



GECF

Gas Exporting
Countries Forum

MONTHLY GAS MARKET REPORT

September 2026



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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, the 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 of the GECF Secretariat that provides insights into short-term developments in the global gas market, covering the full gas supply chain, including gas consumption, gas production, gas trade (pipeline gas and LNG), gas storage and energy prices, while evaluating the impacts of global economic developments and energy policies on the gas sector.

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Peer Review

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HIGHLIGHTS

Gas consumption: Global gas demand showed signs of improvement in August 2026, although trends remained mixed across regions amid the ongoing Middle East crisis. In Europe, gas consumption increased, primarily supported by stronger power-sector demand as widespread heatwaves boosted cooling requirements, while lower nuclear, hydro and wind availability in some markets increased reliance on gas-fired generation. North American gas demand also strengthened, particularly in the US, where elevated temperatures drove higher power-sector consumption. In Asia, demand remained mixed, with weaker gas-fired power generation weighing on gas consumption in several countries.

Gas production: The closure of the Strait of Hormuz continued to disrupt global gas production in August 2026, with Middle Eastern output falling by nearly one third year-on-year as major gas and LNG producers across the region recorded substantial production losses. The impact on global output was partly cushioned by continued production growth in North America, particularly in the US, where higher gas production helped offset a significant portion of the supply decline originating from the Middle East.

Gas trade: Global LNG trade fell significantly by 8.8% y-o-y to 34.3 Mt in August 2026, as the restrictions on LNG transit through the Strait of Hormuz continued to constrain the region's LNG exports. Asia's LNG imports declined by 8.2% y-o-y to 23.0 Mt, reversing two consecutive months of growth, amid reduced Middle Eastern supply and elevated spot LNG prices. Conversely, Europe's LNG imports edged up by 0.5% y-o-y to 8.0 Mt, ending five consecutive months of decline, as a narrowing Asia-Europe spot price spread supported a rebound in US LNG flows to the region. On the infrastructure front, Honduras joined the club of LNG importers in August 2026, receiving its first LNG cargo at the 0.5 Mtpa Puerto Cortes terminal.

Gas storage: European countries continued net gas injections in August 2026, with the EU monthly average gas storage level reaching 63 bcm, or 61% of capacity, compared with 76 bcm a year earlier, as competition with Asia for global spot LNG cargoes constrained the pace of summer replenishment. In the US, the monthly average storage level reached 90 bcm, or 67% of capacity, remaining close to the 90.6 bcm recorded a year earlier. In Asia, combined LNG inventories in Japan and South Korea declined to 7.8 bcm following a warm summer, while tight spot LNG market conditions also limited replenishment.

Energy prices: Gas and LNG spot prices in Europe and Asia recorded their highest monthly averages for the year in August 2026. TTF prices rose by 17% m-o-m to \$21/MMBtu. Similarly, NEA spot LNG prices rose by 12% m-o-m to \$22/MMBtu. In contrast, HH spot prices continued to ease, decreasing by 5% m-o-m to \$2.8/MMBtu. Ahead of the winter heating season, intensifying inter-regional competition will likely keep prices elevated, while any further escalation in the Middle East poses additional upside risks to LNG trade flows and pricing.

FEATURE ARTICLE

Natural gas as a catalyst for energy development in Latin America and the Caribbean

Latin America and the Caribbean (LAC) is gaining importance in the global energy landscape as rising energy needs, development ambitions and growing attention to energy security converge with the emergence of new opportunities to develop the region's abundant energy resources (for the purposes of this analysis, Mexico is excluded from the LAC regional grouping and included in North America). Despite its diverse resource base, LAC continues to face disparities in energy availability, affordability and infrastructure, with energy poverty remaining a challenge in parts of the region. Greater availability of reliable and affordable energy is essential to expand productive capacity, support industrialisation and improve living standards. Against this backdrop, the region's substantial natural gas resources and renewed upstream activity create significant potential to increase gas supply and strengthen the role of natural gas in meeting rising energy needs, while supporting energy access, energy security and climate objectives.

The regional gas market has experienced sustained growth in recent decades, with consumption rising from 98 bcm in 2000 to 163 bcm in 2025, reinforcing natural gas's role in meeting the energy needs. Gas consumption is highly concentrated, with Argentina, Brazil, Venezuela and Trinidad and Tobago together accounting for 75% of demand (Figure i). The market structure varies across the leading markets, reflecting differences in resource bases, domestic production and trade patterns.

Natural gas accounts for 18% of LAC's primary energy mix, compared with 38% for oil and 22% for biomass and waste. The power generation is the largest gas consumer, accounting for 90 bcma of regional consumption (Figure ii). Natural gas continues to serve as a reliable baseload power source, while its ability to provide flexible, dispatchable generation is becoming increasingly valuable as the region's power systems evolve, including as back-up for renewables.

The industrial sector, accounting for 42 bcma of regional gas consumption, represents another significant source of gas demand across LAC. In Argentina, Brazil and Trinidad and Tobago, gas is an important feedstock for fertiliser and petrochemical production, particularly ammonia, urea and methanol. Gas also provides process heat for energy-intensive industries such as steel, cement and metals, where reliable and controllable thermal energy is essential for industrial operations.

Figure i: Gas consumption by country in LAC

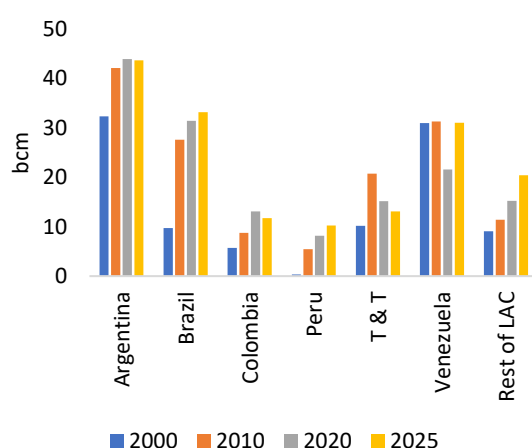
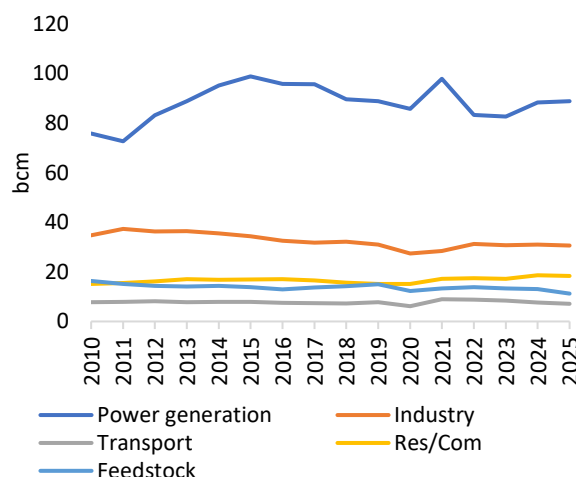


Figure ii: Gas consumption by sector in LAC



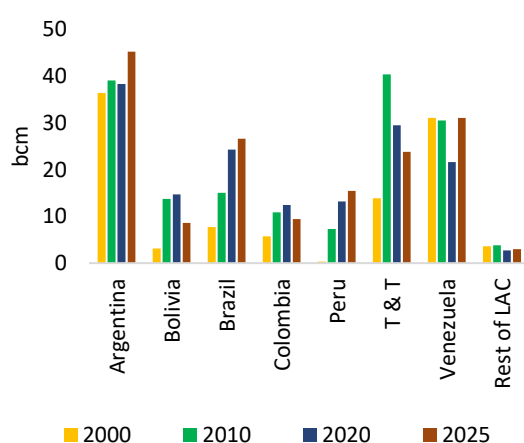
Source: GECF Secretariat based on data from Energy Institute, Cedigaz and Enerdata

The growth in gas consumption has been largely matched by an expansion in domestic production, allowing LAC to maintain a broadly balanced gas market. Between 2000 and 2025, LAC gas output rose from 102 bcm to 163 bcm, in line with the increase in gas consumption over the period. Production growth was driven by the region's major gas producers, including Argentina, Bolivia, Peru and Trinidad and Tobago (Figure iii). Although regional production increased by 60% over this period, compared with 75% globally, the region's substantial resource base and renewed upstream activity provide significant scope for further gas supply growth.

LAC has significant untapped natural gas potential, offering opportunities to expand its resource base and strengthen the region's ability to meet growing energy needs. The region holds 7.3 tcm of proven gas reserves, equivalent to 3.7% of global reserves, while technically recoverable resources (TRR) amount to 61.3 tcm, representing 9.3% of global resources. The substantially larger share of global TRR than proven reserves points to considerable scope for future reserve additions and production as exploration, appraisal and resource development advance. Venezuela holds the largest proven gas reserves in the region, at 5.5 tcm, while Argentina, Brazil and Venezuela have the largest TRR, at 24 tcm, 18 tcm and 7 tcm, respectively (Figure iv). Notably, Venezuela's substantial gas reserve and resource base could support additional regional and global gas supply as unilateral sanctions are gradually eased and investment in gas development accelerates.

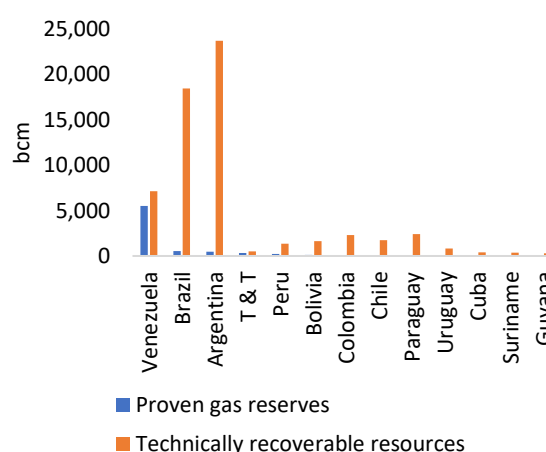
Recent upstream developments among established and emerging producers are creating new opportunities to increase LAC gas production. In Argentina, continued development of the Vaca Muerta formation is driving higher unconventional gas output, while new pipeline and processing infrastructure is expected to support further production growth and enable additional exports. In Brazil, continued development of pre-salt fields is expected to increase associated gas production, supported by investments in offshore production, gas processing and transportation infrastructure. Meanwhile, Guyana and Suriname could become additional sources of associated gas as their rapidly expanding offshore oil sectors generate increasing volumes of gas. Developing the infrastructure needed to capture, process and monetise these resources could bring additional gas to market. Beyond associated gas, further exploration and development of non-associated offshore gas resources could provide another source of production growth as commercial opportunities and supporting infrastructure develop. Together, these developments could broaden LAC's gas supply base and strengthen its production outlook over the medium to long term.

Figure iii: Gas production by country in LAC



Source: GECF Secretariat based on data from Energy Institute

Figure iv: Gas reserves and resources in LAC



Source: GECF Secretariat based on data from Enerdata

With domestic production largely keeping pace with growing gas demand, LAC remains relatively self-sufficient in natural gas, with extra-regional gas imports in the form of LNG accounting for only 10% of regional gas supply. LAC represents a relatively small LNG import market, accounting for around 3% of global LNG imports, with LNG imports expected to reach 13 Mt in 2026. At the same time, the region has developed significant LNG regasification infrastructure along both the Atlantic and Pacific coasts, with 10 LNG importing countries having combined regasification capacity of around 65 Mtpa, half of which is located in Brazil (Figure v). Despite this substantial capacity, utilisation remains low at around 20%, indicating significant scope to increase LNG imports. A further 10 Mtpa of regasification capacity is under development, with Nicaragua, Aruba and the Bahamas expected to emerge as new LNG importers in the short term.

On the export side, Trinidad and Tobago and Peru are the region's LNG exporters, having started exports in 1999 and 2010, respectively, with liquefaction capacities of 11.8 Mtpa and 4.4 Mtpa. However, LNG exports are expected to reach only 11 Mt in 2026 due to limited feedgas availability (Figure vi). Looking ahead, the region's growing gas supply base can support higher LNG exports, with the start-up of 6 Mtpa of FLNG capacity in Argentina by 2028 and potential new projects in Argentina, Guyana and Suriname expected to start operations beyond 2030. Moreover, the escalation of the Middle East conflict in 2026 has heightened LNG importers' focus on supply resilience and diversification of supply sources, creating opportunities for LAC to expand LNG exports while attracting investment to develop its gas resources and related infrastructure.

Figure v: LAC regasification capacity vs LNG imports

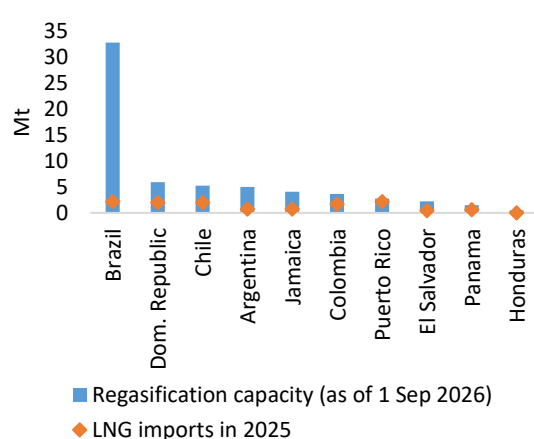
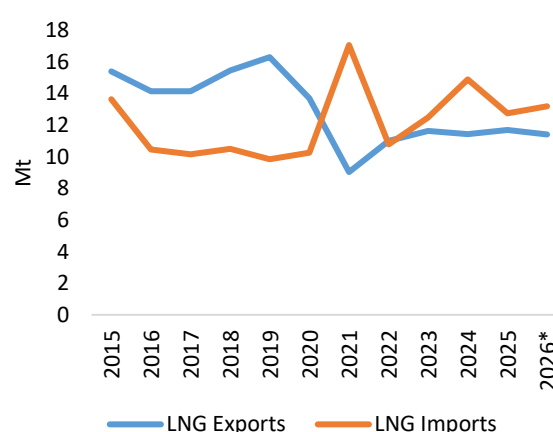


Figure vi: LAC LNG trade (2015-2026)



Source: GECF Secretariat based on data from ICIS LNG Edge, LSEG and Project Updates

Note: 2026* - GECF Secretariat forecast

With LNG imports in LAC constrained by seasonality and affordability, expanding intra-regional pipeline gas trade offers a key opportunity to increase gas supply within the region. While intra-regional pipeline gas trade declined from 18 bcm in 2015 to 7 bcm in 2025, there is significant scope to increase cross-border flows and make greater use of the region's available gas supply. Greater integration would enable surplus gas from producing countries to reach neighbouring markets with unmet demand, while interconnected networks could also facilitate the movement of regasified LNG beyond import terminals. Existing infrastructure provides a foundation for further integration, including the Bolivia–Brazil GASBOL pipeline and Argentina's expanding network connecting Vaca Muerta with Chile, Uruguay and Brazil. Further cross-border connections involving Venezuela, Colombia and Trinidad and Tobago, as well as Guyana and Suriname with northern Brazil, could broaden regional supply options and support a more interconnected and flexible LAC gas market.

Against this backdrop, greater availability of natural gas can enable higher energy consumption and, in turn, support economic growth in LAC, as economic development generally requires increasing amounts of energy. Although primary energy supply in LAC increased from 17 EJ in 2000 to 26 EJ in 2025, growing at a CAGR of 1.7% and keeping the region's share of global supply broadly unchanged at 4.4%, LAC remains relatively undersupplied in primary energy, with energy availability and energy access remaining limited. Per-capita primary energy supply in LAC stands at 49 GJ, below the global average of 73 GJ and levels in North America (219 GJ), the Middle East (140 GJ), Europe (106 GJ) and Asia Pacific (65 GJ), while remaining above Africa (14 GJ). Relatively low energy supply therefore remains a significant constraint on economic development, with GDP per capita in LAC standing at US\$11,000 in 2025, compared with US\$14,500 globally.

In this context, natural gas can contribute to LAC's sustainable development across its economic, social and environmental pillars by providing an abundant, affordable and low-carbon energy source. Economically, natural gas can support industrialisation, electrification and the expansion of digital infrastructure, including data centres and artificial intelligence applications. Socially, it can support rising energy needs associated with higher living standards, demographic growth and urbanisation, including increasing demand for cooling, while contributing to food security through its role as a feedstock for fertiliser production. In particular, natural gas can contribute to reducing energy poverty in the region, as around 20 million people in LAC still lack access to electricity, while per-capita electricity consumption stands at 2.8 MWh, compared with the global average of 3.8 MWh. Furthermore, around 70 million people in the region lack access to clean cooking, with natural gas capable of supporting the transition to clean cooking, particularly where households continue to rely on traditional biomass and waste, which account for 22% of LAC's primary energy supply.

Environmentally, natural gas can support both the energy transition and energy addition needed to meet rising demand. As a relatively low-carbon fuel, it can provide additional energy while limiting the emissions associated with greater reliance on more carbon-intensive fuels. In 2025, oil- and coal-fired generation accounted for 90 TWh and 50 TWh, respectively, while natural gas-fired generation accounted for 230 TWh, or 16% of the regional power mix. The potential for fuel switching is particularly relevant in the Caribbean islands, where several countries continue to rely heavily on oil-fired generation, with small-scale LNG providing an option for these markets. At the same time, natural gas can facilitate the integration of variable renewable energy. The rapid expansion of intermittent wind and solar generation, which reached 300 TWh, or nearly 20% of the power mix, in 2025, compared with 40 TWh, or less than 3%, in 2015, is increasing the value of natural gas as a flexible source of generation during periods of low renewable output, particularly when weather conditions reduce wind and solar availability. Moreover, hydropower, which dominates the regional power mix with a 48% share, also creates a need for flexible generation during periods of low availability caused by droughts, with gas-fired generation providing this flexibility. Brazil provides a clear example: hydro output increased from 363 TWh in 2021 to 426 TWh in 2023 as hydrological conditions improved, reducing the need for gas-fired generation and resulting in a decline in LNG imports from 7.8 Mt to 1 Mt over the same period.

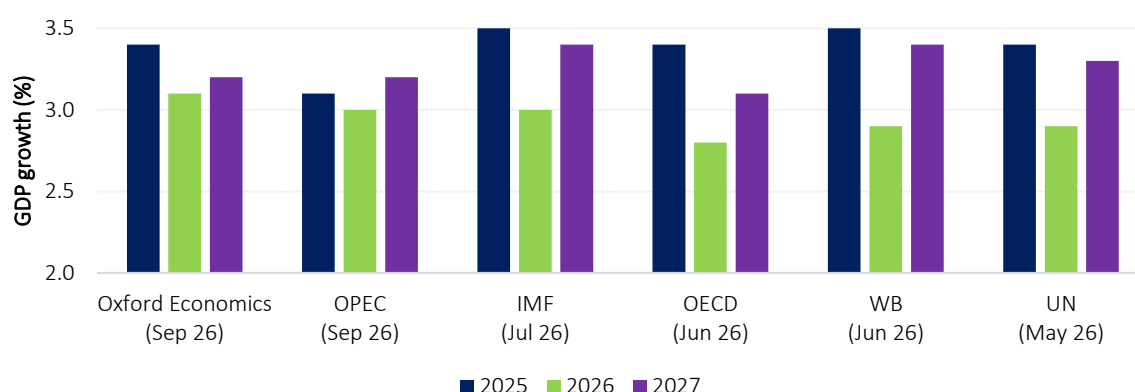
Realising the potential of natural gas in LAC requires sustained investment across the upstream, midstream and downstream sectors. Greater policy coordination, development and use of the region's own natural gas resources, and regional integration of pipeline infrastructure can increase energy availability and affordability, strengthen energy security and contribute to sustainable development and a better balance across the energy trilemma in the region.

1 GLOBAL PERSPECTIVES

1.1 Global economy

Global GDP growth for 2026 based on purchasing power parity was revised upward by 0.2 percentage points to 3.1% by Oxford Economics in September 2026 (Figure 1). The upward revision reflects stronger-than-expected economic performance in the second quarter, with the global economy demonstrating resilience despite ongoing geopolitical tensions in the Middle East. However, the growth outlook for 2027 was revised downward by 0.2 percentage points to 3.2%, reflecting persistent downside risks and continued uncertainty.

Figure 1: Global GDP growth

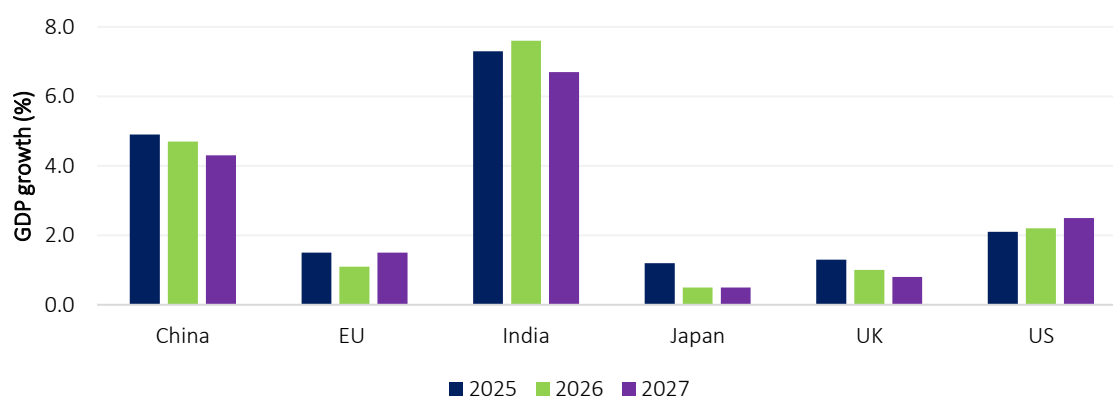


Source: GECF Secretariat based on data from Oxford Economics, OPEC, IMF, OECD, WB and UN

Note: Global GDP growth calculated based on Purchasing Power Parity

In the US, the 2026 GDP growth was maintained at 2.2%, while the 2027 forecast was revised downward by 0.2 percentage points to 2.5%, reflecting weaker consumer spending. In the EU, the 2026 GDP growth estimate was revised upward by 0.2 percentage points to 1.1%, while the 2027 forecast was lowered to 1.5%. China's GDP growth forecasts for 2026 and 2027 were revised down to 4.7% and 4.3%, respectively, amid delays in the implementation of fiscal stimulus measures and continued weakness in domestic activity. Meanwhile, India's GDP growth for 2026 was revised up by 0.9 percentage points to 7.6%, supported by stronger-than-expected growth in the first half of the year. Growth is expected to moderate to 6.7% in 2027 (Figure 2).

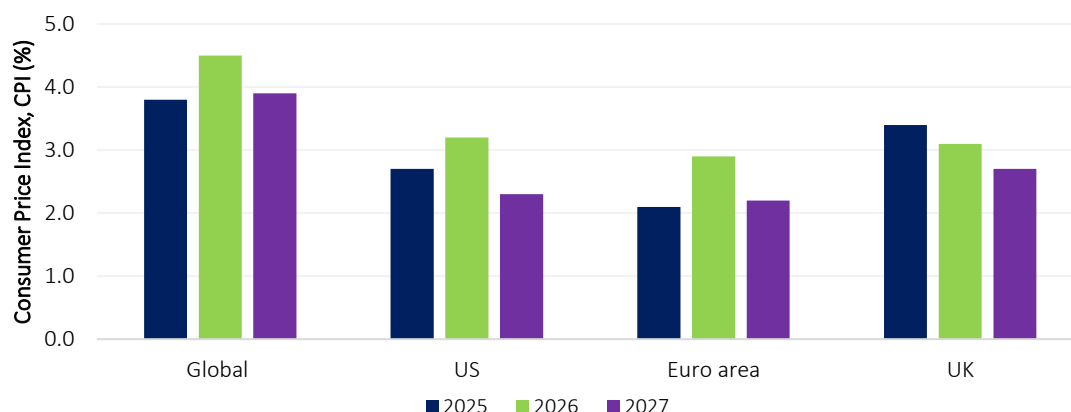
Figure 2: GDP growth in major economies



Source: GECF Secretariat based on data from Oxford Economics

In August 2026, Oxford Economics maintained its global inflation forecast for 2026 at 4.5%, but raised its 2027 forecast by 0.3 percentage points to 3.9% (Figure 3). In the Euro area, inflation projections increased to 2.9% in 2026 and 2.2% in 2027. The inflation rate forecast in the UK was also raised to 3.1% in 2026 and 2.7% in 2027. In the US, the 2026 inflation forecast was maintained at 3.2%, however the 2027 forecast was lowered by 0.1 percentage points to 2.3%.

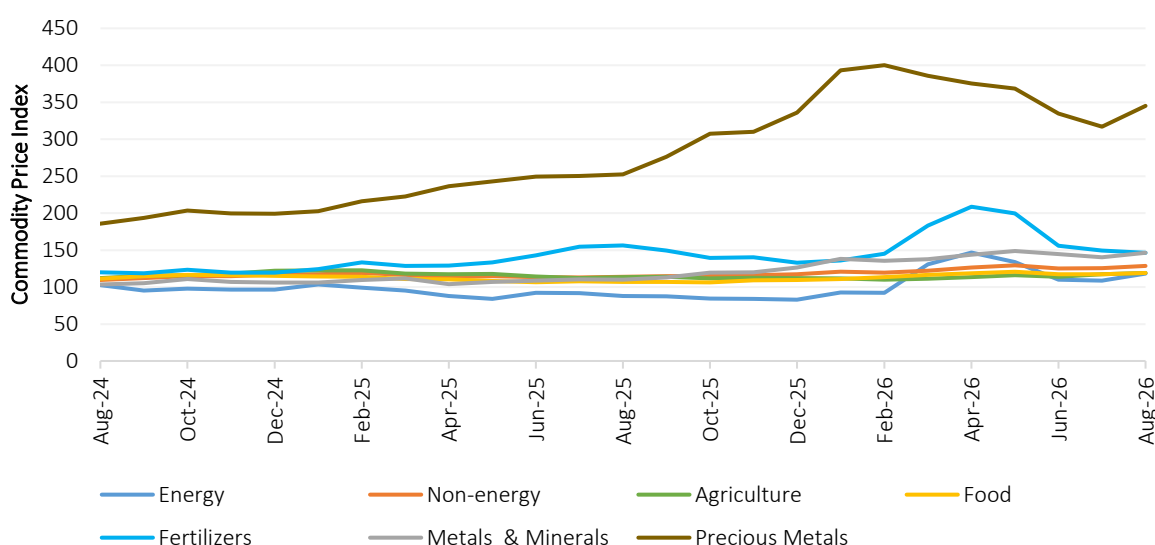
Figure 3: Inflation rates



Source: GECF Secretariat based on data from Oxford Economics

In August 2026, commodity prices across all major sectors experienced upward momentum (Figure 4). The energy price index increased significantly by 9% m-o-m, reflecting stronger oil and gas prices, and was 34% higher than a year earlier. The non-energy price index increased by 2% m-o-m and 13% y-o-y. Fertilizer prices continued to soften, with the index falling 2% m-o-m and 6% y-o-y. The precious metals price index reversed losses of the previous month, increasing by 9% m-o-m and was 37% higher than a year earlier.

