GECF

Gas Exporting Countries Forum

MONTHLY GAS MARKET REPORT

March 2026

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About the GECF

The Gas Exporting Countries Forum (GECF) is an intergovernmental organization comprising the world's leading gas exporters, aimed at fostering cooperation and collaboration among its members by providing a platform for the exchange of views, experiences, information and data on gas-related matters. The GECF includes 20 countries — 12 Member Countries and 8 Observer Countries — spanning four continents. Member Countries are Algeria, Bolivia, Egypt, Equatorial Guinea, Iran, Libya, Nigeria, Qatar, Russia, Trinidad and Tobago, United Arab Emirates and Venezuela, while Observer Countries include Angola, Azerbaijan, Iraq, Malaysia, Mauritania, Mozambique, Peru and Senegal.

The GECF Monthly Gas Market Report (MGMR) is a monthly publication by the GECF Secretariat that provides insights into short-term developments in the global gas market, covering areas such as the global economy, gas consumption, gas production, gas trade (both pipeline gas and LNG), gas storage and energy prices.

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HIGHLIGHTS

Gas consumption: Gas demand weakened across major markets in February 2026. In the EU, consumption declined by 4.4% y-o-y to 37 bcm, mainly due to milder temperatures and stronger renewable output, including wind and hydropower, which reduced gas use in the power sector. US gas consumption fell by 4% y-o-y to 87 bcm, reflecting weaker residential, commercial and industrial demand. Overall, weather conditions and renewable generation have played a key role in shaping short-term gas demand trends.

Gas production: Global gas production trends have showed regional variation in February 2026. US output strengthened its upward trajectory, with a 4.8% y-o-y rise to 87.1 bcm, supported by favourable Henry Hub prices and growing LNG exports. In contrast, European production declined by 0.4% y-o-y to 16.4 bcm, driven by lower output from mature fields in the UK and the Netherlands. Similarly, Asia Pacific witnessed a 1.2% y-o-y decline, with production decreasing to 60 bcm. On the upstream front, Saudi Aramco announced the official startup of the first phase of the Jafurah shale gas development project.

Gas trade: Global gas trade rose in February 2026 driven mainly by LNG imports. Global LNG imports increased by 12% y-o-y to reach a record high of 38.2 Mt for the month, led mainly by exceptionally strong demand in Europe, where imports exceeded 14 Mt for the first time. Higher intra-regional trade in regasified LNG, lower domestic gas production and weaker storage levels supported this trend. Asia also contributed notably to the increase, led by South Korea. The premium of TTF over Asian spot LNG prices continued to attract flexible US LNG cargoes into Europe. In addition, pipeline gas imports showed growth in the EU and China, driven mainly by supply from Russia.

Gas storage: There were warmer-than-average winter temperatures in northern hemisphere countries in February 2026, which impacted the level of gas withdrawals. In the EU, the monthly average gas storage level stood at 36 bcm, representing 35% of capacity, compared to 47 bcm stored one year prior. In the US, the monthly average storage decreased to 58 bcm, or 43% of capacity, which is roughly the same level as one year ago. In Asia, the combined LNG storage levels in Japan and South Korea stood at 12 bcm, an increase of 36% y-o-y.

Energy prices: Spot gas and LNG prices moved unevenly across major markets in February 2026. TTF spot gas price fell by 6% m-o-m to $11.27/MMBtu, as milder weather, stronger wind generation, robust LNG send-out and steady pipeline gas imports loosened European gas balances. In contrast, NEA spot LNG price increased by 3% m-o-m to $10.74/MMBtu, supported by weather-related disruptions in US LNG supply and renewed spot procurement by major Asian importers. Meanwhile, HH spot price fell sharply by 51% m-o-m to $3.60/MMBtu, as milder winter weather reduced heating demand while strong domestic gas production weighed on US prices. In the short term, the escalating conflict in the Middle East is set to tighten global LNG supply and exert upward pressure on spot prices.

FEATURE ARTICLE:

Small-scale LNG expands global energy access through decentralized logistics

The global energy landscape is undergoing a structural shift toward decentralized distribution, driven by the economic and logistical limitations of traditional, large-scale pipeline networks and accelerating decarbonization pressures. This transition is being facilitated by small- and micro-scale LNG solutions, which provide a flexible alternative for producing, transporting, and utilizing natural gas in niche or remote markets that are otherwise inaccessible or uneconomical. By leveraging mobile, intermodal logistics, these solutions transform natural gas from a fixed-route commodity into a versatile energy source, creating a decentralized framework that adapts to localized energy demands. This ensures reliable off-grid energy for critical applications, ranging from local power generation and industrial sites to city gas networks and heavy-duty transport.

Small-scale LNG (SSLNG) is defined as a sector comprising liquefaction and regasification terminals with capacities between 0.05 and 1 Mtpa. This infrastructure employs storage and transport assets such as tank farms and specialized LNG carriers with capacities ranging from 500 to 30,000 m³ or 60,000 m³, depending on industry contexts. Operationally, SSLNG is categorized into two primary value chain models: 1) dedicated chains, where LNG is transported via small-scale LNG carriers from liquefaction plants to small-scale regasification terminals for subsequent maritime (vessels) and inland (trucks) distribution; 2) break-bulk chains, where large-scale regasification terminals serve as hubs to reload LNG onto smaller/bunkering vessels for regional maritime delivery or utilize "virtual pipelines", primarily LNG tank trucks, to supply regional inland end-users directly.

Model 1 (dedicated chains) offers the key advantage of geographic flexibility, as small-scale LNG carriers are able to access remote areas that cannot accommodate conventional large-scale LNG carriers. This model requires lower initial capital investment and can be deployed faster than massive infrastructure projects, making it an ideal “entry-level” solution for rapidly converting smaller power plants from carbon-intensive fuels to cleaner-burning natural gas, while also allowing incremental scaling as local demand grows.

However, this model has a key limitation, as its lack of economies of scale leads to significantly higher unit costs for LNG transport compared with bulk shipments. The dedicated chains are also operationally fragile because supply depends on a specific carrier-terminal pairing; any mechanical failure, scheduling issue, or weather-related delay can seriously disrupt the end-user’s energy supply and continuity. Unlike large-scale infrastructure with extensive storage buffers, this model requires careful operational management, proactive monitoring, and contingency planning, which further increases the overall logistical and operational risk.

In this analysis, Model 1 SSLNG trade encompasses seaborne volumes transported by small-scale LNG carriers with capacities below 60,000 m³, covering both primary exports and the growing volume of re-exports from importing hubs. Between 2015 and 2025, global SSLNG trade more than doubled to reach 2.1 Mt, reflecting a significant expansion in the specialized infrastructure required to serve fragmented and off-grid markets. This growth has been underpinned by the proliferation of marine bunkering facilities for ship-to-ship fuelling and the increased use of LNG tank trucks as the final onshore link for distributing seaborne volumes to inland end-users. Despite this robust decade of expansion, the segment remains a specialized niche, representing only 0.5% of total global seaborne LNG trade in 2025.

On the export side, Malaysia solidified its position as the preeminent SSLNG exporter in 2025, followed by Indonesia, Singapore, Spain, and Russia, primarily by leveraging its extensive network of small-scale loading facilities and regional bunkering hubs to capture emerging demand (Figure i). This market leadership in Southeast Asia was mirrored by a significant structural shift in the Caribbean, where the strategic importance of the United States Virgin Islands (USVI) as a break bulk hub diminished substantially. This decline followed the March 2025 commencement of regular, direct LNG shipments from the US mainland to Puerto Rico.

On the import side, Asia and Europe were the major players (Figure ii). China, Indonesia, Japan, Finland and Sweden solidified their positions as the largest individual importers, each utilizing small-scale solutions to address specific logistical and environmental challenges. In Asia, China continued its dominant role, driven by the massive expansion of LNG-powered heavy-duty trucks and regasification stations in industrial clusters, while Indonesia and Japan focused on providing off-grid power to remote islands and supporting LNG marine bunkering. In Europe, Finland and Sweden led the continent by integrating SSLNG into their industrial sectors and expanding small-scale terminal networks to displace carbon-intensive fuels.

Figure i: Trend in global SSLNG exports by country

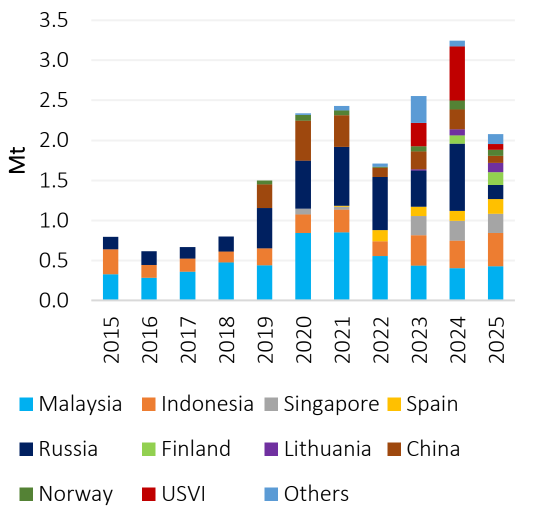
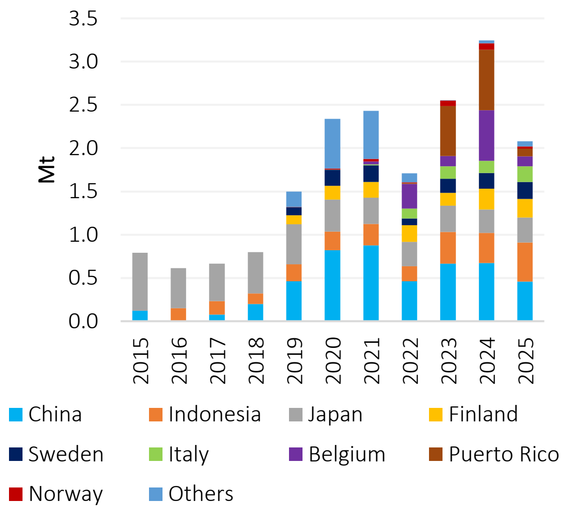


Figure ii: Trend in global SSLNG imports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

In the meantime, Model 2 (break-bulk chains) offers the primary benefit of economies of scale, as it leverages massive liquefaction and large-scale LNG carriers to move the bulk of the volume at a significantly lower unit cost than dedicated small-scale chains. By utilizing large-scale regasification terminals as regional hubs, this model creates a high degree of logistical flexibility, where LNG can be "repackaged" into LNG tank trucks or small vessels to reach a diverse range of inland and coastal end-users without the need for expensive, dedicated maritime infrastructure at every destination.

Conversely, the main disadvantage of this model is the high initial capital requirement and complexity of the regasification terminal, which must be equipped with specialized reloading arms and truck-loading bays to handle small-scale distribution. Furthermore, this model is heavily dependent on existing infrastructure; if a region lacks a large-scale terminal or a well-developed road network for virtual pipelines, the break-bulk approach becomes unfeasible, leaving remote or geographically isolated markets underserved despite its overall cost efficiency.

Break-bulk distribution via trucked LNG functions as an efficient virtual pipeline, bridging the infrastructure gap between large-scale regasification terminals and inland end-users situated beyond the reach of traditional gas grids. This land-based model has emerged as the dominant logistical method within the SSLNG sector, leveraging specialized LNG tank trucks to transport liquefied gas at -162°C to off-grid industrial sites, remote power plants, and refuelling stations. By utilizing the existing road network, these virtual pipelines offer unparalleled scalability. They allow suppliers to match delivery volumes precisely to customer demand without the massive capital expenditure or long-term lead times required to lay physical pipelines.

On a global level, break-bulk distribution via trucked LNG represents the most significant volume driver within the small-scale LNG sector, particularly across Europe and Asia. In Europe, trucked LNG is primarily driven by advanced terminal infrastructure, offering a truck-loading capacity of around 1.8 Mtpa across major import hubs, in particular in Spain, France and the Netherlands, and serving as a critical virtual pipeline for decarbonizing off-grid industries switching from carbon-intensive fuels to meet stringent EU emission standards. This growth is further fuelled by a mature network of LNG refuelling stations supporting a specialized fleet of heavy-duty vehicles as part of a broader transition to cleaner transport fuels. In Asia, trucked LNG growth is driven by large inland gas demand in regions where pipeline infrastructure is either underdeveloped or geographically challenging, making land-based distribution the most practical "just-in-time" energy solution for rapidly expanding decentralized markets. China remains the global leader in this model, using a massive fleet of LNG tank trucks to deliver fuel to industrial users and a domestic fleet of LNG-powered heavy-duty trucks that has now reached 1 million units.

The economics of trucked LNG versus regasified LNG delivered by gas pipelines involve a trade-off between capital intensity and operational flexibility. Physical pipelines require substantial upfront CAPEX but offer the lowest per-unit cost for high-volume, steady-state demand over short-to-medium distances. In contrast, trucked LNG minimizes initial investment but incurs higher OPEX due to fuel, labour and maintenance costs per km travelled. However, trucked LNG becomes economically advantageous for decentralized or remote markets where pipeline construction is geographically challenging. In terms of distances, trucked LNG is economically optimized for deliveries within a 200 to 600 km radius, providing a superior energy-to-payload ratio over CNG while remaining cheaper than constructing new physical pipelines for remote markets at distances up to 900 km. Additionally, the high energy density of LNG, occupying only 1/600th of its gaseous volume, enables cryogenic trailers to deliver "just-in-time" energy with scalable flexibility, avoiding the risk of stranded assets inherent in fixed pipeline networks.

It is important to note that trucked LNG volumes consistently exceed maritime SSLNG deliveries because the majority of loadings occur directly at large-scale regasification terminals (Model 2), entirely bypassing the maritime small-scale transportation step (Model 1).

Furthermore, break-bulk distribution via smaller carriers or bunkering vessels, including ship-to-ship transfers, allows major global hubs like Rotterdam and Singapore to provide just-in-time refuelling at anchorages, bypassing the need for capital-intensive shore-side infrastructure at every berth. By leveraging a global fleet of over 60 active LNG bunkering vessels, this model provides the logistical flexibility necessary to meet stringent international emission mandates while retaining the economies of scale associated with large-scale LNG sourcing.

Micro-scale LNG (MSLNG) represents the smallest and most specialized segment of the small-scale LNG value chain, involving capacities of up to 500 cubic meters. It is focused on either monetizing stranded low-volume gas resources or delivering energy to regions disconnected from conventional infrastructure. MSLNG relies on flexible intermodal transport using ISO containers, forming efficient virtual pipelines. A standard 40-foot cryogenic ISO container holds 20 tonnes of LNG, equivalent to 45 cubic meters of liquid or 27,000 cubic meters in its gaseous state, and can be transported by truck, rail, or ship to final destinations. LNG can be sourced from small-scale liquefaction plants, large-scale regasification terminals, or flared gas recovery sites. The defining characteristic of MSLNG is its modular and adaptable system, distinguishing it from SSLNG, which serves larger regional networks.

The Americas constitute a major regional market, where LNG ISO containers function as a critical virtual pipeline for rapid fuel switching and for providing energy access to off-grid locations. The market experienced a notable shift, peaking at 50,000 tonnes in 2022 before stabilizing at over 25,000 tonnes in 2025. This adjustment was largely driven by the operational maturation of large-scale terminals in Jamaica, which enabled a transition from decentralized MSLNG deliveries to more efficient bulk LNG imports. The US remained the regional anchor, accounting for 24,000 tonnes of ISO-based exports in 2025, while Puerto Rico leveraged its strategic position to re-export 1,400 tonnes to neighbouring Caribbean markets. Currently, Barbados and the Bahamas represent the largest destination markets for these specialized deliveries, while Haiti and Antigua and Barbuda maintain consistent, smaller-volume imports to support localized energy needs.

SSLNG and MSLNG represent a specialized niche within the global energy market. By filling critical gaps in the global distribution network, these segments offer a flexible framework compared to the traditional LNG sector, relying on capital-intensive infrastructure and large economies of scale.

For gas exporters, SSLNG and MSLNG provide a strategic mechanism to monetize stranded assets and diversify their customer base beyond traditional, long-term export contracts. Producers can capture emerging demand in niche markets, such as archipelagic regions, vast continental interiors, and remote industrial or residential zones that are too small for world-scale infrastructure, while minimizing investment risks and avoiding stranded capacity. This flexibility allows exporters to respond dynamically to market shifts and optimize their production by supplying smaller, high-value volumes to niche sectors like LNG bunkering and LNG-fuelled trucks.

For gas importers, SSLNG and MSLNG serve as critical instruments for enhancing energy security. These solutions function as virtual pipelines, providing a reliable energy supply to remote end-users that are geographically or economically isolated from national grids. By utilizing intermodal logistics such as ISO containers and LNG tank trucks, importing nations can scale their gas infrastructure with far lower capital intensity compared to conventional pipeline projects.

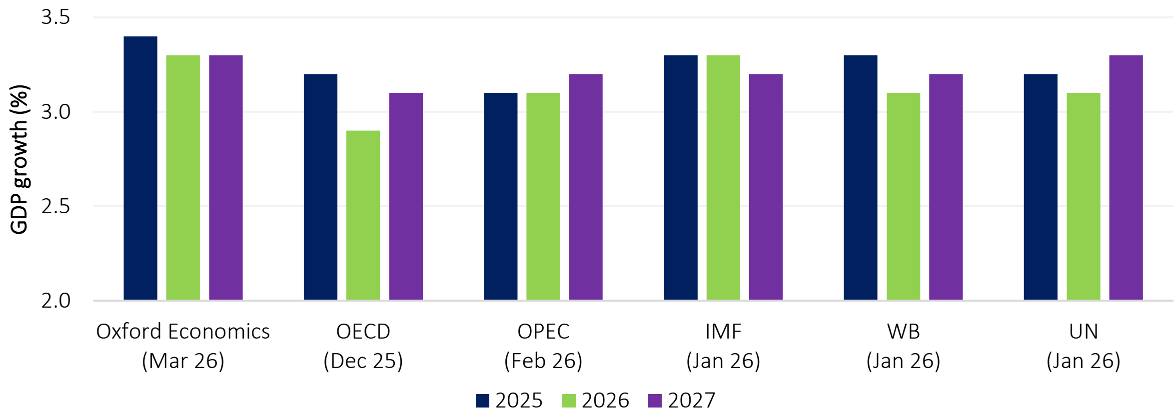
These LNG solutions are particularly important for developing nations across Africa, Asia and the LAC region, providing a scalable entry point into the global gas market. SSLNG requires targeted investment in small-scale coastal infrastructure to serve regional hubs, whereas MSLNG bypasses permanent infrastructure by using standardized ISO containers, allowing rapid deployment in remote or hard-to-reach locations. These solutions promote economic and social development by replacing expensive and carbon-intensive fuels in off-grid industries and isolated communities, reducing energy poverty and fostering local employment. By leveraging these flexible virtual pipelines, emerging economies can quickly establish decentralized energy systems that support industrial growth and enhance long-term resilience, while minimizing the risk of stranded assets.

1 GLOBAL PERSPECTIVES

1.1 Global economy

In March 2026, global GDP growth for 2026, based on purchasing power parity, was estimated by Oxford Economics at 3.3% (Figure 1). Recent geopolitical escalation in the Middle East and climbing energy prices have already reduced the 2026 forecast by 0.1 percentage points. This forecast relies on oil prices avoiding further spikes; however, the risk of prolonged energy instability remains a major threat to global growth. Looking ahead, global economic activity is expected to be stable, with GDP growth in 2027 also forecast at 3.3%.

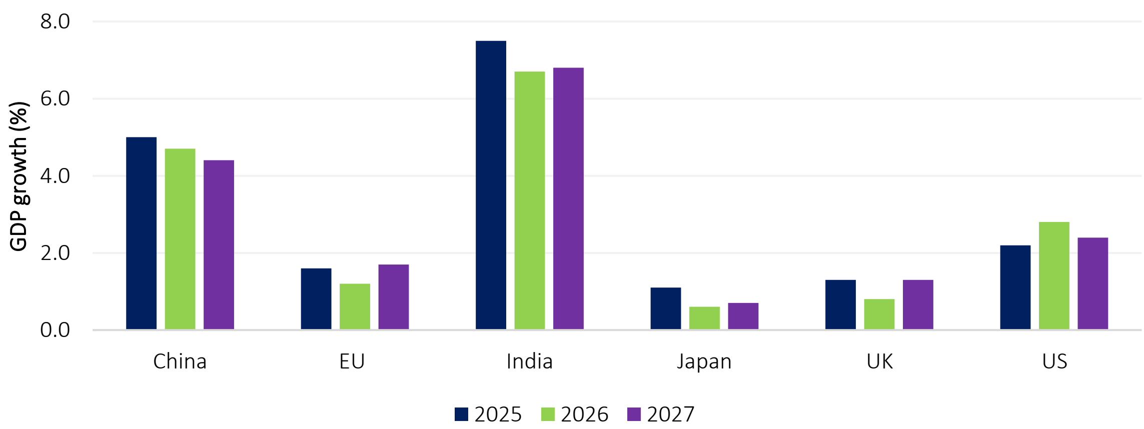
Figure 1: Global GDP growth



Source: GECF Secretariat based on data from Oxford Economics, OPEC, IMF, OECD, WB and UN
Note: Global GDP growth calculated based on Purchasing Power Parity

At the country level (Figure 2), the estimated GDP growth for the US in 2026 was unchanged from one month ago at 2.8%, with larger tax refunds sustaining household spending despite the surging energy costs. Growth is forecasted to weaken to 2.4% in 2027 but this will be dependent on productivity gains. In the EU, GDP growth for 2026 was estimated at 1.2%, a drop of 0.1 percentage points from the previous month. Growth in 2027 is projected to rise to 1.7%, driven by Germany's fiscal stimulus. China's GDP growth for 2026 was estimated at 4.7%. Growth is expected to slow in 2027 to 4.4%, with net exports expected to be a key driver. India's 2026 GDP growth was estimated at 6.7%, with the 2027 outlook rising to 6.8%.

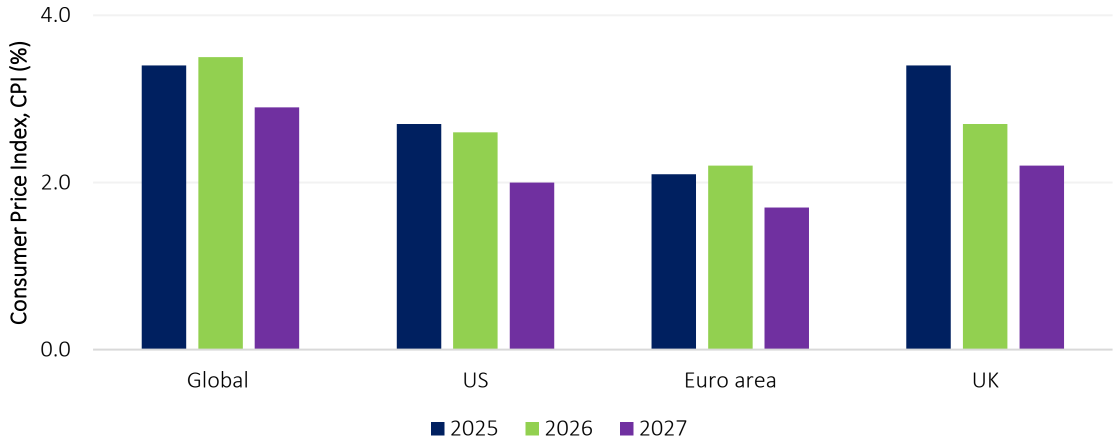
Figure 2: GDP growth in major economies



Source: GECF Secretariat based on data from Oxford Economics

As per Oxford Economics, global inflation in 2026 is estimated to rise by 0.1 percentage points to 3.5%, followed by a sharp 0.6 percentage points decrease in 2027 to 2.9% (Figure 3). In the Euro area, inflation was estimated at 2.2% in 2026, but is forecast to fall to 1.7% in 2027. In the UK, inflation was estimated at 2.7% in 2026 but is expected to fall to 2.2% in 2027. Moreover, in the US, inflation was estimated at 2.6% in 2026, but is expected to ease to 2.0% in 2027.

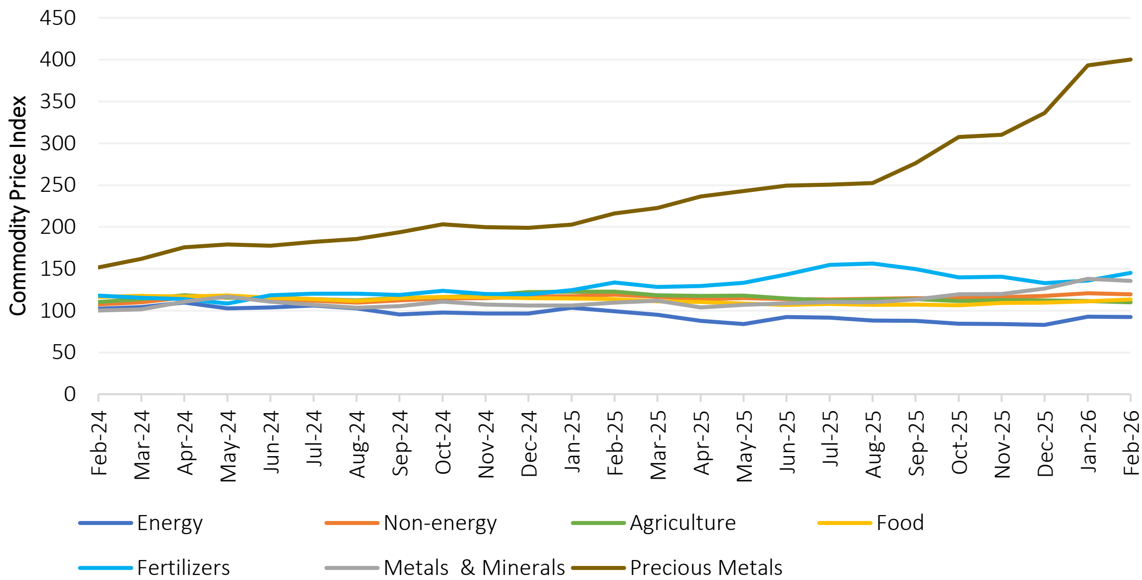
Figure 3: Inflation rates



Source: GECF Secretariat based on data from Oxford Economics

In February 2026, commodity prices in the energy sector declined slightly from the level of the previous month, driven by unseasonably mild weather and softening global demand (Figure 4). In this context, the energy price index was 0.5% lower m-o-m and was also 7% lower than one year prior. The non-energy price index decreased by 1% m-o-m, which was 0.3% higher y-o-y. The fertilizer price index showed increases of 7% m-o-m and 9% y-o-y. The precious metals price index experienced sustained growth, by 2% m-o-m and 85% y-o-y.

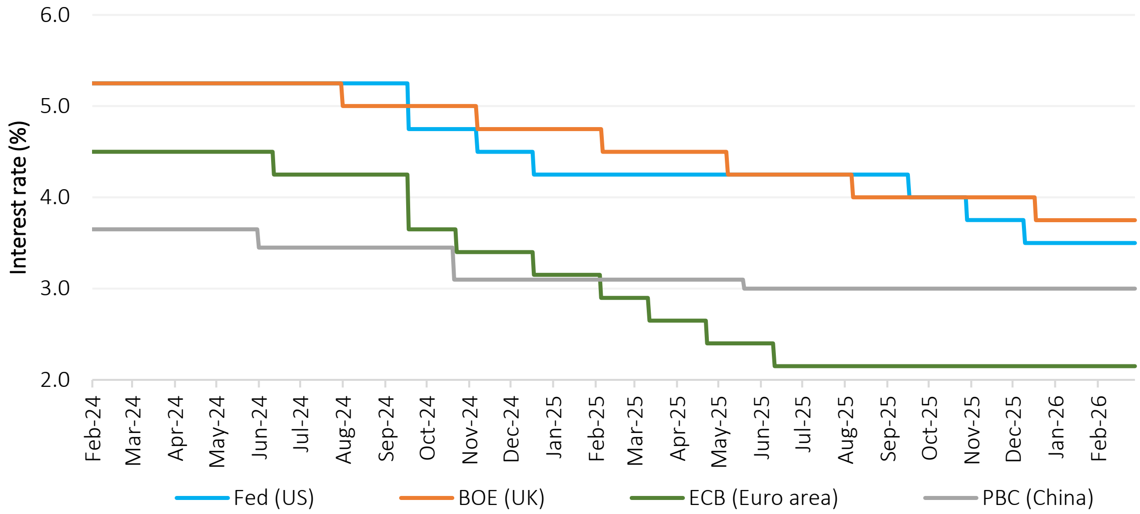
Figure 4: Monthly commodity price indices



Source: GECF Secretariat based on data from World Bank Commodity Price Data
Note: Monthly price indices based on nominal US dollars, 2010=100. The energy price index is calculated using a weighted average of global crude oil (84.6%), gas (10.8%) and coal (4.7%) prices. The non-energy price index is calculated using a weighted average of agriculture (64.9%), metals & minerals (31.6%) and fertilizers (3.6%).

