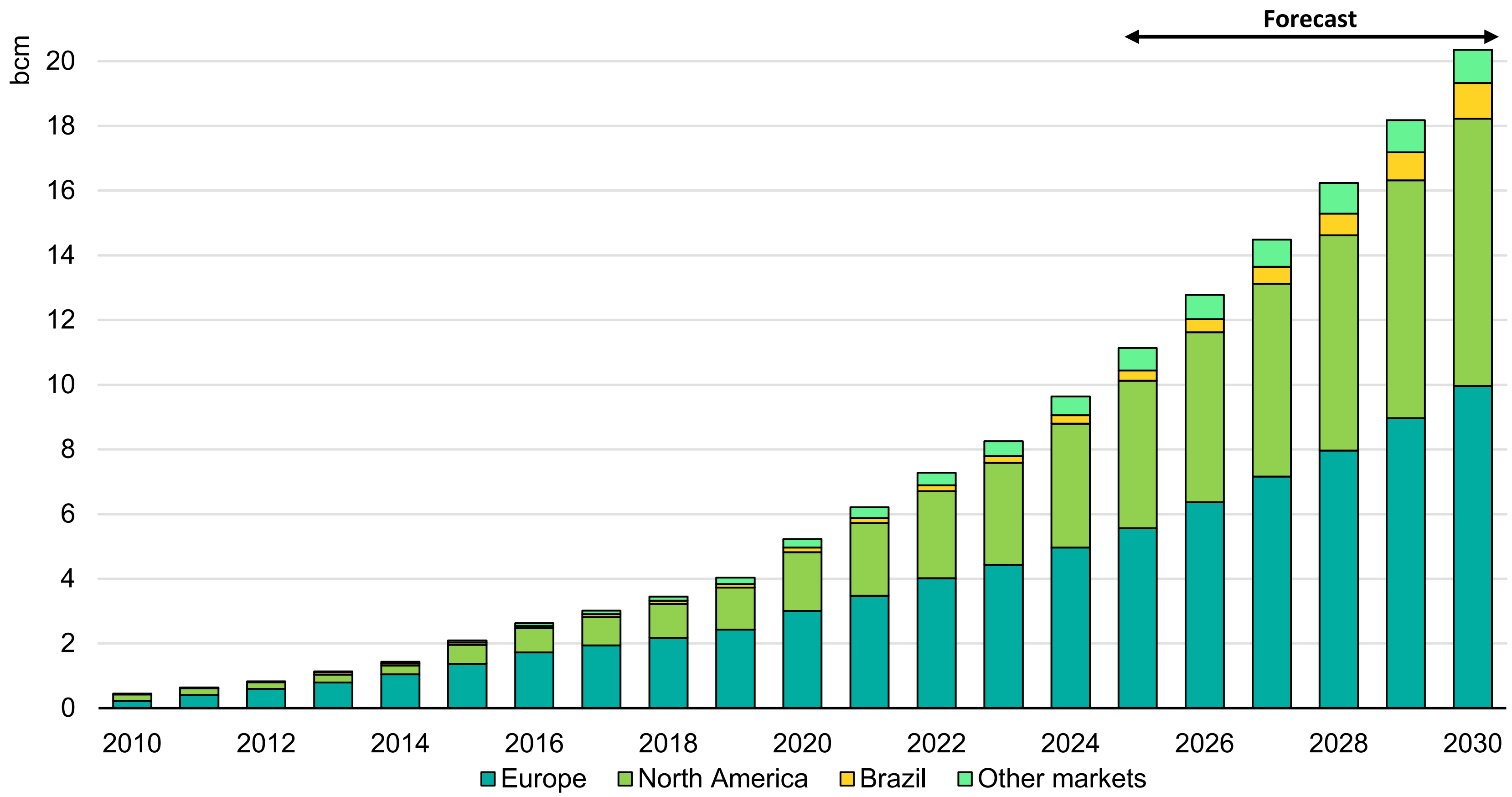
Considering Brazil's **vast agricultural sector**, the country has significant biogas and biomethane production potential. The IEA estimates the country's **combined biogas and biomethane potential** at around 125 bcm/yr – the largest in the world. Brazil's biogas production capacity grew at an average rate of 19% per year between 2018-2024. In 2024, Brazil had over 1 600 biogas plants in operation with an overall installed capacity of 4.7 bcm. Around 60% of the biogas produced was used for power generation and around 37% was upgraded into biomethane.