Figure 4: Monthly commodity price indices

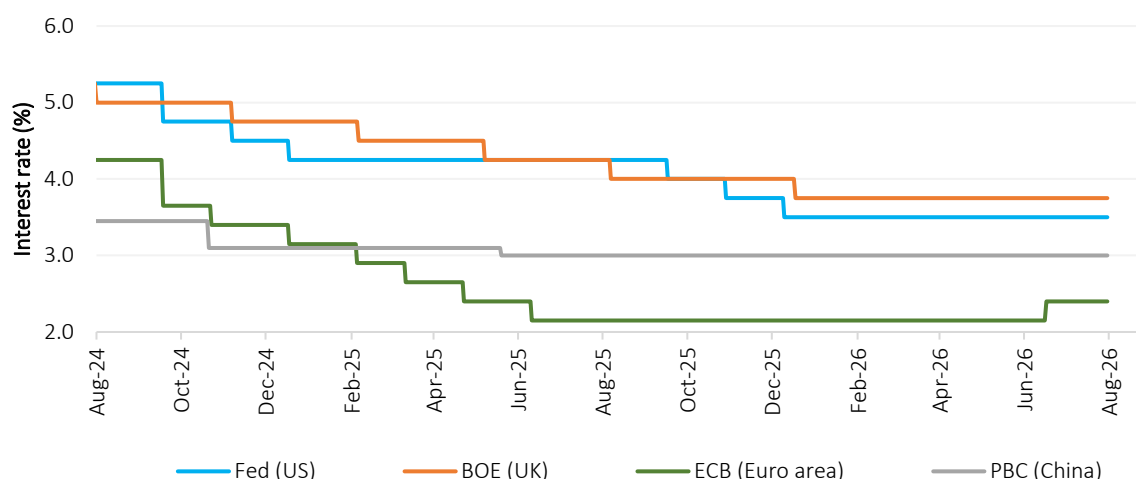


Source: GECF Secretariat based on data from World Bank Commodity Price Data

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 August 2026, global monetary policy remained steady as major central banks chose to maintain their existing benchmark interest rates (Figure 5). The US Federal Reserve (Fed) maintained its benchmark interest rate within the range of 3.5% to 3.75%, which has been unchanged since December 2025. The Bank of England (BOE) has kept its benchmark interest rate at 3.75% since December 2025. The European Central Bank (ECB) also maintained its main refinancing operations rate at 2.40%. Similarly, the People’s Bank of China held its one-year Loan Prime Rate (LPR) at 3.0%.

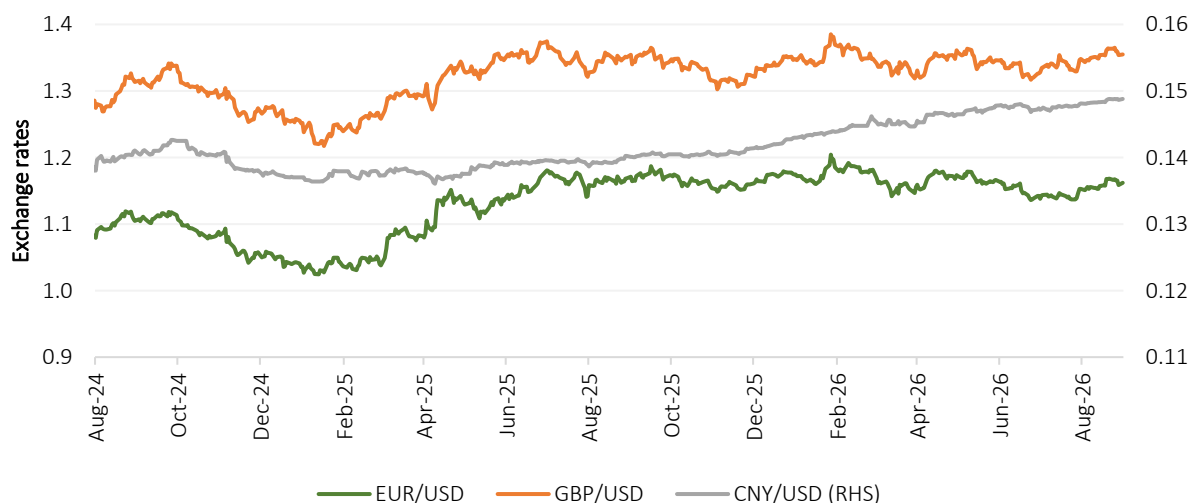
Figure 5: Interest rates in major central banks



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

In August 2026, major global currencies strengthened modestly against the US dollar (Figure 6). The euro averaged \$1.1593 against the US dollar, up 1% m-o-m and relatively stable compared to the previous year. Similarly, the British pound averaged \$1.3542 against the US dollar, reflecting an increase of 1% both m-o-m and y-o-y. The Chinese yuan also strengthened against the US dollar, averaging \$0.1485, increasing by 1% m-o-m and 6% y-o-y.

Figure 6: Exchange rates



Source: GECF Secretariat based on data from LSEG

1.2 Other developments

BRICS: During the 18th BRICS Summit held on 12–13 September 2026 in New Delhi, India, member states unanimously adopted the BRICS New Delhi Declaration 2026, placing energy security, uninterrupted energy trade and the resilience of critical cross-border energy infrastructure among the bloc's priorities. The declaration recognizes that fossil fuels will continue to play an important role in the global energy mix, particularly for emerging markets and developing economies, while supporting a just, orderly, equitable and inclusive energy transition and lower greenhouse gas emissions. It also emphasizes the importance of energy access for national security, economic development and social welfare, and expresses concern over unilateral trade measures, including carbon border adjustment mechanisms, which BRICS members view as potentially creating trade barriers and affecting developing economies.

G20: The G20 Finance Ministers and Central Bank Governors Meeting took place on 31 August – September 1, 2026 in North Carolina, US. Notably, the meeting did not produce a consensus G20 communiqué. Instead, the US presidency issued a Chair's Statement, reflecting unresolved differences, particularly over global trade imbalances. In the Chair's Statement, the ministers recognized that “artificial intelligence is a general-purpose technology with the potential to have profound effects on the global economy. Economies that embrace its responsible development, adoption, and diffusion will likely set the pace of global growth in the years ahead. Abundant and affordable energy access, quality infrastructure investment, predictable investment environments underpinned by macroeconomic stability and the rule of law, and the responsible embrace of AI and other emerging technologies will help facilitate growth.”

China: China has issued its 15th Five-Year Plan for Oil and Gas Development, covering 2026–2030, setting priorities for strengthening domestic oil and gas supply, expanding infrastructure and enhancing energy security. The plan targets total domestic oil and gas production of 440 Mt of oil equivalent by 2030 and calls for continued growth in natural gas output through exploration and development of conventional, shale and coalbed methane resources. It also envisages adding 20,000 km of long-distance oil and gas pipelines, expanding LNG receiving and pipeline gas infrastructure, and increasing natural gas storage capacity to more than 13% of national gas consumption by 2030. The plan further promotes technological innovation, digitization and lower carbon intensity across the oil and gas sector.

South Korea: South Korea has issued its 16th Long-Term Natural Gas Supply and Demand Plan, covering the period through 2038 and setting out long-term demand, supply management, import and infrastructure plans. Baseline natural gas demand is projected to decline from 45.9 Mt in 2026 to 41.0 Mt in 2038, an average annual decrease of 0.94%, with city gas demand rising from 23.6 Mt to 28.2 Mt while power sector demand falls from 22.3 Mt to 12.8 Mt. Separately, supply demand management requirements are projected to remain broadly stable at around 47.6 Mt over the period. The plan also strengthens gas security through expanded storage, greater private sector participation in stockpiling, diversified supply sources and an integrated system for monitoring gas imports and inventories.

2 GAS CONSUMPTION

In the first seven months of 2026, aggregate gas consumption in major gas-consuming countries, accounting for 75% of global gas demand, decreased by 1.2% y-o-y to 1,945 bcm. Consumption declined in North America, the Middle East, and Southern Asia, while the EU recorded growth.

2.1 Europe

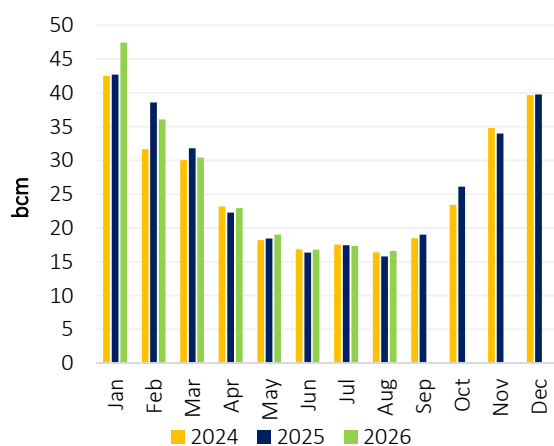
2.2.1 European Union

In August 2026, EU natural gas consumption increased by 5.2% y-o-y to 16.6 bcm (Figure 7). The increase was largely supported by stronger gas demand from the power sector, as unusually warm weather across large parts of Europe boosted electricity consumption for cooling. The average temperature over the European Union reached 20.26°C, around 0.8°C higher than in August 2025, with heatwave conditions affecting several parts of Western, Central and Southern Europe. Meanwhile, gas demand from the residential sector remained seasonally low, while industrial consumption was likely constrained by the summer holiday period.

EU electricity generation increased by 5.6% y-o-y (11.1 TWh). Gas-fired power generation rose strongly by 20.5% y-o-y (6.1 TWh), supported by higher cooling-related electricity demand and reduced availability of some competing generation sources. Nuclear output declined by 11.8% y-o-y (5.8 TWh), as high temperatures and elevated river water temperatures constrained reactor availability in parts of Europe. Hydropower generation also fell significantly, declining by 19% y-o-y (4.4 TWh). In contrast, solar generation maintained strong growth, increasing by 17% y-o-y (7.7 TWh), while wind generation rose by 12% y-o-y (3.3 TWh). Coal-fired generation also increased by 22% y-o-y (3.3 TWh), reflecting stronger overall power demand and lower nuclear and hydro output (Figure 8).

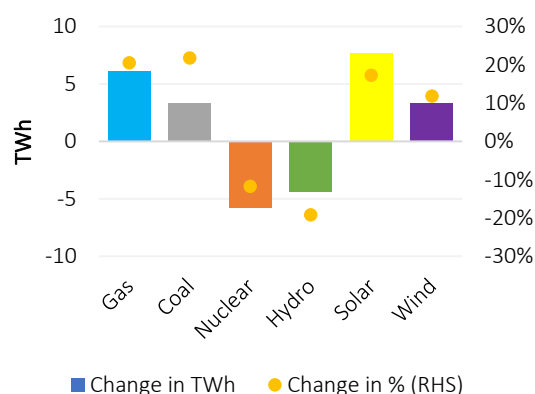
Within the power mix, non-hydro renewables remained the largest source, accounting for 44% of output, followed by nuclear (21%), natural gas (17%), hydropower (9%), and coal (9%). The August generation mix highlights the important role of natural gas in balancing the power system and meeting higher electricity demand during the heatwave conditions.

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 August 2026 (y-o-y change)



Source: GECF Secretariat based on data from Ember

For the period Jan-August 2026, the EU's gas consumption rose by 1.6% y-o-y to 206.7 bcm.

2.1.1.1 Germany

In August 2026, Germany's gas consumption remained broadly stable at 3.31 bcm, compared with 3.30 bcm in August 2025 (Figure 9). Industrial gas consumption increased slightly by around 3% y-o-y (Figure 10), while gas consumption in the power generation sector declined by 14% y-o-y. Despite significantly warmer weather, with the average temperature rising to 20.5°C from 18.6°C in August 2025, the resulting increase in cooling-related electricity demand did not translate into higher gas-fired generation. Instead, exceptionally strong solar and wind output met a substantial share of electricity demand, limiting the call on gas-fired power plants. Residential gas demand remained subdued owing to seasonal factors.

Figure 9: Gas consumption in Germany

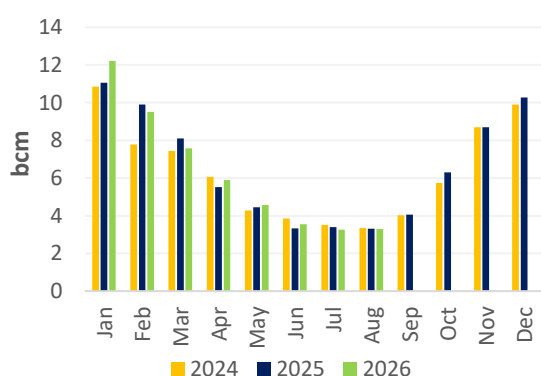
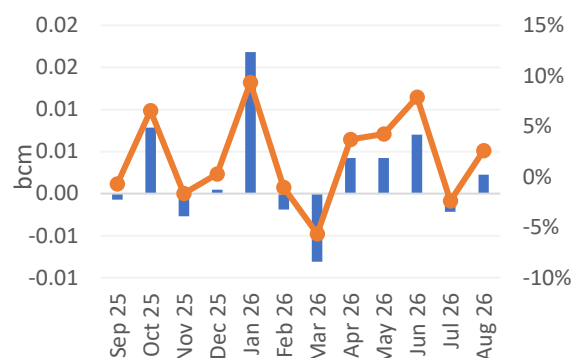


Figure 10: Trend in gas consumption in the industrial sector in Germany (y-o-y change)



Source: GECF Secretariat based on data from LSEG

Germany's electricity generation increased by 10.7% y-o-y (+3.73 TWh) in August 2026, driven mainly by strong renewable generation. Wind recorded the largest increase, rising by 36% y-o-y (+2.51 TWh), while solar generation grew by 15% y-o-y (+1.71 TWh), supported by favourable weather conditions and continued expansion of installed renewable capacity. In contrast, gas-fired generation declined by 14.2% y-o-y (-0.77 TWh), despite stronger overall electricity demand. Hydropower output dropped sharply by 40% y-o-y (-0.80 TWh), reflecting relatively dry conditions and reduced hydro availability. (Figure 11). Within the power mix, non-hydro renewables strengthened their dominant position in the power mix accounting for 67% (Figure 12).

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

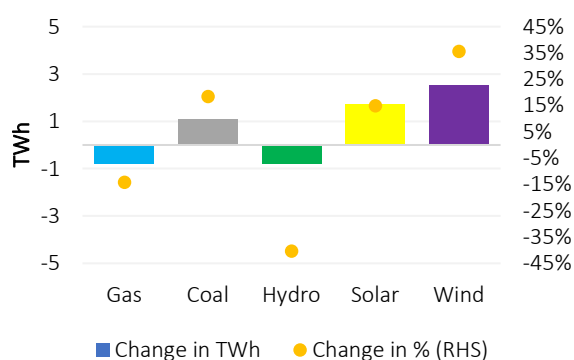
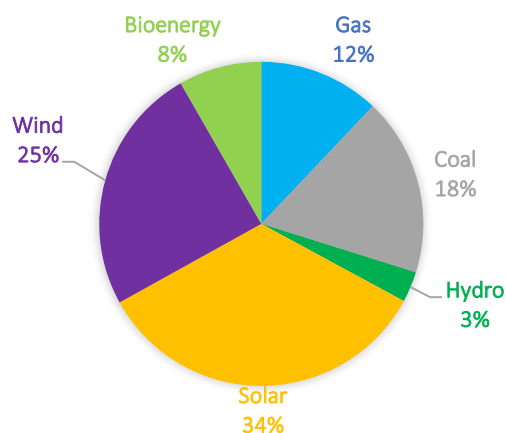


Figure 12: German electricity mix in August 2026



Source: GECF Secretariat based on data from LSEG and Ember

For the period Jan-August 2026, Germany's gas consumption rose by 1.7% y-o-y to 49.8 bcm.

2.1.1.2 Italy

In August 2026, Italy's gas consumption increased by 14% y-o-y to 3.63 bcm (Figure 13). Gas use for power generation increased by 42% y-o-y to 2.19 bcm, as exceptionally high temperatures boosted electricity demand for cooling. Italy's average temperature reached 27.4°C, around 3.1°C higher than in August 2025, reflecting widespread heatwave conditions across the country. In contrast, industrial gas consumption declined by 11% y-o-y to 0.66 bcm, extending the weakness observed in recent months (Figure 14). Residential gas consumption also decreased by 5% y-o-y to 0.71 bcm, remaining subdued due to seasonal factors.

Figure 13: Gas consumption in Italy

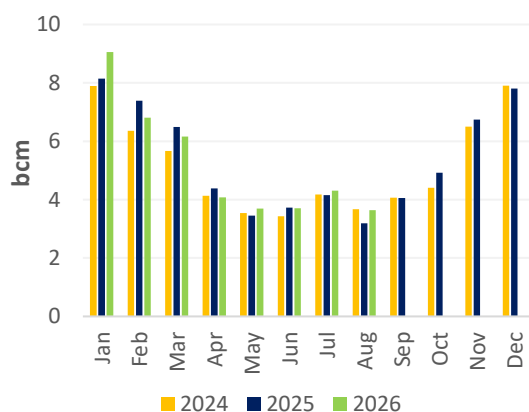
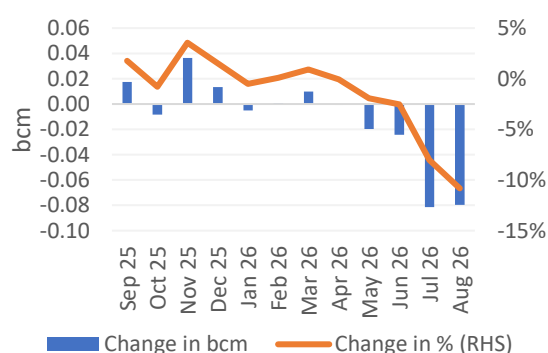


Figure 14: Trend in gas consumption in the industrial sector in Italy (y-o-y change)



Source: GECF Secretariat based on data from Snam

Italy's total electricity generation increased strongly by 24.6% y-o-y (+4.59 TWh) in August 2026. Gas-fired generation recorded the largest increase, rising by 41.7% y-o-y (+3.36 TWh), supported by elevated cooling demand and weaker wind generation. Solar generation also expanded strongly, increasing by 21% y-o-y (+1.05 TWh), while hydropower rose by 18% y-o-y (+0.48 TWh). In contrast, wind generation declined by 23% y-o-y (-0.35 TWh), increasing the need for dispatchable generation, while coal-fired output fell by 24% y-o-y (Figure 15). The combination of exceptionally hot weather, stronger electricity requirements and weaker wind output therefore significantly increased reliance on gas-fired generation. Natural gas remained the largest source in Italy's electricity mix, accounting for 49% of total generation, followed by non-hydro renewables (37%), hydropower (13%) and coal (1%). (Figure 16).

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

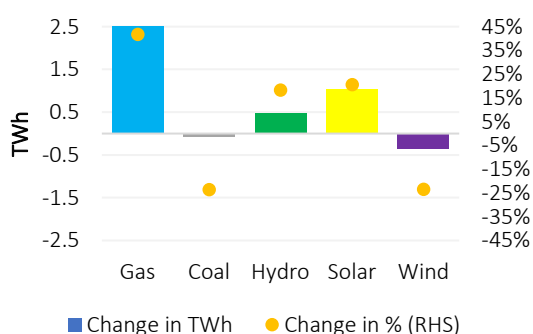
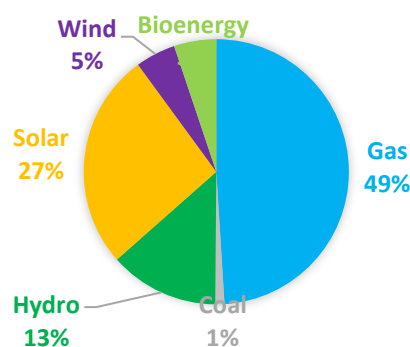


Figure 16: Italian electricity mix in August 2026



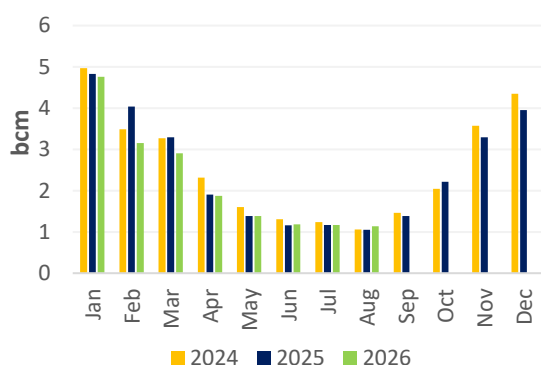
Source: GECF Secretariat based on data from Terna, LSEG and Ember

For the period Jan-August 2026, Italy's gas consumption increased by 1.3% y-o-y to 41.5 bcm.

2.1.1.3 France

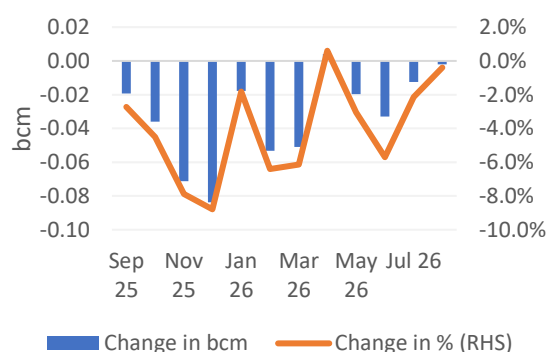
In August 2026, France's natural gas consumption increased by 8.5% y-o-y to 1.14 bcm (Figure 17), primarily driven by a sharp rise in demand from the power generation sector. Gas consumption for power generation surged by 90% y-o-y to 0.24 bcm, as lower nuclear and hydropower availability increased the need for gas-fired generation. Industrial gas consumption remained unchanged y-o-y at 0.54 bcm (Figure 18), whilst residential and commercial demand increased by 8.4% y-o-y to 0.42 bcm. Despite the seasonal weakness in heating requirements, higher temperatures likely supported electricity demand for cooling during periods of elevated summer temperatures.

Figure 17: Gas consumption in France



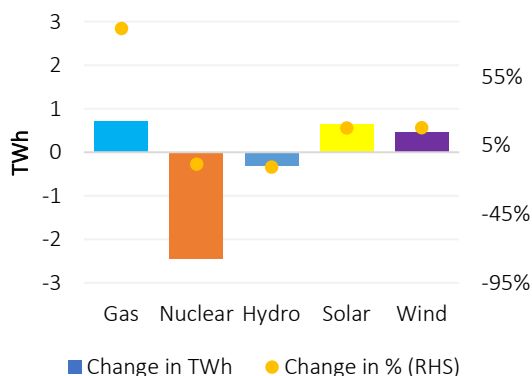
Source: GECF Secretariat based on data from GRTgaz

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



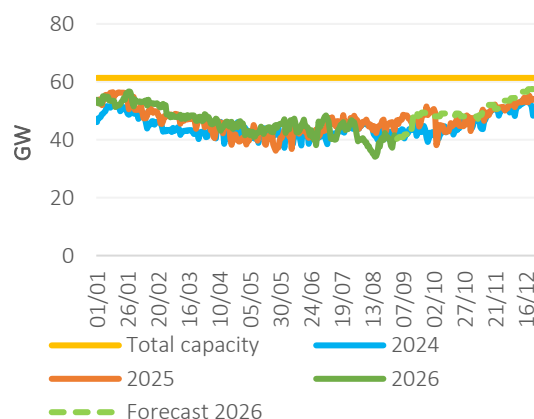
France's total electricity generation declined by 2.3% y-o-y (-0.87 TWh) in August 2026. Nuclear generation, the country's dominant electricity source, decreased by 9% y-o-y (-2.44 TWh). Hydropower output decreased by 10.7% y-o-y, further tightening dispatchable low-carbon supply. Consequently, gas-fired generation surged by 90% y-o-y, partially compensating for lower nuclear and hydro output (Figure 19). Average nuclear capacity declined by 14.5% y-o-y during the month and by 13% compared with July, as several reactors were temporarily shut down or operated at reduced capacity due to elevated river temperatures and low water levels, which constrained cooling water availability (Figure 20). Nuclear energy remained the dominant source in France's electricity mix, accounting for 69%.

Figure 19: Trend in electricity production in France in August 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-August 2026, France's gas consumption declined by 6.7% y-o-y to 17.5 bcm.

2.1.1.4 Spain

In August 2026, Spain's natural gas consumption increased by 9.2% y-o-y to 2.26 bcm (Figure 21). The growth was primarily driven by stronger demand from the power generation sector, where gas consumption surged by 31% y-o-y to 1.08 bcm. Elevated summer temperatures supported cooling-related electricity demand, while lower wind, nuclear and hydropower generation increased the need for gas-fired generation to balance the power system. In contrast, non-power gas demand declined by 5.6% y-o-y to 1.10 bcm, partly offsetting the strong increase in gas use for electricity generation. Industrial gas demand declined by 5.6% y-o-y, extending the downward trend observed in recent months, with the largest declines recorded in the paper manufacturing (-15%) and construction (-14.6%) sectors (Figure 22).

Figure 21: Gas consumption in Spain

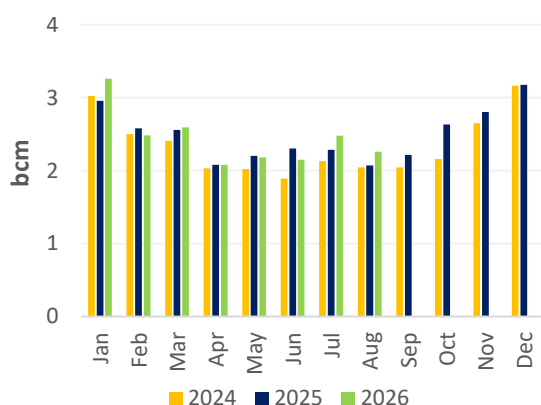
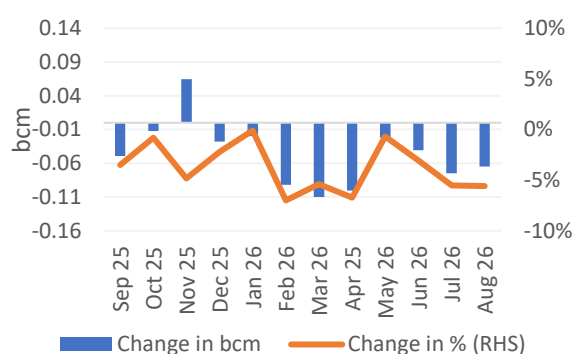


Figure 22: Trend in gas consumption in the industrial sector in Spain (y-o-y change)



Source: GECF Secretariat based on data from Enagas

Spain's electricity generation increased by 7.7% y-o-y (+1.69 TWh) in August 2026. Gas-fired generation rose by 18% y-o-y, supported by stronger electricity requirements and lower output from several competing generation sources. Wind generation declined by 8% y-o-y, while nuclear output decreased by 7% y-o-y and hydropower fell by 10% y-o-y (Figure 23). Within the electricity mix, non-hydro renewables strengthened their leading position, accounting for 51% of total generation, followed by natural gas (23%), nuclear (20%), wind (13%), hydropower (6%), and bioenergy (1%). (Figure 24).

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

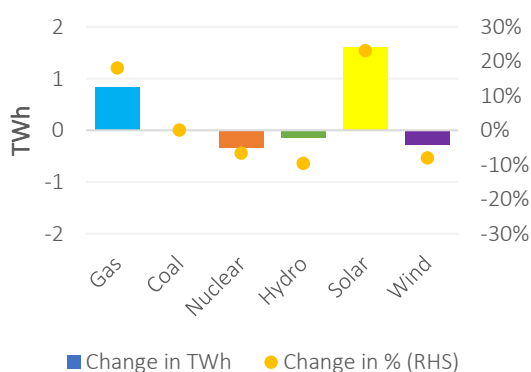
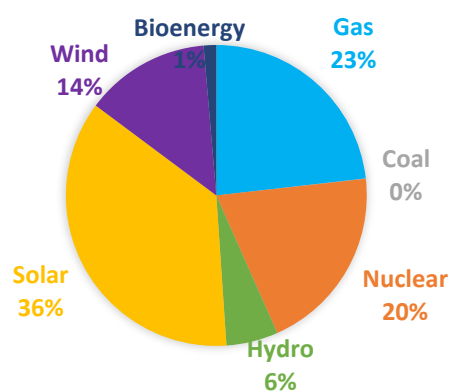


Figure 24: Spanish electricity mix in August 2026



Source: GECF Secretariat based on data from Ember and Ree

For the period Jan-August 2026, Spain's gas consumption rose by 2.3% y-o-y to 19.5 bcm.

2.1.2 United Kingdom

In August 2026, gas consumption in the UK decreased by 4.9% y-o-y to 2.36 bcm (Figure 25), driven by lower demand from the industrial and residential sectors. Residential gas consumption decreased by 11% y-o-y to 1.4 bcm, while industrial gas demand declined by 25% y-o-y (Figure 26). Gas consumption in power generation grew by 8.7% y-o-y to 1 bcm. Strong electricity demand and lower growth in renewable generation boosted the need for additional gas-fired output. For the period Jan-August 2026, UK's gas consumption declined by 2.6% y-o-y to 35 bcm.