In February 2026, the major central banks all maintained their benchmark interest rates, compared to the previous month (Figure 5). The US Federal Reserve (Fed) maintained its benchmark interest rate within the range of 3.5% to 3.75%, which was most recently adjusted in December 2025. The Bank of England (BOE) kept its benchmark interest rate at 3.75%, also having adjusted in December 2025. In addition, the main refinancing operations rate of the European Central Bank (ECB) has held steady at 2.15% since mid-June 2025. Moreover, the People's Bank of China (PBC) kept its one-year Loan Prime Rate (LPR) at 3.0%.

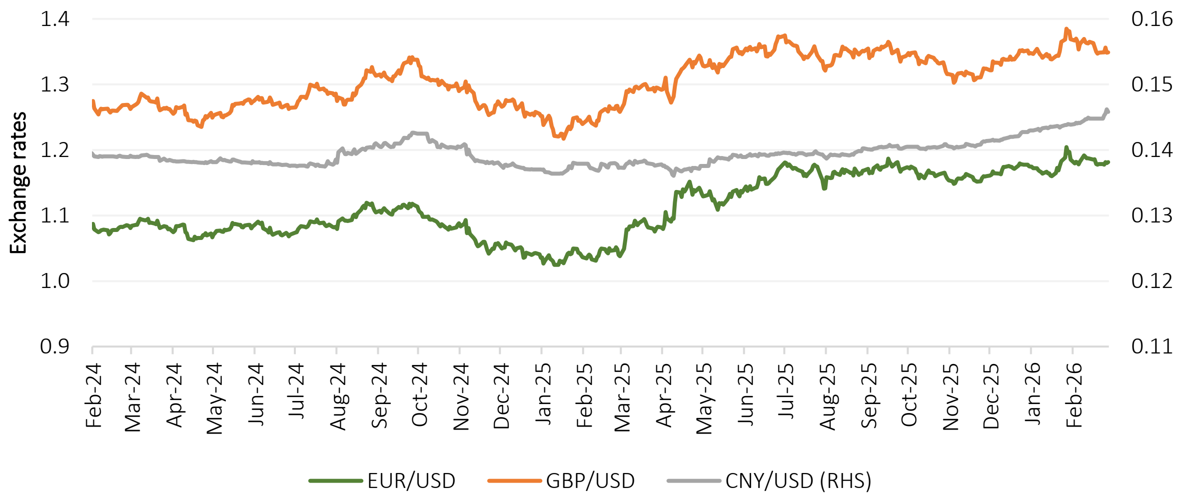
Figure 5: Interest rates in major central banks



Source: GECF Secretariat based on data from US Federal Reserve, Bank of England, European Central Bank and People's Bank of China

In February 2026, the US dollar continued to weaken in comparison to major global currencies (Figure 6). The euro recorded an average exchange rate against the US dollar of $1.1824, representing increases of 1% m-o-m and 13% y-o-y. The British pound also reflected increases of 0.4% m-o-m and 8% y-o-y against the US dollar, with an average exchange rate of $1.3580. The average exchange rate of the Chinese yuan the US dollar was $0.1448, representing increases of 1% m-o-m and 5% y-o-y.

Figure 6: Exchange rates



Source: GECF Secretariat based on data from LSEG

1.2 Other developments

IEA: The IEA 2026 Ministerial Meeting, held in Paris, France on 18–19 February 2026, revealed a notable divergence in how member nations view the global energy transition. While the meeting officially centred on the "Age of Electricity" to address surging power demand from AI and data centres, several gas and oil proponents led by the US expressed significant reservations about the current focus on rapid decarbonization. US Energy Secretary Chris Wright characterized the shift toward a net-zero agenda as a threat to traditional energy security and suggested that the US might reconsider its participation if the organization does not return to its original mandate of stabilizing fossil fuel markets. This internal friction highlighted a growing push for a more pragmatic approach that maintains a long-term role for natural gas amidst global geopolitical tensions.

China: The National People's Congress (NPC) officially adopted the 15th Five-Year Plan (2026–2030) on 12 March 2026, establishing a foundational blueprint that shifts China's focus toward "high-quality development" and technological self-reliance to achieve its 2035 modernization goals. To support this growth, the plan mandates a dual-track energy strategy that prioritizes national security while accelerating the transition to a "new-type power system." Natural gas is formally positioned as a strategic bridge fuel essential for grid stability and industrial decarbonization, aligning with the target of a 25% non-fossil energy share by 2030. To mitigate risks from volatile international markets, the directive calls for expanded domestic gas production and the reinforcement of strategic coal-to-gas reserves.

Europe: The Methane Mitigation Europe Summit held in Amsterdam, Netherlands on 24–26 February 2026 concluded with urgent warnings regarding the upcoming EU methane regulation. Industry leaders and analysts highlighted a looming compliance gap for the 2027 import standards, mandating strict measurement and reporting for all gas entering the bloc. A Wood Mackenzie study released at the summit cautioned that without greater regulatory flexibility up to 43% of European gas imports could be at risk of non-compliance. This potential supply shock threatens to spike prices and trigger widespread coal-switching in the region. In this context, the summit focused on high-level calls for a stop-the-clock implementation phase to safeguard European energy security and prevent a self-inflicted gas shortage.

Artificial Intelligence: The India AI Impact Summit 2026, held in New Delhi on 18–19 February 2026, centred on the "Energy-Compute Nexus" to address the massive electricity demands of global AI expansion. Moving beyond traditional views, the summit redefined AI-driven data centres as dynamic grid assets that require sophisticated, integrated planning to manage highly concentrated power loads. A cornerstone of the New Delhi Declaration was the "Resilient, Efficient & Innovative AI Systems" pillar, which mandates the development of sustainable digital infrastructure and energy-efficient algorithms. This was bolstered by the launch of the AI Impact Casebook on Energy, providing a global roadmap for grid optimization and balancing surging compute requirements with international climate commitments.

Oil market: The IEA unanimously authorised the largest emergency oil release in its history on 11 March 2026, pledging 400 million barrels to stabilise a global market rattled by Middle East conflict. This unprecedented collective action followed an effective blockade of the Strait of Hormuz, where transit volumes plummeted after hostilities began on 28 February. While the release, comprising both crude and refined products, aims to provide immediate liquidity, IEA Executive Director Fatih Birol cautioned that a full recovery remains contingent on restoring secure maritime passage through the Persian Gulf.

2 GAS CONSUMPTION

In January 2026, aggregated gas consumption across some of the major gas consuming countries, which collectively account for 75% of global gas demand, increased by 1.5% y-o-y. Growth was recorded in all regions, including the EU, North America and Asia.

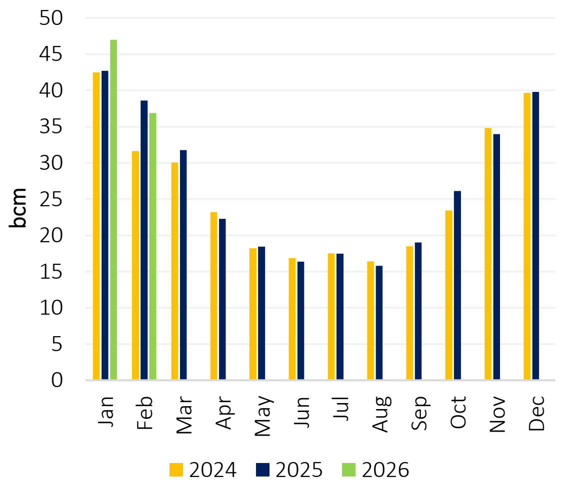
2.1 Europe

2.2.1 European Union

In February 2026, EU natural gas consumption declined by 4.4% y-o-y, reaching 37 bcm (Figure 7). The reduction was mainly driven by lower heating demand in the residential sector, reflecting milder weather conditions across much of the region, although weather conditions varied across the continent. Western, southern and southeastern Europe experienced above-average temperatures, limiting heating demand, while northern parts of Europe and the Baltic region faced colder conditions. Much of western and southern Europe experienced wetter-than-average conditions during the period. These increased precipitation levels supported stronger hydropower generation, which contributed to lower natural gas consumption in the power generation sector. Gas use in the power generation sector also declined, as strong wind output reduced the need for gas-fired electricity generation.

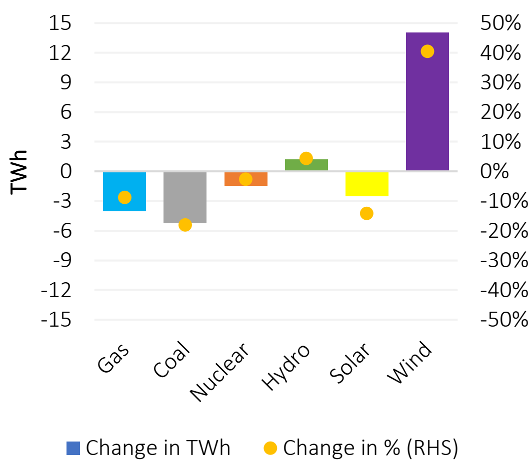
Electricity generation in the EU increased slightly by 1% y-o-y, reaching 220 TWh. However, gas-fired power generation declined by 9% y-o-y, largely due to a substantial expansion in wind output, which displaced part of gas demand in the power sector. Renewable sources continued to strengthen their contribution, with wind generation surging by 40% y-o-y and hydropower rising by 4% (Figure 8). In the electricity generation mix, non-hydro renewables maintained their leading position, accounting for 33%, followed by nuclear (24%), natural gas (19%), hydropower (13%) and coal (11%). These trends highlight the continuing transformation of Europe’s power system, characterized by the growing dominance of renewable energy, while natural gas continues to play an essential role in maintaining system flexibility and reliability.

Figure 7: Gas consumption in the EU



Source: GECF Secretariat based on data from Entsog and LSEG

Figure 8: Trend in electricity production in the EU in February 2026 (y-o-y change)



Source: GECF Secretariat based on data from Ember

For the period Jan-Feb 2026, the EU's gas consumption rose by 3.2% y-o-y to 84 bcm.

2.1.1.1 Germany

In February 2026, natural gas consumption in Germany declined to 9.5 bcm, representing a 4.2% y-o-y decrease (0.4 bcm) (Figure 9). This marked the first contraction after five consecutive months of growth, signalling a return to a softer demand trend. The decline was primarily attributed to weaker consumption in the residential and industrial sectors. Residential demand fell by 11% y-o-y, largely due to milder weather conditions. The average temperature reached 2.5°C in February, compared with 1.9°C in the same month of 2025, making the month around 0.6°C warmer than a year earlier. At the same time, industrial gas consumption edged down by 1% y-o-y, indicating a renewed weakening in industrial demand after the growth observed in recent months (Figure 10).

Figure 9: Gas consumption in Germany

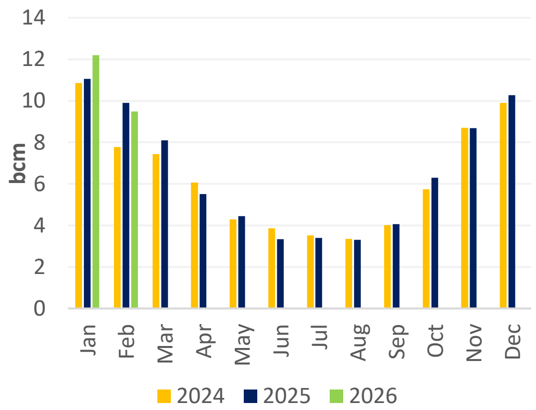
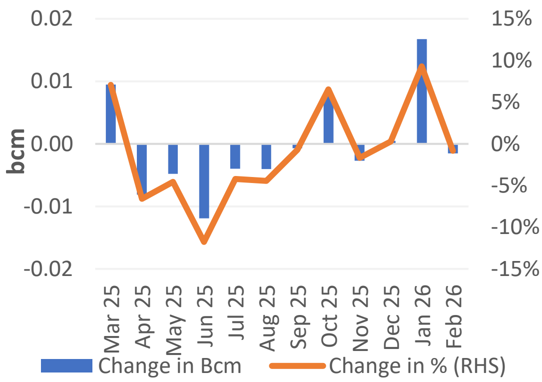


Figure 10: Trend in gas consumption in the industrial sector in Germany (y-o-y change)



Source: GECF Secretariat based on data from LSEG

Total electricity generation rose by 11% y-o-y in January, reaching 41 TWh. Gas-fired power production recorded an increase of 12% y-o-y, largely compensating for a pronounced contraction in hydropower and solar output, which declined by 10% and 7% respectively (Figure 11). Wind generation strengthened, expanding by 62% y-o-y. In Germany's power mix, non-hydro renewables remained the dominant source, accounting for 51% of total electricity generation, followed by natural gas at 23% and coal at 23% (Figure 12).

Figure 11: Trend in electricity production in Germany in February 2026 (y-o-y change)

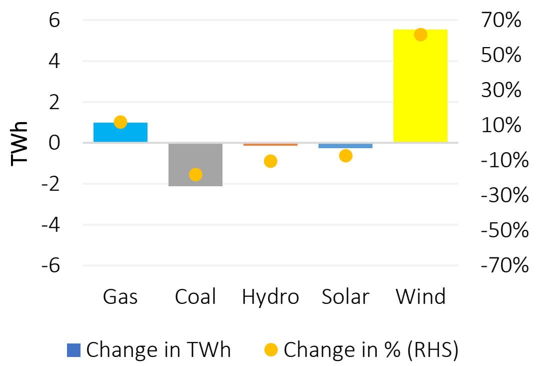
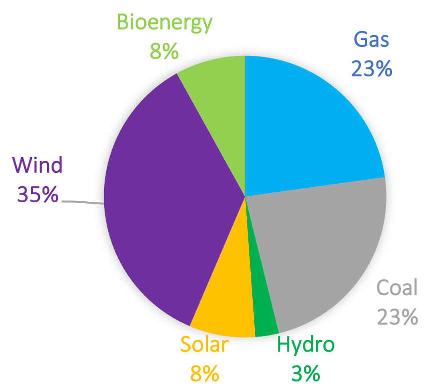


Figure 12: German electricity mix in February 2026



Source: GECF Secretariat based on data from LSEG and Ember

For the period Jan-Feb 2026, Germany's gas consumption rose by 3.5% y-o-y to 22 bcm.

2.1.1.2 Italy

In February 2026, Italy's natural gas consumption increased by 7.8% y-o-y to 6.8 bcm (Figure 13), primarily driven by milder weather conditions across the country. Residential gas demand declined by 10% y-o-y to 3.6 bcm, supported by significantly mild temperatures, with the monthly average reaching 8.3°C, compared with 6.8°C in February 2026, thereby reducing heating requirements in households and commercial buildings. In contrast, industrial gas consumption rose marginally by 0.1% y-o-y to 0.99 bcm, marking a rebound after the first contraction in manufacturing-related demand recorded last month (Figure 14). Meanwhile, the decline in gas use for power generation reflected the increased contribution of wind generation, which offset natural gas demand in the electricity sector.

Figure 13: Gas consumption in Italy

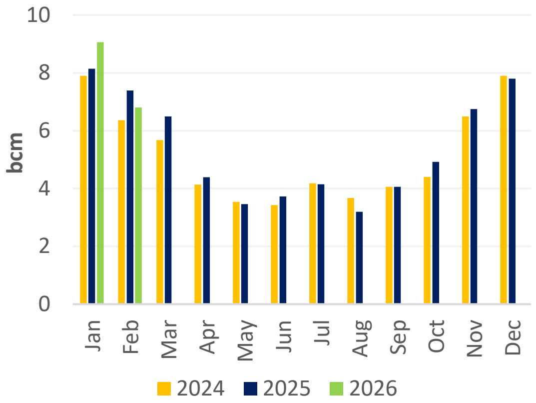
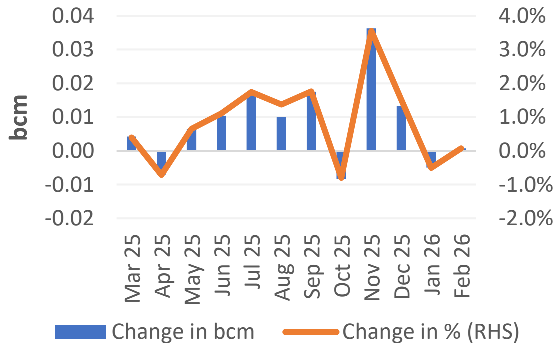


Figure 14: Trend in gas consumption in the industrial sector in Italy (y-o-y change)



Source: GECF Secretariat based on data from Snam

Total electricity generation in Italy increased by 6% y-o-y to 19 TWh. Gas-fired electricity generation declined by 11% y-o-y, driven in part by a sharp increase in wind output, which grew by 117% (Figure 15). Natural gas remained central to balancing the power system, accounting for 54% of total electricity generation. Meanwhile, non-hydro renewable sources contributed 34% of output, underscoring Italy's continued reliance on gas as a key pillar for ensuring power system stability (Figure 16).

Figure 15: Trend in electricity production in Italy in February 2026 (y-o-y change)

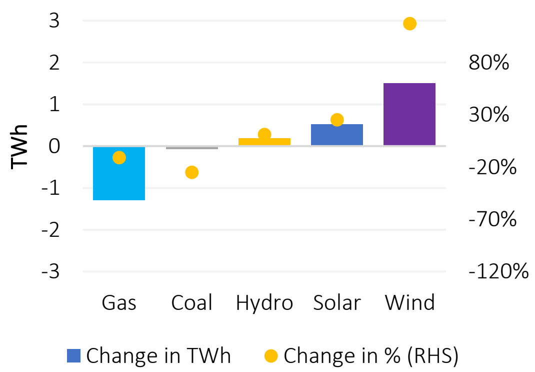
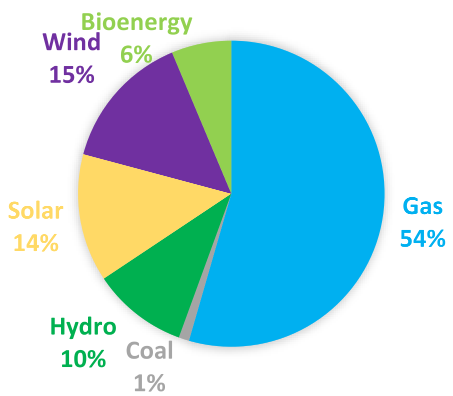


Figure 16: Italian electricity mix in February 2026



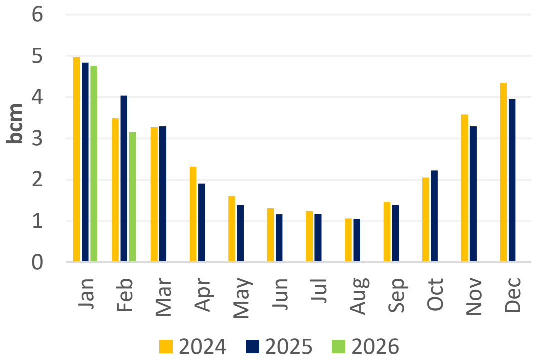
Source: GECF Secretariat based on data from Terna, LSEG and Ember

For the period Jan-Feb 2026, Italy's gas consumption rose by 2.2% y-o-y to 16 bcm.

2.1.1.3 France

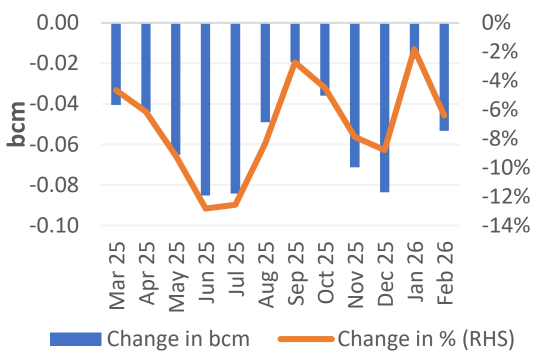
In February 2026, France's gas consumption declined by 22% y-o-y to 3.2 bcm (Figure 17), driven by lower demand in the power generation, industrial and residential sectors. Residential consumption declined by 19% y-o-y to 2.3 bcm, supported by less gas use for heating as warmer temperatures were recorded during the month, with average temperatures at 9.3°C — 2.2°C higher than the same month last year. The industrial sector recorded a decline of 6.4% to reach 0.78 bcm (Figure 18).

Figure 17: Gas consumption in France



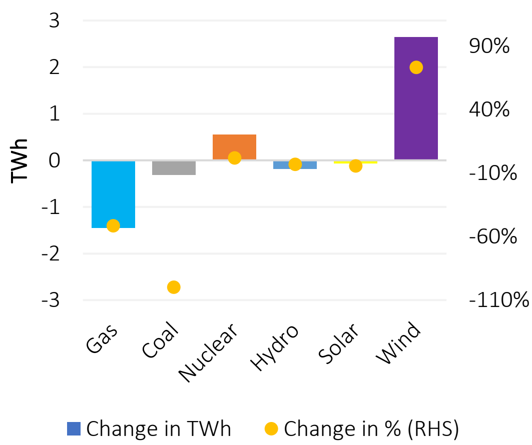
Source: GECF Secretariat based on data from GRTgaz

Figure 18: Trend in gas consumption in the industrial sector in France (y-o-y change)



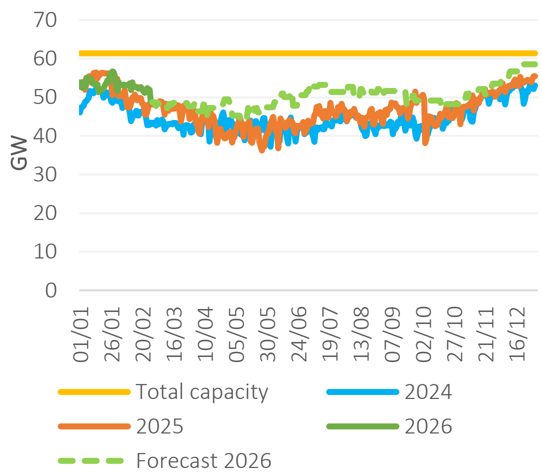
Total electricity generation in France increased by 2.7% to reach 47 TWh. Natural gas generation declined by 52% y-o-y, as wind and nuclear output grew by 73% and 1.7% y-o-y respectively. In contrast, coal and hydro generation continued to decline over the period (Figure 19). French nuclear capacity availability declined by 12% m-o-m but grew by 7.3% y-o-y (Figure 20). In the overall power mix, nuclear energy continued to dominate, representing 69% of total electricity supply, followed by non-hydro renewables (17%), hydro (10%) and natural gas (3%).

Figure 19: Trend in electricity production in France in February 2026 (y-o-y change)



Source: GECF Secretariat based on data from Ember

Figure 20: French nuclear capacity availability



Source: GECF Secretariat based on LSEG and RTE

For the period Jan-Feb 2026, France's gas consumption declined by 11% y-o-y to 7.9 bcm.

2.1.1.4 Spain

In February 2026, Spain's natural gas consumption declined by 3.7% y-o-y to 2.5 bcm, ending a twelve-month streak of continuous growth (Figure 21). The contraction was mainly driven by weaker demand from the industrial, residential and power generation sectors. Gas use in the power generation sector decreased, as strong wind generation reduced the need for gas-fired electricity production. Meanwhile, industrial gas consumption fell by 5% y-o-y, continuing its downward trend and indicating softer industrial activity. The downtick was largely driven by lower consumption in the textile sector (-16%), agro-food sector (-12%), the paper industry (-10%) and metallurgy sector (-6.7%) (Figure 22).

Figure 21: Gas consumption in Spain

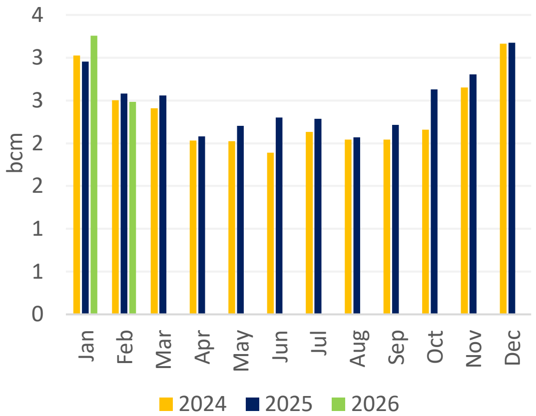
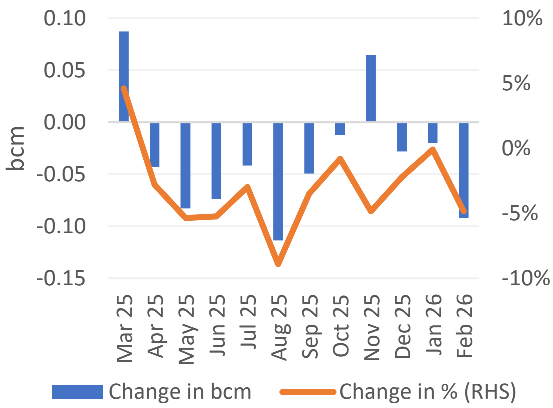


Figure 22: Trend in gas consumption in the industrial sector in Spain (y-o-y change)



Source: GECF Secretariat based on data from Enagas

Spain's total electricity generation declined slightly by 1.2% y-o-y in February, reaching 19.7 TWh. Within this context, gas-fired power output dropped sharply by 24% y-o-y, as natural gas was used less due to strong generation from wind and hydropower under favourable weather conditions (Figure 23). Wind generation recorded an increase of 63% compared with the previous year. In the generation mix, non-hydro renewables remained the leading source, accounting for 44% of total output, while natural gas represented 15%, highlighting its key role in balancing the power system amid fluctuations in renewable supply (Figure 24).

Figure 23: Trend in electricity production in Spain in February 2026 (y-o-y change)

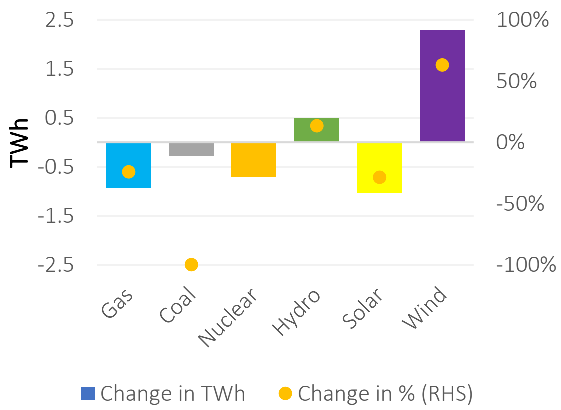
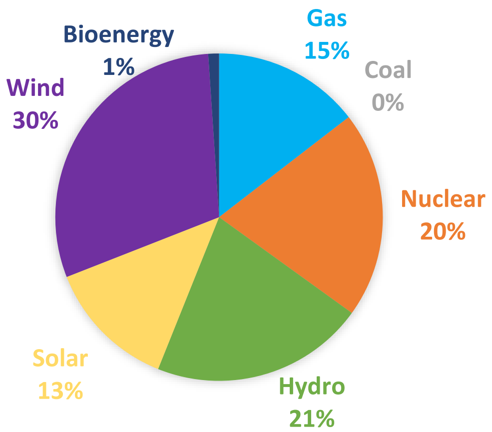


Figure 24: Spanish electricity mix in February 2026



Source: GECF Secretariat based on data from Ember and Ree

For the period Jan-Feb 2026, Spain's gas consumption rose by 3.8% y-o-y to 5.7 bcm

2.1.2 United Kingdom

In February 2026, natural gas consumption in the UK declined by 8% y-o-y to 6.5 bcm (Figure 25), largely reflecting strong wind generation in the power sector, which reduced the need for gas-fired output. This contraction was driven by a warmer-than-normal weather conditions during the month. Residential gas demand fell by 8.3% y-o-y to 5 bcm, average temperatures reached 6.7°C, around 1.7°C higher than a year earlier. Similarly, industrial gas consumption recorded a sharp decline of 22% y-o-y, pointing to persistently weak demand across energy-intensive industries (Figure 26).