According to latest industry data, Brazil currently has 54 biomethane plants. As of July 2025, only 16 of them have been authorised to produce and inject biomethane into the country's gas network (with a capacity of 0.36 bcm/yr). A further 36 biomethane plants (with a capacity of near 0.5 bcm/yr) are in the process of seeking regulatory approval from the National Agency of Petroleum, Natural Gas and Biofuels (ANP).

This forecast expects Brazil's renewable natural gas output to surge to just over 1 bcm/yr by 2030, supported by strong policy support, including the recently enacted Fuel of the Future Law. Notably, the new legislation mandates that by 2034, 10% of the natural gas sold in Brazil must be composed of biomethane, with a gradual increase starting at 1% in 2026.

Europe, North America and Brazil are set to drive biomethane supply growth to 2030

Biomethane production in key markets, 2010-2030



Sources: IEA analysis based on Cedigaz (2024), Global Biomethane Database; Energinet (2025), Energi Data Service; ODRE (2025), Production Quotidienne Consolidée de Biométhane sur le réseau de transport et de distribution par Opérateur.

Expectations for 2030 low-emissions hydrogen production have eased, but progress continues

Despite slower progress in delivering projects than previously expected, global low-emissions hydrogen production remains on a steady growth trajectory and could increase anywhere from fivefold (based on current advanced-stage projects) to fiftyfold (based on current early-stage projects) by 2030.

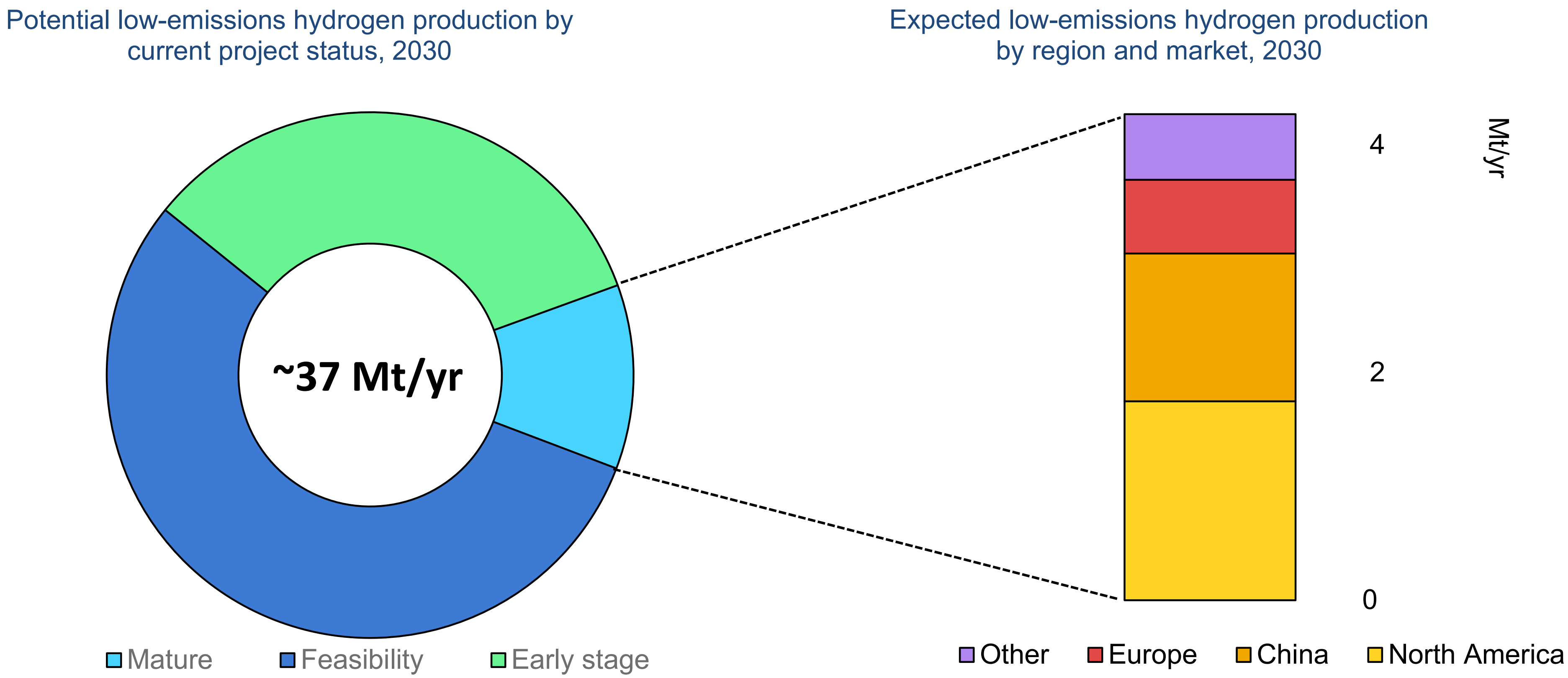
According to data from the IEA Hydrogen Production Project Database, which monitors projects at multiple stages of development and across geographies, the combined project pipeline (including projects at the feasibility study phase) has the potential to drive global low-emissions hydrogen production to about 25 Mt (or 75 bcm-eq) by 2030. While the vast majority of current production remains fossil fuel-based, over 55% of the potential growth to 2030 could be driven by water electrolysis, as technologies continue to progress and projects are increasingly paired with dedicated renewable electricity production sources.

