Gas Market Report, Q1-2026

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Abstract

Natural gas markets continued to rebalance in 2025. Global LNG supply returned to double-digit growth in the second half of the year, supported by the ramping-up of new LNG liquefaction projects in the United States, Canada and Africa. This strong growth is gradually easing market fundamentals and contributing to a more secure and resilient global gas market.

Global LNG supply growth is set to accelerate further in 2026, fostering a stronger increase in natural gas demand, which is expected to reach a new all-time high. Although the LNG supply growth is reducing market tightness, geopolitical tensions and weather impacts may still cause price volatility. Close international co-operation between responsible producers and consumers remains important to reinforce the architecture for secure global gas supplies. The International Energy Agency (IEA) continues to support this process, including through the permanent Working Party on Natural Gas and Sustainable Gases Security (GWP), established in late 2024.

This edition of the quarterly *Gas Market Report* provides a thorough review of market developments in 2025 and an outlook for 2026. The report includes a section dedicated to key policies undertaken in 2025, with a special focus on market reforms introduced in fast-growing markets in Asia.

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Executive summary

The unfolding LNG wave is expected to drive stronger gas demand growth in 2026

2025 was a transitional year for natural gas markets. While supply fundamentals remained tight in the first half of the year, strong LNG production growth gradually eased market conditions starting from July. Following a relatively strong increase in 2024, **global gas demand growth slowed markedly** in 2025 due to a combination of weaker industrial activity and relatively high spot LNG prices in the first half of the year. Market opening reforms continued to gather pace in Asia while the **European Union reached a historic decision to phase out Russian natural gas imports** by November 2027 at the latest.

Global LNG supply growth is set to accelerate further in 2026 to its fastest pace since 2019. This is expected to **foster stronger global gas demand growth**, primarily driven by China and emerging Asian markets.

Global LNG supply hit double-digit growth in the second half of 2025, helping to ease market fundamentals

Global LNG production increased by almost 7% (or 38 bcm) in 2025, with around three-quarters of the growth concentrated in the second half of the year. The Plaquemines LNG plant in Louisiana alone accounted for over 60% of the increase in LNG supply through the year and played a key role in the easing of market conditions.

Supply remained relatively tight in the first half of 2025. While global LNG supply increased by 4% (or 10 bcm) year-on-year (y-o-y) in the first half of 2025, this was partially offset by lower Russian and Norwegian piped gas deliveries to Europe. In addition, stronger storage injections in the European Union contributed to tighter markets. This kept European and Asian benchmark prices 30% and 40%, respectively, above their levels in the same period a year earlier.

Global LNG supply growth accelerated to 10% (or 28 bcm) y-o-y in the second half of 2025, which gradually eased market conditions starting from July. TTF and Asian spot LNG prices fell 14% and 17% respectively in H2 2025 compared with the same period in 2024. **The correlation between European and Asian benchmark prices** rose to a new all-time high of 0.955 in 2025. This reflects the increasingly interconnected nature of regional markets amid the growing share of destination-flexible LNG supplies.

Macroeconomic uncertainty and tighter supply in the first half of 2025 weighed on global gas demand growth

Following a relatively strong increase in 2024, **natural gas demand growth slowed significantly in 2025.** Preliminary data indicate that global **natural gas consumption increased by less than 1%** in 2025. In contrast with previous years, this growth was largely **driven by Europe and North America** while natural gas demand remained subdued in Asia and declined in Eurasia.

In **OECD Europe**, natural gas demand grew by 3%, partly supported by stronger gas burn in the power sector amid lower wind and hydro power output. In **North America**, natural gas consumption increased by an estimated 1%, primarily driven by colder winter temperatures. **Asia**'s natural gas demand in 2025 slowed to its weakest pace since 2022 and remained close to its 2024 levels. In **China**, subdued gas demand combined with a continued increase in domestic gas production and higher piped gas deliveries from Russia, led to a steep decline in LNG imports, which dropped by 14% compared with 2024. In **Eurasia**, natural gas demand declined by around 2% amid mild winter weather conditions in Russia. Combined demand in **Africa** and the **Middle East** grew by an estimated 2.5%, partly driven by oil-to-gas switching dynamics in the power sector.

The United States led a new wave of final investment decisions in LNG liquefaction capacity in 2025

Despite macroeconomic uncertainty, **final investment decisions (FIDs) in LNG liquefaction plants remained robust in 2025**. Over 90 bcm per year of LNG liquefaction capacity has been given the go-ahead, making 2025 the second strongest year for LNG FIDs, after 2019.

The United States is leading the new investment cycle. More than 80 bcm per year of LNG liquefaction capacity reached final investment decisions in the United States in 2025 – a new all-time high for the US LNG industry. The LNG projects include Louisiana LNG, Corpus Christi Train 8&9, CP2 phase 1, Rio Grande LNG Train 4 and Port Arthur phase 2. This new wave of projects is expected to further **solidify the United States' position as the world's largest LNG supplier**. The United States' market share in the global LNG market is expected to increase from around 25% in 2025 to around 33% by the end of the decade.

Strong LNG project development was accompanied by an increase in LNG contracting activity. More than 130 bcm per year of LNG contracts were signed in 2025 – representing the largest volume contracted in the past decade. The **United States** alone accounted for around half of the total contracted volumes in 2025. LNG volumes contracted by **European buyers** from post-FID projects more than doubled compared with 2024, reaching nearly 25 bcm in 2025.

Gas market liquidity continued to improve in 2025 while gas market reforms gathered pace in Asia

Natural gas trading volumes and hub liquidity reached new all-time highs across all key markets in 2025. In the United States, gas volumes traded on **Henry Hub** rose by 8%, while in the **European Union and the United Kingdom** gas trade increased by an estimated 17% in 2025. In Northeast Asia, trading in key gas derivatives rose by 35% despite a decline in China's spot LNG procurements.

This continued growth is supported by a number of factors, including the rising short-term variability in gas-to-power demand and the growing interconnectivity of regional gas markets. These developments necessitate more sophisticated hedging strategies and more active trading along the forward curve.

In Asia, natural gas market reforms continued to gather pace. In **China**, the National Development and Reform Commission introduced new measures to foster effective third-party access to the gas transmission system. **India** introduced a simplified unified gas transport tariff with the aim to reduce variations in transmission pipeline utilisation. **Malaysia** launched a Natural Gas Roadmap that aims to expand third-party access to the country's gas infrastructure. **Singapore** established a new government-owned entity to centralise the procurement and supply of natural gas for the country's power generators.

The European Union reached a historic agreement to phase out Russian gas imports

Russia's full-scale invasion of Ukraine in 2022 disrupted its decade-long energy ties with the European market. Russian piped gas deliveries to the European Union fell by 90% between 2021 and 2025. In December 2025, the European Union reached a historic agreement to **fully phase out Russian gas by November 2027** at the latest – ending over five decades of gas dependence. Overall, the EU measures are expected to reduce Russia's piped and LNG deliveries to the European Union by 33 bcm between 2025 and 2028. This could create **additional market space for non-Russian LNG suppliers** to the European Union.

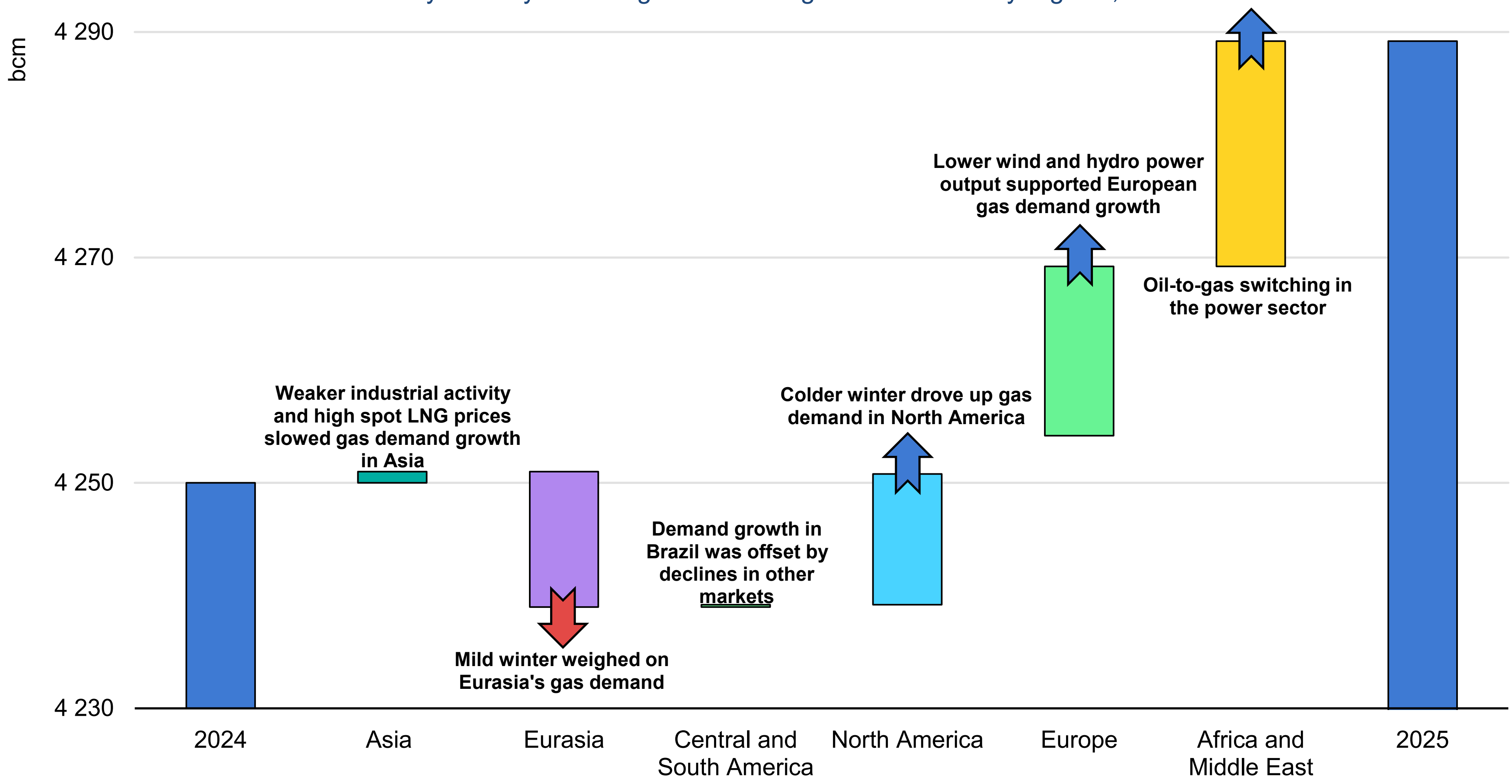
Stronger LNG supply growth is expected to foster higher global natural gas demand growth in 2026

Global LNG supply growth is set to accelerate further in 2026 to its fastest pace since 2019. In our forecast, global LNG production increases by more than 7% (or over 40 bcm) in 2026. North America is again set to drive this growth, with the United States, Canada and Mexico accounting for over 85% of the increase in global LNG supply in 2026.

Easing supply fundamentals are expected to foster stronger global gas demand growth, driven primarily by China and emerging Asian markets. Natural gas demand in the **Asia Pacific region** is expected to increase by 4% in 2026, accounting for around half of global gas demand growth. Natural gas demand is forecast to remain broadly flat in **North America**, and it is expected to decline by 1% in **Central and South America** amid improving hydropower generation. In **Europe**, the continued expansion of renewables is expected to reduce gas demand by 2%. In **Eurasia**, gas consumption is forecast to increase by 3.5% assuming a return to average weather conditions. Gas demand in **Africa** and the **Middle East** combined is expected to increase by 3.5% amid higher gas use in industry and the power sector.

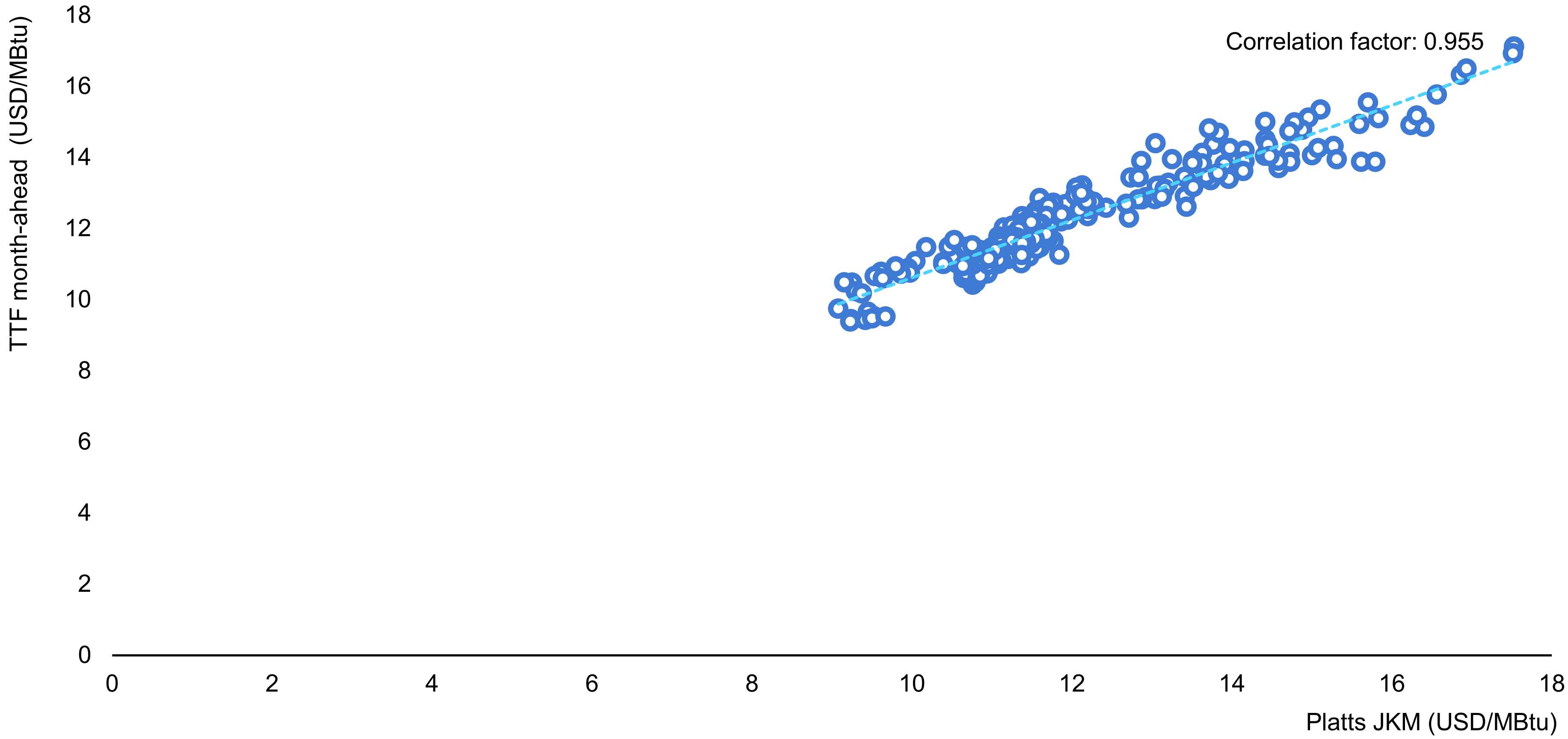
Natural gas demand growth slowed to below 1% in 2025 across key markets

Estimated year-on-year changes in natural gas demand in key regions, 2025



Correlation between Asian and European gas prices rose to a new all-time high in 2025

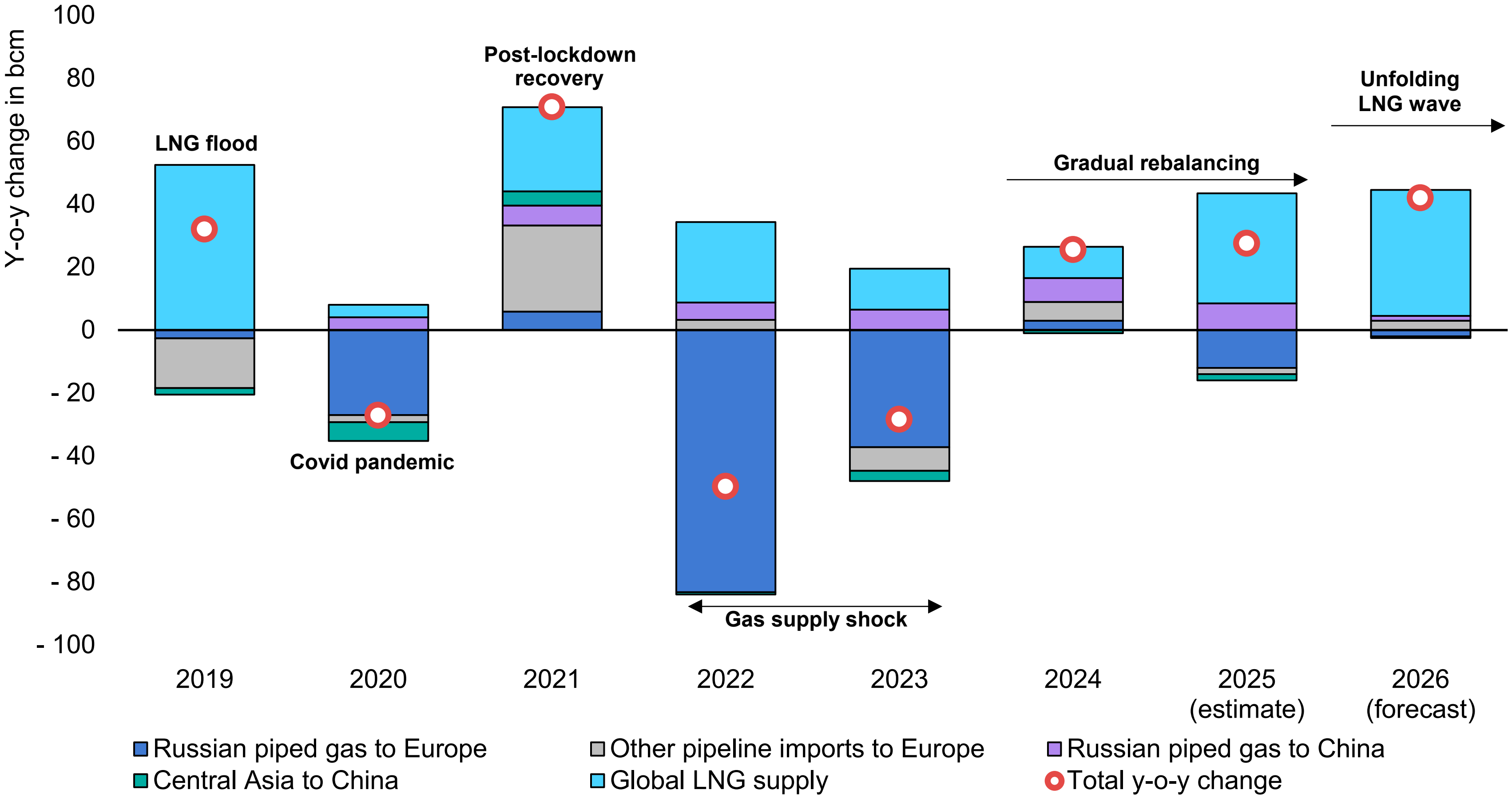
Correlation between TTF month-ahead and Platts JKM prices in 2025



Sources: IEA analysis based on CME Group (2026), Dutch TTF Natural Gas Month Futures Settlements; S&P Global Inc (2026), S&P Global Commodity Insights.

Improving LNG availability is expected to foster stronger gas demand growth in 2026

Year-on-year change in key piped natural gas trade and global LNG supply, 2019-2026



Key gas policies and market trends in 2025

A year of transition: Key gas policies and market trends in 2025

Natural gas markets are transitioning to looser fundamentals from the tight conditions that emerged with the 2022-2023 gas supply shock. This section of the quarterly *Gas Market Report* provides an overview of the key natural gas market trends and policies that emerged in 2025.

Gas prices in both Asia and Europe faced changing pressures comparing the first half of 2025 with the second. While tighter supply fundamentals drove up both TTF and Platts JKM in H1 2025, they fell well below their 2024 levels in the second half of the year amid the strong increase in global LNG supply. The **correlation between Asian and European gas prices** increased to an all-time high of 0.955. This reflects the increasingly intertwined nature of regional markets amid the growing share of destination-flexible LNG supplies. In the United States, Henry Hub prices recovered to their five-year average after reaching unsustainably low levels in 2024.

Natural gas trading volumes and hub liquidity reached new all-time highs across all key markets in 2025. This continued growth is supported by a number of factors, including the rising short-term variability in gas-to-power demand and the growing interconnectivity of regional gas markets. These developments necessitate more sophisticated hedging strategies and more active trading along the forward curve.