Figure 25: Gas consumption in the UK

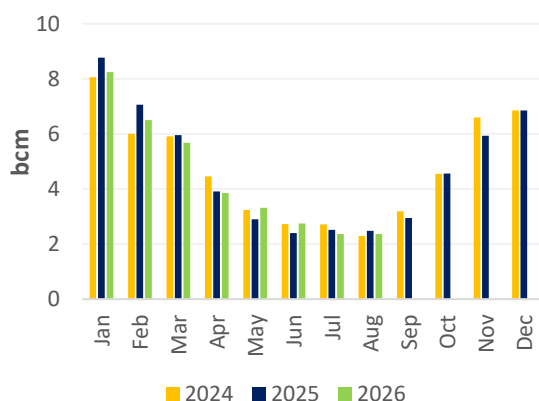
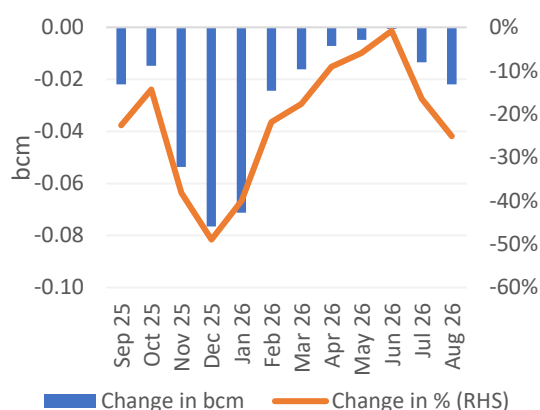


Figure 26: Trend in gas consumption in the industrial sector in the UK (y-o-y change)



Source: GECF Secretariat based on data from LSEG

For the period Jan-August 2026, aggregated gas consumption in the EU and UK increased by 1% y-o-y (2.3 bcm) to reach 242 bcm (Figure 27). The EU was the main contributor to this growth, with a y-o-y increase of 3.3 bcm (Figure 28).

Figure 27: YTD EU and UK gas consumption

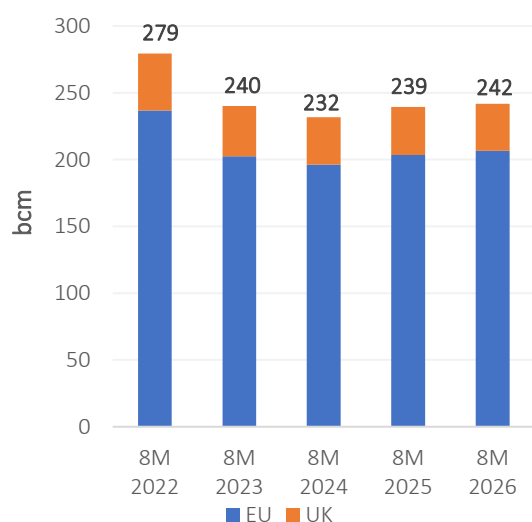
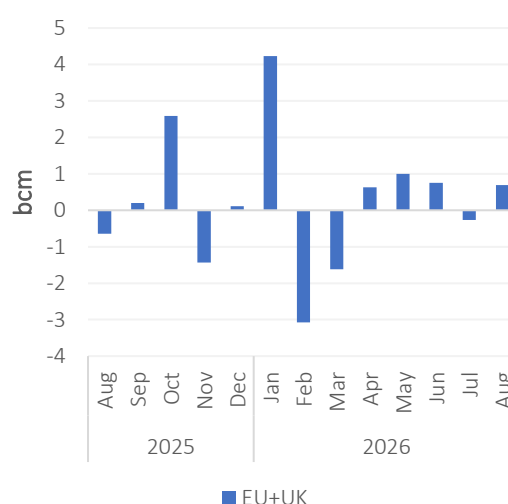


Figure 28: Y-o-y variation in EU and UK gas consumption



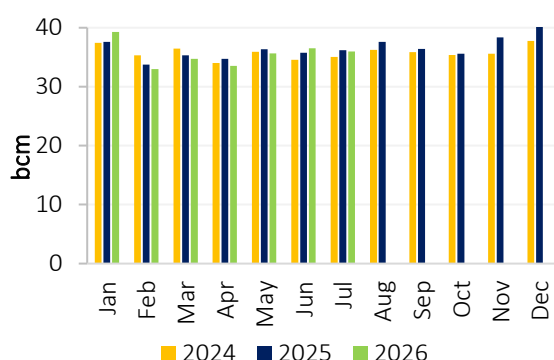
Source: GECF Secretariat based on data from LSEG

2.2 Asia

2.2.1 China

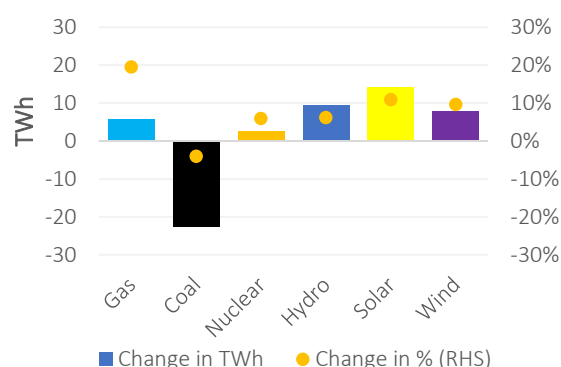
In July 2026, China's apparent gas demand (production + LNG and pipeline gas imports) declined by 0.5% y-o-y to 36 bcm (Figure 29). China's natural gas consumption is expected to exceed 550 bcm by 2030, with supply remaining broadly balanced. Industrial demand will drive around half of the growth, mainly through coal-to-gas switching, although uptake remains price-sensitive. City gas and transport will contribute around 20%, supported by LNG trucks. Gas-fired capacity is projected to reach 240 GW, but declining utilization as renewables expand will increasingly shift gas plants toward flexible peaking and balancing roles (Figure 30). For the period Jan–July 2026, Chinese gas consumption declined by 0.4% y-o-y to 249 bcm.

Figure 29: Gas consumption in China



Source: GECF Secretariat based on data from LSEG

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

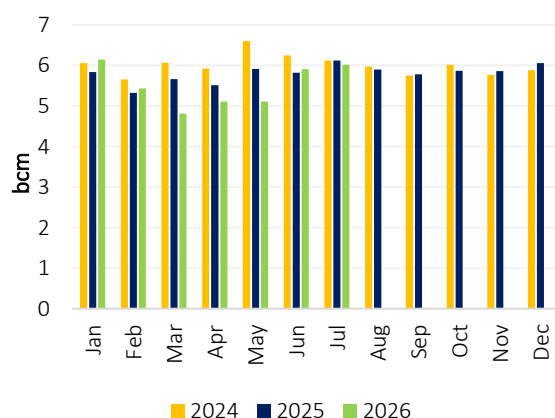


Source: GECF Secretariat based on data from Ember

2.2.2 India

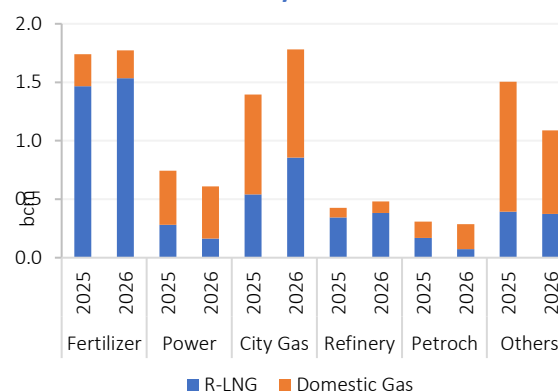
In July 2026, India's gas consumption decreased by 1.6% y-o-y to 6 bcm, driven by a huge decline in the power generation and petrochemical sectors with a drop of -18% and 7.2% y-o-y respectively (Figure 31). However, higher gas consumption was recorded in the fertilizer, city gas and refinery sectors with a rise of 2% (+0.03), 28% (+0.38 bcm) and 13% (0.05 bcm) respectively. City gas was the largest source of gas consumption with a 30% share of total demand, followed by the fertilizer sector with a 29.5% share (Figure 32). For the period Jan–July 2026, India's gas consumption declined by 4.1% y-o-y to 38.5 bcm.

Figure 31: Gas consumption in India



Source: GECF Secretariat based on data from PPAC

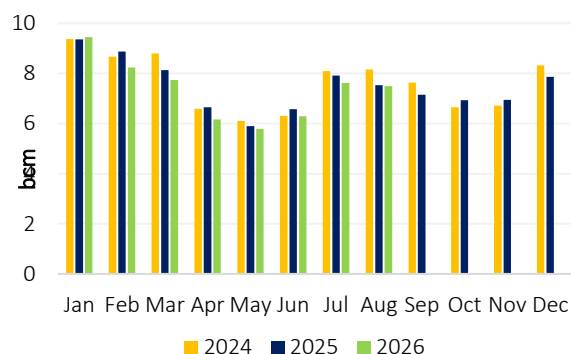
Figure 32: India's gas consumption by sector in July 2026



2.2.3 Japan

In August 2026, Japan's gas consumption declined by 0.5% y-o-y to 7.5 bcm (Figure 33). Japan's gas-fired power generation declined by 11% y-o-y to 23.1 TWh and by 7% from July, reducing LNG demand. The decline reflected 5% lower electricity demand, supported by milder temperatures and weaker industrial and business activity during the Obon holiday. Coal-fired generation decreased by 1.6% y-o-y, while nuclear output remained broadly stable, declining by 0.8%.

Figure 33: Gas consumption in Japan

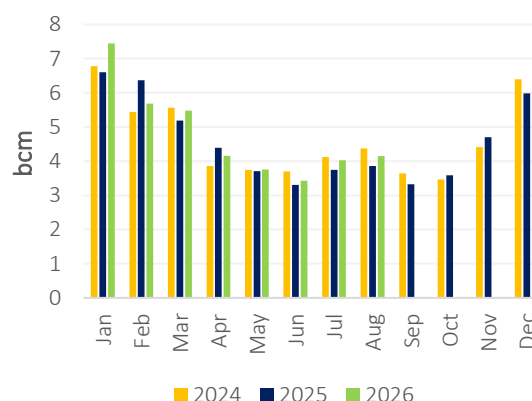


Source: GECF Secretariat based on data from LSEG

2.2.4 South Korea

In August 2026, South Korea's gas consumption increased by 7.7% y-o-y to 4.1 bcm (Figure 34). South Korea's coal-fired generation reached a five-year high of over 29.5 GW in 17–23 August, despite weaker power demand, driven by low LNG inventories and an unexpected nuclear outage. Gas-fired output fell sharply to 15.3 GW. Since April, South Korea has increasingly switched from gas to cheaper coal, with coal imports rising while LNG imports declined amid Middle East supply disruptions.

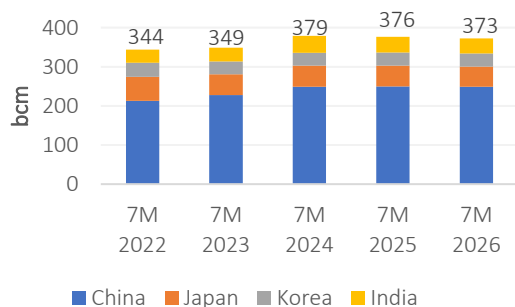
Figure 34: Gas consumption in South Korea



Source: GECF Secretariat based on data from LSEG

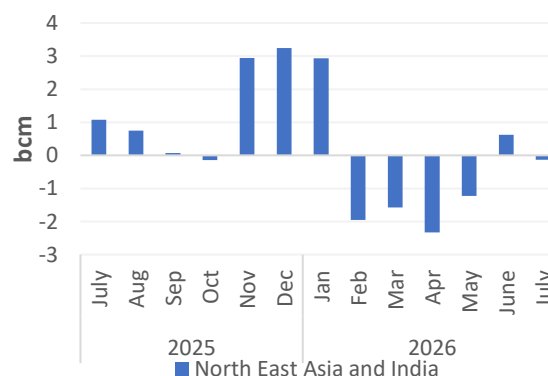
The regional aggregated gas consumption data for the period January-July 2026 in major Asian gas consuming countries, namely China, India, Japan and South Korea, declined by 3.7 bcm y-o-y to reach 373 bcm (Figure 35), driven largely by a decrease of a total of 1.8 bcm for Japan and 1.5 bcm for India (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

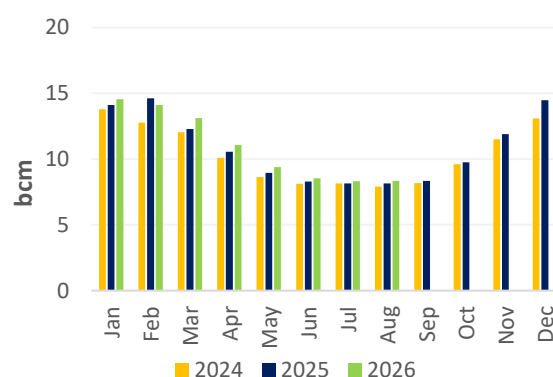


2.3 North America

2.3.1 Canada

In August 2026, Canada's gas consumption rose by 2.3% y-o-y to 8.3 bcm, supported by continued growth in industrial and power sectors (Figure 37). Gas demand from these sectors increased by 2.9% y-o-y to 7.5 bcm, reflecting sustained industrial activity and steady electricity demand. However, the residential and commercial gas consumption recorded a decline of 1.9% and 2.9% y-o-y, respectively. For the period Jan–August 2026, Canada's gas consumption increased to 87.4 bcm, up 2.7% y-o-y.

Figure 37: Gas consumption in Canada



Source: GECF Secretariat based on data from LSEG

2.3.2 US

In August 2026, US natural gas consumption increased by 2.7% y-o-y, mainly driven by stronger demand from the power generation sector (Figure 38). Gas consumption for power generation rose by 6.4% y-o-y, as widespread heatwave conditions across several regions boosted cooling needs and electricity demand. Residential gas consumption also increased by 5.3% y-o-y, while industrial gas demand declined by 1.5% y-o-y and commercial consumption fell by 7.3% y-o-y.

Total electricity generation in the US increased by 8.6% y-o-y. Gas-fired generation rose strongly by 9.6% y-o-y (+18.55 TWh), supported by elevated cooling demand during periods of high temperatures (Figure 39). Solar and wind generation also expanded significantly, both increasing by 24% y-o-y, while coal-fired output rose by 2% and nuclear and hydropower remained broadly stable. Natural gas continued to dominate the electricity mix with a 46% share, followed by coal and nuclear (15% each), solar (11%), wind (7%), hydropower (4%), and bioenergy (1%).

Figure 38: Gas consumption in the US

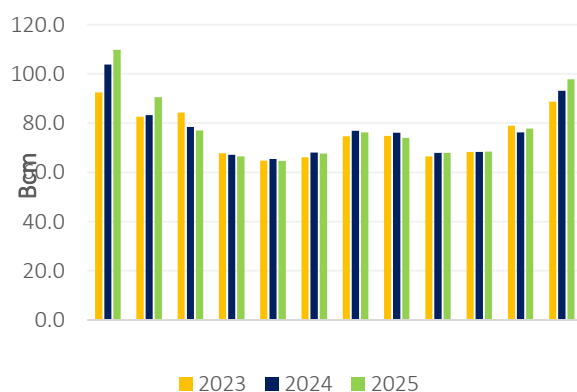
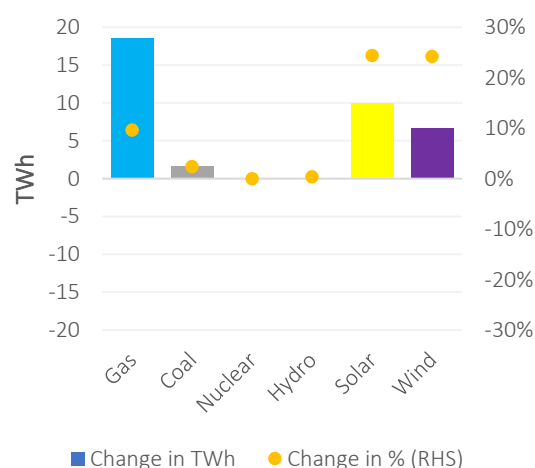


Figure 39: Electricity production in US in August 2026



Source: GECF Secretariat based on data from EIA and LSEG

For the period Jan–August 2026, US gas consumption declined by 0.5% y-o-y to 623 bcm.

2.4 Other developments

2.4.1 Sectoral developments

Senegal advances flexible power generation at Diamba Sud Gold Project: Wärtsilä will supply five Wärtsilä 32 engine generating sets for a new 14 MW captive power plant at the Diamba Sud Gold Project in Senegal. The plant will provide a reliable off-grid power supply for the remote mining operation, with generation capacity designed to respond flexibly to changing operational demand. The plant will initially operate on liquid fuel, while the selected engine technology provides flexibility for a future transition to natural gas or lower-carbon gas blends as regional infrastructure develops. The power plant is also expected to integrate solar and wind capacity, supporting greater fuel efficiency and lower emissions as the project moves towards its planned launch by the end of 2027.

US and South Korea reportedly agree on a \$22.3 billion Texas gas plant to power AI data centers: The US and South Korea have advanced discussions on a potential \$22.3 billion investment in a 6.3 GW gas fired power project in Encinal, Texas, designed to meet rising electricity demand from artificial intelligence data centers and advanced semiconductor manufacturing facilities. The project represents Seoul's inaugural initiative under the \$350 billion bilateral trade agreement and is planned in two phases, with 1.4 GW of gas turbine capacity to be followed by 4.9 GW of highly efficient combined cycle capacity. The phased approach is intended to strengthen local grid reliability, limit upfront financial risks and allow capacity to scale.

Southeast Asia data centre boom to drive structural LNG demand: Wood Mackenzie expects Southeast Asia's data centre capacity to more than triple from 2.8 GW currently to 9.4 GW by 2035, with associated electricity demand rising from 17 TWh to 57 TWh. Gas-fired generation, particularly CCGTs, is expected to play a key role in meeting data centres' 24/7 power requirements, supporting LNG demand as domestic and pipeline gas supplies decline in countries including Singapore, Malaysia and Thailand. In contrast, India's data centre capacity is projected to reach nearly 12 GW by 2035, but LNG is unlikely to gain significant ground due to the higher cost of gas-fired generation compared with renewables paired with battery storage, limited gas infrastructure and the dominance of coal and renewables in the power mix.

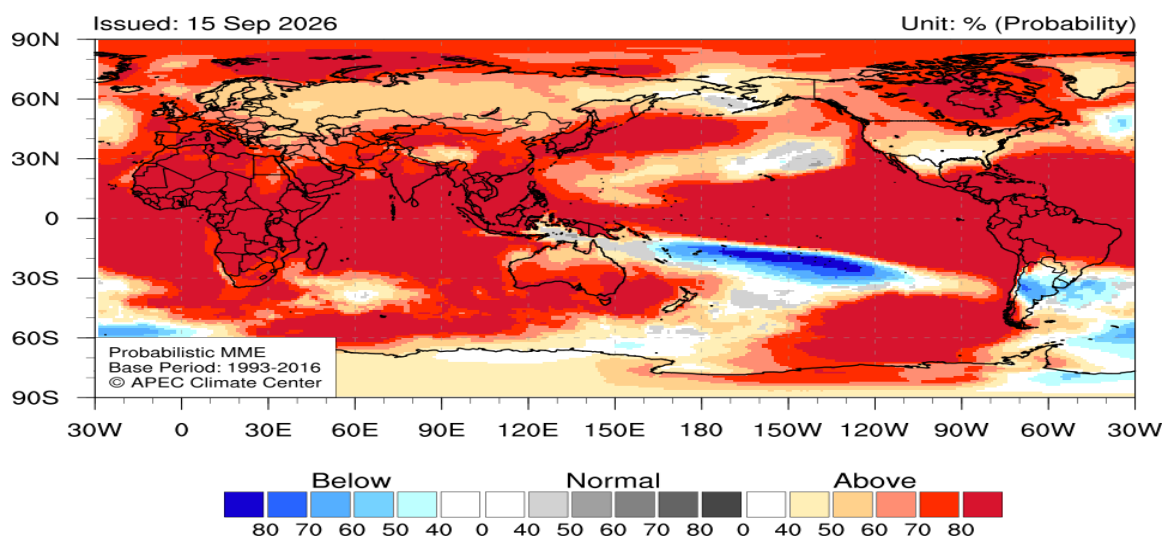
U.S. data centre boom drives surge in gas power development: The US has nearly doubled proposed gas-fired power capacity linked to data centres to 189 GW, pushing total gas-fired capacity under development to 378 GW, according to Global Energy Monitor. The \$647 billion construction plan has positioned the US ahead of China in gas power development, with Texas accounting for 122 GW of the active project pipeline. Developers are increasingly turning to reciprocating engines to avoid lengthy supply backlogs for large gas turbines, with engine capacity earmarked for data centres more than tripling to 45 GW. However, the scale and timing of the proposed projects remain uncertain amid turbine supply constraints, financing challenges, local data centre construction moratoriums and growing public opposition.

South Korea signals expansion of gas-fired power capacity: South Korea's Minister of Climate, Energy and Environment Kim Sung Hwan said the country will "inevitably" increase gas fired power capacity to support rising electricity demand from the semiconductor and artificial intelligence industries. The additional capacity is expected to provide stable power supply for major industrial projects, including semiconductor manufacturing clusters, AI data centres and aerospace complexes. The government plans to reflect the expansion in its 12th Long-Term Electricity Plan, due to be prepared by the end of October.

2.4.2 Weather forecast

According to the APEC Climate Centre, El Niño Alert is now issued for the fifth time, after three months of El Niño Watch in the last previsions. Between October-December 2026, above-normal temperatures are expected across most regions worldwide, except in some parts of the North Atlantic (Figure 40).

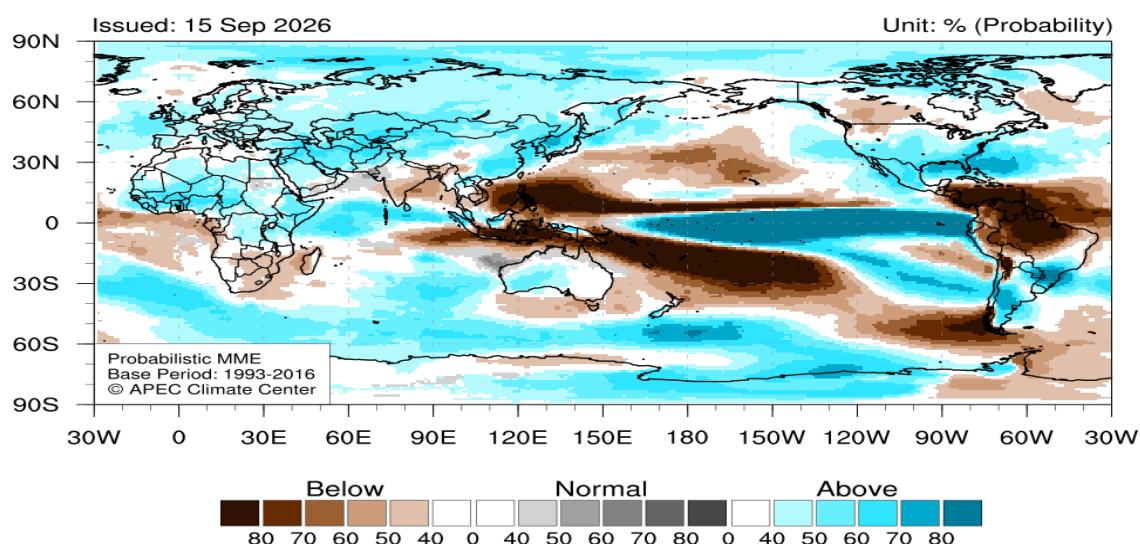
Figure 40: Temperature forecast for October-December 2026



Source: APEC Climate Center

Precipitation is expected to be above average in equatorial Pacific, southeastern South Pacific, southern South America, Arctic sea, Great horn of Africa and equatorial Indian Ocean, West and Central Asia, parts of East Asia, western USA. Below-average precipitation is forecast for the western tropical Pacific, part of Maritime continents and eastern tropical Indian Ocean, subtropical South Pacific, western tropical Atlantic, central America, Caribbean and northern part of South America, eastern tropical Atlantic, eastern and southern India, and extratropical western North pacific (Figure 41).

Figure 41: Precipitation forecast October-December 2026

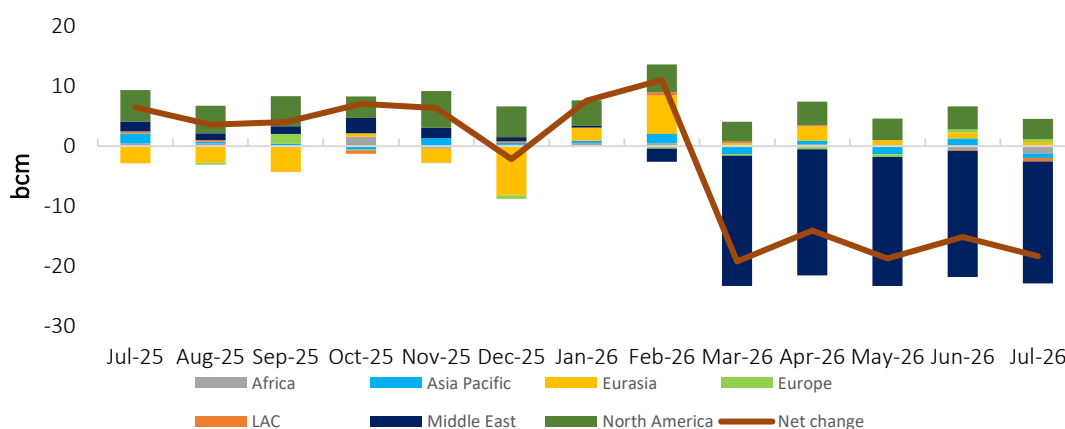


Source: APEC Climate Centre

3 GAS PRODUCTION

In July 2026, global gas production was estimated to have declined by 5.2% y-o-y to stand at 336 bcm. The contraction was primarily driven by the supply shock in the Middle East resulting from the ongoing geopolitical conflict and the closure of the Strait of Hormuz, which reduced the region's gas production by nearly one-third compared with a year earlier, largely owing to lower LNG output. By contrast, continued growth in North American gas production partially mitigated the global supply decline, with increased output in the US and Canada providing a significant offset to the disruption in the Middle East (Figure 42).

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



Source: GECF Secretariat estimation

From a regional perspective, there was a fundamental shift in the regional distribution of the global gas supply, driven by the conflict in the Middle East, with North America keeping its extending position as the frontrunner producing region (dominated by US production), accounting for 35% of global gas production (rising from 31% in July 2025), followed by Eurasia and Asia Pacific, both with 18%, whilst the Middle East share declined to 14% down from 18% in July 2025. Africa, Europe, Latin America and the Caribbean (LAC) held shares ranging from 4% to 6% (Figure 43).

For the period Jan-July of 2026, global gas production was estimated to have declined by 2.8% y-o-y to stand at 2,367 bcm (Figure 44). This decline was mainly driven by the reduction in the Middle East supply; however, it was partially counterbalanced by the strong production growth in North America and Eurasia.