Expanding the project pipeline to include projects currently at concept phase would push 2030 production up to about 37 Mt (or over 110 bcm-eq), with electrolytic hydrogen accounting for about 75% of the increase, highlighting the great potential of these technologies in this timeframe, but also the degree of uncertainty that remains with respect to the pace of their deployment. Currently, the overwhelming majority of announced low-emissions hydrogen projects remain at the feasibility study or concept phases, with less than 10% of potential 2030 production coming from projects at advanced development stages (under construction or having reached FID). Taking into account only those projects that are currently operational or at an advanced development stage, low-emissions hydrogen output would increase more than fivefold from 2024 levels, reaching only about 4.2 Mt (or 12.5 bcm-eq) by 2030.

North America, Europe and China are set to dominate low-emissions hydrogen production by 2030, accounting for about 87% of output from currently operational and advanced-stage projects. North America is expected to be the largest contributor (35% of incremental production), driven almost entirely by fossil-based installations combined with CCUS, linked to a vast and relatively inexpensive natural gas resource base. The technological split is more varied in Europe (18% of incremental production), with electrolytic projects accounting for about 60% of output growth. Finally, in China (34% of incremental production), virtually all growth is set to come from electrolysis.

Globally, low-emissions hydrogen production is likely to remain skewed towards fossil fuel-based technologies in the medium term, although faster growth in electrolytic hydrogen production is set to reduce the fossil fuel share from 85% in 2024 to about 50% in 2030. With electrolysis technologies accounting for the lion's share of early-stage projects (feasibility study and concept phases), faster-than-expected progress on these projects could drive higher growth in power-based low-emissions hydrogen production.

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



Notes: "Mature" comprises projects that are operating, under construction or that have reached FID; "Early stage" comprises projects that remain in the very early planning phases, such as those for which only a co-operation agreement among stakeholders has been announced; and "Feasibility" comprises projects between these two categories.

Source: IEA (2025), Hydrogen Production and Infrastructure Projects (database).

E-methane continues to gain traction in Japan and Finland

E-methane is produced by combining low-emissions hydrogen with carbon resources and could play an important role in decarbonising gas networks without the need for retrofitting. As e-methane can be interchangeable with natural gas, it is easy to inject and mix it into existing gas infrastructure. A switch from natural gas to e-methane can be done seamlessly while maintaining gas supply security. As the United States, Australia and Europe explore ways to produce e-methane, this could help expand global trade in low-emissions gases.