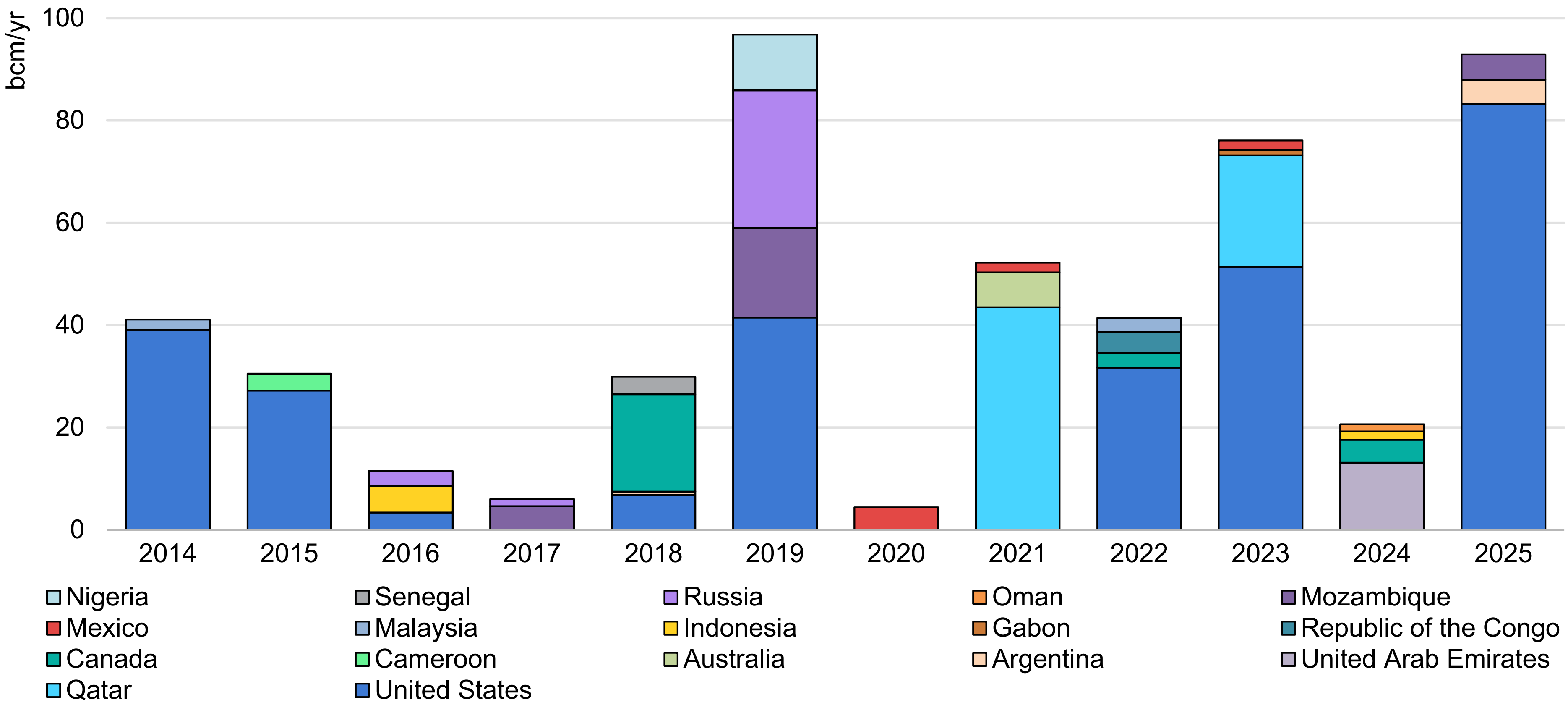
LNG contracting surged to its highest level in our records, highlighting its role as an essential long-term risk-sharing mechanism between sellers and buyers. More than 130 bcm/yr of LNG contracts were concluded in 2025, with an average duration of around 15 years. This was partly driven by the **strong momentum behind LNG project development**. Over 90 bcm/yr of new LNG liquefaction capacity was sanctioned in 2025, making it the second strongest year on record for liquefaction FIDs. In the United States alone more than 80 bcm/yr of LNG liquefaction capacity reached FID – an all-time high for the US gas industry.

In Asia natural gas market reforms continued to gather pace. In **China** the National Development and Reform Commission (NDRC) introduced new measures to foster effective third-party access to the gas transmission system. **India** introduced a simplified unified gas transport tariff with the aim of reducing distortions in transmission pipeline utilisation. **Malaysia** launched a Natural Gas Roadmap, which aims to expand third-party access to the country's gas infrastructure. **Singapore** established a new government-owned entity (Gasco) to centralise the procurement and supply of natural gas for the country's power generators.

The European Union reached an historic agreement in December 2025 to phase out Russian natural gas imports by November 2027 at the latest. Overall, the regulation is expected to reduce Russia's piped and LNG deliveries to the European Union by 33 bcm between 2025 and 2028. This could create additional market space for non-Russian LNG suppliers to EU countries.

2025 was the second strongest year on record for LNG liquefaction FIDs

Final investment decisions for new LNG liquefaction capacity, 2014-2025



Natural gas prices strengthened across all key markets in H1 2025, before softening in H2

Following the all-time highs reached in 2022, natural gas prices moderated significantly across all key markets during 2023-2024. This trend reversed in 2025. **Tighter supply fundamentals** provided upward pressure on Asian spot LNG and European hub prices in the first half of the year, before softening in H2 2025 amid improving LNG supply availability. In the United States, stronger demand growth supported price recovery from the unsustainably low 2024 levels. **Correlation between Asian and European prices reached a new all-time high** reflecting the increasingly globalised nature of natural gas markets.

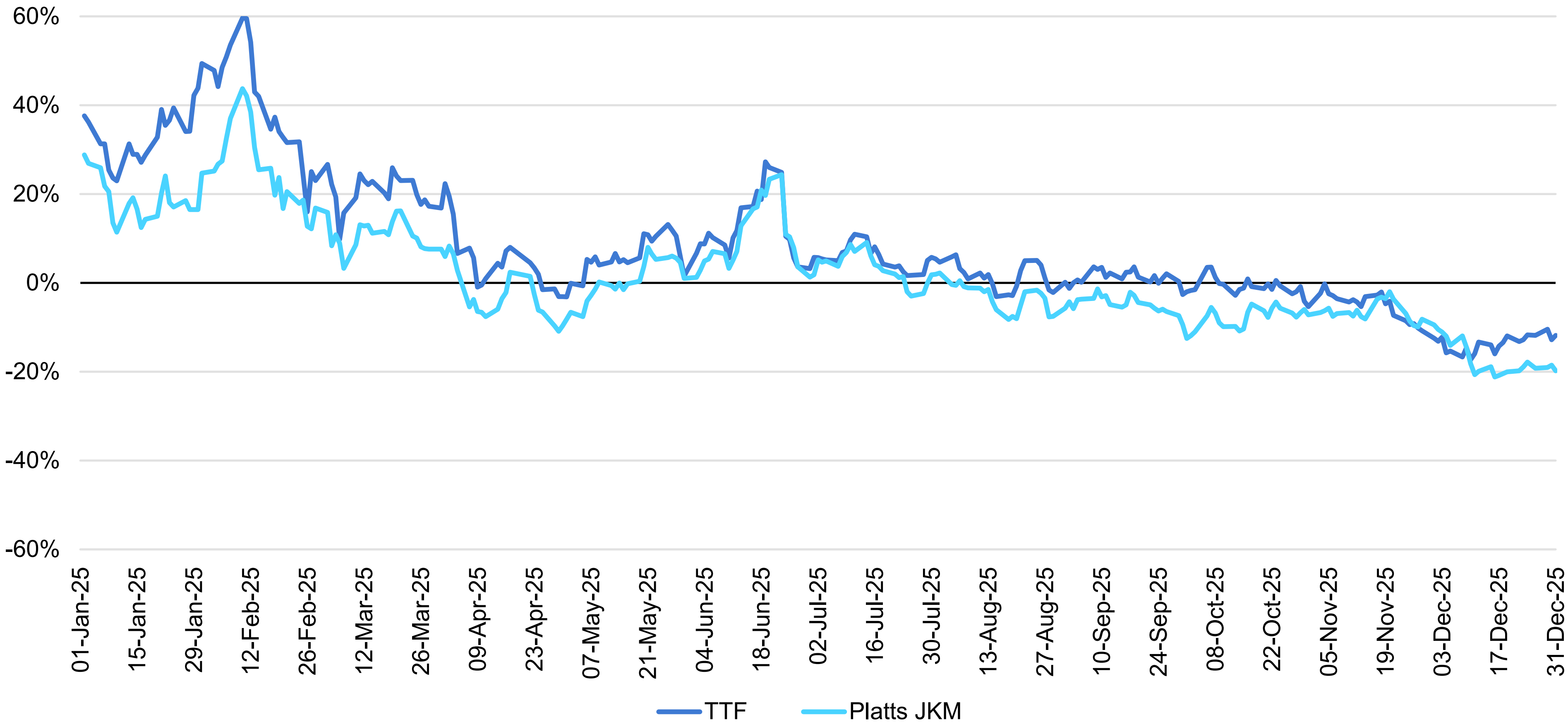
In **Europe** the average TTF month-ahead price was 9% higher in 2025 than in 2024, averaging just below USD 12/MBtu in 2025, more than double the five-year average between 2016 and 2020. Higher gas demand, together with strong storage injections and reduced piped gas flows (both from Russia and Norway) drove up average TTF prices by 40% y-o-y in H1 2025. In contrast, average TTF month-ahead prices stood 14% below their 2024 levels in H2 2025 amid strong LNG inflows, improving wind availability and mild weather conditions in Q4. Price volatility continued to soften in 2025 and averaged 40% – albeit standing almost 30% above its ten-year average between 2010 and 2019. Monthly volatility reached its highest level in June driven by geopolitical tensions in the Middle East. Improving LNG availability together with milder winter weather softened price volatility in Q4 to its lowest level since 2017.

Asian spot LNG prices followed a similar trajectory. Average Platts JKM prices stood 2% higher in 2025 compared with 2024 to average just above USD 12/MBtu, almost double their five-year average between 2016 and 2020. Stronger competition for LNG from Europe drove up JKM prices by almost 30% y-o-y in H1 2025, before declining by more than 15% y-o-y in the second half the year amid improving LNG availability. **The spread between TTF and JKM prices tightened** from an average of near USD 0.95/MBtu in 2024 to just USD 0.23/MBtu in 2025, making Europe more attractive on a netback basis for major LNG suppliers in the Atlantic Basin. Consequently, Europe's LNG imports rose to an all-time high in 2025, which was necessary to refill the region's vast underground storage space. **The correlation between TTF and Platts JKM** reached a new all-time high of 0.955. This reflects the increasingly intertwined nature of regional markets amid the growing share of destination-flexible LNG supplies. **Oil-indexed LNG contracts** oscillated in an estimated range of USD 10-12/MBtu, averaging around 10% below their 2024 levels.

In the **United States** Henry Hub month-ahead prices rose by 50% compared with 2024 to an average of USD 3.6/MBtu, standing 3% above the five-year average between 2019 and 2023. Stronger demand growth together with higher storage injections supported the recovery in US gas prices. Short-term price variability remained above average driven by cold spells in Q1 and Q4, as well as stronger gas-to-power demand volatility through the year.

After strong gains in the first half of the year, Asian and European prices softened in H2 2025

Change in Asian and European natural gas prices compared with 2024 average price level



Sources: IEA analysis based on CME Group (2026), Dutch TTF Natural Gas Month Futures Settlements; S&P Global Inc (2026), S&P Global Commodity Insights.

Global gas trading volumes reached an all-time high in 2025

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, 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 and 2025, 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. The short-term variability of gas-to-power demand continued to increase across the European and US markets, supporting higher trading volumes. The growing interconnectivity of regional gas markets is also supported by additional trading activity, with global portfolio players actively hedging on hubs outside their region of physical delivery.

In the **United States** gas volumes traded on **Henry Hub** rose by 8% in 2025 y-o-y to their highest level in our records. The churn rate averaged 60 through the year, its highest level since at least 2014.

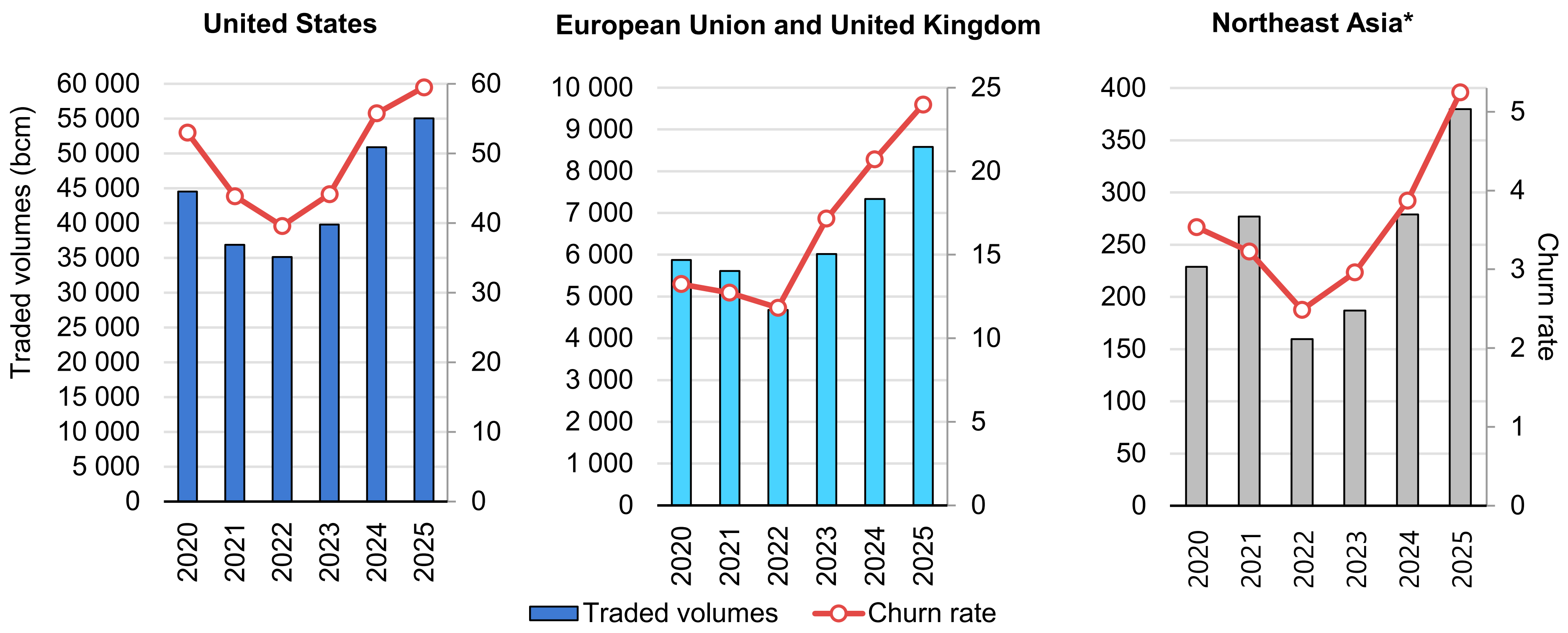
This growth was largely concentrated in H1 2025, with traded volumes rising by nearly 15% y-o-y. Monthly traded volumes reached an all-time high of over 5 500 bcm in December. Cold weather boosted natural gas demand, necessitating more short-term-focused trading operations to optimise deliveries amid a sharp increase in demand. In addition, the rising short-term variability of gas-to-power demand provided additional incentives for gas trading during the year.

Gas traded volumes in the **European Union and the United Kingdom** rose by an estimated 17% in 2025 to an all-time high. This growth was largely driven by the **Dutch TTF**, alone accounting for around 80% of incremental trade volumes. Consequently, its share of total European gas trade firmed up at just over 80% in 2025. Monthly traded volumes reached an all-time high of around 900 bcm in February, when the combination of cold weather and low wind output boosted EU and UK gas demand by around 20% and required an optimisation of positions through short-term trading operations. The churn rate of the combined EU and UK gas markets rose by 15% in 2025 to close to 25 – its highest level on record.

In **Asia** trading in **ICE JKM** derivatives rose by 35% in 2025 despite a decline in spot LNG procurements by China. This indicates more pronounced hedging activity along the forward curve amid greater demand uncertainty. The churn rate remained low in the JKM area, although improved compared with 2025, rising to near 5.

Liquidity continued to improve across all key markets in 2025

Estimated traded volumes and churn rates across key natural gas markets, 2020-2025



* 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.

North America and the Middle East led the increase in LNG contracts in 2025

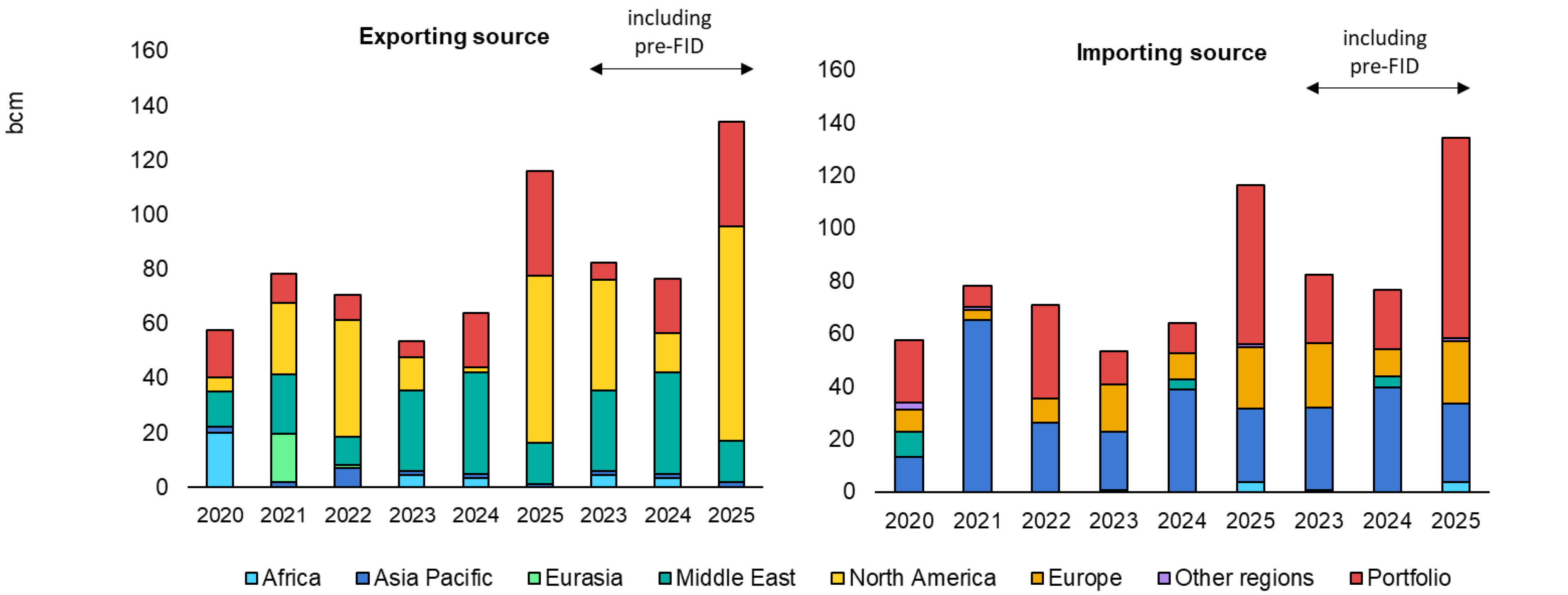
LNG contracting continued to experience strong momentum in 2025. Total LNG contracted volumes reached 130 bcm, standing 38% above their five-year average. This also represents the largest volume recorded over the past decade. Post-FID projects accounted for 85% of the total volumes concluded in 2025. The average duration of the LNG contracts signed in 2025 was around 15 years, highlighting the crucial role long-term contracts play in sharing investment risk between sellers and buyers. In 2025, portfolio players purchasing US-sourced LNG with destination flexibility became the main drivers of contracting activity. Destination flexibility remains a valued option, while pricing structures continue to diversify as market players pursue more sophisticated risk management strategies.

From a supplier's perspective, this strong contracting activity was primarily supported by **the United States and portfolio players**, accounting for 50% and 33% of the total contracted volumes in 2025 respectively. When only post-FID projects are considered, the proportions accounted for by the United States and portfolio players were 52% and 29% respectively. **From a buyer's perspective**, portfolio players and Asian buyers accounted for about 57% and 22% of the total volumes contracted in 2025 respectively, and approximately 52% and 24% of the contracts signed with post-FID LNG projects. LNG volumes contracted by European buyers from post-FID projects more than doubled compared with 2024 and reached nearly 25 bcm in 2025. The United States alone accounted for nearly 70% of the volumes contracted by European buyers. These trends may indicate Europe's intention to reduce its reliance on the spot market and increase the share of flexible long-term LNG contracts. **Contracts with destination flexibility** accounted for 61% of all the volumes contracted in 2025 – a marked increase on 2024. Destination-fixed contracts are primarily concentrated in Asia, with China alone accounting for around 60%. In contrast, destination-flexible volumes are almost entirely contracted by portfolio players, with a share of 90% in 2025.

Pricing mechanisms underpinning long-term LNG contracts are becoming more diverse and complex. The volumes contracted under gas-to-gas index pricing has been increasing in recent years. This trend continued into 2025, primarily supported by contracts tied to United States-based LNG projects and indexed to Henry Hub. Contracts signed in 2025 also included agreements indexed to TTF and JKM, as well as hybrid mechanisms, indicating a move towards diversification of pricing mechanisms. Traditional oil-linked contracts remain favoured by Middle Eastern suppliers.

Europe's LNG contracting activity is on the rise

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



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

China continued its long march to gas market opening in 2025

China has implemented a wide range of gas market reforms during the past two decades, aimed at gradually increasing the role of market-based pricing mechanisms, enabling third-party access to midstream gas infrastructure and fostering trading across the country's nascent gas hubs and exchanges. The share of natural gas sold under market-based pricing mechanisms grew from 20% in 2005 to over 45% in 2024.

Throughout China's recent history of gas market reform, a key stride was the creation of the China Oil and Gas Pipeline Network Corporation (PipeChina) in 2019. Established from the transfer of midstream infrastructure assets (spanning, for natural gas, pipelines, LNG terminals and storage facilities) from China's three national oil and gas companies, PipeChina took on the mission of facilitating more competitive trade in the market through infrastructure unbundling. Progress towards the full effects of this reform is ongoing, bolstered notably by a 2025 communication from China's NDRC on Supervision Measures for Fair and Open Access to Oil and Gas Pipeline Facilities.