Figure 25: Gas consumption in the UK

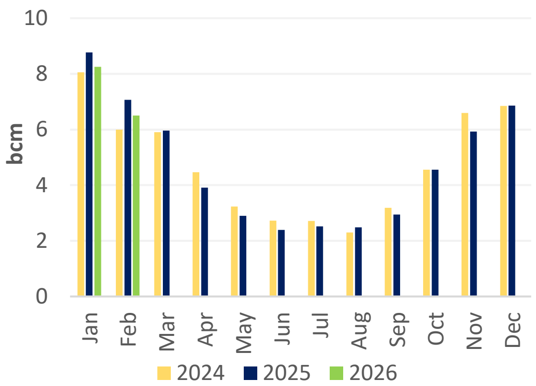
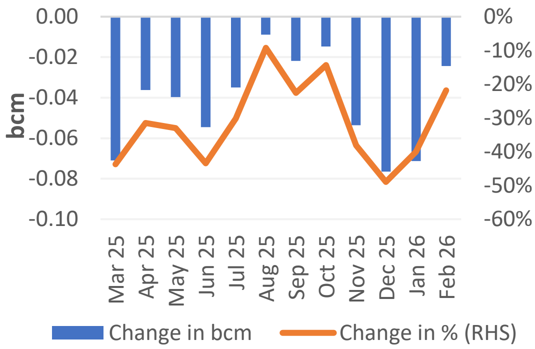


Figure 26: Trend in gas consumption in the industrial sector in the UK (y-o-y change)



Source: GECF Secretariat based on data from LSEG

Total electricity generation in the UK increased by 1.2% y-o-y to 21.2 TWh. However, gas-fired power generation declined by 8.6% y-o-y, largely offset by strong wind output driven by favourable weather conditions. Wind generation rose by 20% y-o-y (Figure 27), whilst nuclear, hydro and solar power-generation output decreased compared to last year. Non-hydro renewables remained the largest contributor to the power mix, accounting for 51%, while natural gas made up 35%, highlighting its role in balancing the electricity grid amid fluctuating renewable output (Figure 28).

Figure 27: Trend in electricity production in UK in February 2026 (y-o-y change)

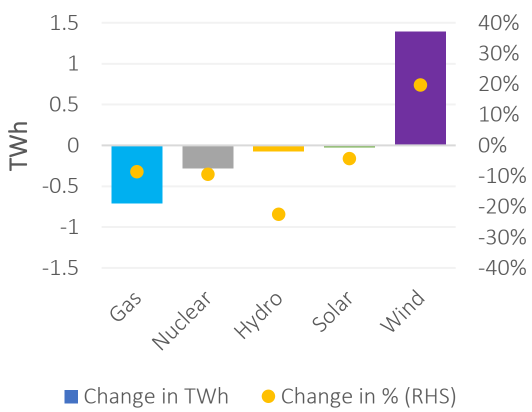
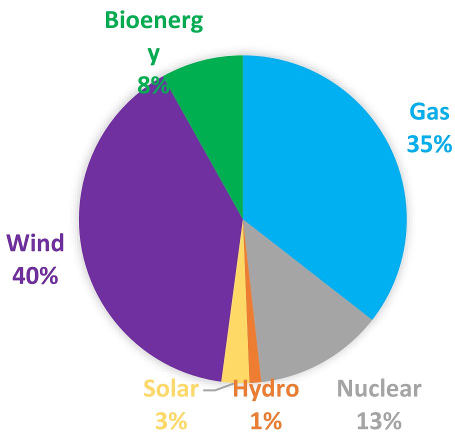


Figure 28: UK electricity mix in February 2026



Source: GECF Secretariat based on data from Ember

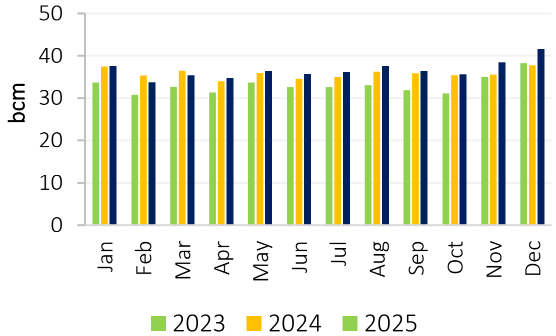
For the period Jan-Feb 2026, UK's gas consumption declined by 6.9% y-o-y to 14.8 bcm

2.2 Asia

2.2.1 China

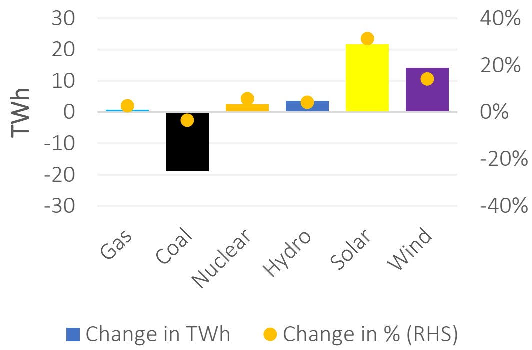
Due to the delay in data publication by the National Bureau of Statistics of China, gas consumption figures for January and February 2026 will be included in the next edition of the MGMR. In December 2025, China's apparent gas demand (production + LNG and pipeline gas imports) recorded a growth of 10% y-o-y to reach 41.5 bcm (Figure 29). China's gas consumption is projected to continue rising, reaching around 450–455 bcm in 2026 and increasing to about 550 bcm by 2030, according to CNPC's ETRI. Industrial demand is expected to be the main driver of growth, supported by coal-to-gas policies and efforts to peak coal consumption, alongside expanding gas use in power generation and LNG-fuelled transport. China's electricity generation reached 919 TWh in December, a rise of 2.7% y-o-y (Figure 30).

Figure 29: Gas consumption in China



Source: GECF Secretariat based on data from LSEG

Figure 30: Y-o-y electricity variation in China

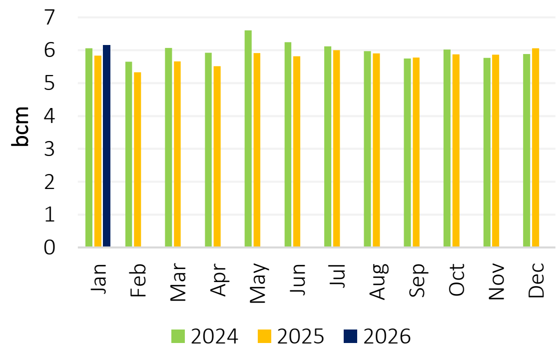


Source: GECF Secretariat based on data from Ember

2.2.2 India

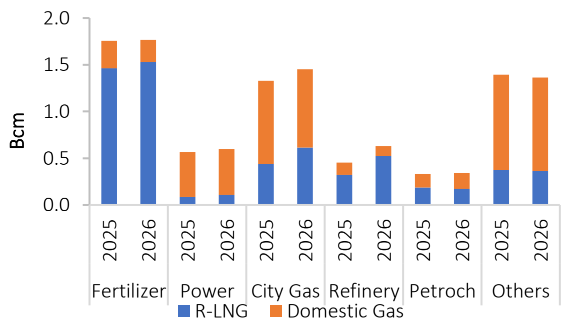
In January 2026, India's gas consumption increased by 5.4% y-o-y to 6.1 bcm, extending the recovery for a third consecutive month following the contraction recorded in October (Figure 31). The rise was largely supported by stronger gas demand across the power generation, city gas distribution, refinery and petrochemical sectors, which posted y-o-y increases of 5.4% (0.1 bcm), 9.3% (0.1 bcm), 38% (0.2 bcm) and 3% (0.01 bcm), respectively. Fertilizer production remained the dominant source of gas demand, accounting for 29% of total consumption, followed by city gas distribution with a 24% share (Figure 32).

Figure 31: Gas consumption in India



Source: GECF Secretariat based on data from PPAC

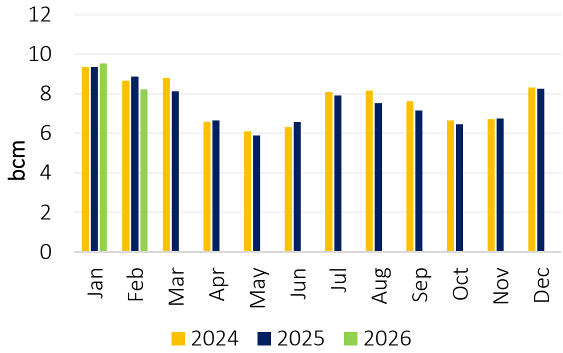
Figure 32: India's gas consumption by sector in January 2026



2.2.3 Japan

In February 2026, Japan's gas consumption decreased by 7.4% y-o-y to 8.2 bcm (Figure 33). Japan's electricity demand declined in February, averaging 108 GW, down 5.7% y-o-y, as warmer weather reduced heating needs. Average temperatures reached 7.8°C, 2.5°C higher than last year. Nuclear generation capacity stood at around 10 GW during the month, with 10 reactors operating across the country.

Figure 33: Gas consumption in Japan

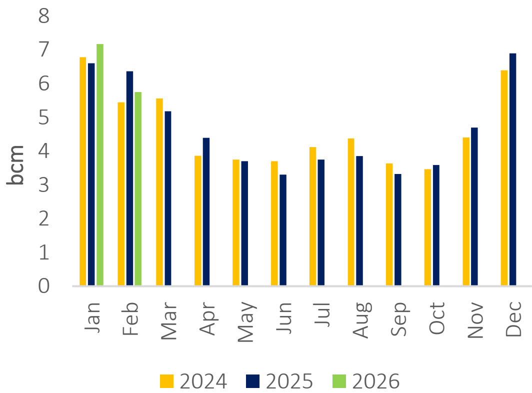


Source: GECF Secretariat based on data from LSEG

2.2.4 South Korea

In February 2026, S. Korea's gas consumption decreased by 9.7% y-o-y to reach 5.7 bcm (Figure 34). Gas demand weakened due to a sharp decline in city gas consumption. Gas sales to the power sector also decreased, while gas-fired generation (14.2 TWh) remained slightly above coal output. Warmer temperatures reduced heating demand. Meanwhile, Seoul announced measures to limit LNG dependence amid the escalating conflict in the Middle East.

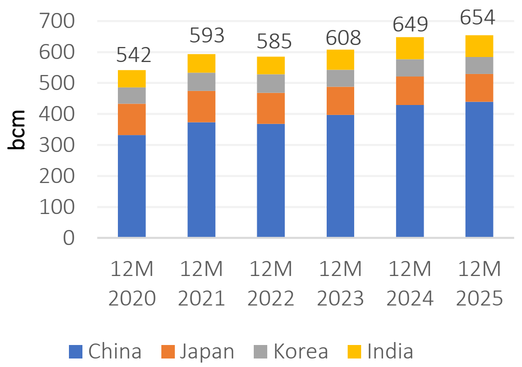
Figure 34: Gas consumption in South Korea



Source: GECF Secretariat based on data from LSEG

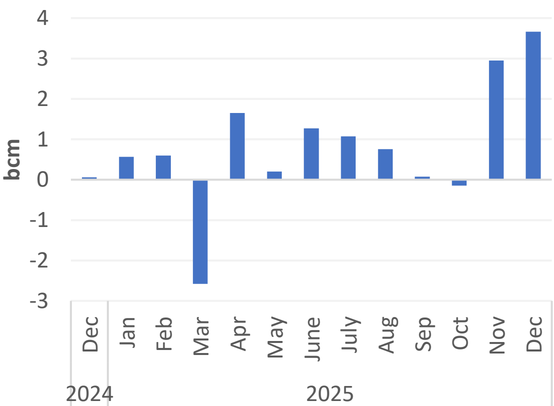
Due to the delay in data publication for China, the regional aggregated gas consumption data will be updated in the next MGMR edition. However in 12M 2025, gas consumption in major Asian gas consuming countries, namely China, India, Japan and South Korea, rose by 5 bcm to reach 62.2 bcm (Figure 35), driven largely by December dynamics (Figure 36).

Figure 35: YTD gas consumption in North East Asia and India



Source: GECF Secretariat based on data from PPCA, LSEG and Chinese custom

Figure 36: Y-o-y variation in aggregated gas consumption of North East Asia and India

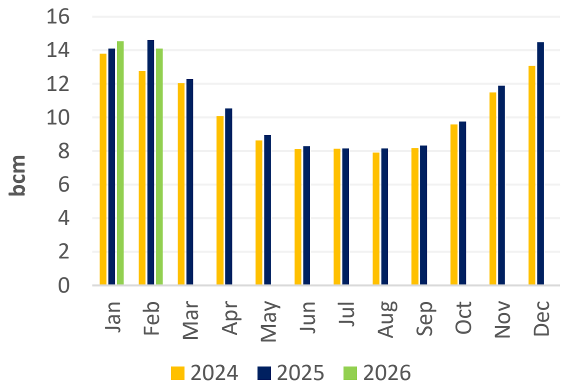


2.3 North America

2.3.1 Canada

In February 2026, Canada's gas consumption declined by 3.5% y-o-y to 14 bcm (Figure 37), largely reflecting warmer-than-normal weather conditions across the country. Residential and commercial gas demand decreased by 10% and 9% y-o-y, respectively, as warmer temperatures reduced space-heating requirements. Gas use in the industrial and power generation segment increased by 1% y-o-y, supported by higher electricity demand during the month.

Figure 37: Gas consumption in Canada



Source: GECF Secretariat based on data from LSEG

2.3.2 US

In February 2026, US gas consumption edged down by 4% y-o-y to 87 bcm (Figure 38), reflecting weaker demand in the residential, commercial and industrial sectors. Residential and commercial gas use declined by 6.5% and 7.6% y-o-y respectively. Industrial gas demand also slipped by 2.7% y-o-y (–0.6 bcm), driven by softer manufacturing activity, indicating that economic fluctuations are increasingly influencing overall seasonal energy requirements.

Total electricity generation in the US decreased by 2.1% y-o-y to 333 TWh. Natural gas-fired power generation declined by 3.7% y-o-y (Figure 39). Natural gas remained the largest contributor to the power mix, accounting for 38%, while nuclear, coal and non-hydro renewables made up 18%, 16% and 21% respectively.

Figure 38: Gas consumption in the US

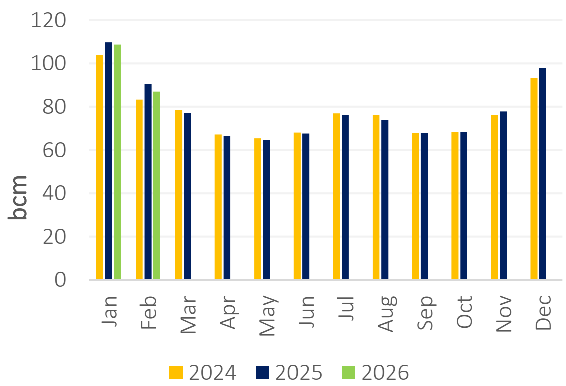
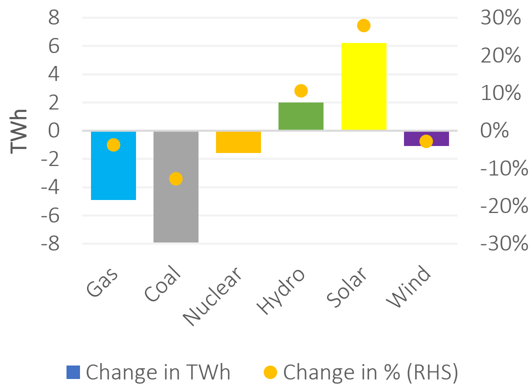


Figure 39: Electricity production in US in Feb 2026



Source: GECF Secretariat based on data from EIA and LSEG

For the period Jan-Feb 2026, US's gas consumption declined by 2.3% y-o-y to 195 bcm.

2.4 Other developments

2.4.1 Sectoral developments

Taiwan's Gas-Fired Power Hits Record High as Energy Mix Shifts Away from Coal: Taiwan's gas-fired generation surged to a historic record of 138.1 TWh in 2025, significantly increasing from 122.2 TWh the previous year and representing a massive leap from just 20.5 TWh in 2001. Natural gas now accounts for 48% of the island's total power generation, bringing it within reach of the government's 50% target share. This transition has directly displaced older fossil fuels, driving coal-fired output down to its lowest level in 24 years at 102.2 TWh. As Taiwan prioritizes cleaner-burning infrastructure, the record-breaking gas output has become the primary pillar of its energy strategy, supported by a growing 12.5% contribution from renewables.

South Korea's SK Multi Utility launches advanced dual-fuel CHP plant in Ulsan: SK Multi Utility began commercial operations at its 300 MW Ulsan LNG-LPG combined heat and power (CHP) plant. The facility is now in a stable operational phase and capable of generating 2.41 TWh of electricity and 1.82 million tons of steam annually. The plant features dual-fuel technology, allowing it to produce power and steam simultaneously by switching between LNG and LPG. By replacing older coal-fired infrastructure with this high-efficiency system, the project enhances the energy reliability and environmental profile of Ulsan's industrial complex.

US Pacifico Energy secures landmark permit for massive gas-fired GW Ranch project: Pacifico Energy has secured a 7.65 GW power generation permit from the Texas Commission on Environmental Quality (TCEQ) for its massive GW Ranch project in West Texas. This venture centres on a high-efficiency gas-fired power plant purpose-built to supply hyperscale data centres and AI infrastructure, operating independently from the main ERCOT grid to protect local ratepayer costs. It will utilize a mix of small and large-scale gas turbines integrated with 1.8 GW of battery storage and 750 MW of solar. Located in Pecos County near the Waha gas hub, the facility will draw from abundant local reserves via a dedicated 15-mile pipeline, representing one of the largest permitted power-for-AI campuses in the U.S. with first power targeted for the first half of 2027.

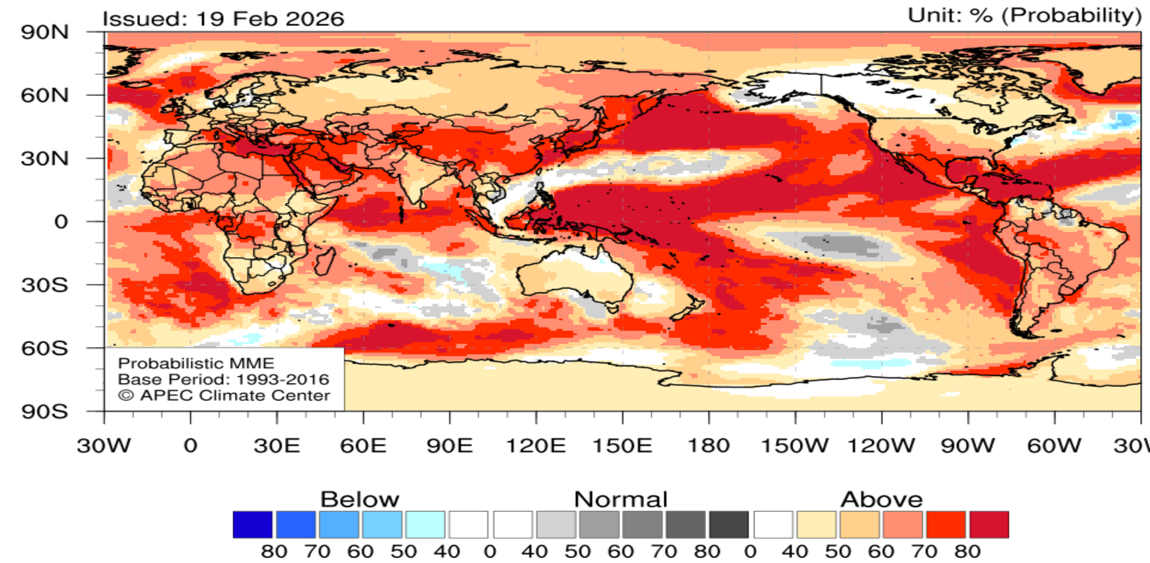
Kuwait's Az-Zour North Project solidified by multi-party agreement: ACWA Power, Gulf Investment Corporation and Kuwait's Ministry of Electricity, Water and Renewable Energy signed an Energy Conversion and Water Purchase Agreement (ECWPA) to launch the $4 billion Az-Zour North Phase 2 & 3 project. This milestone contract, involving a consortium led by the Kuwait Authority for Partnership Projects (60%) and the ACWA-GIC partnership (40%), secures the development of a 2.7 GW CCGT power plant and a massive seawater reverse osmosis desalination facility.

Singapore's LNG bunkering consumption surged to record high in 2025: Singapore's LNG consumption for bunkering rose by 24% to 571,400 tonnes in 2025, driven by the shipping industry's accelerating shift toward cleaner-burning transition fuels. This significant increase highlights the city-state's strengthening position as a premier global hub for alternative marine fuels, supported by expanded infrastructure and a growing fleet of LNG-powered vessels. While traditional fuel oils still dominate the market, the double-digit growth in LNG adoption underscores a critical trend in maritime decarbonization. As more dual-fuel ships enter service, Singapore's strategic investments in LNG bunkering vessels and specialized terminals continue to capture rising demand for low-carbon energy solutions in the regional shipping lanes.

2.4.2 Weather forecast

According to the APEC Climate Center, El Niño Watch was issued, with climate models indicating a possible transition toward El Niño in the coming months. Between March and May 2026, above-normal temperatures are expected across most regions worldwide, except for some tropical ocean areas in the Southern Hemisphere. (Figure 40).

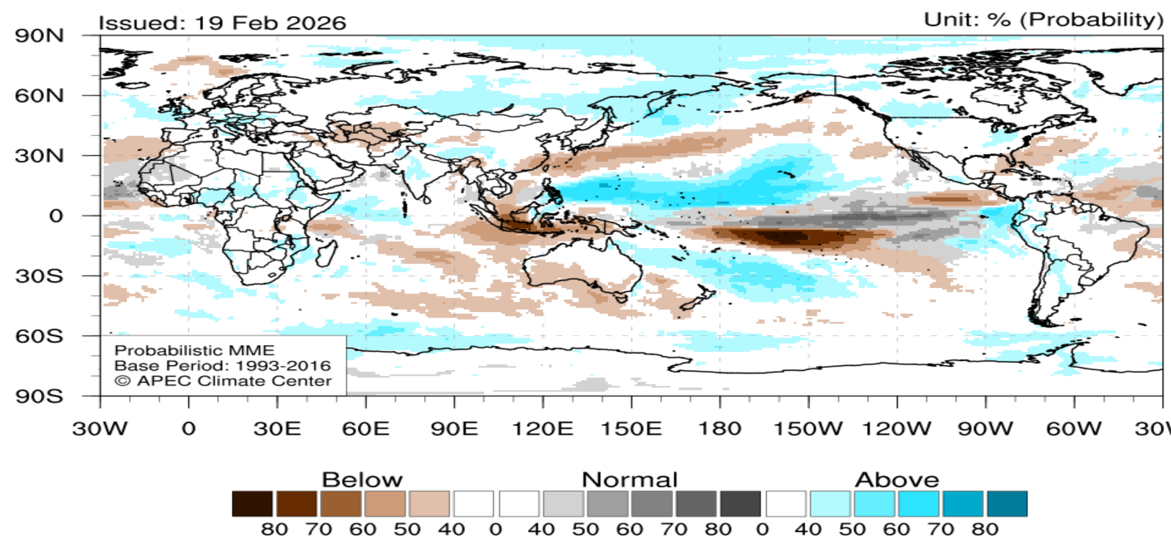
Figure 40: Temperature forecast for March to May 2026



Source: APEC Climate Center

According to the same source, precipitation is expected to be above average in the subtropical North Pacific, the equatorial eastern Pacific the Arctic Ocean, Russia, Central Africa and the southwestern South Pacific. Rainfall is likely near normal in the central and eastern equatorial Pacific and the west coast of North Africa, while below-average precipitation is forecast for the Central Sub-equatorial South Pacific, Indonesia, Central Asia, the Equatorial East Indian Ocean, the Western to Central North Pacific, the Eastern Sub-equatorial North Pacific, Eastern Europe, the Southern Indian Ocean, Western Australia, Central Asia and parts of the tropical and mid-latitude Western North Atlantic (Figure 41).

Figure 41: Precipitation forecast March to May 2026

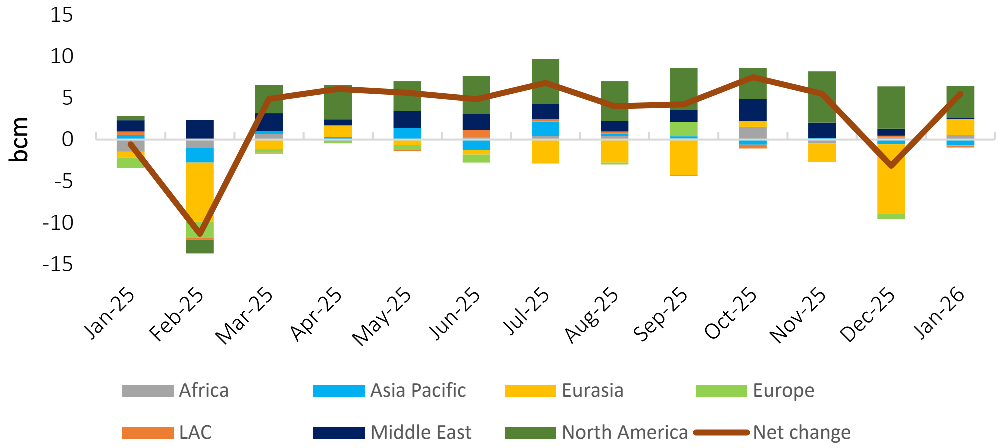


Source: APEC Climate Center

3 GAS PRODUCTION

In January 2026, global gas production was estimated to have risen by 1.5% y-o-y to stand at 376 bcm (Figure 42). North America and Eurasia, specifically the US and Russia, led the growth. On the other hand, LAC witnessed the highest output decline in January, with 1.4% y-o-y reduction, followed by Asia Pacific with 1.2% decline. From a regional perspective, North America kept its leading position as the frontrunner producing region (dominated by the US), accounting for 31% of global gas production, followed by Eurasia with 21% (led by Russia), the Middle East with 18% (led by Iran, Qatar and Saudi Arabia) and Asia Pacific with 16%, while Africa, Europe, Latin America and the Caribbean (LAC) held shares ranging from 3% to 6%.

Figure 42: Y-o-y variation in global gas production



Source: GECF Secretariat estimation

3.1 Europe

In January 2026, gas production in Europe recorded a marginal 0.4% y-o-y decline, with a total output of 16.4 bcm (Figure 43). Over the whole 2025, European output has consistently seen year-on-year reductions, mainly driven by lower gas production in the UK and the Netherlands. However, the magnitude of the overall European production decline was limited by the higher supply from Norway's gas production, along with the rise in Denmark's gas output, mainly from Tyra phase II gas field in the North Sea (Figure 44). Notably, monthly gas production in the EU stood at 2.4 bcm, with the Netherlands and Romania maintaining their positions as top producers.