Figure 43: Regional gas production in July 2026

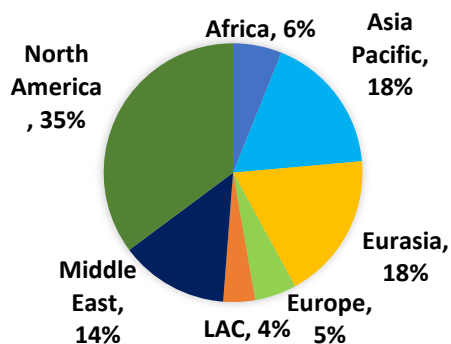
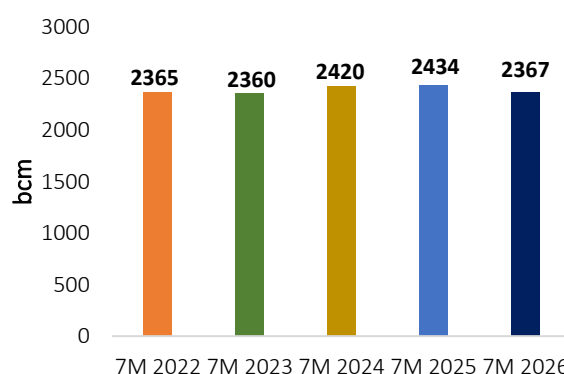


Figure 44: YTD global gas production



Source: GECF Secretariat estimation

3.1 Europe

In July 2026, gas production in Europe witnessed a 3.4% y-o-y uptick, with a total output of 14.3 bcm (Figure 45). This is the first month in 2026 to record a y-o-y increase in the European output, mainly driven by higher Norwegian production. However, the magnitude of overall European production rise in July was limited by the decrease in gas production in the Netherlands and UK (Figure 46). Notably, monthly gas production in the EU stood at 2.5 bcm (slightly lower than 2025 level), with the Netherlands and Romania maintaining their positions as top producers.

Figure 45: Europe's monthly gas production

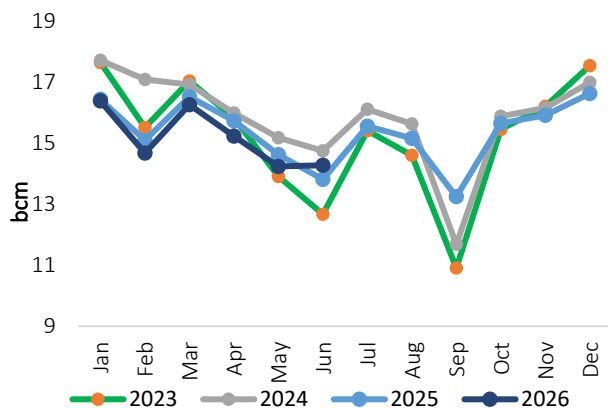
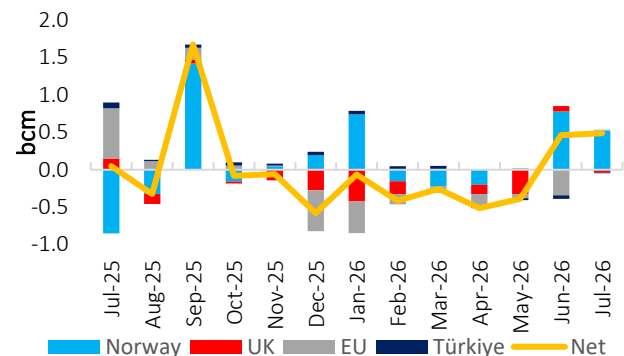


Figure 46: Y-o-y variation in Europe's gas production



Source: GECF Secretariat based on data from LSEG, the Norwegian Offshore Directorate and JODI Gas

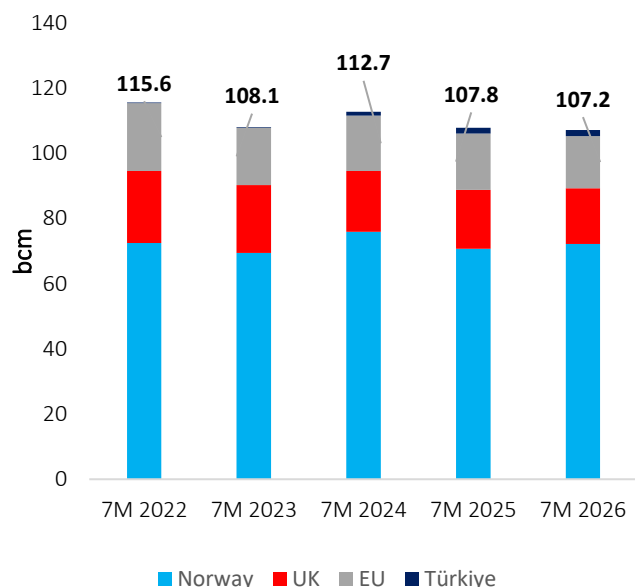
Note: EU countries include Austria, Denmark, Germany, Italy, Netherlands, Poland and Romania

For the period Jan-July of 2026, the aggregated gas output in Europe amounted to 107.2 bcm (Figure 47), representing a 0.6% y-o-y decline, compared with the production level during the same period in 2025, and recording the lowest output in the last 5-year period.

This result indicates a negative production projection in Europe for the full year of 2026. the UK and the Netherlands production decline was the main driver for the European gas production reduction over this period, while Norway - the largest European gas producer with nearly two thirds of cumulative European production –partially counterbalanced the decline, with also showing notable declines.

Denmark is on a positive trajectory trend for the full year of 2026, driven by the rise of Tyra gas field, with both Romania and Türkiye also showing positive projections.

Figure 47: YTD Europe's gas production



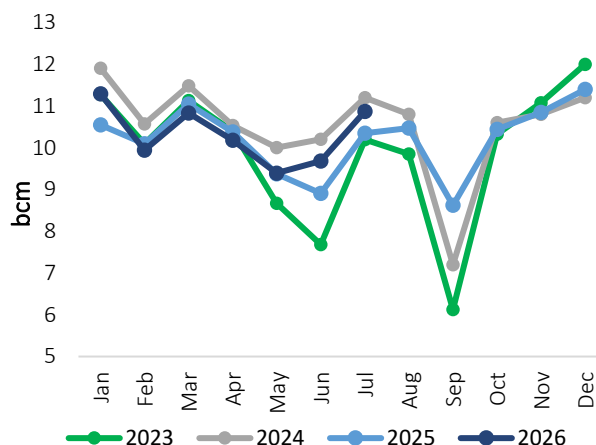
Source: GECF Secretariat based on data from Refinitiv, the Norwegian Offshore Directorate and JODI Gas

3.1.1 Norway

Norway's gas output continued its notable rise of 5% y-o-y, to stand at the level of 10.9 bcm (Figure 48). This was mainly driven by the reduced maintenance period in July, along with the base year effect. Notably, the 130 mcm/d Troll gas field witnessed reduced production for just 1 day, as a result of planned activity. In addition, the 26.4 mcm/d Åsgard gas platform underwent planned maintenance, which ceased its output for a period of 4 days.

For the period Jan-July of 2026, cumulative output amounted to 72.2 bcm, representing a 2.1% y-o-y growth, driven by lower planned and unplanned maintenance durations.

Figure 48: Trend in gas production in Norway



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

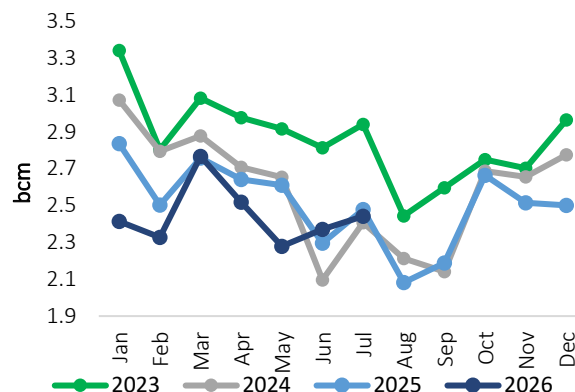
3.1.2 UK

UK gas production maintained its declining trend, to record a 1.5% y-o-y decrease to stand at 2.48 bcm (Figure 49).

This reduction took place over the past period, as a result of reduced output from the UK's mature fields, lack of new gas projects and longer than expected maintenance periods.

For the period Jan-July of 2026, cumulative output declined by 5.6% y-o-y to 17.1 bcm.

Figure 49: Trend in gas production in the UK



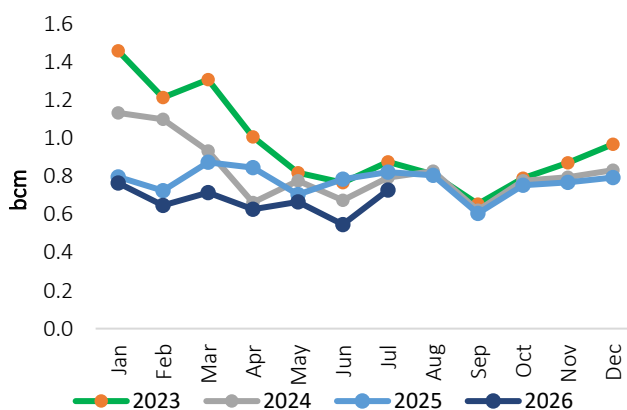
Source: GECF Secretariat based on data from LSEG

3.1.3 Netherlands

The Netherlands' annual gas production kept its downwards trend, with an 11.5% y-o-y decrease, to stand at 0.73 bcm (Figure 50).

For the period Jan-July of 2026, cumulative production in the Netherlands reached 4.7 bcm, representing a 15.5% y-o-y reduction. 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 expected to be depleted in 8 years.

Figure 50: Trend in gas production in the Netherlands



Source: GECF Secretariat based on data from LSEG

3.2 Asia Pacific

In July 2026, gas output in Asia Pacific was estimated to stand at 58.7 bcm, representing a 1.1% y-o-y decline. This decrease was driven by the reduction in Chinese gas output along with the declined output in some regional Asia Pacific producers. For the period Jan-July of 2026, the cumulative regional production reached 410.8 bcm, nearly mirroring last year's level.

3.2.1 China

In July 2026, China's gas production witnessed a slight decline in its output, after months of consistent rise in 2026, to stand at 21.4 bcm, representing a 0.7% y-o-y reduction (Figure 51). This decrease was mainly driven by the shutdown of some major offshore production platforms for maintenance activities. Coal bed methane production continued its annual growth as well, with 8.5% y-o-y rise, to stand at 1.3 bcm. For the period Jan-July of 2026, cumulative production in China reached 154.4 bcm, representing a 1.3% y-o-y growth (Figure 52).

Figure 51: Trend in gas production in China

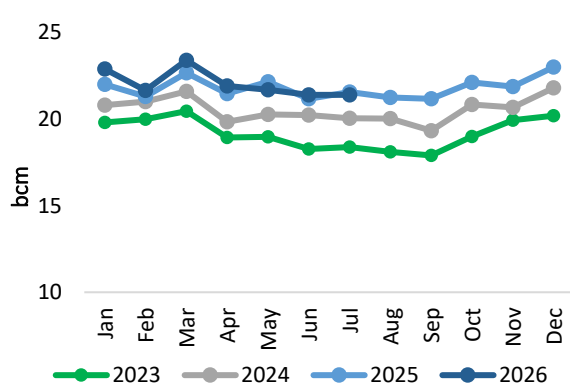
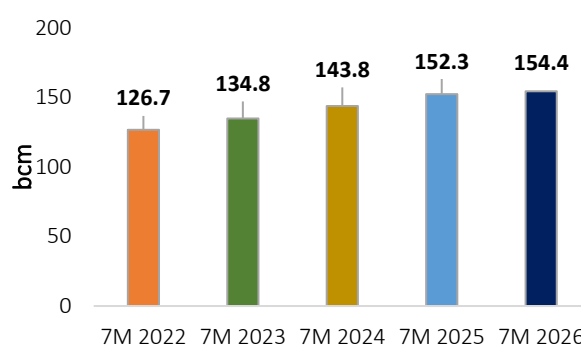


Figure 52: YTD China's gas production



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

3.2.2 India

In July 2026, India's gas production continued its negative trend, declining by 3% y-o-y to stand at 2.84 bcm (Figure 53). The decrease was driven by a reduction in offshore gas output, which represented 73% of Indian production, along with reduced production from the onshore Rajasthan field. Meanwhile, the CBM gas fields recorded a decline of 1.4% y-o-y growth, mainly from the West Bengal fields. For the period Jan-July of 2026, the cumulative production in India amounted to 19.4 bcm, representing a 4.4% y-o-y decline (Figure 54).

Figure 53: Trend in gas production in India

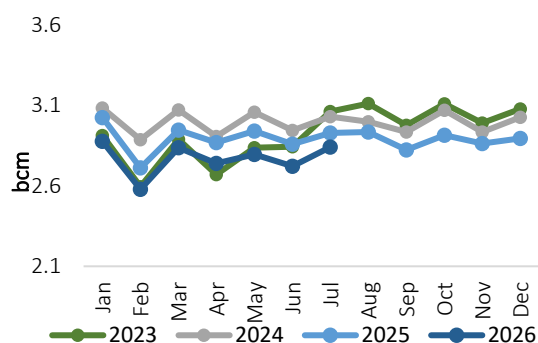
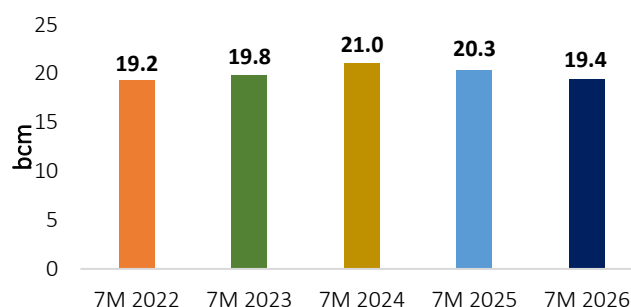


Figure 54: YTD India's gas production

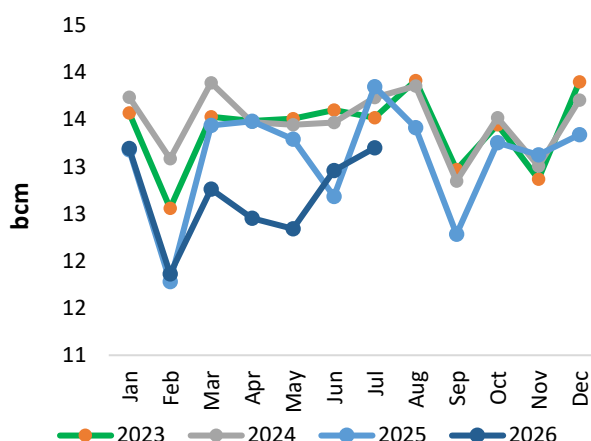


Source: GECF Secretariat based on data from the Ministry of Petroleum and Natural Gas (PPAC)

3.2.3 Australia

In July 2026, Australia's gas production declined by 4.7% y-o-y, to stand at 13.2 bcm (Figure 55). Gas production from CBM fields amounted to 3.35 bcm, representing a 0.3 % y-o-y decline and accounted for 25% of the domestic production. Notably, Australia kept its position as the global leader in terms of CBM production, with sustained growth in the past years and CBM being used as feedstock for LNG export terminals. For the period Jan-July of 2026, the cumulative production in Australia amounted to 88.8 bcm, representing a 3.2% y-o-y reduction.

Figure 55: Trend in gas production in Australia



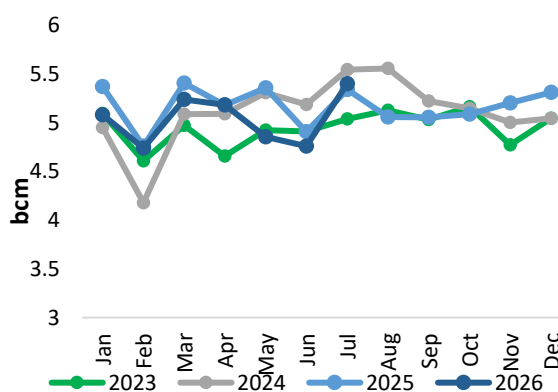
Source: GECF Secretariat based on data from the Australian Department of Energy

3.2.4 Indonesia

In July 2026, Indonesia's gas output rose by 1.1% y-o-y to 5.4 bcm (Figure 56). This was driven by an extensive development drilling campaign, with 73 new development wells drilled during the month.

Their incremental production was able to exceed the natural decline in the producing fields. In addition, 2 new exploration wells were drilled in July, which represented an acceleration for the exploration activity. For the period Jan-July of 2026, the cumulative production reached 35.3 bcm, representing a 2.9% y-o-y decline

Figure 56: Trend in gas production in Indonesia



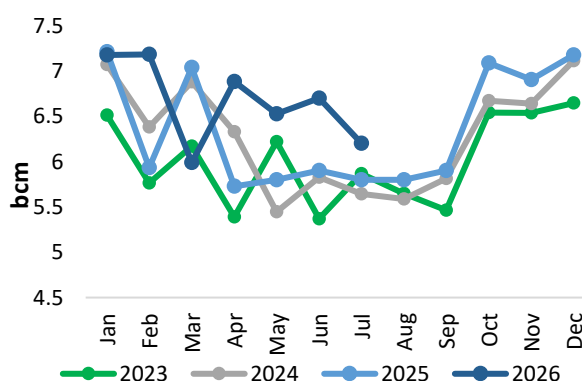
Source: GECF Secretariat based on data from SKK Migas and JODI Gas

3.2.5 Malaysia

In July 2026, Malaysia's gas output was estimated at 6.2 bcm, representing a 6.9% y-o-y production growth (Figure 57).

For the period Jan-July of 2026, the cumulative production in Malaysia reached 46.7 bcm, representing a 7.5% y-o-y growth.

Figure 57: Trend in gas production in Malaysia



Source: GECF Secretariat based on data from the JODI

3.3 North America

In July 2026, gas production in North America (including Mexico) rose by 3.6% y-o-y to reach 118 bcm, driven by strong gas supply growth in the US. For the period Jan-July of 2026, cumulative production in North America reached 797.1 bcm, representing a 3.5% y-o-y growth.

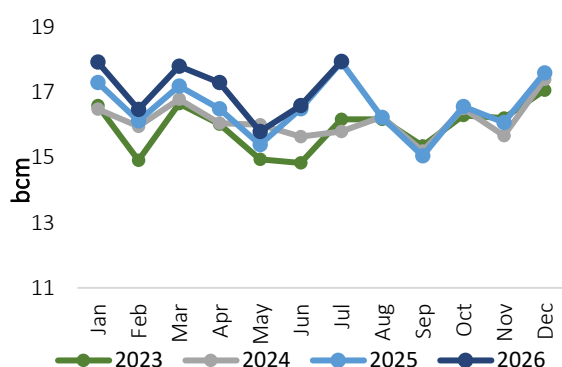
3.3.1 Canada

In July 2026, Canada's gas production grew by 0.1% y-o-y to 18 bcm (Figure 58), supported by an LNG export rise. From a regional perspective, Alberta was responsible for 10.5 bcm of the production, mainly originating from the Bakken shale production, whilst British Columbia accounted for 7 bcm, stemming from tight gas production from the Montney Basin.

For the period Jan-July of 2026, the cumulative production amounted to 120 bcm, representing a 2.5% y-o-y uptick. In this context, Canada is well poised to continue strong production growth, driven by the rising LNG exports and favourable market conditions.

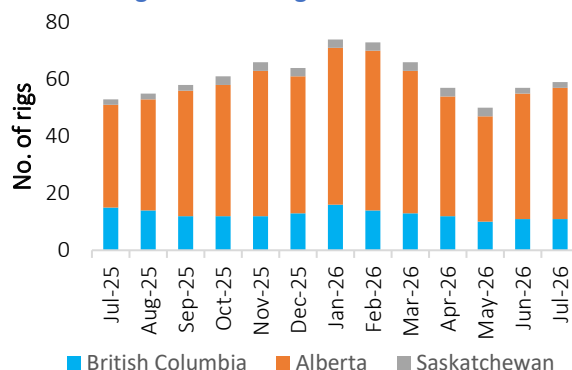
In terms of gas drilling activity, there was an overall 2-rig-increase in July 2026, with Alberta adding 2 drilling rigs, whilst British Columbia and Saskatchewan kept the same level of drilling rigs. Moreover, this represented a 6-rig-increase in the number of drilling rigs, as compared to July 2025 (Figure 59).

Figure 58: Trend in gas production in Canada



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

Figure 59: Gas rig count in Canada



Source: GECF Secretariat based on data from LSEG

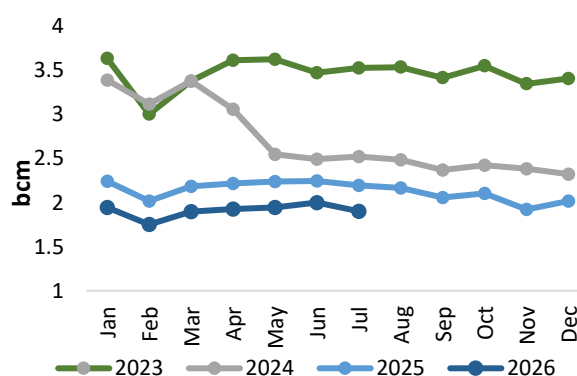
3.3.2 Mexico

In July 2026, Mexico's gas output was estimated at 1.9 bcm, representing a production decrease of 13.5% y-o-y (Figure 60). This reduction was driven by the natural decline in the Mexican legacy fields and lack of new gas field developments.

Associated gas production from oil fields represented 39% of the total Mexican production, at 0.74 bcm.

For the period Jan-July of 2026, the cumulative production in Mexico amounted to 13.4 bcm, representing a 12.9% y-o-y decline.

Figure 60: Trend in gas production in Mexico



Source: GECF Secretariat based on data from the JODI

3.3.3 US

In August 2026, US total gas production kept its consistent growth trend, with a record monthly output of 98.3 bcm, rising by 3.3% y-o-y to (Figure 61). This growth reflected the favourable market dynamics, driven by the increased Henry Hub gas prices, rising gas demand, along with the increased feed gas directed to LNG exports terminals.

In terms of supply distribution, shale dry gas production sustained its frontrunner position in the US dry gas output, accounting for 81% and represented the main driver for the growth, with a 3.5% rise, while conventional gas and associated gas production from shale oil represented the remaining 19%. In terms of field type, associated gas production accounted for about a quarter of total gas output. From a regional perspective, the Appalachian region accounted for 34% of total production, followed by the Permian region output with 25% and Haynesville with 14%.

For the period Jan-Aug 2026, cumulative gas production in the US reached 762 bcm (Figure 62), representing 4% y-o-y growth and therefore provided evidence on the positive trajectory of the US gas supply for the full year.

Figure 61: Trend in gas production in the US

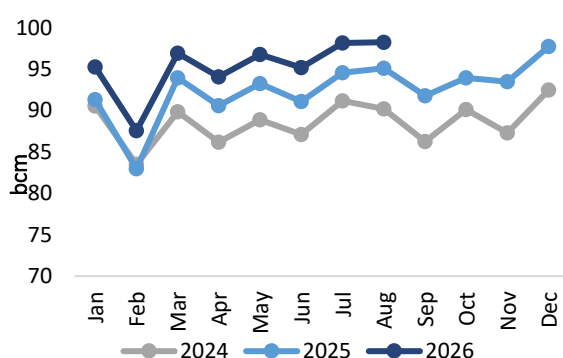
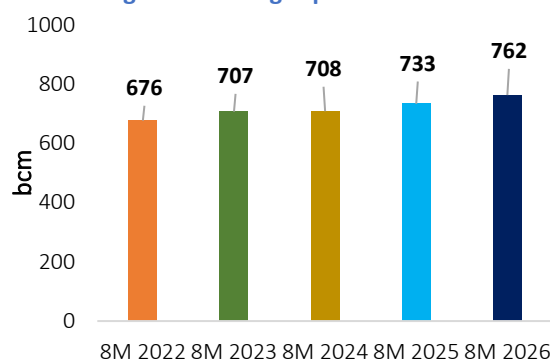


Figure 62: YTD gas production in the US



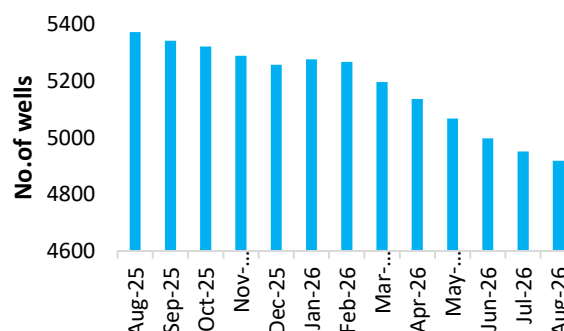
Source: GECF Secretariat based on data from the US EIA

As of August 2026, the number of gas drilling rigs operating in the US stood at 128, marking a 2-rig increase compared to July 2026, and a 6-rig rise, compared to August 2025 (Figure 63), giving evidence of accelerated upstream activity in the US. Additionally in August 2026, the total number of drilled but uncompleted (DUC) wells in the US onshore regions amounted to 4,919, marking a 32-well m-o-m decrease and 453 wells lower than August 2025 (Figure 64). This reduction in DUCs reflected the reliance of the operators on their inventory of drilled wells, targeting the benefits of bringing the gas to market, during favourable conditions.

Figure 63: Gas rig count in the US



Figure 64: 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 July 2026, gas production in LAC was estimated at 13.3 bcm (4.3% y-o-y decline), mainly driven by lower output in Argentina and Brazil. For the period Jan-July of 2026, cumulative production reached 90.3 bcm, representing a 0.4% y-o-y growth.

3.4.1 Argentina

In July 2026, Argentina's gas production stood at 4.9 bcm, representing a decline of 1.7% y-o-y (Figure 65). Most of the gas output originated from the Vaca Muerta (shale gas) Basin, however the conventional gas fields witnessed a 7% growth. Notably, shale gas production witnessed a 4.3 % y-o-y decline to stand at 2.7 bcm, accounting for 55% of total gas production (Figure 66). Moreover, tight gas production reached 0.37 bcm representing a 7.6% share of the total production, whilst the remaining output was produced from conventional fields. For the period Jan-July of 2026, cumulative production in Argentina reached 31 bcm, a 0.5% y-o-y rise.

Figure 65: Trend in gas production in Argentina

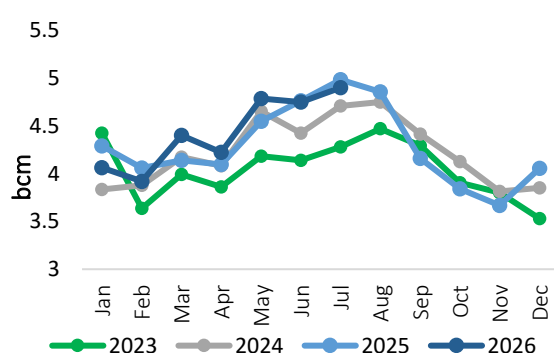
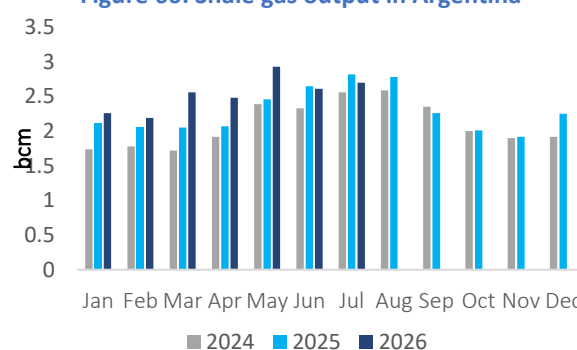


Figure 66: Shale gas output in Argentina



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

3.4.2 Brazil

In July 2026, Brazil's marketed gas production witnessed a decline of 6.4%, to achieve an output level of 1.85 bcm, driven by high gross gas production that stood at 6.7 bcm (12 % y-o-y rise) and large reinjection volumes (Figure 67), with the pre-salt fields representing 79% of the total production. Notably, 89% of production originated from offshore fields. In terms of distribution, 58% of gross gas production was reinjected into reservoirs, while there was a 29.5% reduction in flaring compared to the previous month, and a 14.8% reduction compared to July 2025. The decrease in flaring was mainly due to the completion of commissioning of the P-79 platform in the Búzios field. (Figure 68). For the period Jan-July of 2026, cumulative production reached 12.8 bcm, a 10.2% y-o-y growth.