The supervision measures, which entered into force in November 2025, supplement the overarching principles behind China's unbundling push by providing more specific guidelines and rules as to the responsibilities of transmission pipeline facility operators.

With this publication, the NDRC notably provided clarification in three key areas.

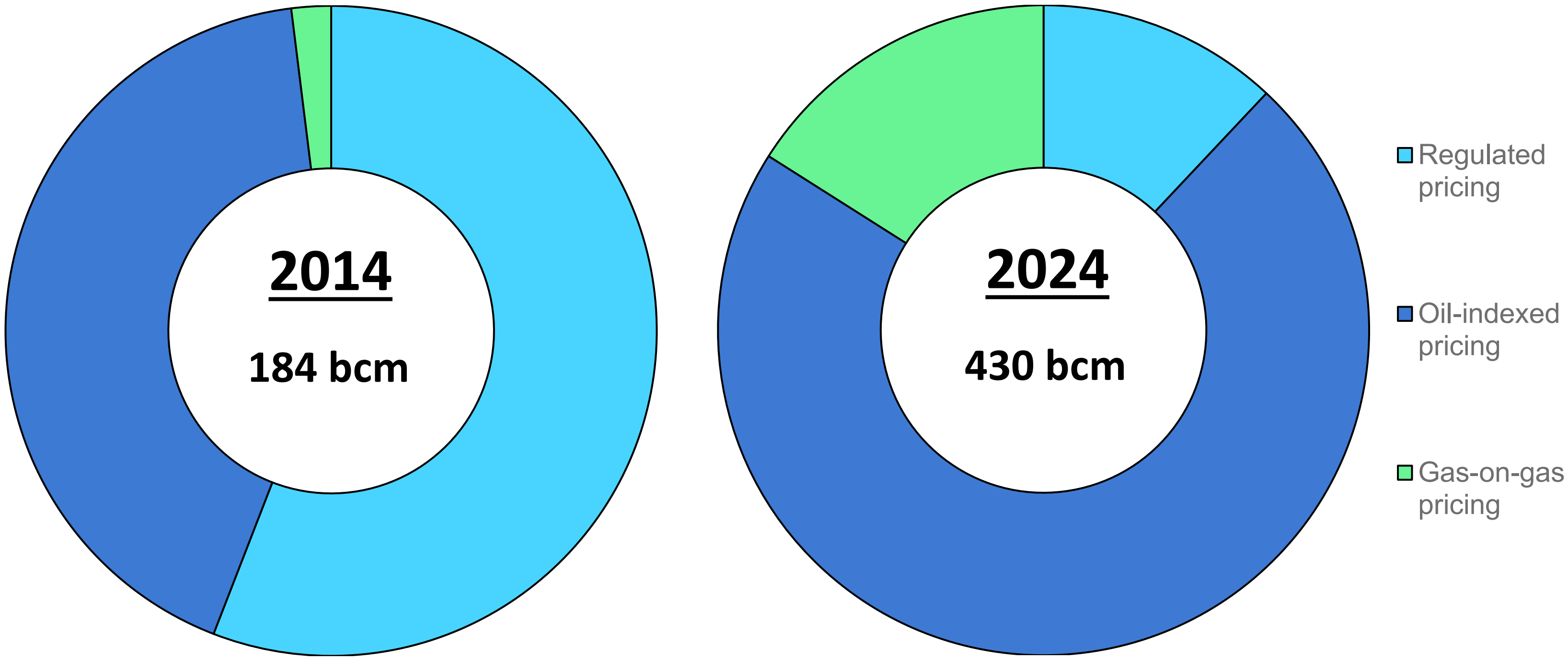
The first is the requirement to set up dedicated registration channels for prospective infrastructure users with clear rules as to capacity allocation, representing a step in the direction of standardisation, as well as transparency and predictability for pipeline shippers.

Second, the introduction of penalty clauses for the violation of rules on infrastructure access and use – as well as the specification of exceptions to these rules – provides a crucial addition to the effectiveness and enforcement of unbundling regulation. Finally, the measures also set out guidelines for the reporting of information to authorities, the market and registered users, establishing further standards with respect to data and information transparency, key elements upholding the principle of third-party access. Enhanced market transparency is crucial to reduce information asymmetry between market participants and to foster natural gas trading on an equal footing.

While full implementation of third-party access rules and PipeChina's mandate is likely to take time, the NDRC's supervision measures provide a necessary step in reaching these objectives. With time, these measures are expected to contribute to a better reflection of costs and deepening of trade in China's natural gas market.

The share of market-based pricing in China has grown strongly in the past decade

Natural gas price formation in China, 2014 and 2024



Note: Oil-indexed and gas-on-gas pricing represent market-based price formation.
Source: IEA analysis based on International Gas Union (2025), Wholesale Gas Price Survey 2025 Edition.

India continued its midstream gas market reforms in 2025

India has taken a series of important regulatory steps in 2025 to strengthen gas security of supply, while also highlighting the need to further assess transmission tariff design.

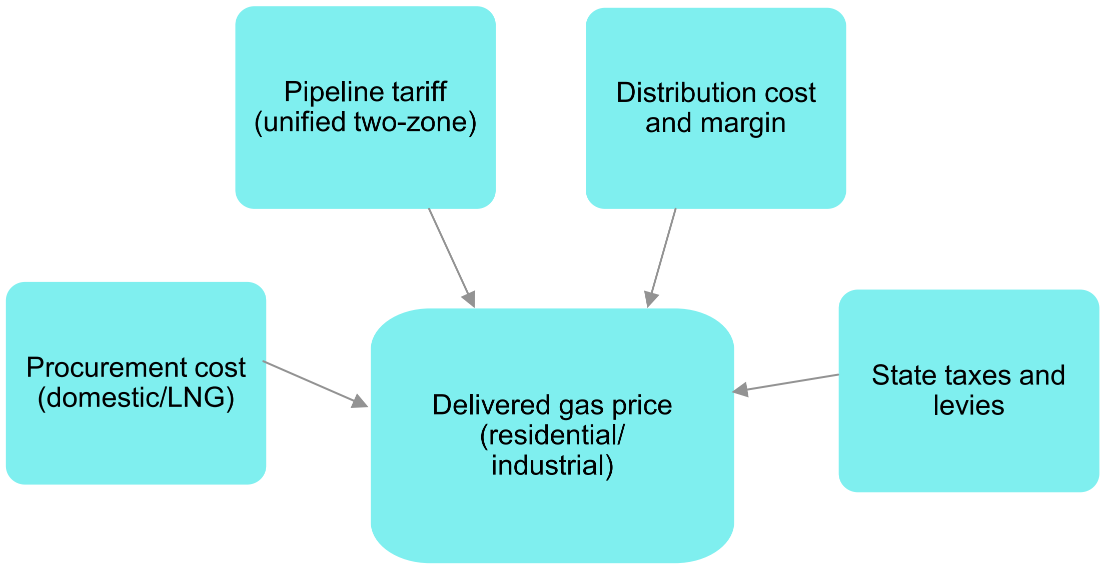
The government is currently considering a new requirement for LNG import terminals to retain at least 10% spare regasification capacity above operating levels as an emergency reserve for security-of-supply purposes. The measure remains under consultation but could, if adopted, offer a cost-effective strategic buffer – rather than developing underground gas storage – to mitigate the impact of short-term supply disruptions, although it would not fully insulate the market from global price volatility. At the same time, the recently notified LNG Terminal Regulations (2025) introduce greater transparency through mandatory disclosure of regasification and service charges, while reliance on commercial negotiation for third-party access underscores the importance of complementary transmission tariff reforms.

In parallel, the Petroleum and Natural Gas Regulatory Board (PNGRB) has approved a simplified unified gas transport tariff, reducing the number of national zones from three to two. This consolidation maintains a zonal framework, providing some harmonisation of charges while keeping locational signals, and allows most consumers located close to entry points to benefit from lower transport charges within the two-zone system. However, PNGRB has extended preferential tariff treatment to CNG and PNG consumers, for whom the Zone-1 tariff applies nationwide, irrespective of distance. Structural factors – such as ongoing network development, fragmented ownership and the absence of a virtual trading point – continue to limit the feasibility of adopting a hub-based or entry-exit system at this stage. While a single entry-exit tariff model could in theory simplify the structure and support a virtual hub, India's size and potential congestion mean that multiple zones or a zonal approach may better reflect physical and logistical realities. A careful assessment of alternative models through stakeholder consultation will be essential before any wider adoption. The draft Petroleum and Natural Gas Rules (2025) introduce reporting requirements on capacity availability in transmission pipelines. Earlier drafts had proposed extending similar reporting obligations to underutilised capacity at LNG import terminals, although these provisions were not retained in the final LNG terminal regulations.

Taken together, these regulatory developments point to a gradual shift toward more consistent market rules, while reinforcing the case for continued analytical review and stakeholder consultation to evaluate further transmission infrastructure reforms. Overall, the direction of reform is broadly consistent with the PNGRB High-Level Expert Committee's Vision 2040 report, which highlights the importance of independent system operation and expanded third-party access to support India's long-term gas market development.

India's simplified two-zone gas tariff improves pricing consistency, but regional cost factors still influence delivered gas prices

Key cost components shaping delivered natural gas prices in India



Natural gas market reforms continued at a varied pace in other Asian markets in 2025

Natural gas market reforms continued to advance across South and Southeast Asian countries in 2025. These were driven by a variety of considerations, including supply security concerns (e.g. Singapore), the need to reform prices (e.g. Pakistan), enhance third-party access to infrastructure (e.g. Malaysia) or support domestic production (e.g. the Philippines).

Singapore established a new government-owned entity, Singapore GasCo Pte Ltd (Gasco), in May 2025 to centralise the procurement and supply of natural gas for the country's power generators amid growing concerns over supply security and price volatility. Gasco is tasked with aggregating demand, negotiating long-term contracts on favourable terms, and diversifying supply sources to ensure stable prices and a reliable fuel supply.

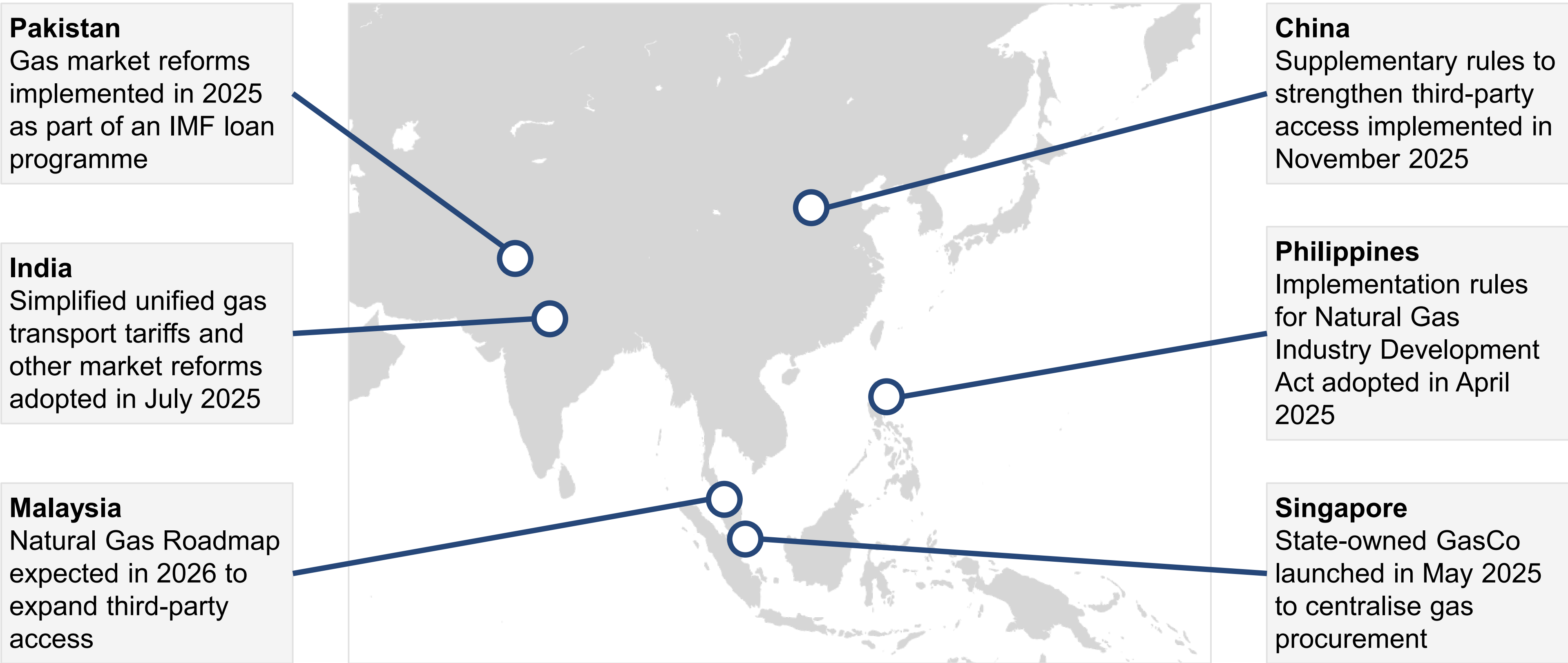
In **Malaysia** the Ministry of Economy has been developing a Natural Gas Roadmap, which was originally scheduled for launch in the second half of 2025 but has since been delayed to 2026. The roadmap aims to remove the remaining barriers to third-party access to the country's gas infrastructure, which is currently dominated by Petronas. The plan is also expected to outline a series of measures to boost investment in new pipelines, regasification terminals and the development of Malaysia's downstream gas market. Further gas price liberalisation – including in the power generation sector – is also reportedly under consideration in the new roadmap.

Pakistan implemented a number of gas market reforms in 2025 as part of its 37-month USD 7 billion IMF loan programme approved in September 2024. In June 2025, the Economic Coordination Committee raised natural gas prices for industrial users and power plants by 10% to improve cost recovery at the country's cash-strapped gas utilities. Earlier in 2025, the government introduced a 5% levy – rising progressively to 20% by August 2026 – on natural gas supplied to captive power plants to encourage large industrial consumers to shift to Pakistan's underutilised electricity grid. Since January 2025, exploration and production companies have also been allowed to sell up to 35% of their gas directly to end users without going through the state-owned utilities SNGPL and SSGC. The government also set up a working group to phase out cross-subsidies for residential gas users and replace them with targeted, means-tested transfers, although the new support scheme is not expected to be implemented before 2026.

The Philippines' Department of Energy adopted rules in April 2025 to implement the Philippine Natural Gas Industry Development Act, which requires power generators and utilities to source a minimum share of their supply from domestic natural gas. The measure is intended to revive exploration and production following steep declines at the Malampaya field and to limit the country's dependence on imported LNG.

Governments across Asia continued to pursue gas market reforms in 2025

Key gas market reforms and policy initiatives in Asia, 2025



The European Union agreed to phase out Russian gas by November 2027 at the latest

Russia's full-scale invasion of Ukraine led to the break-up of its decades-long energy ties with the European market, with Russian piped gas deliveries to the European Union falling by 90% between 2021 and 2025. In early December 2025, the European Union agreed to fully phase out Russian gas by November 2027 at the latest, ending over five decades of gas dependence.

The leaders of the European Union adopted the Versailles Declaration on 11 March 2022 and agreed to phase out the dependency on Russian fossil fuels as soon as possible. Building on the Versailles Declaration, the European Commission published the Communication on the REPowerEU Plan in May 2022 with the aim of rapidly reducing the European Union's dependence on Russian fossil fuels and building a more resilient energy system. The European Commission presented the REPowerEU Roadmap in May 2025 to set out a co-ordinated, secure and gradual phase-out of Russian gas, oil and nuclear energy imports. This was followed by the European Commission's legislative proposal in June 2025 to gradually phase out the import of Russian gas and oil by the end of 2027. In addition, the European Union adopted its 19th sanctions package against Russia on 23 October 2025. The new sanctions package introduced a full ban on Russian LNG imports from 1 January 2027. On 3 December 2025, the Council and the European Parliament reached a provisional agreement on a legally binding regulation to phase out Russian natural gas imports. The European Parliament voted on the regulation on 17 December 2025, which introduces a gradual phase-out of Russian natural gas imports:

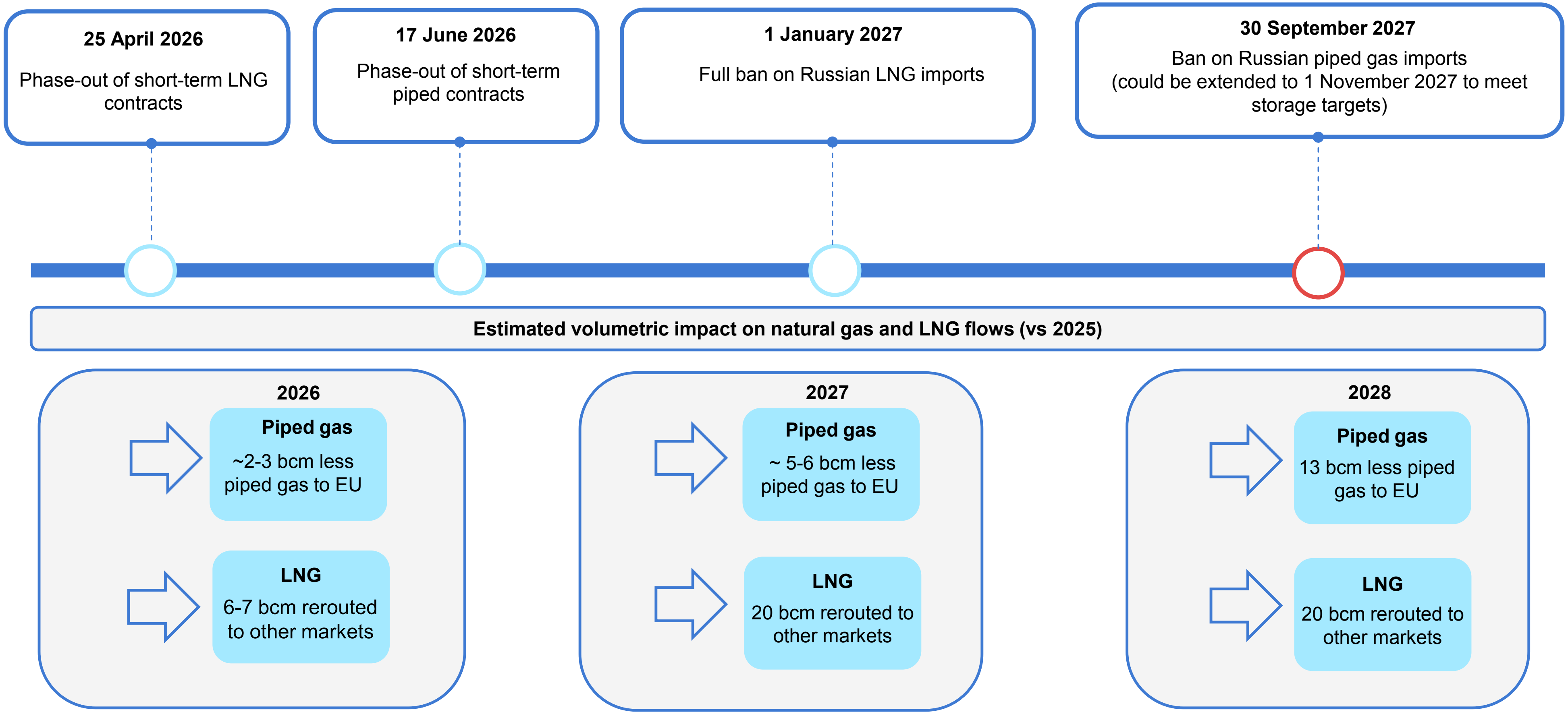
- For **short-term supply contracts** concluded before 17 June 2025, the prohibition on Russian gas imports will apply from 25 April 2026 in the case of LNG and 17 June 2026 for pipeline gas.
- For **long-term LNG import contracts**, the prohibition will apply from 1 January 2027.
- For **long-term pipeline gas contracts**, the prohibition will apply on 30 September 2027 provided that member states are on track to fulfil the storage filling targets in the gas storage regulation, and at the latest on 1 November 2027.

The regulation introduces pre-authorisation procedures to ensure that the prohibition on Russian gas imports is respected in practice. This includes providing proof of place of production of natural gas imports prior the entry to the European Union (although not applicable to major gas exporting countries that have a ban on Russian gas imports and/or have no gas import infrastructure).

Overall, the regulation is expected to reduce Russia's piped and LNG deliveries to the European Union by 33 bcm between 2025 and 2028. This could create additional market space for non-Russian LNG suppliers to EU countries. The regulation does not apply to Russian natural gas transiting the European Union to non-EU countries.

The phase-out of Russian gas creates additional market space for non-Russian LNG suppliers

Timeline for the phase-out of Russian natural gas imports into the European Union and estimated volume



Sources: Timeline of the phase-out as provided by Council of the European Union (2025), Council and Parliament strike a deal on rules to phase out Russian gas imports for an energy secure and independent Europe. Potential volumetric impact reflects IEA assumptions based on the analysis of the regulation.