Figure 43: Europe's monthly gas production

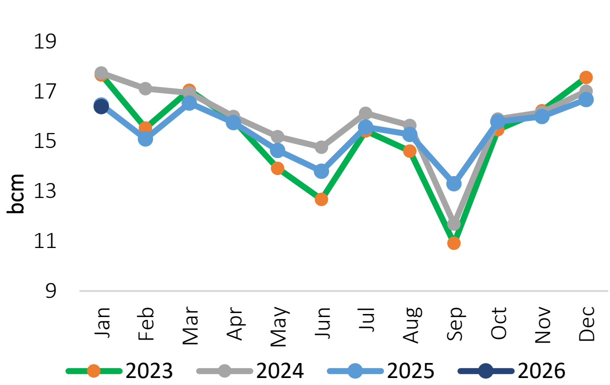
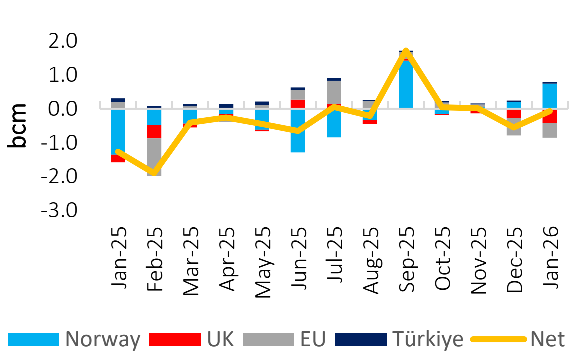


Figure 44: Y-o-y variation in Europe's gas production



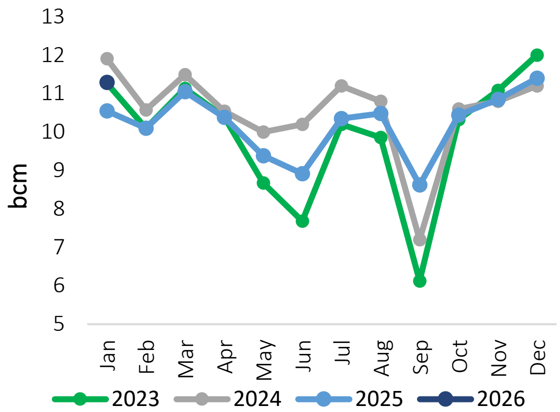
Source: GECF Secretariat based on data from LSEG, the Norwegian Offshore Directorate and JODI Gas
Note: EU countries include Austria, Denmark, Germany, Italy, Netherlands, Poland and Romania

3.1.1 Norway

Norway's gas output witnessed its largest monthly rise during the last 12 months, to stand at the level of 11.3 bcm (7% y-o-y) to start the year with a healthy supply growth, unlike the declining y-o-y trend in 2025 (Figure 45).

This was mainly driven by lower planned and unplanned maintenance durations. Notably, the 31 mcm/d Åsgard field witnessed reduced production for just one day, as result of unplanned outage. In addition, the 20.6 mcm/d Aasta Hansteen gas field underwent planned maintenance, which slashed its output by 10 mcm/d, but only for a period of 2 days.

Figure 45: Trend in gas production in Norway



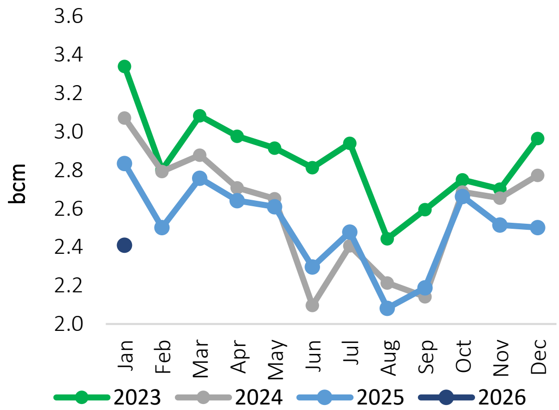
Source: GECF Secretariat based on data from the Norwegian Offshore Directorate

3.1.2 UK

UK gas production declined by 15% y-o-y to stand at 2.4 bcm in December 2025 (Figure 46). This is a continuation of the declining trend in the past period, with this lowest January monthly production in decades, driven by the reduced output from the UK mature fields, lack of new gas projects and longer-than-expected maintenance periods.

Multiple unplanned maintenance activities took place at the 9 mcm/d Bacton Perenco terminal that ceased its production for a period of 4 days.

Figure 46: Trend in gas production in the UK



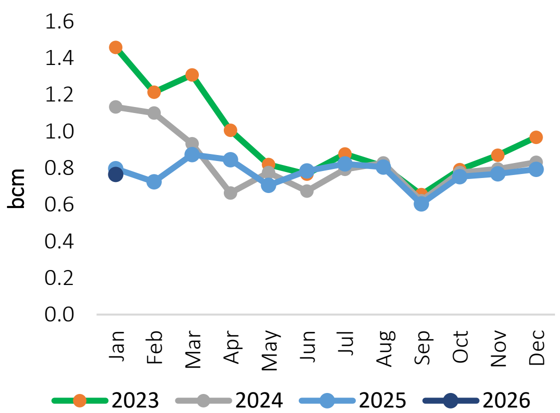
Source: GECF Secretariat based on data from LSEG

3.1.3 Netherlands

The Netherlands' gas production maintained a declining trend, with a 3.9% y-o-y reduction, to stand at 0.76 bcm (Figure 47). This represented a continuation in output declines observed recently for Dutch production, reflecting a continued negative outlook.

With the absence of new field development or rejuvenation, this production drop from the ageing Dutch fields is likely to continue in the coming years, with the remaining reserves reaching depletion in 9 years.

Figure 47: Trend in gas production in the Netherlands



Source: GECF Secretariat based on data from LSEG

3.2 Asia Pacific

In January 2026, gas output in Asia Pacific was estimated to stand at 60 bcm representing a 1.2% y-o-y reduction. This decrease was driven by the declining output in some regional Asia Pacific producers, which was counterbalanced by the rise in the Chinese gas production.

3.2.1 China

Due to the delay in data publication by the National Bureau of Statistics of China, gas production figures for January and February 2026 will be included in the next edition of the Monthly Gas Market Report (Figure 48). In December 2025, China's gas production maintained its growth trend to stand at 23 bcm, representing a 6% y-o-y uptick. Coal bed methane production continued its annual growth as well, with 14% y-o-y rise, to stand at 1.5 bcm (Figure 49). Notably, authorities in central China's Hubei province announced that exploration activities in 2025 resulted in the identification of 420 bcm of shale gas recoverable resources in the province.

Figure 48: Trend in gas production in China

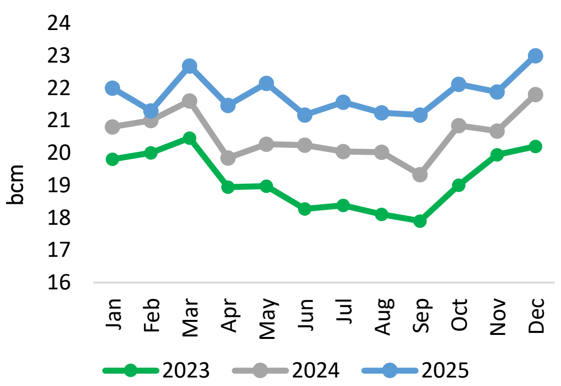
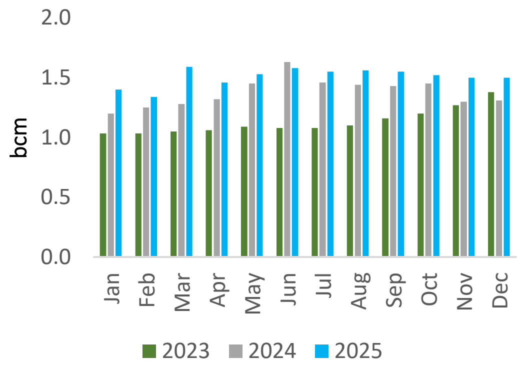


Figure 49: China's CBM gas production

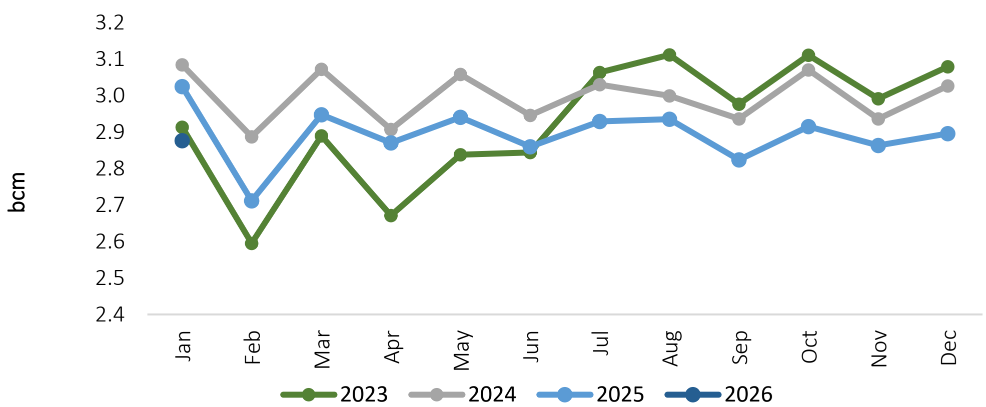


Source: GECF Secretariat based on data from the National Bureau of Statistics of China (NBS)

3.2.2 India

In January 2026, India's gas production continued its negative trend, declining by 4.9% y-o-y to stand at 2.88 bcm (Figure 50). The decrease was driven by a reduction in offshore gas output, which represented 73% of Indian production, along with decreased output from the onshore Rajasthan field, which witnessed a 13.9% y-o-y reduction. Meanwhile, the CBM gas fields recorded a 5.1% y-o-y uptick, mainly from the West Bengal fields.

Figure 50: Trend in gas production in India



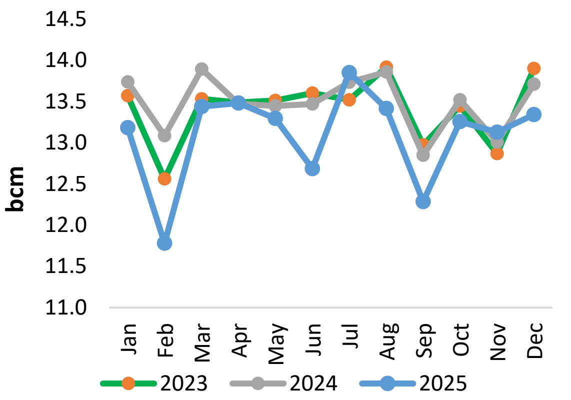
Source: GECF Secretariat based on data from the Ministry of Petroleum and Natural Gas (PPAC)

3.2.3 Australia

In December 2025, Australia's gas production decreased by 2.7% y-o-y to stand at 13.3 bcm (Figure 51). Gas production from CBM fields amounted to 3.5 bcm, representing a 1 % y-o-y rise and accounted for 26% of the total domestic production. Notably, Australia kept its position as the frontrunner CBM producer globally, with consistent growth in the past years and CBM being used as feedstock for LNG export terminals.

For the full year of 2025, the cumulative production dropped by 2.9% to 157 bcm.

Figure 51: Trend in gas production in Australia



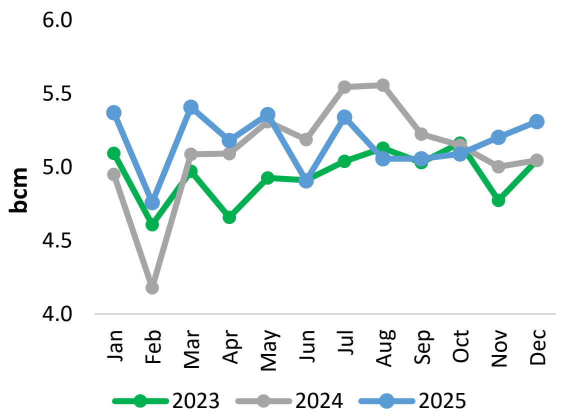
Source: GECF Secretariat based on data from the Australian Department of Energy

3.2.4 Indonesia

In December 2025, Indonesia's gas output rose by 5.2% y-o-y to 5.3 bcm (Figure 52). This was driven by an extensive development drilling campaign, with 107 new development wells drilled during the month. The incremental production was able to exceed the natural decline in the producing fields.

For the full year of 2025, cumulative production rose by 1.2% to 62 bcm. This was driven by the startup of multiple gas projects, with 980 new development wells drilled, in addition to 35 new exploration wells.

Figure 52: Trend in gas production in Indonesia



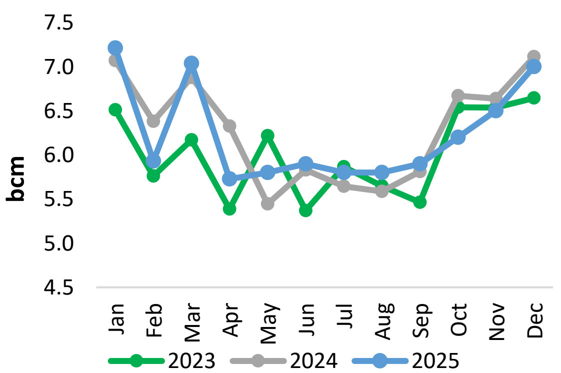
Source: GECF Secretariat based on data from SKK Migas and JODI Gas

3.2.5 Malaysia

In December 2025, Malaysia's gas output was estimated at 7 bcm, representing a production decline of 2% y-o-y (Figure 53). Notably, PETRONAS is making strategic moves to expand Malaysia's hydrocarbon resources with the award of two key technical evaluation agreements.

For the full year of 2025, cumulative production in Malaysia nearly mirrored that previous year production of 75 bcm.

Figure 53: Trend in gas production in Malaysia



Source: GECF Secretariat based on data from the JODI

3.3 North America

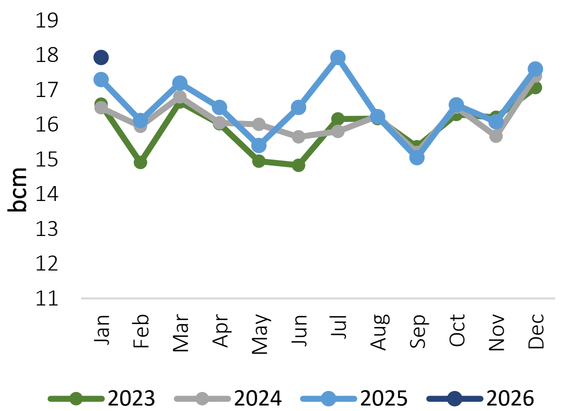
In January 2026, gas production in North America (including Mexico) rose by 3.5% y-o-y to reach 115 bcm, driven by strong gas supply growth in the US and Canada.

3.3.1 Canada

In January 2026, Canada's gas production rose by 4% y-o-y to 17.9 bcm (Figure 54), supported by an LNG export ramp up. From a regional perspective, Alberta was responsible for 10.6 bcm of the production, mainly originating from the Bakken shale production, while British Columbia accounted for 6.9 bcm, stemming from tight gas production from the Montney Basin. In this context, Canada is well poised to continue strong production growth in 2026, driven by the start of LNG exports and favourable prices.

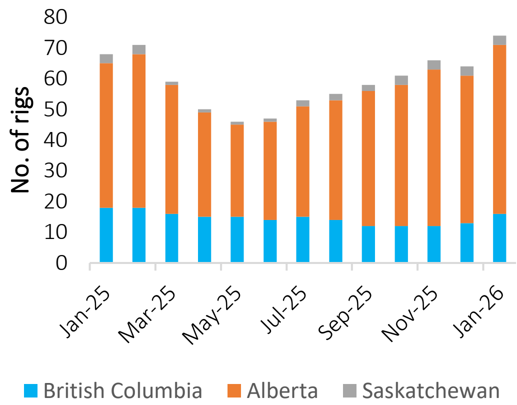
In terms of gas drilling activity, there was a strong 10-rig-increase in January 2026, specifically in British Columbia, which added 7 more drilling rigs, while Alberta added 3 additional gas rig and Saskatchewan kept the same level. Overall, this represented a 6-rig-increase in the number of drilling rigs, as compared to January 2025 (Figure 55).

Figure 54: Trend in gas production in Canada



Source: GECF Secretariat based on data from CER, Alberta and British Colombia Energy Regulators

Figure 55: Gas rig count in Canada



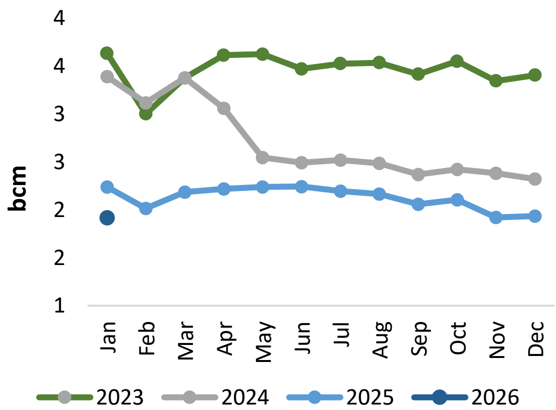
Source: GECF Secretariat based on data from LSEG

3.3.2 Mexico

In January 2026, Mexico's gas output was estimated at 1.92 bcm, representing a production reduction of 14% y-o-y (Figure 56).

For the full year of 2026, Mexico's gas production is projected to nearly mirror the level of 2025, driven by the expected commissioning of new major gas field startups in 2026. This is expected to counterbalance the natural decline in the Mexican legacy fields and keep production at the same level.

Figure 56:Trend in gas production in Mexico



Source: GECF Secretariat based on data from the JODI

3.3.3 US

In February 2026, US total gas production strengthened its growth trend, with a monthly output rising by 4.8% y-o-y to 87.1 bcm (Figure 57). This growth reflected the favourable market dynamics, driven by the increased Henry Hub gas prices, rising gas demand for heating, along with the increased feed gas directed to LNG exports terminals.

In terms of supply distribution, shale dry gas production sustained its leading position in the US dry gas output, accounting for 80% and it was the main driver for the growth, with a 2.1% uptick, while conventional gas and associated gas production from shale oil, represented the remaining 20%. In terms of field type, associated gas production represented 25% of the total gas output. From a regional perspective, the Appalachian region accounted for 31% of total gas production, followed by the Permian region output with 22% and Haynesville with 13%.

For the period Jan-Feb 2026, cumulative gas production in the US reached 182 bcm (Figure 58), representing 4.6% y-o-y growth and therefore provided a strong start in domestic gas output for the full year (2.5% projected growth).

Figure 57: Trend in gas production in the US

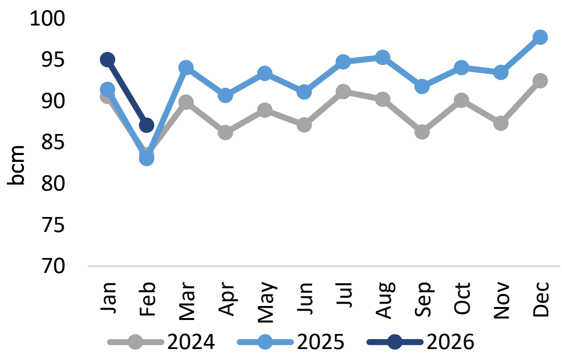
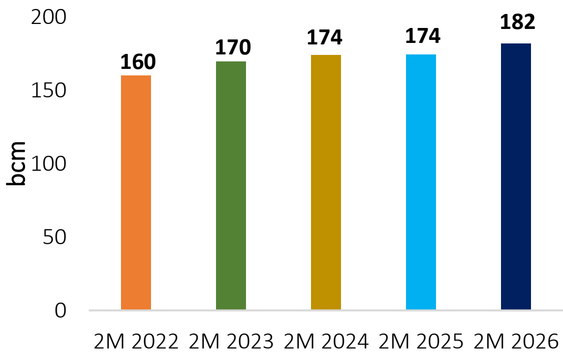


Figure 58: YTD gas production in the US



Source: GECF Secretariat based on data from the US EIA

As of February 2026, the number of gas drilling rigs operating in the US stood at 133, marking a 9-rig increase compared to January 2026, and a 32-rig rise, compared to February 2025 (Figure 59), giving evidence of accelerated upstream activity in the US. Additionally in February 2026, the total number of drilled but uncompleted (DUC) wells in the US onshore regions amounted to 4,977, marking a 16-well m-o-m decrease and 938 wells lower than February 2025 (Figure 60). This m-o-m reduction in DUCs reflected the slowdown in the completion activity during February, driven by the weather condition that hindered the operation and the pipeline infrastructure constrains in the Permian region.

Figure 59: Gas rig count in the US

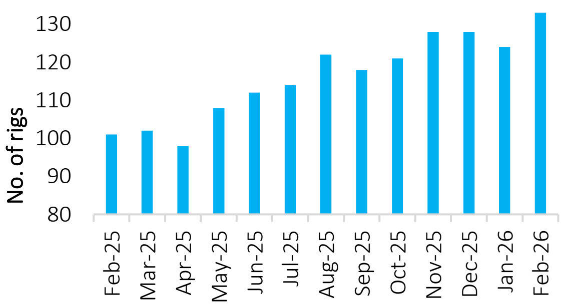
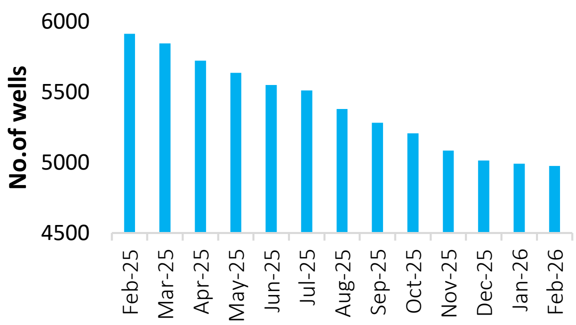


Figure 60: DUC wells count in the US



Source: GECF Secretariat based on data from Baker Hughes *Source: GECF Secretariat based on data from the US EIA*

3.4 Latin America and the Caribbean (LAC)

In January 2026, gas production in LAC was estimated at 12.8 bcm (1.4% y-o-y rise), mainly driven by reduced output in both Argentina and Venezuela.

3.4.1 Argentina

In January 2026, Argentina's gas production stood at 4.1 bcm, representing a 5.3% y-o-y reduction (Figure 61). Most of the gas output originated from the Vaca Muerta (shale gas) Basin, however the decline mainly originated from the conventional gas fields. Notably, shale gas production witnessed a 22% y-o-y rise to stand at 2.26 bcm, accounting for 56% of total gas production (Figure 62). Moreover, tight gas production reached 0.4 bcm, to represent a 9.6% share of the total production, whilst the remaining output was produced from conventional fields.

Figure 61: Trend in gas production in Argentina

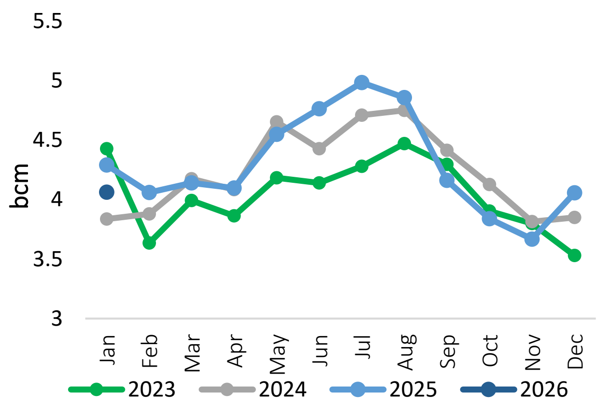
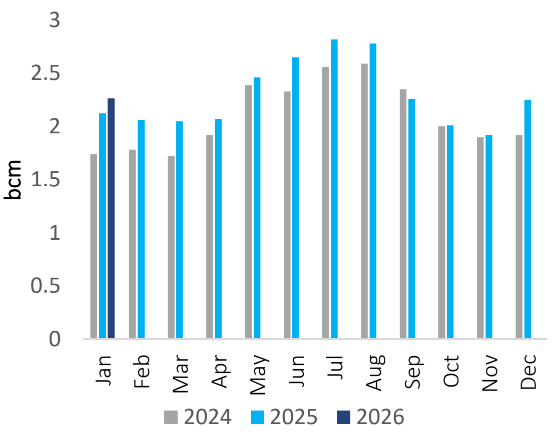


Figure 62: Shale gas output in Argentina



Source: GECF Secretariat based on data from Argentinian Ministry of Economy

3.4.2 Brazil

In January 2026, Brazil's marketed gas production continued its strong growth for the eleventh consecutive month, to achieve an output level of 1.9 bcm (20% y-o-y growth) driven by high gross gas production that stood at 6 bcm (24 % y-o-y rise) (Figure 63), with the pre-salt fields representing 79% of the total production. Notably, 87% of production originated from offshore fields. In terms of distribution, 54% of gross gas production was reinjected into reservoirs, while there was a 16.9% increase in flaring compared to the previous month and a 27% increase compared to January 2025. The increase in flaring is mainly due to the commissioning of the P-78 platform in the Búzios Field, which began operations on December 31, 2025 (Figure 64).

Figure 63: Gross gas production in Brazil

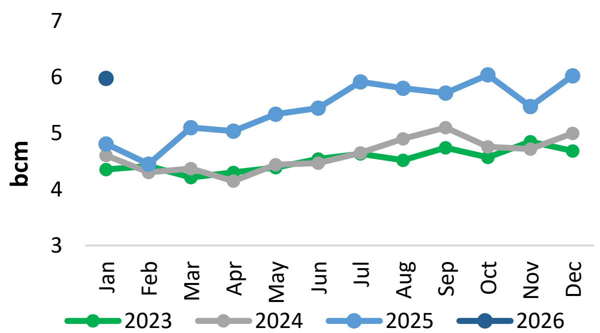
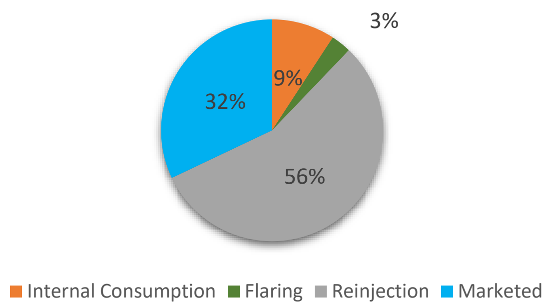


Figure 64: Distribution of gross gas production



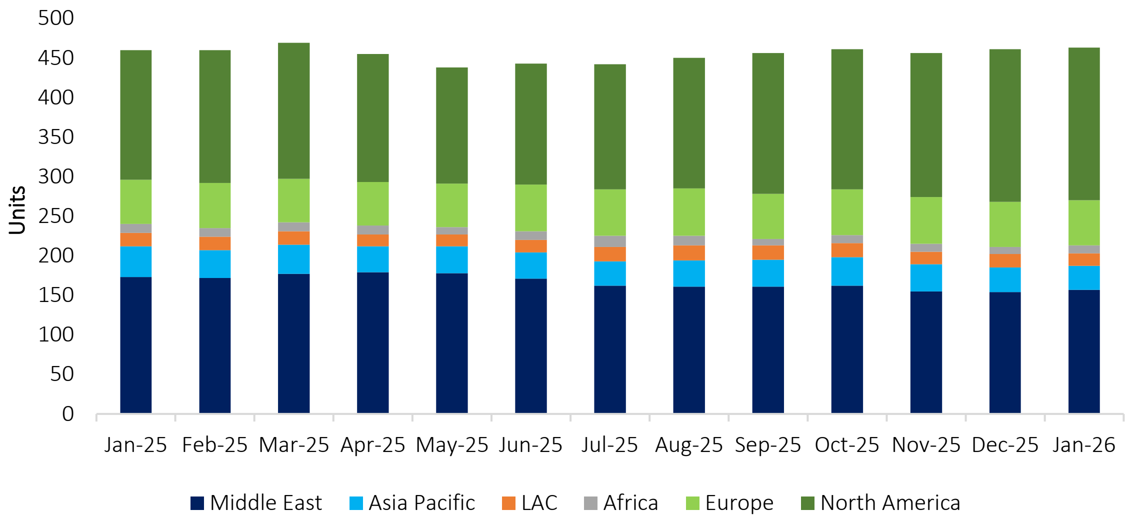
Source: GECF Secretariat based on data from the Brazilian National Agency of Petroleum (ANP)

3.5 Other developments

3.5.1 Upstream tracker

In January 2026, the number of gas drilling rigs globally ramped-up by 5 additional units m-o-m, reaching 469 rigs (Figure 65). This was driven mainly by the accelerated drilling activity in the Middle East, specifically in Saudi Arabia, along with Asia Pacific, specifically in China. Onshore drilling accounted for the majority with 437 units, while offshore accounted for 32 rigs.

Figure 65: Trend in monthly global gas rig count



Source: GECF Secretariat based on data from Baker Hughes
Note: Figure excludes Eurasia and Iran

In January 2026, global exploration activity resulted in the total volume of discovered gas and liquids amounting to 70 million barrels of oil equivalent (boe), the relatively modest outcome reflects a concentration of discoveries in mature basins and the absence of large, standalone frontier finds (Figure 66). Natural gas accounted for 54% of the discovered volumes (12 bcm). 9 new discoveries were announced, five of which were offshore. In terms of regional distribution, Asia Pacific dominated the new discovered volumes with 38% (primarily in Philippines and Australia), followed by Europe (Norway) with 21% (Figure 67). The Malampaya East discovery, offshore Philippines, was the most significant discovery announced in January. The Malampaya East well marked the Philippines first natural gas discovery in a decade.