Figure 67: Marketed gas production in Brazil

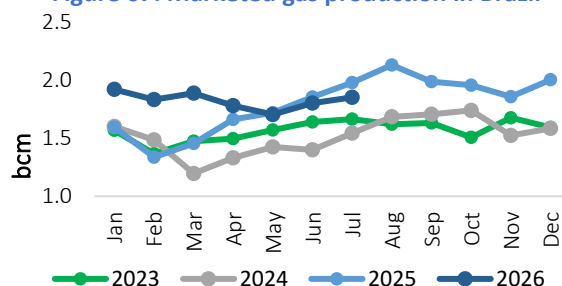
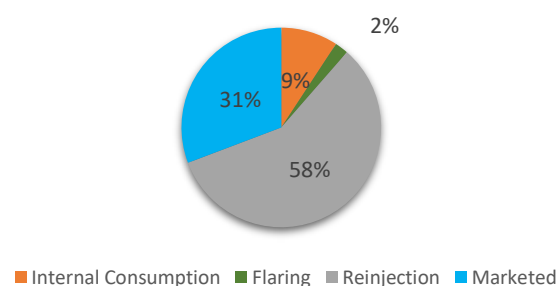


Figure 68: Distribution of gross gas production



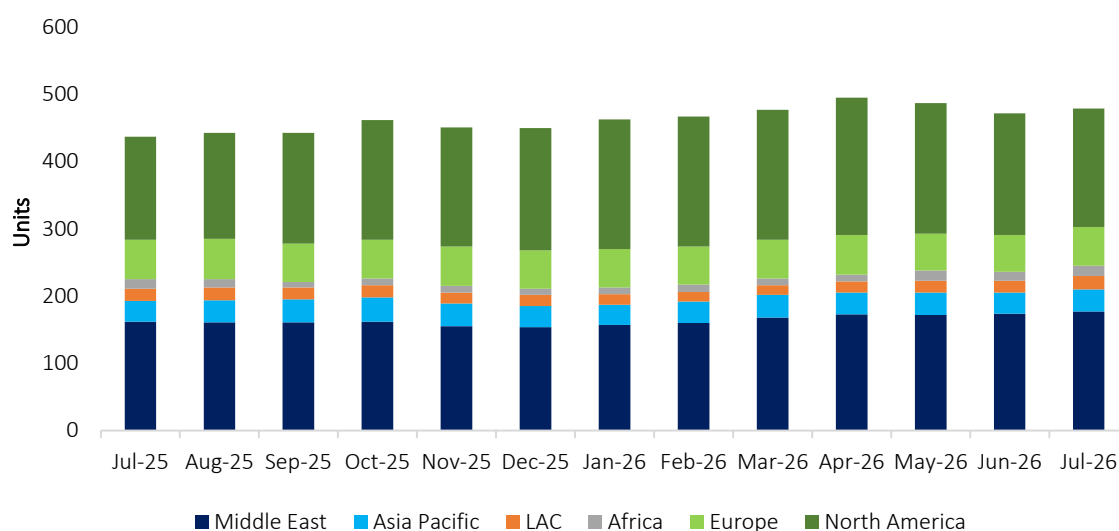
Source: GECF Secretariat based on data from the Brazilian National Agency of Petroleum (ANP)

3.5 Other developments

3.5.1 Upstream tracker

In July 2026, the number of gas drilling rigs globally accelerated by 7 additional units m-o-m, reaching 488 rigs (Figure 69). This was driven mainly by the increased drilling activity in North America, specifically in the US and Canada. Onshore drilling accounted for the majority with 455 units, while offshore accounted for 33 rigs.

Figure 69: Trend in monthly global gas rig count

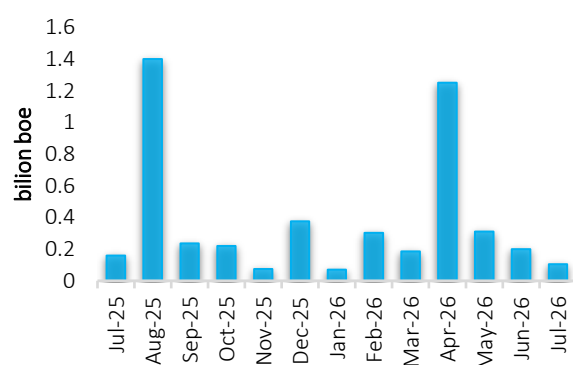


Source: GECF Secretariat based on data from Baker Hughes

Note: Figure excludes Eurasia and Iran

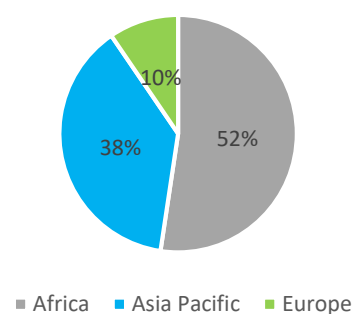
In July 2026, global exploration activity resulted in the total volume of discovered gas and liquids amounting to 105 million barrels of oil equivalent (boe) (Figure 70). with equal shares of liquids (52 million Bbl) and gas (9 bcm). Four new discoveries were announced in July and all of them were onshore. In terms of regional distribution, Africa (52%) dominated the new discoveries mainly in Nigeria and Egypt, followed by Asia Pacific with 38% (Vietnam) and Europe with 10% (Norway) (Figure 71). The Rong Doi Moi discovery, which is in the Nam Con Son Basin about 320 km southeast of Vung Tau, onshore Vietnam was the most significant gas discovery during the month. For the period Jan-July of 2026, cumulative discovered volumes reached 2.5 billion boe.

Figure 70: Monthly discovered oil and gas volumes



Source: GECF Secretariat based on data from Rystad

Figure 71: Discovered oil and gas volumes in July 2026 by region



3.5.2 Regional developments

Equinor starts production at Troll phase three, stage two in North Sea: Equinor has begun production from the Troll phase three, stage two subsea project in the Norwegian North Sea, bringing additional gas to the Troll A platform. The new output is expected to contribute to maintaining jobs and supplying high volumes of gas to Europe from both Troll A and the Kollsnes processing plant. The latest development is set to accelerate the recovery of around 55 bcm of gas from the Troll West reservoir, an amount roughly equivalent to nearly two years of France's gas demand. The Troll partnership comprises Equinor, Petoro, Shell, TotalEnergies and ConocoPhillips. Troll phase three, stage two makes use of the subsea installations established during the phase three project by applying the same design and standardised systems. Phase three began operations in 2021.

BP started production from Fayoum well ahead of schedule in Egypt: BP has started production from the Fayoum-4 well in Egypt's West Nile Delta around two years ahead of schedule, adding approximately 80 mmscf/d (0.8 bcma) of natural gas. The accelerated start-up was enabled by connecting the well to existing West Nile Delta infrastructure through the Giza-Fayoum pipeline, avoiding substantial new subsea development. The project forms part of BP's planned 1.5 billion USD investment in Egyptian gas exploration and development in FY2026/27, as Egypt seeks to reverse production declines and reduce its LNG import requirements. The development also highlights the value of infrastructure-led exploration and tie-backs in bringing new gas supplies to market quickly.

Iran announced new gas in southern Fars province: Iran has discovered an estimated 5.7 tcf of recoverable gas in the southern province of Fars, according to the Ministry of Oil. The discovered gas was described as sweet, which should reduce the cost of developing and operating the field. The discovery also contains significant volumes of condensate. This is Iran's second significant gas discovery in Fars province in two years.

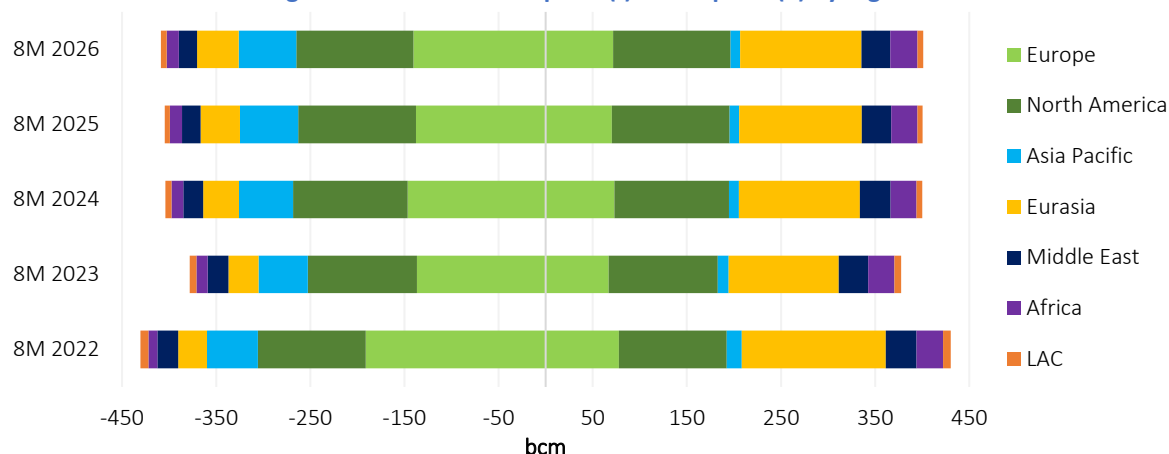
Eni announced Final Investment Decision for Cyprus' Cronos project: Eni has reached the Final Investment Decision (FID) to develop its Cronos project, in deep waters offshore Cyprus, with the target to bring the first Cypriot gas to market in 2028. The project, operated by Eni, will bring to production the gas volumes from Cronos field, in Block 6, which holds more than 3 Tcf of gas initially in place (GIIP). Production is expected to reach a plateau of 500 mmscf/d; gas will be transported and processed in existing Zohr facilities, in Egypt, then transferred and liquefied in the Damietta LNG plant for export as LNG to international markets, primarily Europe.

4 GAS TRADE

4.1 PNG trade

Cumulative global PNG imports grew by 1% y-o-y between January and August 2026, reaching an estimated 409 bcm (Figure 72). This expansion was driven by higher import volumes in the EU, Canada, and Kazakhstan, which more than offset reduced inflows into the US and China. Eurasia retained its position as the leading exporting region, capturing a 32% share of global exports in 2026, while exports from African nations posted a 3% increase y-o-y.

Figure 72: Global PNG imports (-) and exports (+) by region

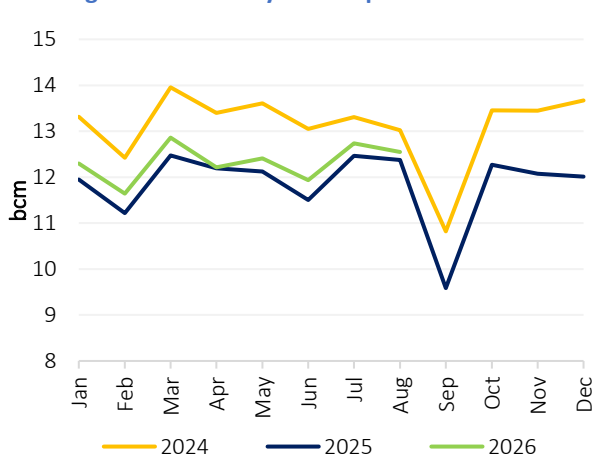


Source: GECF Secretariat based on data from Cedigaz, ENARGAS, Eurostat, GACC, JODI, LSEG and US EIA

4.1.1 Europe

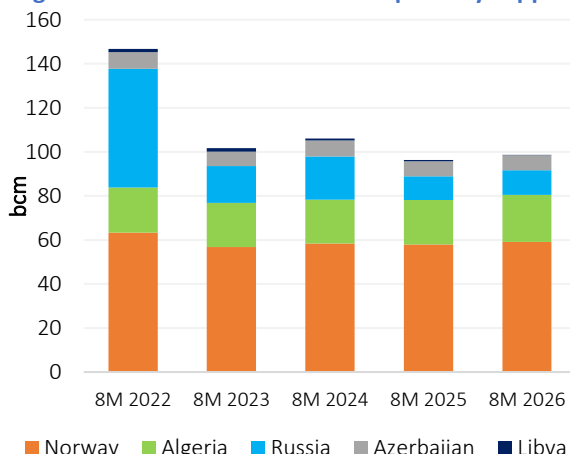
EU PNG imports rose 1% y-o-y to 12.5 bcm in August 2026 (Figure 73). Although the average daily delivery rate of 405 mmcmd represented a 1% decrease m-o-m, this brought the EU's cumulative PNG imports for the first eight months of the year to 99 bcm, marking a 2% increase y-o-y. This expansion was driven by higher supply from Norway, Algeria, and Russia (Figure 74).

Figure 73: Monthly PNG imports to the EU



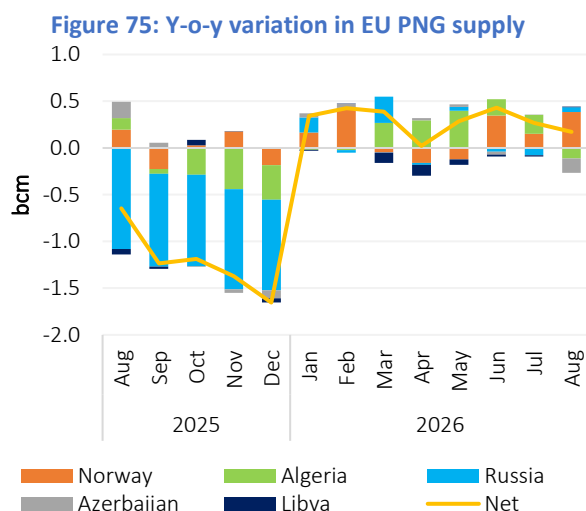
Source: GECF Secretariat based on data from LSEG

Figure 74: Year-to-date EU PNG imports by supplier

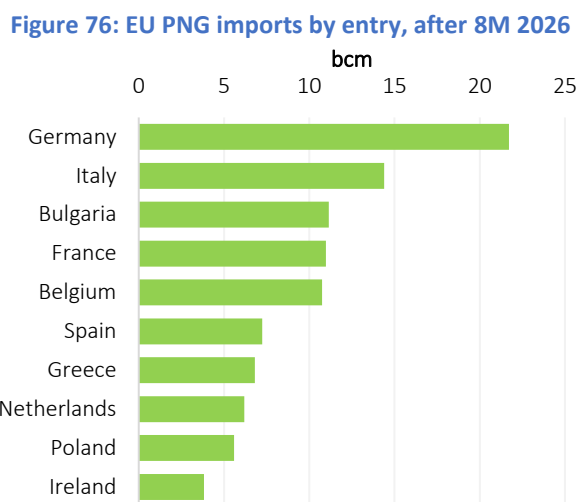


Source: GECF Secretariat based on data from LSEG

EU PNG imports posted positive net y-o-y growth in every month throughout 2026, driven by higher supplies from Algeria earlier in the year and increased volumes from Norway in recent months (Figure 75). Furthermore, a substantial monthly import volume by the Netherlands pushed its y-o-y variation into positive territory, allowing it to surpass Poland in the ranking of EU PNG entry points for 2026 thus far (Figure 76).



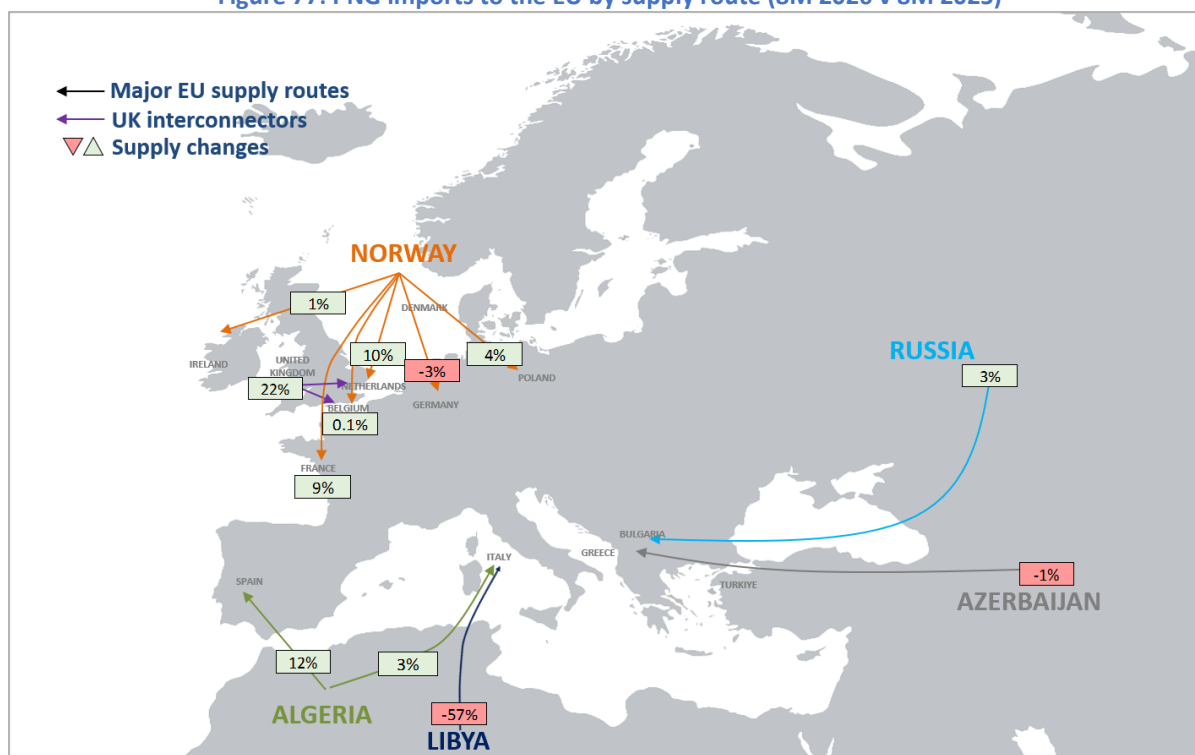
Source: GECF Secretariat based on data from LSEG



Source: GECF Secretariat based on data from LSEG

Figure 77 shows the PNG imports to the EU via the major supply routes during the 8M 2026 period, relative to the same period in 2025. Norwegian pipeline deliveries to the Netherlands increased by 10% y-o-y, while supply to France grew by 9% y-o-y. Algerian exports to Spain grew by 12%, while Russian supply via TurkStream increased by 3% y-o-y. Over the same period, the cross-border interconnectors with the UK delivered 6.2 bcm of regasified LNG into mainland Europe, marking a 22% y-o-y increase.

Figure 77: PNG imports to the EU by supply route (8M 2026 v 8M 2025)



Source: GECF Secretariat based on data from LSEG

4.1.2 Asia

China imported 6.9 bcm of PNG in July 2026, marking a 2% decline y-o-y (Figure 78). Moreover, daily deliveries averaged 224 mmcmd, reflecting a 6% m-o-m contraction. PNG comprised 48% of total July gas imports, representing just the third month in 2026 where LNG receipts surpassed pipeline supplies. Nevertheless, PNG and LNG sustained equal shares of total gas imports across the year to date. Cumulative PNG imports totalled 46.5 bcm through the first seven months, which was down 1% y-o-y (Figure 79).

Figure 78: Monthly PNG imports in China

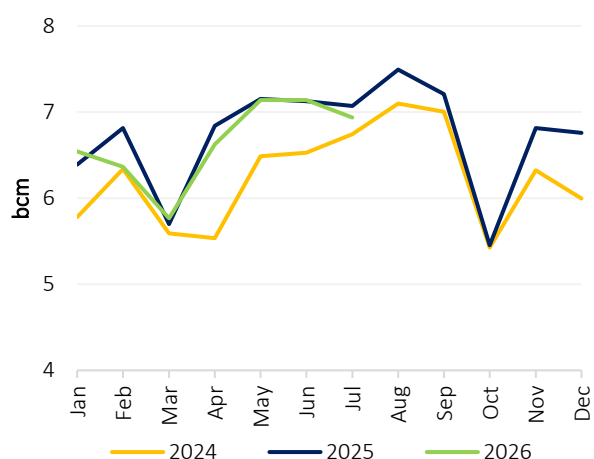
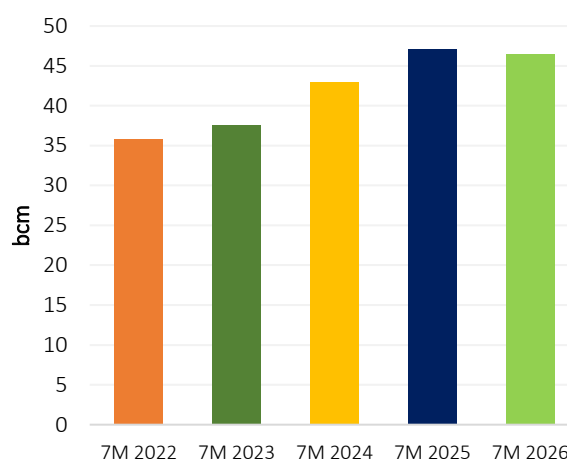


Figure 79: Year-to-date PNG imports in China



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

In June 2026, Singapore imported 0.63 bcm of PNG from Indonesia and Malaysia, rising 11% y-o-y and 1% m-o-m (Figure 80). This lifted cumulative PNG imports for the first half of the year to 3.6 bcm, up 22% y-o-y.

Concurrently, Thailand imported an estimated 0.34 bcm of PNG from Myanmar during June, dropping 16% y-o-y and 7% m-o-m (Figure 81). Consequently, Thailand's cumulative 2026 PNG imports reached 2.1 bcm, representing a 23% decrease y-o-y.

Figure 80: Monthly PNG imports in Singapore

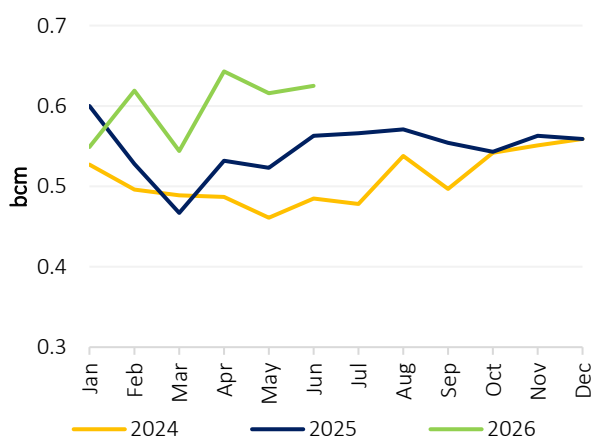
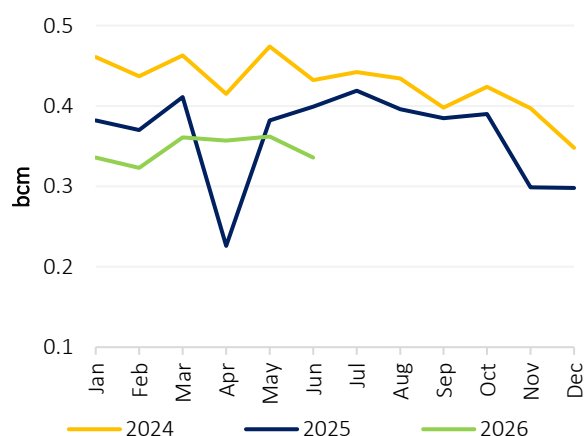


Figure 81: Monthly PNG imports in Thailand



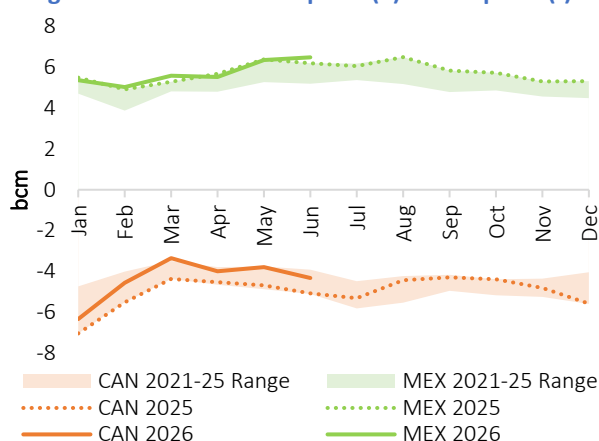
Source: GECF Secretariat based on data from JODI Gas

4.1.3 North America

Mexico imported 6.5 bcm of PNG from the US in June 2026, representing a 5% increase y-o-y and a 2% gain m-o-m (Figure 82). This volume elevated Mexico's first-half cumulative imports to 34 bcm, up by 1% y-o-y.

Concurrently, net PNG flows from Canada to the US totalled 4.3 bcm in June, down 15% y-o-y but rebounding 14% m-o-m. Gross exports from Canada to the US ticked up m-o-m to 6.4 bcm, whereas flows in the reverse direction declined m-o-m to 2.1 bcm. For the year to date, cumulative net flows from Canada to the US contracted 16% y-o-y to 26 bcm.

Figure 82: Net US PNG exports (+) and imports (-)



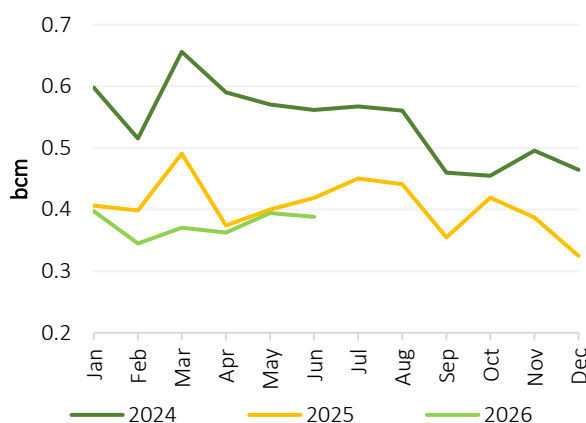
Source: GECF Secretariat based on data from US EIA

4.1.4 Latin America and the Caribbean

Bolivia's pipeline natural gas exports contracted 7% y-o-y to 0.39 bcm in June 2026 (Figure 83), although daily flows edged up 2% m-o-m. This performance brought cumulative Bolivian exports for the first half of the year to 2.3 bcm, a 9% reduction y-o-y.

Concurrently, Argentina delivered 0.26 bcm of PNG to Chile and Uruguay in June, achieving a 7% y-o-y increase despite a 6% m-o-m decline in daily shipment rates. Consequently, Argentina's cumulative exports through the first six months advanced 23% y-o-y to total 1.9 bcm.

Figure 83: Monthly PNG exports from Bolivia



Source: GECF Secretariat based on data from JODI Gas

4.1.5 Other developments

ECOWAS greenlights Atlantic Gas Pipeline project: In July 2026, member states of the Economic Community of West African States (ECOWAS) signed an intergovernmental agreement formalising support for the estimated \$25 billion Nigeria-Morocco Atlantic Gas Pipeline. Once operational, the pipeline will transport 30 bcm of natural gas annually. Of this volume, 15 bcm is expected to be directed toward domestic West African electricity, industrial, and mining development, while the remaining half will flow to Morocco and onwards to European markets via an existing link to Spain.

FERC begins review of Kinder Morgan's southeast expansion: Kinder Morgan has formally applied for federal approval of the \$1.7 billion Mississippi Crossing Project, to transport 21.7 bcma across Mississippi and Alabama. Filed with the Federal Energy Regulatory Commission (FERC) in June 2025, the project aims to meet an 8% surge in regional energy demand driven by industrial growth and the retirement of coal-fired power plants. If approved, construction is slated to begin in 2027, with the pipeline expected to be operational by November 2028.

4.2 LNG trade

4.2.1 LNG imports

In August 2026, global LNG imports declined significantly by 8.8% (3.32 Mt) y-o-y to 34.29 Mt (Figure 84). The decline was driven by weaker imports in Asia and the Middle East and Africa (MEA), while Europe's LNG imports remained broadly stable compared with a year earlier. The ongoing Middle East conflict continued to constrain global LNG trade, as restrictions on transit through the Strait of Hormuz suppressed LNG exports from Qatar and the UAE.

Between January and August 2026, global LNG imports declined by 1.2% (3.51 Mt) y-o-y to 281.75 Mt. Lower LNG supply from the Middle East amid the conflict weighed particularly on imports into Asia and Europe (Figure 85).

