Gas Market Report, Q1-2025

INTERNATIONAL ENERGY AGENCY

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Abstract

Global consumption of natural gas returned to structural growth in 2024, reaching an all-time high. Gas demand is expected to increase further in 2025, primarily supported by fast-growing Asian markets. At the same time, the global gas balance remains fragile, with the supply side remaining tight and geopolitical tensions continuing to fuel price volatility. While the halt of Russian piped gas transit via Ukraine on 1 January 2025 should not pose an imminent supply security risk for the European Union, it could increase the EU's LNG import requirements and tighten market fundamentals this year.

This edition of the quarterly *Gas Market Report* by the International Energy Agency (IEA) provides a thorough review of market developments in 2024 and an outlook for 2025. As part of the IEA's Low-Emissions Gases Work Programme, the report includes a section dedicated to policy and market developments related to biomethane, low-emissions hydrogen and e-methane.

The current gas market context highlights the need for responsible producers and consumers to work together to reinforce the architecture for secure global gas supplies. To support this, the IEA established in late 2024 a permanent Working Party on Natural Gas and Sustainable Gases Security (GWP), building on the Agency's longstanding gas security activities, including the work of the Task Force on Gas and Clean Fuels Market Monitoring and Supply Security.

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Executive summary

Global gas demand reached a new all-time high in 2024, with the balance remaining fragile

Following the supply shock of 2022/23, natural gas markets moved towards a gradual rebalancing and returned to structural growth last year. **Global gas demand reached a new all-time high** in 2024 and is expected to expand further in 2025, primarily supported by some fast-growing markets in Asia. Meanwhile, the **global gas market balance remains fragile**. Below-average growth in liquefied natural gas (LNG) output has kept **supply tight**, while **extreme weather events** have added to market strains. **Geopolitical tensions** have continued to fuel price volatility. Though the **halt of Russian piped gas transit via Ukraine** on 1 January 2025 does not pose an imminent supply security risk for the European Union, it could increase LNG import requirements and tighten market fundamentals in 2025.

The Asia Pacific region and industrial uses of gas were the main drivers of higher demand

Preliminary data indicate that **natural gas consumption increased by 2.8%**, or 115 billion cubic metres (bcm), year-on-year (y-o-y) in 2024, above the 2% average growth rate between 2010 and 2020. First estimates indicate that natural gas met around 40% of the increase in global energy demand in 2024 – a greater share than any other fuel. This relatively strong growth was mainly due to the Asia Pacific region, which accounted for almost 45% of incremental gas demand in 2024 on the back of continued economic expansion. Gas use for **industry and for the energy sector's own needs** were the primary drivers behind global trends and met almost 45% of demand growth. There was a modest recovery in Europe's industrial gas demand, although it remained well below pre-crisis levels.

Natural gas continues to displace oil and oil products in various sectors. This trend is supported by policies, regulations and market dynamics. In the **Middle East**, oil-to-gas switching in the power sector continued in 2024. In road transport, the rapid **scaling up of LNG-fuelled trucks in China** – with record sales in 2024 – has contributed to lower diesel demand there. The use of LNG as a **bunkering fuel** is also expected to increase amid more stringent emissions regulations for shipping. The displacement of oil and oil products in these sectors is expected to continue over the medium term.

Extreme weather events highlight the crucial role of gas supply flexibility in ensuring heat and electricity security

The **sensitivity of natural gas demand** to changes in weather patterns, including cold snaps and heatwaves, is increasing. Climate change is driving **more extreme weather events**, while in markets with a **growing share of variable renewables**, gas-based generation plays an increasingly important backup role in ensuring electricity supply security at times when wind and/or solar output is low.

In the **United States**, gas demand surged to an all-time high of 3.9 bcm per day during **winter storm Heather** in January 2024. Gas demand in the residential and commercial sectors rose by 70% between 11 and 16 January as below-average temperatures pushed up space heating requirements. Gas-fired power plants increased their output by more than 40% between 13 and 16 January, accounting for nearly 80% of additional power generation.

In **India**, **powerful heatwaves** during the summer of 2024 drove up gas-fired power generation to multi-year highs. Gas demand for power generation in India rose by 32% in the May-July period y-o-y as higher cooling needs increased electricity use. Incremental gas demand was primarily met through increased LNG imports.

In South America, both **Brazil and Colombia** faced extreme droughts last year, limiting their hydropower output and sharply increasing the call on gas-fired power plants, with most incremental gas demand met via LNG.

In **Europe**, **slow wind speeds** in the first half of November 2024 led to a sharp decline in wind power output y-o-y. Gas-fired power plants played a key role in providing backup to the power system by increasing their output by nearly 80% y-o-y. Higher gas demand was primarily met through larger storage withdrawals.

These events highlight the need for **a careful assessment of investment in the assets that enable the secure delivery of gas**, including gas storage, as well as the development of mechanisms that allow for greater supply flexibility.

Tight gas supply fundamentals are expected to linger into 2025, weighing on global demand growth

Global LNG supply grew by 2.5% (or 13 bcm) in 2024 – well below its average growth rate of 8% between 2016 and 2020. **Project delays**, together with **feedgas supply issues** at certain legacy producers (including in Angola, Egypt, and Trinidad and Tobago), weighed on LNG production growth. However, **it is set to accelerate to 5%, or just over 25 bcm, in 2025** amid the expected start and ramping up of several large LNG projects, notably in North America. This includes Phase 1 of the Plaquemines LNG project (which loaded its first LNG cargo in December 2024), the Corpus Christi Stage 3 expansion, and LNG Canada. **Africa and Asia** are also expected to contribute to LNG supply growth in 2025. **Russia's Arctic LNG 2 project** is not considered as a source of firm LNG supply in the current forecast due to sanctions.

Growth in LNG supply is set to be partially offset by lower Russian piped gas deliveries to Europe. This forecast assumes **no Russian piped gas deliveries through Ukraine for the remainder of the year**. Our assessment indicates this **should not pose an immediate supply security risk** to EU member states, considering their ample storage capacity, midstream interconnectivity and access to the global LNG market. But the **vulnerability of Moldova** – which declared a 60-day state of emergency in December ahead of the halt of Russian piped gas deliveries – is significantly greater, requiring close co-operation with its regional and international partners to ensure energy supply security through the winter season. In **the region of Transnistria**, heat and hot water supply cuts for residential consumers have been in place since 1 January.

The halt of Ukrainian transit for the full year would **reduce Russian piped gas supplies** to Europe by around 15 bcm in 2025 compared with 2024. Notably, **natural gas inventory levels in the European Union** were already down 15 bcm year-on-year at the beginning of 2025, potentially increasing demand this summer to replenish storage sites. These factors, taken together, could necessitate higher European LNG imports this year, tightening the global gas balance.

Due to tighter market fundamentals, **growth in global gas demand is forecast to slow to below 2%** in 2025. As in 2024, growth is set to be **largely driven by Asia**, which is expected to account for almost 45% of incremental gas demand.

Low-emissions gases have continued to benefit from a wide range of policy support

This edition of the quarterly *Gas Market Report* provides an overview of the key policy and market developments related to **low-emissions gases**, which can play an important role in decarbonising gas supply chains and the broader energy system. **Global biomethane output** increased by an estimated 15% in 2024 to over 10 bcm, with growth led by Europe and North America. Subsidies and support mechanisms for **low-emissions hydrogen** became more robust in 2024, although project developments and final investment decisions remained relatively modest.

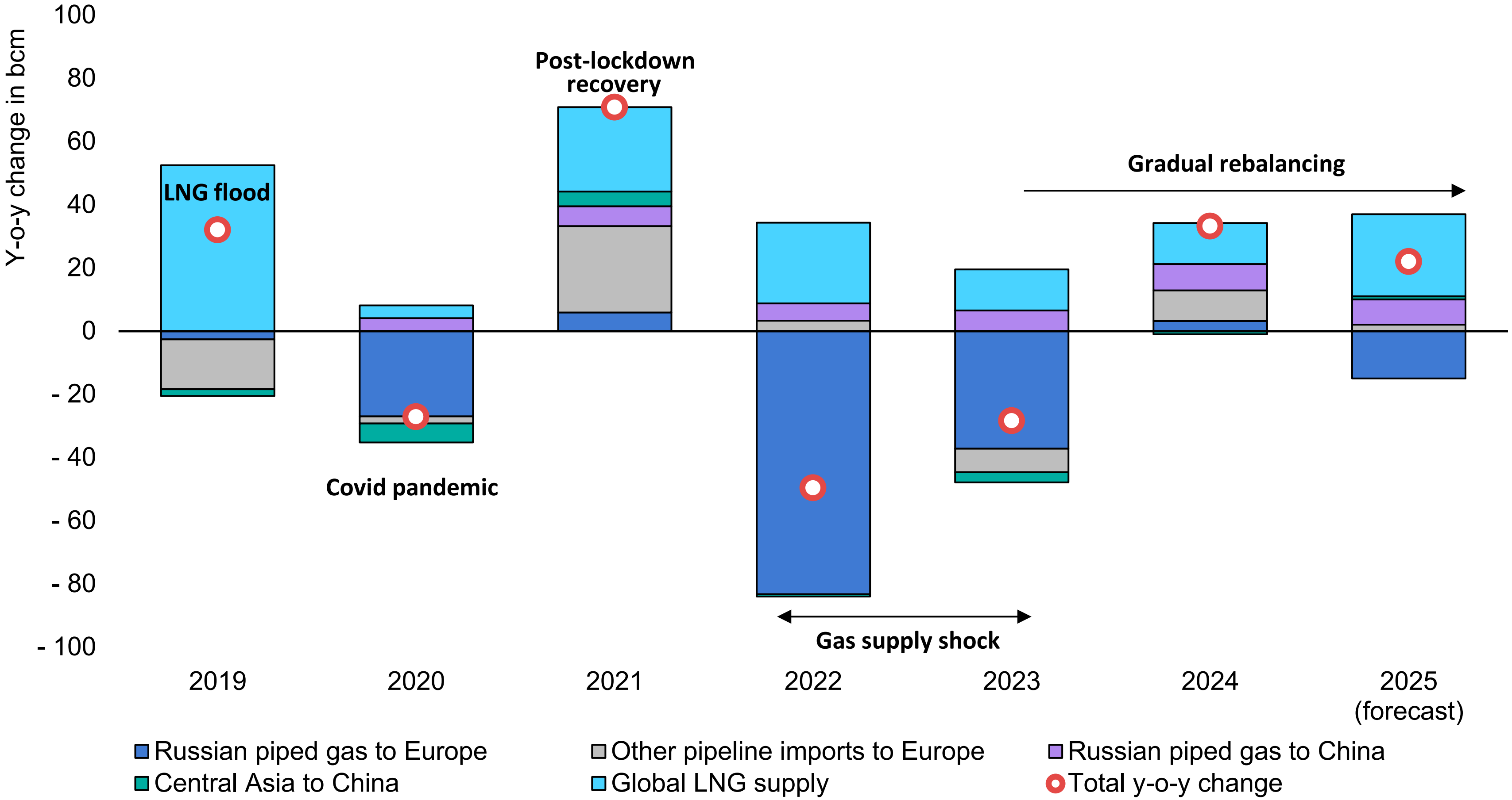
International co-operation on gas and LNG supply security is being strengthened

With tight gas market conditions and geopolitical tensions continuing, the IEA has called for greater international co-operation to enhance gas supply security. Responsible producers and consumers need to work together to reinforce **the architecture for safe and secure global gas supplies**. A number of new initiatives were launched in 2024 with the aim of improving market transparency, data exchange and co-operation mechanisms on gas and LNG. This included the **Global Early Warning Mechanism** established by the European Union and Japan.

Building on the IEA's longstanding work on gas supply security, the IEA established in late 2024 a permanent **Working Party on Natural Gas and Sustainable Gases Security (GWP)** under the Standing Group on Emergency Questions, which aims to facilitate data and information exchange among its members and to promote dialogue between producers and consumers. In April 2025, the IEA will convene an International Summit on the Future of Energy Security**,** hosted by the UK government. The Summit will address traditional and emerging risks related to energy security, including for natural gas.

Tight gas supply fundamentals are expected to linger into 2025

Year-on-year change in key piped natural gas trade and global LNG supply, 2019-2025



Key gas policies and market trends in 2024

Natural gas prices softened across all key markets in 2024…

Following the all-time highs reached in 2022, natural gas prices moderated significantly across all key markets in 2023. This trend continued in 2024, although **European and Asian spot prices remained well above their historic averages**, while tighter market fundamentals drove up natural gas prices in the second half of the year. The correlation between Asian and European prices reached an all-time high, reflecting the increasingly globalised nature of natural gas markets.

In **Europe**, TTF month-ahead prices fell by more than 15% compared with 2023 to average USD 11/MBtu in 2024, still more than double their five-year average between 2016 and 2020. Continued demand reduction, together with high storage levels and improving supply fundamentals, provided downward pressure on gas prices. Price volatility moderated from its 2022 and 2023 highs, although it remained strong at near 50% on average in 2024, 50% above its ten-year average between 2010 and 2019. Limited LNG supply growth, geopolitical tensions and uncertainty around Russian piped gas deliveries fuelled price volatility through the year.

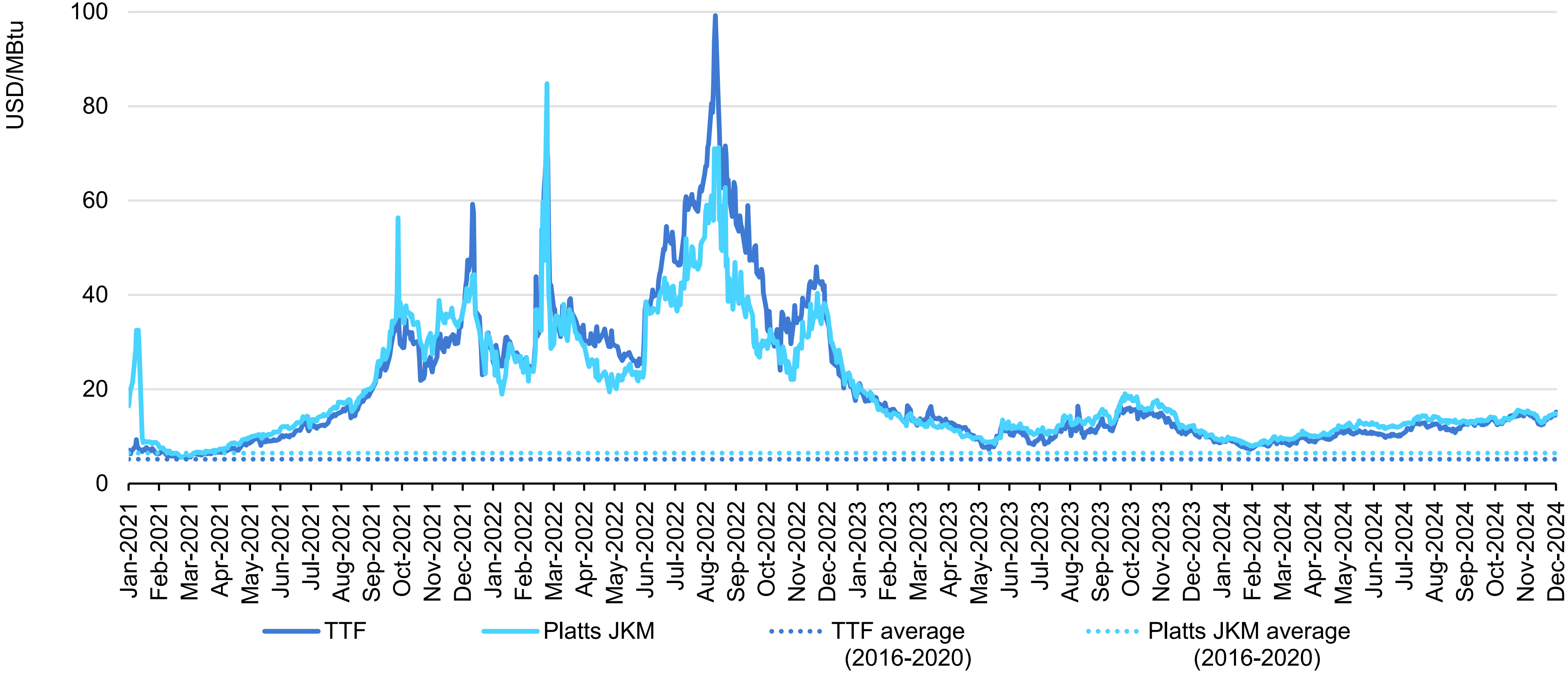
Asian spot LNG prices followed a similar trajectory. Platts JKM prices fell by 14% compared with 2023 to average near USD 12/MBtu, almost double the five-year average between 2016 and 2020. Lower competition for LNG from Europe softened prices in 2024. Price volatility remained elevated and averaged 40% in 2024, 90% above its ten-year average between 2010 and 2019. Heightened volatility reflected tight supply fundamentals, geopolitical tensions and longer shipping routes due to congestion on the Panama Canal in H1 2024. **Oil-indexed LNG contracts** oscillated in an estimated range of USD 11-13/MBtu, close to 2023 levels.

Platts JKM regained its premium over TTF in the second half of 2023 and averaged USD 0.9/MBtu above TTF prices in 2024. High European inventory levels and continued demand reductions depressed TTF prices below JKM. This incentivised stronger LNG flows towards Asian markets, which increased by 9% in 2024, while deliveries to Europe plummeted by around 18% compared with 2023. Despite the strong volatility displayed both on the Asian and European markets, **the correlation between TTF and Platts JKM rose to an all-time high of 0.95**. This reflects the increasingly intertwined nature of regional markets amid the growing share of destination-flexible LNG supplies. Decade-low spot LNG charter rates also contributed to stronger interconnectivity.

In the **United States**, Henry Hub month-ahead prices fell by 9% compared with 2023 to average USD 2.4/MBtu, their lowest annual average since 2020. Strong associated natural gas production and mild winter temperatures in Q1 moderated US natural gas prices. Price volatility remained above average, supported by the higher share of natural gas in power generation.

…albeit remaining well above historic averages in Asia and Europe

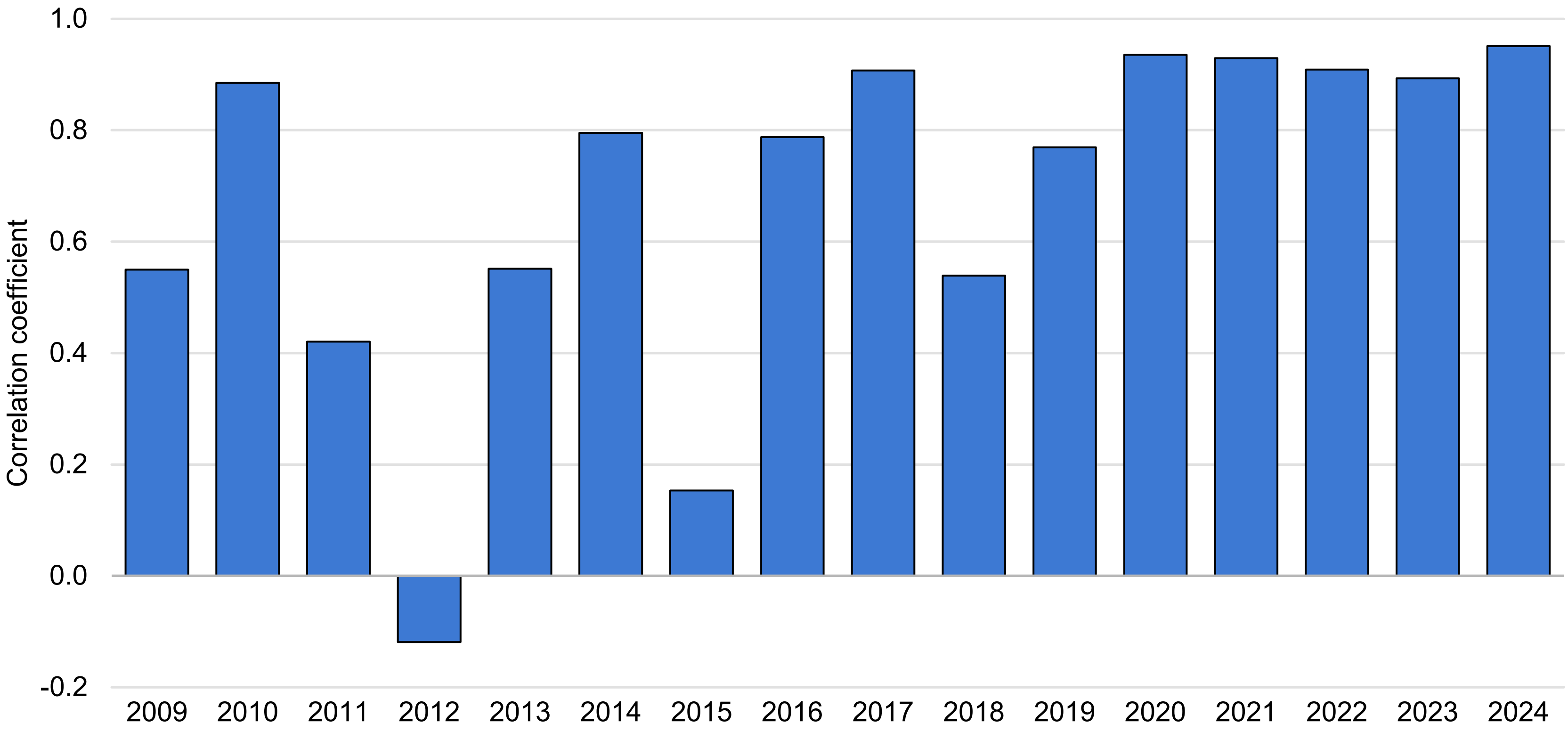
Natural gas prices in key Asian and European markets, 2021-2024



Note: TTF and Platts JKM average prices take 2016-2020 as a reference period.
Sources: IEA analysis based on CME Group (2025), Dutch TTF Natural Gas Month Futures Settlements; S&P Global Inc (2025), S&P Global Commodity Insights.

The correlation between TTF and Asian spot LNG prices rose to an all-time high in 2024

Annual correlation between TTF month-ahead and Platts JKM prices, 2009-2024



Sources: IEA analysis based on CME Group (2025), Dutch TTF Natural Gas Month Futures Settlements; S&P Global Inc (2025), S&P Global Commodity Insights.

Global gas trading volumes rose to all-time highs in 2024

Natural gas hubs enable market participants to trade gas in open, competitive gas markets. Traded products range from short-term contracts to products with a delivery horizon several years ahead (derivatives). Derivatives allow market participants to develop sophisticated risk management strategies. **Hub liquidity** ensures that demand from market participants is matched by supply in a time- and cost-efficient manner without causing significant price changes. The **churn rate** indicates liquidity by measuring how many times a unit of gas is exchanged before being delivered to end consumers. A churn rate above 10 usually indicates a liquid market.

Following a decline in hub liquidity in 2022 amid soaring margin requirements, natural gas trading volumes started to recover in 2023. This trend continued in 2024, with **natural gas trading volumes and churn rates rising to all-time highs across all key markets**. This strong growth has been driven by a number of factors. Margin calls continued to moderate, which reduced costs associated with holding positions and consequently supported higher trading volumes. Continued supply uncertainty – amid rising geopolitical tensions – provided additional incentives to midstream utilities and trading companies to hedge their positions along the forward curve. The growing interconnectivity of regional gas markets is also supporting additional trading activity, with global portfolio players actively hedging on hubs outside their region of physical delivery. Algorithmic trading enhanced with artificial intelligence may have also contributed to higher trade volumes.