Figure 66: Monthly discovered oil and gas volumes

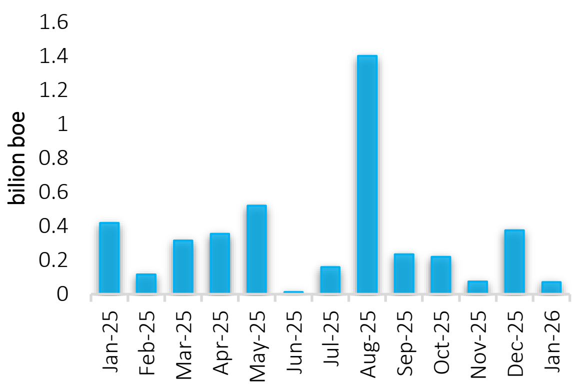
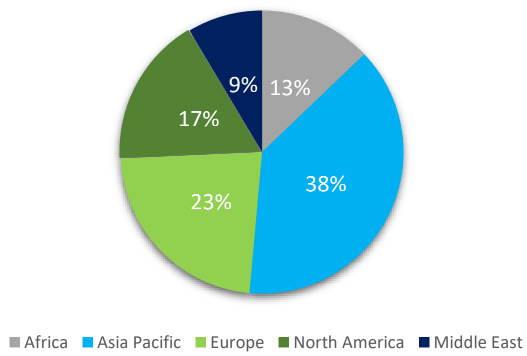


Figure 67: Discovered oil and gas volumes in January 2026 by region



Source: GECF Secretariat based on data from Rystad

3.5.2 Regional developments

QatarEnergy wins Libya offshore exploration license: QatarEnergy was part of a consortium that won an offshore exploration license in the State of Libya following the conclusion of the "Libya Bid Round", marking its first entry into the country's upstream sector. The results of the competitive bid process, the first to be held in Libya since 2007, were announced by the National Oil Corporation (NOC) awarding the exploration and production rights for offshore block O1 to the consortium of QatarEnergy (40% participating interest) and Eni (the operator, 60% participating interest).

Eni announced a significant gas discovery in the Calao Basin in Côte d'Ivoire: Eni has announced a significant oil, gas and condensate discovery in the Calao South area of Block CI-501 offshore Côte d'Ivoire — marking one of the largest recent hydrocarbon finds in West Africa. The Murene South-1X exploration well encountered high-quality reservoirs in deepwater (2,200 m), confirming an estimated 5 trillion cubic feet (Tcf) of gas alongside around 450 million barrels of condensate. This discovery sits within the broader Calao complex, a promising frontier next to the prolific Baleine field — already established as a key producing asset in the Ivorian offshore space. With development activities under way, the combined production outlook strengthens Côte d'Ivoire's role as an emerging regional energy hub.

Malaysia announced new licensing round: PETRONAS has launched the Malaysia Bid Round 2026 (MBR 2026), offering 15 opportunities comprising nine exploration blocks and six Discovered Resource Opportunity (DRO) clusters across the Malay, Sarawak and Sabah Basins. Under the MBR 2025, new PSC awards including the Permata Cluster, comprising the South East Collins, Lokan, Axinit, Realgar and Manikam fields, were awarded to Bridge Petroleum, marking its entry into Malaysia. Separately, the Cendramas PSC was awarded to a consortium led by PT Medco Energi Internasional Tbk, with Dialog Group Berhad and EnQuest as partners. MBR 2026 reflects PETRONAS' strategy to attract diverse upstream investments by combining exploration upside with commercially ready DRO opportunities across Malaysia's core basins as it aims to sustain 2 MMboe/d of production to 2035.

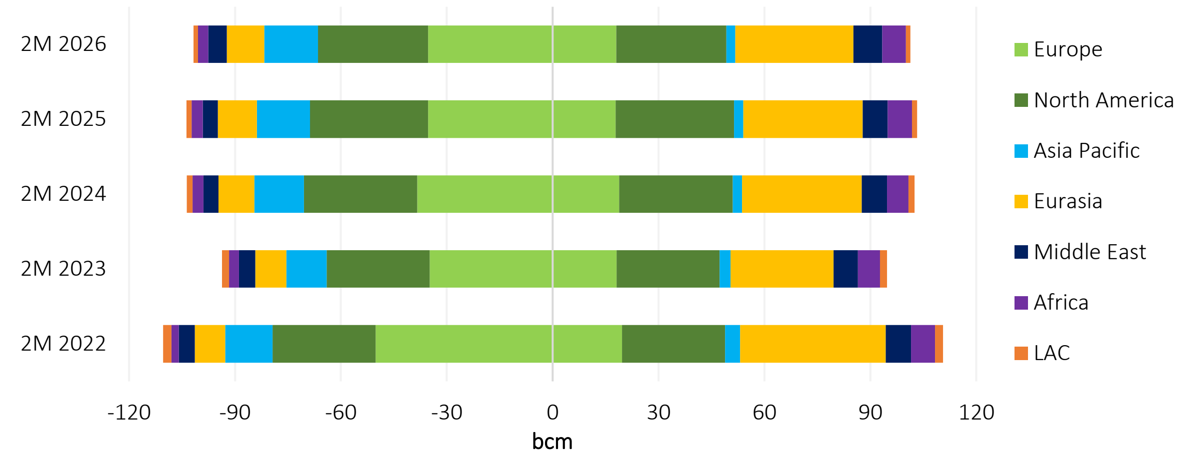
Saudi Aramco announced the Jafurah shale gas field commissioning: On 11 February 2026, Saudi Aramco commenced production from the Jafurah unconventional gas field following the completion of Phase 1. The first stage of the project provides a gas processing capacity of 450 mmscfd. The $100 billion development has started producing condensate, marking the first export of hydrocarbons from the field. Jafurah is estimated to hold 229 Tcf of gas and 75 billion bbl of condensate, making it the biggest liquid-rich shale gas play in the region. With Phase 2 targeted for completion by 2030, Aramco aims to reach 2 Bcf/d of gas capacity. The start-up aligns with the Kingdom's Vision 2030 initiative of boosting domestic gas supply and reduce the dependency on crude oil for generating power.

4 GAS TRADE

4.1 PNG trade

Global PNG imports after two months of 2026 were estimated at a cumulative 102 bcm, which represented a decrease of 2% compared to one year prior (Figure 68). During this period, imports in the Middle East increased by 25% y-o-y, driven by higher pipeline flows along the Dolphin line from Qatar to the UAE. On the supply side, Eurasian countries continue to anchor global PNG exports, accounting for one third of total exports.

Figure 68: Global PNG imports (-) and exports (+) by region

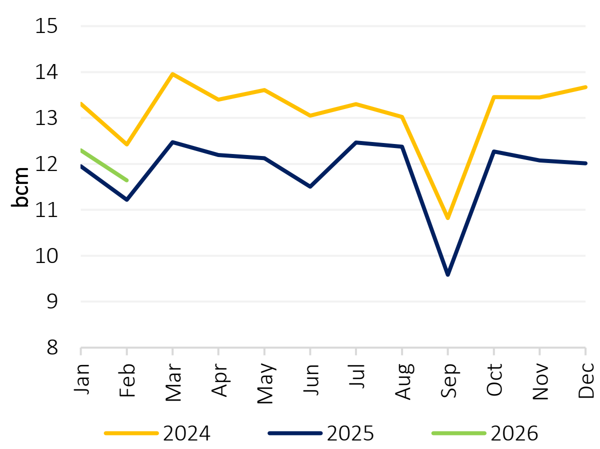


Source: GECF Secretariat based on data from Cedigaz, ENARGAS, Eurostat, GACC, JODI, LSEG and US EIA

4.1.1 Europe

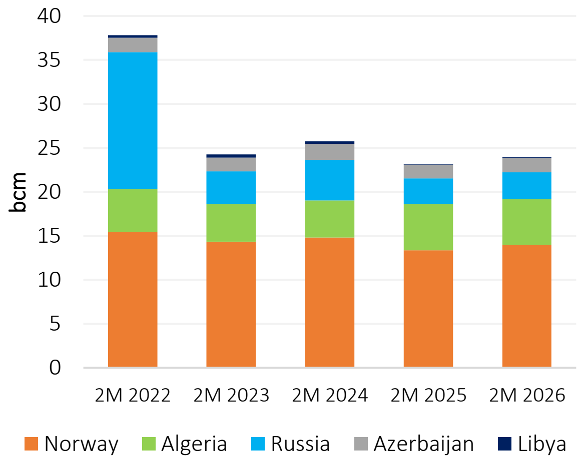
In February 2026, there was a decrease in EU PNG imports by 5% compared to the previous month, which brought the aggregated total to 11.6 bcm (Figure 69). After two months of 2026, cumulative PNG imported by the EU reached 24 bcm, which was 3% greater than the previous year (Figure 70). Norway accounted for 58% of the regional PNG supply in 2026 thus far, while Algeria contributed 22%.

Figure 69: Monthly PNG imports to the EU



Source: GECF Secretariat based on data from LSEG

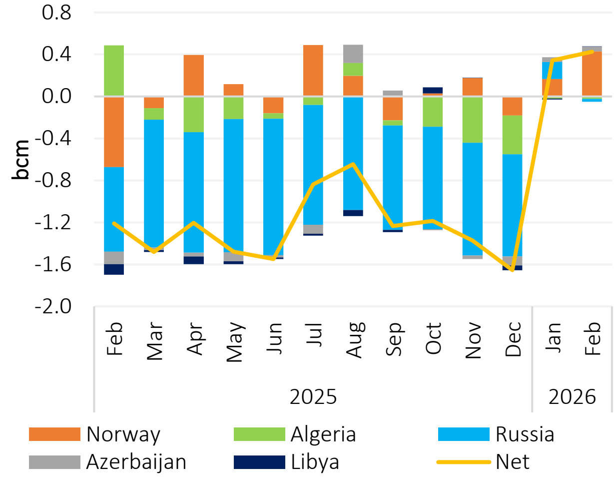
Figure 70: Year-to-date EU PNG imports by supplier



Source: GECF Secretariat based on data from LSEG

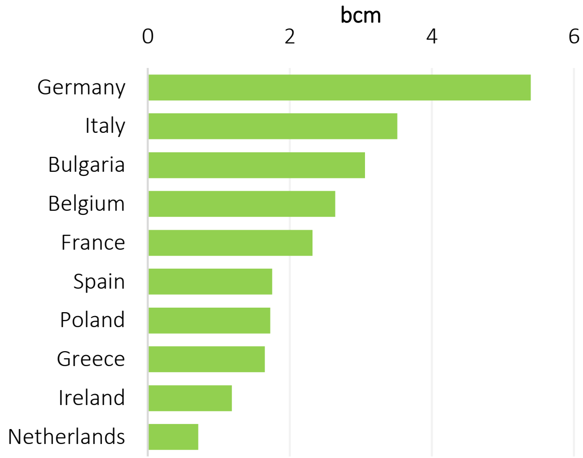
There was a net 0.4 bcm increase in PNG supply to the region in February 2026 compared to the previous year, driven particularly by Norway (Figure 71). There were 5.4 bcm of PNG flows entering the region via Germany, accounting for 23% of total regional inflows (Figure 72). The Netherlands is the smallest entry point in 2026, despite the large gas corridor from Norway.

Figure 71: Y-o-y variation in EU PNG supply



Source: GECF Secretariat based on data from LSEG

Figure 72: EU PNG imports by entry, after 2M 2026

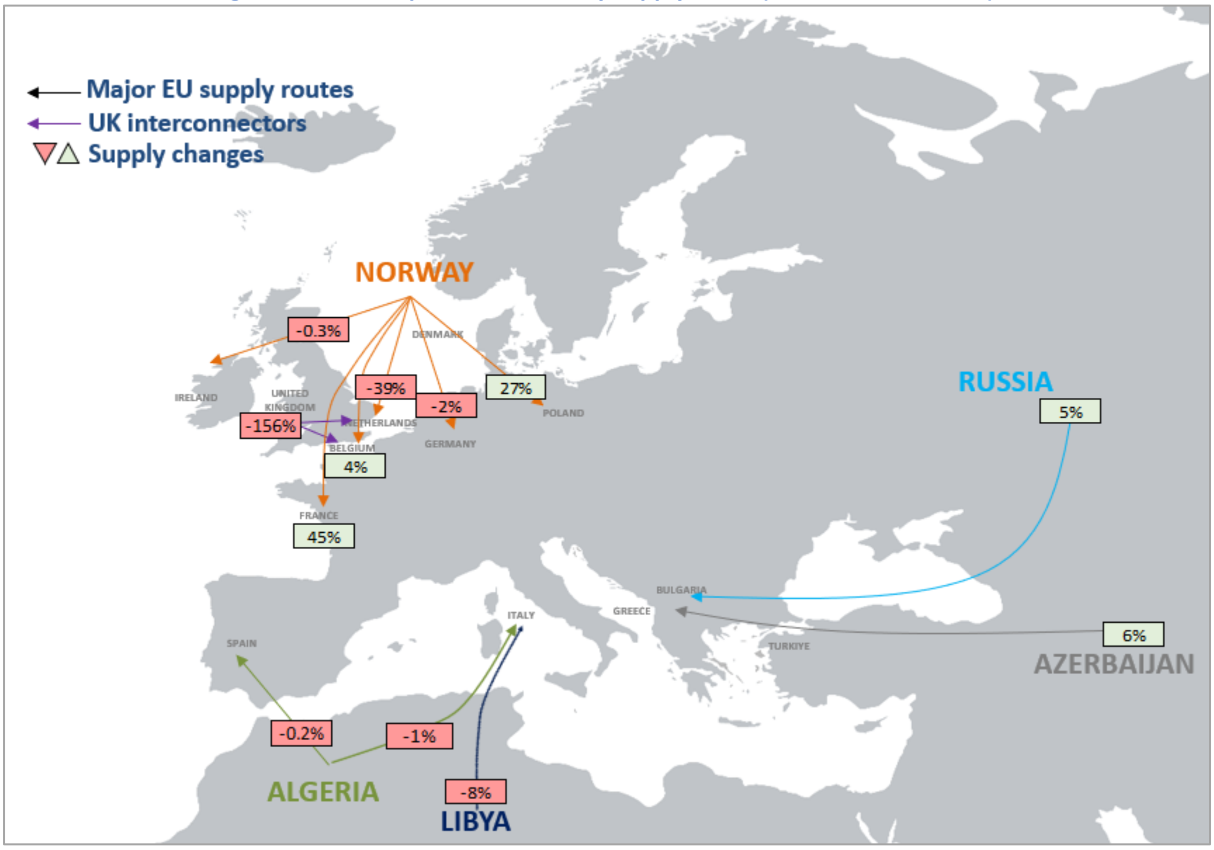


Source: GECF Secretariat based on data from LSEG

Figure 73 shows the PNG imports to the EU via the major supply routes during the 2M 2026 period, compared with 2M 2025. Norway increased flows y-o-y to France (45%), Poland (27%) and Belgium (4%), while all of its other supply routes declined. Russian supply via the Turkstream pipeline also increased by 5%, while Azeri PNG exports to the EU increased by 6%.

In addition, there were 0.3 bcm of net gas imports via the interconnectors from the UK to mainland Europe in 2026 thus far, compared to one year ago when there were 0.5 bcm of flows in the direction from the EU towards the UK.

Figure 73: PNG imports to the EU by supply route (2M 2026 v 2M 2025)



Source: GECF Secretariat based on data from LSEG

4.1.2 Asia

Due to the holiday period associated with the Chinese New Year celebrations, there was a delay in the publication of the country's import statistics. However, PNG imports in Q1 2026 are expected to increase y-o-y, driven by the increase in flows via Russia's Power of Siberia 1 pipeline, increased gas demand for heating amidst colder winter temperatures and the favourable price differential compared to imported LNG. This would represent a continuation of the recent trend of surging pipeline gas imports, marked by a significant sequence of twenty consecutive months of y-o-y increases in Chinese PNG imports (Figure 74). Cumulative Chinese PNG imports in 2025 increased by 8% y-o-y, to reach 81 bcm (Figure 75).

Figure 74: Monthly PNG imports in China

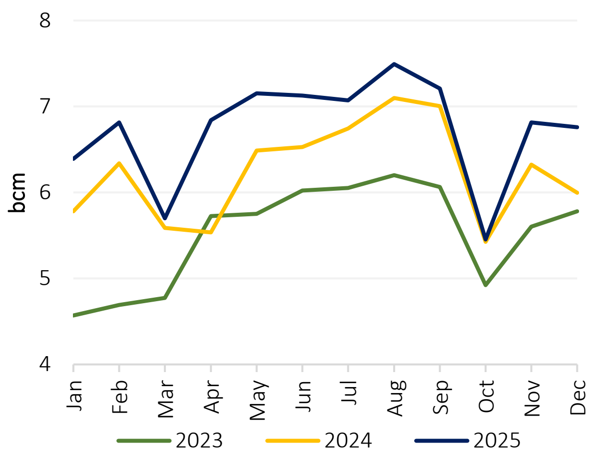
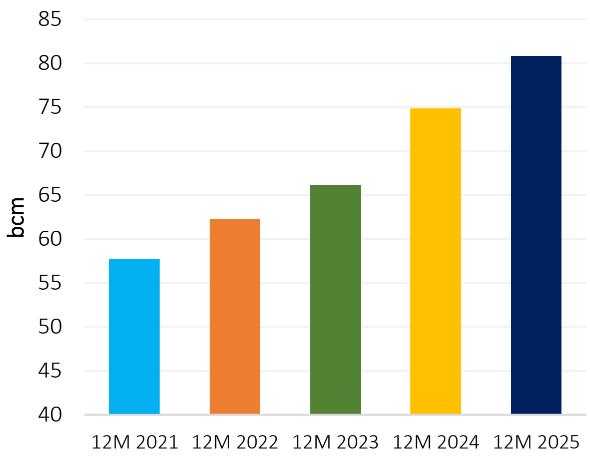


Figure 75: Year-to-date PNG imports in China



Source: GECF Secretariat based on data from LSEG and General Administration of Customs China

In December 2025, Singapore imported 0.56 bcm of PNG from Indonesia and Malaysia (Figure 76). This volume was the same as one year prior, but was 1% lower m-o-m. Across the entire 2025 period, PNG imports totalled 6.6 bcm, which was an increase of 8% y-o-y. In the same month, Thailand imported 0.30 bcm of PNG from Myanmar (Figure 77). This volume represented a decrease of 14% y-o-y, but was the same level as in the previous month. Cumulative PNG imports in 2025 decreased by 15% y-o-y, to reach 4.4 bcm.

Figure 76: Monthly PNG imports in Singapore

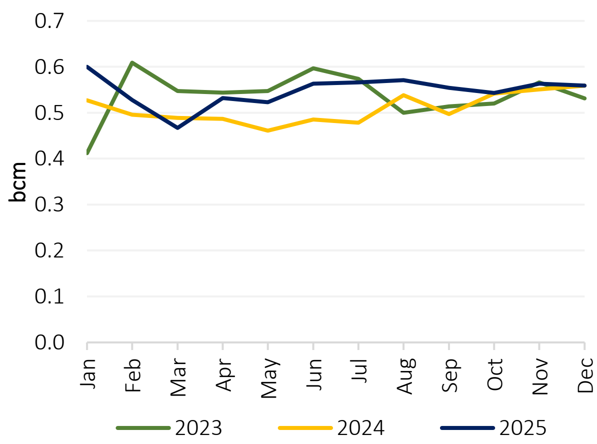
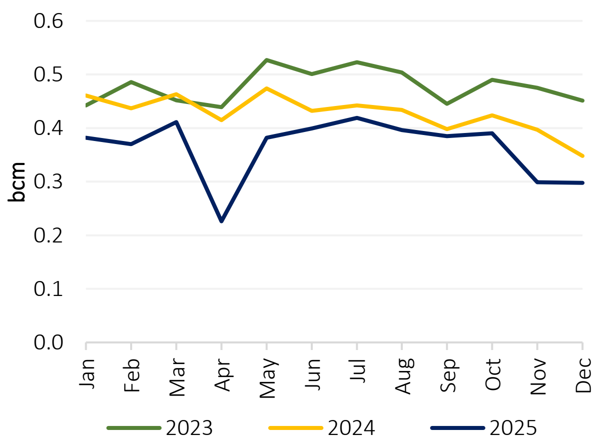


Figure 77: Monthly PNG imports in Thailand

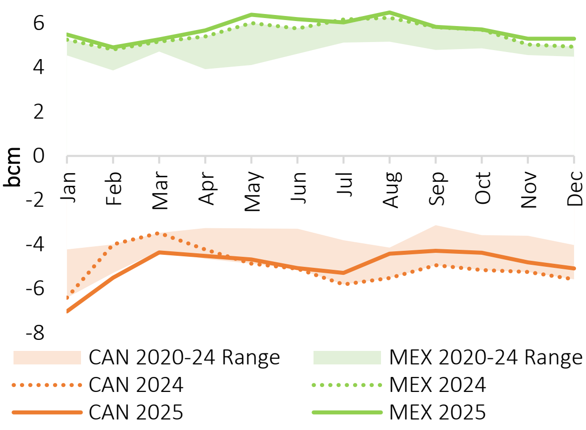


Source: GECF Secretariat based on data from JODI Gas

4.1.3 North America

In December 2025, Mexico imported 5.3 bcm of PNG from the US. This volume was 7% greater y-o-y, but was unchanged m-o-m (Figure 78). Over the course of 2025, Mexico's total PNG imports increased by 3% to reach 69 bcm. In the same month, there were 5.1 bcm of net PNG flows from Canada to the US, a decrease of 9% y-o-y, but 6% higher than the previous month. Flows from Canada to the US rose m-o-m to 8.8 bcm and flows from the US to Canada increased m-o-m to 3.8 bcm. In 2025, net flows from Canada to the US decreased by 2% y-o-y to total 59 bcm.

Figure 78: Net US PNG exports (+) and imports (-)

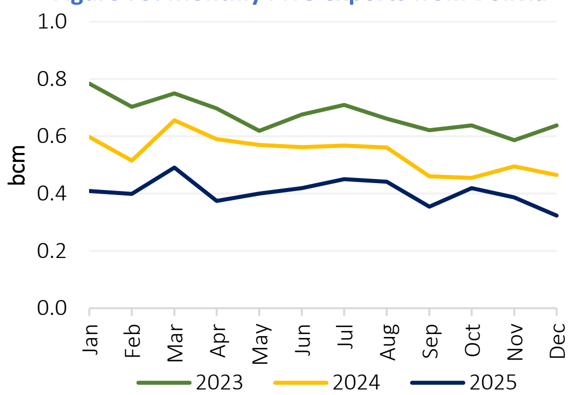


Source: GECF Secretariat based on data from US EIA

4.1.4 Latin America and the Caribbean

In December 2025, Bolivia exported 0.32 bcm of PNG to Brazil, representing decreases of 30% compared to one year prior, as well as of 17% compared to the previous month (Figure 79). Over the entire year, total Bolivian PNG exports decreased by 25% y-o-y, to reach 4.9 bcm. During the same month, Chile imported 0.18 bcm from Argentina. This volume represented decreases of 4% y-o-y, as well as of 25% m-o-m. Total PNG imports in 2025 increased by 21% to reach 2.8 bcm.

Figure 79: Monthly PNG exports from Bolivia



Source: GECF Secretariat based on data from JODI Gas

4.1.5 Other developments

Türkiye expands gas export route: Turkiye's BOTAS has doubled the gas exit capacity on its side of the Strandzha 1/Malkoclar interconnection point with Bulgaria, increasing the potential flow from 3.5 bcma to 8 bcma, in a move to boost exports of its gas supplies (including imported LNG and domestic production) to Eastern Europe. While this capacity expansion significantly exceeds Bulgaria's current entry capacity of 4 bcma, BOTAS noted that full utilisation requires corresponding investment and upgrades by Bulgarian operator Bulgartransgaz, which has already indicated intentions to increase LNG sourcing from Turkey and Greece as part of its energy diversification efforts.

Study recommends Argentina-Chile gas integration: A study by OLACDE and Latin American development bank CAF has recommended a $4.2 billion investment into three pipeline infrastructure projects, to deepen gas integration between Argentina and Chile. The proposed upgrades aim to expand Argentina's gas pipeline network from Vaca Muerta to its central and northern regions, boosting domestic supply and increasing exports to Chile, which currently relies on Argentina for about half of its gas imports. These projects are projected to lower Chile's long-term energy costs and reduce Argentina's gas imports and liquid fuel consumption, by expanding the capacity of existing pipelines and constructing a new one.

4.2 LNG trade

4.2.1 LNG imports

In February 2026, global LNG imports rose by 12% (4.01 Mt) y-o-y to reach 38.20 Mt, marking a record high for the month (Figure 80). Europe drove the strong increase in global LNG imports, while Asia also had a notable import contribution. The premium of the TTF gas price over the Asian spot LNG price continued to support the flow of flexible US LNG cargoes into Europe, as deliveries to Europe provided higher netbacks than shipments to Asia.

For the period January to February 2026, global LNG imports increased by 12% (8.8 Mt) y-o-y to 81.27 Mt, driven mainly by stronger imports in Asia and Europe (Figure 81).

Figure 80: Trend in global monthly LNG imports

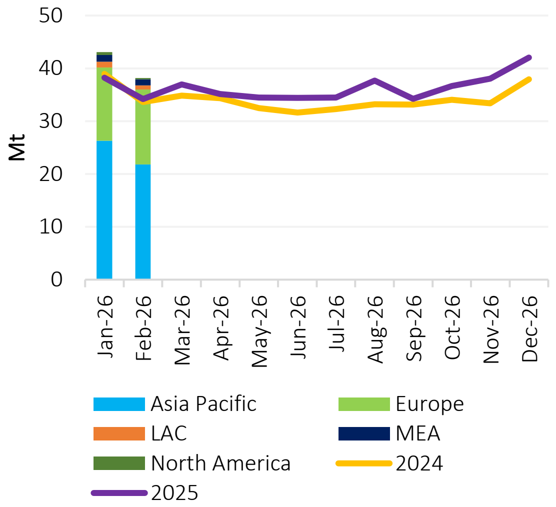
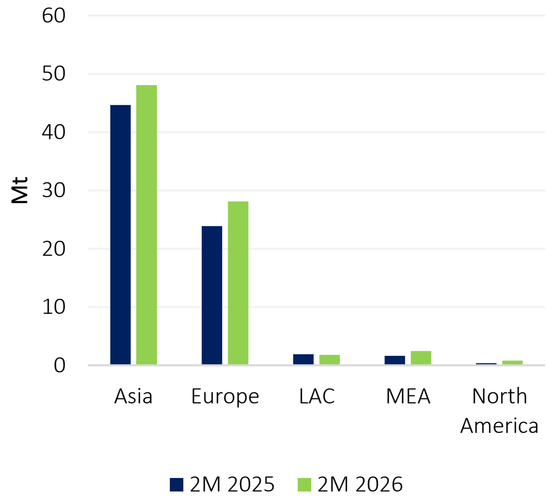


Figure 81: Trend in regional YTD LNG imports



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.1 Europe

In February 2026, Europe's LNG imports reached a record high of 14.21 Mt, up 20% (2.34 Mt) y-o-y (Figure 82), even though it is the shortest calendar month. This marks the first time the region's monthly LNG imports exceeded 14 Mt. The increase was supported by stronger intra-regional trade in regasified LNG, lower domestic gas production and reduced gas storage levels. At the country level, higher imports in Belgium, Germany, Greece, Italy, Lithuania, the Netherlands, Poland, Spain and the United Kingdom more than offset lower imports in France (Figure 83).

For the period January to February 2026, Europe's LNG imports totalled 28.13 Mt, representing an increase of 18% (4.24 Mt) y-o-y.