Gas market update

Global gas demand growth slowed to below 1% in 2025

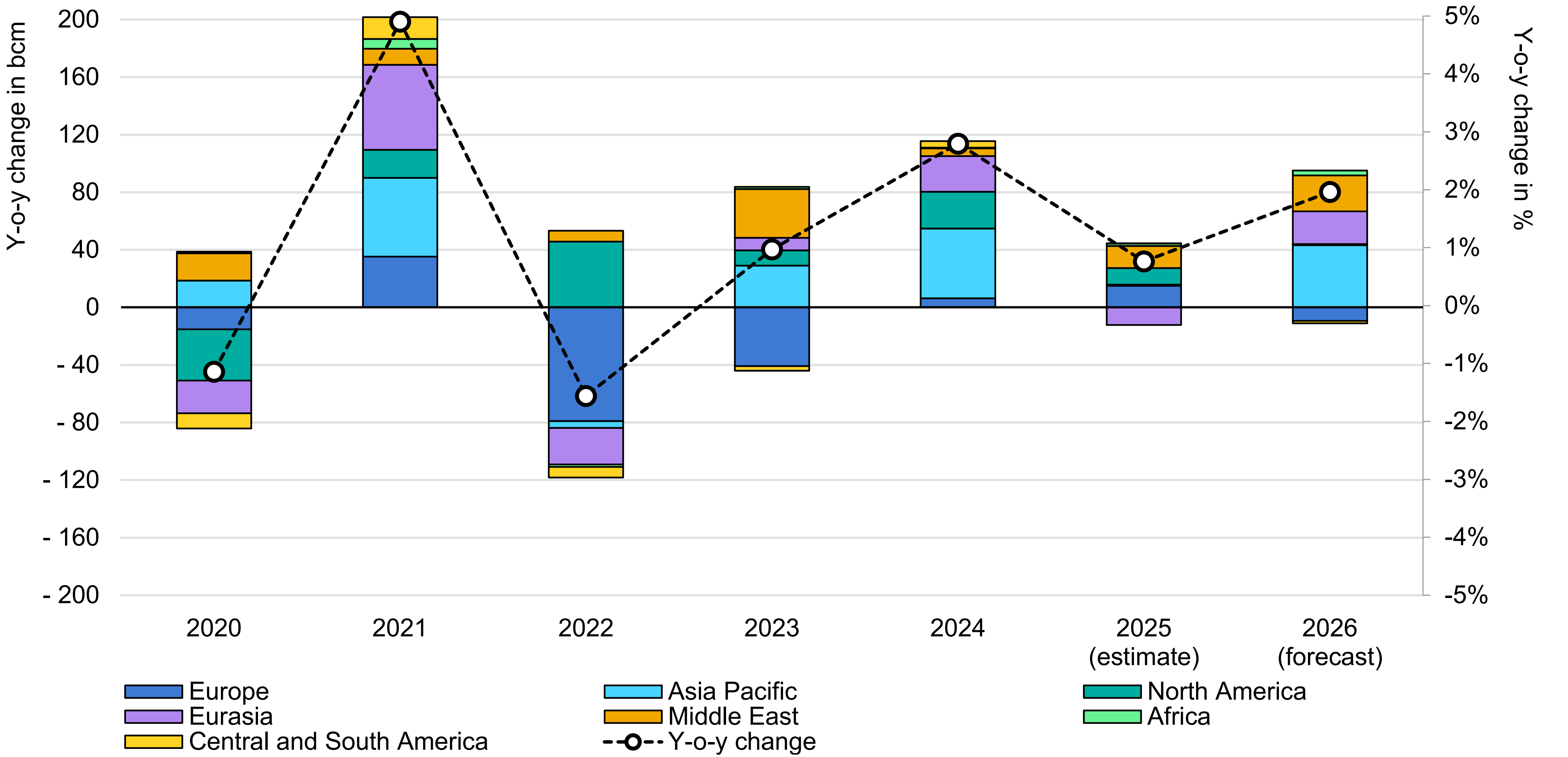
Following a relatively strong increase in 2024, **global gas demand growth slowed markedly** in 2025. A weaker macroeconomic environment together with relatively high spot LNG prices in H1 2025 weighed on natural gas consumption. In contrast with previous years, demand **growth was largely concentrated in Europe**, while in Asia natural gas consumption remained subdued and in Eurasia it declined.

Supply fundamentals remained relatively **tight in the first half of the year**. While global LNG supply increased by 4% (or 10 bcm) y-o-y in H1 2025, this was partially offset by lower Russian and Norwegian piped gas deliveries to Europe. In addition, stronger EU storage injections further tightened market fundamentals. This kept TTF and Platts JKM prices 30% and 40% above their previous year's levels in H1 2025, respectively. **Strong LNG supply growth** of more than 10% (or 28 bcm) y-o-y in H2 2025 **moved markets towards a gradual easing** from July on. Average TTF and Asian spot LNG prices fell 14% and 17% below their previous year's levels in H2 2025, respectively. Preliminary data suggest that global **natural gas demand increased by less than 1%** in 2025. In **OECD Europe**, natural gas demand grew by 3%, largely supported by stronger gas burn in the power sector amid lower wind and hydropower output. In **North America**, natural gas consumption increased by an estimated 1%, primarily driven by colder winter temperatures. Natural gas demand remained broadly in **Central and South America**, as stronger gas use in Brazil was offset by declines in the region's other markets. **Asia**'s natural gas demand in 2025 slowed to its weakest pace since 2022 and remained close to its 2024 levels. **Eurasian** gas demand declined by around 2% amid mild winter weather conditions. Combined demand in **Africa** and the **Middle East** grew by an estimated 2.5%, partly driven by oil-to-gas switching dynamics in the power sector.

Global gas consumption is expected to reach a new all-time high in 2026, with demand growth accelerating to nearly 2%. **Global LNG supply** is forecast to increase by over 7% (or more than 40 bcm), primarily driven by the United States, Canada and Qatar. Improving supply fundamentals are expected to foster stronger demand growth. Natural gas demand in the **Asia Pacific region** is expected to increase by more than 4% in 2026 to account for around half of global gas demand growth. In **North America** natural gas demand is projected to remain broadly flat, while it is expected to decline by 1% in **Central and South America**. In **Europe** the continued expansion of renewables is expected to reduce gas demand by 2%. In **Eurasia**, gas consumption is forecast to increase by 3.5% assuming a return to average weather conditions. Combined demand in **Africa** and the **Middle East** is projected to increase by 3.5% amid higher gas use in industry and the power sector.

Stronger LNG supply is set to accelerate global gas demand growth in 2026

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



Colder weather supported natural gas demand growth in North America in 2025

Natural gas consumption in North America increased by an estimated 1% (or 12 bcm) y-o-y in 2025. This growth was largely supported by the residential and commercial sectors, as colder winter temperatures in Q1 and Q4 increased space heating requirements across Canada and the United States. In contrast, gas-to-power declined through the year, as higher natural gas prices weighed on gas-fired power generation. Natural gas use in industry and the energy sector grew marginally compared with 2024.

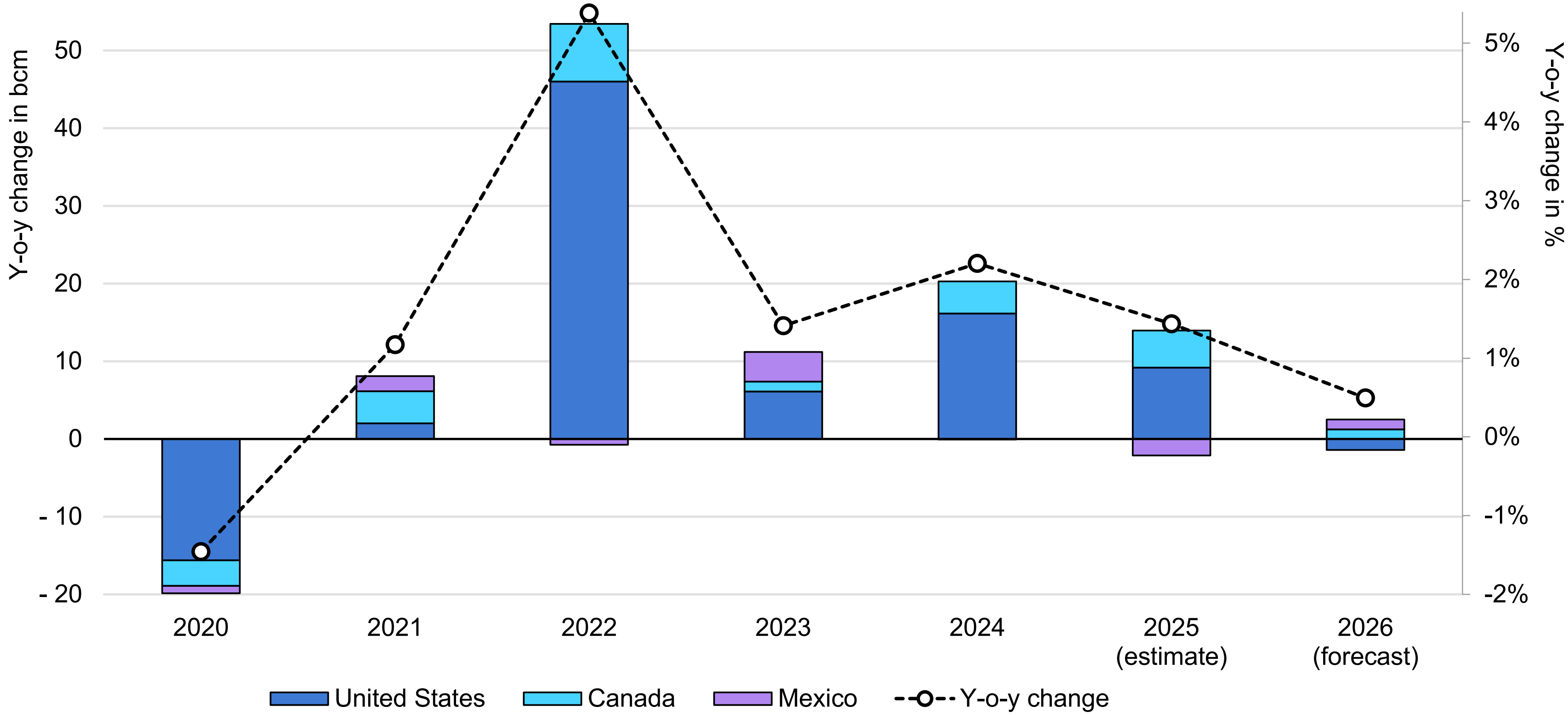
First estimates indicate that natural gas consumption in the **United States** increased by an estimated 1% (or 9 bcm) y-o-y in 2025. This growth was largely supported by stronger gas demand in the **residential and commercial sectors** over the winter season. Combined heating degree days in Q1 and Q4 increased by nearly 9% compared with 2024, which drove up natural gas use in the buildings sector by around 8.5% y-o-y. In contrast, **gas-to-power demand** in the United States declined by an estimated 3.5% (or around 13 bcm) y-o-y in 2025 amid stronger renewable power output and price-driven gas-to-coal switching. Tighter market fundamentals drove up natural gas prices, with Henry Hub spot prices rising by over 60% in 2025 compared with their previous year's levels. This strong increase in natural gas prices weakened the cost-competitiveness of gas-fired power generation vis-à-vis coal-fired power plants, which increased their output by more than 10% y-o-y. Consequently, the share of natural gas in power generation declined from 42% in 2024 to around 40% in 2025. Natural gas demand in **industry and the energy sector** increased by an estimated 1% (or 4 bcm) y-o-y, partly supported by stronger gas use by the country's growing LNG liquefaction fleet.

In **Canada** natural gas demand rose by an estimated 3.5% (or nearly 4 bcm) y-o-y in 2025. Similarly to the United States, colder weather conditions in Q1 and Q4 prompted higher gas use in the residential and commercial sectors. Combined gas demand in the industrial and power sectors rose by 2.7% y-o-y in the first ten months of 2025, largely supported by stronger gas-fired generation. In **Mexico** natural gas consumption declined by an estimated 2.5% (or 2 bcm) in 2025, primarily driven by lower gas burn in the power sector. Despite lower gas demand, Mexico's piped gas imports from the United States rose by 2.5% y-o-y in the first ten months of 2025 amid declining domestic gas production and higher LNG exports (relying on US-sourced feedgas).

Natural gas demand in North America is forecast to remain broadly flat in 2026. Natural gas use in the industrial and energy sectors is forecast to increase, partly driven by the region's expanding LNG liquefaction fleet. Gas-to-power demand is projected to grow marginally following the decline recorded in 2025. Gas use in the residential and commercial sectors is forecast to decline, largely offseting the growth expected in other sectors.

Natural gas demand is expected to remain broadly flat in North America in 2026

Year-on-year change in natural gas demand in North America by key market, 2020-2026



Sources: IEA analysis based on EIA (2026), Natural Gas Consumption; StatCan (2026), Supply and disposition of natural gas.

Natural gas demand in Central and South America stagnated in 2025

Following an increase of 3% in 2024, natural gas demand remained broadly flat in Central and South America in 2025. While the region's gas demand stagnated, both Argentina and Brazil substantially increased domestic gas production, which weighed on the Central and South America's LNG imports, declining by more than 10% in 2025.

Argentina's natural gas demand declined by 2% y-o-y in the first 10 months of 2025. Gas-to-power demand increased by around 4% y-o-y amid weaker hydropower generation in the first half of 2025. In contrast, gas burn in the power sector declined by more than 10% y-o-y during July-October amid improving hydropower output. Natural gas use in the residential and commercial sectors declined by around 1% y-o-y during the heating season (April-October) amid milder winter weather conditions. The country's industrial gas demand declined by 3.4% y-o-y in the first 10 months of 2025. Argentina's natural gas production increased by over 3% y-o-y in the first 11 months of 2025, primarily driven by strong shale gas output (up by 10% y-o-y) from the Vaca Muerta formation. Argentina started to export small volumes of piped gas from Vaca Muerta to Brazil via Bolivia in April and October. During 2025, Argentina reached FID on two FLNG projects with a combined capacity of 8 bcm/yr, which are expected to start operations in 2027 and 2028.

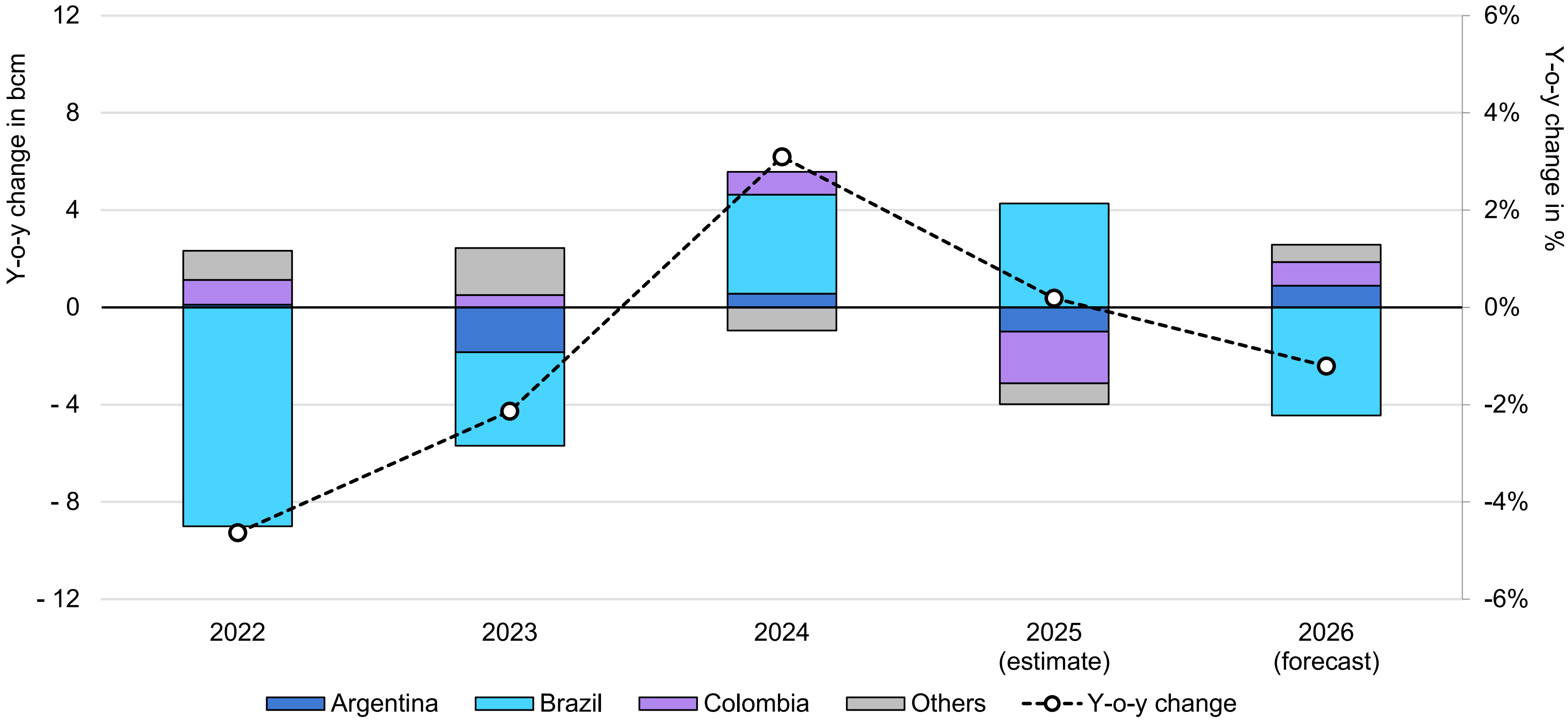
In **Brazil**, primary gas supply grew by an estimated 15% in 2025. This strong growth was largely supported by the country's rapidly expanding domestic gas production, which increased by around 17% compared with 2024. The Rota 3 pipeline (6.5 bcm/yr), commissioned in September 2024, enables greater takeaway from the offshore Santos Basin. Gas-to-power demand grew by more than 12% y-o-y in the first 11 months of 2025 amid lower hydropower output.

Other markets displayed varied demand patterns. In **Trinidad and Tobago** natural gas demand declined by 3% y-o-y in the first 8 months of 2025. In **Columbia** gas consumption dropped by almost 20% in 2025, as gas burn in the power sector plummeted by nearly 50% y-o-y in the first 11 months of 2025 amid a recovery in hydropower generation. In contrast, **Chile's** gas demand grew by 8% y-o-y in the first 9 months of 2025, partly supported by stronger gas use in the power sector. In **Peru** gas consumption declined by 1.3% in 2025, while **Bolivian** gas consumption grew by 2% y-o-y in the first 10 months of 2025, supported by stronger gas use in the residential and commercial sectors (up by 13% y-o-y), as well as higher gas demand in transport (up by 6%) and industry (up by 3%). LNG inflows to **Central America and the Caribbean markets** remained broadly flat, suggesting stagnating natural gas demand.

In 2026, natural gas demand in Central and South America is expected to decline by 1%. While gas use in indusry is forecast to continue to expand, this growth is largely offset by lower gas-to-power demand amid the expected recovery in hydropower output.

Stronger hydro output is expected to reduce gas demand in Central and South America in 2026

Year-on-year change in natural gas demand in Central and South America by key market, 2022-2026



Sources: IEA analysis based on ANP (2026), Boletim Mensal da Produção de Petróleo e Gás Natural; BMC (2026), Informes Mensuales; Central Bank of Trinidad and Tobago (2026), Statistics; MEEI (2026), Monthly bulletins; CNE (2026), Generación bruta SEN; ENARGAS (2026), Datos Abiertos; ICIS (2026), ICIS LNG Edge; IEA (2026), Monthly Gas Data Service; JODI (2026), Gas Database; OSINERG (2026), Reporte diario de la operación de los sistemas de transporte de gas natural.

Asia's natural gas demand remained broadly flat in 2025

Following strong growth of 5.5% in 2024, Asia's natural gas demand in 2025 slowed to its weakest pace since 2022, remaining broadly flat. The region's natural gas consumption fell by 1.5% y-o-y in H1 2025 due to a combination of weaker industrial activity, relatively high spot LNG prices, mild weather conditions in northeast China and improving nuclear availability in Japan. Preliminary data suggest that the declines recorded in the first half of the year were broadly offset by stronger natural gas use during Q3-4 2025, albeit the pace of demand growth remaining well below 2024 levels. In 2026, Asia's gas demand is projected to grow significantly more rapidly, by more than 4%, driven by rebounding industrial demand due to improved LNG availability, and by modest increases in the power, residential and commercial sectors.

China's natural gas demand is estimated to have grown by about 1% in 2025, marking a clear slowdown compared with 2024. Despite slightly weaker demand y-o-y in the first part of 2025, driven notably by lower heating demand and uncertain economic fundamentals, overall gas demand picked up in the second half of the year. While industrial activity indicators remained muted through much of the year, demand in sectors including manufacturing and chemicals is expected to record higher than in 2024. Overall economic growth suggests that the economy fared better than previously expected despite geopolitical uncertainty. Gas use in power generation, residential and commercial applications and in transport also contributed to overall demand growth. Gas supply remained more than ample throughout the year. Imports from Russia via the Power of Siberia pipeline ran at capacity for their first full year, adding nearly 8 bcm of supply, more than offsetting a decline in pipeline imports from Central Asia. Chinese domestic production grew by over 6% y-o-y, only slightly slower than in 2024, driven predominantly by conventional resource basins. Given relatively fragile demand fundamentals and reduced storage injection needs (following lower withdrawals in the previous winter), LNG imports fell by 14% y-o-y (or 15 bcm), acting as the supply-side balancing lever in the Chinese market. In 2026, we expect Chinese gas demand growth to pick up to about 5% y-o-y, driven predominantly by the industrial sector and power generation as easing LNG market fundamentals allow second-tier buyers to return to the global market.