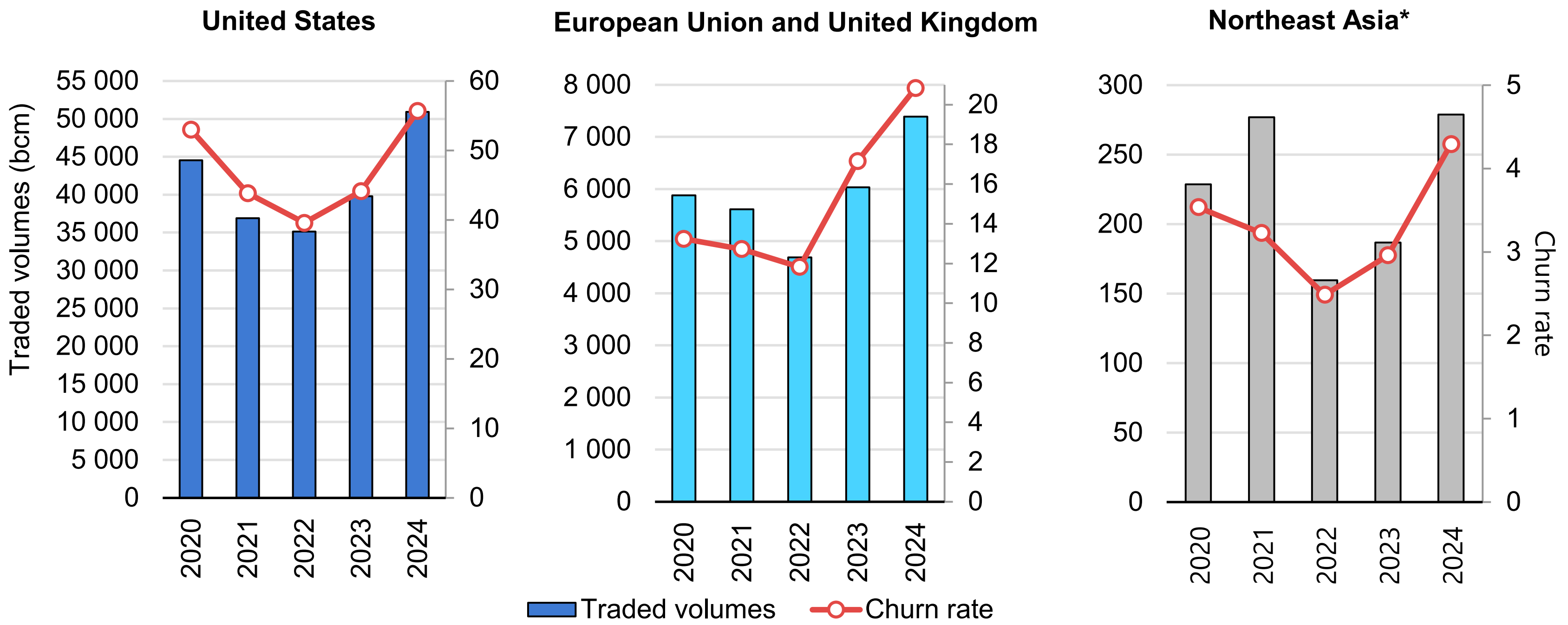
In the **United States** gas volumes traded on **Henry Hub** rose by 28% in 2024 to their highest level in IEA records. The churn rate averaged 55 in 2024, its highest level since at least 2014. Lower gas prices in 2024 reduced the costs associated with trading, while the rising short-term variability of gas-to-power demand provided additional incentives for gas trading. As reported by CME Group, the share of gas trading originating outside the United States rose to a record 25% on Henry Hub in the first ten months of 2024. This highlights the growing role of Henry Hub as a hedging venue used by global portfolio players, focused on LNG.

Traded gas volumes in the **European Union and the United Kingdom** rose by an over 25% in 2024. Traded volumes reached an all-time high, surpassing their previous record in 2020. This growth was largely driven by the **Dutch TTF**. Consequently, its share of total European gas trade firmed up to around 80% in 2024. The churn rate of the combined EU and UK gas markets rose by more than 20% y-o-y to an average of above 20, its highest level on record.

In **Asia** trading in **ICE JKM** derivatives rose by near 50% in 2024 amid stronger spot LNG procurements and more pronounced hedging activity. The churn rate remained low in the JKM area, although it improved compared with 2023, rising to above 4.

Hub liquidity rose across all key markets in 2024

Estimated traded volumes and churn rates across key natural gas markets, 2020-2024



* Based on ICE JKM traded volumes. Northeast Asia = China, Japan and Korea.
Sources: IEA analysis based on various sources, including CME (2025), Volume and Open Interest; ICE (2025), Report Center; London Energy Brokers' Association (2025), Monthly Volume Reports.

Strong LNG contracting activity continued in 2024, led by the Middle East

The LNG market has continued to gain flexibility and liquidity. The share of total active contracted volumes with destination flexibility[1] increased from 30% in 2016 to 48% in 2024. The share of portfolio players as buyers rose from 26% in 2016 to 42% in 2024. Portfolio players procure a mix of LNG supplies from various origins and resell to customers to meet their requirements through term and spot contracts. LNG contracting activities have continued to show strong momentum. The contracted volume in 2024 was 68 bcm/yr, 27% higher than the volume in 2023. When including pre-FID projects, the volumes signed in 2024 reached 83 bcm/yr. Average annual contracted volumes including pre-FID projects were 88 bcm/yr between 2022 and 2024, an increase of 15% compared with the average annual contracted volumes signed between 2019 and 2021.

On the supply side, the Middle East was a main driver of the contracted volumes, accounting for 55% (or 37 bcm/yr) of the volumes signed with post-FID projects in 2024. Since 2023 Qatar has been driving contracting activity, with the largest share of contracted volumes (38%). Portfolio players accounted for 30% (or 20 bcm/yr), a significant increase compared with the volumes signed in 2023. While North America accounted for 8% (or 6 bcm/yr) of the volumes signed with post-FID projects, it accounted for 25% (or 21 bcm/yr) of contracted volumes including pre-FID volumes.

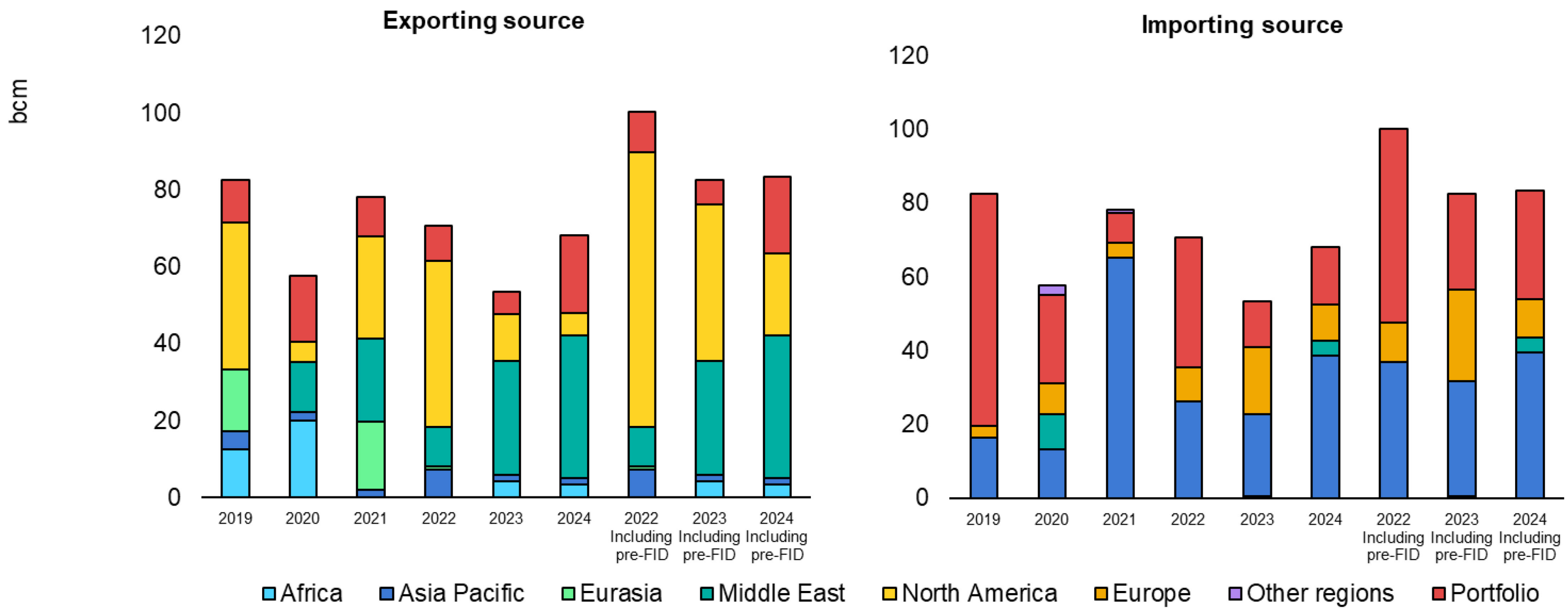
On the import side, Asian buyers continued to dominate the share of contracted volumes. In 2024 Asia accounted for 57% (or 39 bcm/yr) of the volumes signed with post-FID projects. In 2024 India accounted for 40% of the contracted volumes, the largest share among Asian buyers, exceeding China, which had the largest share (around 70%) from 2021 to 2023. The volumes purchased by portfolio players amounted to 16 bcm/yr (or 23%), increasing by 24% compared with 2023. Conversely, the volumes purchased by European buyers were 10 bcm/yr (or 14%), decreasing by 46% compared with 2023.

The share of long-term agreements (with a duration of ten years and over) in the total contracted volume in 2024 was more than 80%, showing that the trend seen since 2018 of a growing share of long-term agreements continued in 2024. In addition, the average duration of contracted volumes in 2024 with post-FID projects was more than 14 years. Securing long-term LNG contracts can be one way of ensuring future energy security and mitigating risks associated with future market price volatility.

[1] 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.

On the import side, Asian buyers have been driving new LNG agreements

Volume of contracts concluded in each year split by exporting and importing source, 2019-2024



Notes: Contracted volumes used for the analysis are associated with confirmed export projects that have taken FID. 2024 represents volumes signed by the end of December 2024. "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.

Policies and market dynamics continued to support oil-to-gas switching in 2024

Natural gas is increasingly displacing oil and oil products in various sectors. This trend is supported by policies, evolving regulatory frameworks and market dynamics. In the **Middle East** the role of natural gas in the power sector has been increasing in the past decade and oil-to-gas switching continued in 2024, driven by Iran, Iraq, Kuwait and Saudi Arabia. In road transport the rapid scale-up of **LNG trucks in China** – with record sales in 2024 – is contributing to China's lower diesel demand. The use of LNG as a **bunkering fuel** is also expected to increase amid increasingly stringent emissions regulations. Based on the current order book, the number of LNG-fuelled ships is expected to almost double and reach over 1 200 vessels by 2028 (excluding LNG carriers). The displacement of oil and oil products in the power sector and long-haul transport is expected to continue over the medium term.

Middle East

Saudi Arabia is the largest user of oil for power generation, burning an estimated 1.1 million barrels per day of liquids in its power plants. The country's Liquid Displacement Program aims to replace oil with a 50:50 mix of gas and renewables in the electricity mix. Aramco upgraded its 2030 gas production target to a 60% increase from 2021 levels, driven by the Jafurah Basin gas project. Additionally, Saudi Arabia launched phase 3 of its gas transmission grid expansion and had over 8 GW of new CCGT capacity under construction and another 28 GW under development in 2024.

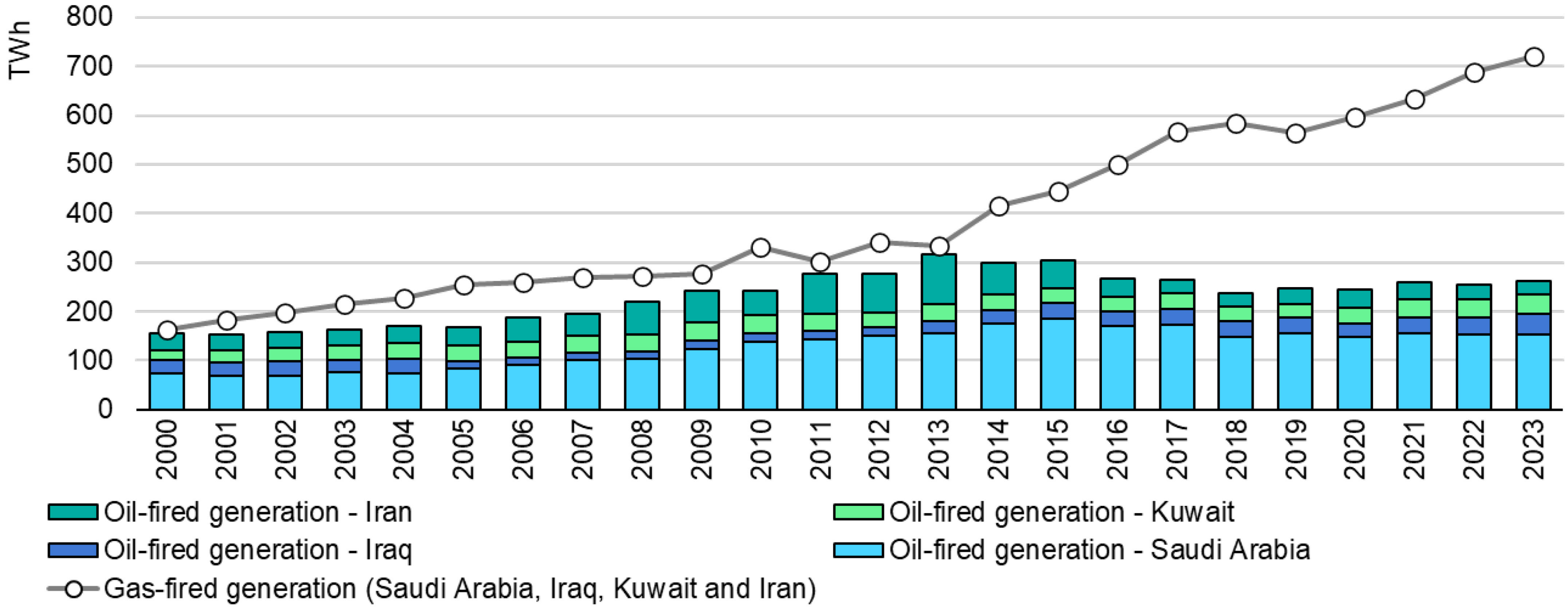
Iraq has made slow but steady progress towards reducing gas flaring since the early 2010s, but in mid-2024 it still captured only 65% of its gross natural gas output while flaring away 12 bcm annually. In early 2024 Iraq committed to reducing crude burning for power generation from May to December 2024 to meet OPEC+ obligations and the government-owned South Gas Company announced an accelerated gas utilisation plan to maximise gas capture volumes and reduce power sector oil use by 2028.

Kuwait faces a power crunch, in a country where nearly 45% of electricity is generated using oil. The government plans to add 12 GW of new capacity (9 GW of which gas-fired) by 2028. However, as of Q3 2024 only about 1 GW of new CCGT capacity had been approved.

Iran banned the use of mazut, a polluting type of heavy fuel oil, in three large power plants with a combined capacity of 4.5 GW in November 2024 to improve air quality. The ban was followed by electricity shortages and rolling blackouts almost immediately, which casts doubt on the phase-out of mazut from all 14 power plants using the fuel in Iran in the foreseeable future.

Fuel switch: Gas-to-power gains ground while oil stagnates in key Middle Eastern economies

Oil-fired and gas-fired power generation in Saudi Arabia, Iraq, Kuwait and Iran, 2000-2023



Note: 2023 values for Iraq are estimated.
Sources: IEA analysis based on Ember (2025), Yearly Electricity Data; JODI (2025), Gas World Database; JODI (2025), Oil World Database.

Policy signals support LNG in road transport in China, but fuel price dynamics remain key

In 2024 demand for heavy-duty road transport fuel in China saw the emergence of two key trends that suggest underlying shifts in the sector. These have important implications for natural gas demand growth. The first was the slowing of growth in road transport diesel demand – used exclusively in heavy-duty vehicles (HDVs) – and the second was a significant rise in the share of LNG-powered trucks in the Chinese HDV fleet. Links can be drawn between these trends, but continued momentum for natural gas in road transport is likely to require stronger policy support given that fuel economics as a driver have proven volatile.

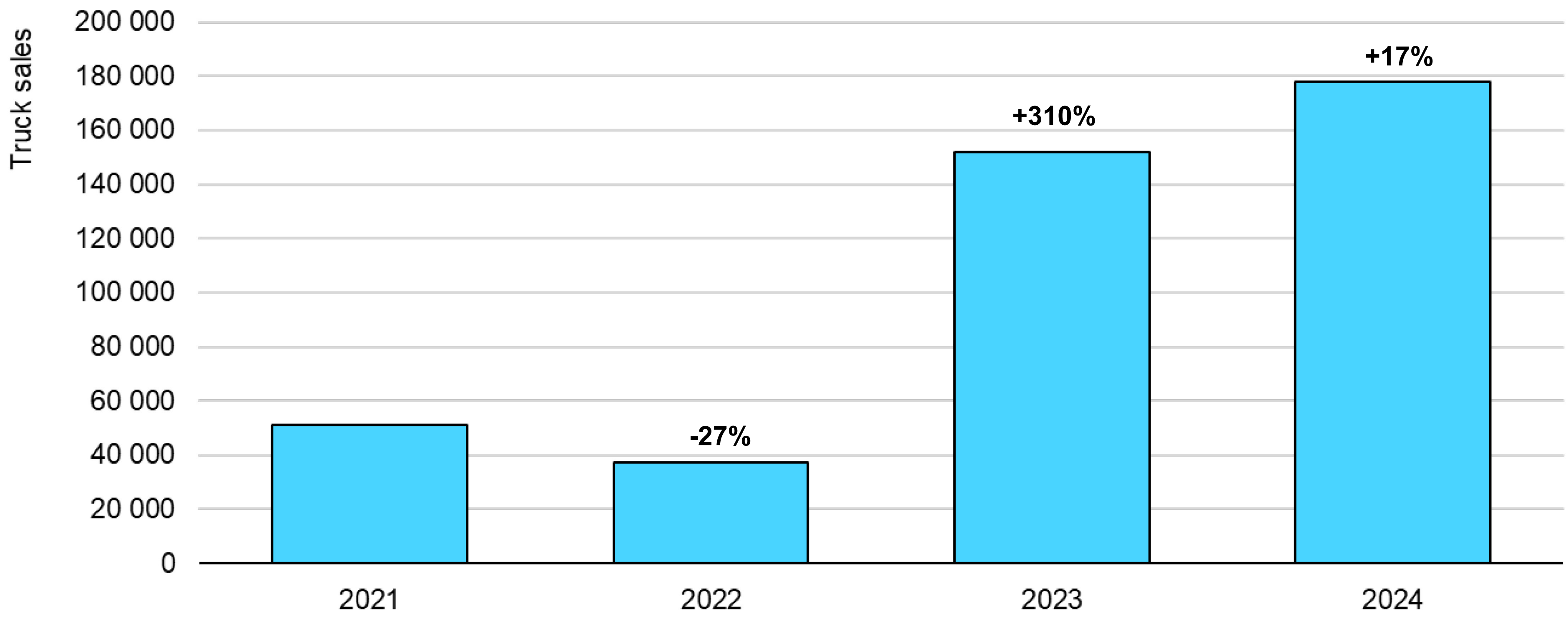
For a number of years China has imposed increasingly stringent road transport emissions regulations, helping reduce both pollution and greenhouse gas emissions from all road vehicle segments. The sixth such package of emissions standards – China VI – was released in 2018 and came into force in phases up to mid-2023, targeting the HDV segment as the most significant contributor to road transport emissions. Diesel truck manufacturers have adapted their vehicle offerings to comply with the imposed rules, but the policy framework also opened the door to alternative drivetrain solutions such as electric and natural gas-driven engines.

The latest National Development and Reform Commission (NDRC) Measures for the Administration of Natural Gas Utilisation from June 2024 categorises HDV transport as a priority sector for LNG as a fuel, and other policy documents – including the Opinions on Improving the Institutional Mechanisms and Policy Measures for the Green and Low-Carbon Energy Transformation published in 2022 – put forward the promotion of natural gas in transport uses. However, while a policy ecosystem favourable to the idea of promoting natural gas as a road-transport fuel has developed, economics remain the primary driver of natural gas penetration in heavy-duty trucking.

The sale of LNG-powered trucks accelerated in 2023 and 2024, just as LNG prices eased to competitive levels with diesel. However, as LNG prices again rose above the switching point with diesel during H2 2024, new LNG truck registrations tumbled immediately, suggesting that vehicle purchase decisions remain highly sensitive to short-term operating cost considerations. Furthermore, LNG truck sales remain constrained by the availability of refuelling infrastructure, whose buildout depends heavily on local and provincial implementation of national guidelines. Ultimately, authorities' decisions on building out LNG refuelling infrastructure have been supported by economic considerations around the availability of affordably priced gas. Given the volatility of LNG diesel price competitiveness, continued growth in transport demand for natural gas could require stronger policy support.

LNG truck sales in 2023 and 2024 remained multiples above previous year levels

LNG-powerd truck sales by year in China, 2021-2024



Sources: IEA analysis based on CVWorld (2025).

Stricter environmental regulations drive surge in LNG-powered ship orders

The maritime industry is undergoing a significant transformation driven by a pressing need to reduce GHG emissions and comply with stricter environmental regulations.

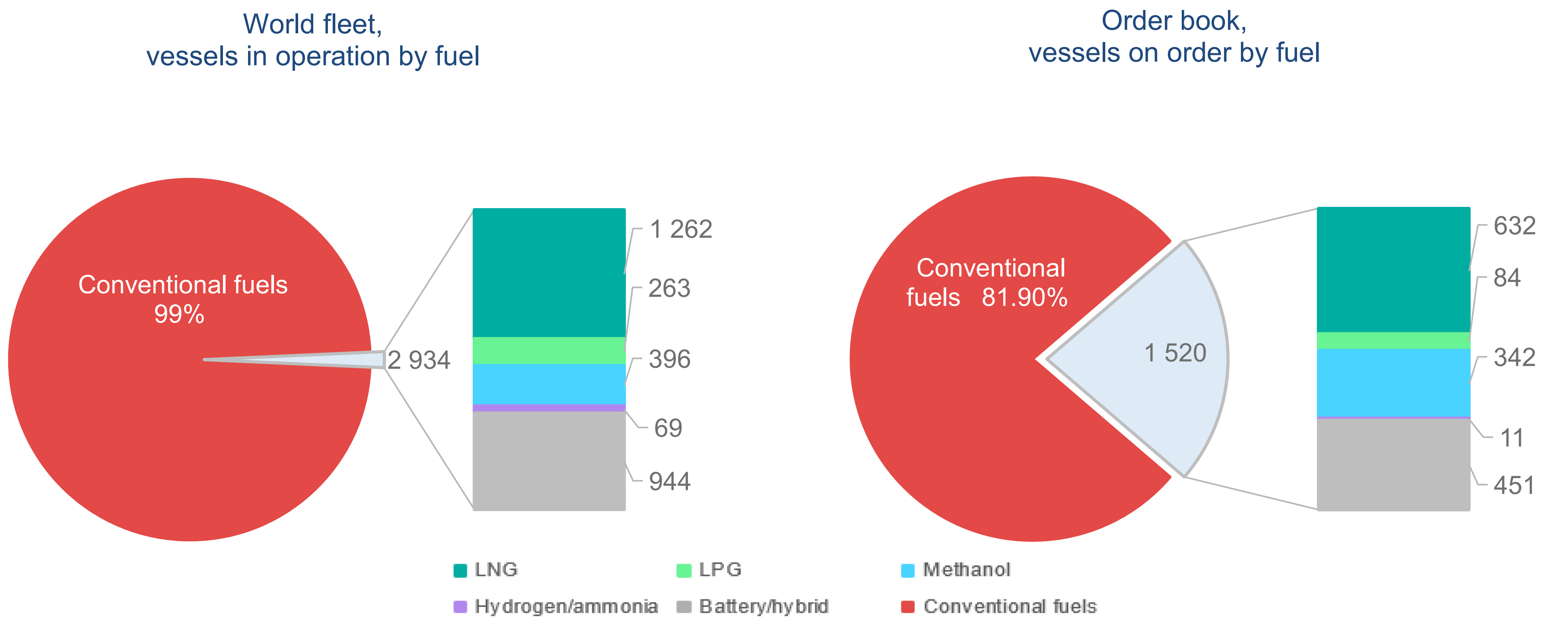
Introduced in 2023, the **IMO Carbon Intensity Indicator (CII)** is a mandatory operational rating system that measures a ship's efficiency in terms of CO_2 emissions per unit of transport work performed. Like an energy efficiency label for buildings, the CII assigns a rating from A (best) to E (worst) according to a ship's annual efficiency ratio (AER). The AER is calculated using a ship's CO_2 emissions and its transport work, which considers factors like cargo capacity and distance travelled. The CII regulation incentivises ship operators to improve operational practices and invest in technologies that enhance fuel efficiency. Ships with a poor CII rating face potential consequences, including restrictions on their ability to operate in certain regions.

The **EU Emissions Trading System (EU ETS)** is a market-based mechanism designed to curb GHG emissions from various sectors, including maritime transport. The EU ETS extended to maritime transport emissions from 1 January 2024 and requires shipping companies operating within the European Union to purchase allowances to cover their CO_2 emissions. The number of allowances available is gradually reduced over time, forcing companies to emit less or purchase additional allowances through the EU ETS. The mechanism creates a financial incentive for shipping companies to reduce their carbon footprint. Companies with a lower carbon intensity (emitting less CO_2 per unit of transport work) will require fewer allowances, leading to cost savings. This regulation is expected to accelerate the adoption of cleaner fuels and technologies in the maritime sector.