Figure 84: Trend in global monthly LNG imports

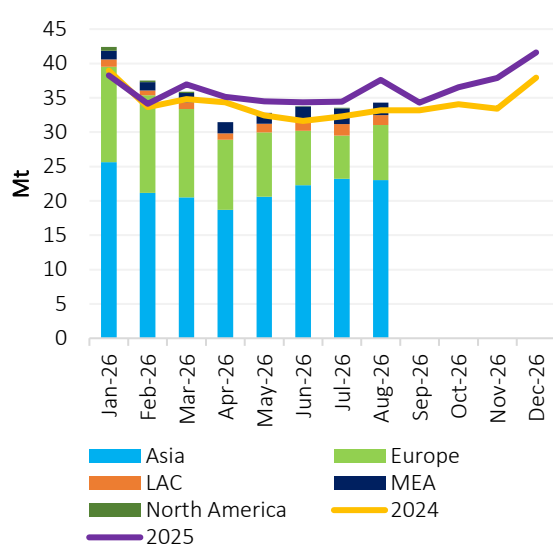
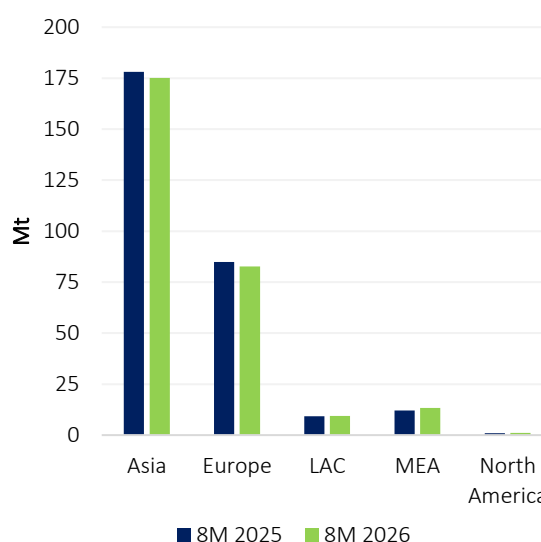


Figure 85: Trend in regional YTD LNG imports



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.1 Europe

In August 2026, Europe's LNG imports edged up by 0.5% (0.04 Mt) y-o-y to 7.99 Mt, reversing five consecutive months of y-o-y declines (Figure 86). The modest recovery was supported by a narrowing of the spot LNG price spread between Asia and Europe, which encouraged a rebound in US LNG flows to Europe after cargoes had increasingly shifted towards Asia in previous months. At the country level, higher LNG imports in Croatia, Italy and Spain drove the regional increase, offsetting declines in Belgium, France, Lithuania and Poland (Figure 87).

The increase in Croatia's LNG imports was driven by higher supplies from Norway and Trinidad and Tobago, while a significant rise in US LNG deliveries boosted imports in Italy and Spain. Conversely, lower Russian LNG supplies contributed to weaker imports in Belgium and France, as Russia's LNG exports to Europe declined y-o-y while its exports to Asia increased. In Lithuania, the decline reflected lower LNG imports from West Africa and the US, while Poland's imports fell due to reduced Qatari LNG supply amid the ongoing Middle East conflict.

For the period January to August 2026, Europe's LNG imports reached 82.65 Mt, representing a decline of 2.7% y-o-y (2.31 Mt).

Figure 86: Trend in Europe's monthly LNG imports

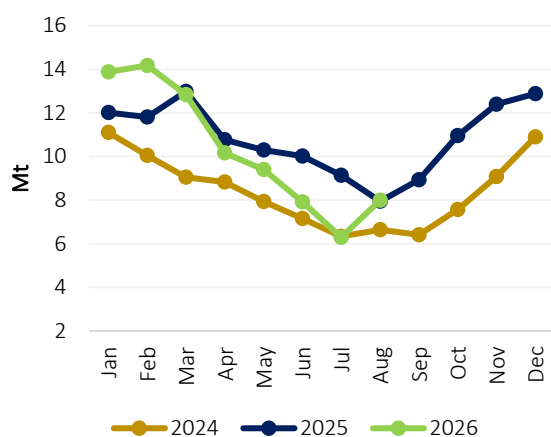
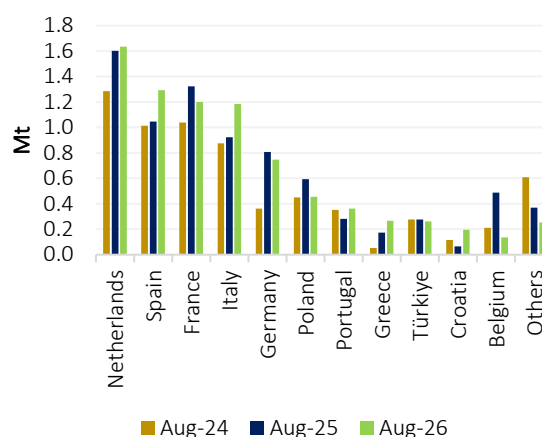


Figure 87: Top LNG importers in Europe



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.2 Asia

In August 2026, Asia's LNG imports fell by 8.2% (2.06 Mt) y-o-y to 23.04 Mt, reversing two consecutive months of growth (Figure 88). The decline was driven by a combination of lower LNG supply from Qatar and the UAE amid the Middle East conflict, a narrow Asia-Europe spot price spread and elevated spot LNG prices, which discouraged some spot LNG buying. Imports fell mainly in Bangladesh, China, Japan, Pakistan, Singapore and South Korea, while India, Indonesia, Malaysia and Thailand recorded significant increases (Figure 89).

The decline in Bangladesh's LNG imports was attributed to a technical outage at one of its floating storage and regasification units (FSRUs). Lower Qatari LNG supplies contributed to weaker imports in China, Japan, Pakistan, Singapore and South Korea, while elevated spot LNG prices also discouraged spot purchases in several North East Asian markets. Conversely, India's LNG imports increased on stronger gas demand from the fertilizer sector, while higher intra-country trade boosted imports in Indonesia and Malaysia. In Thailand, LNG imports rose on stronger gas demand for power generation, lower pipeline gas imports and stable domestic gas production.

For the period January to August 2026, Asia's LNG imports fell by 1.6% (2.89 Mt) y-o-y to 175.16 Mt.

Figure 88: Trend in Asia's monthly LNG imports

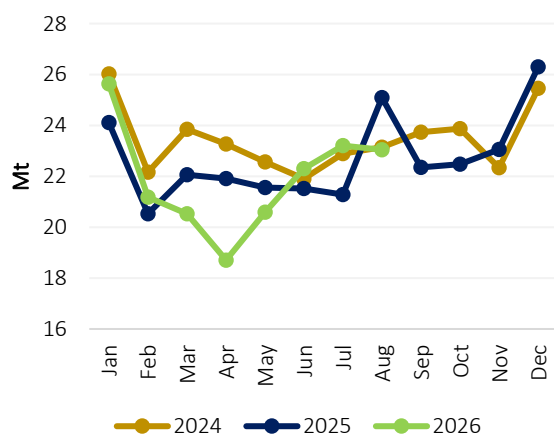
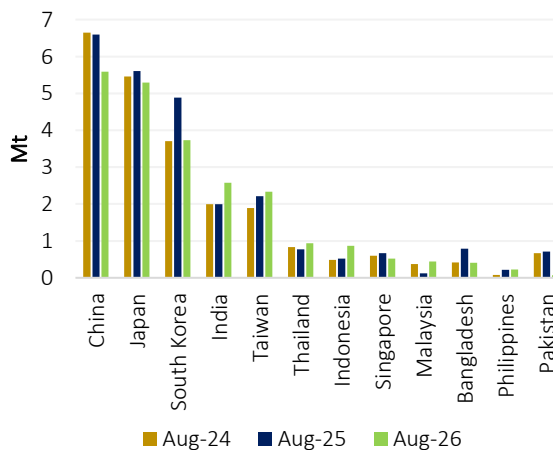


Figure 89: LNG imports in Asia Pacific by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.3 Latin America & the Caribbean (LAC)

In August 2026, LNG imports in Latin America and the Caribbean (LAC) remained stable at 1.47 Mt, unchanged from a year earlier (Figure 90). A sharp decline in Brazil's LNG imports was offset by higher imports in Colombia and the Dominican Republic (Figure 91). Furthermore, Honduras joined the club of LNG importers in August.

Brazil's LNG imports fell mainly due to an outage at the GNA II gas-fired power plant at Açú Port in Rio de Janeiro, which reduced imports through the Açú LNG terminal. Conversely, Colombia's LNG imports increased on stronger gas demand for power generation amid lower hydro levels associated with El Niño, alongside declining domestic gas production. Similarly, higher gas demand for power generation supported stronger LNG imports in the Dominican Republic.

From January to August 2026, LAC's LNG imports grew by 2.0% (0.19 Mt) y-o-y to 9.48 Mt.

Figure 90: Trend in LAC's monthly LNG imports

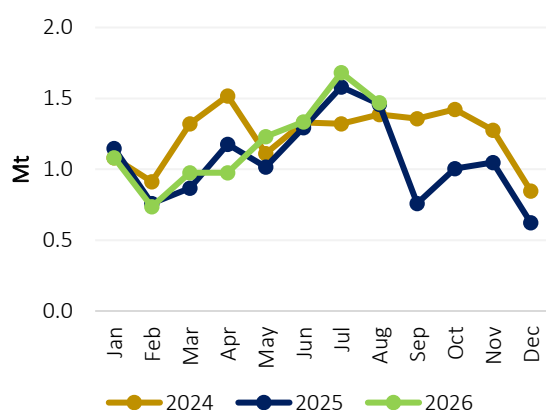
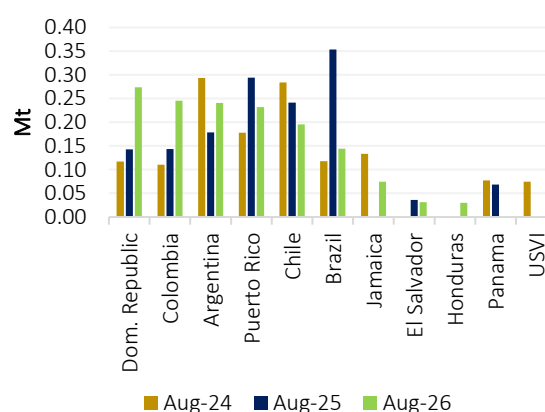


Figure 91: Top LNG importers in LAC



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.4 Middle East and Africa (MEA)

In August 2026, LNG imports in the MEA fell by 38% (1.09 Mt) y-o-y to 1.80 Mt, the first y-o-y decrease since December 2023 (Figure 92). Weaker LNG imports in Bahrain and Kuwait drove the decline, which was partially offset by higher imports in Egypt (Figure 93). The Middle East conflict has weighed on Bahrain and Kuwait's LNG imports, while robust gas demand and lower domestic gas production continue to support stronger LNG imports in Egypt.

From January to August 2026, MEA's LNG imports rose by 10% (1.25 Mt) y-o-y to 13.31 Mt.

Figure 92: Trend in MEA's monthly LNG imports

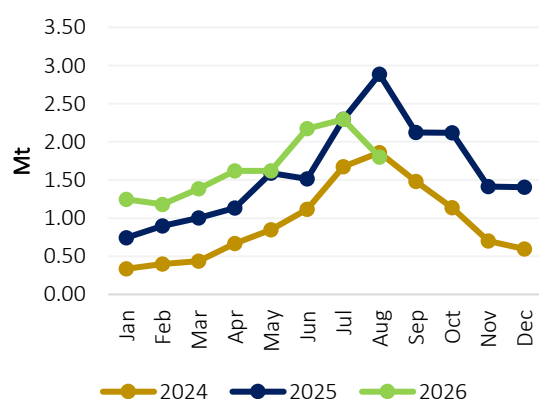
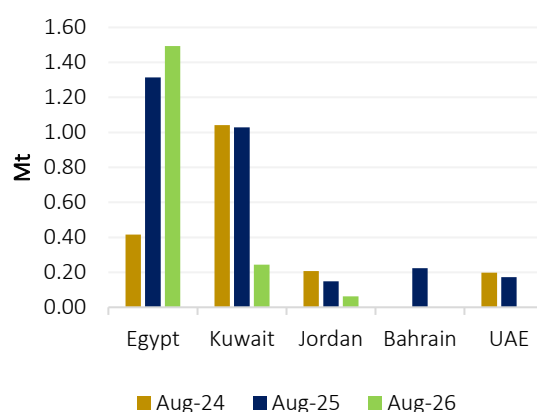


Figure 93: Top LNG importers in MEA



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2 LNG exports

In August 2026, global LNG exports declined by 6.6% (2.40 Mt) y-o-y to 33.87 Mt, although the pace of decline moderated compared with July (Figure 94). Ongoing restrictions on LNG transit through the Strait of Hormuz amid the Middle East conflict continued to constrain Middle Eastern supply and weigh on global exports. Higher exports from non-GECF countries were insufficient to offset lower exports from GECF member countries. The US, Australia and Russia were the world's three largest LNG exporters during the month.

As a result, the share of global LNG supply from non-GECF countries increased from 56.4% in August 2025 to 69.4% in August 2026, while the share of LNG re-exports edged up from 0.6% to 0.7%. Conversely, the share of GECF member countries fell sharply from 43.0% to 29.9%.

Between January and August 2026, global LNG exports declined by 1.7% (4.76 Mt) y-o-y to 279.32 Mt, driven by lower exports from GECF member countries (Figure 95).

Figure 94: Trend in global monthly LNG exports

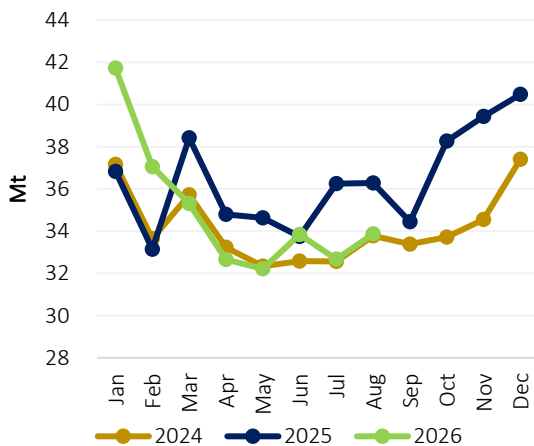
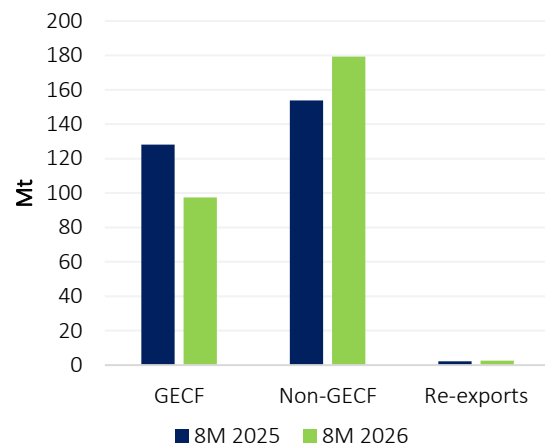


Figure 95: Trend in YTD LNG exports by supplier



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.1 GECF

In August 2026, LNG exports from GECF member countries continued to decline, falling by 35% (5.49 Mt) y-o-y to 10.12 Mt (Figure 96). The lower LNG exports were attributed to continued restrictions on LNG transit through the Strait of Hormuz, which prolonged disruptions to Middle Eastern LNG exports (Figure 97). Qatar accounted for the largest decline, while Algeria, Angola and the United Arab Emirates (UAE) also recorded lower exports. Conversely, LNG exports from Nigeria, Peru, Russia and Trinidad and Tobago increased significantly.

The escalation of the Middle East conflict and continued restrictions on LNG transit through the Strait of Hormuz significantly constrained LNG exports from Qatar and the UAE, with several laden LNG vessels idling outside Ras Laffan awaiting transit. Algeria's LNG exports declined due to lower feedgas availability, while planned maintenance at the Angola LNG facility reduced exports. Conversely, stronger feedgas availability supported higher LNG exports from Nigeria and Trinidad and Tobago, while lower maintenance activity boosted Peru's exports. In Russia, increased exports from Arctic LNG 2 and reduced maintenance at Yamal LNG drove exports higher.

For the period January to August 2026, LNG exports from GECF member countries declined sharply by 24% (30.55 Mt) y-o-y to 97.51 Mt.

Figure 96: Trend in GECF monthly LNG exports

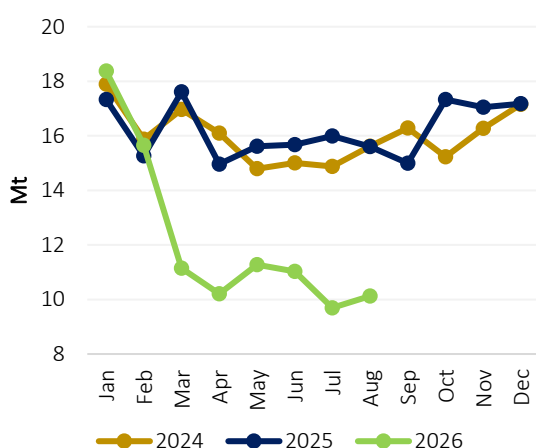
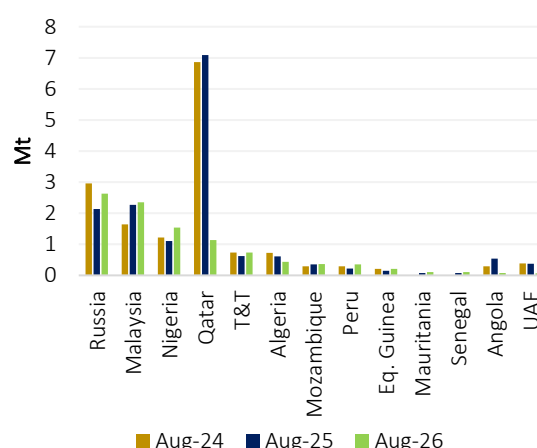


Figure 97: GECF's LNG exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.2 Non-GECF

In August 2026, LNG exports from non-GECF countries rose by 15% (3.07 Mt) y-o-y to a record monthly high of 23.52 Mt (Figure 98). The increase was driven mainly by the ramp-up of new LNG export projects, alongside stronger feedgas availability and lower maintenance activity. The US led the growth, with Australia, Canada, Republic of the Congo, Mexico and Norway also contributing to the increase, whilst Cameroon's LNG exports fell sharply (Figure 99).

In the US, LNG exports increased on the ramp-up of production at the Corpus Christi, Golden Pass and Plaquemines LNG facilities, alongside lower maintenance at Cameron and Corpus Christi LNG facilities compared with a year earlier. Australia's LNG exports rose mainly due to the continued ramp-up following the restart of Darwin LNG and lower maintenance at the Ichthys LNG facility. Meanwhile, the ramp-up of new LNG facilities boosted exports from Canada, Congo and Mexico, while reduced maintenance at Hammerfest LNG supported higher exports from Norway. Conversely, Cameroon exported its final LNG cargo in July 2026 before the Kribi FLNG vessel departed the country for redeployment to Argentina.

For the period January to August 2026, non-GECF LNG exports surged by 17% (25.54 Mt) y-o-y to reach 179.26 Mt.

Figure 98: Trend in non-GECF monthly LNG exports

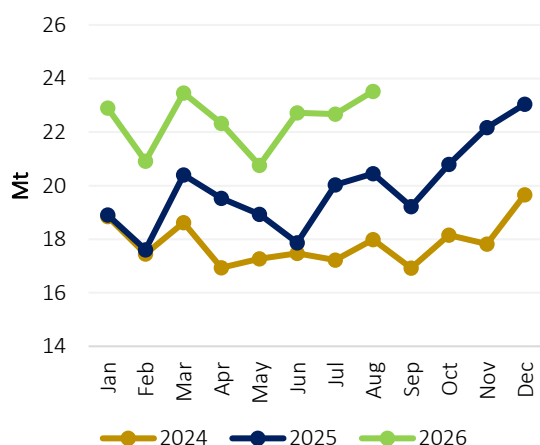
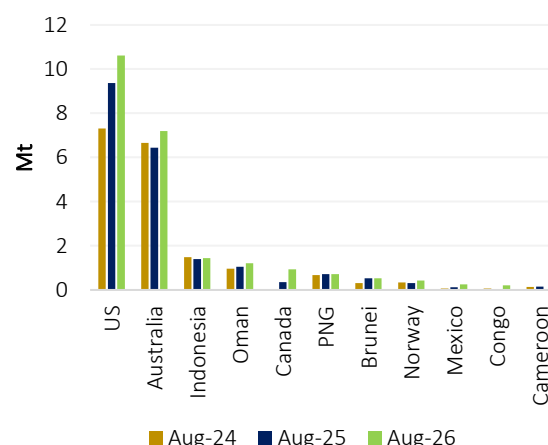


Figure 99: Non-GECF's LNG exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.3 Global LNG re-exports

In August 2026, global LNG re-exports remained relatively stable, edging up by 5.7% (0.01 Mt) y-o-y to 0.22 Mt (Figure 100). A sharp increase in re-exports from Indonesia offset declines elsewhere, particularly in Spain.

Indonesia re-exported three LNG cargoes from the Arun LNG terminal during the month, with two delivered to Japan and one to South Korea. Under its LNG storage and re-export agreement at Arun, TotalEnergies re-exported one cargo each to Japan and South Korea, while Santos delivered one cargo to Japan. Meanwhile, Spain's LNG re-exports declined amid a tighter domestic gas market, following weaker LNG imports since the onset of the Middle East conflict.

For the period January to August 2026, global LNG re-exports grew by 11% (0.26 Mt) y-o-y to 2.55 Mt. The growth was driven by higher re-exports from China and Indonesia, which more than offset declines in Brazil, Finland, Singapore and the US Virgin Islands (USVI) (Figure 101).

Figure 100: Trend in global monthly LNG re-exports

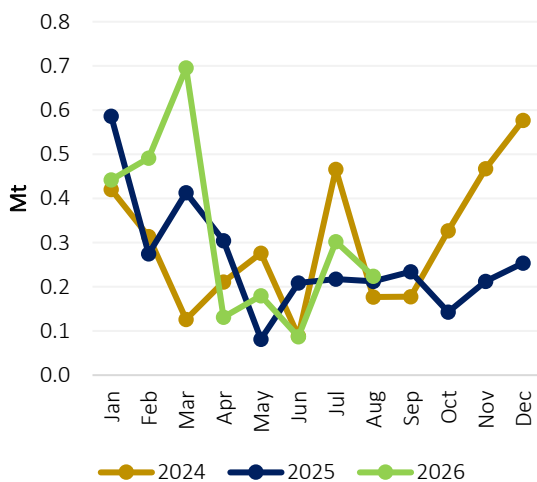
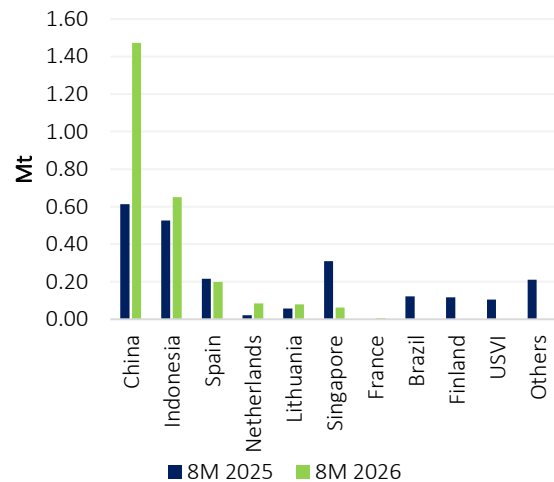


Figure 101: Global YTD LNG re-exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

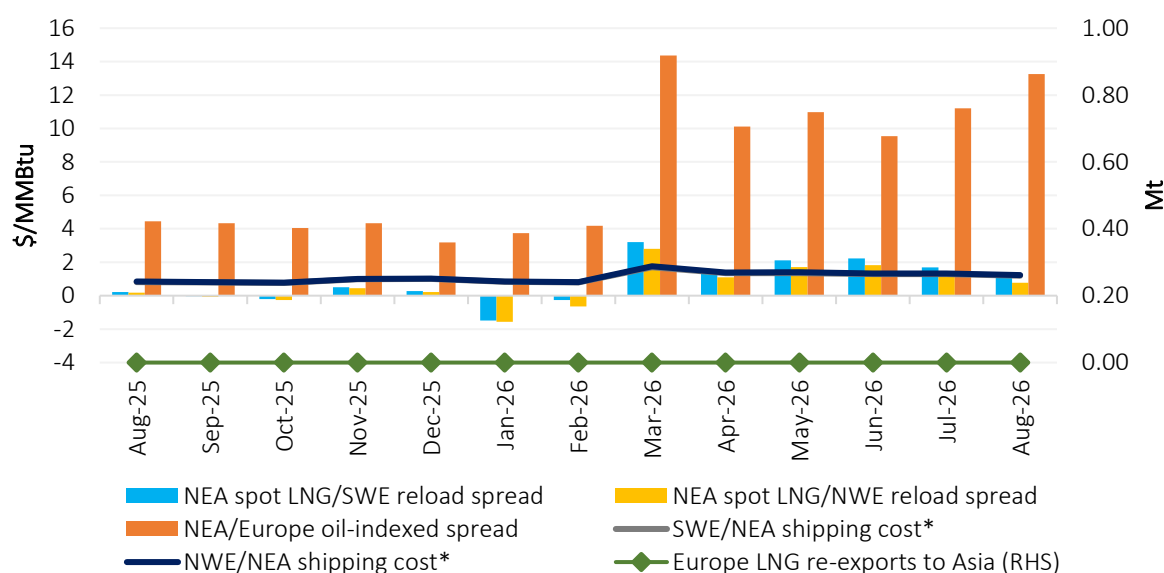
4.2.4 Arbitrage opportunity

In August 2026, arbitrage opportunities for LNG re-exports from Europe to Asia were closed, as North East Asia (NEA) spot LNG and European LNG reload prices converged, pushing the price spreads below one-way spot shipping costs from Europe to Asia (Figure 102). Conversely, the premium of the NEA spot LNG price over European oil-indexed LNG widened further above the corresponding shipping costs.

The NEA–Southwest Europe (SWE) and NEA–Northwest Europe (NWE) spreads narrowed from \$1.69/MMBtu and \$1.29/MMBtu in July to \$1.18/MMBtu and \$0.78/MMBtu in August, respectively, reflecting a stronger increase in European LNG reload prices than in the NEA spot LNG price. Meanwhile, the NEA premium over European oil-indexed LNG increased sharply from \$11.20/MMBtu to \$13.25/MMBtu, whilst one-way shipping costs from Europe to Asia declined from \$1.31/MMBtu to \$1.22/MMBtu.

Consequently, no LNG cargoes were re-exported from Europe to Asia in August. The global LNG market remained tight amid constrained Middle Eastern supply due to the regional conflict, with Asia and Europe continuing to compete for flexible LNG cargoes.