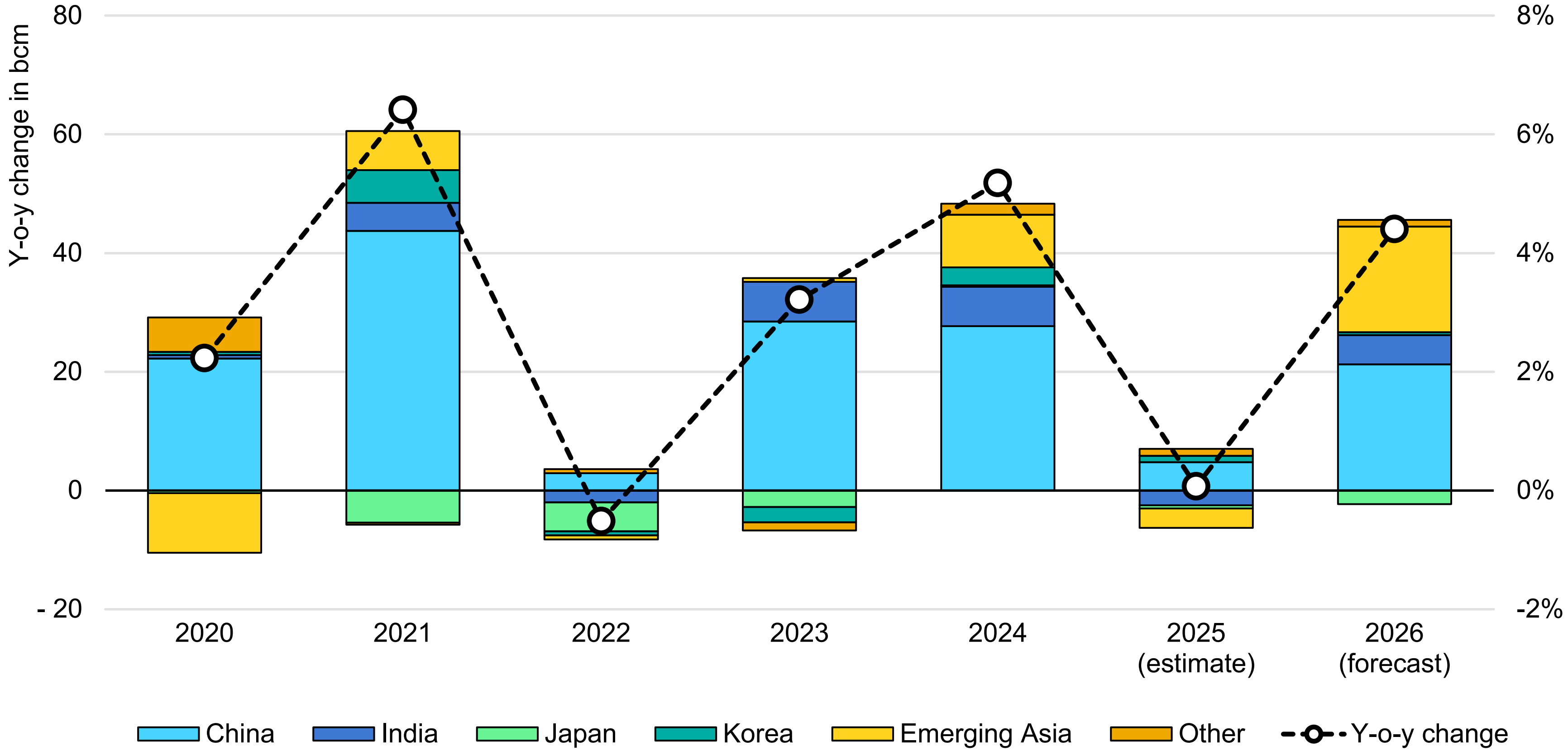
Japan's natural gas consumption decreased by an estimated 1% y-o-y in 2025, driven by reduced gas use for power generation amid higher renewable output and improving nuclear availability. In 2026, Japan's gas demand is expected to decline by close to 2.7%, mainly driven by lower gas use in power generation amid nuclear restarts and robust renewable growth. Tokyo Electric Power Company's Kashiwazaki-Kariwa Nuclear Power Plant Unit 6 (1.356 GW) is moving toward restarting operations following approval by the local mayor last December. It is scheduled to begin operations on January 20th, undergo pre-operation inspections, and if approved, commence commercial operation on February 26th. If commercial operation begins without incident, it will mark the first time in 15 years since the earthquake that a Tokyo Electric Power Company nuclear power plant has been operational. If the unit is brought back online, gas demand in 2026 is expected to decline further. **Korea**'s natural gas demand increased by an estimated 1% y-o-y in 2025, mainly driven by the power sector, along with more modest increases in the residential and commercial sectors. Despite the addition of new nuclear capacity, gas demand in 2026 is projected to remain flat, as declining coal use in the power generation sector and modest increases in industrial, residential and commercial consumption offsets the headwinds from nuclear.

India's total natural gas consumption declined by an estimated 3.5% y-o-y in 2025, with the contraction primarily concentrated in key industrial sectors. Gas-to-power demand and gas use in oil refining fell by about 16% y-o-y in the first 11 months of 2025, while consumption in fertiliser production declined by around 2% y-o-y. In the power sector, demand normalised following the exceptional heatwave-driven surge in 2024. In both refining and fertilisers, higher LNG prices made alternatives such as LPG and naphtha more competitive, further reducing gas use. Not all segments weakened, however. City gas demand remained robust, rising nearly 9% y-o-y, supported by ongoing expansion of city gas distribution networks and the continued increase in CNG vehicle use. India's domestic gas production declined by roughly 3% y-o-y over the same period. As demand fell more sharply than domestic supply, LNG imports dropped significantly – by nearly 7% y-o-y in the first ten months of 2025. Looking ahead to 2026, a recovery is anticipated, with gas consumption forecast to grow by about 7% supported by the continued build-out of city gas networks and CNG filling stations, rising industrial gas use and increasing electricity needs – particularly to meet peak demand.

First estimates indicate that **Emerging Asia**'s natural gas consumption fell by around 1% y-o-y in 2025. The region's LNG imports (net of reloads) grew by close to 4% through the year, only partially offsetting the production declines recorded in some of the region's producers. **Thailand**'s natural gas consumption fell by 5% y-o-y in the first 11 months of 2025, primarily driven by steep declines in power sector gas use. In **Indonesia** natural gas consumption declined by around 1% y-o-y in the first 10 months of 2025. First estimates suggest that **Malaysia**'s gas demand increased by around 1.5% y-o-y in the first 10 months of 2025. **Pakistan**'s natural gas consumption is estimated to have declined by around 8% y-o-y in 2025, partly driven by weaker gas burn in the power sector. The country's domestic gas output fell by 9% y-o-y in H1 2025 amid deteriorating upstream productivity. Pakistan's LNG imports fell by 10% y-o-y in 2025. In contrast, natural gas demand in **Bangladesh** grew by an estimated 4% in 2025, primarily supported by industry. The country's LNG imports increased by 31% y-o-y in 2025 amid stronger demand and a continued decline in domestic natural gas output. **In 2026**, Emerging Asia's gas consumption growth is expected to accelerate to around 7%, driven by recovering gas use in both the power and industrial sectors amid rising overall energy needs, moderating prices and improving macroeconomic conditions.

China and Emerging Asia are expected to drive stronger gas demand growth in Asia in 2026

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



Note: Emerging Asia comprises Bangladesh, Indonesia, Malaysia, Myanmar, Pakistan, the Philippines, Singapore, Thailand and Viet Nam.
Sources: IEA analysis based on ICIS (2026), ICIS LNG Edge; JODI (2026), Gas World Database; PPAC (2026), Gas Consumption; EPPO (2026), Energy Statistics, Korea Energy Economics Institute (2026), Monthly Energy Statistics, Ministry of Economy, Trade and Industry of Japan (2026), METI Statistics.

European natural gas consumption grew by 3% in 2025

Natural gas consumption in OECD Europe rose by around 3% (or 12 bcm) in 2025, its strongest increase since 2021. Growth was **primarily concentrated** in Q1, when cold weather and lower renewable power output drove up natural gas demand by 9% y-o-y. Following this strong increase in Q1, European natural gas demand remained broadly flat in Q2-4 2025. The **power sector was the most important driver** behind higher gas use through the year, as stronger electricity demand together with weaker wind and hydropower output drove up gas-based power generation. In contrast, higher natural gas prices weighed on natural gas use in industry in 2025.

Distribution network-related demand rose by an estimated 2% (or almost 4 bcm) in 2025, with growth entirely concentrated in Q1. Heating degree days increased by more than 10% y-o-y in Q1, which naturally drove up space heating requirements across households and commercial entities. This growth was partially offset in Q4 2025, when milder winter weather conditions reduced natural gas use in buildings by an estimated 1.5% y-o-y. While temperatures were on average milder in Q4 2025, Europe faced a cold spell in mid-November, which led to a sharp increase in gas use across the residential and commercial sectors. Daily natural gas demand surged by more than 70% between 14 and 21 November, highlighting the crucial role natural gas plays in ensuring security of heat supply.

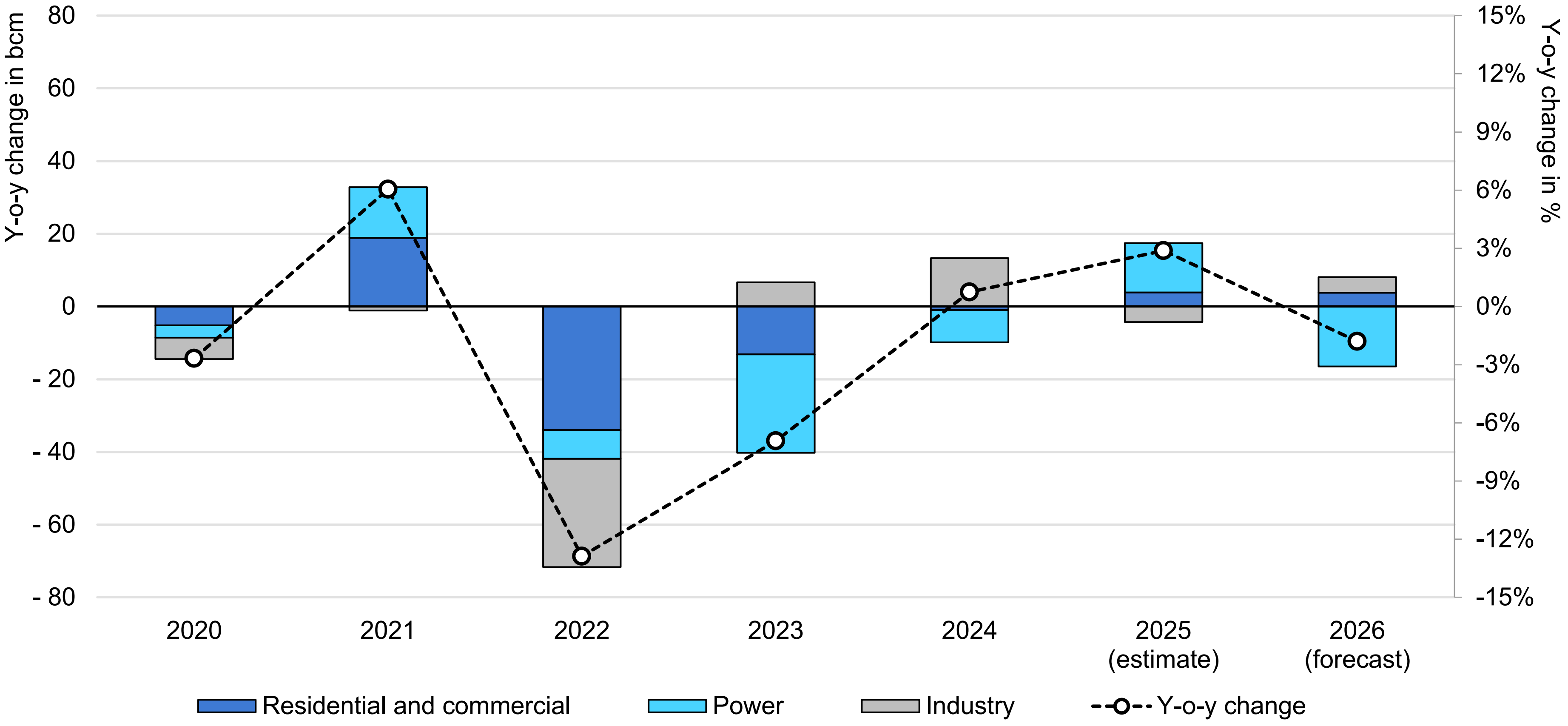
Gas-to-power demand rose by 11% (or 13 bcm) in 2025. This steep increase was supported by a combination of stronger electricity consumption (up by around 1%) and lower renewable power output. While solar power generation rose by an impressive 24% compared with 2024, this was more than offset by lower wind and hydropower generation. Wind power output recorded a 1% y-o-y decline amid slower wind speeds across Northwest Europe, while hydropower generation fell by around 12%, primarily due to lower hydro availability in Southern Europe.

Natural gas consumption in industry declined by around 3% in 2025 amid higher natural gas prices. Estimated industrial gas consumption decreased by 2.5% in Belgium, by 7% in France, by 5% in Spain, and by more than 10% in the Netherlands in 2025. First data suggest that this decline was primarily driven by the refining and fertiliser sectors.

This **forecast** expects Europe's natural gas demand to decline by 2% in 2026. The continued expansion of renewables is projected to reduce gas burn in the power sector by 12%. In contrast, natural gas use in industry is expected to increase by around 3% amid improving supply availability. Gas demand across the residential and commercial sectors is forecast to increase by 2% assuming average weather conditions.

Europe’s natural gas demand is projected to decline by 2% in 2026

Year-on-year change in natural gas demand by sector in OECD Europe, 2020-2026



Sources: IEA analysis based on Enagas (2026), Natural Gas Demand; ENTSOG (2026), Transparency Platform; EPIAS (2026), Transparency Platform; Trading Hub Europe (2026), Aggregated consumption.

The start of the LNG wave is reaching the global gas market

LNG trade grew by a robust 6.7% (or 37 bcm) in 2025, marking a clear acceleration from more moderate average annual growth of below 3% (or about 14 bcm) over the previous five years. With new liquefaction projects ramping up – particularly in North America – the next long-anticipated LNG supply wave started reaching the market in 2025, helping ease the global gas market tightness that had settled in since the 2022-2023 supply shock. However, while Europe relied on this extra supply to import a record amount of LNG, Asian imports fell year-on-year, highlighting that 2025 remained a transition year for overarching gas market conditions. In 2026, the continued ramp-up of new LNG export projects is expected to bring even more incremental supply to the market, helping drive LNG import growth in both Asia and Europe.

The start of a new LNG supply wave outweighed declines at key legacy LNG exporters

2025 is expected to have marked the beginning of the LNG supply wave that is set to materialise in the second half of this decade, kick-started by new liquefaction projects coming online predominantly in North America. Combined exports from Canada, Mexico and the United States grew by 32% (or 38 bcm) y-o-y in 2025. US exports led the charge, with Plaquemines LNG (which exported its first cargo in the final days of December 2024) contributing about 23 bcm of new supply on its own and the Corpus Christi Train 3 expansion project delivering close to 4 bcm of extra supply, skewed towards the second half of 2025. Further upside came from Freeport LNG thanks to improved operations at the plant, as well as to debottlenecking works undertaken in 2024.

Canada and Mexico together drove about 4.5 bcm of extra supply following the start-up of LNG Canada (the country's first liquefaction project) in July and the ramp-up of Fast LNG Altamira in Mexico following the start of exports in the third quarter of 2024.

Despite the production ramp-up of two new African liquefaction projects in 2025 (Tango FLNG in Congo and Tortue FLNG in Senegal) and improved operations in Angola, Mozambique and Nigeria adding over 5 bcm of supply, continued declines at some legacy producers scaled back the continent's incremental exports to less than 2 bcm. First among these was Algeria, where exports fell by 18% (or nearly 3 bcm) y-o-y as a result of tightening domestic market fundamentals. While Egyptian LNG exports had already fallen drastically in 2023 and 2024, the near halting of loadings meant that they fell by a further 0.4 bcm in 2025 (see Egypt below).

The Middle East is the only other region to have seen material net growth in LNG exports, led by Qatari loadings increasing by about 5.5% (or 6bcm) on strong upstream production and optimised liquefaction operations. While loadings from Central and South America also improved, exports grew only marginally y-o-y.

In Asia, exports fell by about 1% y-o-y (or 1.8 bcm). Australia led the decline, with the NWS LNG plant permanently shutting down one of its five trains in July due to declining feedgas availability from ageing upstream assets. Indonesian LNG loadings also declined and a record share of its cargo shipments were destined for the domestic market. Faced with strong domestic demand, the government increasingly exercised export limitations, diverting several cargoes to the domestic market that would otherwise have been exported. The only noticeable increase in exports in the region came from Papua New Guinea where exports rose by about 7.5% y-o-y (or 0.8 bcm), recovering to average output levels of recent years.

Russian exports also slowed in 2025, hampered by international sanctions on its two small-scale plants (Vysotsk LNG and Portovaya LNG) since March. Exports from the country's largest plant, Yamal LNG, were also down by about 7.5% y-o-y (or 2 bcm), linked notably to a more intensive planned maintenance schedule. In total, despite sporadic deliveries to China from the sanctioned Arctic LNG 2, Russian LNG exports fell by about 7% y-o-y (or 3 bcm).

Finally, Norway was also a significant source of downside LNG supply as planned and unplanned maintenance significantly affected loadings from May to August. As a result, Norwegian LNG exports fell by nearly 35% y-o-y (or over 2 bcm).

On the import side, 2025 brought about somewhat of a reversal in trade dynamics compared with 2024. In 2024, robust pipeline supply in Europe and a sharp slide in global gas prices early in the year combined to drive an 18% y-o-y (or 30 bcm) decline in European LNG imports and a 7% y-o-y (or 26 bcm) increase in Asian LNG imports in that year.

In 2025, however, European LNG imports returned to growth, increasing by 30% y-o-y (or 40 bcm), more than the incremental LNG supply that reached the global market. The combined effect of the halt in the Ukrainian transit agreement for Russian gas to Europe, lower Norwegian pipeline deliveries, more robust demand and increased storage injection needs led to a tighter European balance, sparking an increased reliance on LNG to balance the regional market.

Outside Europe, Egypt is the market that saw the largest import growth by far, with an incremental take of over 9 bcm y-o-y (or 280%), pushing the country's total LNG imports to a record 12.5 bcm as domestic production fell to decade lows and demand remained strong.

Conversely, LNG imports declined by 3% y-o-y (or 11 bcm) in Asia, although not all markets followed this trend. As in 2022 (when Asian LNG imports scaled back in parallel with a significant increase in European imports), China accounted for the most significant drop in LNG imports in 2025, falling by 14% y-o-y (or 15 bcm). The largest monthly decreases occurred in the first half of the year, coinciding with a period over which spot LNG prices remained above prior-year levels. Combined with weak demand dynamics and robust alternative supply (from both pipeline imports and domestic production), these market conditions facilitated a scale-back in Chinese spot market buying. While overall weaker industrial activity played a role in China's LNG import pull-back in both 2022 and 2025, the repeat of these episodes at times of strong LNG import growth in Europe highlights China's growing role as a balancing lever in the global LNG market.

Imports into India, Pakistan and Japan fell by about 4%, 10% and 1% y-o-y, respectively, for a total decline of over 3 bcm in 2025. Spot pricing is likely to have played a role in declining imports in both India and Pakistan, where a share of imports has shown to be highly price elastic. The decline in Japan, conversely, was mostly attributable to power sector dynamics, with the continued recovery in nuclear availability, growth in solar PV generation and relatively competitive coal prices compared with other thermal sources.

However, a number of other Pacific Basin markets – including much smaller ones – maintained LNG import growth. Chinese Taipei, where the last nuclear reactor was disconnected from the grid in May 2025, increased its LNG imports by 10% y-o-y (or 3 bcm). Bangladesh's imports grew by over 30% y-o-y (or 2.5 bcm), as the country's state-owned gas distributor accelerated spot purchases to complement term LNG imports in supporting power generation.

The Philippines and Viet Nam, which both started importing LNG in 2023, increased their imports by about 45% and 65% y-o-y, respectively in 2025 (or 1 bcm and 0.3 bcm, respectively) as LNG-to-power projects ramped up in both countries.

In Central and South America, LNG imports eased by 12% y-o-y (or over 2 bcm) as Argentinian domestic gas production grew and hydro conditions in both Brazil and Colombia improved, reducing power sector gas burn.

Middle Eastern LNG imports grew by 9% y-o-y (or 1 bcm) as Bahrain began importing LNG at its previously largely inactive regasification terminal to meet summer power load.

Stronger supply growth set to support import activity across most regions

In 2026, we expect global LNG supply to increase by over 7%, or 42 bcm, as new liquefaction projects continue to ramp up production and some (although not all) of the downside factors that emerged in 2025 are cast aside.

North America is again set to drive supply growth, with the United States, Canada and Mexico together providing close to 37 bcm of incremental supply to the market. In the United States, Plaquemines LNG's two phases (27 bcm/yr capacity) are expected to reach full utilisation in 2026, the remaining trains of the Corpus Christi Stage 3 expansion project (14 bcm/yr capacity) are expected to start before the year's end and Golden Pass LNG (21 bcm/yr capacity) is set to start exports in the first half 2026 (delayed from an original target start in 2024).

LNG Canada Train 2 (7 bcm/yr capacity) is set to export its first cargo in Q1 2026, ramping up through the rest of the year, while Energia Costa Azul LNG (4.4 bcm/yr capacity), Mexico's second liquefaction plant, is set to start around mid-year.

Key projects are set to come online outside North America as well. Qatar's North Field East project (43.5 bcm/yr capacity) is set to start in the second half 2026 and to progressively ramp up production over the coming years (although some of this extra supply in 2026 could be partially offset by a return to more normal production levels from existing capacity following a record year in 2025). In Australia Pluto LNG Train 2 (6.8 bcm/yr capacity), supported by first gas at the offshore Scarborough field, is also expected to start in the second half of the year.