As a country level, stronger gas demand in Poland contributed to the increase in LNG imports. In Greece, weaker pipeline gas imports combined with higher exports of regasified LNG to neighbouring countries lifted LNG intake. The increase in the Netherlands reflected lower pipeline gas imports and declining domestic gas production, while in the United Kingdom, reduced pipeline gas inflows required additional LNG supply, pushing imports to their highest level since January 2023. By contrast, lower LNG imports in France were linked to stronger pipeline gas imports.

Figure 82: Trend in Europe's monthly LNG imports

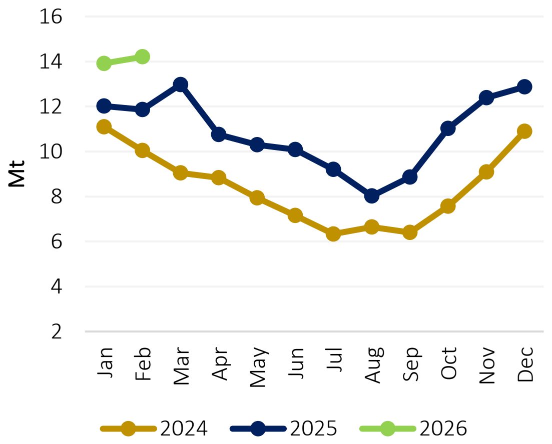
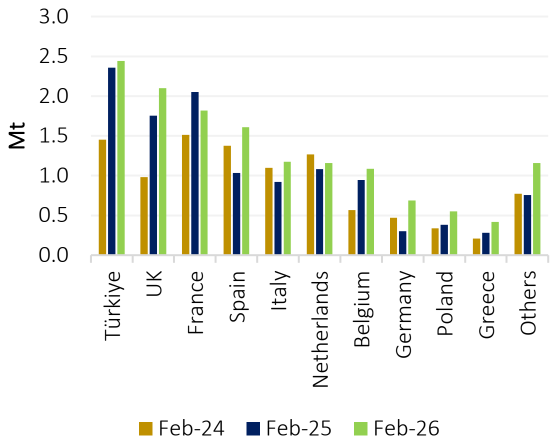


Figure 83: Top LNG importers in Europe



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.2 Asia Pacific

In February 2026, Asia's LNG imports stood at 21.81 Mt, representing an increase of 6.2% (1.28 Mt) y-o-y (Figure 84) and was the fourth consecutive monthly y-o-y increase. South Korea drove the increase in LNG imports in the region while Bangladesh, Japan and Thailand contributed to a lesser extent, together offsetting a decline in China (Figure 85).

For the period January to February 2026, Asia's LNG imports grew by 7.7% (3.4 Mt) y-o-y to reach 48.09 Mt.

The increase in South Korea's LNG imports compared with a year earlier was driven by LNG restocking of reduced inventories after colder weather in January 2026. Similarly, higher gas consumption in the power sector, combined with LNG restocking, supported stronger LNG imports in Japan. In Bangladesh, stronger spot LNG demand amid declining domestic gas production boosted imports. Higher LNG imports in Thailand reflected lower pipeline gas imports and increased gas use for power generation. Conversely, China's LNG imports fell to a multi-year low due to weaker gas consumption during the extended Lunar New Year holiday period, ample gas and LNG inventories as well as rising domestic gas production.

Figure 84: Trend in Asia's monthly LNG imports

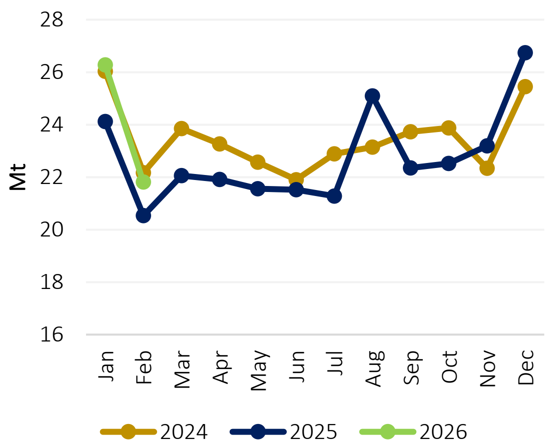
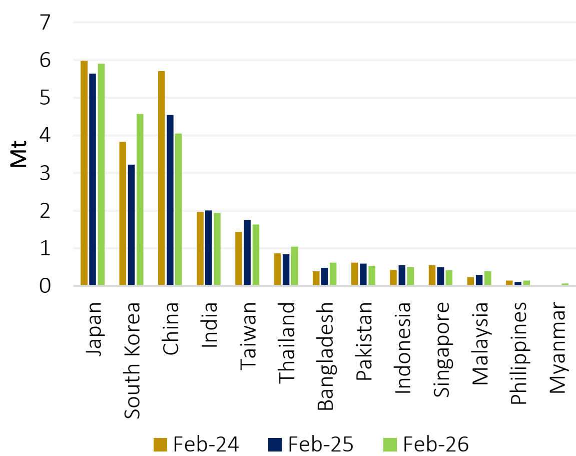


Figure 85: LNG imports in Asia Pacific by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.3 Latin America & the Caribbean (LAC)

In February 2026, LNG imports in LAC remained broadly stable at 0.74 Mt (Figure 86). Within the region, El Salvador and Panama recorded higher LNG imports, while imports declined in Chile, Dominican Republic and the United States Virgin Islands (USVI) (Figure 87).

For the period January to February 2026, LAC's LNG imports fell by 4.7% (0.09 Mt) y-o-y to 1.82 Mt.

Higher LNG imports in El Salvador and Panama were supported by stronger deliveries from Nigeria and the US, respectively. In Chile, lower LNG imports likely reflected stronger pipeline gas imports from Argentina, while the decline in the Dominican Republic was linked to reduced LNG imports from the US. Meanwhile, lower LNG imports into the USVI reflected reduced use as an LNG break-bulking hub in the Caribbean.

Figure 86: Trend in LAC's monthly LNG imports

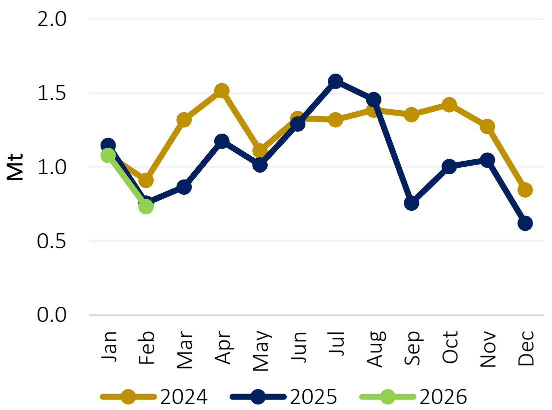
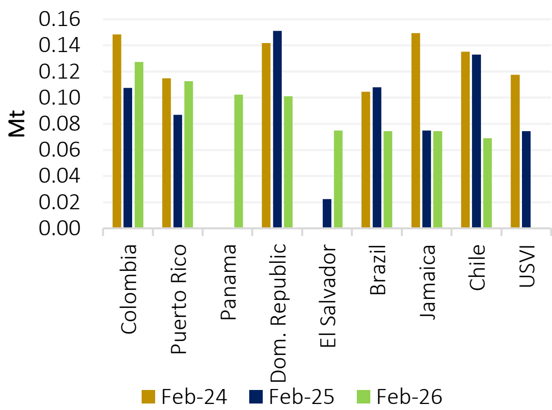


Figure 87: Top LNG importers in LAC



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.4 Middle East and Africa (MEA)

In February 2026, LNG imports in the MEA stood at 1.18 Mt, up 32% (0.28 Mt) y-o-y (Figure 88). Egypt accounted for most of the increase, caused by lower domestic gas availability, which more than offset a sharp decline in Kuwait's LNG imports (Figure 89). Kuwait's LNG imports fell to a multi-year low, with only one LNG cargo received from Qatar.

For the period January to February 2026, MEA's LNG imports rose by 48% (0.79 Mt) y-o-y to 2.43 Mt.

Figure 88: Trend in MEA's monthly LNG imports

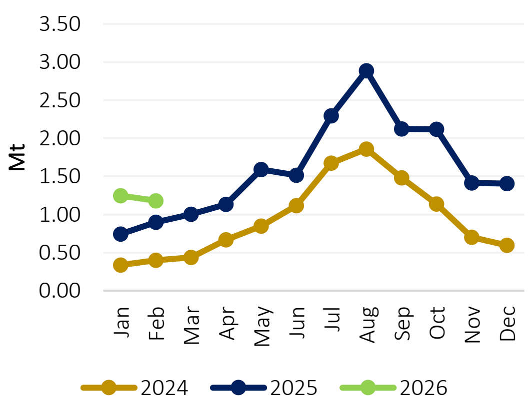
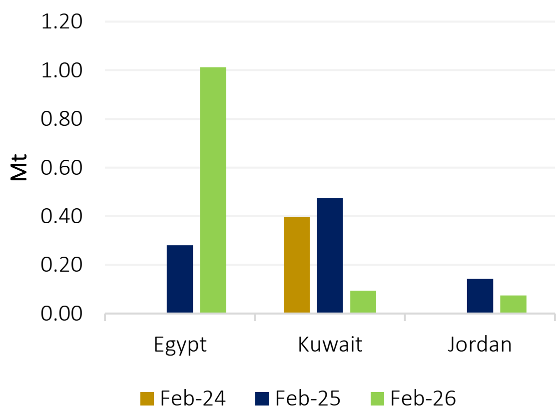


Figure 89: Top LNG importers in MEA



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2 LNG exports

In February 2026, global LNG exports continued to surge, rising by 14% (4.66 Mt) y-o-y to 37.78 Mt (Figure 90). Non-GECF countries accounted for the bulk incremental increase while GECF member countries and LNG re-exports contributed to a lesser extent.

For the period January to February 2026, global LNG exports jumped by 15% (10.25 Mt) y-o-y to 80.20 Mt, driven by stronger exports from both GECF and non-GECF countries (Figure 91).

The stronger increase in LNG exports from non-GECF countries drove its share in global LNG exports higher from 53.2% in February 2025 to 56.4% in February 2026. Meanwhile, the share of GECF member countries declined from 46.0% to 42.4% while the share of re-exports edge higher from 0.8% to 1.2% respectively.

The US, Qatar and Australia maintained their top position in LNG exports during the month.

Figure 90: Trend in global monthly LNG exports

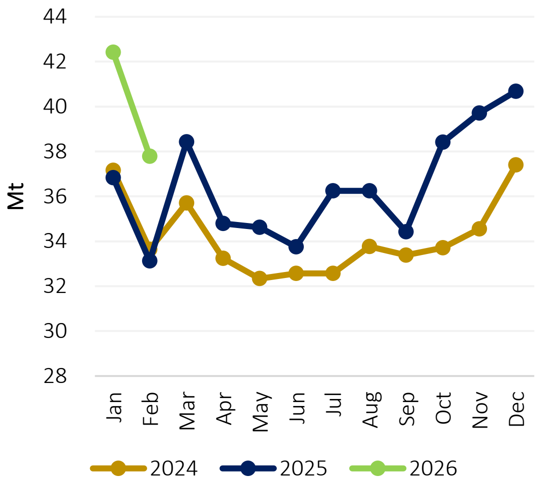
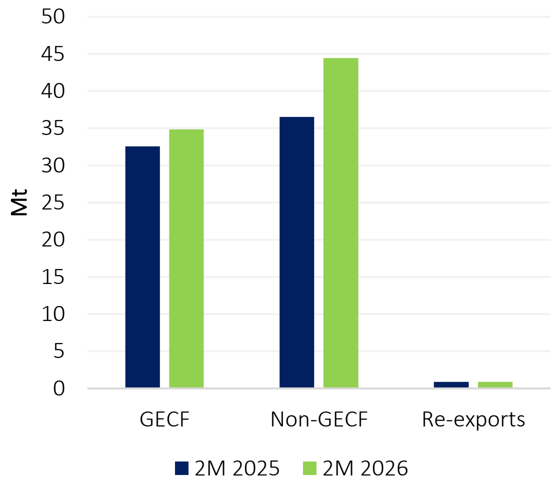


Figure 91: Trend in YTD LNG exports by supplier



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.1 GECF

In February 2026, LNG exports from GECF Member and Observer Countries reached 16.03 Mt, an increase of 5.2% (0.79 Mt) y-o-y (Figure 92). Higher exports from Malaysia, Mauritania, Nigeria, Russia and Senegal more than offset lower exports from Qatar and the United Arab Emirates (Figure 93).

For the period January to February 2026, GECF LNG exports rose by 7.0% (2.29 Mt) y-o-y to 34.86 Mt.

In Malaysia and Nigeria, stronger feedgas availability supported higher LNG exports. In Nigeria, reduced maintenance activity at Bonny LNG, compared with a year earlier, also contributed to the increase. Higher exports from Mauritania and Senegal reflected the continued ramp-up of production at Greater Tortue Ahmeyim FLNG Phase 1, while rising production at Arctic LNG 2 supported stronger LNG loadings from Russia.

In contrast, lower LNG exports from Qatar were linked mainly to shipment timing, as stronger loadings in January led to slightly lower export volumes in February, while the start of regional tensions in the Middle East also affected loadings toward the end of the month. In the United Arab Emirates, lower exports likely reflected reduced feedgas availability.

Figure 92: Trend in GECF monthly LNG exports

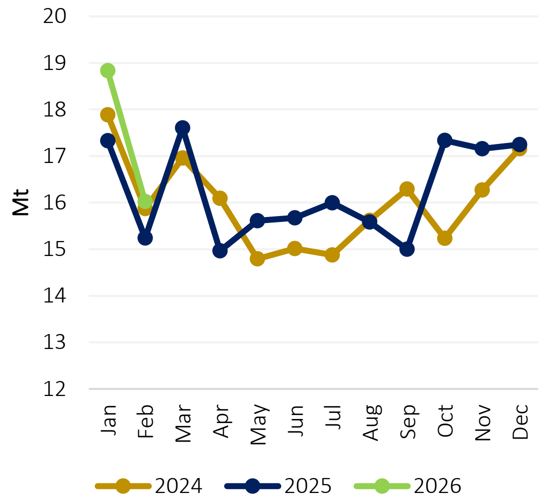
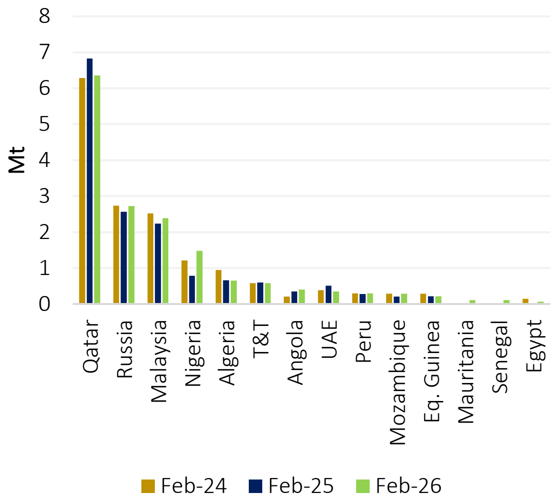


Figure 93: GECF's LNG exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.2 Non-GECF

In February 2026, LNG exports from non-GECF countries surged by 21% (3.68 Mt) y-o-y to 21.29 Mt (although down m-o-m) setting a new record high for the month (Figure 94). The US remained the main source of supply growth, while Australia, Brunei, Canada, Indonesia and Oman also made notable contributions (Figure 95).

For the period January to February 2026, non-GECF LNG exports reached 44.45 Mt, up 22% (7.93 Mt) y-o-y.

Higher US LNG exports were driven by the continued ramp-up in production at Corpus Christi LNG and Plaquemines LNG, which more than offset lower exports from Elba Island LNG due to an unplanned outage. Similarly, the ramp-up of production at LNG Canada supported stronger exports from Canada. In Australia, the recent resumption of exports from Darwin LNG, together with higher loadings from North West Shelf LNG, boosted LNG exports. Meanwhile, stronger feedgas availability lifted exports from Brunei and Oman, while lower maintenance activity than a year earlier supported higher LNG exports from Indonesia.

Figure 94: Trend in non-GECF monthly LNG exports

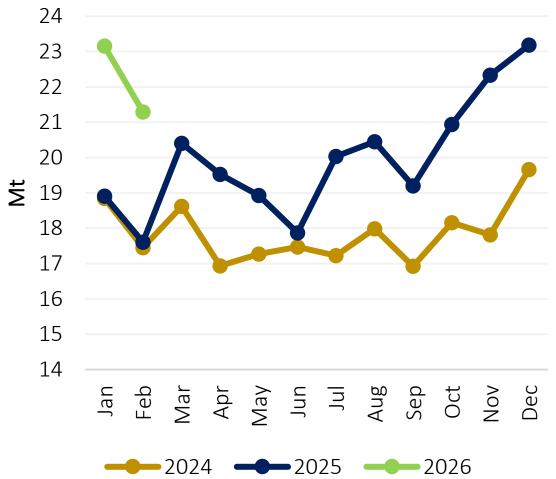
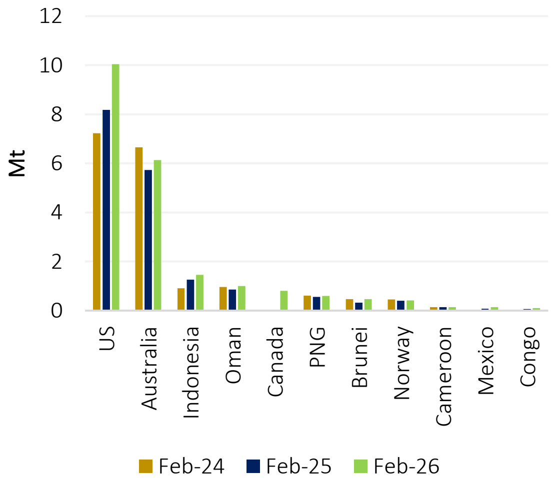


Figure 95: Non-GECF's LNG exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.3 Global LNG re-exports

In February 2026, global LNG re-exports jumped by 69% (0.19 Mt) y-o-y to 0.47 Mt, which is the highest monthly level since January 2025 (Figure 96). China was the main driver of the increase, more than offsetting lower re-exports from the United States Virgin Islands (USVI).

For the period January to February 2026, global LNG re-exports edged up by 4.3% (0.04 Mt) y-o-y to 0.90 Mt, driven mainly by China, while Brazil and the USVI led recorded declines (Figure 97).

The increase in China's LNG re-exports reflected weak domestic gas demand, ample LNG inventories and stronger spot LNG demand in neighbouring markets. China re-exported five LNG cargoes during the month, with two cargoes each delivered to South Korea and Thailand and one cargo to India, compared with two cargoes in February 2025. Meanwhile, the role of the USVI as an LNG break-bulking hub in the Caribbean continued to weaken, as regular LNG deliveries from the US to Puerto Rico reduced the need for re-export operations.

Figure 96: Trend in global monthly LNG re-exports

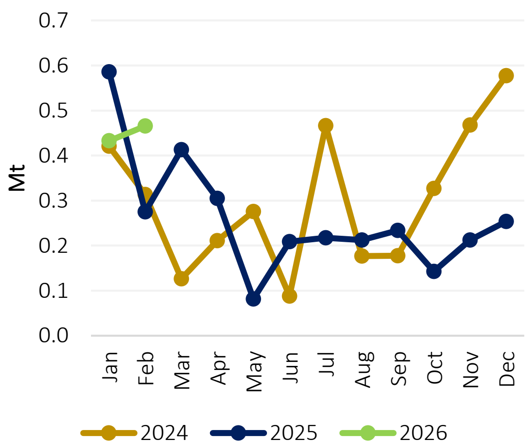
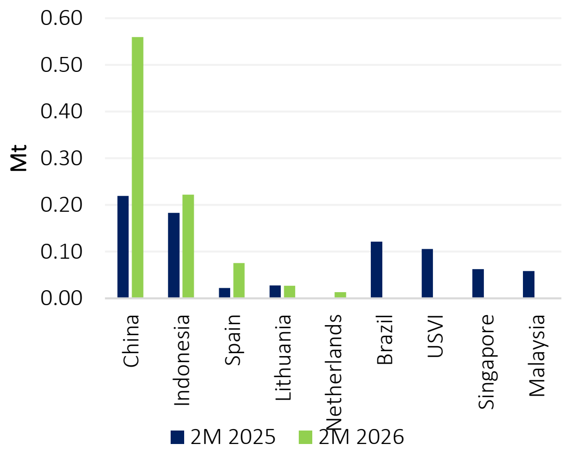


Figure 97: Global YTD LNG re-exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

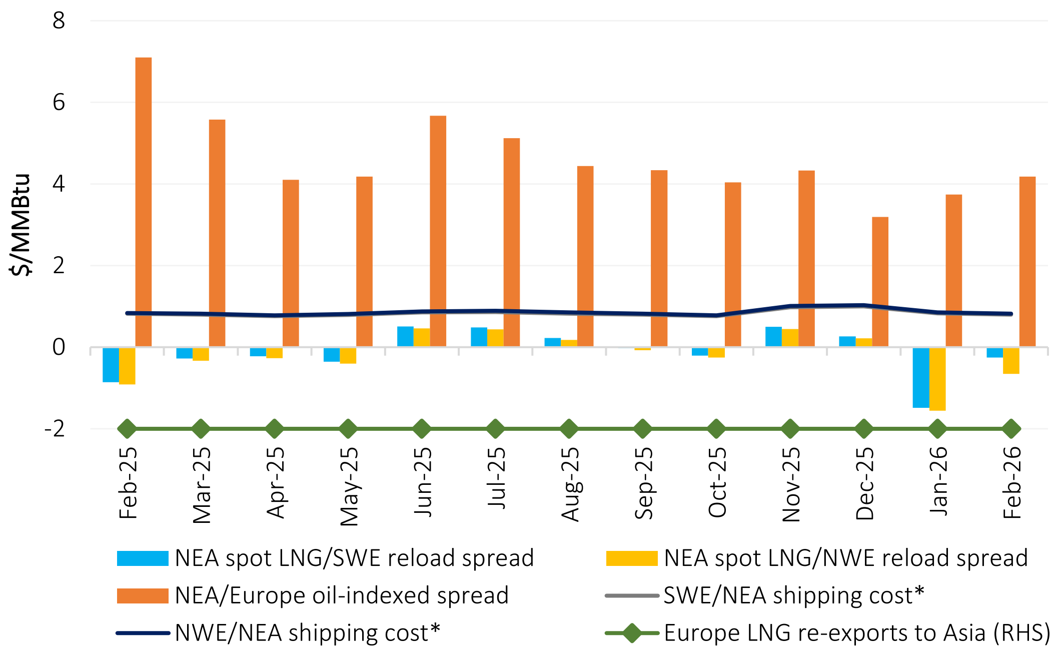
4.2.4 Arbitrage opportunity

In February 2026, the arbitrage for LNG re-exports from Europe to Asia remained closed, as European LNG reload prices continued to trade at a premium over North East Asia (NEA) spot LNG prices (Figure 98). In contrast, Asian spot LNG prices maintained a substantial premium over European oil-indexed LNG, remaining well above one-way shipping costs.

The NEA/Southwestern Europe (SWE) and NEA/Northwestern Europe (NWE) spreads narrowed m-o-m, improving from -\$1.49/MMBtu and -\$1.56/MMBtu in January to -\$0.25/MMBtu and -\$0.65/MMBtu, respectively. This reflected a rise in NEA spot LNG prices alongside lower European LNG reload prices. Meanwhile, the NEA premium over European oil-indexed LNG widened from \$3.74/MMBtu to \$4.18/MMBtu, while average one-way shipping costs from Europe to Asia edged down by \$0.03/MMBtu to \$0.81/MMBtu.

As a result, no LNG cargoes were re-exported from Europe to Asia in February 2026. Compared with February 2025, the NEA/SWE and NEA/NWE spreads improved from -\$0.86/MMBtu and -\$0.91/MMBtu, respectively. Over the same period, the NEA premium over oil-indexed LNG narrowed from \$7.10/MMBtu, while one-way shipping costs on both routes declined slightly by \$0.02/MMBtu.

Figure 98: Price spreads & shipping costs between Asia & Europe spot LNG markets

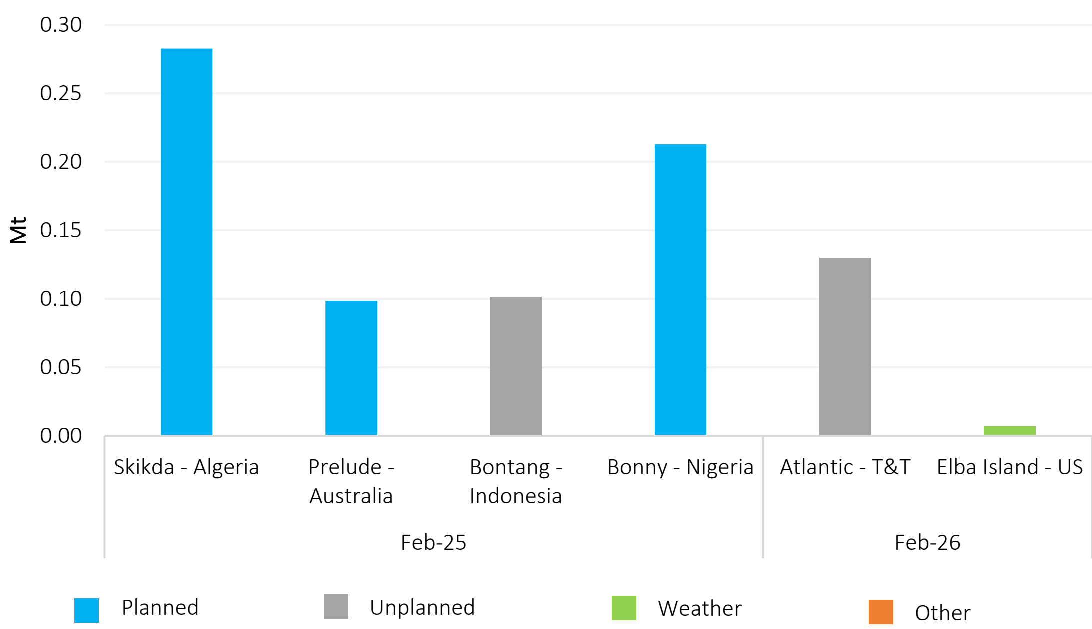


Source: GECF Secretariat based on data from GECF Shipping Model, Argus and ICIS LNG Edge
(*): One-way spot shipping costs

4.2.5 Maintenance activity at LNG liquefaction facilities

In February 2026, total disruptions at global LNG liquefaction facilities, including planned maintenance, unplanned outages and other operational issues, stood at just 0.14 Mt, down from 0.70 Mt in February 2025 (Figure 99). Disruptions were limited to only two LNG facilities: an unplanned outage at Atlantic LNG in Trinidad and Tobago and cold weather-related impacts at Elba Island LNG in the United States.

Figure 99: Maintenance activity at LNG liquefaction facilities during February (2025 and 2026)



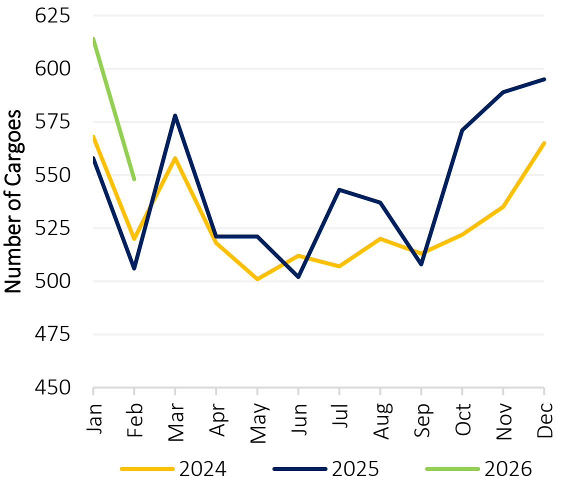
Source: GECF Secretariat based on information from Argus, ICIS LNG Edge and LSEG

4.2.6 LNG shipping

In February 2026, there were 548 LNG cargoes exported globally (Figure 100). With fewer days in this month, this total represented an 11% decrease m-o-m. Nevertheless, this number of delivered shipments was 8% greater than one year ago and was also a record high for the month.