Set to take effect in 2025, **FuelEU Maritime** is a European Union regulation that directly targets the carbon intensity of the fuel used by ships operating within the bloc. It establishes progressive lifecycle GHG emission reduction targets for ships, essentially mandating the use of cleaner fuels over time.

The combined effect of these regulations is a surge in demand for vessels propelled with alternative fuels. Solutions currently available to reduce carbon emissions in shipping include **LNG** and **methanol**. LNG is popular due to its low NO_x, SO_x and PM emissions, but has challenges such as methane slip and storage requirements. Methanol is gaining traction for its ease of handling and dual-fuel capability, despite its lower energy density. Longer-term options under development include **ammonia and hydrogen**, which have no direct CO_2 emissions but face challenges in storage, safety, and infrastructure development. LNG-powered ships currently account for around half of new orders, with a 106% increase in 2024. By 2028 the number of LNG-fuelled ships is expected to nearly double to over 1 200 vessels.

The future shipping market relies on more diverse fuels, of which LNG is an important part



Sources: IEA analysis based on DNV (2024), Alternative Fuels Insights for the shipping industry – AFI platform data (accessed 19 November 2024).
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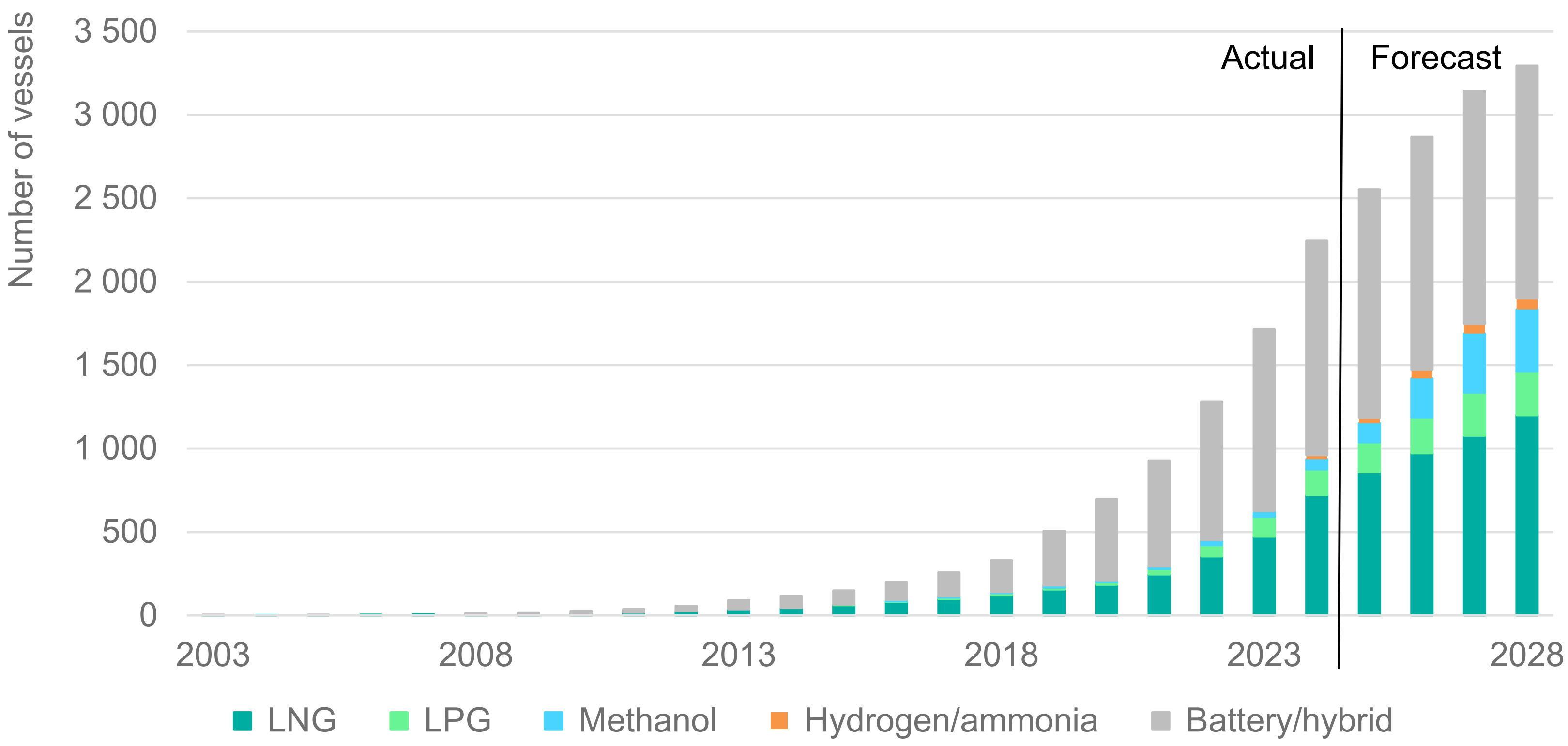
The number of ships running on alternative fuels on order for delivery by 2028 is rising sharply

Growth in the use of alternative fuels in the world fleet, 2003-2028



Note: LNG carriers are not included in the LNG figures.
Sources: IEA analysis based on DNV (2024), Alternative Fuels Insights for the shipping industry – AFI platform data (accessed 19 November 2024).
Disclaimer: The positions or views stated in such document are solely those of the author and do not necessarily represent the views of DNV and/or the third-party data owner.

International co-operation on gas and LNG supply security is being strengthened

The 2022/23 gas supply shock transformed natural gas markets in a structural manner. The steep cuts in Russian gas supply reduced Europe’s ability to optimise between flexible piped gas flows and LNG imports and hence largely eroded Europe’s role as a global balancing market.

In this new context, the International Energy Agency called for greater international co-operation to enhance gas supply security. Responsible producers and consumers will need to work together to reinforce the architecture for safe and secure global gas supplies amid mounting geopolitical tensions. A number of new initiatives were launched in 2023 and 2024 with the aim of improving market transparency, data exchange and co-operation mechanisms supporting the joint procurement of LNG.

The European Union and Japan launched a Global Early Warning Mechanism

In 2023, in the aftermath of the energy crisis, the European Commission (DG Energy) and Japan (METI) decided to intensify their co-operation on international energy security. Building on the dialogue facilitated by the IEA’s Task Force on Gas and Clean Fuels Market Monitoring and Supply Security (TFFS), the Commission and Japan launched a Global Early Warning Mechanism (GEWM), where participating parties can exchange information related to their gas and LNG security of supply (e.g. regular status updates, incidents and their preliminary assessment). The European Commission offers a secure online platform to facilitate the swift exchange of information among authorised participants. The GEWM has continued to gain traction since 2023. In addition to the European Commission and Japan, Australia, Canada, Korea and the United States are now participating in the initiative.

Japan strengthened co-operation on LNG supply security with Italy and Korea

The 13th LNG Producer Consumer Conference, co-hosted by Japan (METI) and the IEA in October 2024, provided a key platform to enhance dialogue and co-operation mechanisms on gas and LNG supply security. Korea’s Ministry of Trade, Industry and Energy (MOTIE) and Japan’s METI agreed to co-operate to secure stable LNG supplies. As part of the initiative, Japanese and Korean companies (including JERA and KOGAS) will explore opportunities for joint procurement, cargo swaps and other forms of co-operation.

In addition, Japan Organization for Metals and Energy Security (JOGMEC) and ENI signed a memorandum of co-operation aimed at expanding co-operation on gas supply security and supporting the diversification of LNG procurement.

Singapore is exploring joint LNG procurement opportunities together with other Asian LNG buyers

Singapore's Energy Market Authority (EMA) signed several memoranda of understanding (MoUs) with other Asian market players in 2024 to enhance co-operation along LNG supply chains. In April 2024 EMA and Japan's JERA signed an MoU to share best practices in LNG procurement and supply management, while fostering mutual co-operation in LNG procurement and optimisation between JERA and Singapore.

In June 2024 EMA and KOGAS signed an MoU to promote knowledge exchange on LNG procurement and supply chain management, as well as for the exchange of personnel for training and learning purposes. EMA and KOGAS signed a second MoU in October 2024, with an expanded scope to explore joint procurement of LNG by Singapore and KOGAS.

In November 2024 EMA and PetroChina International Company (PCI) signed an MoU on LNG supply and management. Under the MoU, the parties will explore collaboration opportunities to strengthen each other's LNG supply chains, exchange information on market fundamentals and evaluate joint procurement opportunities. The potential joint LNG procurement is expected to facilitate better contractual terms and pricing. Furthermore, the co-operation could also extend to supporting Singapore's development into an Asian LNG hub.

The European Union's Joint Gas Purchasing mechanism became a permanent instrument

As part of the temporary emergency measures adopted through Council Regulation 2022/2576, the European Union launched its Joint Gas Purchasing mechanism in April 2023. The mechanism aims to make use of the European Union's collective market power to negotiate better prices with international suppliers, essentially establishing a two-step system:

- Demand aggregation via the AggregateEU platform. (Participation is voluntary, except for volume requirements equivalent to 15% of gas storage filling needs. After 2025 participation is purely voluntary).
- Joint purchasing: following the matching of demand with supply via the platform, companies can voluntarily conclude contracts with gas suppliers, either individually or jointly (through consortiums).

The Joint Gas Purchasing mechanism, along with other emergency measures, was extended in November 2023 for a period of 12 months. As part of the EU Hydrogen and Gas Decarbonisation Package, Regulation 2024/1789 transformed the voluntary demand aggregation and Joint Gas Purchasing mechanism into a permanent instrument.

Gas market update

Global gas demand returned to structural growth in 2024

Natural gas demand **returned to structural growth and reached a new all-time high in 2024**, as markets gradually rebalanced following the 2022/23 gas supply shock. Limited LNG supply growth and geopolitical tensions continued to provide upward pressure on gas prices in key import markets in Q2-Q4. This forecast expects a slowdown in global gas demand growth in 2025, although natural gas consumption is projected to reach a new all-time high again in 2025.

Preliminary data suggest that **global gas demand increased by 2.8% (or around 115 bcm)** in 2024. This is well above the historical 2% average growth rate between 2010 and 2020. Asia alone accounted for over 40% of incremental gas demand, primarily driven by China and India. In addition, gas demand recorded strong gains in the gas-rich markets of Eurasia and the Middle East, with their combined gas demand expanding by an estimated 3% in 2024. Natural gas consumption in the Americas grew at a more moderate rate of 1.7%, primarily supported by higher gas burn in the power sector. In Europe natural gas consumption increased marginally compared with 2023.

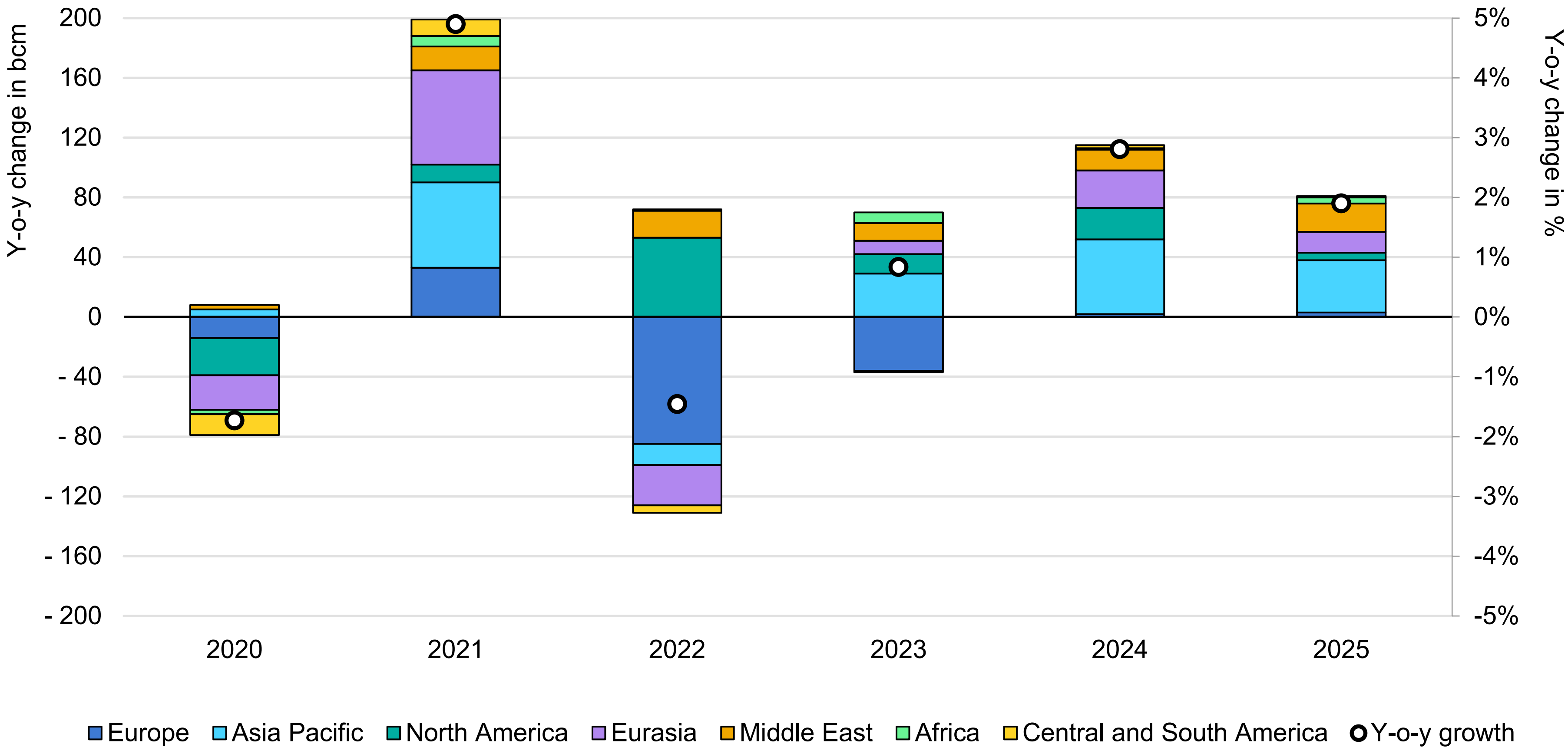
From a sectoral perspective, global gas consumption growth was largely supported by **industry and energy own use**, accounting for around 45% of incremental gas demand in 2024. This was partly supported by continued economic expansion in the fast-growing Asian markets, as well as recovery in Europe's industrial gas demand, which nonetheless remains well below its pre-crisis levels. **Gas-to-power demand** grew by near 2.5% y-o-y, as the strong gains in North America, the fast-growing Asian markets and Eurasia were partially offset by lower gas-fired power generation in Europe. Gas demand in the **residential and commercial** sectors grew by less than 2% in 2024.

Global gas demand growth is forecast to slow in 2025, with an increase of 1.9% (or around 80 bcm). Similarly to 2024, this growth is **largely supported by Asia**, which alone is expected to account for almost 45% of incremental gas demand. **Industry and the energy sector remain the primary driver** behind stronger gas use and is projected to contribute over 45% of demand growth. Following a strong growth in 2024, gas-to-power demand is expected to increase only marginally in 2025, amid the continued expansion of renewables.

LNG supply is forecast to increase by 5% (or above 25 bcm) in 2025, led by North America with the start and ramp-up of several new LNG liquefaction facilities, including LNG Canada, Plaquemines phase 1, Corpus Christi expansion stage 3 and Altamira FLNG. The halt of **Russian piped gas transit via Ukraine** on 1 January 2025 is expected to result in a supply loss of nearly 15 bcm in 2025, which, together with higher storage injection needs in Europe, could tighten market fundamentals, especially in the first half of the year. This in turn is expected to weigh on the pace of gas demand growth, especially in price-sensitive import markets.

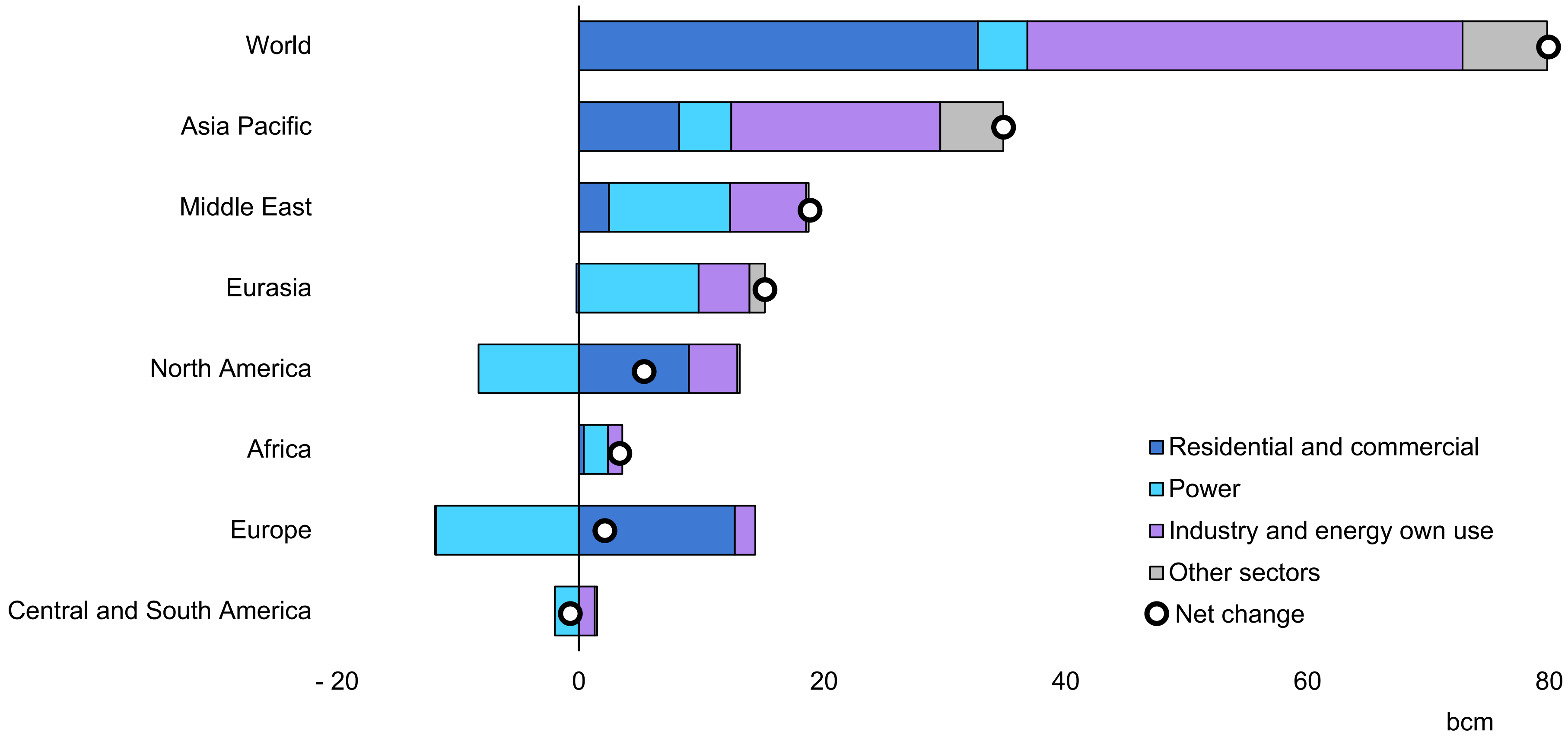
Natural gas demand growth is expected to slow down in 2025

Year-on-year change in natural gas demand in key regions, 2020-2025



Asian markets and industry drive incremental gas demand in 2025

Forecast change in natural gas consumption by region and sector, 2025 vs 2024



North American gas demand increased by an estimated 1.8% in 2024

Natural gas consumption in North America rose by an estimated 1.8% (or just over 20 bcm) y-o-y in 2024. This growth was **primarily supported by gas-to-power demand**. Natural gas use in the residential and commercial sectors remained close to its 2023 level, as the demand decline recorded in Q1 2024 was offset by higher consumption in Q4. Gas demand in industry increased marginally compared with 2023.

In the **United States** natural gas consumption increased by an estimated 1.9% (or 17 bcm) y-o-y in 2024, with growth primarily driven by the power sector. Natural gas demand in the residential and commercial sectors declined marginally compared to 2023. During February-May milder weather conditions diminished gas use in the residential and commercial sectors, which plummeted by around 9% y-o-y in this period. This decline was partially offset by stronger space heating requirements in Q4 2024, when gas use in the residential and commercial sectors grew by 4% y-o-y. Gas burn in the **power sector** continued its expansion and rose by around 4% (or 17 bcm) in 2024. This growth was primarily supported by higher electricity consumption, which grew by a near 3% y-o-y. Sizzling heatwaves pushed up gas-fired power generation to an all-time high in July. In addition, the continued decline in natural gas prices supported additional coal-to-gas switching, with coal-fired generation declining by near 4% in 2024. Natural gas demand in **industry** remained close to the previous year's level in 2024.

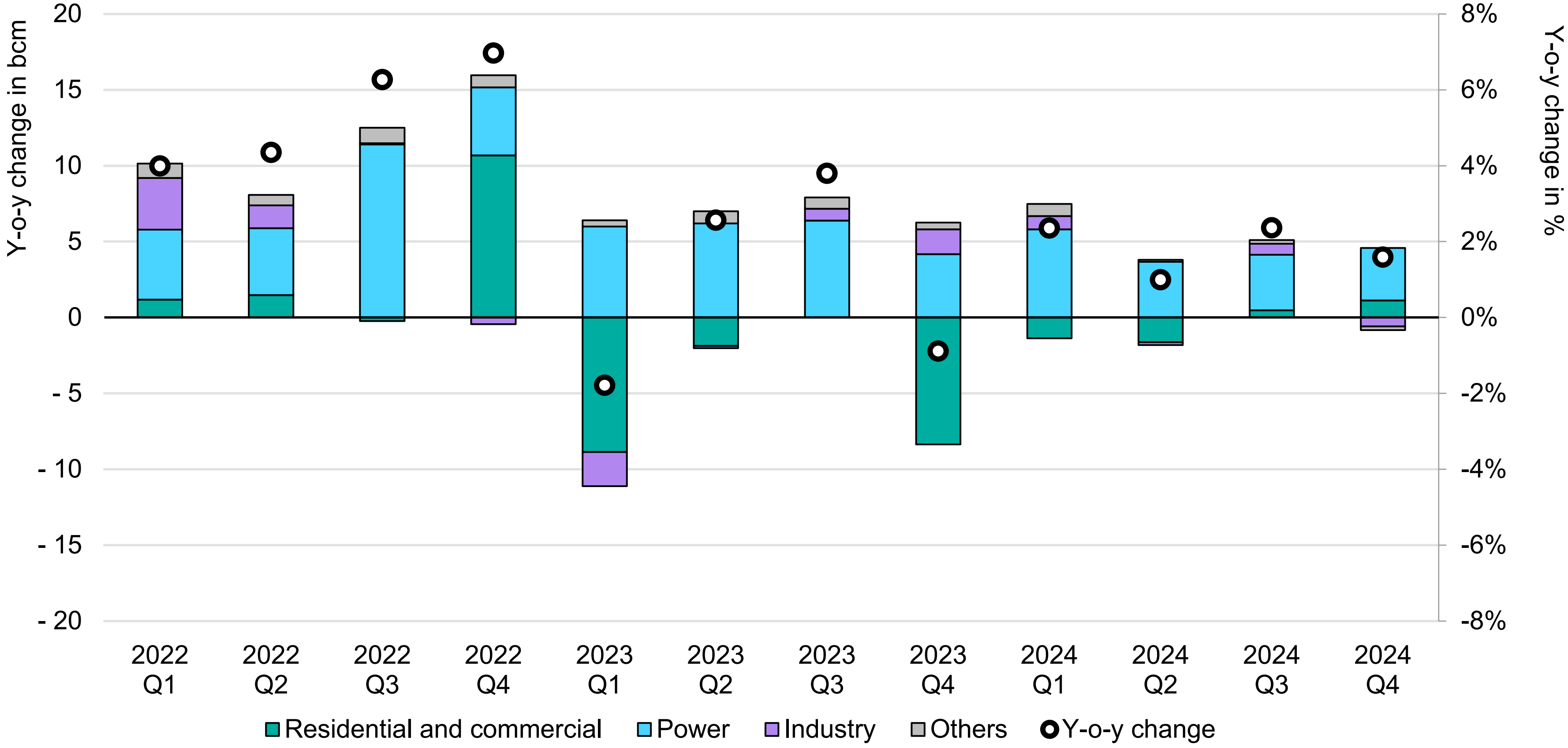
In **Canada** natural gas consumption increased by an estimated 3% (or 3.5 bcm) in 2024. Similarly to the United States, unseasonably mild weather conditions initially weighed on gas use in the residential and commercial sectors, which declined by 10% (or almost 2 bcm) y-o-y in the first five months of 2024. These losses were partially offset by the year-on-year increase recorded in residential and commercial demand in Q4 2024. Combined gas demand in the industrial and power sectors rose by 7% y-o-y in Q1-Q3 2024, largely supported by stronger gas-fired generation at the expense of coal-fired power plants.

