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Gas Exporting Countries Forum

MONTHLY GAS MARKET REPORT

November 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 by the GECF Secretariat that provides insights into short-term developments in the global gas market, covering areas such as the global economy, gas consumption, gas production, gas trade (both pipeline gas and LNG), gas storage and energy prices.

Acknowledgements

The Monthly Gas Market Report (MGMR) is prepared by the experts from the Gas Market Analysis Department (GMAD) of the Gas Exporting Countries Forum (GECF).

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The authors of the report would like to extend their appreciation to HE Dr. Philip Mshelbila, Secretary General of the GECF, for his contribution to the development of the report.

Peer Review

GaffneyCline energy advisory (GCea)

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HIGHLIGHTS

Gas consumption: Global gas consumption remained under pressure in October 2026, although regional developments varied, reflecting differences in weather conditions, energy prices and sectoral demand. In Europe, gas consumption declined y-o-y in both the EU (−10%) and the UK (−13%), mainly due to lower heating requirements amid unusually mild temperatures, with the EU recording its second-warmest October on record. In North America, US gas consumption increased by 2% y-o-y, supported by stronger demand from the power sector. In Asia, China and Japan experienced lower gas consumption amid elevated LNG spot prices and subdued buying interest, while India and South Korea registered growth, driven primarily by stronger demand from the residential and commercial sectors.

Gas production: The continued closure of the Strait of Hormuz constrained global gas supply in October 2026, with Middle Eastern production remaining significantly below year-earlier levels as major regional gas and LNG producers continued to face substantial supply disruptions. Higher production in North America, particularly in the US, where output rose by 7% y-o-y, provided a partial offset; however, this increase was insufficient to compensate for the losses in the Middle East, leaving global gas production below year-earlier levels.

Gas trade: Global LNG imports declined by 4.4% y-o-y to 34.9 Mt in October 2026, primarily reflecting lower deliveries to Europe. European imports fell by 16% y-o-y to 9.2 Mt, driven by reduced Qatari LNG supplies amid continued restrictions on transit through the Strait of Hormuz, as well as the redirection of some Russian LNG cargoes from Europe to Asia. In contrast, Asian LNG imports increased by 1.3% y-o-y to 22.8 Mt, recovering after two consecutive months of decline. Despite elevated spot prices and reduced Middle Eastern supplies, increased deliveries from North America, Russia and West Africa supported Asian imports, partly driven by demand for winter stock replenishment.

Gas storage: The EU's monthly average gas storage level stood at 77 bcm in October 2026, compared with 86 bcm a year earlier. In the US, continued net injections brought the monthly average storage level to 103 bcm (77% of capacity), below the 107 bcm recorded a year ago. In Asia, combined LNG inventories in Japan and South Korea totalled 8.8 bcm (45% of capacity), down 40% y-o-y, reflecting tighter LNG availability in the global market.

Energy prices: Gas and LNG spot prices in Europe and Asia surged to multi-year highs in October 2026, with TTF and NEA spot LNG prices averaging $29/MMBtu, up 12% and 9% m-o-m, respectively. In contrast, US Henry Hub spot prices edged up by just 1% m-o-m to $3/MMBtu, reflecting the relative insulation of the domestic market from international supply disruptions. Looking ahead, prolonged supply constraints, combined with colder-than-normal weather, could further tighten market balances and expose prices to upward pressure.

FEATURE ARTICLE

Strategic role of natural gas in advancing sustainable development in Sub-Saharan Africa

As the international community marked World Sustainability Day on 28 October 2026, attention focused on progress towards achieving the Sustainable Development Goals (SDGs). More than a decade has passed since the UN General Assembly adopted the SDGs in September 2015, leaving only four years until the deadline of 31 December 2030. Despite sustained international efforts, progress remains deeply inadequate and uneven, as highlighted in The Sustainable Development Goals Report 2026, published by the UN in July 2026. This shortfall is particularly evident in Sub-Saharan Africa (SSA), where widespread poverty, food insecurity and limited access to essential public services continue to hinder development. These persistent challenges affect all three interrelated dimensions of sustainable development: economic, social and environmental.

Economic development in SSA remains significantly below that of other world regions, with SSA having the lowest GDP per capita globally. In 2025, GDP per capita in SSA stood at approximately $5,800 in PPP terms (current international dollars), up from $4,200 in 2015. By comparison, the global average rose from $15,300 to $25,700 over the same period, underscoring the persistent income disparity. Many countries in the region continue to face structural constraints, including limited economic diversification, low productivity, inadequate infrastructure and insufficient investment, which impede industrialisation and long-term economic growth.