Figure 102: Price spreads & shipping costs between Asia & Europe spot LNG markets



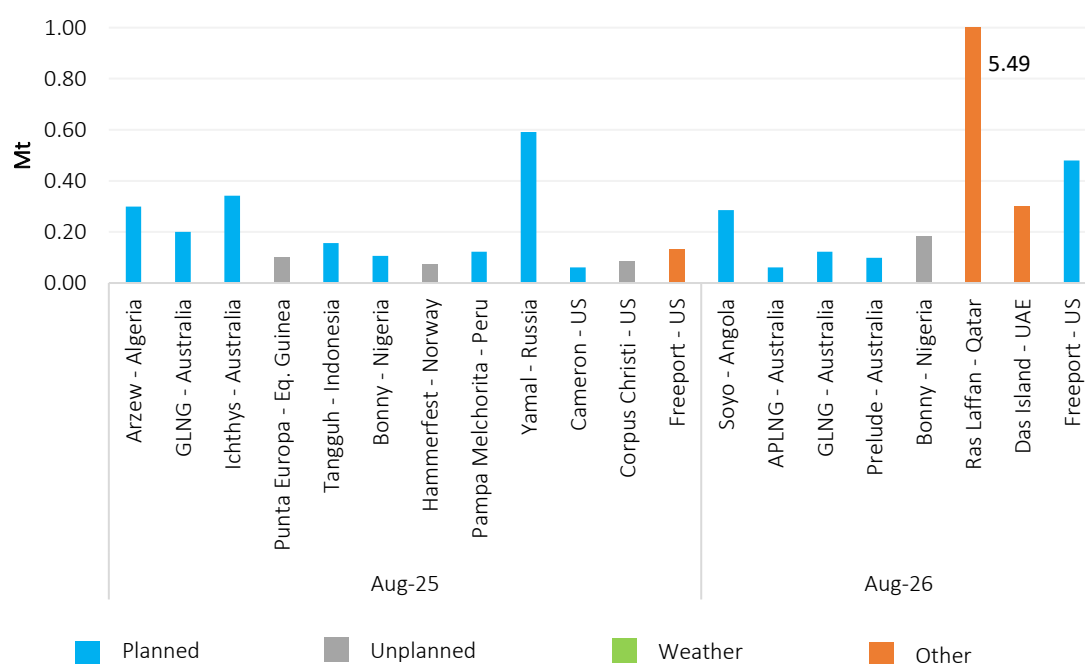
Source: GECF Secretariat based on data from GECF Shipping Model, Argus and ICIS LNG Edge

(*): One-way spot shipping costs

4.2.5 Maintenance activity at LNG liquefaction facilities

In August 2026, disruptions at global LNG liquefaction facilities, including planned maintenance, unplanned outages and other operational issues, remained elevated, rising from 2.27 Mt in August 2025 to 7.02 Mt in August 2026 (Figure 103). The significant increase was driven by restrictions in LNG transit through the Strait of Hormuz, amid the Middle East conflict, which impacted operations at Qatar's Ras Laffan and the UAE's Das Island LNG facilities. Further disruptions were caused by planned maintenance at several LNG facilities in Angola, Australia, Nigeria and the US.

Figure 103: Maintenance activity at LNG liquefaction facilities during August (2025 and 2026)

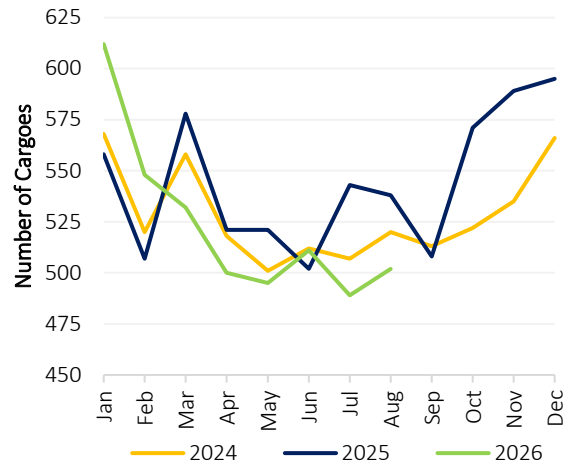


Source: GECF Secretariat based on information from Argus, ICIS LNG Edge and LSEG

4.2.6 LNG shipping

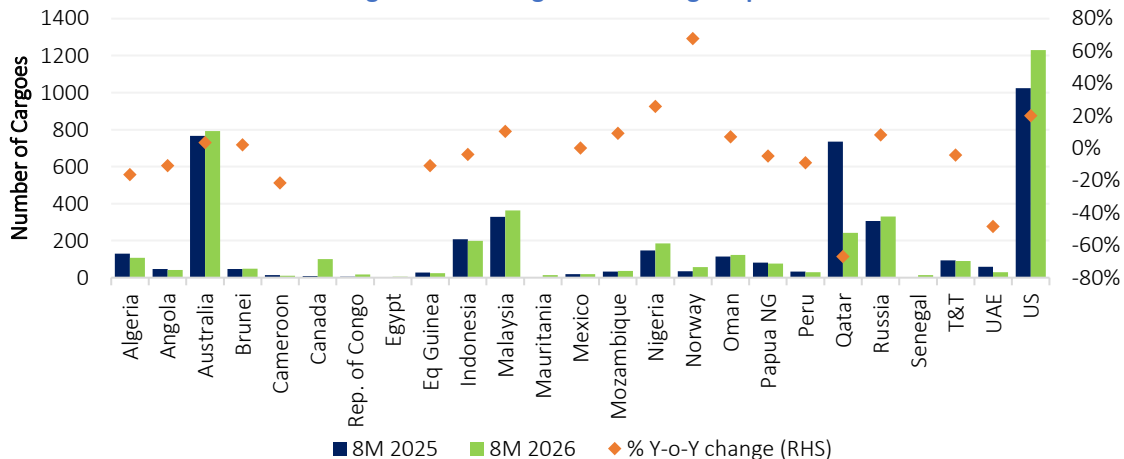
Global LNG cargo loadings rose by 13 shipments m-o-m to reach 502 in August 2026. This marked a 7% decrease y-o-y, a seasonal trend compounded by reduced loadings from Qatar and the UAE (Figure 104). Over the first eight months of the year, cumulative shipments declined by 79 cargoes to 4,189. GECF countries comprised 36% of these loadings, spearheaded by Malaysia, Russia, and Qatar. On a year-to-date basis, the United States (+206) and Nigeria (+38) posted the largest absolute gains in export cargoes, while Egypt (+400%) and the Republic of the Congo (+260%) achieved the highest percentage growth (Figure 105).

Figure 104: Number of LNG export cargoes



Source: GECF Secretariat based on data from ICIS LNG Edge

Figure 105: Changes in LNG cargo exports



Source: GECF Secretariat based on data from ICIS LNG Edge

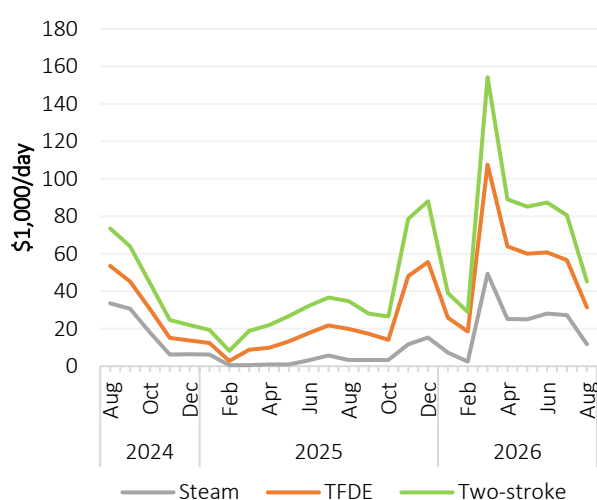
In August 2026, the LNG carrier spot charter market maintained the downward trend since rates spiked in March (Figure 106). Monthly average rates for TFDE carriers fell 45% m-o-m to \$31,400 per day, remaining 58% higher y-o-y while standing \$28,500 per day below the five-year average. Similarly, the average spot rate for two-stroke vessels decreased 44% m-o-m to \$45,100 per day, though it retained a 30% premium over the previous year. Meanwhile, steam turbine carriers experienced a steeper 57% m-o-m decline, averaging \$11,700 per day, yet still holding 255% higher y-o-y.

During August 2026, spot charter rates for LNG carriers experienced a steep and continuous decline, with fixtures returning to pre-conflict levels by late month. This sharp downturn was primarily driven by a heavily oversupplied regional fleet and a firmly closed inter-basin arbitrage. With Asian cooling demand easing and European demand rising for storage injections, cargo flows pointed heavily toward nearby Europe rather than northeast Asia. This shortened voyage lengths, sending excess vessels back to the Atlantic. Furthermore, over 100 newbuild vessels entered the market in 2026 against stagnant loading demand caused by the de facto closure of the Strait of Hormuz. The inter-basin arbitrage deteriorated so severely that round-trip equivalent rates for Asia plunged below zero, making it economically

preferable for firms to sublet excess tonnage at negative rates rather than sail east. Rates only managed to hold steady late in the month due to thin fixing activity and a lack of active chartering. Market participants are now largely looking towards upcoming winter requirements and the upcoming commissioning of the Plaquemines LNG export terminal to provide potential fundamental support later in the year.

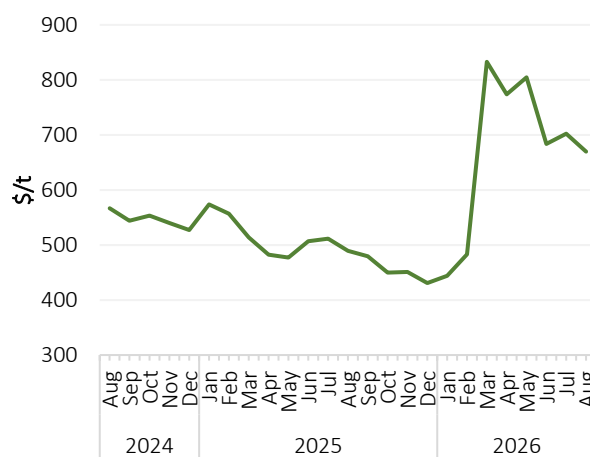
In August 2026, the average price of shipping fuels decreased by 4% m-o-m to an estimated \$670 per tonne (Figure 107). Despite this contraction, prices remained elevated at 37% higher y-o-y and 14% above the five-year monthly average, primarily driven by a sustained rally in global crude oil prices.

Figure 106: Average LNG spot charter rate



Source: GECF Secretariat based on data from Argus

Figure 107: Average price of shipping fuels

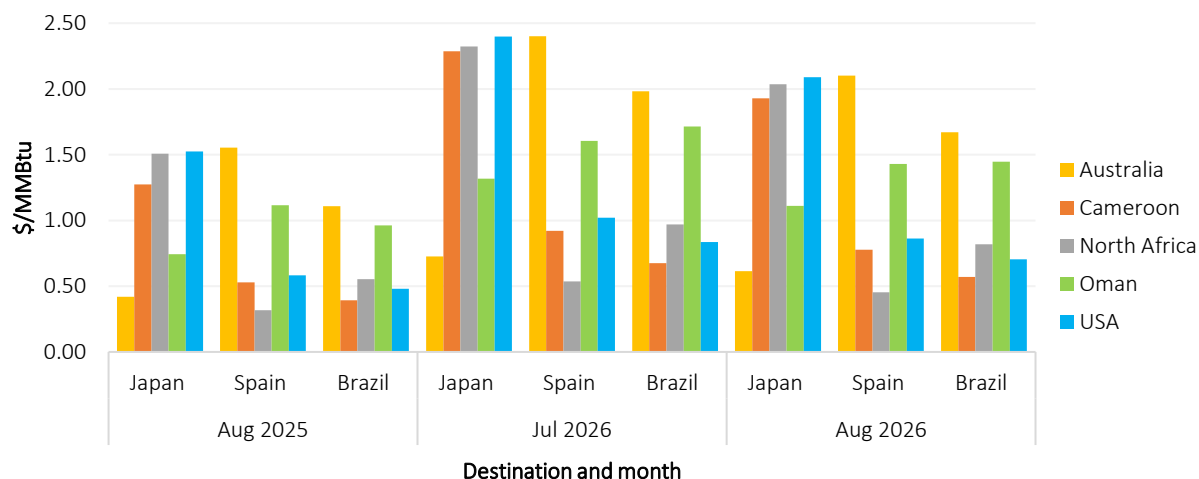


Source: GECF Secretariat based on data from Argus and Platts

There was a decrease in spot shipping costs for TFDE LNG carriers in August 2026 compared to the previous month, by up to \$0.36/MMBtu on certain routes (Figure 108). This was driven by the decreases in the monthly average spot charter rates and in the cost of shipping fuels, despite the increase in the delivered spot LNG prices.

Compared to one year ago, in August 2026 the monthly average LNG carrier spot charter rate, the cost of shipping fuels, and the delivered spot LNG prices were also all higher. As a result, spot LNG shipping costs were up to \$0.66/MMBtu higher than in August 2025.

Figure 108: Spot shipping costs for TFDE LNG carriers



Source: GECF Shipping Cost Model

4.2.7 Other developments

Honduras joins the club of LNG importers: Honduras joined the ranks of LNG-importing countries in August 2026 with the arrival of its first cargo at the 0.5 Mtpa Puerto Cortes LNG terminal. The cargo, supplied under Centrica Energy's long-term SPA with Exodus, was loaded at the Sabine Pass LNG facility in the US aboard the GasLog Windsor and arrived on 7 August. Under the agreement, Centrica Energy will supply around six cargoes annually, transferred via ship-to-ship operations to the Bilbao Knutsen floating storage unit (FSU). The LNG will supply the Brassavola power plant, which is being expanded from 150 MW to 240 MW, supporting energy diversification and security.

China's 15th Five-Year Plan targets expansion in LNG import capacity: China's 15th Five-Year Plan for natural gas targets an increase in LNG receiving capacity from around 170 Mtpa at end-2025 to 200 Mtpa by 2030, reflecting a shift in LNG terminals from import towards strategic hubs for storage, peak-shaving, supply security and as a regional hub. The target is intended to provide spare capacity and strengthen LNG's role as a strategic backup rather than signal equivalent growth in imports. The Plan also encourages gas-fired power generators to secure multi-year contracts with flexible supply provisions, highlighting the growing role of LNG in supporting peak demand, power-system flexibility and national energy security.

Golar LNG advances development of its fourth FLNG unit: Golar LNG is expanding its floating LNG (FLNG) fleet with an order for a fourth floating liquefaction unit, valued at \$2.45 billion and offering 3.5 Mtpa of liquefaction capacity, with delivery expected by end-2029. The company is in advanced charter discussions for the unit across several regions and has secured options supporting further fleet growth. A letter of intent with Seatrium Energy and an existing option with CIMC Raffles could eventually expand Golar's fleet of FLNG vessels. Golar expects to proceed gradually with additional units as contracts are secured, amid growing global FLNG demand and constraints on shipyard capacity and critical equipment.

El Nino triggers new Panama Canal restrictions: The Panama Canal Authority (ACP) is implementing new transit restrictions due to severe El Nino-induced dry conditions that have significantly depleted Gatun Lake. Effective September 4, daily transit slots for larger Neopanamax vessels will drop from ten to nine, followed by an overall daily crossing cap reduction from 36 to 32 on September 15. Although recent LNG traffic hit its highest rate since late 2023, these capacity caps are expected to halt spot-market LNG flows this autumn. Narrow price spreads between Asia and Europe fail to justify soaring auction costs, compounded by waiting times of up to 18 days. The ACP warned that further unannounced water-saving measures could follow if El Nino conditions persist into next year.

In August 2026, LNG contracting activity hit a lull, with just one (1) LNG agreement signed (Table 1).

Table 1: New LNG sale agreements signed in August 2026

Contract Type	Exporting Country	Project	Seller	Importing Country	Buyer	Volume (Mtpa)	Duration (Years)
SPA	Brunei	Brunei LNG	Brunei LNG	Japan	Japex	N/A	N/A

Source: GECF Secretariat based on Project Updates and News

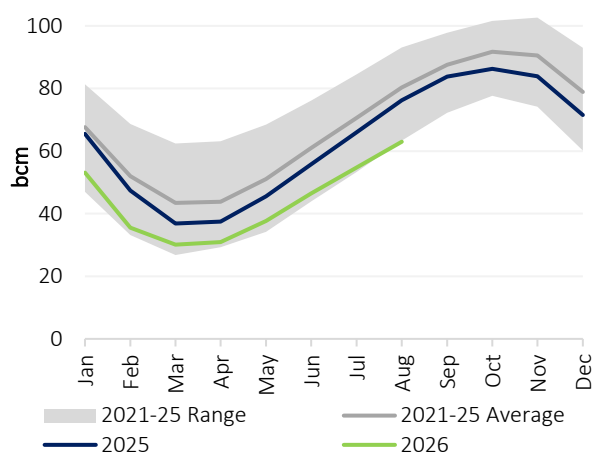
N/A: Not Available

5 GAS STORAGE

5.1 Europe

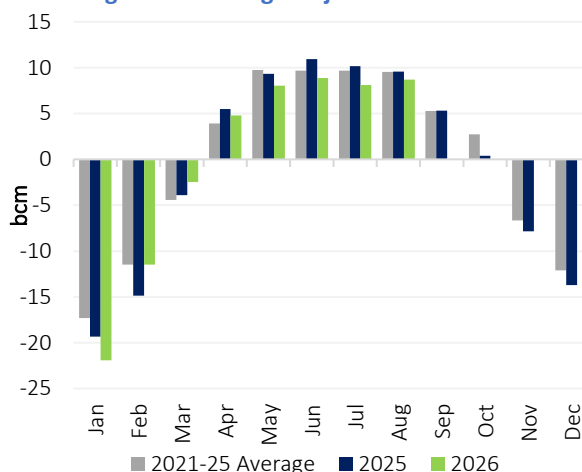
Net gas injections continued through August 2026, albeit at a slower pace than in recent years, due to ongoing tight global LNG supplies and unfavourable storage economics. The average daily volume of gas in EU underground storage rose to 63.0 bcm, up from 54.8 bcm the previous month (Figure 109). This inventory level was still 13 bcm lower y-o-y and 17 bcm below the five-year average, marking the lowest average stock level for August since 2013. Total EU stocks advanced from 58.6 bcm on 31 July to 67.4 bcm on 31 August, bringing the average regional storage fill level to 65%.

Figure 109: Monthly average UGS level in the EU



Source: GECF Secretariat based on data from AGSI+

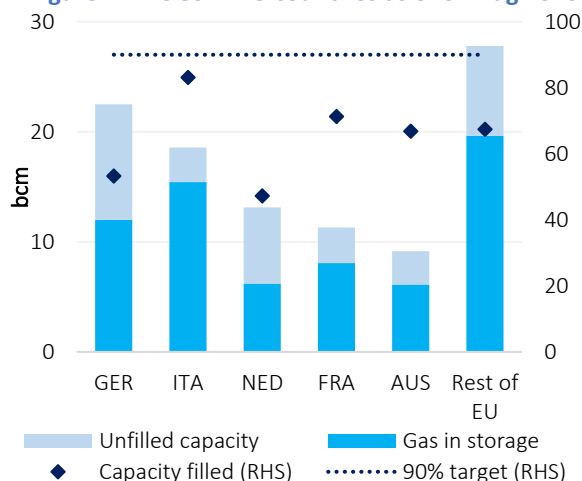
Figure 110: Net gas injections in the EU



Source: GECF Secretariat based on data from AGSI+

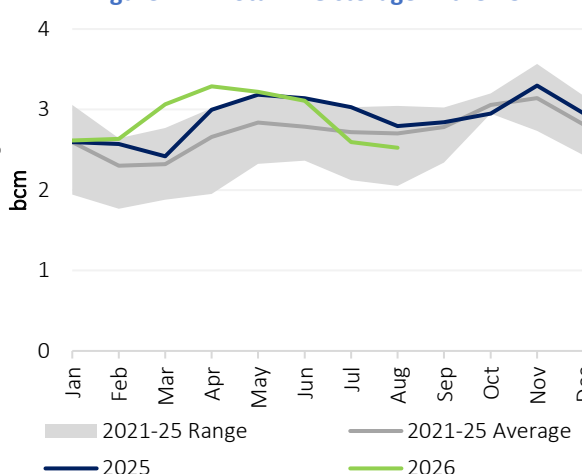
There were 8.7 bcm of net gas injections across the EU in August, down from 9.6 bcm one year prior and 9% below the five-year historical average for that month (Figure 110). France accelerated its restocking efforts to reach a 71% fill level, whereas Germany (53%) and the Netherlands (47%) continued to lag behind other major EU nations (Figure 111). EU LNG storage averaged 2.5 bcm during the month, representing 45% of total capacity, which was down 10% y-o-y and 7% below the five-year monthly average (Figure 112).

Figure 111: UGS in EU countries as of 31 Aug 2026



Source: GECF Secretariat based on data from AGSI+

Figure 112: Total LNG storage in the EU

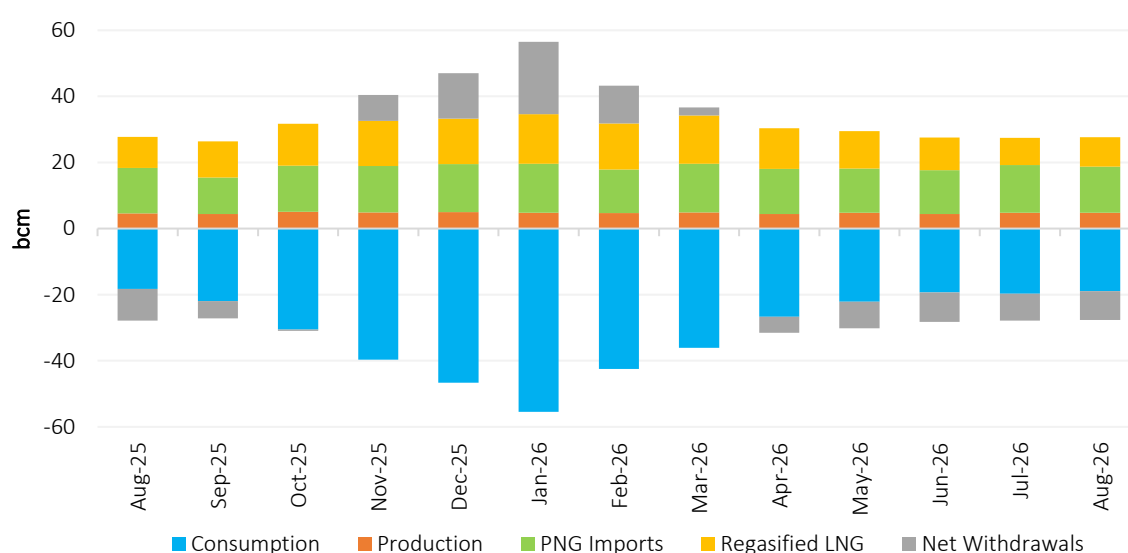


Source: GECF Secretariat based on data from ALSI

Market conditions have shifted slightly in recent weeks as narrowing spreads provide some relief to storage economics, yet the EU's energy balance remains fundamentally vulnerable. While improving winter-summer price differentials have begun to restore commercial margins for gas injections across the continent, a persistent JKM-TTF price gap continues to attract flexible LNG shipments toward lucrative Asian buyers. This development has kept inventory replenishment rates constrained through August 2026, while the outlook for the remainder of the injection season points to continued supply tightness.

In August 2026, external gas imports represented 83% of combined EU and UK gas supply, slightly below 84% a year earlier, while domestic production covered the remaining 17% (Figure 113). PNG strengthened its position as the primary supply source, increasing its share from 50% to 51%. Conversely, regasified LNG send-out accounted for 32% of regional gas supply, down from 34% in August 2025, as European buyers continued to face strong competition from Asian markets for flexible, uncommitted spot LNG cargoes.

Figure 113: EU + UK monthly gas balance



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

Table 2 outlines the EU and UK gas supply and demand balance for August 2026.

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

	2025	Aug-25	Aug-26	8M 2025	8M 2026	Change* y-o-y	Change** 2026/2025
(a) Gas Consumption	378.23	18.30	18.96	239.41	241.00	4%	1%
(b) Gas Production	58.90	4.57	4.75	39.53	37.58	4%	-5%
Difference (a) - (b)	319.33	13.73	14.21	199.88	203.42	3%	2%
PNG Imports	162.14	13.79	14.03	108.69	111.40	2%	2%
Regasified LNG	147.08	9.35	8.87	95.92	94.11	-5%	-2%
Net Withdrawals	8.46	-9.58	-8.72	-7.39	-2.64	-9%	-64%
Variation	1.64	0.17	0.03	2.66	0.55		

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

(*): y-o-y change for August 2026 compared to August 2025

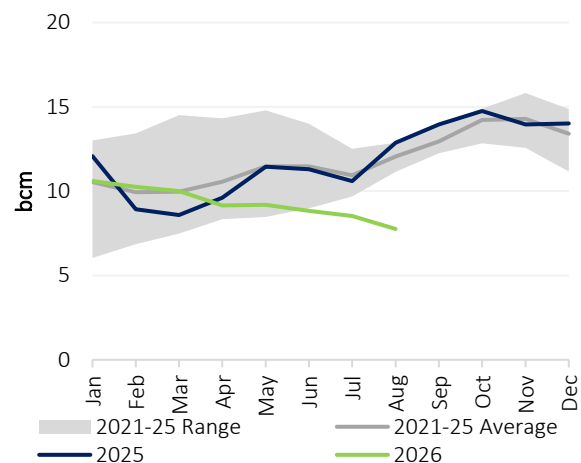
(**): y-o-y change for 8M 2026 compared to 8M 2025

5.2 Asia

In August 2026, combined LNG inventories in Japan and South Korea declined by 9% m-o-m to an estimated 7.8 bcm (Figure 114). These reserves sat 40% lower y-o-y and lagged 4.3 bcm behind the five-year average.

In Japan, estimated storage levels fell 19% y-o-y to reach 4.9 bcm, driven by heightened gas-for-power generation for summertime air-conditioning load, as well as cautious inventory management by utilities ahead of the winter heating season. South Korea experienced a 58% decline y-o-y to stand at an estimated 2.9 bcm, driven by constrained LNG procurement.

Figure 114: LNG in storage in Japan and South Korea



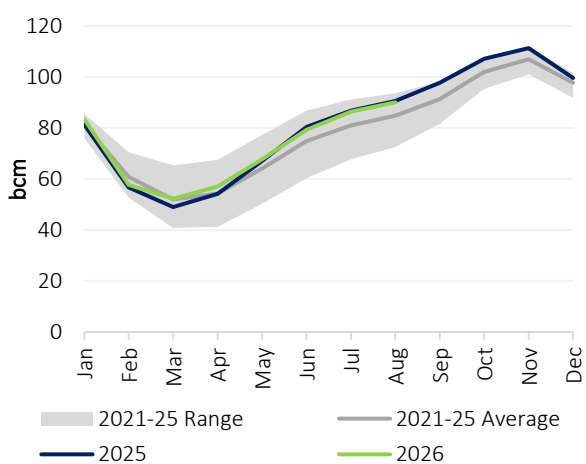
Source: GECF Secretariat based on data from LSEG

5.3 North America

The US progressed its gas injection season through August 2026, as average UGS volumes climbed to 90.0 bcm from 86.4 bcm the previous month (Figure 115). This total was lower 0.5 bcm y-o-y, but was 5.3 bcm above the five-year historical average, lifting average UGS capacity utilization to 67%.

Driven by strong summertime gas-for-cooling demand, net monthly restocking reached 2.7 bcm, falling short of the 3.9 bcm injected in August 2025 and the five-year average August injection of 3.8 bcm. This brought cumulative summer restocking for 2026 to 40 bcm, slightly behind the 44 bcm accumulated by the same point in the previous year.

Figure 115: Monthly average UGS level in the US



Source: GECF Secretariat based on data from US EIA

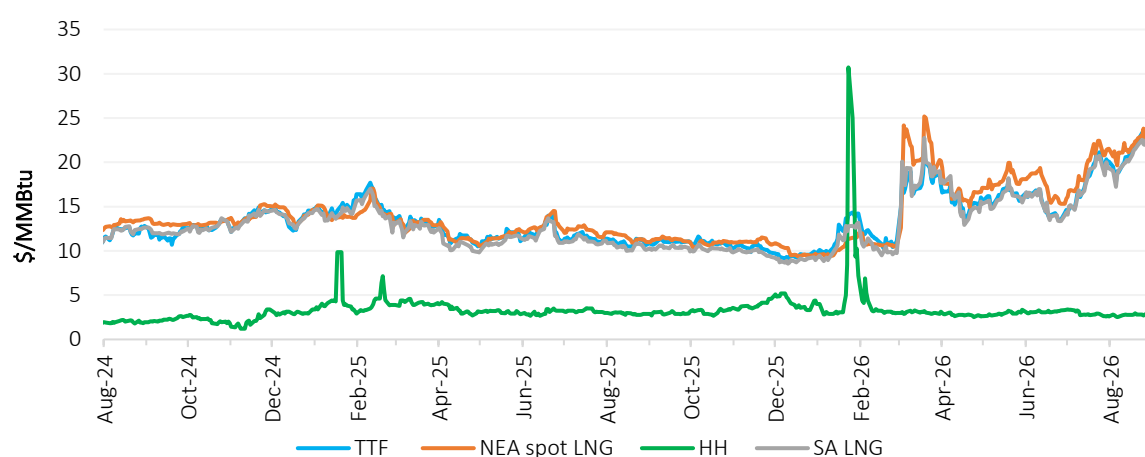
6 ENERGY PRICES

6.1 Gas prices

6.1.1 Gas & LNG spot prices

In August 2026, gas and LNG spot prices in Europe and Asia continued to rise, accompanied by heightened market volatility (Figure 116 and Figure 117). Geopolitical uncertainty in the Middle East and growing competition for flexible LNG cargoes sustained the upward momentum in spot prices across both regions. Daily TTF and NEA LNG spot prices rose above \$23/MMBtu, surpassing the levels recorded at the onset of the conflict. Ahead of the winter heating season, intensifying inter-regional competition will likely keep prices elevated, while any further escalation in the Middle East poses additional upside risks to LNG trade flows and pricing.