Mexico natural gas consumption grew by an estimated 0.5% (or 0.5 bcm) in 2024, primarily driven by the power sector. The decline in domestic gas production together with higher demand in Mexico supported stronger piped gas imports from the United States (up by 4% in 2024). In August, Mexico started to export LNG from the Altamira FLNG facility (which relies on US feedgas supplies). Mexico exported just over 0.5 bcm of LNG in the second half of 2024.

North Amercian natural gas demand in 2025 is projected to remain close to its 2024 level. After reaching an all-time high in 2024, gas-to-power demand is expected to marginally decline in 2025 amid the continued expansion of renewables. In contrast, gas use in the residential and commercial sectors is expected to increase, assuming average weather conditions.

…with growth primarily driven by the power sector

Estimated year-on-year change in quarterly natural gas demand by sector in the United States, 2022-2024



Sources: IEA analysis based on EIA (2025), Natural Gas Consumption; Natural Gas Weekly Update.

The shale boom and weather shocks reshape gas dynamics in Central and South America in 2024

Preliminary data show that natural gas consumption in Central and South America rose by 1.6% (or 2.3 bcm) y-o-y in 2024, driven by increased usage for power generation and in the residential and commercial sectors. This demand growth led to a 17% y-o-y rise in LNG imports, although trends varied between countries.

In **Argentina** natural gas production rose by 4.8% in the first 11 months of 2024, driven primarily by increased shale gas production from the Vaca Muerta formation. This growth put the country on course for its highest natural gas production levels since 2006 and contributed to a 45% y-o-y decrease in LNG imports, which amounted to just 1.49 bcm in 2024, the lowest in over a decade. Significant progress is being made to bolster exports in the coming years: a 3.3 bcm/yr FLNG terminal in Río Negro is planned to start operations by 2027, and an LNG liquefaction plant with a capacity of up to 41 bcm/yr has been proposed. Initial gas flows of 2 mcm/d to Brazil are projected to begin in early 2025 via pipelines across Bolivia, with total traded volumes (including LNG) potentially expanding to 30 mcm/d by 2030. Gas demand in Argentina increased by 1.2% (or 0.4 bcm) y-o-y in the first 10 months of 2024. While the record cold winter boosted residential and commercial demand by 4.2% (or 0.42 bcm) y-o-y in the same period, industrial gas use fell by 3.7% (or 0.4 bcm) due to the ongoing recession. Gas-to-power demand increased by 4.4% (or 0.49 bcm) due to low hydro.

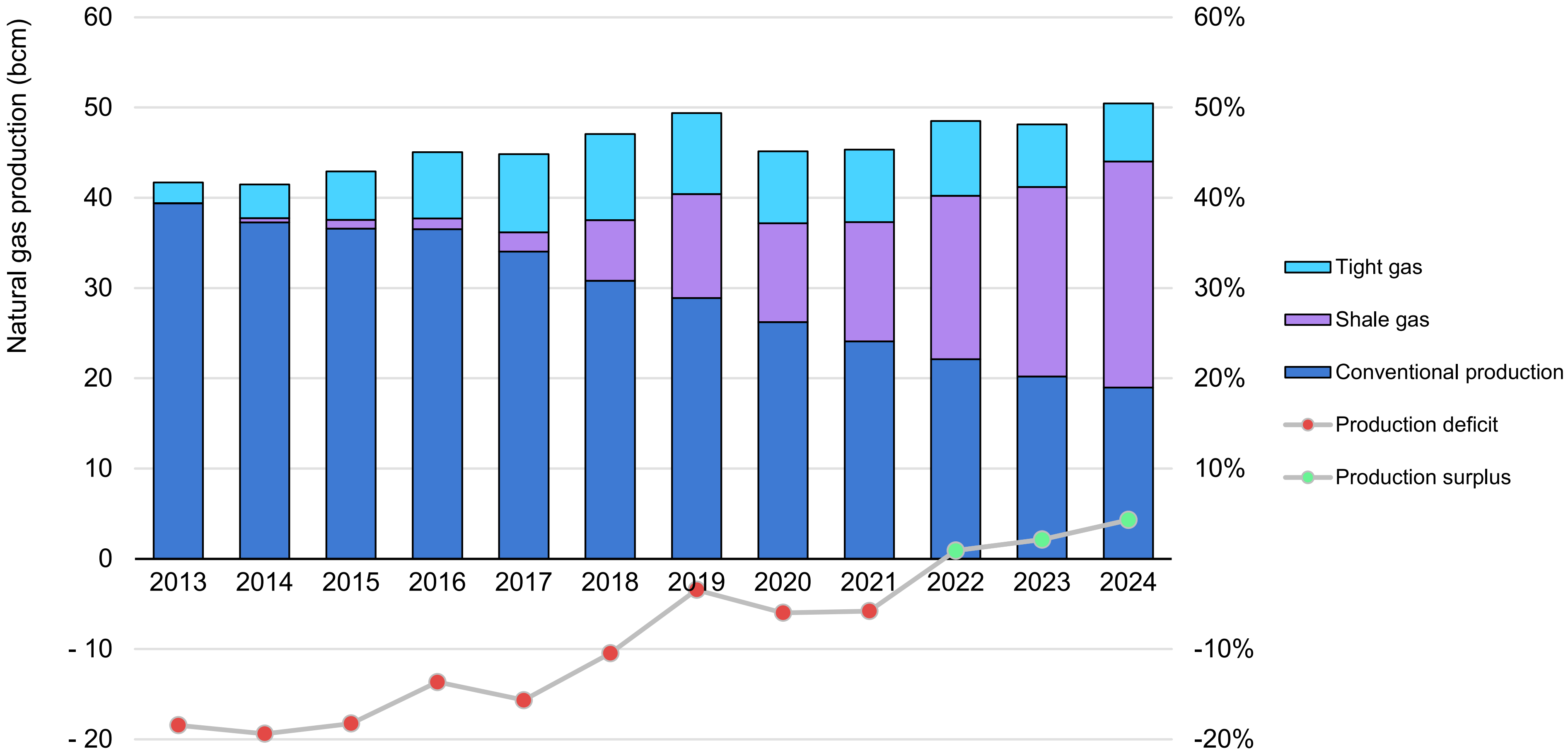
The worst drought ever recorded in **Brazil** and its impact on hydropower led to a 55% increase in backup gas-fired power output in 2024, supported by a 2.4 bcm increase in LNG imports. During September and October 2024 Brazil imported as much LNG as in the whole of 2023. In contrast, piped gas imports from Bolivia declined by 11% y-o-y to less than 60% of their 2017 levels. While gas demand in upstream oil and gas activities increased by 3.7% (or 0.15 bcm) in Q1-Q3 2024, natural gas use in industry fell by 3% (or 0.26 bcm).

In **Trinidad and Tobago** gas production ramped up in Q3 2024, albeit remaining 4.4% (or 0.9 bcm) lower y-o-y. Demand similarly recovered, driven by increased ammonia manufacturing, remaining flat overall y-o-y. LNG exports decreased by 2.1% (or 0.22 bcm) y-o-y. Consumption in **Venezuela** increased by 8.8% (or 1.1 bcm) y-o-y during first nine months of 2024. **Colombia** relied heavily on gas-fired power generation again in September and October, and input to power plants increased by 44.9% y-o-y in 2024. LNG imports in 2024 accounted for half of all imports received at the Cartagena LNG terminal since it started operations in 2016. Natural gas demand continued to grow in **Central America** and the Caribbean markets, where combined LNG imports increased by 1.2% y-o-y in 2024.

This **forecast** expects natural gas demand in Central and South America to decrease by 0.9% (or 1.4 bcm) in 2025, as weak La Niña conditions lead to increased rainfall and milder temperatures, although stronger industrial demand is expected in the region.

Shale gas drives Argentina's expanding production and export plans amid stable demand

Natural gas production by type in Argentina, 2013-2024



Note: Data for 2024 are preliminary, based on data available at the time of publication.
Sources: IEA analysis based on data provided by Ministerio de Economía (2025); IEA Natural Gas Information (2025).

Asia's natural gas demand grew by an estimated 5.5% in 2024

Asian natural gas consumption expanded by around 5.5% in 2024, accounting for over 40% of incremental global gas demand. This strong increase was primarily driven by China and India, with both gas markets displaying double-digit growth rates during the year. Economic growth, widespread heatwaves in Q2 and relatively low LNG prices in H1 2024 supported gas demand in Asia. Preliminary data indicate that natural gas demand growth in Asia slowed from over 7% in H1 2024 to around 4% in H2 2024, amid higher hydro and nuclear availability, slowing industrial activity in China and higher spot LNG prices. In 2025, Asia's gas demand growth is expected to slow down to below 4% amid tighter market conditions.

China's natural gas demand is expected to have grown by about 8% y-o-y in 2024, similar to the growth rate experienced in 2023. This strong demand growth occurred despite the tapering of overall economic growth, suggesting a particular positioning of natural gas in the broader energy mix. On the one hand, a slowdown in building and manufacturing activity has gone hand-in-hand with a decline in gas demand growth in industry. On the other, competitive domestic LNG pricing against diesel (through much of the year) drove accelerated uptake of natural gas in transport, and summer heatwaves led to strong growth in power sector gas burn. With GDP forecasts pointing toward softer Chinese growth in 2025, incremental industrial demand for gas is likely to ease further in 2025, although industry remains the single largest gas-consuming sector, accounting for 37% of Chinese demand. As a result, total demand is set to see growth of close to 7% in 2025, down from 2024 rates. On the supply side, domestic production is expected to be the largest provider of incremental volumes as emphasis on developing both conventional and unconventional resources continues to drive output. Pipeline imports of natural gas are set to experience another year of strong growth in 2025, as volumes through the Power of Siberia connection from Russia grow to full contractual volumes of 38 bcm/yr, aided by the completion of the final connecting sections to the Shanghai area in late 2024.

Japan's gas demand in the first ten months of 2024 remained broadly flat. In the power generation sector, cold weather in March and the summer heatwave raised gas-fired power generation. While gas demand in the industrial sector decreased by 2% in the first ten months of 2024 compared with 2023, demand in the residential and commercial sectors was almost flat. Power demand increased by around 1% y-o-y in the first ten months of 2024, in contrast to a decrease of approximately 3% y-o-y in 2023 as a whole. While nuclear output and renewable availability increased in 2024, the upward trend in power demand was sufficient to increase gas-fired power generation. Total gas demand in 2025 is assumed to decrease by 4%, mainly due to the growth of nuclear output. Onagawa 2 and Shimane 2 restarted power generation in November and December

2024, respectively. These restarts are likely to decrease the output from gas-fired power plants.

Korea's gas demand increased by 7% y-o-y in the first 10 months of 2024. The power generation and city gas sectors were contributors to the growth in gas demand during this period. Gas-fired power generation increased mainly due to the summer heatwave. Total gas demand in 2025 is assumed to decrease by 3%, driven by the increase in nuclear output and renewable availability. A new nuclear power plant (Shin Hanul 2) started operation in April 2024. Further plants (Saeul 3 and Saeul 4) are under construction. Demand from industry and in the residential and commercial sectors are assumed to increase slightly, but will not be sufficient to offset the decline in the power generation sector.

Preliminary data show that apparent gas consumption (including net production and LNG imports) in **India** rose by 11% y-o-y in 2024, driven by industry and oil refining. This demand growth led to a 21% y-o-y rise in LNG imports, supported by average spot LNG prices in India that were more than 12% lower than a year ago. Demand growth was driven by industry (up 3 bcm or 22% y-o-y) and oil refining (up 1.2 bcm or 26% y-o-y), but double-digit growth was also recorded in residential and commercial gas consumption (up 14%) and transport (up 12%).

Domestic production has been declining slightly since July 2024 (comparing monthly production with 2023). However, incentives for gas producers and investment in exploration and production are expected to further boost production with the aim of achieving greater energy security.

India's LNG imports increased throughout 2024, supported by lower relative prices. In 2024 the number of LNG cargoes tendered for delivery (both supplier offers and user invitations) in India increased by 70% y-o-y. The number of cargoes awarded increased by 85%, while the number of cargoes not awarded decreased by 20%.

In 2024 India was the world's fourth-largest LNG importer, accounting for nearly 7% of global LNG imports, and it remains an attractive market for long-term suppliers. Just over 15 bcm/yr of new sales and purchase agreements were signed in 2024, including the renewal for 20 years of Qatar's 10 bcm/yr contract starting from 2028. The strategy of diversifying LNG supplies in the coming years is reflected in the signing of new long-term contracts with portfolio players totalling more than 4 bcm/yr, with the remainder of the 15 bcm/yr of newly signed contracts coming from the United Arab Emirates and the United States.

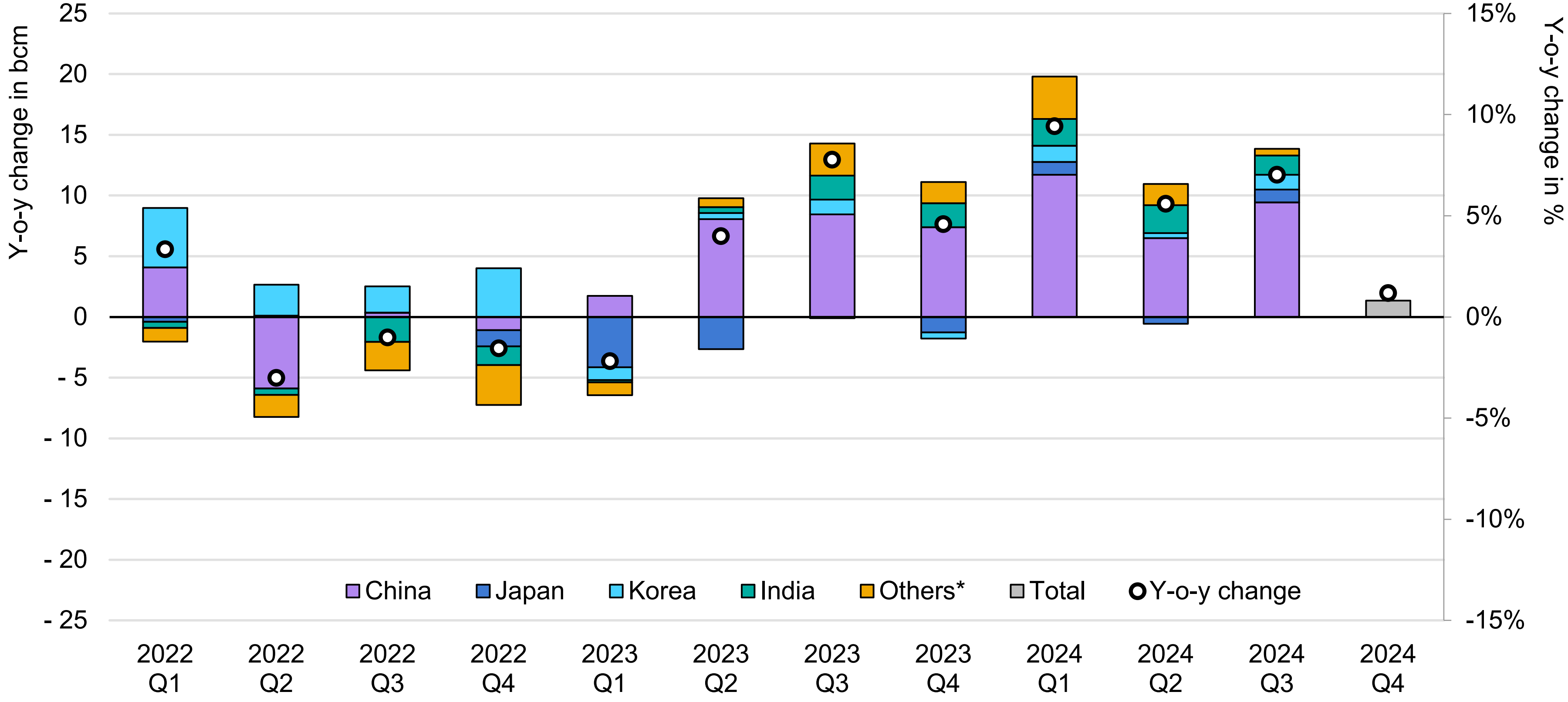
This forecast expects natural gas demand in India to increase by 8% (or 6 bcm) in 2025, assuming average weather conditions, driven by the country's growing energy needs and rapid economic expansion.

Emerging Asia's gas consumption increased by an estimated 2.5% in 2024. This growth was largely concentrated in the region's gas-rich markets (Indonesia and Malaysia), where growing domestic gas production continued to support higher gas consumption. In contrast, natural gas demand in the region's import-reliant markets

(Bangladesh, Pakistan and Thailand) started to soften in H2 2024 amid the strong increase in spot LNG prices. Natural gas consumption in **Thailand** rose by 2.5% (or 1 bcm) y-o-y in the first eleven months of 2024, as the demand growth recorded in Q1 2024 was partially offset by the demand declines recorded during the April-November period. Gas burn in the power sector rose by 6.5% (or 1.7 bcm) y-o-y in the first eleven months of 2024, while gas use in industry dropped by nearly 13% (or 1 bcm) y-o-y during the same period. In the transport sector, natural gas consumption plummeted by over 15% (or 0.2 bcm) y-o-y in the first eleven months of 2024. Estimated natural gas demand in **Bangladesh and Pakistan** fell by 1% in 2024. The strong increase in LNG imports (up by 13%) was not sufficient to offset the decline in domestic production. **Indonesia**'s gas demand grew by 7% (or 2 bcm) y-o-y in the first ten months of 2024, primarily driven by the power and industrial sectors. In **Malaysia** natural gas demand increased by an estimated 8% (or 2.5 bcm) y-o-y in the first ten months of 2024, supported by the continued expansion of domestic production during this period. Natural gas demand in Emerging Asia is forecast to increase by close to 2.5% in 2025, primarily driven by the power and industrial sectors.

China and India dominated Asia's gas demand growth in 2024

Year-on-year change in quarterly gas demand in Asia, Q1 2022-Q4 2024

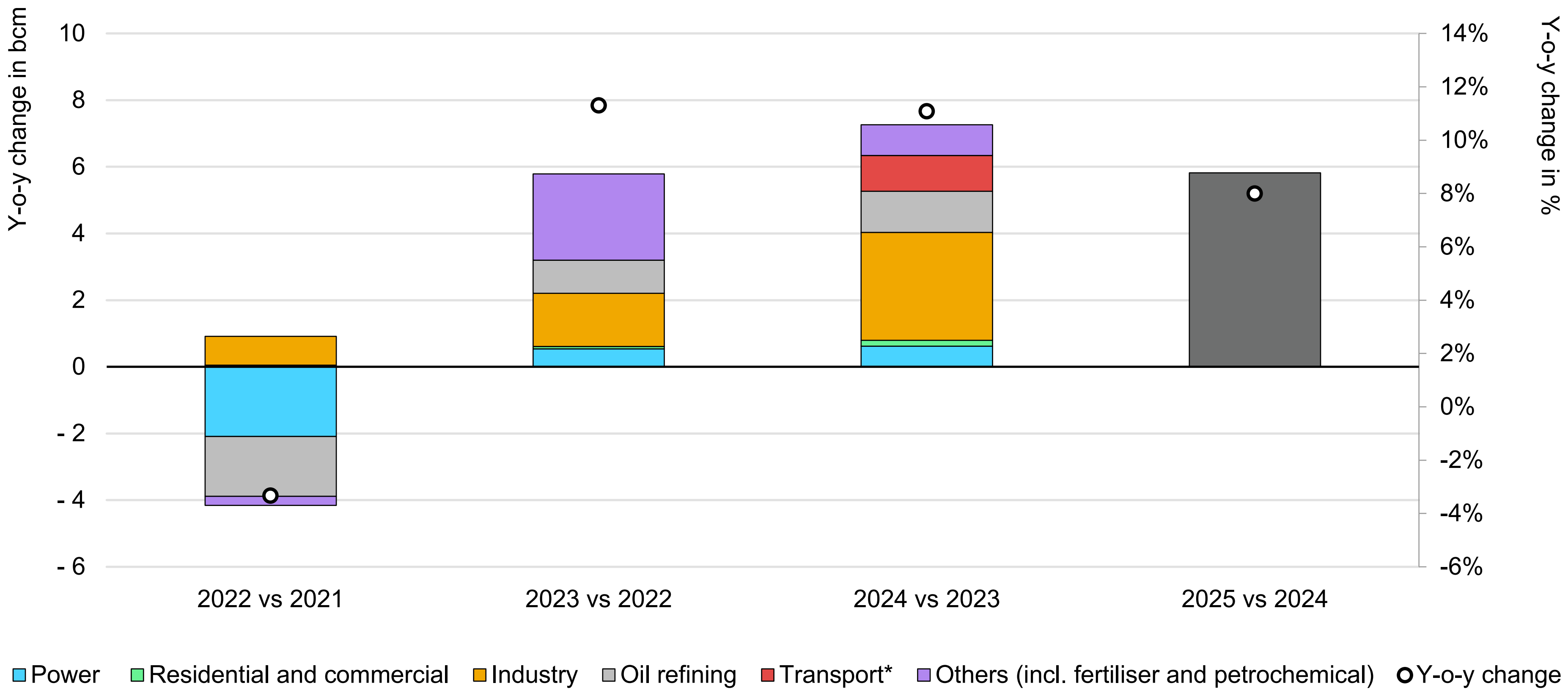


* Others comprise Bangladesh, Indonesia, Malaysia, Pakistan, the Philippines, Singapore and Thailand.

Sources: IEA analysis based on ICIS (2025), ICIS LNG Edge; CQPGX (2025), Nanbin Observation; JODI (2025), Gas World Database; PPAC (2025), Gas Consumption; EPPO (2025), Energy Statistics; Korea Energy Economics Institute (2025), Monthly Energy Statistics; Ministry of Economy, Trade and Industry of Japan (2025), METI Statistics.

India's gas consumption is set to continue to grow at a rapid pace in 2025

Estimated year-on-year change in gas demand in India, 2022-2025



* Including transport by pipeline and CNG consumption.
Sources: IEA analysis based on Petroleum Planning and Analysis Cell (2024), Sectoral Consumption.

European natural gas consumption increased marginally in 2024 compared to 2023…

Natural gas consumption in OECD Europe rose by an estimated 0.5% (or 2.5 bcm) in 2024. The demand reduction recorded in the first half of the year (down by 4% y-o-y) was more than offset by the strong demand growth recorded in Q4 2024. Preliminary data suggest that European gas consumption rose by 9% (or over 10 bcm) y-o-y in Q4 2024 – its strongest year-on-year quarterly growth since Q2 2021, when demand was recovering following the Covid-induced lockdowns. Colder weather, lower wind power output in November and the continued recovery in industrial gas use supported higher natural gas consumption in Q4 2024.