Social progress in SSA is constrained by persistent poverty and limited access to essential services, including healthcare, education and sanitation. The region accounts for two-thirds of the global population living in extreme poverty. These challenges are compounded by high levels of energy poverty and inadequate energy infrastructure. Around 600 million people, or 45% of SSA's population, lack access to electricity, representing 85% of the 655 million people worldwide without electricity. Similarly, around 1 billion people, or 77% of SSA's population, lack access to clean cooking, accounting for nearly half of the 2 billion people worldwide without access to it.

Environmental sustainability in SSA is undermined by the extensive use of traditional biomass for cooking, as fuelwood and charcoal contribute to forest degradation and expose households to harmful indoor air pollution. Moreover, continued reliance on oil and coal for power generation drives up greenhouse gas emissions and air pollution. These challenges are further compounded by the region's growing vulnerability to climate change, limited adaptive capacity and restricted access to cleaner energy alternatives, particularly among low-income and rural households.

Persistent sustainable development challenges in SSA are closely linked to low levels of energy consumption and reliance on carbon-intensive fuels. Adequate and reliable energy supplies are essential for expanding economic activity, supporting industrialisation, creating employment, improving access to healthcare and education, enhancing agricultural productivity, and ensuring the provision of clean water and sanitation. Although primary energy consumption in the region, excluding biomass, increased from 10.3 EJ in 2015 to 12.3 EJ in 2025 (Figure i), representing a compound annual growth rate of 1.8%, SSA's share of global primary energy consumption excluding biomass remained broadly unchanged at only 2%, highlighting the limited scale of its modern energy supply. Reflecting the severity of energy poverty across the region, per-capita primary energy consumption in SSA, excluding biomass, stood at just 9.3 GJ in 2025, the lowest level globally and well below the global average of 73 GJ. This substantial energy deficit underscores the challenge of meeting the region's growing energy needs while improving living standards.

Addressing this energy deficit requires balancing the often-competing priorities of energy addition and energy transition. Given SSA's substantial unmet energy needs and limited access to modern energy services, priority should be given to energy addition, alongside a gradual energy transition.

Energy addition is essential to SSA's economic and social development. The region accounts for 16% of the global population but only 3.6% of global GDP in PPP terms, highlighting the significant disparity between its demographic weight and economic output. Narrowing this gap requires expanding energy supply, as energy is a cross-cutting enabler of all 17 SDGs, not only SDG 7. Reliable and affordable energy underpins industrialisation, food security, healthcare and education, access to clean water and climate action, among other development priorities.

Energy transition is also important for reducing the environmental and health impacts associated with energy consumption. Although the region accounts for only 3% of global greenhouse gas emissions, equivalent to 1.3 Gt CO_2e, SSA relies heavily on biomass, which remains the dominant source of total primary energy consumption, exceeding the combined contribution of all other energy sources (Figure ii). Biomass consumption in SSA nearly doubled between 1990 and 2025, reaching nearly 13 EJ and accounting for 22% of global biomass consumption. The combustion of traditional biomass, particularly fuelwood and charcoal, can generate substantial direct CO_2 emissions per unit of energy, while its widespread use contributes to forest degradation and harmful indoor air pollution, increasing health risks and environmental pressures across the region.

Figure i: Primary energy consumption in SSA, excluding biomass, 1990-2025

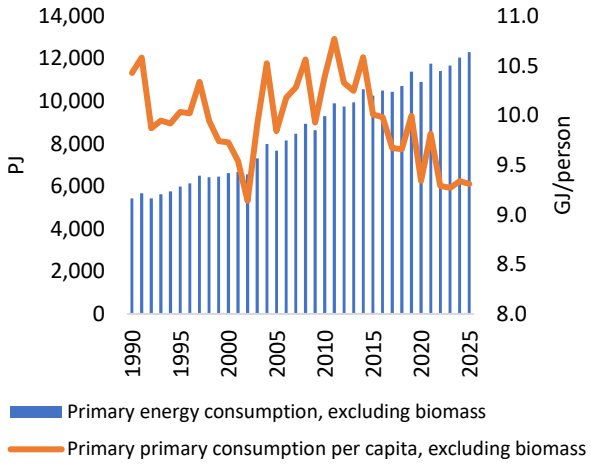
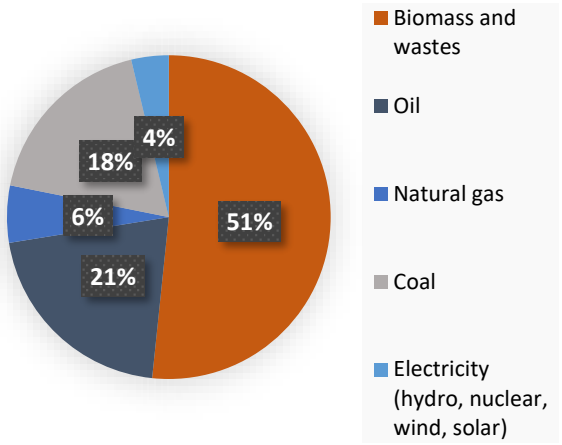