Finally, two West African projects are set to start up in 2026: Congo FLNG 2 (3.3 bcm/yr capacity), the country's second project, and Cap Lopez LNG (1 bcm/yr capacity) in Gabon. Further supply upside is set to come from the ramp-up of Senegal's Tortue FLNG (3.4 bcm/yr capacity), which started operations in 2025. However, the continent faces downside pressure too, as Algerian exports risk declining for a third year in a row and the Hilli Episeyo FLNG unit (3.3 bcm/yr capacity) offshore Cameroon is set for decommissioning in the year.

Other global downside factors that emerged in 2025 are not expected to affect the market in the same way this year. After three years of decline, Egyptian exports have relatively little space to decline further before ceasing altogether; sanctions on two of Russia's liquefaction plants were already in place for most of 2025; and, after significant maintenance in 2025, Norway's Hammerfest LNG is expected to return to normal operations in 2026. That being said, traditional downside risks related to feedgas availability, plant operations and unforeseen events remain highly relevant in 2026.

LNG supply growth in 2026 is expected to allow imports to increase simultaneously in Europe and Asia, a shift from dynamics over the past six years where LNG import growth in one region coincided with a reduction in the other. Higher storage injection needs, a progressive recovery in demand and increased pipeline exports to Ukraine are expected to increase Europe's LNG take this year, although by much less than in 2025. The region's LNG imports could grow by around 7% (or 12.5 bcm).

The continued emergence – and acceleration – of the LNG supply wave in 2026 is expected to continue easing broader market tightness and competition for the commodity. Under more benign market conditions, we expect importers in Asia to have greater opportunities to renew spot market purchases, increasing overall LNG imports by around 6% (or over 22 bcm). China remains key as pipeline imports flatline and gas demand growth is expected to recover, although LNG imports are set to remain well below their 2021 peak. India, among the more price-responsive markets in the region, is expected to return to import growth as well, surpassing its 2020 LNG import peak.

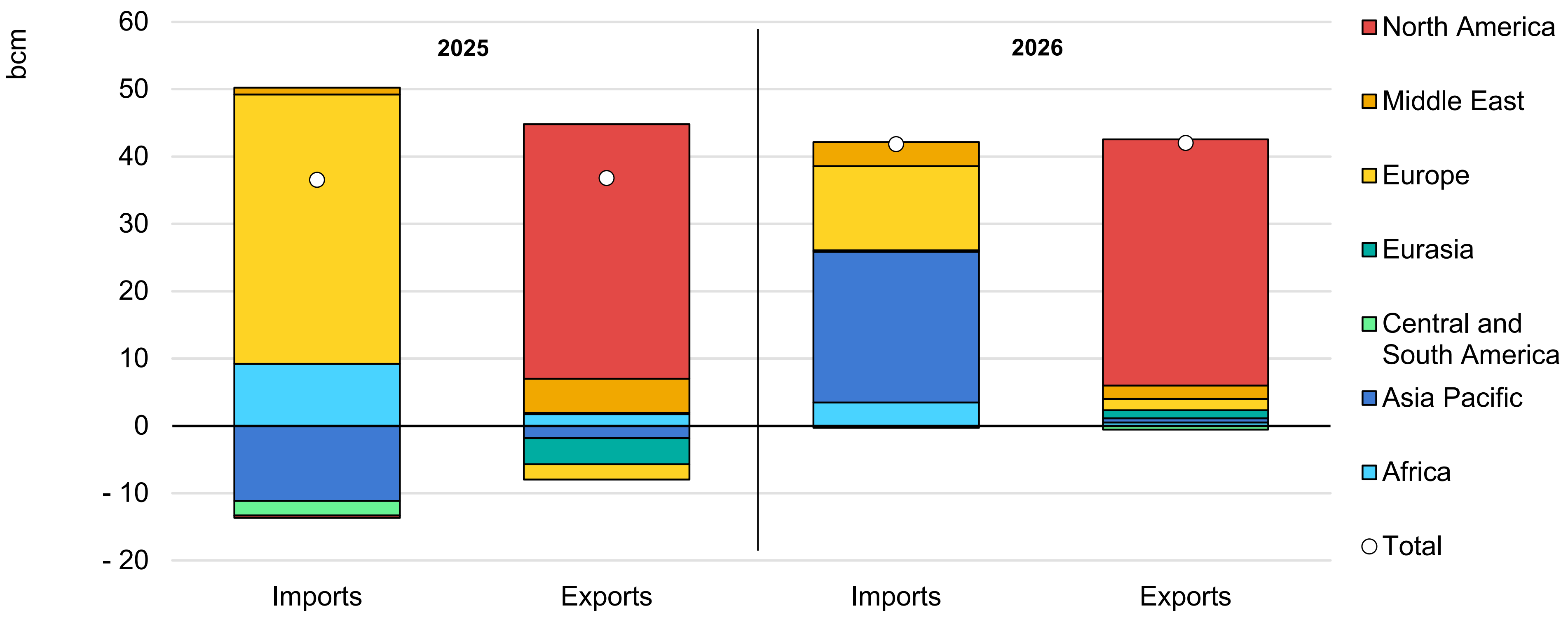
Smaller markets in the region, where LNG imports play a key role in supporting rapidly growing electricity demand, are set to act as a third pillar of LNG import growth, although they are likely to remain highly reactive to how market conditions evolve. As always, spot LNG pricing, the scaling-up of renewable power generation and electricity demand growth are all set to be key influencing factors in the region.

Other regions are also set to take advantage of improving LNG market fundamentals. Markets in the Middle East, where fuel oil is increasingly being substituted by natural gas in electricity generation, are set to increase their LNG imports. Iraq is expected to start importing LNG following the planned commissioning of a floating LNG terminal as an alternative to pipeline gas imports from Iran. In Egypt – Africa's only LNG importer – the relative stabilisation of domestic production since the start of 2025 and planned debottlenecking works on Israel-Egypt pipeline capacity could limit LNG import growth in 2026. However, domestic demand is likely to keep LNG needs at robust levels.

In Central and South America, a return to more normal drought and hydro conditions and growing Argentine gas production are likely to act as bearish factors on the region's LNG imports. However, LNG imports into Caribbean and Central American markets – which grew at an average annual rate of about 15% from 2018 to 2025 – are likely to continue increasing.

Both Asia and Europe are set to benefit from continued LNG supply growth in 2026

Incremental year-on-year LNG supply and demand by region, 2025 and 2026



Source: IEA analysis based on ICIS (2026), LNGEdge.

Growing LNG feedgas requirements drive US natural gas production growth

After a flat 2024, **US dry gas production regained momentum in 2025**, growing by 4% y-o-y and reaching an all-time high. All major basins had returned to production growth by Q2 2025 as demand-side drivers accumulated – predominantly rapidly rising LNG exports – and Henry Hub prices remained above prior-year levels through the whole of 2025. Looking ahead production growth is expected to continue into 2026, driven by increased feedgas requirements for LNG exports and stable domestic demand dynamics. Nevertheless, production upside could be affected by infrastructure limitations, particularly in the Appalachian Basin but also in the Permian. Furthermore, with LNG feedgas requirements as the primary demand-side driver, US production growth will be sensitive to the actual pace of liquefaction project ramp-ups.

Permian

The Permian accounted for close to 50% of US production growth in 2025, in line with the basin's leading role in driving incremental production in recent years. The importance of oil market dynamics in driving associated gas production meant that the basin was largely sheltered from US gas market weakness in 2024. In 2025, Permian Basin oil production growth slowed considerably, reflecting weaker crude market fundamentals as oil prices fell year-on-year. Still, Permian associated gas production growth remained robust at around 10% y-o-y in 2025 (compared with 13% y-o-y in 2024), helped by rising gas-to-oil ratios, both from ageing wells and from new wells being drilled in gassier zones of one of the United States' oldest oil-producing basins. These dynamics are expected to continue supporting Permian gas production growth during 2026.

However, Permian gas dynamics remain sensitive to pipeline offtake constraints. Simultaneous maintenance on the Permian Highway Pipeline (connecting Waha Hub in west Texas with the US Gulf Coast) and the El Paso system (running westward to demand centres in California and the Southwest) in October 2025 drove Waha Hub prices to USD -9.12/MBtu, their deepest ever negative territory, as shipping gas to potential buyers became more difficult. These events highlight persistent infrastructure bottlenecks despite the Matterhorn Express Pipeline's start-up in October 2024, which alleviated constraints in central Texas but shifted pressure eastward closer to LNG export terminals. Although pipeline projects such as Blackcomb – which aims to move Permian gas to the Gulf Coast – have been sanctioned, commissioning could slip to beyond 2026, suggesting limited incremental takeaway capacity in the near term.

Appalachian

Appalachian Basin gas production grew by about 1.6% y-o-y, contributing around 15% to US incremental output in 2025 and surpassing the region's 2023 peak annual production. This growth was largely helped by the additional takeaway capacity provided by the Mountain Valley Pipeline (MVP), which came online in late 2024. The pipeline, commissioned 10 years after originally planned due to a series of legal and regulatory setbacks, provides an extra connection to the Transcontinental Pipeline to transport gas to demand centres in both the Northeast and the South. However, while the basin benefits from abundant and low-cost natural gas reserves, with the MVP already nearing peak utilisation, takeaway constraints remain a key factor in regional dynamics. Recently approved pipelines are expected to come online only in the medium term, while minor gathering expansions likely to be commissioned in 2026 are set to provide only limited relief. Nevertheless, strong in-basin demand fundamentals – notably from in-basin gas-to-power demand driven by data centres – and the appeal of low-cost operations should continue to support production growth in 2026.

Haynesville

Haynesville shale production saw a major turnaround in 2025. After a period of year-on-year decline through all of 2024 and early 2025, monthly production had returned to year-on-year growth by Q2 2025. As a higher-cost region, it proved to be the most affected by weak pricing dynamics in 2024. Producers deferred well completions during the low-price environment and the rig count continued its downward trend in Q1 2025. However, with Henry Hub prices up year-on-year from December 2024 onwards, wells that were drilled but not completed were progressively brought online. While Henry Hub prices in H1 2025 averaged 74% higher than in the same period in 2024, Haynesville production growth sped up in the second half of the year, coinciding with an acceleration in US LNG exports.

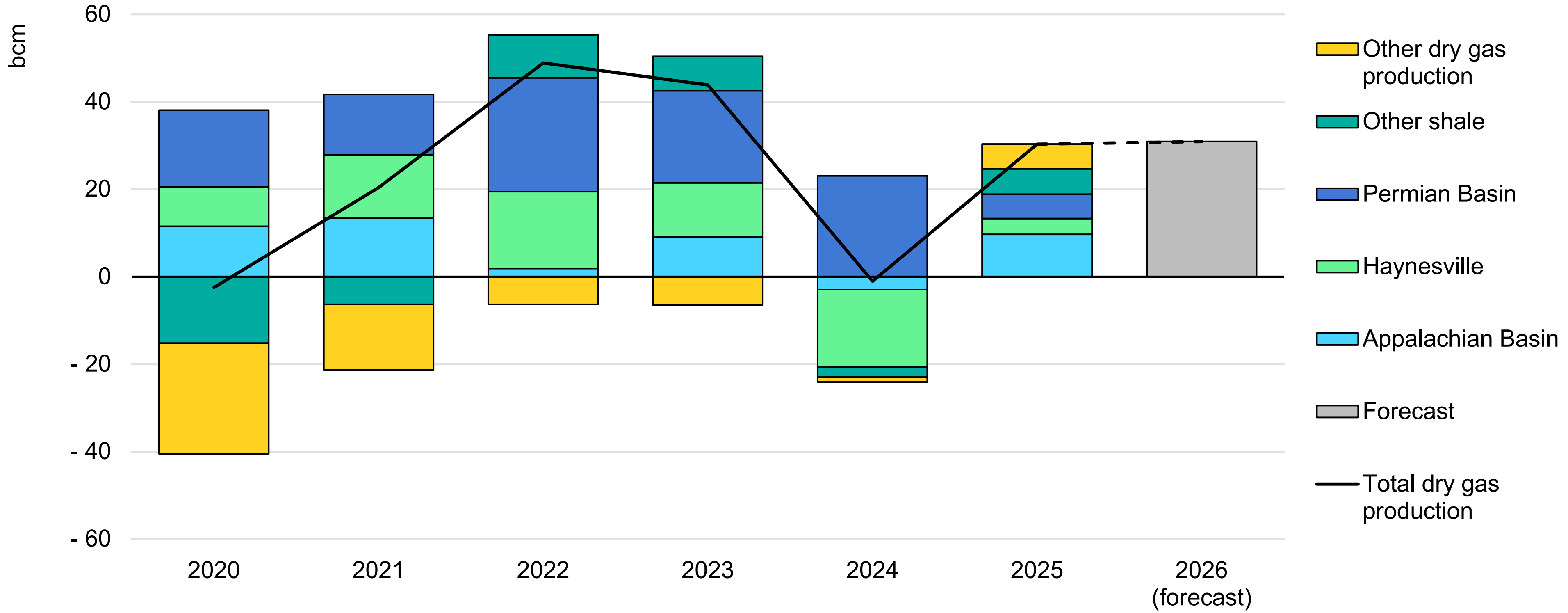
By the second half of 2025, the rig count in Haynesville was up year-on-year, signalling confidence in more bullish gas market fundamentals going into 2026. Still, Haynesville production rose only 0.7% y-o-y in 2025, still 11% below its 2023 peak, highlighting the cautious nature of this revival. The basin’s proximity to major LNG export hubs and its favourable infrastructure position make it well-placed to benefit from accelerating LNG exports. However, producers in the region will remain reactive to underlying gas price dynamics, highly influenced by the delicate balance between the ramp-up in new liquefaction projects and how fast new supply comes to market.

Short-term outlook

The continued ramp-up of new liquefaction projects is expected to remain a major market driver in 2026. US LNG exports grew by over 30 bcm in 2025 and are expected to grow by more than 20 bcm in 2026, compared with average annual incremental LNG exports of only about 15 bcm over the previous five years. Further export needs are set to come from the ramp-up of a second liquefaction terminal in Mexico supplied by gas from the United States. Despite this historically large increase in LNG export requirements, the US natural gas market is expected to remain well-supplied, with dry gas production expected to grow by about 2% in 2026.

US dry gas production returned to growth across most plays in 2025

Year-on-year change in dry natural gas production by basin in the United States, 2020-2026



Note: 2025 includes estimated data; 2026 is forecast value.
Source: IEA analysis based on Energy Information Administration (2026), Natural Gas.

Europe's LNG imports rose to an all-time high in 2025

OECD Europe's primary natural gas supply increased by an estimated 5.5% (or almost 25 bcm) in 2025. The strong increase in LNG imports offset the declines recorded in piped gas imports, while OECD Europe's non-Norwegian gas production increased marginally compared with last year.

Europe's **LNG imports** rose by 30% (or 40 bcm) and reached an all-time high of over 175 bcm in 2025. Stronger domestic demand, together with lower piped gas imports and higher storage injections during April-October, kept European LNG netback prices at a premium compared with key Asian markets. This in turn incentivised flexible LNG cargoes to flow towards Europe. Consequently, the share of LNG in Europe's primary natural gas supply rose from 30% in 2024 to 38% in 2025. The United States increased its LNG deliveries to Europe by 60% y-o-y in 2025 and accounted for almost all incremental LNG supply to Europe during the year. The strong supply of US LNG played a key role in refilling Europe's gas storage sites ahead of the 2025/26 winter season. **Russian LNG** inflows fell by 10% (or 2 bcm), although Russia remained Europe's second-largest LNG supplier. Belgium, France and Spain accounted for over 85% of Europe's total LNG imports from Russia in 2025.

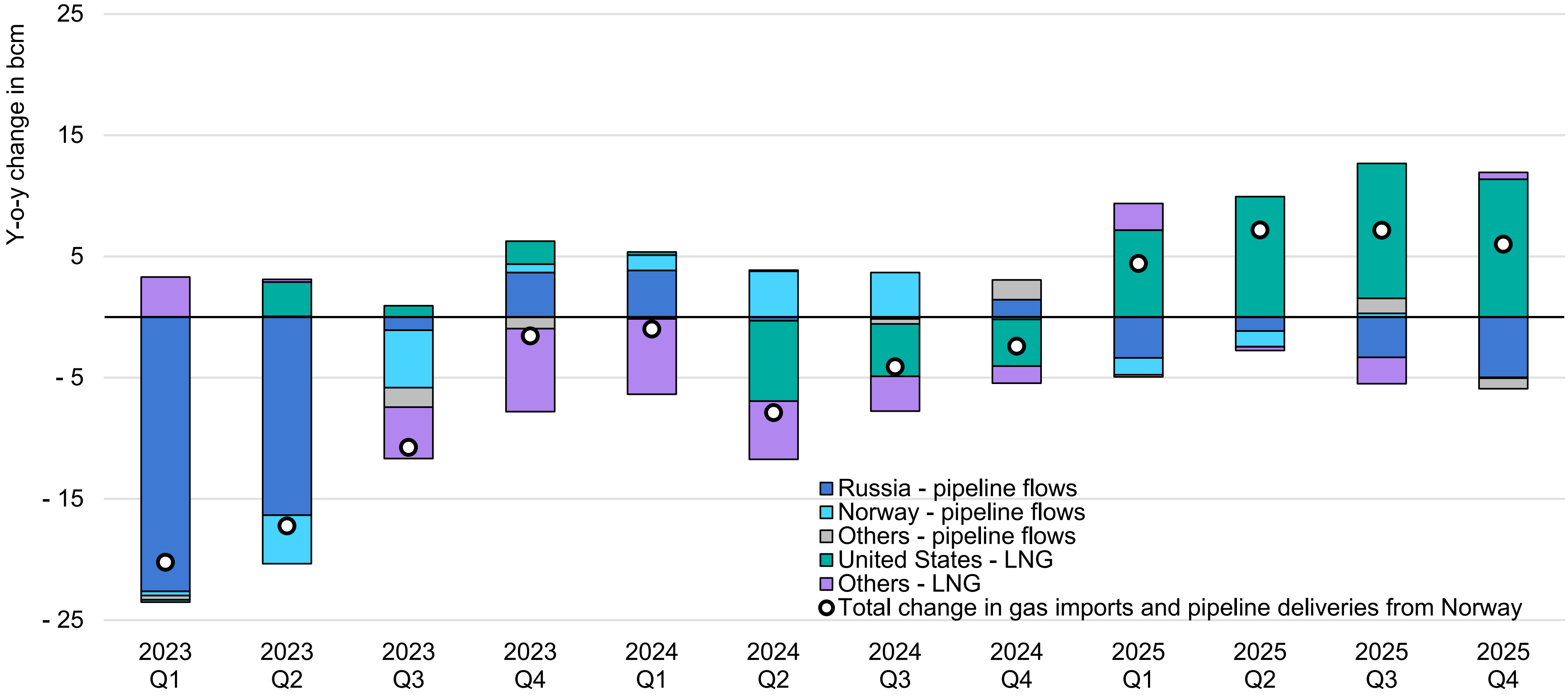
Norway's piped gas deliveries to the rest of Europe declined by 2% (or almost 2.5 bcm) in 2025 amid unplanned outages and higher levels of maintenance activity. **Non-Norwegian domestic production** grew by 1% (or 0.7 bcm) y-o-y in the first 11 months of 2025. Natural gas output in United Kingdom dropped by around 4% (or 1 bcm) y-o-y amid the deteriorating production rates of its ageing fields in the North Sea. These declines were largely offset by strong production growth recorded in Denmark, Italy and Türkiye. In Denmark domestic production increased by over 64% (or 1 bcm) y-o-y on the back of the redeveloped Tyra field. In Türkiye natural gas output grew by more than 40% (or 0.9 bcm) y-o-y, with growth driven by the ramp-up of the Sakarya field.

Russia's piped gas supplies to the European Union fell by 45% (or almost 13 bcm) in 2025 amid the halt of gas transit via Ukraine. Exports to Türkiye grew by 2% y-o-y in the first 11 months of 2025. The share of Russian piped gas in Europe's gas demand is estimated at around 8% in 2025. Piped gas supplies from **North Africa**'s flows declined by 4%, while deliveries from **Azerbaijan** to the European Union fell by 2% 2025.

Europe's LNG imports are expected to continue to increase in 2026 and reach a new all-time high of over 185 bcm, primarily driven by stronger storage injection requirements and higher piped gas exports to Ukraine. Norway's piped gas deliveries to the rest of Europe are expected to recover close to their 2024 levels, while imports from North Africa and Azerbaijan are projected to marginally increase. These higher deliveries are expected to be partly offset by lower piped imports from Russia and Iran (following the expiry of the contract with Türkiye in July 2026).

Strong US LNG supply played a crucial role in refilling Europe's gas storage sites in 2025

Year-on-year change in quarterly European natural gas imports and deliveries from Norway, Q1 2023-Q4 2025



Sources: IEA analysis based on ENTSOG (2026), Transparency Platform; Eurostat (2026), Energy Statistics; ICIS (2026), LNG Edge; JODI (2026), Gas World Database.

Eurasian gas production declined in 2025, driven by lower output in Russia

Following growth of 5% in 2024, Eurasia's natural gas output declined by an estimated 2% in 2025, primarily driven by lower output in Russia. Weaker domestic demand together with lower extra-regional gas exports (both piped and LNG) depressed Eurasia's natural gas production.