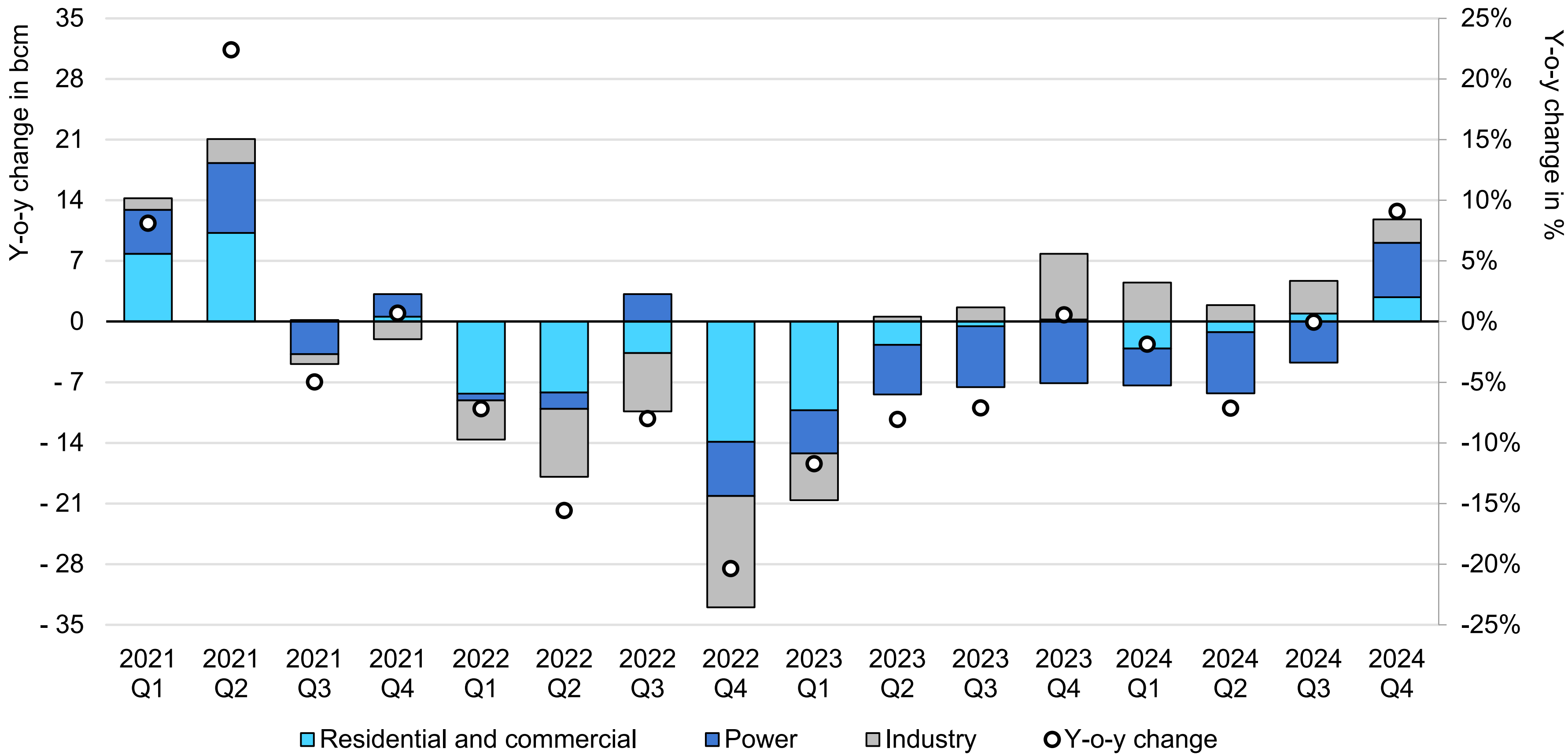
Distribution network-related demand remained close to its 2023 levels, as lower space heating demand in Q1 2024 was offset by stronger gas use in the residential and commercial sectors in Q4 2024. Mild winter weather conditions in Q1 2024 naturally weighed on space heating requirements in buildings and reduced residential and commercial demand by 4% y-o-y. Residential and commercial gas demand continued to decline in Q2, then recording a modest year-on-year increase in Q3, primarily driven by stronger gas use by commercial entities. Heating degree days increased by 5% y-o-y in Q4 2024, which drove up space heating requirements in the residential and commercial sectors. First data suggest that distribution network-related demand rose by 5% (or 3 bcm) y-o-y in Q4 2024. Estimated heating intensity (gas use per heating degree day) rose by 7% y-o-y in 2024, potentially indicating behavioural changes less conducive to gas demand savings.

Gas-to-power demand plummeted by nearly 8% (or 10 bcm) in 2024, with the reduction primarily concentrated in Q1-Q3. The steep decline in gas-fired power output was primarily driven by the strong increase in renewable electricity generation, which rose by almost 10% (or near 150 TWh) in 2024. In contrast with the rest of the year, slow wind speeds in November 2024 led to a sharp decline in wind power output, declining by 16% (or 10 TWh) y-o-y during the month. Gas-fired power plants played a key role in providing backup to the power system by increasing their output by nearly 40% (or over 15 TWh) y-o-y. Natural gas consumption in **industry** continued to recover in 2024, benefiting from the lower price environment. Gas use in industry increased by an estimated 9% (or 10 bcm) in 2024, albeit remaining 10% below its 2021 levels.

This **forecast** projects natural gas demand in OECD Europe to remain close to its 2024 levels, as lower gas burn in the power sector is expected to offset stronger gas use in the residential and commercial and industrial sectors. The continued expansion of renewables is projected to reduce gas-to-power demand by around 10% in 2025, while gas demand in the residential and commercial sectors is expected to increase, assuming average winter weather conditions. Gas use in industry is forecast to increase marginally, as demand recovery slows amid a higher gas price environment.

…with growth primarily concentrated in Q4 2024

Estimated year-on-year change in quarterly natural gas demand in OECD Europe, 2021-2024



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 is set to accelerate in 2025, but the market balance remains vulnerable

LNG market growth improved slightly in 2024 from the record low experienced in 2023, albeit remaining far below the recent historical average. Few liquefaction projects came online – reflecting a relatively slim project pipeline as well as project delays – and a number of existing projects faced performance and feedgas issues. Global LNG trade grew by about 2.5% (or 13 bcm), supported predominantly – but not solely – by North America and the Asia Pacific region on the supply side. The Asia Pacific region was also central to demand-side dynamics, with imports growing by the largest volume since 2018. European LNG imports, conversely, fell by a record and almost equal volume. In 2025 new liquefaction projects are expected to push LNG market growth to close to 5% (or 26 bcm).

From 2018 to 2023, North America was the largest contributor to annual LNG supply growth. However, incremental volumes from the region fell to their lowest in nearly ten years in 2024 as only two new projects came online. Altamira LNG (2 bcm/yr capacity) in Mexico started exporting in August and Plaquemines LNG (27 bcm/yr capacity) exported its first cargo only in late December 2024. In fact, higher incremental volumes came from better performance at existing projects than from new projects in 2024. Sabine Pass LNG and Freeport LNG were key drivers of these incremental volumes, having recovered from major scheduled maintenance in 2023 (for the former) and a complete restart in Q1 2023 (for the latter). Despite improved utilisation rates, Freeport LNG continued to face sporadic outages in 2024, keeping exports well below nameplate capacity. In total, North American LNG exports were up by about 3.6%, or just over 4 bcm.

Asia Pacific LNG exports were also up by nearly 5 bcm (or 2.7%) after four years of lacklustre dynamics. Australia, the world's third-largest exporting country, contributed to the upside, thanks notably to Prelude FLNG recovering from significant maintenance downtime in H2 2023. However, Indonesia and Malaysia both contributed even more to incremental exports. The start of Tangguh LNG train 3 in late 2023 drove Indonesian exports up by 9.5% in 2024, and Malaysian exports were up by over 5.5% as new upstream projects supported feedgas volumes.

Russia and the Middle East each contributed around 3 bcm of incremental LNG supply in 2024. In Russia a heavy maintenance schedule at Yamal LNG and debottlenecking works at the Vysotsk LNG plant, both taking place in 2023, improved output in 2024. In the Middle East the majority of incremental supply came from the United Arab Emirates.

Finally, Africa was the only region to see a significant net decrease in exports, although country-specific dynamics were varied. On the upside, improved feedgas availability helped drive Nigerian LNG exports up by 5% (or by1 bcm), while improved operations at Coral South LNG in Mozambique (after starting up in late 2022) also led to 1 bcm (or 29%) of incremental supply. The start-up of Tango FLNG in Congo also added 0.5 bcm to the global balance. Downside factors were stronger, however, ultimately leading to a net drop in exports of 2.7 bcm for the region as a whole (down 5%). Egypt was the primary factor, with output falling by 3.5 bcm (or 78%) as exports had completely ceased by May 2024 due to a combination of stronger domestic demand and production constraints. Similar dynamics pared back Algerian LNG exports by nearly 2 bcm (or 10.5%).

On the import side, the market saw a significant shift in 2024. LNG import growth in the Asia Pacific region more than doubled from 2023 levels, reaching 9.3% (or 32 bcm) y-o-y, the largest volumetric increase since 2018. China remains the largest contributor to growth in the region (and globally). Its imports grew by 11% (or 10.5 bcm) as the second pillar of broader supply growth in the country (behind domestic production growth, but ahead of pipeline imports).

Indian LNG imports grew by a record amount of over 6 bcm (up 21%) in 2024 thanks to robust demand for RLNG (regasified LNG) in the city gas distribution and oil refining sectors, as well as softer domestic gas production dynamics. Other emerging LNG importing markets in the region, while individually small, together drove another 8.4 bcm (up 18%) of incremental LNG imports.While market drivers in each of these countries remained diverse, a pan-Asian heatwave (driving power sector gas burn) and gas price benchmarks below prior-year levels for much of H1 2024 were key to the broader market context and a return to spot buying.

Outside the typical Asian growth markets, Japan and Korea returned to LNG import growth in 2024, despite both representing mature markets with low to negative demand growth trajectories. While Japanese imports grew by just 1.3% (or 1.2 bcm), Korean imports soared by nearly 7% (or 4 bcm). Again, heatwaves drove strong cooling demand for which gas-fired power plants provided significant upside flexibility, despite continued growth in nuclear generation. This 2024 hiccup in an otherwise more subdued trend for these markets is a clear reminder of the degree of demand volatility that can occur in any given year, and not just in Asia.

On the flipside of the strong Asian pull on the LNG market, European buying dropped significantly. Underground storage levels ended March 2024 at record highs, natural gas demand continued to fall in 2024 (due notably to improved nuclear availability and growing renewable power generation eating into power sector gas burn) and pipeline gas imports were up on 2023 levels (particularly from Norway). Taken together, these elements led to a 29 bcm (or 18%) drop in LNG imports. Northwestern Europe and Iberia led the charge, with the United Kingdom alone reducing its take by 9 bcm (or 46%) y-o-y.

Market movements in other continents were far smaller in volume terms, but remained significant in a regional context. Mirroring a drop in LNG exports, African LNG imports soared by close to

3.5 bcm from near-zero levels in 2023, driven almost exclusively by Egypt as the country's domestic gas balance deteriorated year-on-year.

Dynamics in Central and South America also netted only a small shift in volumetric terms, but Brazil and Colombia offered another case study in demand-side volatility. With droughts significantly curtailing hydropower output, gas-fired power generation provided upward flexibility, leading to combined growth in LNG imports of close to 200% (or 4 bcm). Argentina helped ease some of the demand-side pressure as growing domestic shale gas production led to a 45% (or 1.2 bcm) drop in LNG imports.

Finally, Middle Eastern imports were up by 21% (just over 2 bcm) y-o-y as Jordanian LNG imports grew more than fivefold – with most of these volumes being piped to Egypt – and power sector gas burn drove Kuwaiti imports.

2025 is set to bring about a shift in global LNG market dynamics as more liquefaction projects ramp up or come online and as pipeline supply risks in Europe lead to a return to growth in LNG imports for the region. Under the assumption that Ukrainian transit of Russian pipeline deliveries to Europe does not resume following the lapse of the previous transit agreement, Europe is set to balance its market by taking in around 16% (or 21 bcm) more LNG y-o-y in 2025.

Asia Pacific LNG imports are set to grow by about 2.5% (or 9 bcm) in 2025, growth about a quarter that of 2024, as the global market remains somewhat constrained, reviving strong cross-basin competition for cargoes that had eased in 2024. Emerging Asian LNG markets are likely to feel this pressure, leading to less spot buying and a slowing of LNG import growth to about 6.5% (compared to 18% in 2024). China and India are also expected to see their growth slow (7% and 10%, respectively, vs 11% and 21% in 2024), in line with more tempered natural gas demand growth and continued competition for cargoes internationally.

On the supply side, North America is set to become the second-largest exporting region in 2025, ahead of the Middle East and behind Asia Pacific, with liquefaction projects ramping up across the United States, Canada and Mexico. US LNG exports are expected to grow by 14% (or nearly 17 bcm) as Plaquemines LNG ramps up production from a December 2024 start and the Corpus Christi Stage 3 expansion (composed of seven 2 bcm/yr trains) progressively comes online. Better uptime at Freeport LNG should also drive some supply growth.

In Mexico, Altamira LNG is set to ramp up production following commercial start in Q3 2024, and the eponymous LNG Canada is expected to start exports in H1 2025.

Outside North America, relatively little net growth is expected at the regional level. African LNG exports are set to grow by about 4%, but provide only a little over 2 bcm of net incremental volumes. The start of Greater Tortue LNG (delayed from late 2024 to mid-2025) and Congo LNG (in late 2025), combined with the ramp-up of Tango FLNG in Congo (from a 2024 start), should lead to higher gross upside. However, Egypt is not expected to return to exports in 2025, taking about 1 bcm out of the balance and scaling back the continent's export growth. Furthermore, downside risks remain around Algerian LNG supply after a 10.5% drop in 2024, and around any further potential delays in bringing new liquefaction projects online regionally.

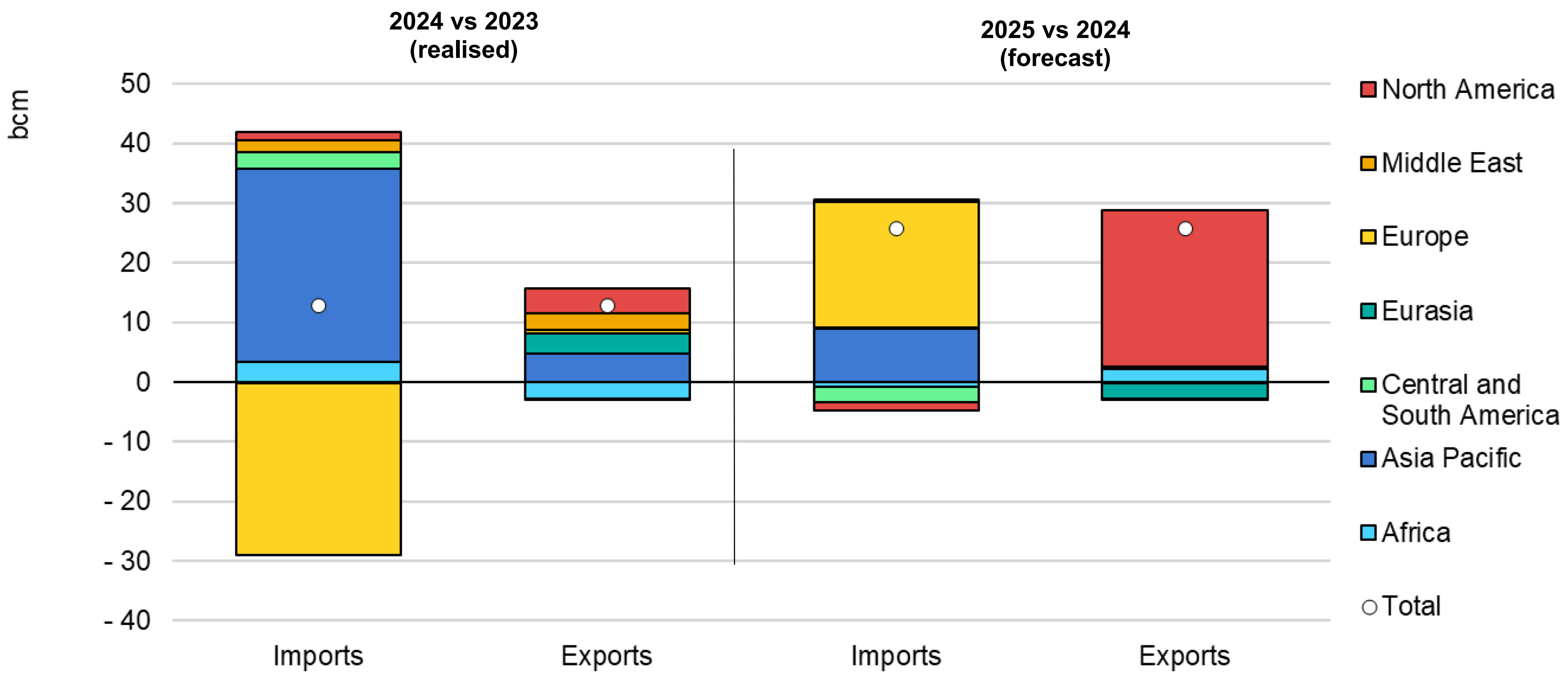
The only significant downside at a regional level is set to come from Russia after the country's two small-scale LNG export terminals (Portovaya and Vysotsk) were impacted by a fresh round of US sanctions in January 2025. These sanctions are likely to drastically reduce operations at these two plants as potential volumes would have a difficult time finding an import destination. As a result, Russia LNG expors could fall by around 5% y-o-y.

LNG supply from Asia, the Middle East and Latin America is expected to stay broadly stable year-on-year at the regional level, with relatively small upside and downside movements in individual markets.

Overall, LNG market growth is set to reach close to 5% (or about 26 bcm) in 2025, a net acceleration from 2024 levels. Nevertheless, the market balance remains vulnerable to further liquefaction project delays and to weather impacts across both major and minor importing regions. In short, the market is expected to remain highly sensitive to any new pressures – in both supply and demand – in 2025.

Europe is expected to return to LNG import growth as North America drives incremental supply

Year-on-year incremental LNG imports and exports by region, 2025 vs 2024



Source: IEA analysis based on ICIS (2024), ICIS LNG Edge.

Spot LNG charter rates dropped to historical lows amid excess shipping capacity

As global LNG trade volumes continue to expand, the ton-mile[2] metric has shown a consistent upward trend. In 2024 the ton-mile during the interseasonal periods (off-peak season) was marginally higher than in the previous year.

Despite persistent shipping constraints on routes via the Panama Canal and the Red Sea, spot LNG charter rates remained stable throughout 2024 and significantly below 2023 levels. Spot charter represents only a small fraction of the global LNG shipping market, but serves as a key indicator of market tensions. In the second half of 2024, quarterly average rates were more than 65% lower than 2023 levels. Specifically, in Q4 2024 the day rates for TFDE standard LNG carriers averaged USD 26 000 in the Atlantic (down 85% y-o-y) and USD 32 000 in the Pacific (down 80% y-o-y), reaching levels not observed since Q2 2020 during the Covid-19 crisis, when global LNG demand and the associated need for transport vessels plummeted.

During the fourth quarter of 2024, JKM-TTF spreads narrowed, as TTF month-ahead prices rose in response to perceived supply risks despite ample European gas storage. Even when Asian LNG prices caught up and were at a slight premium to TTF, when factoring in freight and other costs, it remained marginally more profitable to deliver LNG from the United States to Europe than to Asia via the Cape of Good Hope, resulting in a series of cargoes being diverted from Asia towards Europe in late November. These diversions, along with commercial swaps and portfolio optimisation, improved vessel availability by reducing average voyage durations.

Another factor contributing to the historic low spot LNG charter rates in November 2024 was the absence of a steep contango. In the past two years a pronounced contango (where future prices are significantly higher than current prices) encouraged traders to store LNG on vessels, waiting to sell at higher prices later. This practice increased demand for LNG carriers, driving up charter rates. However, with a flatter contango in 2024, this incentive diminished, reducing the demand for floating storage and pushing spot charter rates to low levels.

In summary, the Pacific and Atlantic LNG shipping spot charter markets appear to have reached a new equilibrium, suggesting an adequate supply of LNG vessels in both basins.

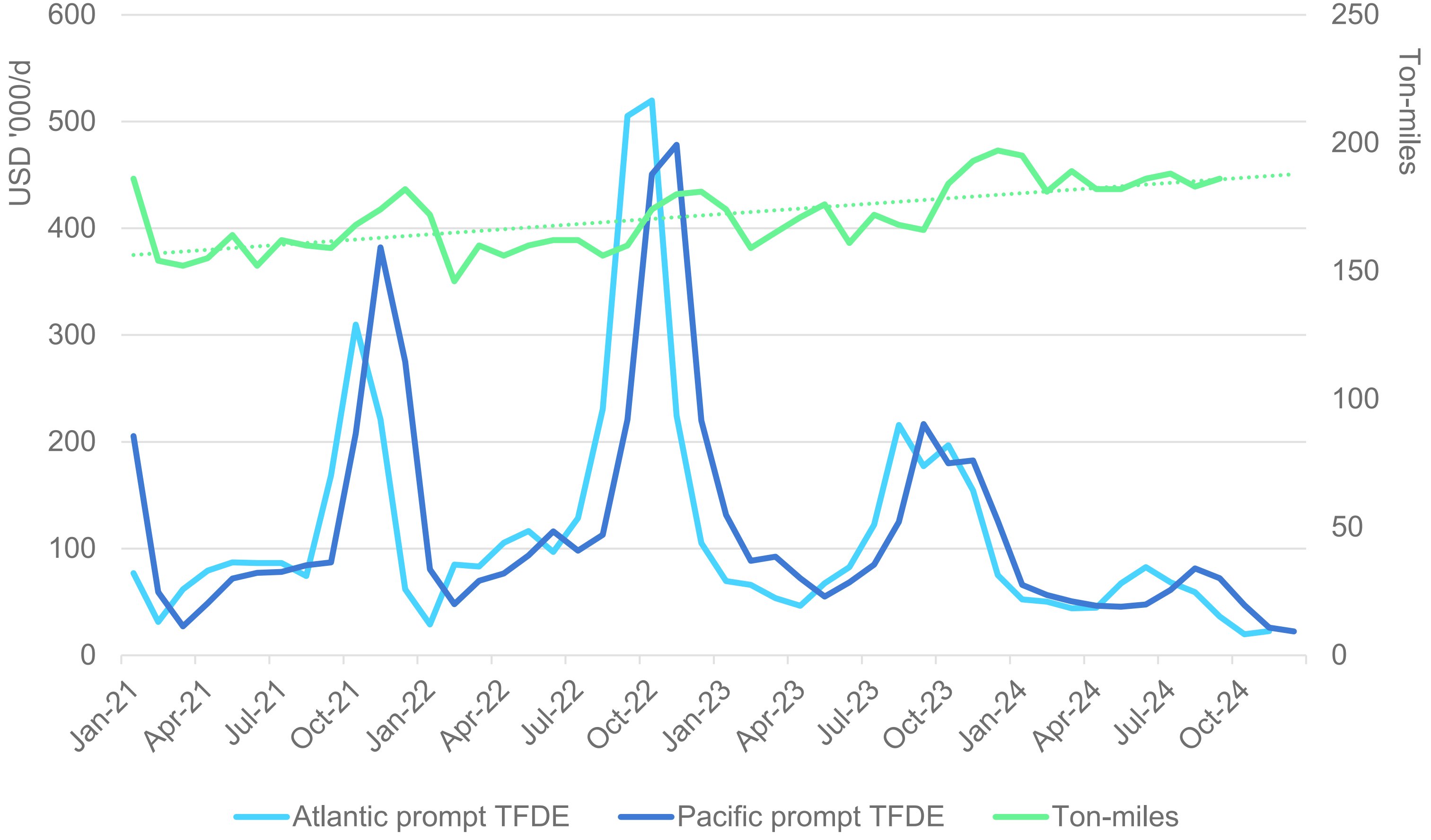
[2] Ton-mile is the tonnage transported multiplied by the distance transported, and is an indicator used to express the volume of activity of ships and other vessels.

In 2024 the fleet of LNG carriers expanded by an estimated 68 vessels, twice as many as in 2023, underscoring the accelerating growth in LNG transport capacity. Considering the current order book, the LNG carrier fleet is set to grow considerably over the next few years. This is in line with orders for newbuild ships, which are intended to meet the future needs of new LNG liquefaction projects, particularly in Qatar and North America, and to replace older ships with more efficient and lower-emission vessels. Delays at LNG production facilities, such as those already announced at Golden Pass in the United States, could result in a fleet of LNG carriers that is larger than is required for global LNG transport needs in 2025. As of December 2024, forward curves suggest that LNG charter day rates for standard TFDE vessels are projected to average USD 40 000 in 2025, down by 20% compared with their 2024 levels.

The continued expansion of the LNG carrier fleet, coupled with efficient utilisation and commercial swaps, has mitigated the impact of logistical disruptions without a dramatic price response. However, potential future challenges include geopolitical tensions in key regions, and sudden price spikes and temporary shipping shortages in the event of unexpected demand shocks, such as the January 2021 cold spell in Northeast Asia. These could suddenly disrupt global supply chains and affect market stability.

Spot LNG ship charter rates have declined despite increased ton-miles in Q4 2024

Average day rate for LNG carriers in Atlantic and Pacific basins and ton-mile metric, 2021-2024



Source: IEA analysis based on Spark Commodities.