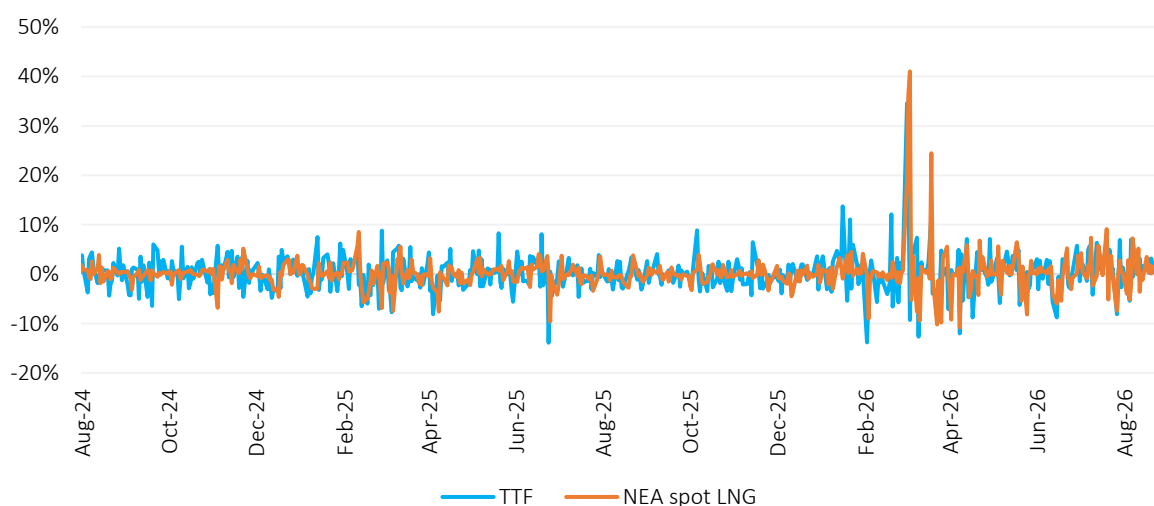
Figure 116: Daily gas & LNG spot prices



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 117: Daily variation of spot prices



Source: GECF Secretariat based on data from Argus and LSEG

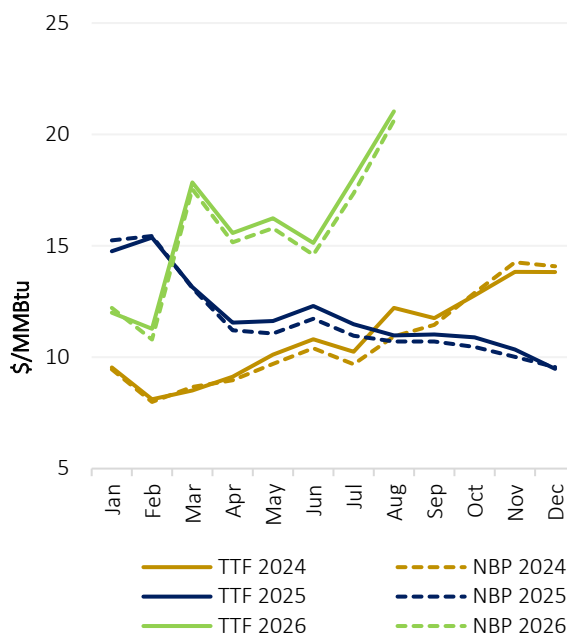
6.1.1.1 European spot gas and LNG prices

In August 2026, the TTF spot gas price averaged \$21.03/MMBtu, increasing sharply by 17% m-o-m and 92% y-o-y. Similarly, the NBP spot price averaged \$20.62/MMBtu, increasing 19% m-o-m, and 93% y-o-y (Figure 118). During the month, daily TTF prices peaked at \$23.33/MMBtu, the highest level recorded since December 2022.

European gas and LNG prices rose sharply, recording the highest monthly average of the year. Ongoing tensions in the Middle East combined with reduced Norwegian supply amid seasonal maintenance and persistently low EU gas storage levels, exerted significant upward pressure on spot prices.

For the period January to August 2026, TTF and NBP prices averaged \$15.89/MMBtu and \$15.51/MMBtu, increasing by 26% and 25% y-o-y, respectively.

Figure 118: Monthly European spot gas prices



Source: GECF Secretariat based on data from LSEG

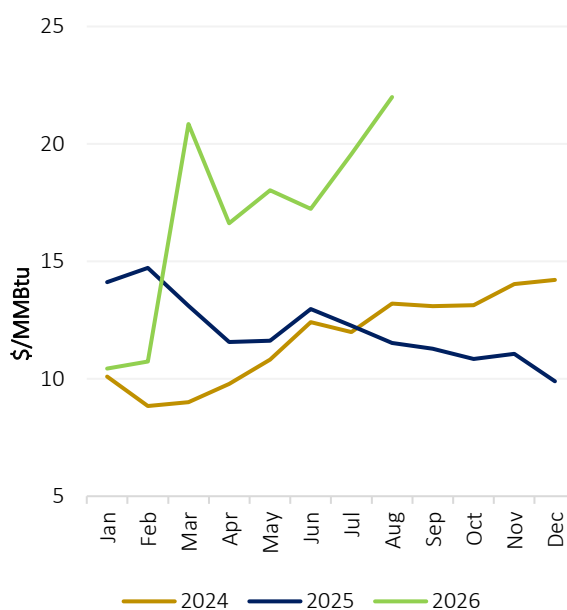
6.1.1.2 Asian spot LNG prices

In August 2026, the average North East Asia (NEA) spot LNG price averaged \$21.99/MMBtu, reflecting increases of 12% m-o-m and 91% y-o-y (Figure 119). Daily NEA spot LNG price soared to \$23.96/MMBtu, the highest level since January 2023.

Asian LNG prices tracked gains in European spot prices, supported by heightened geopolitical uncertainty and increasing competition for flexible LNG cargoes ahead of the winter heating season.

For the period January to August 2026, NEA spot LNG price averaged \$16.93/MMBtu, reflecting an increase of 33% y-o-y.

Figure 119: Monthly Asian spot LNG prices



Source: GECF Secretariat based on data from Argus

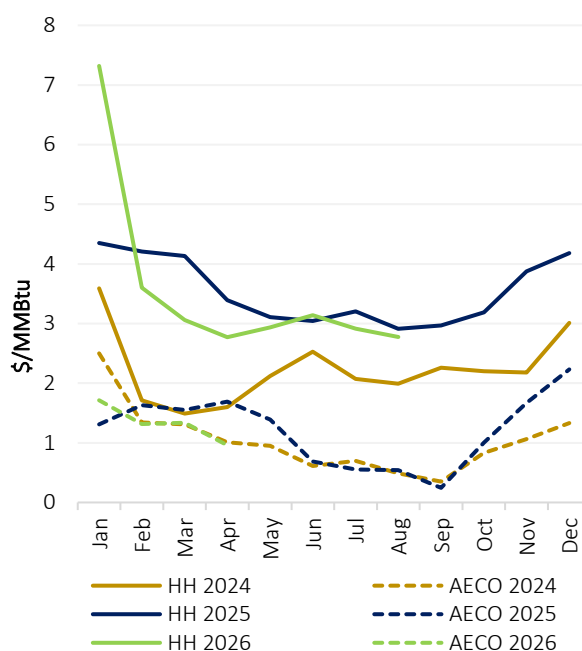
6.1.1.3 North American spot gas prices

In August 2026, the Henry Hub (HH) spot gas price averaged \$2.77/MMBtu, decreasing by 5% m-o-m and y-o-y. Similarly, the AECO spot prices averaged \$1.01/MMBtu decreasing by 14% m-o-m, but was 86% higher y-o-y (Figure 120). Daily HH prices fell to a low of \$2.53/MMBtu at the start of the month.

In the US, HH spot prices declined for the second consecutive month, as robust domestic natural gas production and relatively high storage levels exerted downward pressure on prices.

For the period January to August 2026, HH and AECO spot prices averaged \$3.56/MMBtu and \$1.25/MMBtu, decreasing by 1% and 7%, respectively.

Figure 120: Monthly North American spot gas prices



Source: GECF Secretariat based on data from LSEG

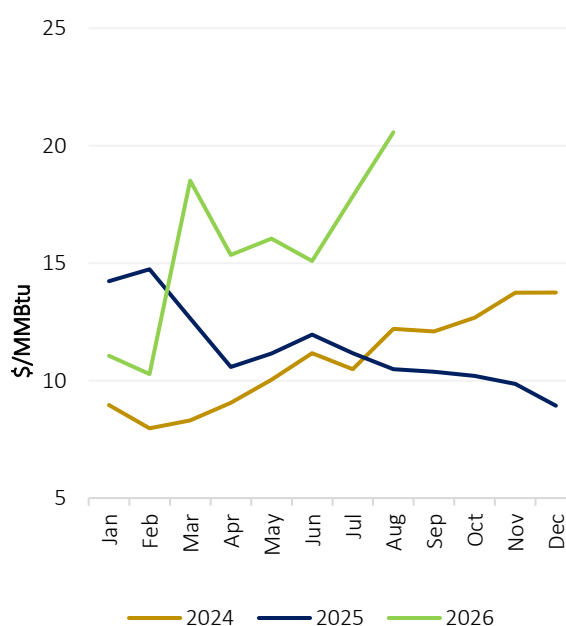
6.1.1.4 South American spot LNG prices

In August 2026, the South America (SA) spot LNG price averaged \$20.57/MMBtu, increasing by 15% m-o-m and 96% y-o-y (Figure 121). During the month, daily SA spot LNG prices rose to a high of \$22.57/MMBtu.

The SA spot LNG prices continued to align with broader global LNG market trends, tracking substantial gains in European and Asian prices. Delivered LNG prices in Argentina, Brazil and Chile averaged \$20.54/MMBtu, \$20.41/MMBtu and \$20.76/MMBtu, respectively.

For the period January to August 2026, the SA spot LNG price averaged \$15.59/MMBtu, up 29% y-o-y.

Figure 121: Monthly South American spot LNG prices



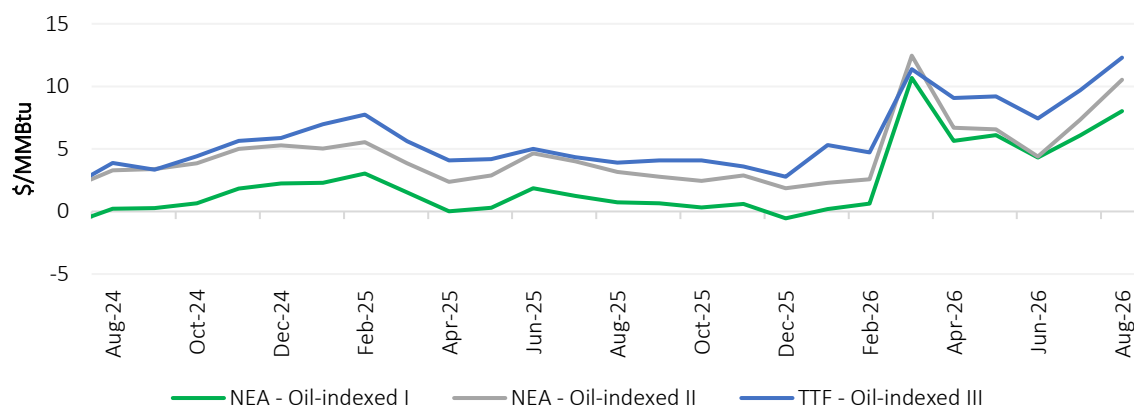
Source: GECF Secretariat based on data from Argus

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 August 2026, the Oil-Indexed I LNG price averaged \$13.96/MMBtu, rising modestly by 4% m-o-m and 29% y-o-y. Meanwhile, the Oil-Indexed II LNG price averaged \$11.48/MMBtu decreasing by 6% m-o-m, but was 37% higher y-o-y. In Europe, the Oil-Indexed III LNG price averaged \$8.74/MMBtu, reflecting increases of 5% m-o-m and 23% y-o-y. During the month, the premium of NEA spot LNG over Oil-Indexed I and Oil-Indexed II prices increased to \$8.0/MMBtu, and \$10.5MMBtu, respectively. Similarly, the TTF spot gas premium over Oil-Indexed III widened to \$12.3/MMBtu (Figure 122).

Figure 122: 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 (12.1% for 2026) 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 August 2026, the NEA–TTF price spread narrowed slightly to \$0.96/MMBtu. TTF spot prices experienced a sharper uptick than the NEA spot LNG prices during the month (Figure 123). Meanwhile, the TTF–HH price spread widened to \$18.26MMBtu (Figure 124).

Figure 123: NEA-TTF price spread

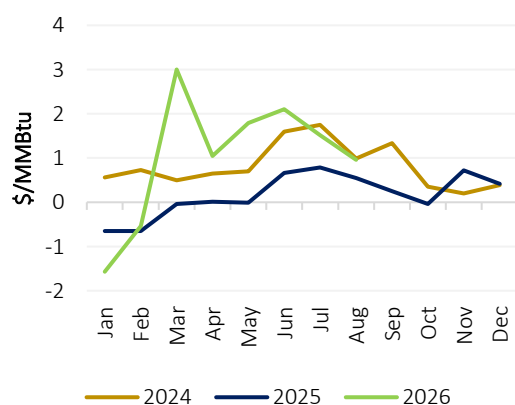
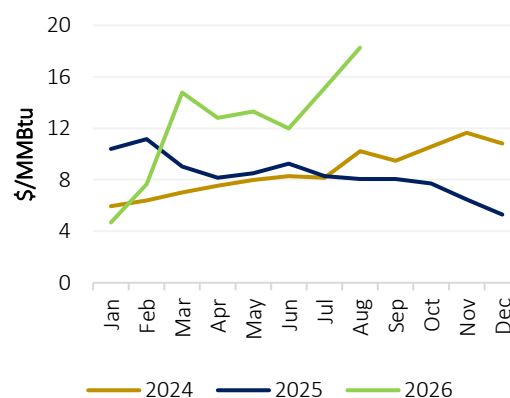


Figure 124: TTF-HH price spread



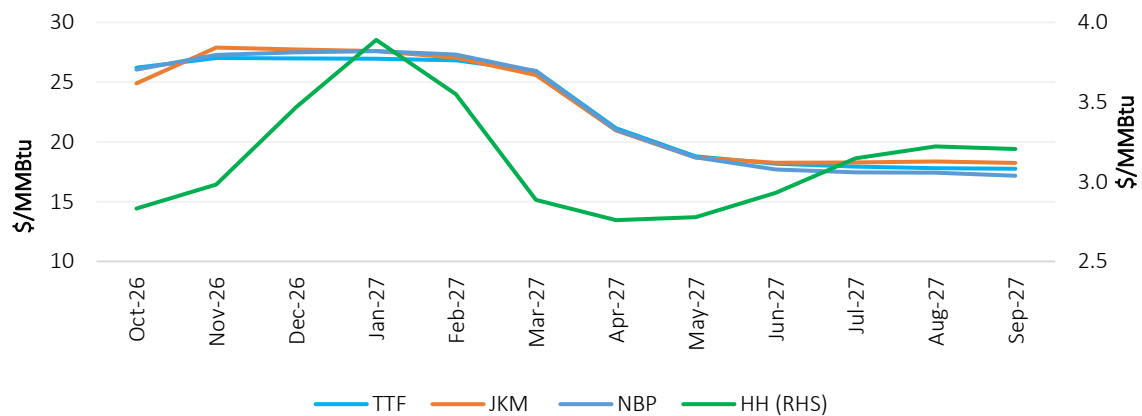
Source: GECF Secretariat based on data from Argus and LSE

6.1.4 Gas & LNG futures prices

As of 11 September 2026, the average futures prices for the 12-month period from October 2026 to September 2027 stood at \$22.63/MMBtu for TTF, \$22.59/MMBtu for NBP, and \$22.79/MMBtu for JKM (Figure 125). Notably, all three benchmark prices were around 40% higher than the previous expectations presented in the GECF MGMR August 2026 assessment on 7 August 2026. Over the same period, Henry Hub futures averaged \$3.14/MMBtu, around 1% lower than previous expectations (Figure 126).

Looking ahead, the JKM–TTF spread is expected to be negative in October 2026 with TTF trading at a \$1.3/MMBtu premium to JKM. Subsequently, the spread returns positive for the rest of the year.

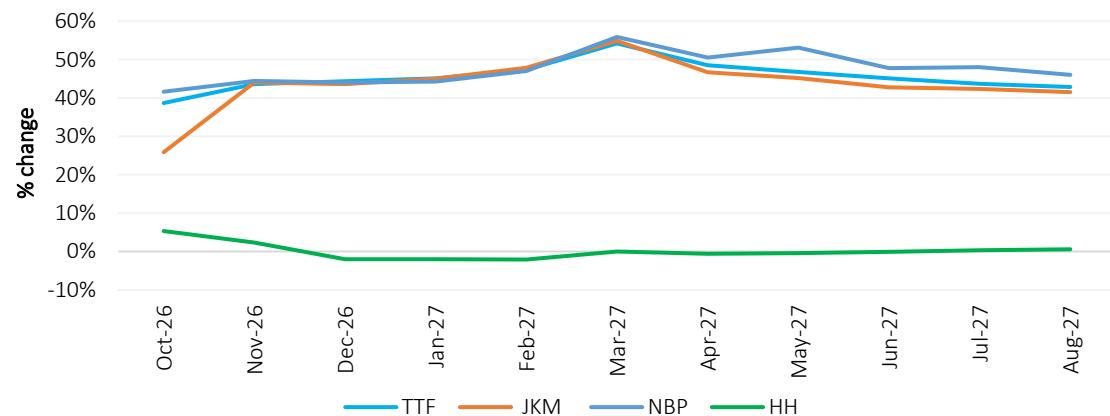
Figure 125: Gas & LNG futures prices



Source: GECF Secretariat based on data from LSEG

Note: Futures prices as of 11 September 2026

Figure 126: Variation in gas & LNG futures prices



Source: GECF Secretariat based on data from LSEG

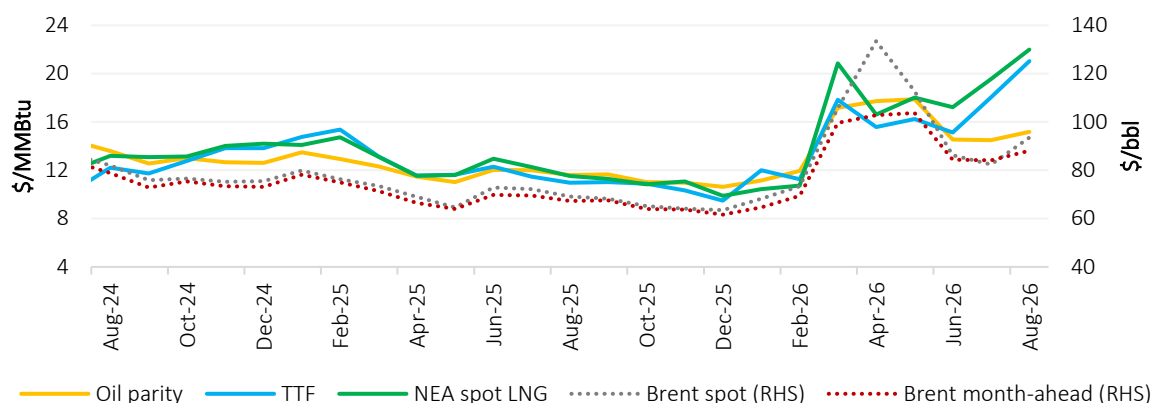
Note: Comparison with the futures prices as of 7 August 2026, as reported in GECF MGMR August 2026

6.2 Cross commodity prices

6.2.1 Oil prices

In August 2026, the average Brent crude spot price averaged \$93.59/Bbl, increasing sharply by 14% m-o-m and 35% y-o-y. Similarly, the month-ahead Brent price averaged \$88.08/Bbl, increasing by 5% m-o-m and 31% y-o-y. Furthermore, TTF spot prices traded at a premium of \$5.8/MMBtu to the oil parity price, while NEA spot LNG prices traded at a \$6.8/MMBtu premium (Figure 127).

Figure 127: Monthly crude oil prices



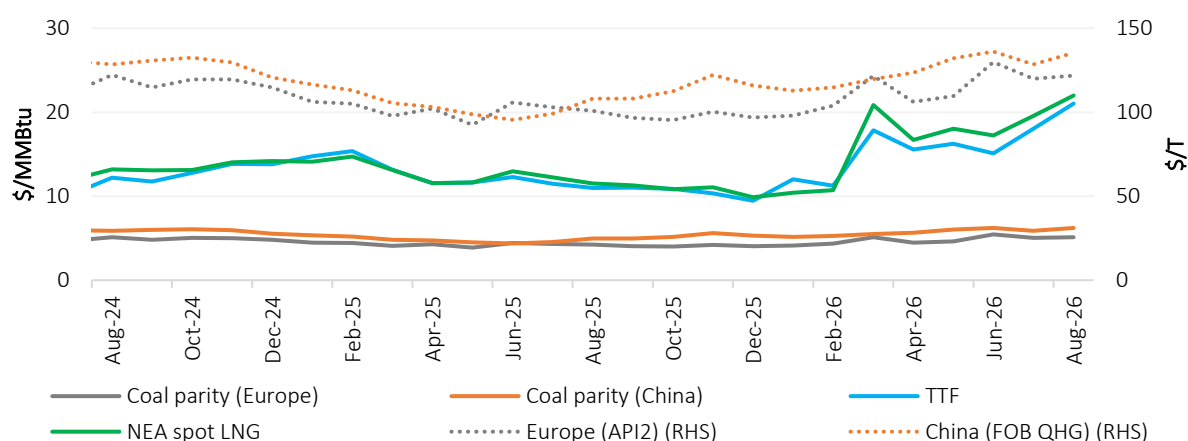
Source: GECF Secretariat based on data from Argus and LSEG

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 August 2026, the European coal price (API2) averaged \$121.83/t, increasing by 2% m-o-m and 21% y-o-y. The premium of TTF spot gas over API2 parity widened compared to the previous month to \$15.91/MMBtu. Similarly, in China, the Qinhuangdao (QHG) coal price averaged \$135.43/t, increasing by 5% m-o-m and 25% y-o-y. The premium of NEA spot LNG over QHG parity increased to \$15.78/MMBtu (Figure 128).

Figure 128: Monthly coal parity prices



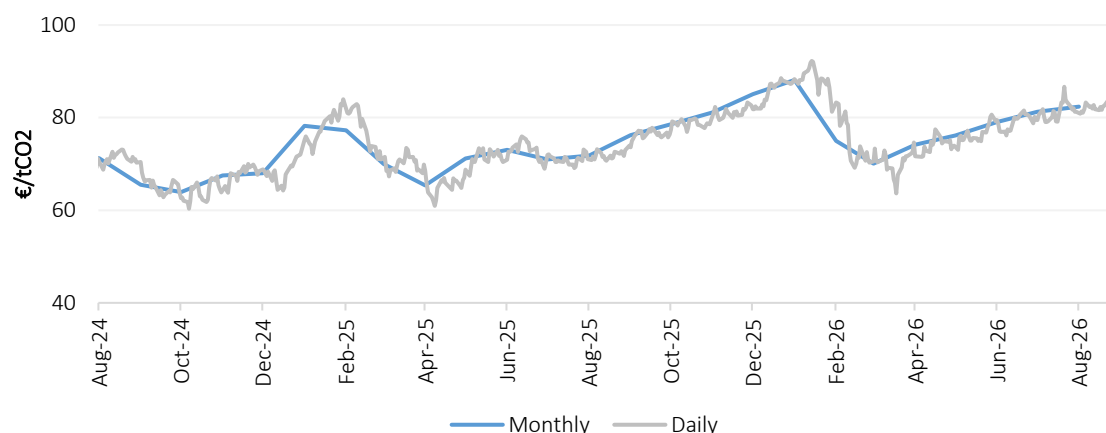
Source: GECF Secretariat based on data from Argus and LSEG

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 August 2026, the EU carbon price averaged €82.36/tCO₂, reflecting increases of 1% m-o-m and 15% y-o-y (Figure 129). During the month, the daily EU carbon price climbed to a peak of €84.42/tCO₂.

Figure 129: EU carbon prices

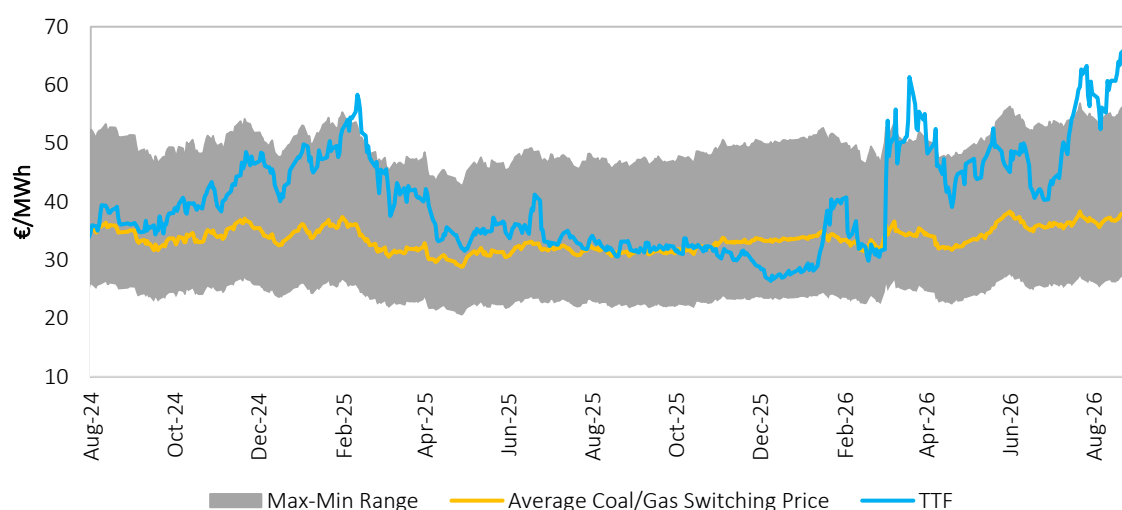


Source: GECF Secretariat based on data from LSEG

6.2.4 Fuel switching

In August 2026, TTF prices remained above the upper bound of the coal-to-gas switching range during the month (Figure 130). Furthermore, the average monthly price spread increased significantly to €24.3/MWh, indicating that coal likely remained relatively more competitive over gas in the power generation sector.

Figure 130: 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, CO₂ 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
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
EMDE	Emerging Markets and Developing Economies
EU	European Union
EU ETS	European Union Emissions Trading Scheme
EUA	European Union Allowance
Fed	United States 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
mmcmd	Million cubic metres per day
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
OECD	Organization for Economic Co-operation and Development
PNG	Pipeline Natural Gas
PPAC	India's 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

Tcm	Trillion cubic metres
tCO₂	Tonne of carbon dioxide
TFDE	Tri-Fuel Diesel Electric
TTF	Title Transfer Facility
TWh	Terawatt hour
UGS	Underground Gas Storage
UAE	United Arab Emirates
UK	United Kingdom
US	United States
y-o-y	year-on-year

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