Following the steep declines recorded in 2022 and 2023, Russia's natural gas output grew by 7% (or 47 bcm) in 2024, supported by a combination of stronger domestic demand (up by 5%) and higher natural gas exports (both to China and Europe). This trend was reversed in 2025, with preliminary data indicating that Russia's natural gas production declined by 3% (or 22 bcm) amid weaker domestic demand and lower exports. Deliveries to the domestic market fell by almost 3%. This decline was largely concentrated in Q1, when milder winter temperatures reduced both gas supplied directly to buildings and gas-based district heating (down by 9% y-o-y in Q1). In addition, a weaker macroeconomic environment weighed on gas use in industry and the power sector.

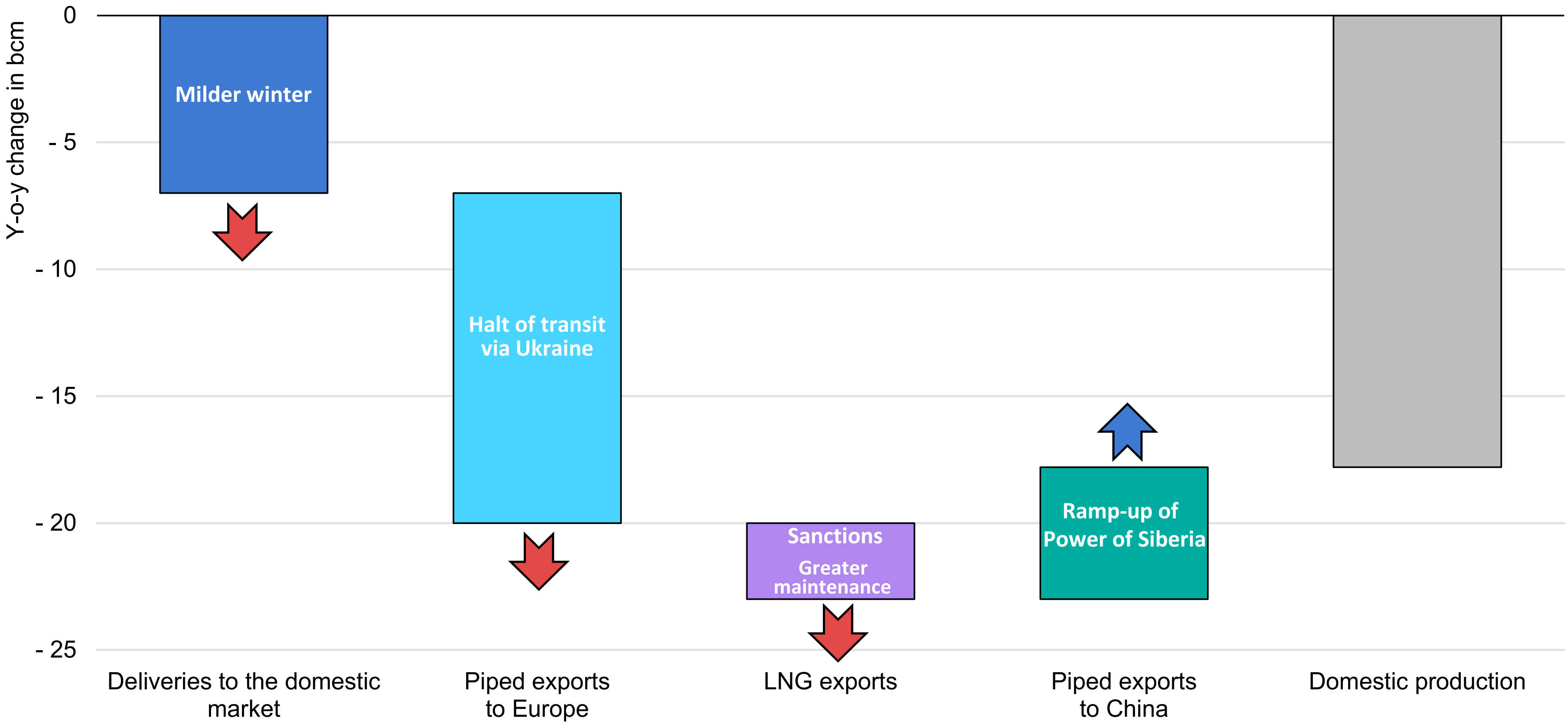
Russia's piped gas exports to Europe fell by an estimated 25% (or around 13 bcm) y-o-y. This was largely due to lower piped gas deliveries to the European Union (down by 45% y-o-y) following the halt of gas transit flows via Ukraine after 1 January 2025. This decline was only partially offset by higher piped gas supplies to China and Central Asia. Russia's gas exports to China via the Power of Siberia pipeline system increased by 25% (or almost 8 bcm) and reached nearly 39 bcm in 2025. In addition, Russia continued to ramp up its piped supplies to Uzbekistan via Kazakhstan through the Central Asia-Centre pipeline system, with total exports rising by an estimated 30% to over 7 bcm in 2025. Russia's LNG exports declined by around 7% (or 3 bcm) y-o-y in 2025 amid the sanctions imposed on the mid-scale Portovaya and Vysotsk LNG plants and the greater maintenance at Yamal LNG.

Natural gas production displayed varying patterns across Central Asian countries. In Turkmenistan natural gas production grew by an estimated 3% in 2025 to around 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 2025, reflecting deteriorating upstream deliverability in the country. In Kazakhstan, estimated sales gas production grew by over 10% (or around 3.5 bcm) y-o-y in the first 11 months of 2025. Central Asia's piped gas exports to China declined by an estimated 5% (or over 2.5 bcm) in 2025. In Azerbaijan, sales gas production grew by 1% (or 0.5 bcm) y-o-y in the first 11 months of 2025. This was partly supported by higher deliveries to Türkiye, which increased by 4% (0.4 bcm) y-o-y during the same period of the year.

This forecast expects Eurasia's gas production to increase by almost 3% in 2026, albeit remaining 10% below its 2021 levels. Russia is projected to account for the bulk of growth in 2026, with higher gas production supported by a recovery in domestic demand.

Weaker domestic demand and lower exports weighed on Eurasia's gas output in 2025

Estimated year-on-year change in natural gas production, exports and deliveries to domestic markets in Eurasia, 2025 vs 2024



Sources: IEA analysis based on ENTSOG (2026), Transparency Platform; ICIS (2026), LNG Edge and various news sources.

Middle Eastern gas supply and demand set to rebound in 2026 after a soft 2025

Gas production in the Middle East is estimated to have grown by around 2.5% in 2025. This is broadly in line with the average growth rate over the previous five years, as underperformance and war-related disruptions in Iran were offset by strong growth in Qatar and Saudi Arabia, the region's second- and third-largest producers, respectively. In 2026, total regional output is expected to grow by around 3%, led by Qatar, Saudi Arabia and Israel. Gas consumption in the region is estimated to have grown by around 2.5% in 2025 and is projected to expand by almost 4% in 2026, mainly driven by the power generation sector in both periods.

Iran's gas production is estimated to have grown only marginally in 2025. A weeks-long outage at the South Pars Phase 14 processing plant during the 12-day war with Israel in June and reported pressure declines across the South Pars field since 2024 contributed to the subdued performance. In 2026, Iranian production is projected to increase by less than 1%, supported by projects to reduce gas flaring. Domestic consumption also remained flat in 2025 as the suspension of urea and ammonia production during the June 2025 war weighed on industrial demand, while a reported switch to mazut tempered gas use in the power sector. Gas consumption is projected to grow by 2% in 2026, driven mainly by the power sector, where gas accounts for around 80% of the generation mix. Iran's 10 bcm/yr long-term gas supply contract with Türkiye expires in mid-2026 and is expected to be renewed at a lower volume, leading to lower exports from H2 2026.

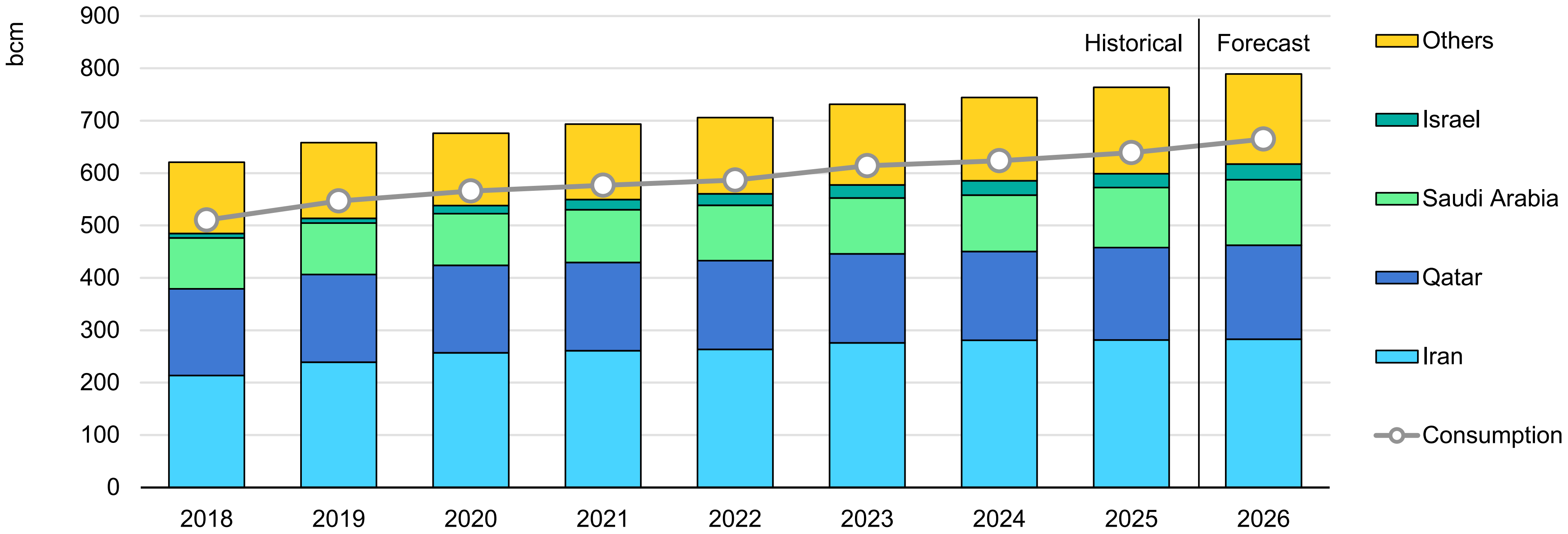
Qatar's gas production returned to a healthy 4% growth in 2025 following a small decline in 2024. Most of the production increase boosted LNG exports, which grew by close to 6% in 2025, while domestic demand increased by a modest 2%, driven by industry and power. In 2026, Qatar's gas production is expected to increase by 2%, supported by the initial ramp-up of the North Field East expansion project, which is due to come online in Q3 2026.

Saudi Arabia's gas production increased by an estimated 6% in 2025 and is projected to rise by another 9% in 2026, driven by the recent start-up of the Jafurah Phase 1 (2 bcm/yr) and Tanajib (27 bcm/yr) projects. Close to 90% of the incremental production in 2025-2026 is to fuel Saudi Arabia's growing CCGT fleet and the oil-to-gas switching programme in the power sector.

Israel's gas production in 2025 remained flat at 27 bcm, as output gains were constrained by maintenance and expansion-related outages and a temporary shutdown of both the Leviathan and Karish fields during Israel's 12-day war with Iran in June. In 2026, gas production is set to grow by more than 10% and reach 30 bcm due to the expansion of the Leviathan and Tamar fields, which are scheduled to be completed in Q4 2025 and H1 2026, respectively. Domestic consumption increased by an estimated 5% in 2025 and is set to grow by another 1% in 2026, driven by the power sector, where Israel plans to phase out routine coal burning by the end of 2026.

Following slow growth in recent years, Middle Eastern supply and demand accelerate in 2026

Natural gas production in selected countries and total gas consumption in the Middle East, 2018-2026



Sources: IEA analysis based on ICIS (2026), LNG Edge, Middle East Economic Survey (2026), MEES.

Africa’s net LNG exports declined amid rising domestic demand and subdued production

Africa’s natural gas production declined by an estimated 1% in 2025, primarily driven by lower output in Egypt. The region’s natural gas use continued to expand and grew by an estimated 3%. This growth was driven by expanding power generation and industrial activity, and efforts to replace more carbon-intensive fuels. In contrast, Africa’s net LNG exports declined by 15% y-o-y in 2025, falling to their lowest level since 2016. This was primarily due to lower exports from Algeria and Egypt’s rising LNG imports.

Algeria’s gas balance in 2025 was shaped by the dual forces of upstream renewal and structural decline in mature reservoirs. While ageing fields, maintenance cycles and rising domestic demand continue to limit export capacity, certain upstream developments in 2025 are expected to increase production over the medium term. In July 2025, Sonatrach signed firm agreements with TotalEnergies and QatarEnergy for the Ahara perimeter, and with Eni for expansion in the Berkine Basin. These contracts are projected to contribute up to 5.5 bcm of additional gas production per year by 2028, supported by total investment exceeding USD 8 billion. Recently, however, Algeria’s LNG exports have fallen sharply, declining by 18% y-o-y in 2025. Lower feedgas availability, seasonal prioritisation of domestic markets and infrastructure downtime all contributed to this contraction.

Egypt’s gas sector remained under pressure in 2025, after years of domestic production decline. The country’s natural gas production fell by almost 15% (or nearly 7 bcm) y-o-y in the first 11 months of 2025. Demand remained broadly flat over the period, necessitating the ramp-up of imports. LNG inflows surged to over 12 bcm in 2025, compared with roughly 3 bcm in 2024, with the United States supplying close to 80% of these volumes. Pipeline inflows from Israel remain essential. In the first 11 months of 2025, Israel supplied 8.4 bcm of piped gas to Egypt, accounting for almost 15% of the country’s total gas demand. Egypt’s regasification capacity has expanded through multiple FSRUs at Ain Sokhna, Alexandria, and Damietta, supporting rising domestic demand for power generation, industrial use, and cooling during peak summer months. LNG exports remain marginal – about 1 bcm in 2024 and just 0.5 bcm in 2025 – as domestic supply takes priority.

Nigeria remains Africa’s largest LNG exporter, with 2025 export performance benefiting from improved feedgas availability. The country’s domestic market absorbs less than half of its gas production. In August 2025, long-term agreements signed by the Nigerian National Petroleum Company Ltd and upstream producers committed roughly 13 bcm/yr of feedgas to Nigeria LNG Ltd (NLNG) for existing liquefaction trains and the delayed Train 7 expansion. Once operational, Train 7 is expected to raise total NLNG capacity from 30 bcm/yr to 40 bcm/yr. The proposed Padah LNG facility could add further capacity, but no FID has been reached yet.

Sustained upstream investment and secure gas supply remain critical to maintaining Nigeria's leading LNG export position.

A major structural shift in 2025 was the emergence of **new exporters in West Africa**. The Greater Tortue Ahmeyim project delivered its first LNG cargo in April 2025, marking the entry of **Senegal** and **Mauritania** into the global LNG market. Uniquely, Senegal became both an LNG exporter and an LNG importer simultaneously in spring 2025. This dual status reflects its transitional position: offshore production, processed via FLNG, is fully geared towards export, while limited midstream transport and distribution infrastructure onshore means LNG imports remain necessary to meet domestic power and industrial needs. In December 2025, **Congo** LNG Phase 2 came on stream ahead of schedule, increasing total liquefaction capacity to approximately 4 bcm/yr. Phase 1, launched in February 2024, established core offshore infrastructure. Phase 2 adds the Nguya FLNG vessel, three platforms and upgraded compression, enabling one of the world's fastest large-scale LNG deployments at 35 months.

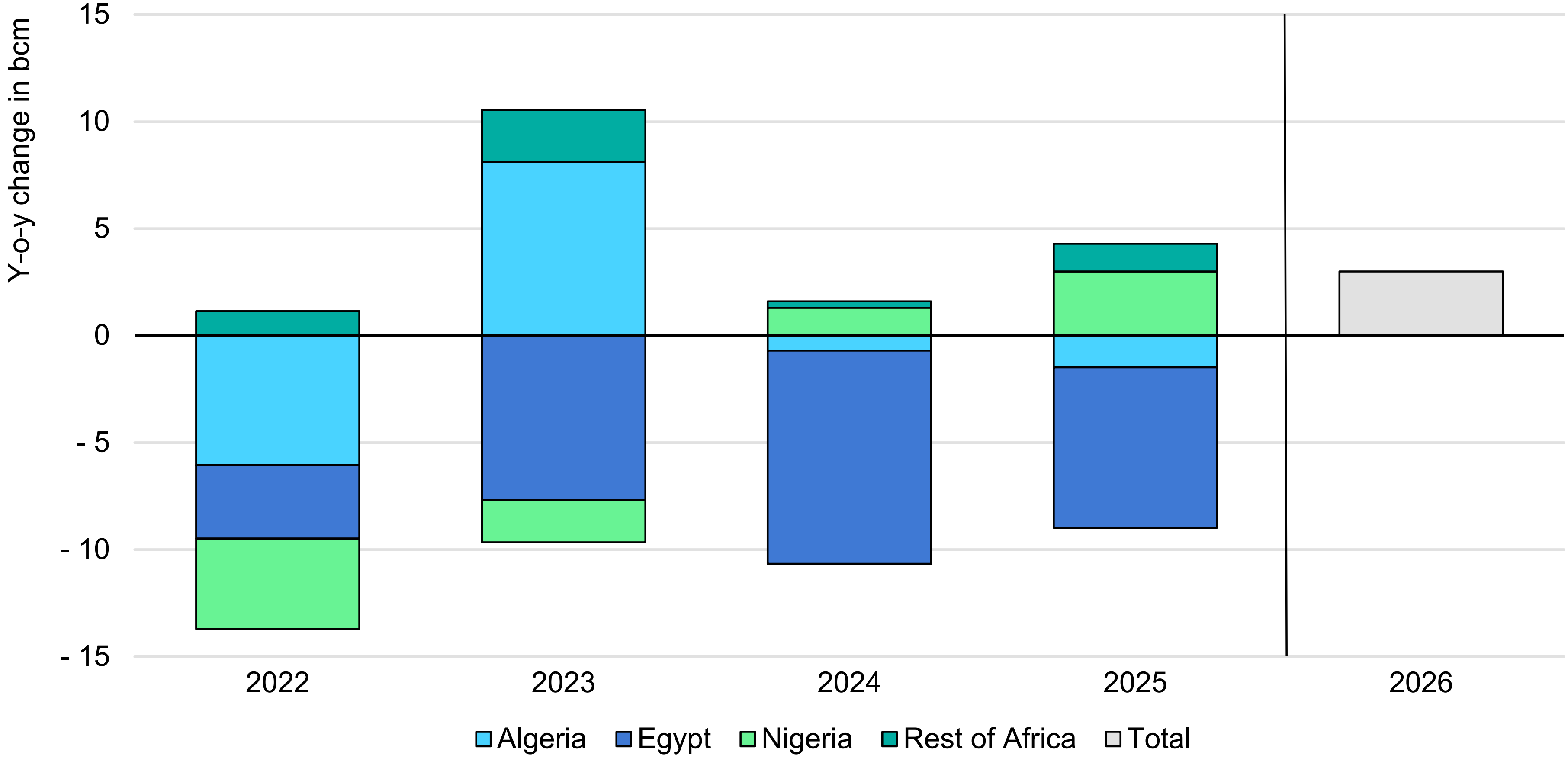
Mozambique's offshore sector continues to establish its long-term LNG ambitions. Coral South FLNG remains the country's sole producing liquefaction facility, while the Coral North FLNG project – approved in early 2025 and reaching FID in October – will add 4.9 bcm/yr of new capacity once it comes online in 2028. Despite the 2019 FID for Mozambique LNG and the recent lifting of force majeure for both major onshore projects, persistent security issues and renewed financing uncertainties continue to cast doubt over large-scale onshore LNG developments in Mozambique, limiting near-term production growth.

In summary, Africa's gas sector in 2025 can be characterised by a complex balance between rising domestic demand, constrained supply and evolving LNG export capacity. While traditional exporters such as Nigeria, Algeria and Egypt face challenges in maintaining output and managing domestic priorities, new entrants like Senegal, Mauritania and Congo signal a gradual diversification of Africa's LNG landscape. Rapid infrastructure development, exemplified by projects like Congo LNG Phase 2 and Mozambique's offshore expansions, demonstrates Africa's potential to scale up production efficiently, yet domestic market readiness and security risks remain significant constraints. Overall, Africa's gas sector is navigating a transitional phase, where strategic planning, upstream investment and infrastructure development will be critical to reconciling domestic energy needs with global export ambitions.

Africa's natural gas demand is expected to increase by almost 2.5% in 2026, largely driven by stronger gas use in the power, industry and energy sectors. The region's natural gas output is projected to grow by a mere 1%. Consequently, Africa's net LNG exports are forecast to continue to decline in 2026.

Africa’s natural gas production recovery is expected to strengthen in 2026

Year-on-year change in natural gas production in Africa, 2022-2026



Source: JODI (2026), World Gas Database and various news sources.

Asian and European gas prices continued their downward trend in Q4 2025

Natural gas prices continued their downward trend across the key Asian and European markets and fell well below the previous year's levels in Q4 2025. Improving LNG availability and relatively weak demand in Asia provided downward pressure on gas prices. In contrast, tighter market fundamentals in the United States kept Henry Hub prices well above their 2024 levels in Q4 2025.

In **Europe** TTF spot prices fell by 8.5% compared with Q3 to an average of just below USD 10.5/MBtu in Q4 2025, standing 23% below the previous year's Q4 levels. The strong inflow of LNG (up 30% y-o-y), together with milder winter weather and stronger wind power output, provided downward pressure on European hub prices. By the beginning of December, TTF prices had fallen below USD 9.5/MBtu, their lowest level since May 2024. Short-term price variability also decreased. Volatility on TTF month-ahead fell by 30% y-o-y in Q4 2025 to just 29%, its lowest Q4 average since 2017. Strong global LNG supply growth and the absence of unforeseen supply and/or demand patterns limited short-term price variability on the European market.