Japan is taking an active approach toward the early deployment of e-methane as part of its broader decarbonisation strategy. In July 2025, the Japanese government revised the enforcement regulation of the Gas Business Act. Under this amendment, three major city gas suppliers in Japan – Tokyo Gas, Osaka Gas and Toho Gas – are now required to ensure that at least 1% of their city gas supply is derived from e-methane or biomethane by 2030. In addition to this binding requirement, a non-binding target has also been set, aiming for 5% of the total gas supply to take the form of these low-carbon gases by 2030. This legislative change aligns with the long-term decarbonisation goals of Japan's city gas suppliers, who have committed to replacing 50-90% of their city gas supply with e-methane or biomethane by 2050. Given the high cost of e-methane, the revised law explicitly allows for biogas to be used as an alternative to fulfil the regulatory and voluntary targets. Moreover, to support the adoption of e-methane, the amendment permits a portion of the procurement cost of e-methane to be included in the cost basis for transmission and distribution charges. This change is intended to ease the financial burden on gas suppliers and promote the integration of cleaner energy sources into the city gas infrastructure.

In Finland, even more ambitious targets have been set. Starting in 2028, the country aims to replace 1.5% of its gas supply with synthetic fuels, increasing this share to 4% by 2030. These targets exceed the EU Renewable Energy Directive III (RED III) requirement of 1% by 2030. To achieve this goal, in June 2025 Belgian-based development company Tree Energy Solutions and Finnish wind power company CPC announced plans to develop a project in the Port of Rauma, Finland. The project will feature an electrolyser with a capacity of 500 MW to produce e-methane. The facility is expected to generate approximately 60 000 tonnes of renewable hydrogen annually, which will be combined with biogenic carbon dioxide to produce more than 125 000 tonnes of synthetic natural gas per year. According to Tree Energy Solutions, a portion of the produced synthetic natural gas will be liquefied and transported. The project is scheduled to undergo a pre-FEED (preliminary front-end engineering design) phase in 2026, with FID expected in 2028.

The majority of e-methane projects remain at the pre-FID stage

Key global e-methane production projects

Companies involved	Country of production	Description
Tokyo Gas, Toho Gas, Mitsubishi Corporation and Sempra Infrastructure	United States	Agreement to conduct a feasibility study of the production of e- methane in proximity to Cameron LNG terminal in the United States. Pre FEED completion in 2024, and aims to reach FID in 2025.
Total, Tree Energy	United States	Studying a large-scale production unit in the United States. This project is expected to produce 0.10-0.20 Mt per year of e-methane by 2030.
Osaka Gas USA, Tallgrass and Green Plains	United States	Project to construct a production plant in the northern United States and utilise the Freeport LNG liquefaction facility to export LNG to Japan. Agreement to conduct a feasibility study on e-methane production at the Freeport LNG export terminal in the United States. E-methane supply could reach 0.20 Mt per year by 2030.
Tokyo Gas, Osaka Gas Australia, Toho Gas and Santos	Australia	Pre-FEED study on a project to produce e-methane at Moomba in the Cooper Basin. The project aims to produce 0.13 Mt/yr or more of e-methane and export to Japan from 2030 at the earliest.
Marubeni, Osaka Gas and Peru LNG	Peru	A project to study the production of e-methane in Peru and its delivery to Japan and Peru. The production of e-methane could reach 0.06 Mt per year by 2030.
Nordic Ren-Gas	Finland	Planning six projects to produce e-methane in Finland (Tampere, Lahti, Kotka, Mikkeli, Pori and Kerava). Construction of the Tampere project is set to begin in 2025, with commercial operations starting in 2027.
Freija	Finland	FEED study for an e-methane project in Nokia, Tampere region. Production would start in 2029.
Masdar, INPEX, Tokyo Gas and Osaka Gas	United Arab Emirates	Agreement to conduct a feasibility study on e-methane production in Abu Dhabi. Tokyo Gas and Osaka Gas are planning to offtake e-methane in volumes equivalent to 1% of each company’s annual urban gas demand.
Oman LNG and Hitachi Zosen	Oman	Memorandum of understanding to study the commercial feasibility of a small pilot plant at a site adjacent to the existing LNG plant and produce 1 200 normal cubic meters per hour of e-methane.
Tree Energy, CPC	Finland	A 500 MW synthetic natural gas project planned at Finland’s Port of Rauma, targeting annual production of 0.13 Mt. Permitting is underway, with pre-FEED in 2026 and FID expected in 2028.

Source: IEA analysis based on companies’ announcements.