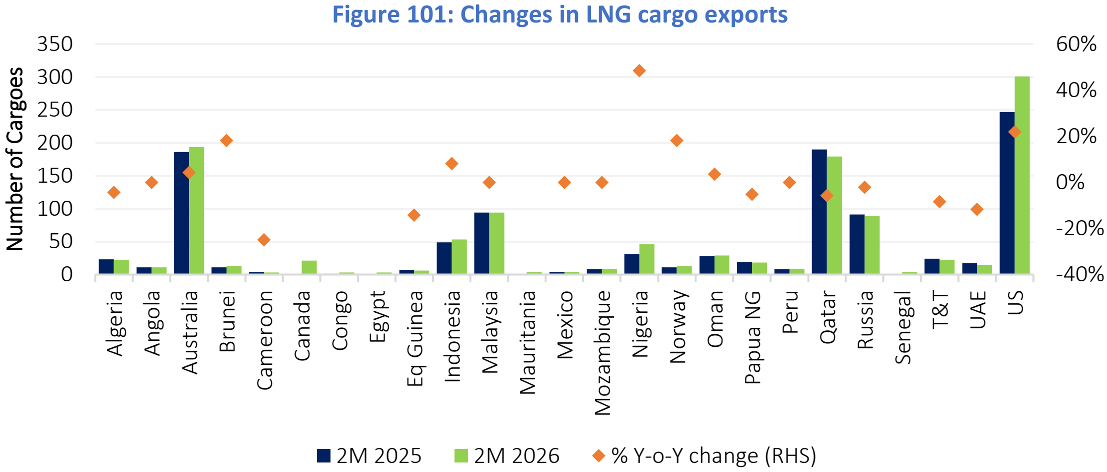
After two months of 2026, total shipments increased by 98, to reach 1,162. GECF countries loaded 44% of these cargoes, led by Qatar, Malaysia and Russia. The US (54) and Nigeria (15) lead in terms of y-o-y increases in cargoes in 2026 thus far, while the largest percentage increases were attributed to Nigeria (48%) and the US (22%) (Figure 101).

Figure 100: Number of LNG export cargoes



Source: GECF Secretariat based on data from ICIS LNG Edge

Figure 101: Changes in LNG cargo exports



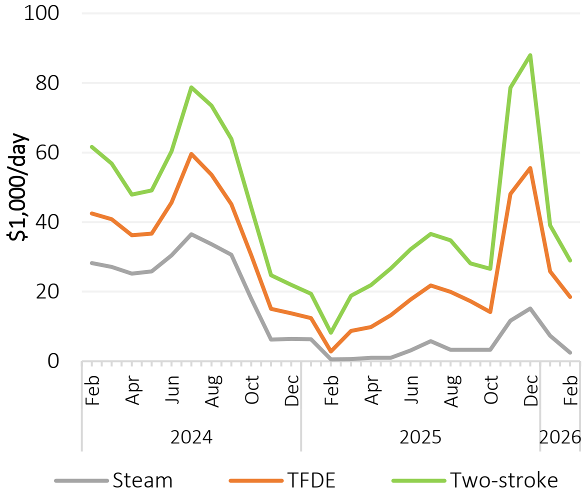
Source: GECF Secretariat based on data from ICIS LNG Edge

In February 2026, there were further decreases in the spot charter rate, concerning all segments of the global LNG carrier fleet (Figure 102). For TFDE carriers, the dominant vessel option for spot LNG trade, the monthly average rate decreased by 28% m-o-m to reach $18,500 per day. This average charter rate was notably 561% higher than one year ago, but was $18,800 per day lower than the five-year average price for the month. The average spot charter rate for two-stroke vessels reached $28,900 per day, which was 26% lower m-o-m but 252% higher y-o-y. Steam turbine LNG carriers recorded an average rate of $2,500 per day, which was a decrease of 66% m-o-m, but an increase of 400% compared to one year ago.

Although the monthly average rate decreased, the daily rates painted a different picture, with a rebound in the final third of the month, driven primarily by tightening availability in the Atlantic Basin. While the global market remained structurally oversupplied, severe winter weather across Italy and Germany caused significant unloading delays at multiple import terminals, which created logistical bottlenecks preventing timely vessel return to loading windows. On the supply side, US export facilities recovered utilisation rates following the impact of winter storms. However, with the inter-basin arbitrage largely closed and North East Asian demand subdued during the Lunar New Year, journey lengths remained short.

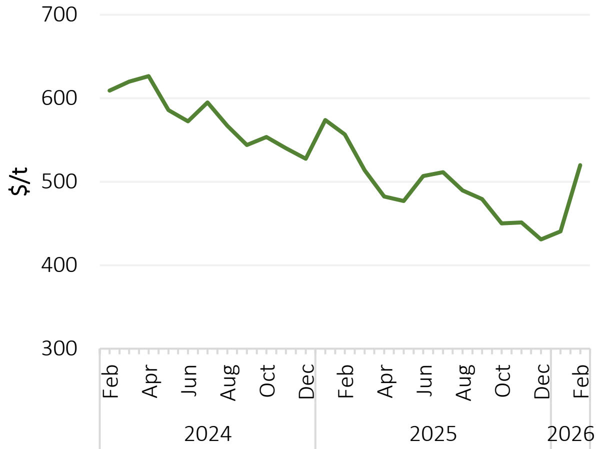
In February 2026, the average price of shipping fuels surged by 18% m-o-m, reaching an estimated $520 per tonne (Figure 103). This average price was 7% lower than one year ago, as well as 12% lower than the five-year average price for this month.

Figure 102: Average LNG spot charter rate



Source: GECF Secretariat based on data from Argus

Figure 103: Average price of shipping fuels

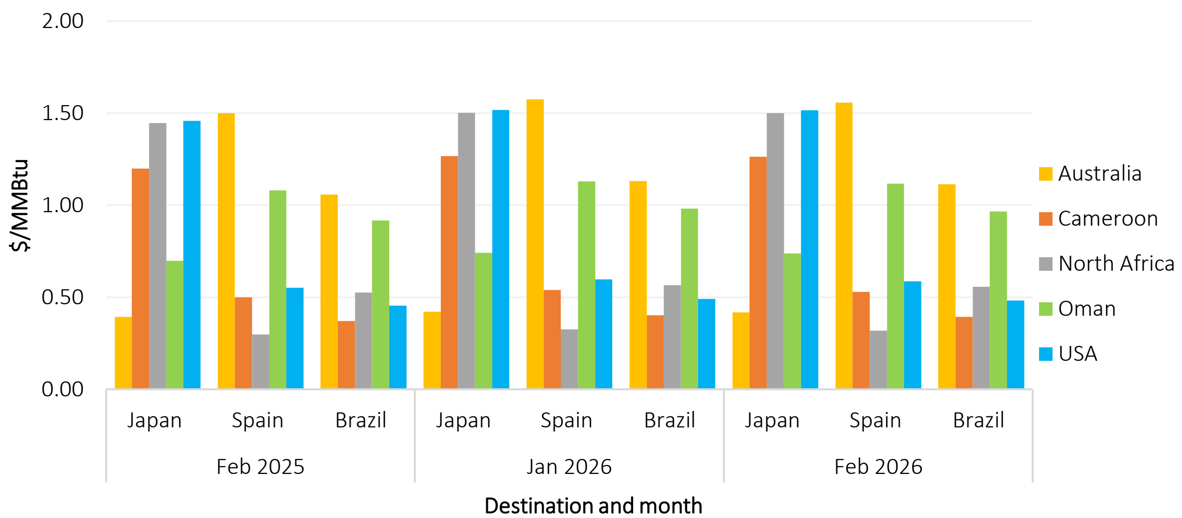


Source: GECF Secretariat based on data from Argus and Platts

Spot shipping costs for TFDE LNG carriers in February 2026 were largely unchanged from the previous month, decreasing by up to just $0.02/MMBtu on certain routes (Figure 104). This was due to the decrease in the monthly average LNG carrier spot charter rate offsetting the increases in the cost of shipping fuels, despite the delivered spot LNG prices remaining around the same level.

Compared to one year ago, in February 2026 the monthly average spot charter rate was much higher, but the cost of shipping fuels and delivered spot LNG prices were all lower. The net effect of these fundamentals almost cancelled each other out, resulting in LNG shipping costs that were up to $0.07/MMBtu higher than in February 2025.

Figure 104: Spot shipping costs for TFDE LNG carriers



Source: GECF Shipping Cost Model

4.2.7 Other developments

Colombia advanced Buenaventura LNG import terminal: Colombia is advancing the development of a new LNG import terminal on its Pacific coast through the Buenaventura LNG Terminal project, following financial close reached in February 2026. The fast-track terminal, being developed by Regasificadora del Pacífico, is expected to begin receiving LNG cargoes in Q3 2026 and will strengthen gas supply security in western Colombia. Under a contract with Ecopetrol, the project will provide regasification and logistics services for around 60 mmscfd of natural gas. Exmar will lease and operate a floating storage unit under a five-year agreement, supported by approximately $130 million in senior debt financing.

Cedar LNG award FLNG contract to Exmar (Canada): Exmar has been selected by Cedar LNG Partners to provide marine and operational expertise for the floating LNG unit Megúgu. Majority-owned by the Haisla Nation in partnership with Pembina Pipeline Corporation, Cedar LNG is the world's first Indigenous majority-owned LNG facility and is designed to operate using renewable electricity, giving it one of the lowest carbon intensities in the LNG sector. EXMAR will support construction, pre-operations and future operations as the FLNG unit is built at Samsung Heavy Industries. The project is expected to cost $4 billion and begin operations by the end of 2028.

South Korea pioneers nuclear-powered shipping with new LNG carrier design: The American Bureau of Shipping has granted Approval in Principle to a nuclear-powered LNG carrier design, a collaboration between South Korea's Samsung Heavy Industries and the Korea Atomic Energy Research Institute. The design incorporates a small modular reactor, specifically a molten-salt reactor (MSR), which uses liquid salt mixed with nuclear fuel and coolant to generate power. This 100 MW MSR is designed to provide propulsion for the vessel, potentially eliminating the need for fuel replacement over its entire lifespan. This project marks one of the first applications of this technology for clean maritime power.

In February 2026, eight (8) LNG agreements were signed (Table 1).

Table 1: New LNG sale agreements signed in February 2026

Contract Type	Exporting Country	Project	Seller	Importing Country	Buyer	Volume (Mtpa)	Duration (Years)
SPA	Qatar	North Field East	QatarEnergy	Japan	JERA	3	27
SPA	Qatar	North Field East	QatarEnergy	Malaysia	PETRONAS	2	20
SPA	Malaysia	Portfolio	PETRONAS	Thailand	PTT	0.3	5
SPA	US	Commonwealth LNG	Commonwealth LNG	Portfolio	Mercuria	1	20
SPA	US	Commonwealth LNG	Commonwealth LNG	Portfolio	Saudi Aramco	1	20
SPA	US	Portfolio	Sabine Pass/Corpus Christi	Taiwan	CPC	1.2	24
LOI	US	Alaska LNG	Glenfarne	Portfolio	TotalEnergies	2	20
SPA	US	Portfolio	Venture Global	South Korea	Hanwha Aerospace Co.	1.5	20

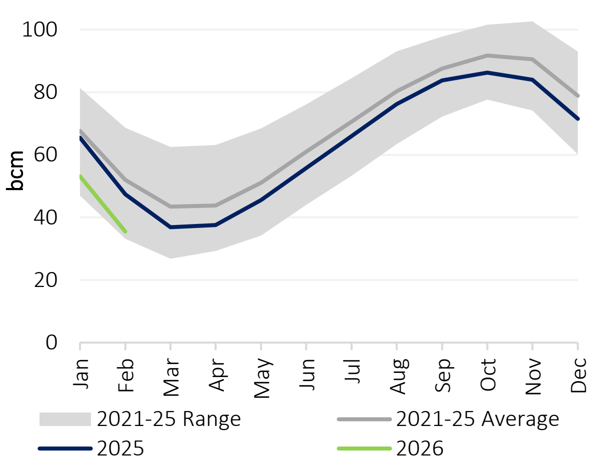
Source: GECF Secretariat based on Project Updates and News

5 GAS STORAGE

5.1 Europe

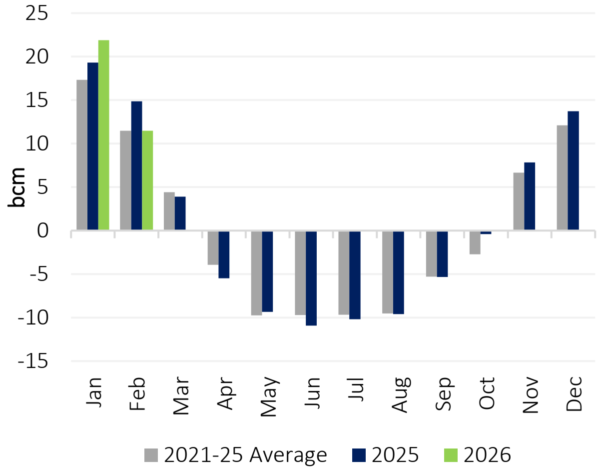
The net gas withdrawal season continued in Europe, as the average daily volume of gas in underground storage in the EU decreased to 35.5 bcm in February 2026, down from 53.1 bcm one month prior (Figure 105). This monthly average storage level was 12 bcm lower y-o-y, 16.5 bcm below than the five-year average and was also the lowest level for February since 2022. The EU's aggregated gas stocks decreased from 42.8 bcm on 31 January to 31.3 bcm on 28 February. The average regional capacity utilisation by the end of the month fell to 30%.

Figure 105: Monthly average UGS level in the EU



Source: GECF Secretariat based on data from AGSI+

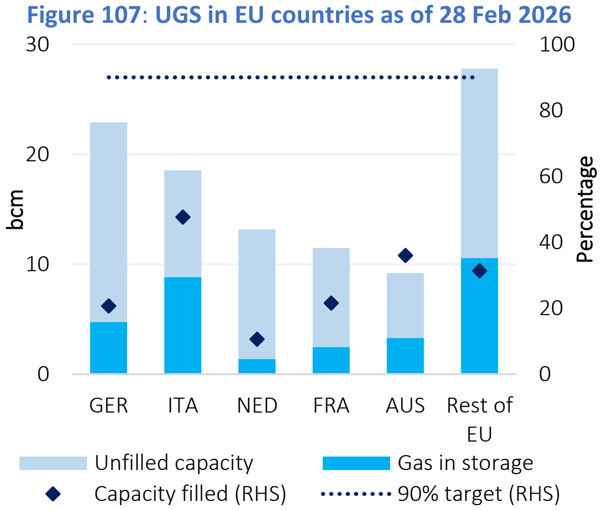
Figure 106: Net gas withdrawals in the EU



Source: GECF Secretariat based on data from AGSI+

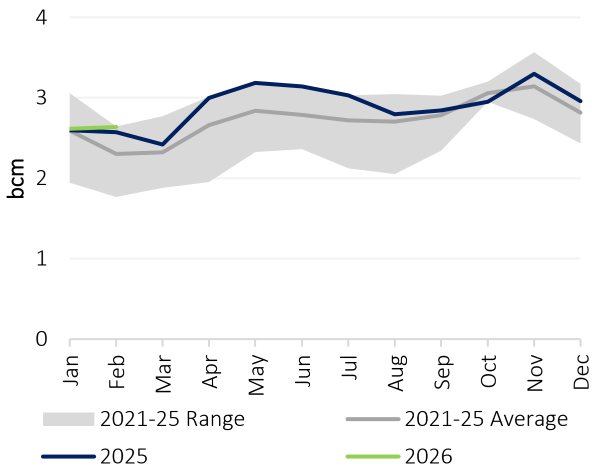
With warmer-than-average temperatures across the continent, there were 11.5 bcm of net gas withdrawals in February 2026. This was the same level as the five-year average withdrawal for the month, but was 23% less gas withdrawn than one year ago (Figure 106). EU countries have withdrawn a combined 55 bcm over the winter season thus far, compared to 60 bcm at the same time last year. Gas stocks in the Netherlands are particularly low (11% filled), while France and Germany are both close to the 20% mark (Figure 107). The average LNG storage level in the EU was 2.6 bcm, representing 47% of capacity (Figure 108). Moreover, this storage level was 3% higher y-o-y, as well as 15% higher than the five-year average.

Figure 107: UGS in EU countries as of 28 Feb 2026



Source: GECF Secretariat based on data from AGSI+

Figure 108: Total LNG storage in the EU

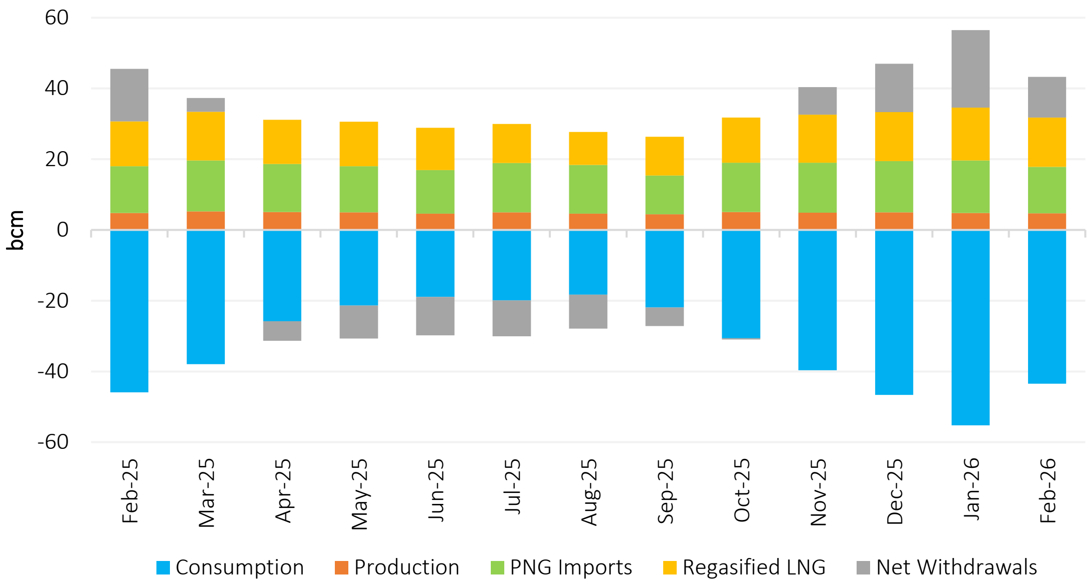


Source: GECF Secretariat based on data from ALSI

In Europe, gas storage is critical for balancing supply and demand. During the winter months, these reserves are essential to supplement production and imports, ensuring there is enough capacity to meet the seasonal surge in heating requirements.

In February 2026, the contribution of gas storage to the combined supply mix of the EU and UK declined to 27%, compared with 33% a year earlier, while continuing to underline the strategic importance of inventories during peak winter demand. Total gas imports accounted for 62% of supply, up from 53% in January. Within imports, regasified LNG represented 32% of total supply, remaining slightly above pipeline gas imports at 30%. Domestic production continued to play a smaller role, contributing 11% of the overall supply mix (Figure 109).

Figure 109: EU + UK monthly gas balance



Source: GECF Secretariat based on data from AGSI+, JODI Gas and LSEG

Table 2 below provides data on the gas supply and demand balance for the EU + UK for the month of February 2026.

Table 2: EU + UK gas supply/demand balance for January 2026 (bcm)

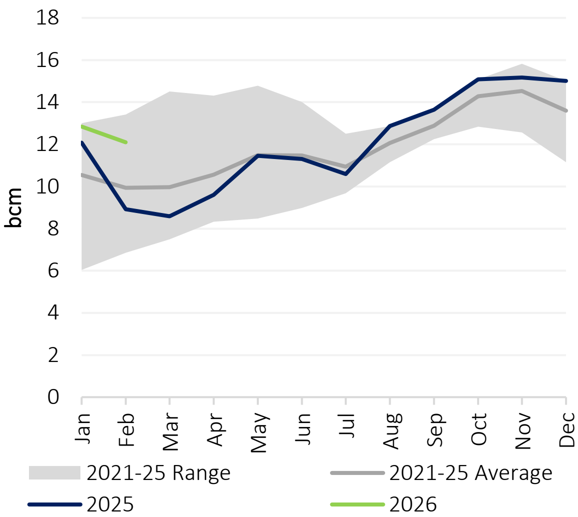
	2025	Feb-25	Feb-26	2M 2025	2M 2026	Change* y-o-y	Change** 2026/2025
(a) Gas Consumption	378.23	45.96	43.50	97.13	98.76	-5%	2%
(b) Gas Production	58.90	4.80	4.70	10.12	9.51	-2%	-6%
Difference (a) - (b)	319.33	41.16	38.80	87.01	89.25	-6%	3%
PNG Imports	162.14	13.22	13.17	27.67	27.96	0%	1%
Regasified LNG	147.08	12.64	13.91	24.75	28.91	10%	17%
Net Withdrawals	8.40	14.90	11.50	34.20	33.40	-23%	-2%
Variation	1.70	0.41	0.22	0.39	-1.03		

Source: GECF Secretariat based on data from AGSI+, JODI Gas and LSEG
(*): y-o-y change for February 2026 compared to February 2025
(**): y-o-y change for 2M 2026 compared to 2M 2025

5.2 Asia

In February 2026, there were an estimated 12.1 bcm of combined LNG stocks in Japan and South Korea, which was 6% lower m-o-m (Figure 110). Furthermore, the combined stock level stood at 36% higher than one year prior and was 2.2 bcm greater than the five-year average for the month. This was driven by the well-stocked inventories entering the winter season, together with the moderately warm temperatures experienced during the month. The estimated LNG storage level in Japan stood at 7.7 bcm, which was 20% higher compared to the previous year. In South Korea, the estimated storage level stood at 4.4 bcm, which was 77% greater than one year ago.

Figure 110: LNG in storage in Japan and South Korea



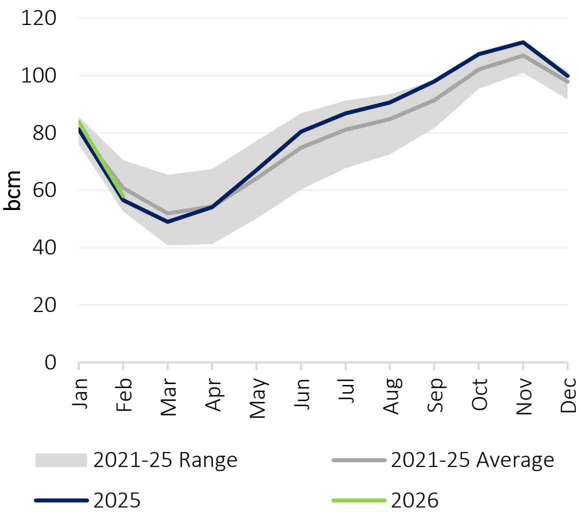
Source: GECF Secretariat based on data from LSEG

5.3 North America

In contrast to the winter storms and plummeting temperatures in the previous month, there was a warmer-than-average February 2026 in the US. As a result, the average volume of gas in storage fell to 58.0 bcm, down from 83.8 bcm in the previous month (Figure 111). US gas stocks remained 1.3 bcm higher y-o-y, but were 2.8 bcm less than the five-year average for the month. The average UGS capacity utilisation stood at 43%.

During the month there were 16.3 bcm of net withdrawals in the US, which was similar to the five-year average withdrawal for the month, but less than the 18.0 bcm of one year ago. Moreover, the US has withdrawn 59 bcm during the winter season thus far.

Figure 111: Monthly average UGS level in the US



Source: GECF Secretariat based on data from US EIA

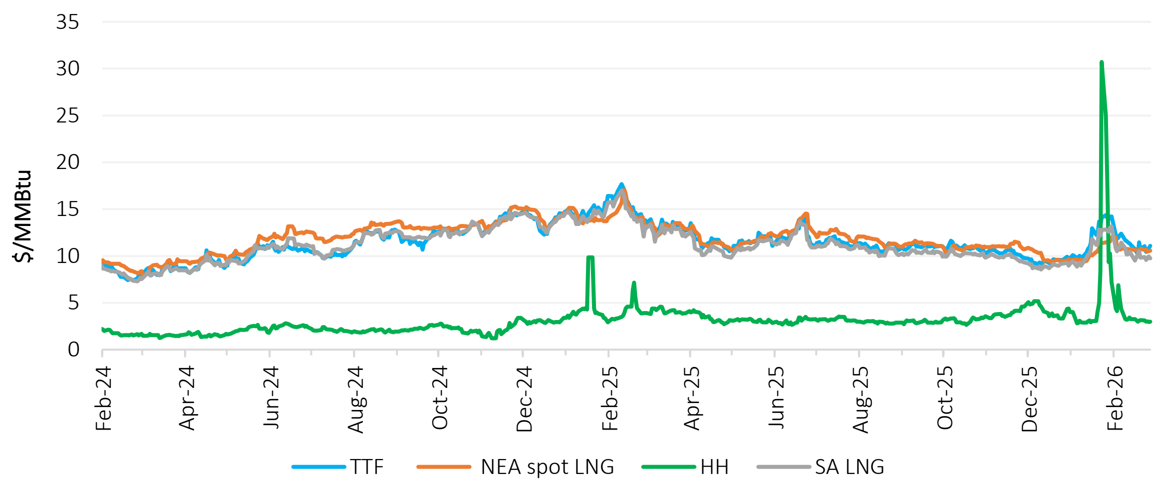
6 ENERGY PRICES

6.1 Gas prices

6.1.1 Gas & LNG spot prices

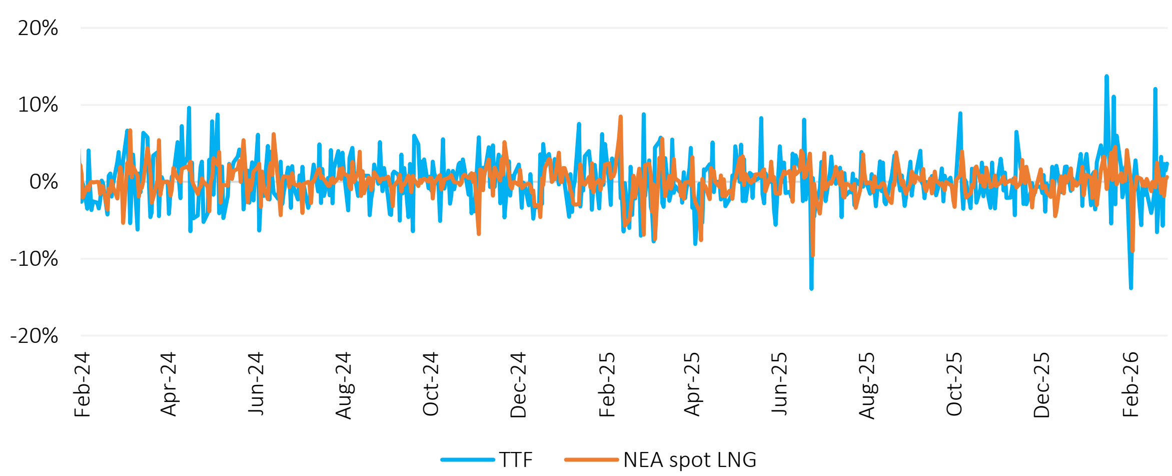
In February 2026, European spot gas and LNG prices, together with North American spot gas prices, showed a bearish trend, declining month-on-month amid slightly lower market volatility as winter weather conditions stabilised compared with January. By contrast, Asian spot LNG prices were slightly bullish, rising above European spot LNG prices while remaining below European gas hub prices (Figure 112 and Figure 113). All major spot gas and LNG benchmarks were lower than in February 2025, reflecting milder Northern Hemisphere weather compared with a year earlier and stronger LNG supply availability. Looking ahead, spot prices are expected to strengthen in the coming months, as the Middle East conflict has constrained LNG flows through the Strait of Hormuz and is likely to tighten the global LNG market.

Figure 112: Daily gas & LNG spot prices



Source: GECF Secretariat based on data from Argus and LSEG
Note: SA LNG price is an average of the LNG delivered prices for Argentina, Brazil and Chile based on Argus assessment.