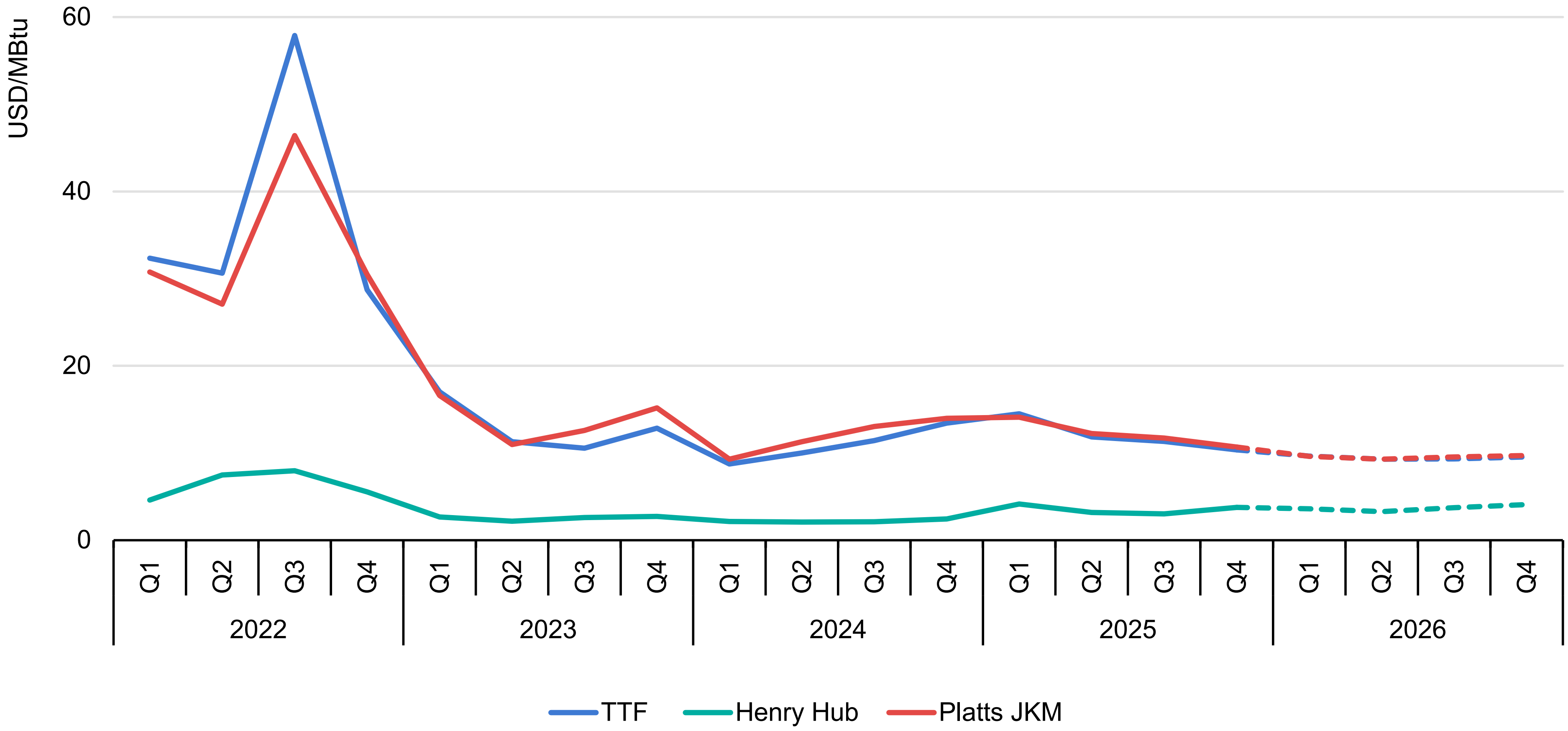
In **Asia** Platts JKM prices followed a similar trajectory and declined by 9% on the quarter to an average of just over USD 10.5/MBtu in Q4 2025, standing almost 25% below Q4 2024 levels. The spread between JKM and TTF tightened from USD 0.4/MBtu in Q3 to USD 0.3/MBtu in Q4 2025. Hence, on a netback basis the European market remained more attractive to the key suppliers in the Atlantic Basin (including the United States). Similarly to TTF, the short-term variability of Asian spot LNG prices continued to drop off. Volatility on JKM declined by 23% y-o-y to just below 30%, its lowest Q4 average since 2018. Subdued regional demand, together with improving LNG supply availability and the continued ramp-up of Russian piped gas deliveries to China, weighed on regional price levels. In China the nationwide LNG ex-factory price declined by more than 10% y-o-y to an average of CNY 4 300/tonne (just over USD 11/MBtu). Oil-indexed LNG prices traded in an estimated range of USD 10-11/MBtu.

In the **United States** Henry Hub spot prices grew by almost 25% on the quarter to an average of USD 3.75/MBtu in Q4 2025, trading 55% above Q4 2024 levels. Colder weather boosting gas demand across the residential and commercial sectors provided upward pressure on Henry Hub prices.

Forward curves as at the end of December suggest that Asian and European natural gas prices could soften in 2026 amid stronger LNG supply growth. TTF prices could decline by 20% in 2026 compared with the previous year and average just below USD 9.5/MBtu. In Asia JKM prices could decline by almost 20% to an average of just over USD 9.5/MBtu. In contrast, forward curves suggest that Henry Hub prices could increase by more than 5% and average around USD 3.7/MBtu, supported by tighter market fundamentals.

Stronger LNG supply is expected to moderate Asian and European spot prices in 2026

Main spot and forward natural gas prices, 2022-2026



Note: Future prices are based on forward curves as at the end of December and do not represent a price forecast.
Sources: IEA analysis based on CME Group (2026), Henry Hub Natural Gas Futures Quotes; Dutch TTF Natural Gas Month Futures Settlements; LNG Japan/Korea Marker (Platts) Futures Settlements; EIA (2026), Henry Hub Natural Gas Spot Price; Powernext (2026), Spot Market Data; S&P Global (2026), Platts Connect.

Spot LNG charter rates remained depressed in 2025 amid structural oversupply of LNG shipping

The LNG charter market remained subdued throughout 2025. Despite spikes in November and December, the average spot rates for 2025 stood at USD 40 250/day in the Atlantic and USD 33 000/day in the Pacific. This represented y-o-y declines of 22% and 36%, respectively. These levels remain far below the five-year averages of USD 103 400/day in the Atlantic and USD 102 200/day in the Pacific for the period 2021-2025, reflecting an exceptional degree of market weakness. Structural oversupply continued to dominate market fundamentals, with fleet growth significantly outpacing global LNG trade expansion. While early December briefly saw spot spikes above USD 130 000/day in the Atlantic and close to USD 90 000/day in the Pacific, these were short-lived, low-liquidity outliers driven by winter demand and did not alter the overall depressed annual average.

In contrast to the overall weakness of average spot charter rates during 2025, forward LNG charter rates in December 2026 point to firmer market expectations. Forward prices indicate an average 30% y-o-y increase, with the Atlantic and Pacific Basins rising by 22% and 38%, respectively. This reflects expectations of tighter effective vessel availability during seasonal peaks or in regions affected by rerouting, security considerations, and higher demand from Asian buyers.

Strong newbuild deliveries maintain excess capacity

The global LNG carrier fleet expanded significantly in 2025, with newbuild deliveries far exceeding retirements. Based on current delivery schedules and historical scrappage trends, net additions totalled around 75 LNG carriers in 2025, with 2026 expected to approach 90 new vessels despite rising retirements. This sustained influx keeps utilisation rates low and continues to exert downward pressure on spot charter rates. Spot market liquidity remains limited, as charterers favour multi-year contracts over short-term fixtures.

The composition of deliveries is changing. Conventional long-haul carriers still dominate, but LNG bunkering vessels and flexible multi-service units are becoming a growing part of the mix. While these smaller or multi-purpose vessels enhance operational flexibility and support LNG as a marine fuel, they have moderate impact on the core long-haul segment, providing only partial relief from oversupply pressures.

Fleet efficiency is also improving. New vessels feature dual-fuel engines, advanced cargo containment systems, hybrid shaft generators and air lubrication technology, enhancing fuel efficiency and reducing methane slip. These innovations support compliance with IMO EEXI[1] and CII[2] regulations and increase operational flexibility, even as the rapid pace of fleet growth keeps spot rates subdued.

Chartering behaviour reflects market caution

Weak spot conditions encouraged a clear shift towards longer-term chartering in 2025. Publicly reported time-charter activity remained modest, and private deals were also fewer than in previous years. Shipowners were increasingly looking for multi-year stability, while charterers relied on existing portfolios rather than the spot market. This limited appetite for short-term fixtures reduced spot liquidity and reinforced downward pressure on prompt rates. Older vessels, particularly steam-turbine carriers, faced growing challenges due to lower fuel efficiency and higher operating costs. Many remain active on shorter intra-basin routes where their limitations have less impact, highlighting the depth of oversupply. Market conditions have not yet forced widespread scrapping despite low competitiveness.

LNG tanker routes adjust amid partial Panama Canal recovery and limited Red Sea transits

In 2025, LNG tanker routes reflected a partial reopening of the Panama Canal and very limited transits through the Red Sea. Charterers adjusted voyages to manage security risks and operating costs. While Panama restrictions eased following earlier droughts, most US Gulf cargoes continued to be delivered to Europe and Latin America rather than long-haul destinations in Asia. Only a handful of LNG tankers transited through the Red Sea, as operators factored in war-risk insurance costs and security concerns. Consequently, inter-basin routes to Asia experienced longer voyages, uneven vessel availability and higher shipping costs. These selective routing adjustments illustrate how episodic operational and geopolitical constraints can temporarily tighten vessel availability, even as structural oversupply persists.

LNG tanker fleet oversupply is set to persist in 2026

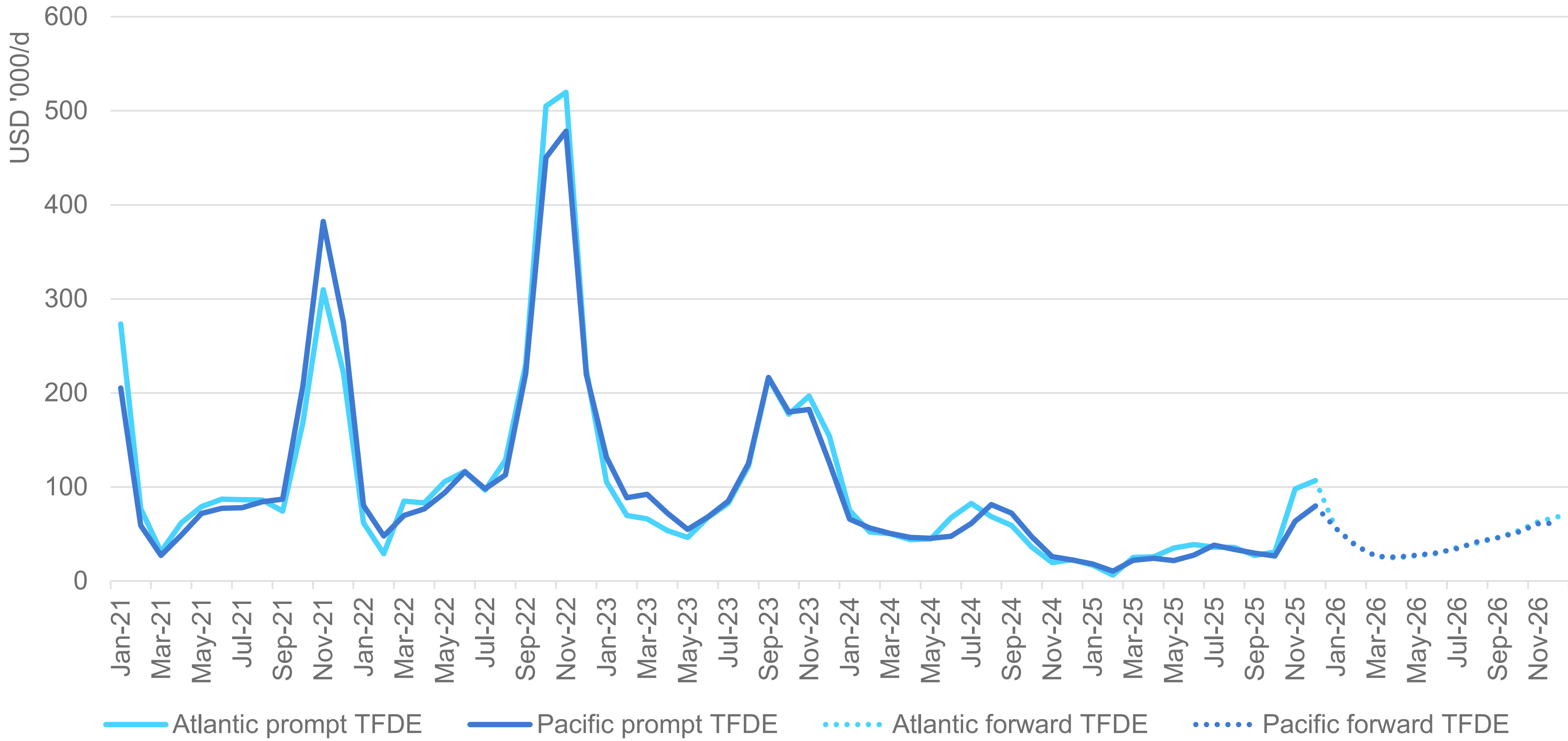
Because of the ongoing wave of newbuild deliveries, the global LNG carrier fleet is expected to remain oversupplied during 2026. Freight charter rates are likely to stay below long-term averages, as vessel capacity continues to outpace growth in seaborne LNG trade. At the same time, episodic disruptions – including longer voyage routings, higher insurance costs and risk-driven cargo diversions – may create pockets of tighter effective availability during peak seasons or along vulnerable corridors. A more sustained rebalancing is expected only after additional liquefaction capacity currently under construction comes online, most likely post-2027, which would increase tonne-mile demand and improve overall fleet utilisation. Until then, LNG shipping is tending to reflect a tension between structural oversupply and intermittent operational and geopolitical constraints.

[1] Energy Efficiency Existing Ship Index, a mandatory IMO measure setting technical efficiency standards for existing ships to reduce CO_2 emissions per unit of transport work.

[2] Carbon Intensity Indicator, an IMO metric rating a ship's annual operational carbon intensity, with corrective measures required for vessels not meeting performance targets.

Forward LNG charter rates until December 2026 signal a 30% y-o-y increase, reflecting expectations of tighter vessel availability

Monthly average day rate for LNG carriers in Atlantic and Pacific Basins, January 2021-December 2026



Note: TFDE = tri-fuel diesel electric vessel.
Source: Spark Commodities, as of 31 December 2025.

Early winter storage positions varied across regions amid diverging supply fundamentals

Natural gas storage levels have followed diverging dynamics since the start of the 2025/26 heating season across different markets, highlighting differing market pressures and levels of concern around security of supply.

In the European Union, low storage levels at the end of winter 2024/25 sparked concerns around reaching the pre-winter 2025/26 fill targets and ensuring sufficient reserves to counter increased seasonal demand and volatility. Despite slightly higher than average injections in the 2025 filling period, early November peak fill remained about 13% (or 14 bcm) below 2024 levels, and short of the EU 90% storage fill target ahead of winter.

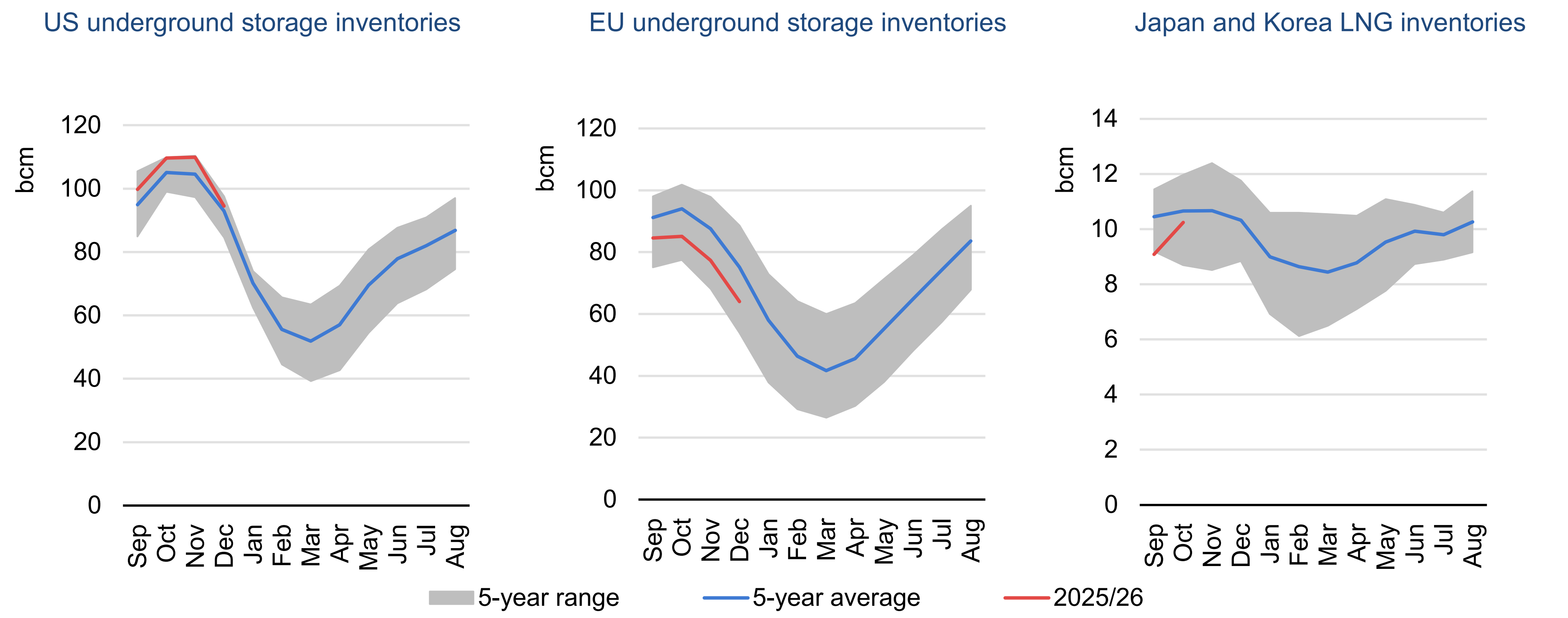
Early winter withdrawals were broadly in line with the five-year average and remained slightly below stockdraw over the same period in 2024. Still, storage levels remained at a deficit of about 14% (or 11 bcm) to prior-year levels by the end of the year, or at their second-lowest level in more than a decade. Despite this relatively weak storage position, the continued downward trend in European gas hub prices in Q4 2025 suggests that the market deemed EU storage levels sufficient in a context of growing global LNG supply.

In Ukraine, storage levels recovered from extremely low levels at the end of the 2024/25 winter, starting November 2025 with slightly more gas in store than in 2024 thanks to injections of close to 8 bcm (61% more than in the 2024 filling period). Maximum fill levels were still nearly 30% below 2023 levels, but much slower withdrawals in November and December 2025 allowed storage levels to end the year only 9% (or less than 1 bcm) below those at the end of 2023 and more than 50% (or 2.5 bcm) higher than those at the end of 2024.

The storage position in the United States remained more robust during the start of the winter. Fill levels trended above the five-year average from May onward, with the pre-winter maximum fill in line with the November 2024 peak. Injections in 2025 totalled nearly 30% (or 13 bcm) higher than in 2024, despite higher prices year-on-year in the filling period amid increasing feedgas deliveries to liquefaction plants and growing domestic demand. Above-average withdrawals in Q4 2025 left year-end US underground gas storage levels about 2% below their end-2024 point, but still about 2% above the five-year average.

Japanese LNG stocks trended at or above the five-year average through much of 2025 as LNG imports remained robust, approaching the winter with typical inventory levels. In Korea, LNG stocks trended toward the bottom of the five-year inventory range (and well below prior-year levels) from May through the start of winter. By the end of October, LNG stocks were about 23% below the five-year average and 28% lower than at the same point in 2024. However, combined stocks in the two countries had risen in line with the recent average by October.

Withdrawal rates likely to lead to diverging end-of-winter storage positions across key markets



Sources: IEA analysis based on EIA (2026), Weekly Natural Gas Storage Report; GIE (2026), AGSI+ Database; JODI (2026), World Gas Database.

Annex

Summary table

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

	Consumption					Production				
	2022	2023	2024	2025	2026	2022	2023	2024	2025	2026
Africa	168	170	170	175	179	250	250	240	235	238
Asia Pacific	904	933	981	982	1 025	675	695	715	730	745
of which China	*373*	*402*	*429*	*434*	*455*	*218*	*230*	*245*	*260*	*274*
Central and South America	153	149	154	154	153	152	150	151	152	155
Eurasia	618	627	652	640	662	860	830	860	845	865
of which Russia	*487*	*495*	*521*	*506*	*527*	*672*	*638*	*685*	*663*	*687*
Europe	541	500	507	522	512	230	215	218	212	215
Middle East	585	618	624	639	664	715	740	760	775	795
North America	1 127	1 138	1 164	1 175	1 176	1 240	1 285	1 280	1 315	1 365
of which United States	*914*	*922*	*944*	*953*	*951*	*1 021*	*1 061*	*1 060*	*1 090*	*1 115*
World	**4 096**	**4 135**	**4 251**	**4 286**	**4 371**	**4 122**	**4 165**	**4 224**	**4 264**	**4 378**

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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