Annex

Summary table

World inland natural gas consumption by region and key country, base case demand projection, bcm

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Africa	168	170	170	173	178	184	189	190	194
Asia Pacific	904	933	987	993	1 041	1 069	1 105	1 141	1 178
of which China	*373*	*402*	*432*	*437*	*463*	*476*	*492*	*510*	*529*
Central and South America	153	149	154	154	152	152	155	159	161
Eurasia	617	625	652	646	665	669	677	683	686
of which Russia	*487*	*495*	*521*	*514*	*530*	*532*	*538*	*541*	*542*
Europe	541	503	507	522	510	504	488	475	465
Middle East	587	614	620	631	655	678	693	712	729
North America	1 130	1 140	1 160	1 168	1 172	1 175	1 192	1 205	1 220
of which United States	*916*	*923*	*941*	*947*	*950*	*949*	*965*	*978*	*995*
World	**4 099**	**4 134**	**4 250**	**4 288**	**4 373**	**4 432**	**4 499**	**4 564**	**4 634**

World inland natural gas consumption by region and key country, high case demand projection, bcm

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Africa	168	170	170	173	178	185	189	191	195
Asia Pacific	904	933	987	993	1 041	1 081	1 125	1 171	1 231
of which China	*373*	*402*	*432*	*437*	*463*	*481*	*502*	*525*	*558*
Central and South America	153	149	154	154	152	153	156	161	164
Eurasia	617	625	652	646	665	669	677	683	686
of which Russia	*487*	*495*	*521*	*514*	*530*	*532*	*538*	*541*	*542*
Europe	541	503	507	522	510	506	491	483	476
Middle East	587	614	620	631	655	679	694	712	730
North America	1 130	1 140	1 160	1 168	1 172	1 176	1 193	1 206	1 220
of which United States	*916*	*923*	*941*	*947*	*950*	*951*	*967*	*979*	*995*
World	**4 099**	**4 134**	**4 250**	**4 288**	**4 373**	**4 448**	**4 526**	**4 607**	**4 703**

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)
AFTC	Alternative Fuels Tax Credit
ANP	National Petroleum Agency (Brazil)
BMC	Colombian Mercantile Exchange (Colombia)
CAPEX	capital expenditure
CBG	compressed biogas
CCUS	Carbon Capture, Utilisation and Storage
CME	Chicago Mercantile Exchange (United States)
CNE	National Energy Commission (Chile)
CO_2	carbon dioxide
CQPGX	Chongqing Petroleum Exchange (the People's Republic of China)
EIA	Energy Information Administration (United States)
ENARGAS	National Gas Regulatory Entity (Argentina)
ENTSOG	European Network of Transmission System Operators for Gas
EPC	engineering, procurement and construction
EPIAS	Energy Markets Operations Inc. (Republic of Türkiye)
EPPO	Energy Policy and Planning Office (Thailand)
EU	European Union
EUR	Euro
FCEVs	fuel cell electric vehicles
FID	final investment decision
FLNG	floating liquefied natural gas
FOB	free on board
FSRU	floating storage and regasification unit
FY	fiscal year
GHGs	greenhouse gases
GIE	Gas Infrastructure Europe
GMR	IEA Gas Market Report
GST	goods and services tax
HDDs	heating degree days
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
ITC	investment tax credit
JKM	Japan Korea Marker
JODI	Joint Oil Data Initiative
JPY	Japanese yen
LBG	liquefied biomethane
LCFS	Low Carbon Fuel Standard
LCV	light commercial vehicles
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)
MVP	Mountain Valley Pipeline
NBP	National Balancing Point (United Kingdom)
NDRC	National Development and Reform Commission (the People's Republic of China)
NLNG	Nigeria liquefied natural gas
OECD	Organisation for Economic Co-operation and Development
ONS	National Electric System Operator (Brazil)
OSINERG	Energy Regulatory Commission (Peru)
PPAC	Petroleum Planning and Analysis Cell (India)
PTC	production tax credit
RNG	renewable natural gas
RFS	Renewable Fuel Standard
SAF	sustainable aviation fuel
SBL	Strategic Buffer LNG
SMR	steam methane reforming
SPA	Sales and Purchase Agreement
SRMCs	short-run marginal cost
TAP	Trans Adriatic Pipeline
TFDE	Tri-fuel diesel electric
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/hr	cubic metres per year per hour
m^3/yr	cubic metres per year
Nm^3	normal cubic metre
TWh	terawatt hour

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