After a flat 2024, US production growth is expected to rise on growing LNG exports in 2025

US dry gas production dynamics saw a clear change in 2024 as growth tapered significantly, the slowdown contrasting with a multi-year period of strong, near-continuous growth and representing a third extended period of rebalancing in ten years. Whereas output grew at a compound annual growth rate of about 4.6% from 2014 to 2023, production growth turned marginally negative in 2024 as a well-supplied market faced moderate domestic demand dynamics and weak LNG export growth.

In 2025 new liquefaction projects are expected to revive demand-side pressure and stimulate upstream activity, although dry gas production growth is expected to remain relatively modest at about 1%. Record high production levels in Q4 2023 and relatively benign winter demand – except for a recurring February cold snap – left the US market in a position of oversupply in the first half of the year. As Henry Hub prices slid to lows last seen in summer 2020, upstream operators implemented spending cutbacks, leading to a dip in production. In the Haynesville, where drilling costs are high in line with the depth of the resource play, dry gas output fell by about 13% (or 17 bcm) y-o-y in 2024, with year-on-year cuts in every month. Cutbacks in Appalachian Basin production were more mild and concentrated mostly in H1, totalling just 2% (or 6 bcm) over the entire year.

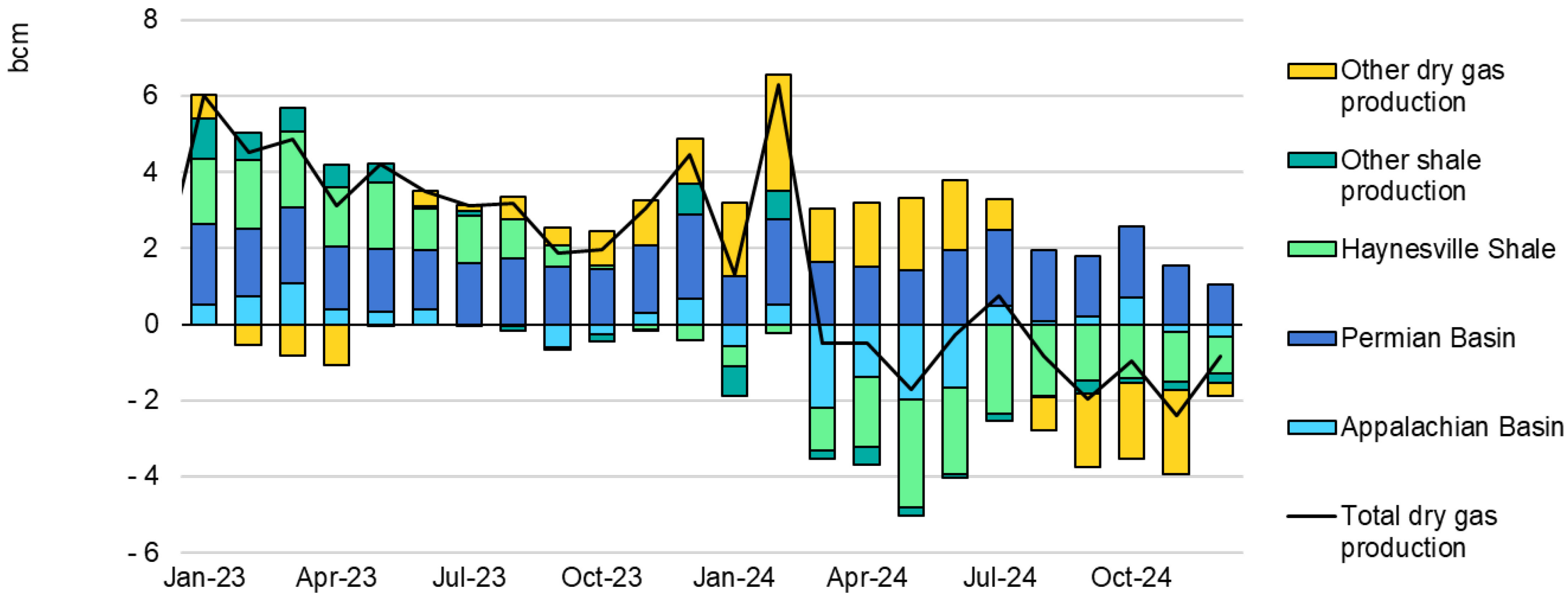
Dynamics in the Permian Basin were notably different as associated gas production was carried higher by strong oil market fundamentals. High crude prices kept Permian oil production on a robust growth path for the year, leading to 12% growth in gas production for the basin. Growth in other dry gas production was also notable, reaching above 3% (or 6 bcm).

These contrasting upstream dynamics netted a marginal drop in production in 2024 of about 0.2%, compared with a 0.3% easing in 2020 amid the Covid-19 demand shock and a 1.7% drop in 2016 as a result of a precipitous fall in oil and gas prices weakening supply-side fundamentals. With more robust demand-side drivers expected in 2025, the 2024 rebalancing is set to give way to firmer production fundamentals in 2025.

US LNG exports are expected to grow by about 14% y-o-y in 2025 as new liquefaction projects and expansions are scheduled to come online. The ramping up of two LNG projects in Mexico using piped gas from the United States will add further demand-side pressure to the US market. US dry gas production is set to grow by a little over 1% in 2025 as oil market dynamics keep Permian gas production on an upward trend and the unwinding of upstream CAPEX cuts leads to more positive fundamentals in Haynesville and Appalachian production. Key pipeline completions in 2024 are also set to help Permian and Appalachian throughput. However, the return to production growth could yet prove bumpy as exploration and production actors measure increased spending against Henry Hub price expectations.

2024 US dry gas production trends contrasted with strong fundamentals of previous years

Year-on-year change in monthly dry gas production in the United States, 2022-2024



Notes: November and December 2024 include estimated data.
Sources: IEA analysis based on EIA (2025), Natural Gas Data; Natural Gas Weekly Update.

Eurasian natural gas production returned to growth in 2024…

Eurasia's natural gas production declined by 13% (or 130 bcm) between 2021 and 2023. This steep decline was primarily driven by Russia and its collapsing piped gas deliveries to Europe, and to a lesser extent by deteriorating upstream deliverability in Uzbekistan. The region's gas output started to gradually recover in the second half of 2023 and preliminary data indicate that Eurasia's natural gas production rose by 5.5% (or 45 bcm) in 2024, albeit remaining 9% (or 85 bcm) below its 2021 levels. The recovery in 2024 was supported by a combination of stronger domestic demand and higher exports.

Russia's natural gas production plummeted by 15% (or 125 bcm) between 2021 and 2023. Lower piped gas exports to Europe accounted for around 95% of this steep decline. First data suggest that 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 over 35% y-o-y, with total deliveries for the full year reaching over 31 bcm. Piped gas deliveries to Europe rose by an estimated 7% y-o-y. In addition, Russia has been ramping up its piped gas exports to Uzbekistan via Kazakhstan through the Central Asia-Centre pipeline system. Russia and Uzbekistan signed a contract in June 2023 for the initial supply of 9 mcm/d starting from October 2023, although it is understood that volumes significantly increased in 2024.

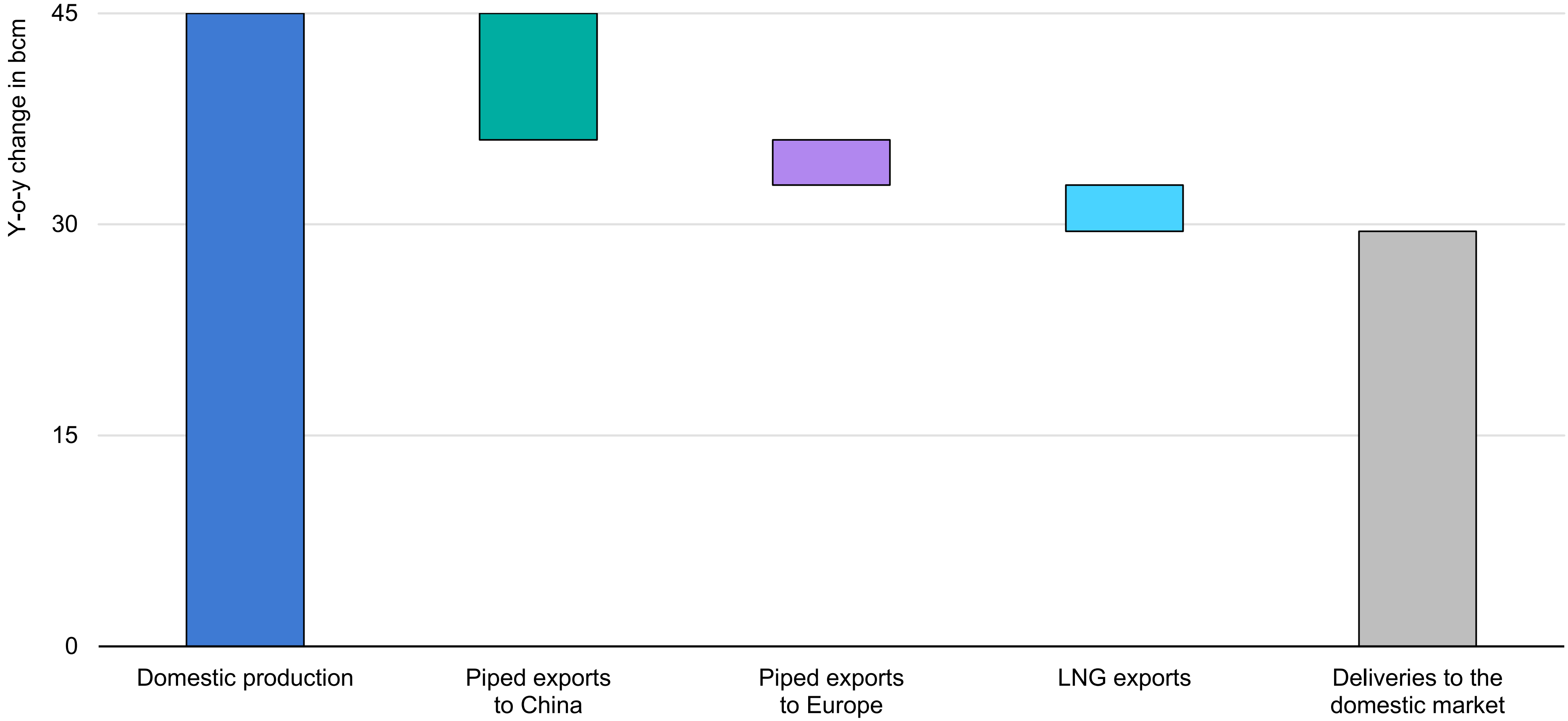
Russia's LNG output increased by 8% (or over 3 bcm) y-o-y in 2024, with Asia accounting for around half of total Russian LNG exports. Gas deliveries to the domestic market increased by an estimated 4.5% (or around 23 bcm) in 2024. This was partly supported by colder than average winter weather, which drove up space heating requirements in Q1, stronger thermal power generation (up by 3.7% y-o-y in the first 11 months of 2024) and higher gas use in industry.

Natural gas production displayed varying patterns across Central Asian countries. In Turkmenistan natural gas production remained broadly stable in 2024 at just over 80 bcm. In contrast, natural gas production in Uzbekistan declined by 4.5% (or 2 bcm) y-o-y in the first 11 months of 2024, reflecting deteriorating upstream deliverability in the country. In Kazakhstan estimated sales gas production declined marginally by 1% (or 0.3 bcm) y-o-y in the first 11 months of 2024, and in the same period sales gas production grew by 6% (or 2 bcm) y-o-y in Azerbaijan. This was partly supported by higher deliveries to Europe, which increased by 6% (or 1.25 bcm) y-o-y during the same period of the year.

This forecast expects Eurasia's gas production to increase by 1.5% in 2025, and remaining almost 10% below its 2021 levels. Russia is projected to account for the bulk of the growth in 2025, with higher gas production supported both by domestic demand and exports to China and Central Asia.

…supported both by stronger domestic demand and higher exports

Estimated year-on-year change in natural gas production in exports and deliveries to the domestic market in Eurasia, 2024 vs 2023



Sources: IEA analysis based on ENTSOG (2024), Transparency Platform; ICIS (2025), LNG Edge; and various news sources.

Europe’s primary gas supply fell by 4.5% in 2024…

OECD Europe’s primary natural gas supply fell by an estimated 4.5% (or over 20 bcm) in 2024. High storage levels reduced storage injection needs through the summer, which together with lower gas consumption and higher piped gas imports weighed on the region’s LNG imports. The region’s domestic production continued to decline.

Europe’s **LNG imports** declined by 18% (or close to 30 bcm) in 2024. The continued demand decline in H1 2024, together with lower storage injections over the summer and stronger piped gas deliveries kept European hub prices below Asian spot LNG prices in 2024. This in turn incentivised flexible LNG cargoes to flow towards Asia instead of Europe. LNG retained its position as Europe’s dominant source of primary gas supply although its share declined from 37% in 2023 to 32% in 2024. LNG flows from the United States fell by 18% (or 14 bcm) in 2024, although **the United States kept its position as Europe’s largest LNG supplier** with a share of 47% in Europe’s total LNG imports. LNG flows from Qatar declined by 30% (or 6 bcm) y-o-y, as flows were redirected towards the more lucrative Asian markets. In contrast, **Russian LNG** inflows rose by 17% (or 3 bcm) y-o-y, solidifying Russia’s position as Europe’s second-largest LNG supplier. Russian LNG deliveries remain highly concentrated. Belgium, France and Spain accounted for 85% of Europe’s total LNG imports from Russia in 2024.

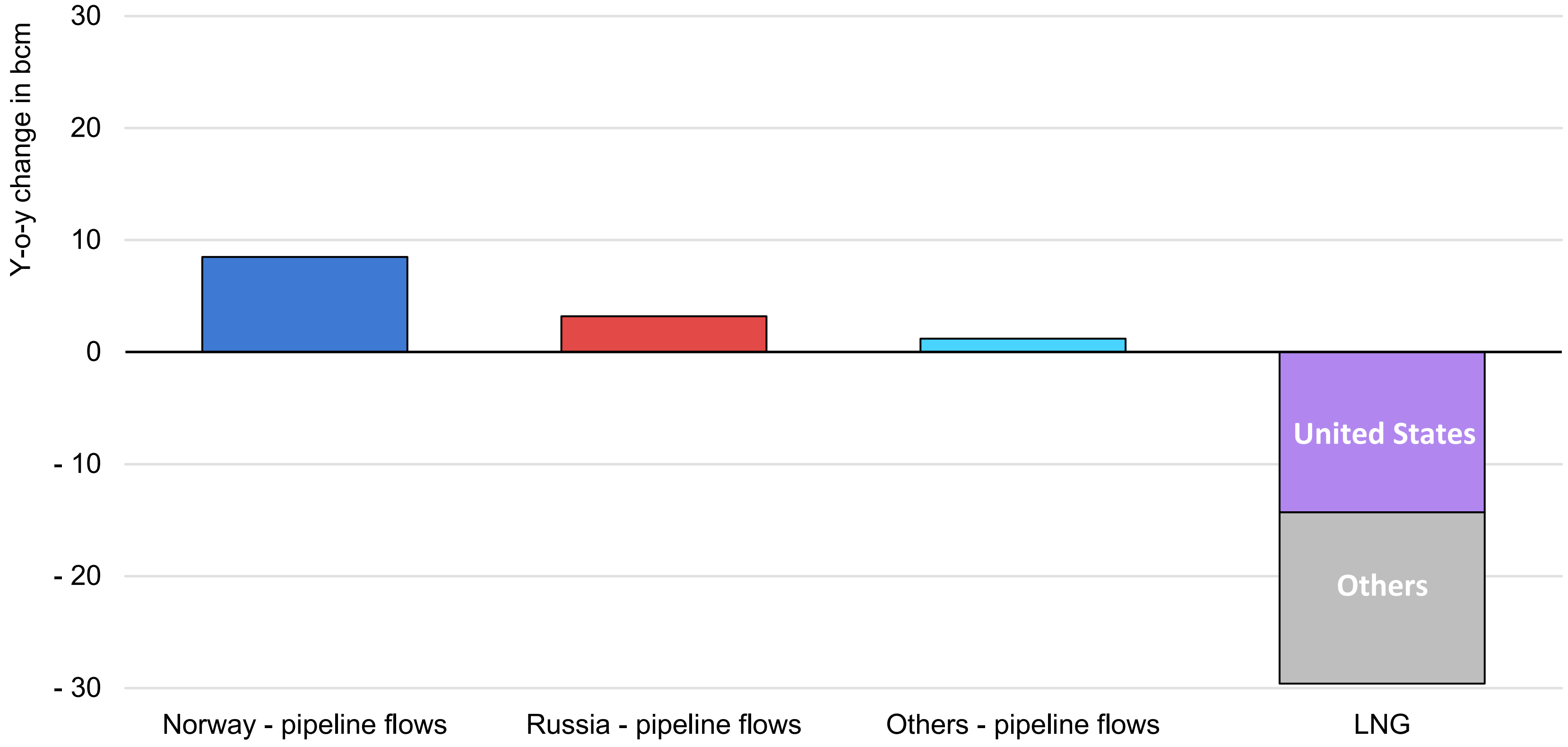
Norway’s piped gas deliveries to the rest of Europe increased by 8% (or 8.5 bcm) in 2024 amid a lower level maintenance works. **Non-Norwegian domestic production** fell by around 6% (or 4 bcm) y-o-y in the first ten months of 2024. This decline was primarily driven by **Netherlands** and the **United Kingdom**. In contrast, Türkiye’s natural gas production rose by more than threefold to near 1.8 bcm in the first ten months of 2024, amid the continued ramp-up of the Sakarya field in the Black Sea.

Russia’s piped gas supplies increased by an esimated 7% (or 3 bcm) in 2024 -albeit remaining 70% below their 2021 levels. Deliveries to the European Union rose by more than 12%. The share of Russian piped gas in Europe’s gas demand stood just above 10% in 2024. Piped gas deliveries from **North Africa** fell by 6% in 2024, while **Azeri flows** via the TAP pipeline remained close to their 2023 levels.

Russia’s gas transit flows via Ukraine halted on 1 January 2025 and this **forecast** does not assume their restart. This would translate into a decline of 13 bcm of Russian piped supplies to the European Union compared to 2024. Lower Russian piped gas supplies, together with the expected increase in gas demand is forecast to increase Europe’s LNG imports by more than 15% in 2025.

…with the region's LNG inflows plummeting by 18% compared to last year

Y-o-y change in OECD Europe's natural gas imports and deliveries from Norway, 2024 vs 2023



Sources: IEA analysis based on ENTSOG (2025), Transparency Platform; Eurostat (2025), Energy Statistics; Gas Transmission System Operator of Ukraine (2025), Transparency Platform; ICIS LNG Edge; JODI (2025), Gas World Database.

Gas production in the Middle East continues to grow in the face of geopolitical tensions

The Middle East has historically been one of the main engines of global gas production growth. Five countries, representing 85% of the region's gas output, are expected to add more than 20 bcm of production between 2023 and 2025, marking a 3.3% increase over the two-year period.

Iran's gas production growth is estimated at less than 2% in 2024 and just over 1% in 2025, driven by a series of gas capture projects aimed at reducing flaring and incremental production increases at South Pars Phase 11.

Qatar saw a 2% production decline in 2024 due to shrinking domestic consumption amid the country's rapid solar PV rollout. Given the lower domestic demand and strong export prospects, Qatar is undertaking the Barzan Gas Diversion Project to direct feedgas flows to the country's LNG export facilities from the Barzan processing plant, which started operation in 2020 and was initially dedicated solely to the domestic market. Gas production in 2025 is expected to remain broadly flat as Qatar's next major expansion project at North Field East is not expected to start up before 2026.

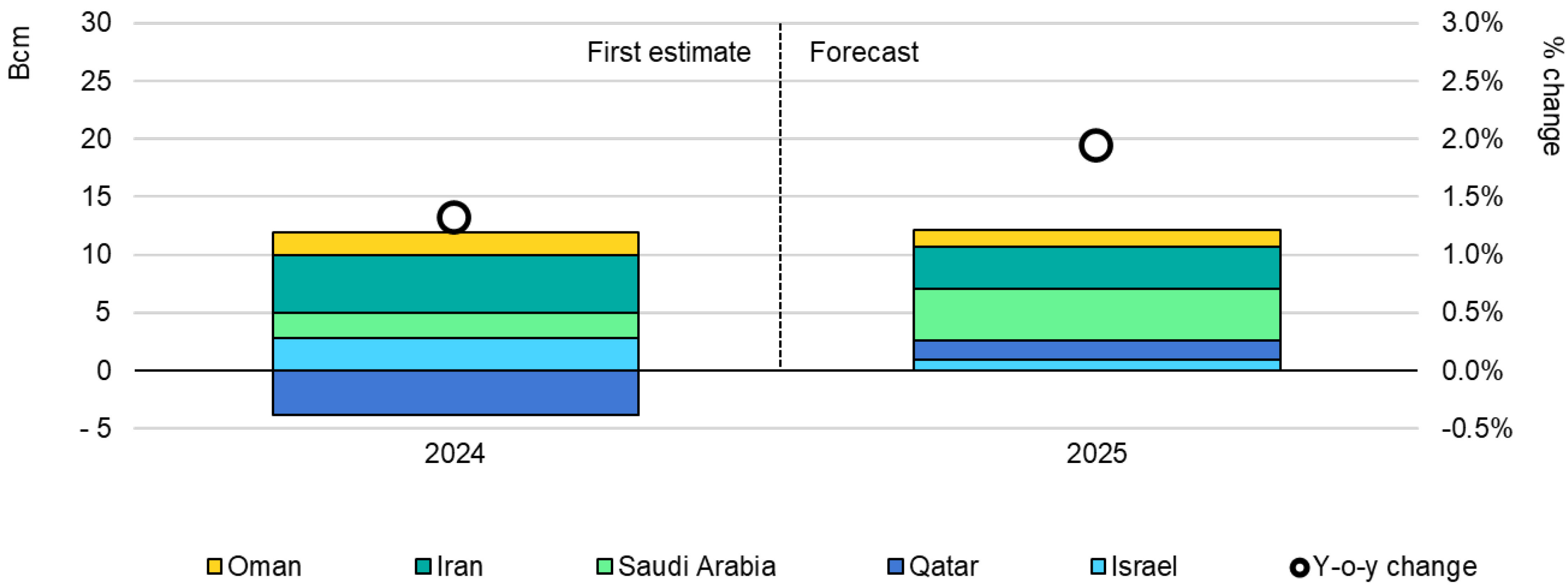
Saudi Arabia's gas production increased by an estimated 2% in 2024, thanks largely to the full-year impact of production from the Hawiyah Gas Plant expansion project and the first phase of the South Ghawar unconventional development, both of which came online in late 2023. Gas production is projected to grow by 4% in 2025, driven by the planned start-up of the Jafurah Phase 1 (2 bcm/yr) and Tanajib (27 bcm/yr) projects over the course of the year.

Oman increased its natural gas output by more than 4% in 2024, and it is projected to register further growth of 3% in 2025 as production from Block 10 continues to ramp up and the ongoing debottlenecking of the domestic gas grid enables higher production from existing fields.

Israel's gas production increased by 11% to an estimated 27 bcm in 2024, and it is projected to grow by another 4% in 2025 to nearly 28 bcm. Production at the Tamar field bounced back in 2024 from a 2023 dip caused by a month-long emergency shutdown in Q4 2023 during the early stages of the war in Gaza. Output from Leviathan also recovered strongly from a temporary production curtailment in 2023 due to infrastructure bottlenecks, and the Karish field resumed its ramp-up despite the ongoing **fighting** in Gaza and Lebanon and tensions with Iran during much of 2024. However, the expansion projects at the Tamar and Leviathan fields (adding a combined 7 bcm/yr of production capacity) have been delayed by at least six months due to the conflict and are now expected to be completed only at the end of 2025. This will keep production growth in 2025 relatively modest compared to the previous year.

Middle Eastern gas production in 2024-2025: Modest gains amid delays

Yearly gas production growth in selected Middle Eastern countries, 2024-2025



Africa's top natural gas producers are balancing production with domestic energy needs and LNG export requirements

Despite significant natural gas reserves, almost 9% of the world total, Africa continues to experience weak production growth, primarily due to insufficient investment in the sector. Depressed upstream activity limited Africa's natural gas demand growth to below 1% in 2024. The continent's gas demand is forecast to increase by 2% in 2025.