Figure 113: Daily variation of spot prices



Source: GECF Secretariat based on data from Argus and LSEG

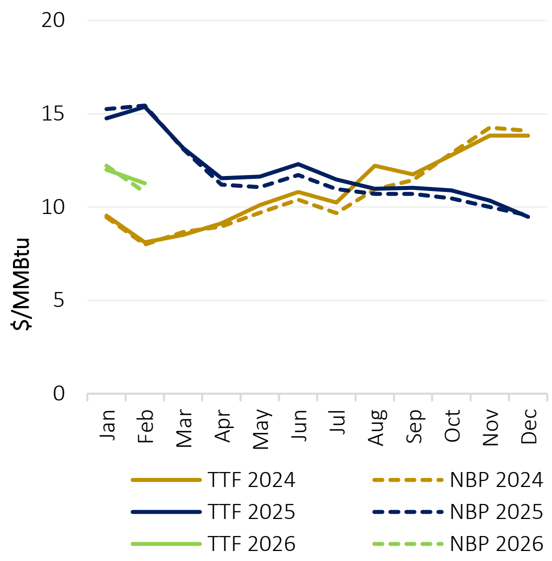
6.1.1.1 European spot gas and LNG prices

In February 2026, the TTF spot gas price fell by 6% m-o-m and 27% y-o-y to \$11.27/MMBtu (Figure 114). Similarly, the NBP spot price declined by 12% m-o-m and 30% y-o-y to reach \$10. 79/MMBtu.

For the period January to February 2026, the TTF and NBP prices dropped 23% and 25% y-o-y to average \$11.64/MMBtu and \$11.50/MMBtu, respectively.

European gas prices declined m-o-m due to reduced heating demand across Northwest Europe and the UK, while stronger wind generation, robust LNG send-out and steady pipeline imports loosened market balances. Easing geopolitical risk also reinforced bearish market sentiment.

Figure 114: Monthly European spot gas prices



Source: GECF Secretariat based on data from LSEG

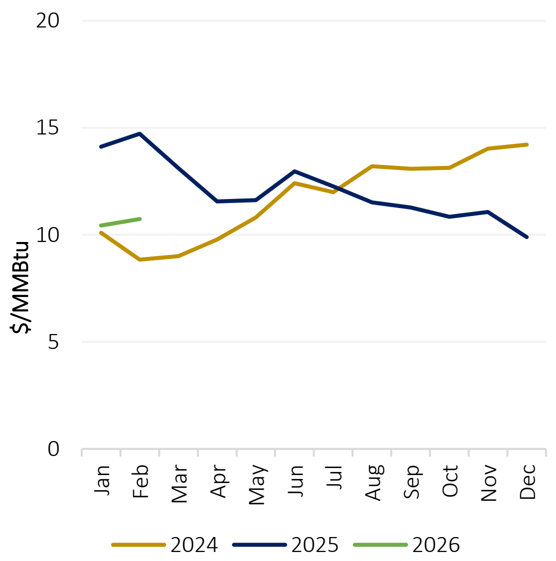
6.1.1.2 Asian spot LNG prices

In February 2026, the average North East Asia (NEA) spot LNG price increased by 3% m-o-m but declined by 27% y-o-y to reach \$10.74/MMBtu (Figure 115).

For the period January to February 2026, the NEA spot LNG price averaged \$10.59/ MMBtu, a sharp decline of 27% y-o-y.

The NEA spot LNG prices increased m-o-m as weather-related disruptions to US feedgas supply tightened Atlantic Basin LNG availability, while renewed spot procurement from major Asian importers supported demand. Additional upward pressure came from geopolitical tensions in the Middle East and strong European demand, which limited flexible cargo availability for Asia.

Figure 115: Monthly Asian spot LNG prices



Source: GECF Secretariat based on data from Argus

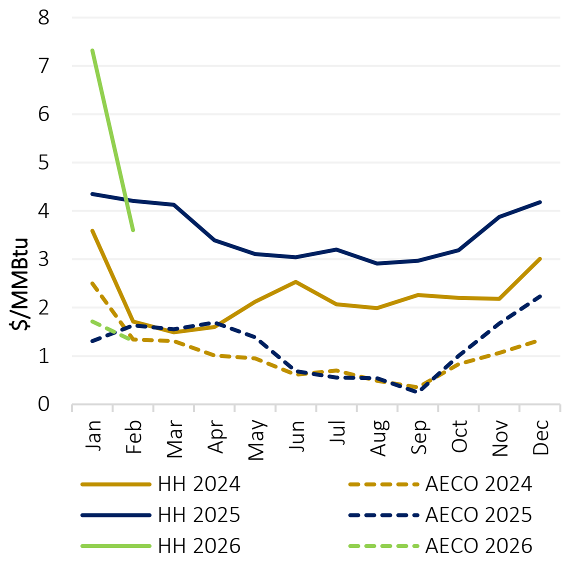
6.1.1.3 North American spot gas prices

In February 2026, the Henry Hub (HH) spot gas price fell sharply by 51% m-o-m from the multi-year high recorded in January to $3.60/MMBtu and was also down 14% y-o-y. Similarly, AECO spot gas prices declined by 23% m-o-m and 19% y-o-y to $1.31/MMBtu (Figure 116).

For the period January to February 2026, the HH and AECO spot gas prices increased by 28% and 3% y-o-y to $5.46/MMBtu and $1.51/MMBtu, respectively.

The m-o-m decline in US HH spot gas price was attributed to milder winter weather, which reduced heating demand, combined with strong domestic gas production and lower market volatility. Similarly, reduced heating demand drove the decline in Canada's AECO spot gas price.

Figure 116: Monthly North American spot gas prices



Source: GECF Secretariat based on data from LSEG

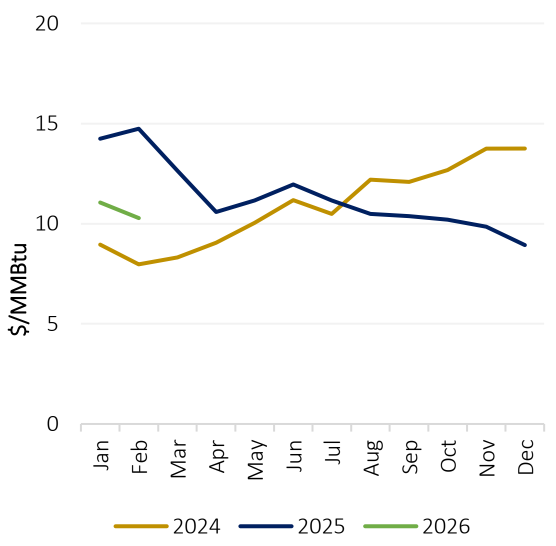
6.1.1.4 South American spot LNG prices

In January 2026, the South America (SA) spot LNG price declined by 7% m-o-m and 31% y-o-y to $10.28/MMBtu (Figure 117). During the month, the monthly average price moved to a premium over spot LNG prices in NW and SW Europe for the first time since May 2025.

For the period January to February 2026, the South American spot LNG price averaged $10.67/MMBtu, down 26% y-o-y.

Spot LNG prices in South America continued to closely track European gas and LNG benchmarks, reflecting direct competition with European markets for spot cargoes. Average delivered spot LNG prices stood at $10.25/MMBtu in Argentina, $10.18/MMBtu in Brazil and $10.40/MMBtu in Chile.

Figure 117: Monthly South American spot LNG prices

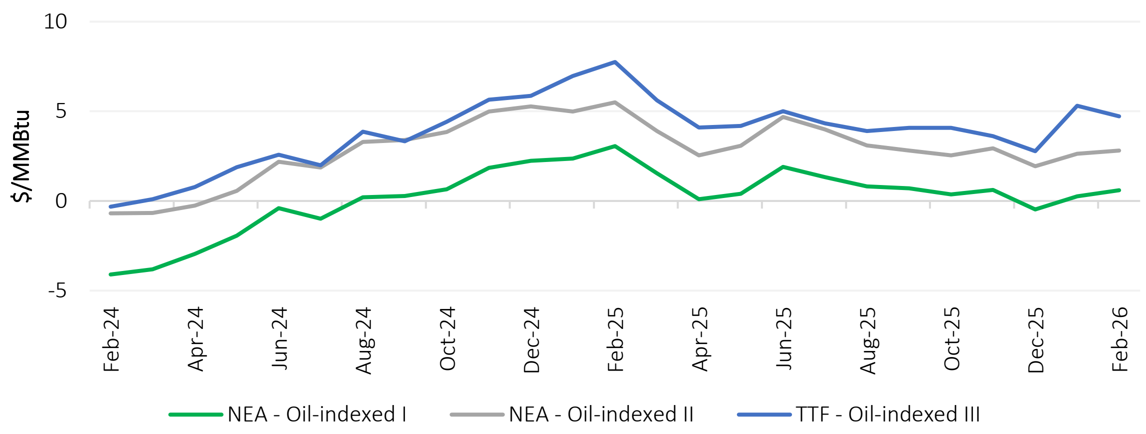


Source: GECF Secretariat based on data from Argus
Note: SA LNG price is an average of the LNG delivered prices for Argentina, Brazil and Chile based on Argus assessment

6.1.2 Spot and oil-indexed long-term LNG price spreads

In February 2026, the average Oil-indexed I LNG price declined slightly by 1% m-o-m and 13% y-o-y to $10.14/MMBtu. Oil-indexed II LNG prices edged up by 1% m-o-m but remained 14% lower y-o-y at $7.92/MMBtu. In Europe, Oil-indexed III LNG prices averaged $6.56/MMBtu, down 2% m-o-m and 14% y-o-y. During the month, North East Asia spot LNG widened its premium over Oil-indexed I LNG to $0.60/MMBtu. Its premium over Oil-indexed II LNG also increased to $2.82/MMBtu, while the premium of TTF spot gas over Oil-indexed III LNG narrowed to $4.71/MMBtu (Figure 118).

Figure 118: Spot and oil-indexed LNG price spreads



Source: GECF Secretariat based on data from Argus and LSEG
Note: Oil-indexed I LNG prices are calculated using the traditional LTC slope (14.9%) and 6-month historical average of Brent. Oil-indexed II LNG prices are calculated using the 5-year historical average LTC slope (11.6% for 2025) and 3-month historical average of Brent. Oil-indexed III LNG prices are based on Argus' assessment for European oil-indexed long-term LNG prices.

6.1.3 Regional spot gas & LNG price spreads

In February 2026, the NEA-TTF spread remained in negative territory, as the TTF spot gas price continued to trade above the NEA spot LNG price despite lower TTF prices and firmer NEA spot LNG prices. Nevertheless, the TTF premium over NEA spot LNG narrowed to $0.54/MMBtu (Figure 119). Meanwhile, the TTF–HH spread surged to $7.67/MMBtu, driven by a slump in the HH spot gas price (Figure 120).

Figure 119: NEA-TTF price spread

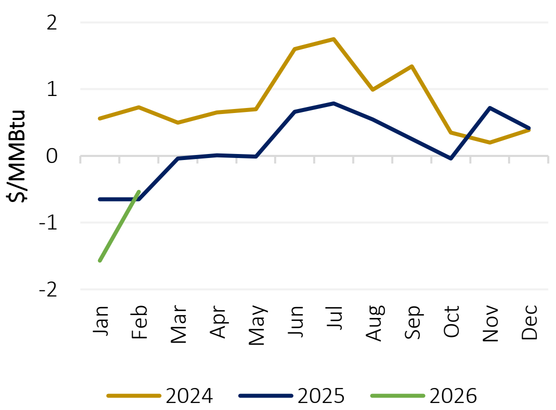
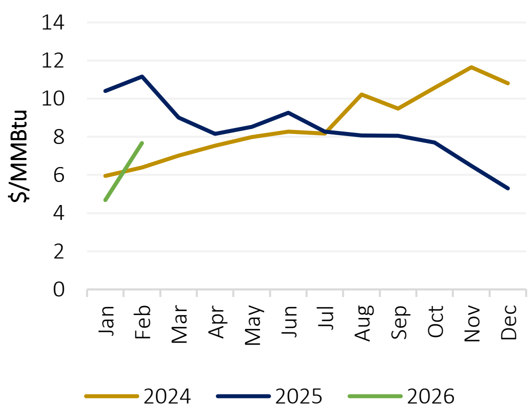


Figure 120: TTF-HH price spread



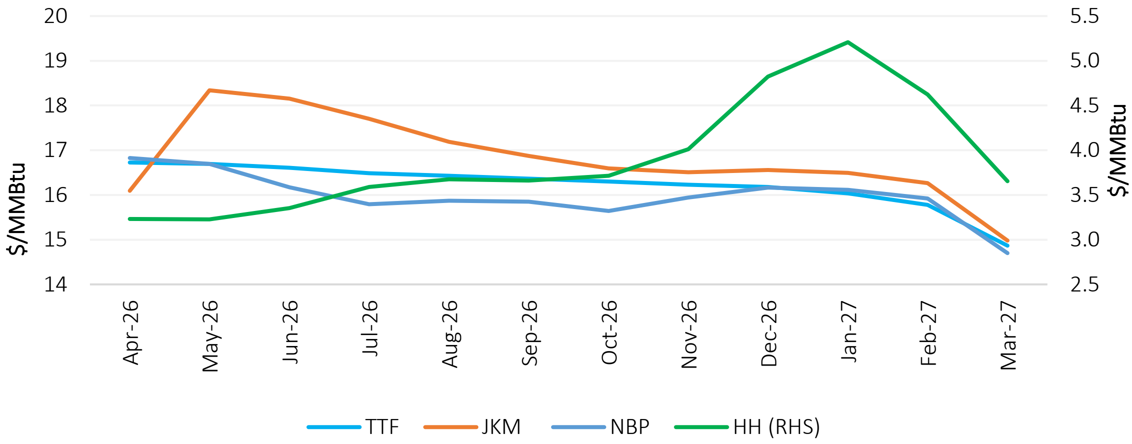
Source: GECF Secretariat based on data from Argus and LSEG

6.1.4 Gas & LNG futures prices

As of 13 March 2026, average futures prices for TTF, NBP and JKM over the 12-month period from April 2026 to March 2027 stood at $16.23/MMBtu, $15.97/MMBtu and $16.81/MMBtu, respectively (Figure 121). These forward-curve averages were notably higher than the futures expectations assessed on 13 February 2026 in the GECF MGMR February 2026. Over the same period, HH futures averaged $3.72/MMBtu, also above earlier expectations (Figure 122). Futures strengthened amid the impact of the Middle East conflict, which disrupted LNG trade through the Strait of Hormuz and is expected to tighten the global LNG market.

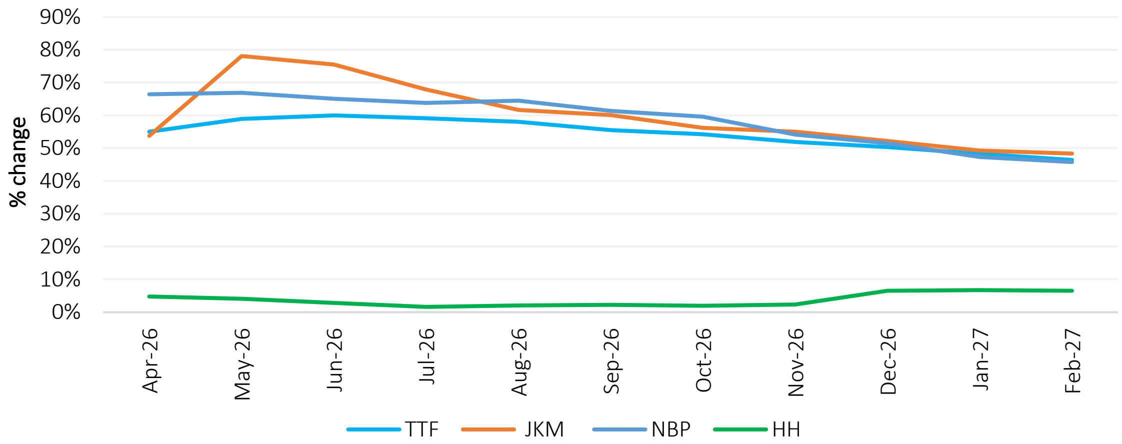
The JKM forward curve shows a premium over TTF from May 2026 onward, before both benchmarks converge by March 2027. Asian LNG buyers have been more directly affected by disruptions to LNG flows from Qatar and the United Arab Emirates through the Strait of Hormuz, with Asia expected to re-emerge as the premium LNG market needed to attract spot cargoes away from Europe.

Figure 121: Gas & LNG futures prices



Source: GECF Secretariat based on data from LSEG
Note: Futures prices as of 13 March 2026

Figure 122: Variation in gas & LNG futures prices



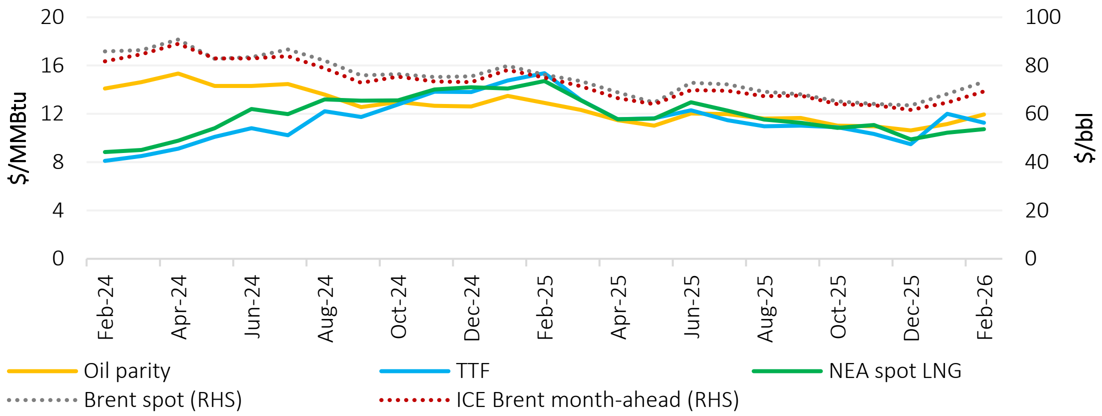
Source: GECF Secretariat based on data from LSEG
Note: Comparison with the futures prices as of 13 February 2026, as reported in GECF MGMR February 2026

6.2 Cross commodity prices

6.2.1 Oil prices

In February 2026, the average Brent Crude spot price rose by 8% m-o-m to $73.34/bbl, although it remained 4% y-o-y. Similarly, the month-ahead Brent price increased by 7% m-o-m to $69.37/bbl, but was still down 7% y-o-y. Both marked the highest monthly oil price levels since July 2025. During the month, the TTF spot gas price moved from a premium over oil parity to a discount of $0.69/MMBtu, while the discount of NEA spot LNG prices to oil parity widened to $1.22/MMBtu (Figure 123).

Figure 123: Monthly crude oil prices

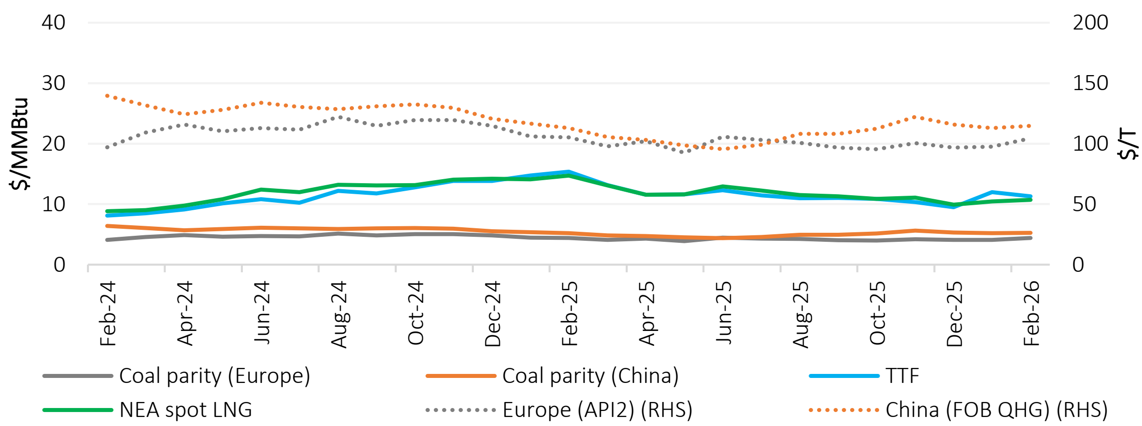


Source: GECF Secretariat based on data from Argus and LSEG
Note: Conversion factor of 5.8 was used to calculate the oil parity price in $/MMBtu based on the ICE Brent month-ahead price.

6.2.2 Coal prices

In February 2026, the European coal benchmark, API2 coal, increased by 7% m-o-m to $104.41/t, but edged slightly lower by 1% y-o-y. The premium of the TTF spot gas price over API2 parity narrowed slightly to $6.90/MMBtu. In China, the Qinhuangdao coal price increased by 2% m-o-m and 2% y-o-y to $114.76/t. Meanwhile, the premium of NEA spot LNG prices over QHG parity widened slightly to $5.50/MMBtu (Figure 124).

Figure 124: Monthly coal parity prices

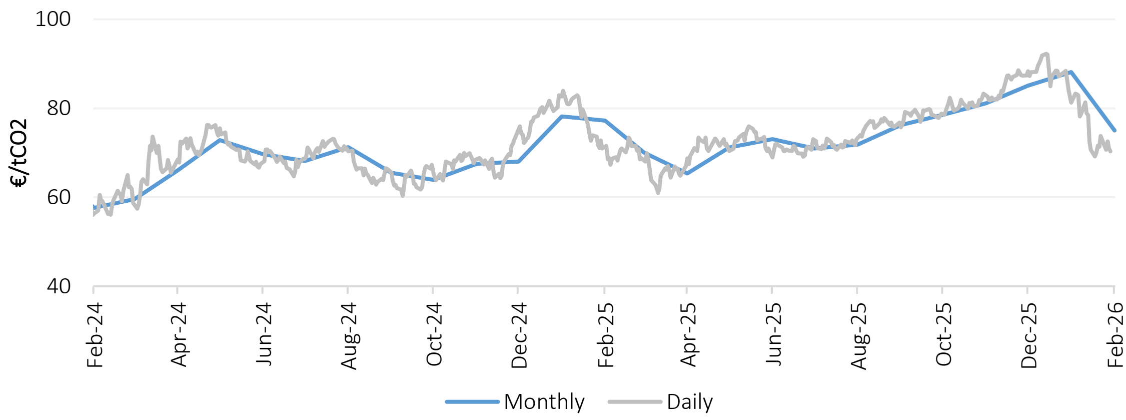


Source: GECF Secretariat based on data from Argus and LSEG
Note: Conversion factors of 23.79 and 21.81 were used to calculate the coal prices in $/MMBtu for Europe (API2) and China (QHG) respectively.

6.2.3 Carbon prices

In February 2026, the EU carbon price fell sharply by 15% m-o-m and 3% y-o-y to €75.00/tCO_2, which is the lowest monthly average since August 2025 (Figure 125). During the month, the daily EU carbon price reached a low of €69.18/tCO_2.

Figure 125: EU carbon prices

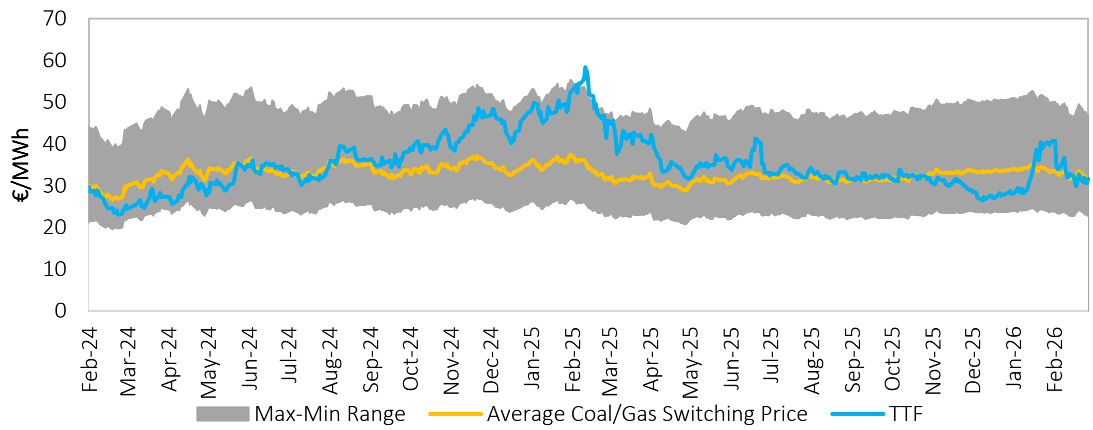


Source: GECF Secretariat based on data from LSEG

6.2.4 Fuel switching

In February 2026, lower TTF spot prices improved the competitiveness of gas relative to coal in the EU power sector, as prices remained broadly within the range supportive of coal-to-gas switching (Figure 126). TTF traded above the average switching price during the first half of the month before moving to a slight discount in the second half. On a monthly average, the spread between TTF and the coal-to-gas switching level remained marginal at just €0.40/MWh. Looking ahead, TTF spot prices are expected to remain above the average switching price, which would strengthen coal's competitiveness over gas in the EU power sector.

Figure 126: Daily TTF vs coal-to-gas switching prices



Source: GECF Secretariat based on data from LSEG

Note: Coal-to-gas switching price is the price of gas at which generating electricity with coal or gas is equal. The estimate takes into consideration coal prices, CO_2 emissions prices, operation costs and power plant efficiencies. The efficiencies considered for gas plants are max: 56%, min: 46%, avg: 49.13%. The efficiencies considered for coal plants are max: 40%, min: 34%, avg: 36%.

ANNEXES

Abbreviations

Abbreviation	Explanation
AE	Advanced Economies
AECO	Alberta Energy Company
Bbl	Barrel
bcm	Billion cubic metres
bcma	Billion cubic metres per annum
bcm/yr	Billion cubic metres per year
CBAM	Carbon Border Adjustment Mechanism
CBM	Coal bed methane
CCS	Carbon, Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CDD	Cooling Degree Days
CNG	Compressed Natural Gas
CO_2	Carbon dioxide
CO_{2e}	Carbon dioxide equivalent
CPI	Consumer Price Index
DOE	Department of Energy
EC	European Commission
ECB	European Central Bank
EEXI	Energy Efficiency Existing Ship Index
EMDE	Emerging Markets and Developing Economies
EU	European Union
EU ETS	European Union Emissions Trading Scheme
EUA	European Union Allowance
Fed	Federal Reserve
FID	Final Investment Decision
FSU	Floating Storage Unit

FSRU	Floating Storage Regasification Unit
G7	Group of Seven
GDP	Gross Domestic Product
GECF	Gas Exporting Countries Forum
GHG	Greenhouse Gas
HDD	Heating Degree Days
HH	Henry Hub
IEA	International Energy Agency
IMF	International Monetary Fund
IMO	International Maritime Organization
JKM	Japan Korea Marker
LNG	Liquefied Natural Gas
LAC	Latin America and the Caribbean
LPR	Loan Prime Rate
LT	Long-term
MMBtu	Million British thermal units
mcm	Million cubic metres
mmscfd	Million standard cubic feet per day
MENA	Middle East and North Africa
METI	Ministry of Trade and Industry in Japan
m-o-m	month-on-month
Mt	Million tonnes
Mtpa	Million tonnes per annum
MWh	Megawatt hour
NEA	North East Asia
NBP	National Balancing Point
NDC	Nationally Determined Contribution
NGV	Natural Gas Vehicle

NZBA	Net-Zero Banking Alliance
OECD	Organization for Economic Co-operation and Development
PNG	Pipeline Natural Gas
PPAC	Petroleum Planning & Analysis Cell
PSV	Punto di Scambio Virtuale (Virtual Trading Point in Italy)
QHG	Qinhuangdao
R-LNG	Regasified LNG
SA	South America
SPA	Sales and Purchase Agreement
SWE	South West Europe
T&T	Trinidad and Tobago
TANAP	Trans-Anatolian Natural Gas Pipeline
TCFD	Task Force on Climate-Related Financial Disclosure
Tcm	Trillion cubic metres
tCO2	Tonne of carbon dioxide
TFDE	Tri-Fuel Diesel Electric
TEU	Twenty-foot equivalent unit
TTF	Title Transfer Facility
TWh	Terawatt hour
UGS	Underground Gas Storage
UAE	United Arab Emirates
UK	United Kingdom
UQT	Upward Quantity Tolerance
US	United States
y-o-y	year-on-year

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