In recent years, **Egypt**'s natural gas production has been hit by a steady decline in output from its largest field, Zohr. In the first ten months of 2024, Egypt's domestic gas production fell by 15% (or 7 bcm) y-o-y. As a result, Egypt has shifted from being a net exporter to a net importer of LNG in 2024, aided by the restart of the Ain Sukhna FSRU and the use of the Aqaba regasification facility in Jordan. Egypt has also been increasing its piped gas imports from Israel, which grew by 20% (or 5 bcm) y-o-y in the first ten months of 2024 and accounted for 15% of Egypt's primary gas supply. To prioritise domestic energy needs, especially during the peak summer months, Egypt has significantly reduced LNG exports, leading to a decline of close to 80% y-o-y in 2024, with exports curtailed since May. To address the shortfall in gas for power generation, Egypt has launched five emergency tenders since June as a temporary fix, the latest of which was awarded for Q4 delivery, for a total of 20 LNG cargoes. In 2024, Egypt imported the highest LNG volumes in seven years. However, Q4 deliveries fell well below the planned 20 LNG cargoes, with only 12 cargoes – including those via Jordan – or 1.8 bcm, discharged since October. The state-owned EGAS postponed some LNG deliveries from late 2024 to early 2025, affecting four shipments so far. Additionally, a planned tender for Q1 2025 cargoes is now likely to be delayed and seek fewer than the 20 cargoes originally envisaged. Although the LNG import slump in Q4 appears to be largely due to lower demand since mid-November, volumes have also been constrained by technical problems at the 5.5 bcm/yr Hoegh Galleon FSRU, moored at Ain Sukhna since late June. In late November 2024, Egypt's energy ministry announced a reassessment of LNG import needs due to vessel diversions and the need to cut costs. The ministry emphasised the importance of minimising import costs while maintaining flexibility in the delivery schedule. Despite reports of operational issues at the Ain Sukhna FSRU, the ministry stated that the facility is operating smoothly.

Reflecting the priority that **Nigeria** places on LNG exports over domestic consumption, which accounts for less than half of its total gas production, the country remains Africa's leading LNG exporter. However, its LNG exports have faced a number of challenges in recent years, mainly due to upstream and security issues that have affected feedgas production. In 2024 Nigeria achieved its first year-on-year increase in full-year LNG exports since 2019. This positive trend was largely driven by strong spot sales, which helped boost overall export volumes. Specifically, LNG exports from Nigeria rose by 7% in 2024, which translates into an increase of 1.2 bcm y-o-y. This growth is significant as it marks a recovery from the previous declines and highlights the country's efforts to overcome the obstacles that have hampered its LNG production and export capabilities. Driven by the “Decade of Gas” initiative launched in 2021, Nigeria is poised to witness substantial investment from major international companies, with TotalEnergies planning a USD 750 million investment in a new gas project to boost LNG exports from the NLNG legacy plant, and Shell committing up to USD 1 billion over the next decade to develop Nigerian gas infrastructure.

In 2024 several key developments significantly benefitted **Algeria**'s gas and LNG markets, supporting increased production and international interest. Algeria's sales gas production has increased by 25% over the past four years, driven by reduced reinjection volumes and new greenfield developments. Notable projects include the Hassi Ba Hamou and Hassi Mouina fields, part of the southwest gas project, which have been brought onstream and are expected to add 4.5 bcm/yr of sales gas. Despite the decline in domestic gas demand in 2024, falling production puts pressure on exports, which fell by 6.6% to a four-year low of 48 bcm, with LNG down 10% y-o-y. Algeria remains a crucial supplier of natural gas to Europe, particularly Spain and Italy, while the government aims to diversify the country’s energy mix to avoid over-reliance on natural gas, with a target of 22 GW of installed renewable capacity by 2030. From an exploration perspective, Algeria signed six new contracts under improved financial and tax conditions set by the government, attracting investment of over USD 7 billion. The country has also signed 14 memoranda of understanding (MoUs) with foreign oil and gas companies, indicating a significant shift in investor interest. The country is leveraging its strategic location to expand LNG and pipeline exports, supported by new gas supply deals and exploration drilling by global majors. In November 2024 Algeria launched its first gas field licensing round in a decade, backed by a reformed hydrocarbon law, to attract global energy investors. This move aims to revitalise Algeria's upstream sector and provide a long-term alternative to meet European gas demand, especially in light of the reduced Russian gas supplies following its full-scale invasion of Ukraine. The bid round includes six onshore blocks, with a strong focus on expanding Algeria's gas resources. Algeria has an estimated 480 bcm (17 trillion cubic feet [Tcf]) of undeveloped conventional resources. The development of these resources, combined with infrastructure-led exploration, could extend Algeria’s sales gas growth into the 2030s. Unconventional gas, particularly shale and tight gas, holds enormous potential, likely in the hundreds of Tcf. However, commercial viability remains a challenge due to high costs and slow operational approvals. ExxonMobil and Chevron have signed MoUs to evaluate and develop these opportunities.

Asian and European gas prices stood at more than double their historic average in Q4 2024

Natural gas prices recorded gains across the key Asian and European import markets in Q4 2024 compared to the previous quarter amid tighter market fundamentals and continued supply uncertainty. In the United States spot prices at Henry Hub remained at multi-year lows.

In **Europe**, TTF spot prices soared by 18% on the quarter to an average of near USD 13.5/MBtu in Q4 2024 – more than double their Q4 average during the 2016-2020 period. Higher natural gas demand (up by 9% y-o-y) combined with lower LNG inflows (down by 12% y-o-y) and continued uncertainties around Russian piped gas flows all provided upward pressure on prices. Gazprom halted commercial gas deliveries to Austria's OMV in the second half of November following an arbitration award in favour of OMV. TTF month-ahead prices rose by more than 7% during 13-18 November, following OMV's statement on a potential halt of supplies. While Gazprom stopped commercial gas deliveries to OMV, its overall physical gas flows to the European Union remained intact.

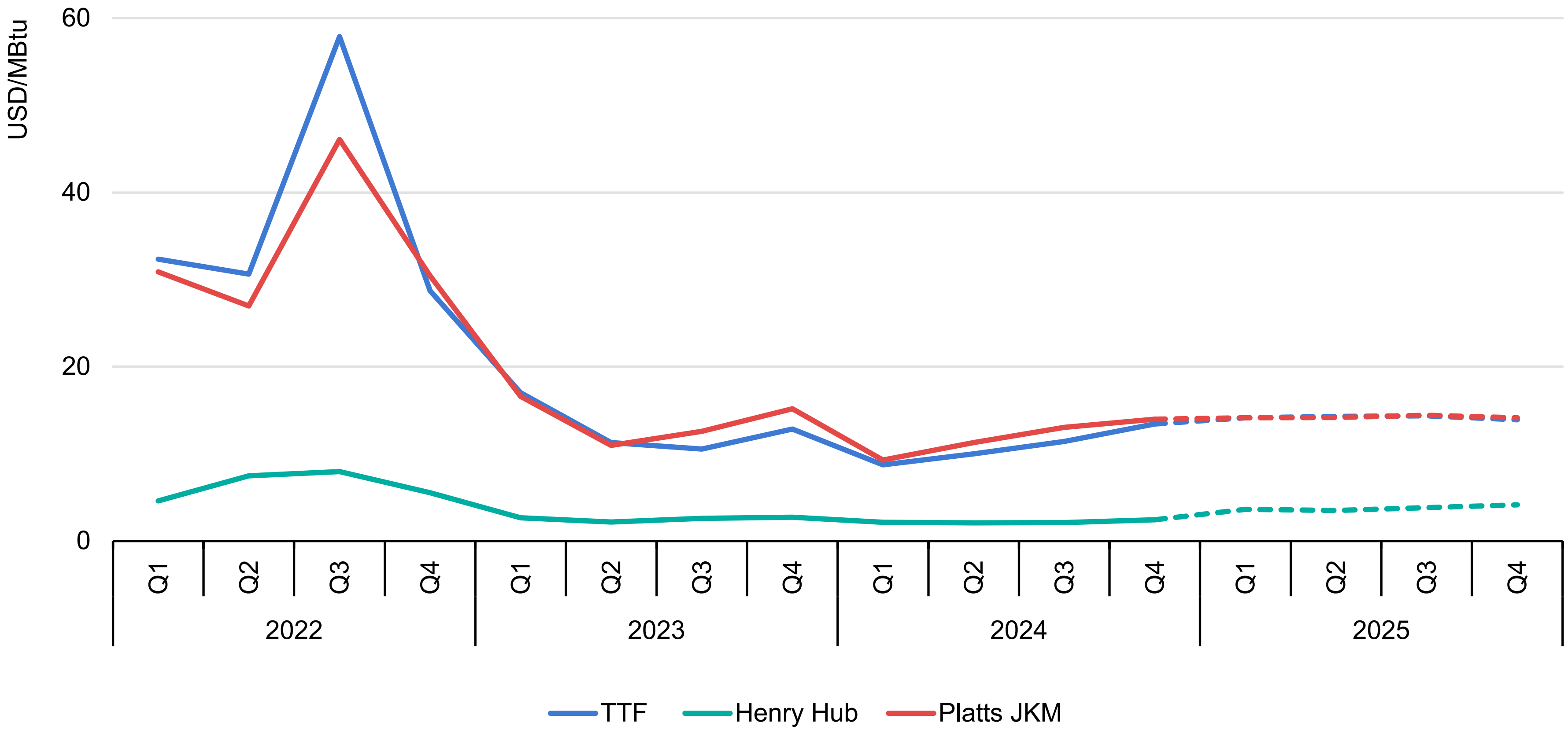
In **Asia**, Platts JKM prices followed a similar trajectory and rose by 7% on the quarter to an average 14/MBtu in Q4 2024 – as in Europe, more than double their Q4 average during the 2016-2020 period. Although continued demand growth and stronger competition with Europe for flexible LNG cargoes provided upward pressure on Asian spot prices, the JKM premium over TTF collapsed from an average of USD 1.6/MBtu in Q3 to USD 0.5/MBtu in Q4. This incentivised stronger LNG flows towards Europe at the expense of Asia in December, in sharp contrast with first 11 months of 2024.

In the **United States**, Henry Hub prices rose by 15% on the quarter and averaged USD 2.4/MBtu in Q4 2024 – their lowest Q4 average since 2019. Strong associated gas production, together with mild weather and relatively high storage levels, provided downward pressure on gas prices. Record high associated gas production and limited takeaway capacity kept Permian gas prices below an average of USD 0.6/MBtu in 2024 – their lowest Q4 levels on record.

Forward curves as of mid-January 2025 suggest that TTF prices could increase by 30% in 2025 compared with their 2024 levels and average at just over USD 14/MBtu. Higher storage injection demand through the summer, together with the halt of Russian piped gas transit via Ukraine and continuing competition with Asia for flexible LNG cargoes, are expected to support higher gas prices. Forward curves indicate that JKM prices could increase by 20% in 2025 to an average of just over USD 14/MBtu. The JKM price premium over TTF is expected to tighten from USD 0.9/MBtu to USD 0.1/MBtu in 2025, which is expected to incentivise stronger LNG flows towards Europe. Based on forward curves, Henry Hub prices in the United States are expected to increase by over 70% to average USD 3.8/MBtu amid tighter market fundamentals.

European hub prices are expected to trade close to Asian spot LNG in 2025

Main spot and forward natural gas prices, 2022-2025



Note: Future prices are based on forward curves as of mid-January 2025 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 Inc (2025), S&P Global Commodity Insights.

End-winter 2024/25 storage levels will be key signal for market balance through rest of year

Natural gas storage levels in key markets around the globe were in a robust position at the start of winter 2024/25, ensuring key balancing capabilities were available to regional gas markets and the global LNG market for the rest of the winter. However, steep withdrawals in Q4 2024, reduced Russian pipeline flows to Europe and the risk of concurrent cold spells across the northern hemisphere present bearish factors for storage fill in Q1 2025.

EU storage facilities entered winter above the regulatory 90% fill target by 1 November 2024, but below fill levels reached ahead of winter 2023/24. While volumes of gas in store stayed on a par with 2023 levels throughout much of Q3, injections tailed off in October, slowed by eight days of net withdrawals in the month (compared to none in 2023) as regasification send-out was down year-on-year and demand remained relatively stable. As a result, maximum volumes in store ahead of winter in 2024 remained about 4 bcm (4%) short of the maximum reached in 2023.

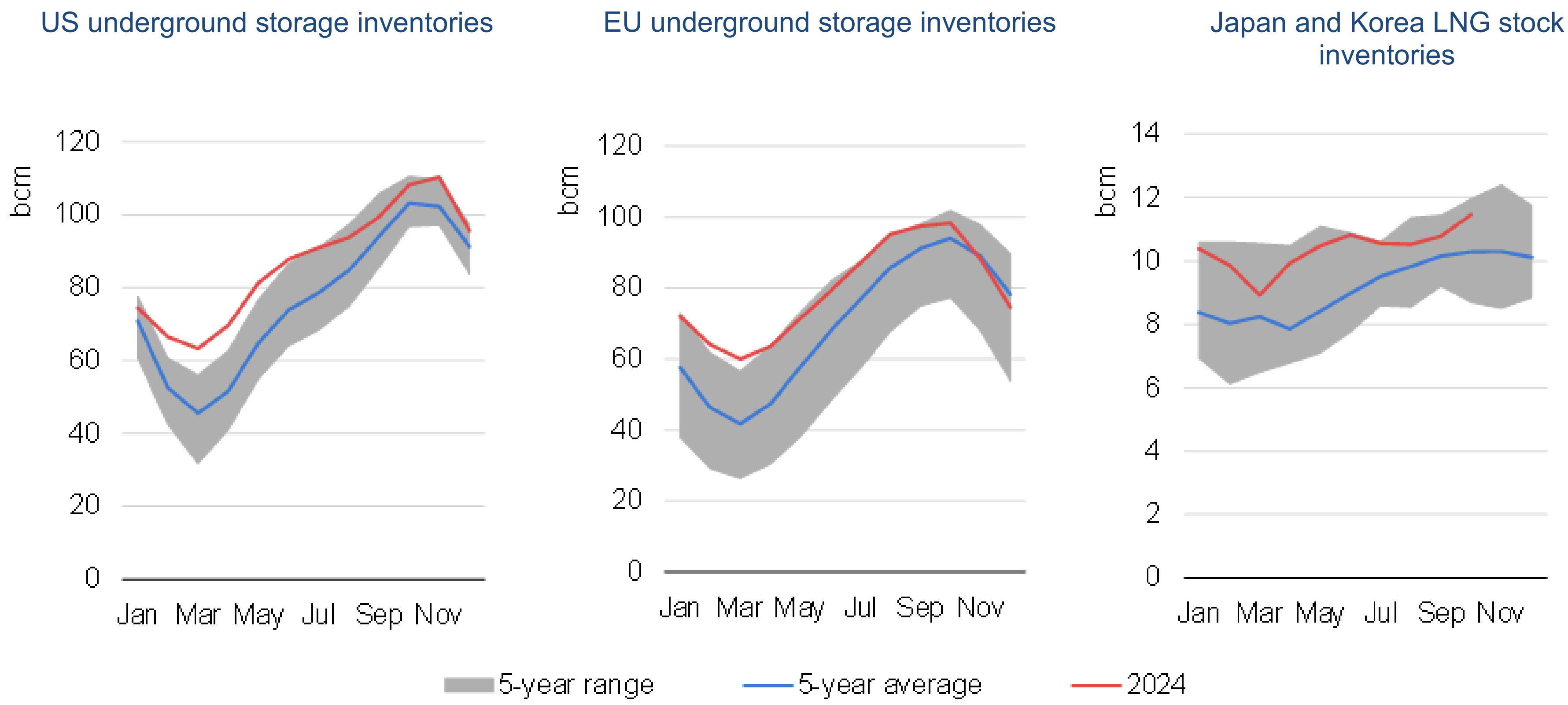
An early-November cold spell also led to an earlier and much more pronounced start to consistent net withdrawals, and despite withdrawal rates normalising by late November, 24 bcm of gas was withdrawn from EU storage sites from peak fill to the end of the year, compared with 14 bcm in 2023. EU storage levels entered 2025 down about 14 bcm (or 16%) compared with the start of 2024 (and just below the five-year average level) and were just 65% full by mid-January. Although volumes in store are likely to remain adequate to help balance volatility during the rest of the winter, low end-March storage fill – particularly in the case of supply disruptions and extended cold spells – could tighten the European balance for the rest of 2025.

In the United States exceptionally high storage fill at the end of the 2023/24 winter allowed volumes in store to track above 2023 levels for the whole of 2024, even as net injections in the filling season were 14% (or 8 bcm) below 2023 levels. Maximum fill levels – reached in mid-November – topped the five-year range (3% above the 2023 high point) and, despite strong December withdrawals, storage fill was above average at the start of 2025.

Beyond the typical uncertainty around winter weather patterns, the pace of US LNG and pipeline export growth – due to new US and Mexican liquefaction projects – could add further demand-side pressure to the US market. Depending on upstream reactivity to price signals, storage withdrawals could have an increased role in balancing the market and tempering volatility in Q1 2025.

LNG storage levels in Japan and Korea trended around 2023 levels from June to October thanks to strong LNG imports in both markets. By the end of October, their combined stocks remained close to the top of the recent historical range, providing a key buffer to volatility for the the winter months.

Strong Q4 2024 withdrawals bring storage fill back down toward or below average levels



Sources: IEA analysis based on EIA (2024), Weekly Working Gas in Underground Storage; GIE (2024), AGSI+ Database; IEA (2024), Monthly Gas Data Service; JODI (2024), Gas World Database.

Low-emissions gases

Biomethane and low-emissions hydrogen benefitted from a greater policy focus in 2024

Low-emissions gases (including biomethane, low-emissions hydrogen[3] and e-methane[4]) can play an important role in decarbonising gas supply chains and the broader energy system. Recognising their growing importance, the International Energy Agency has developed a **Low-emission Gases Work Programme** to track closely market developments in this sphere and facilitate dialogue between emerging producers and consumers. This section provides an overview of the key policy and market developments relating to low-emissions gases in 2024.

Biomethane

In the **United States** biomethane (also known as renewable natural gas or RNG) continues to benefit from increasingly stringent fuel requirements. In June 2023 the Environmental Protection Agency established biofuel volume requirements and standards for cellulosic biofuel (which primarily apply to biomethane) for 2023-2025 as part of the **Renewable Fuel Standard (RFS) program**. The new rule increased volume targets for cellulosic biofuel by 25% in 2023, 29% in 2024 and 33% in 2025 compared with the previous target. Based on the revised targets, US biomethane production could increase to around 4 bcm in 2025.

At the state level, in February 2024 **New Mexico** passed House Bill 41, which establishes a statewide programme known as the Clean Transportation Fuel Standards. The bill is scheduled for implementation in July 2026 and targets a 20% reduction in the carbon intensity of transport fuels by 2030 and a 30% reduction by 2040, compared to the state's 2018 baseline. New Mexico's clean fuel standards are expected to increase demand for RNG in the transport sector over the medium term.

In early November 2024 the **California Air Resources Board** made the Low Carbon Fuel Standard (LCFS) regulation stricter while continuing to support RNG production and use in the transport sector. More rigorous road fuel decarbonisation targets are likely to increase demand for credits generated by RNG producers thanks to avoided methane emissions. Additionally, the amendment confirms that RNG projects that begin construction before 2030 will be eligible to continue receiving avoided methane credits through to 2040, a key element of visibility for the industry.

At the federal level, the Renewable Natural Gas Incentive Act 2024 was introduced to the Senate in May 2024. The proposed act would create a USD 1.00 per gallon tax credit for dispensers of RNG used

[3] Low-emissions hydrogen includes hydrogen produced via electrolysis where the electricity is generated from a low-emission source (renewables or nuclear), biomass or fossil fuels with CCUS.

[4] 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).

for transport. Hence, it would encourage commercial truck and transit fleets to use biomethane. As of January 2025 the act has yet to pass the Senate.

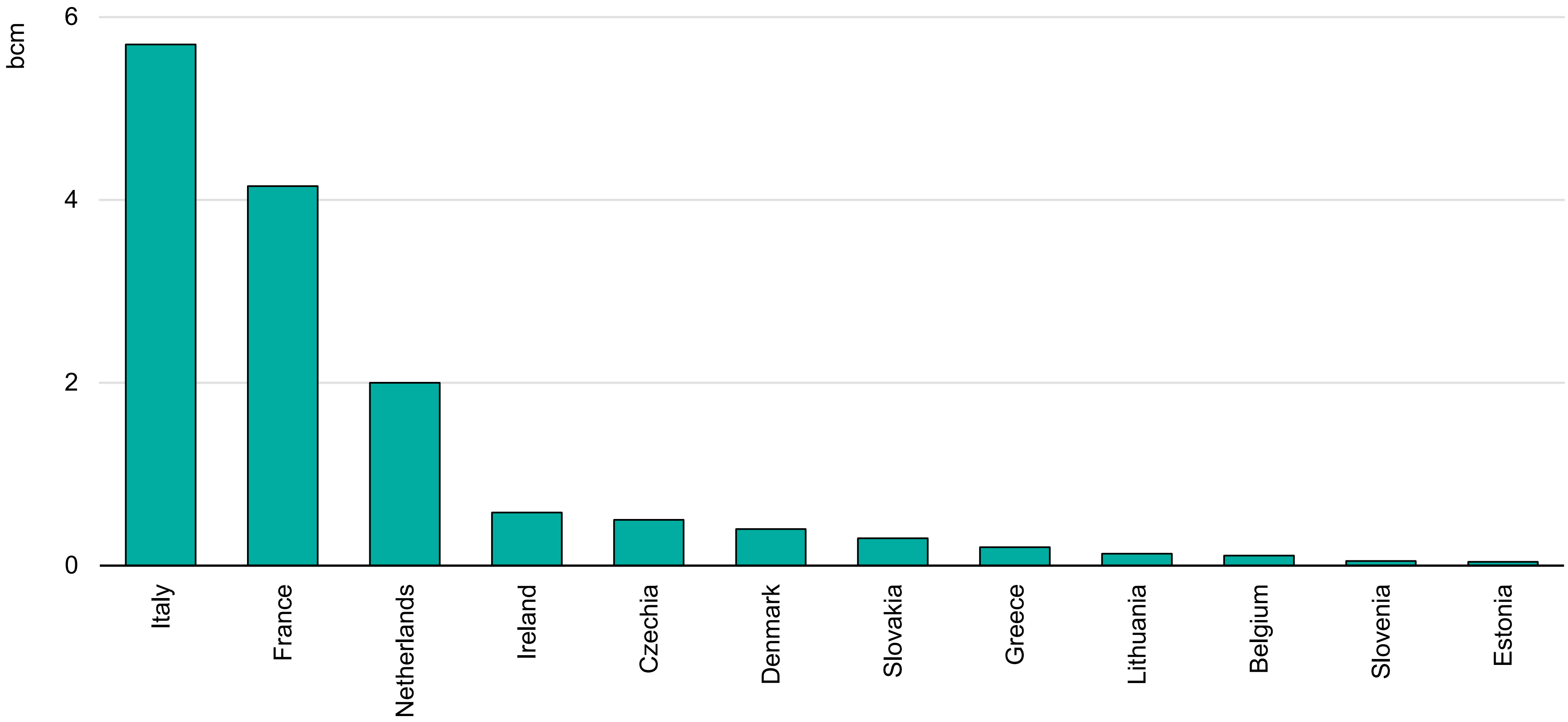
In the **European Union** the REPowerEU plan of 2022 introduced a biomethane production target of 35 bcm/yr by 2030. While the target is not legally binding, biogas and biomethane production targets are being firmed up in the in the draft updates to the National Energy and Climate Plans (NECPs) of EU member states. As of end December 2024, 13 member states included biomethane targets in their draft or final NECP. The combined targets of these member countries would total near 15 bcm/yr of biomethane production by 2030.

In addition, several EU member countries adopted biomethane strategies and/or action plans. In March 2024 **Portugal** published its Biomethane Action Plan 2024-2040. The plan sets a target to replace 18.6% of natural gas demand with biomethane by 2040. In the first phase (2024-2026), the action plan aims to develop the biomethane market in Portugal by creating a favourable regulatory framework for the implementation of new projects, by removing grid access barriers and encouraging the conversion of biogas plants to biomethane production. The second phase of the action plan aims to consolidate the biomethane market and increase domestic production. In May 2024 **Ireland** published its National Biomethane Strategy. The strategy sets an ambitious biomethane production target of 5.7 TWh/yr (or 0.5 bcm/yr) by 2030. It is based on five key pillars (sustainability, demand creation, the bioeconomy and circular economy, economics of biomethane and enabling policy requirements) and is accompanied by 25 key strategic actions. In November 2024 **Romania** published its draft Energy Strategy, including a target to increase the share of biomethane in the gas network to 5% by 2030 and 10% by 2050.

Biomethane is also benefiting from greater policy support in markets outside Europe and North America. In November 2023 **India** approved the mandatory blending of compressed biogas (CBG) into the domestic gas supply. The mandate will be set at 1% of total compressed natural gas and domestic piped natural gas consumption from 2025, and raised gradually to 5% from 2028/29. During 2024 the government developed an enabling framework for the scale-up of CBG. This includes providing financial support for biomass aggregation and financial assistance for the development of pipeline connectivity between CBG plants and the city gas distribution network. In **Brazil** President Lula enacted the Fuel of the Future Law in October 2024. The law establishes a National Programme for the Decarbonisation of Natural Gas Producers and Importers and for the Promotion of Biogas, with the aim of fostering research into, and the production, trade and use of, biomethane.

Biomethane targets are being firmed up in the NECPs of EU member states

Biomethane targets by 2030 in the draft and final National Energy and Climate Plans of EU member states



Source: IEA analysis based on European Commission (2024), National Energy and Climate Plans.

Low-emissions hydrogen subsidies and sustainability rules made progress in 2024

Although 2024 was a year of consolidation rather than breakneck growth for low-emissions hydrogen, subsidies and supportive policy measures continued to be rolled out in several key jurisdictions.

In the **United States** the Department of Energy (DOE) awarded USD 750 million for 52 hydrogen projects in March 2024 as part of the Bipartisan Infrastructure Law. This funding covers up to 50% of the cost of electrolyser manufacturing and fuel cell supply chains. The DOE also allocated USD 1.7 billion to six industrial projects utilising hydrogen, under the USD 6 billion Industrial Demonstration Program.

The **EU** Net Zero Industry Act, which went into effect in June 2024, sets a target to manufacture 40% of strategic technologies, including electrolysers and fuel cells, within the European Union by 2030. In April 2024 the European Hydrogen Bank awarded EUR 720 million (USD 750 million) to seven projects totalling 1.5 GW of electrolyser capacity in its first auction. A second auction opened in December 2024, offering up to EUR 1.2 billion (USD 1.24 billion) for qualifying renewable hydrogen projects. An additional EUR 836 million was made available by Austria, Lithuania and Spain to support renewable hydrogen projects in their respective countries under the so-called “Auction-as-a-service” mechanism.

In July 2024 the EU published the Hydrogen and Gas Decarbonisation Package, setting the outlines of a regulatory framework for hydrogen infrastructure. A delegated act defining low-carbon hydrogen must be in place within 12 months of the adoption of the package, and transposition into national law must take place by August 2026.

In February 2024 the third round of Important Projects of Common European Interest (IPCEIs) was approved, allocating EUR 6.9 billion in the form of state aid to hydrogen infrastructure projects. The fourth round, earmarking a further EUR 1.4 billion in state aid for hydrogen use in transport, was approved in May 2024.

In **Japan** the Hydrogen Society Promotion Act was enacted in May 2024, allocating JPY 3 trillion (USD 19.4 billion) to suppliers of low-carbon hydrogen for use within Japan through a 15-year contract-for-difference (CfD) subsidy. The CfD scheme opened in November 2024 and remains open until March 2025, with priority given to applications received by January 2025.

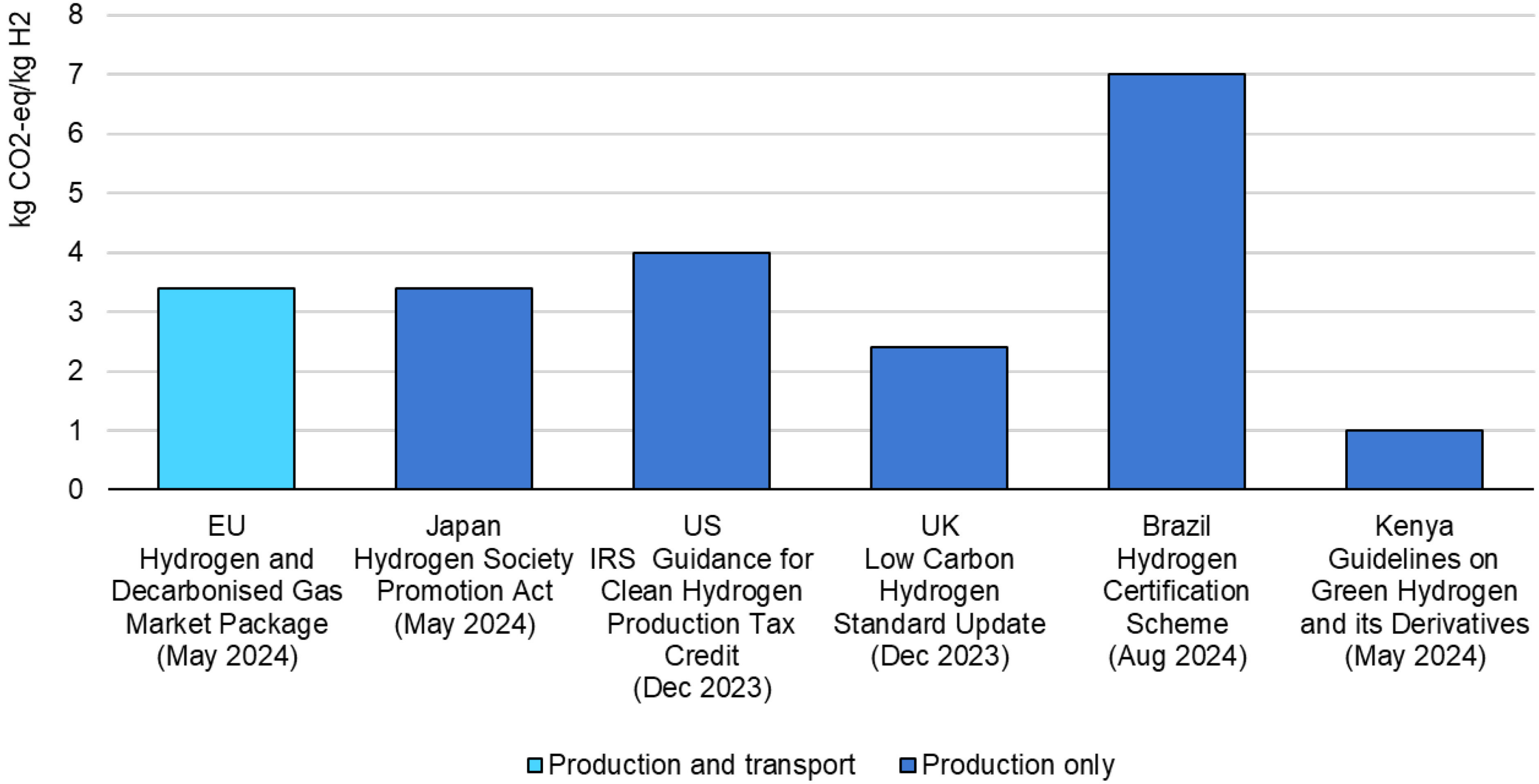
Australia's 2024 budget introduced AUD 8 billion (USD 5.2 billion) in subsidies for low-emissions hydrogen projects. This included a hydrogen production tax incentive worth AUD 6.7 billion (USD 4.4 billion) under the Future Made in Australia Bill and an additional AUD 1.3 billion (USD 0.9 billion) for the existing Hydrogen Headstart programme to bridge the cost gap for green hydrogen projects.

In **Brazil** a clean hydrogen law passed in 2024 provides BRL 18.3 billion (USD 3.2 billion) in tax credits for low-emissions hydrogen producers and consumers for five years starting in 2025. The law set a relatively high carbon intensity threshold (7 kg of CO_2 equivalent per kg of hydrogen) to accommodate biofuel-based production methods, such as ethanol steam reforming, but the incentive will be proportional to GHG savings, thus rewarding less GHG-intensive pathways.

Important progress was also made on defining the rules of what qualifies as low-emissions hydrogen in a few key markets since the end of 2023. Rules on sustainability criteria and specific GHG intensity thresholds for low-emissions hydrogen were proposed or finalised in the United States, Japan, Kenya, Brazil, the United Kingdom, and the European Union between December 2023 and December 2024.

Shades of green: GHG criteria for low-emissions hydrogen differ markedly across geographies

GHG intensity thresholds for low-emissons hydrogen in standards adopted or announced since December 2023



Biomethane recorded strong growth in 2024…

Global biomethane production rose more than sevenfold between 2013 and 2023. Preliminary data suggest that this strong growth continued in 2024. RNG output increased by almost 20% (or 1.6 bcm) in 2024 to over 10 bcm. This rapid expansion was primarily driven by the United States and Europe, together accounting for over 85% of incremental biomethane supply.

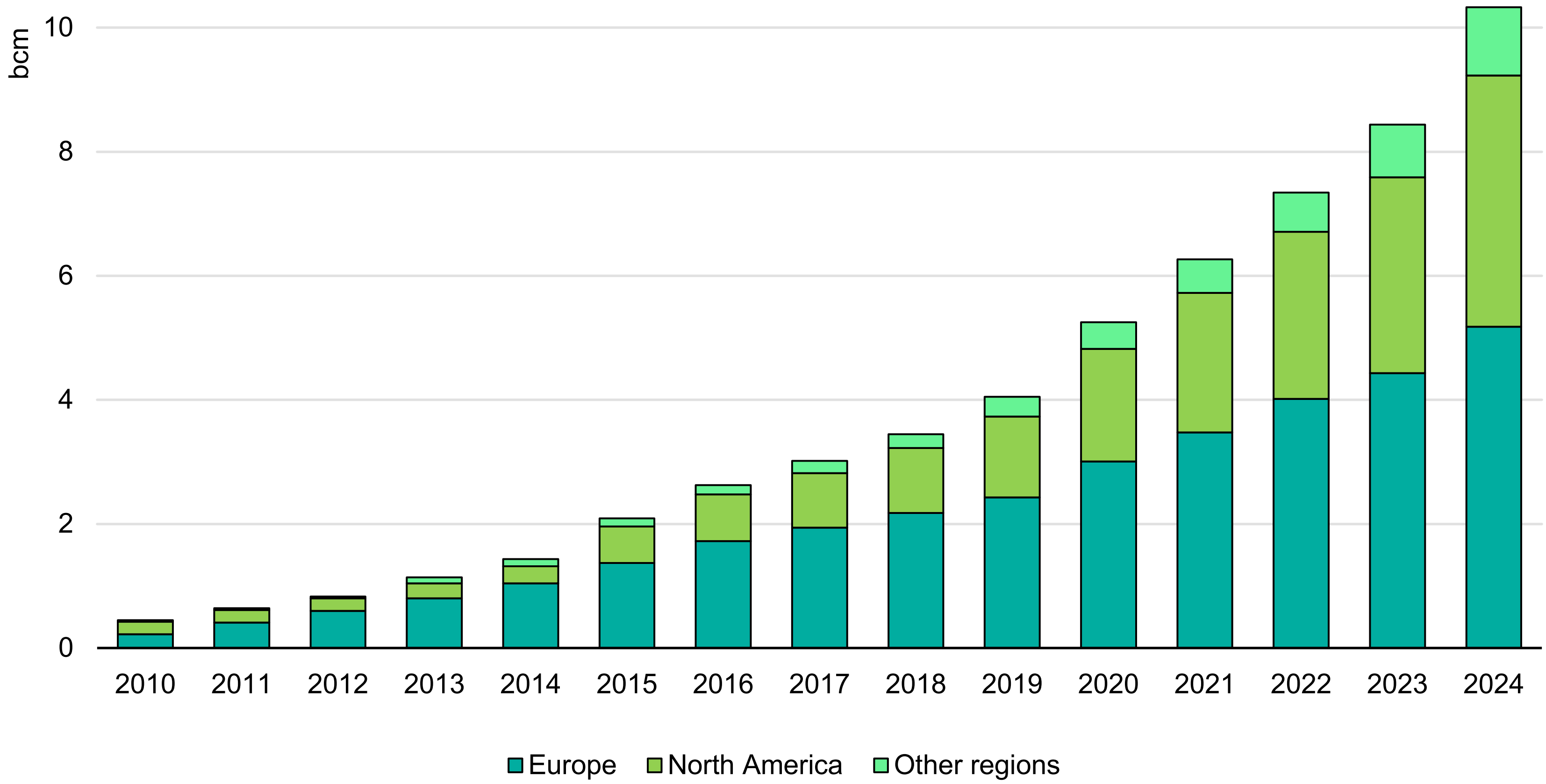
The **United States** further solidified its position as the world's largest producer of RNG in 2024. Biomethane output increased by more than 25% (or 0.7 bcm) and reached over 3.5 bcm. Hence, the United States alone accounted for more than 40% of incremental biomethane production in 2024. This strong growth was primarily driven by the **transport sector** and the renewable fuel standards (RFS) set by the Environmental Protection Agency. Around 90% of RNG in the United States is consumed as a transport fuel and less than 10% is used for power generation. In terms of feedstock, **municipal solid waste** accounts for almost 70% of biomethane production, followed by agricultural and food waste (25%) and waste water (5%). At the start of July 2024 Canada and the United States had 433 operational biomethane production facilities, with 162 under construction and 290 in development, according to the RNG Coalition.

Biomethane production grew by an estimated 15% (or more than 0.7 bcm) in **Europe**, primarily supported by France. **Germany** remains Europe's largest biomethane market. The country experienced the rapid expansion of RNG production during 2010-2015, although growth has slowed down significantly since then, with production hovering just above 1 bcm/yr. In the first nine months of 2024, seven new biomethane plants were put into operation with a capacity of just over 20 mcm/yr. **France**'s biomethane output rose almost fourfold between 2020 and 2023 and became Europe's second-largest producer in 2023, ahead of Denmark. This strong growth is enabled by the country's agricultural sector, with agricultural waste accounting for almost 80% of feedstock. Preliminary data indicate that France's RNG output rose by 27% in 2024 to over 1 bcm. The country is expected to become Europe's largest biomethane producer in 2025. **Denmark** recorded years of strong biomethane growth, with the country's output rising at an average annual growth rate of 28% between 2019 and 2023. This strong growth slowed in 2024, when Denmark's RNG output grew by just 2%, due to a change in the country's support mechanisms. Denmark's biomethane production totalled just over 0.8 bcm in 2024 and accounted for 38% of the country's total gas demand. In addition to Germany, France and Denmark as Europe's top three biomethane producers, both **Italy and the Netherlands** are rapidly expanding their RNG output.

Besides Europe and North America, biomethane production is also increasing in Brazil, China and India.

…largely supported by Europe and North America

Biomethane production by region, 2010-2024



Sources: IEA analysis based on Argonne National Laboratory (2025), Renewable Natural Gas Database; Biogas Partner (2025), Biogaspartner Einspeiseatlas Deutschland; Cedigaz (2025), 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.

Electrolyser projects gain momentum, but policy support remains vital

Momentum behind low-emissions hydrogen continued to grow in 2024 as both supply and installed electrolyser capacity continued on a growth path. Nevertheless, while market dynamics remain positive, key benchmarks remain short of prior expectations, as project delays, FID postponements and outright cancellations have slowed progress in strengthening the wider low-emissions hydrogen ecosystem.[5] The rationalisation of projects points towards the sector entering a maturing phase, a period that could help it sharpen its focus on segments where it would have the most impact. However, evidence also shows that project development continues to face important challenges, and addressing them will be key to ensuring that project momentum is not lost.

Low-emissions hydrogen continues to account for only a fraction of global hydrogen production and remains focused on a few key markets. Installed electrolysis capacity nearly doubled year-on-year in 2023, with China accounting for 80% of the growth and a further 12% located in Europe. In 2024 the regional breakdown is expected to have been similar, although less than 10% of the circa 3.5 GW of the year's potential new capacity (based on projects under construction and having taken FID) had actually started operations by late Q3 2024. Furthermore, despite the growth experienced in recent years, installed electrolyser capacity at the end of 2023 remained far below expectations from a few years ago: in 2021, analysis in the IEA Global Hydrogen Review expected installed capacity to be six times higher than the actual number of 1.4 GW.

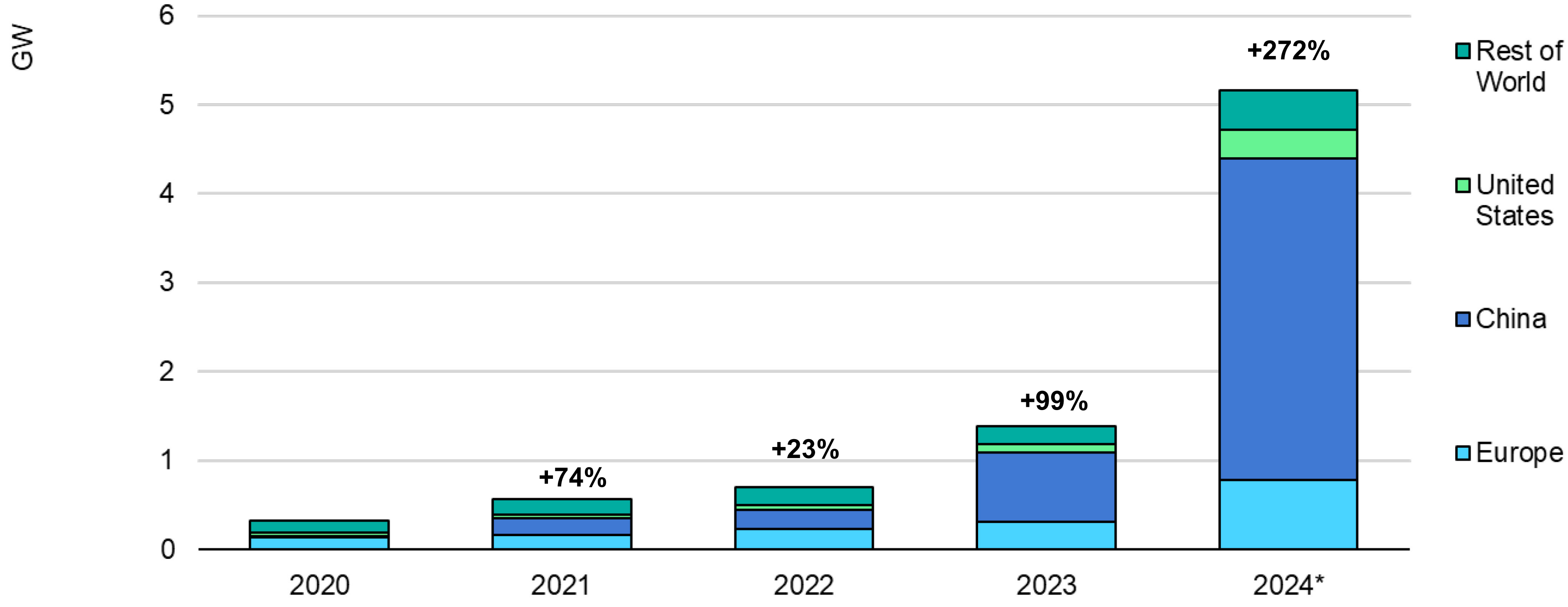
Uncertainty around both regulation and demand continues to dog project development, as does rigidity in making funding available. This has proven to be the case in Europe, where projects in Portugal, Spain, France, Germany and other countries have been delayed or cancelled due to business cases no longer being viable – notably in view of significant cost increases – or too much uncertainty around end-use rules and offtake potential. That being said, where state aid has been confirmed, FIDs have progressed markedly, leading to a quadrupling of European investment decisions y-o-y for the September 2023 to August 2024 period. The US market has not been immune from complications in project rollouts either, with the 1 GW-plus Hy Stor project cancelling a capacity reservation agreement in 2024, only months after having signed it. Its missing out on a public funding scheme in 2023 is likely to have played a role in the setback.

The low-emissions hydrogen project pipeline remains robust, offering considerable potential for electrolysis capacity growth by the end of the decade. However, realising this potential will require converting project announcements into FIDs and on to commercial starts. Doing so will hinge on promoting stability and visibility for project sponsors, as well as on providing sufficient support to firm up business cases.

[5] Please refer to the IEA Global Hydrogen Review 2024 for further analysis of global hydrogen developments.

China drives potential electrolyser capacity additions to record high in 2024

Installed electrolyser capacity by region, 2020-2024



* 2024 number represents potential capacity additions based on projects under construction and having taken FID.
Source: IEA (2024), IEA Hydrogen Production Database (October 2024).

Policy and financial support can contribute to expanding e-methane production

E-methane is produced by combining low-emissions hydrogen with carbon resources. As e-methane can be interchangeable with natural gas, it could play a key role in decarbonising gas networks. Without the need for retrofitting, e-methane is easy to inject and mix into existing gas infrastructure such as LNG ships, receiving terminals and tankers, and gas pipelines and consumer gas equipment. It is possible to convert systems from natural gas to e-methane seamlessly and limit the social costs associated with its introduction. However, its high production costs require further technological development, policy support and global co-operation.

During 2024 global collaboration to promote e-methane production made progress. In March 2024, eight companies promoting e-methane (or electric natural gas [e-NG]) announced the creation of a global e-NG Coalition with the aim of accelerating global deployment. The outcome document of the Japan–US Clean Energy and Energy Security Initiative in 2024 states that Japanese companies have signed letters of intent with US companies to avoid CO_2 double counting in respect of e-methane. In October 2024 Australian Gas Industry Trust and the Japan Gas Association signed a memorandum of understanding to support e-methane projects and discussions on the CO_2 accounting rules between the two countries.

Financial support can boost the development of e-methane production projects. A Finnish e-methane production project located in Lahti has been selected as winner in the first European Hydrogen Bank auction. In addition, Finland's Ministry of Economic Affairs and Employment has granted the project an investment subsidy for e-methane production at the facility. A further Finnish project to produce e-methane, this time in Kotka, has been awarded a grant from the EU Innovation Fund. In 2024 the Japanese government passed its Hydrogen Society Promotion Act, which includes 15-year contract-for-difference production subsidies for domestic and imported low-carbon hydrogen and its derivatives (including ammonia, e-fuels and e-methane), with funds totalling JPY 3 trillion.

Japan aims to develop new technologies to improve e-methane production efficiency in order to reduce costs. A number of companies are working to develop innovative methane manufacturing technologies, such as the Hybrid Sabatier reaction, PEM (polymer electrolyte membrane) CO_2 reduction and SOEC (solid oxide electrolysis cell) methanation. These technologies can produce e-methane directly from water and CO_2 without the need to procure hydrogen. With expectations that these technologies will improve production efficiency, the development activities are supported by a Japanese government fund, the Green Innovation Fund.

Japan aims to develop innovative technologies to reduce e-methane production costs

Key innovative methanation technologies in Japan

Technology	Stage	Description
Conventional Sabatier reaction	Existing technology	The conventional Sabatier reaction requires hydrogen and CO_2 as raw materials. This is an established basic technology with a chemical reaction at high temperatures (up to 500 °C). Improvement of efficiency and management of the thermal reaction are challenges.
Hybrid Sabatier reaction	Innovative technology under development	The Hybrid Sabatier reaction does not require hydrogen. The raw materials are water and CO_2. This is an innovative technology with an electrochemical reaction at low temperature (up to 220 °C) and high efficiency. Increasing size and ensuring durability and reliability are challenges.
PEMCO2 reduction	Innovative technology under development	The PEMCO2 reduction reaction does not require hydrogen. The raw materials are water and CO_2. This is an innovative technology with an electrochemical reaction at low temperature (up to 100 °C) and low cost. Increasing size and ensuring durability and reliability are challenges.
SOEC methanation	Innovative technology under development	SOEC methanation does not require hydrogen. The raw materials are water and CO_2. This is an innovative technology with an electrochemical reaction at high efficiency and high temperature (up to 800 °C). Development of cells for high-temperature electrolysis and improving the durability of the catalyst are challenges.

Annex

Summary table

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

	Consumption					Production				
	2021	2022	2023	2024	2025	2021	2022	2023	2024	2025
Africa	168	169	176	177	181	260	251	254	246	252
Asia Pacific	891	877	906	956	991	648	660	675	690	712
of which China	*367*	*364*	*393*	*426*	*455*	*205*	*218*	*230*	*246*	*261*
Central and South America	153	148	147	149	148	148	151	147	148	150
Eurasia	649	622	631	656	671	960	865	830	860	875
of which Russia	*516*	*487*	*495*	*516*	*530*	*762*	*672*	*638*	*682*	*693*
Europe	609	524	488	490	493	222	230	215	221	217
Middle East	562	580	592	606	625	692	715	725	741	765
North America	1 091	1 144	1 157	1 178	1 183	1 172	1 240	1 288	1285	1310
of which United States	*874*	*919*	*928*	*946*	*944*	*967*	*1 021*	*1 061*	*1 060*	*1 074*
World	**4 123**	**4 063**	**4 097**	**4 212**	**4 292**	**4 102**	**4 112**	**4 134**	**4 190**	**4 281**

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
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
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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