Figure ii: Total primary energy consumption in SSA by energy source, 2025



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

However, expanding energy supply in SSA faces significant constraints across available energy sources. Despite abundant solar and wind resources, SSA accounts for only 0.7% of global installed solar capacity and 0.3% of global installed wind capacity. Scaling up these sources would require substantial investment in generating capacity, transmission networks, energy storage and backup generation. Other energy sources also face constraints. Nuclear power currently operates only in South Africa within SSA, while wider deployment would require substantial investment and long development periods. Hydropower projects face high capital requirements and long construction periods, while generation can be vulnerable to drought in some countries. Although coal and oil can contribute to energy supply, their higher carbon emissions and other environmental and health impacts make them less suitable for supporting a lower-emissions development pathway.

Against this backdrop, natural gas offers SSA a critical opportunity to accelerate energy addition by providing reliable and affordable energy from its abundant resources. At the same time, natural gas can facilitate a pragmatic, just and balanced low-carbon energy transition, as it emits less CO_2 per unit of energy produced than coal, oil and traditional biomass, which together account for 90% of SSA's primary energy mix. Furthermore, natural gas-fired power generation can provide flexible backup for intermittent renewable energy sources, facilitating their integration into the region's energy systems and contributing to SDGs related to environmental sustainability and climate action.

Major upstream discoveries over the past two decades, particularly offshore, highlight SSA's gas resource potential, including both non-associated and associated gas. According to Rystad Energy, the region holds 7.6 tcm of proven gas reserves (4% of the global total), of which Nigeria accounts for 6 tcm. It also has 33 tcm of technically recoverable resources (TRR; 5% of the global total), concentrated largely in Nigeria, Mozambique, Tanzania, Senegal, Mauritania and Angola. With gas production reaching 90 bcm in 2025 (Figure iii) and major gas projects advancing, SSA is poised to become an increasingly important driver of global gas supply growth over the medium to long term.

At the same time, gas consumption in SSA is increasing but remains insufficient to address the region's energy deficit, with demand concentrated in power generation and industry (Figure iv).

In power generation, natural gas can play a key role in accelerating economic development and addressing low electricity access while improving living standards. Total electricity generation in the region reached 560 TWh in 2025, accounting for 1.7% of global output. This equates to just 440 kWh per capita, around nine times lower than the global average. Coal dominates the region's power mix, accounting for 38% of generation, largely driven by South Africa, while oil contributes 7% (Figure v). Despite SSA's substantial gas resources, natural gas accounts for 14%, or 80 TWh, which is lower than the gas-fired power generation in Germany, Türkiye and Thailand individually. Expanding gas-fired generation can also facilitate coal- and oil-to-gas switching, reducing emissions.

In the industrial sector, natural gas can play a key role in industrialisation by providing process heat across a wide range of industries and serving as a feedstock for fertilizer and petrochemical production. Expanding domestic industries could reduce import dependence, with fertilizer manufacturing improving fertilizer availability, boosting agricultural productivity and strengthening food security, and the petrochemical industry diversifying the industrial base.

Figure iii: SSA's gas production by country, 2000-2025

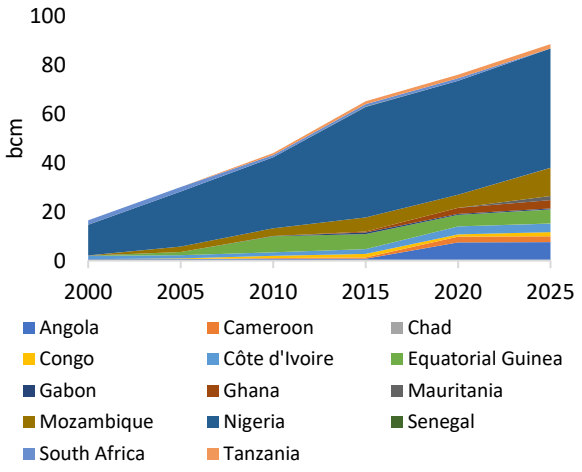
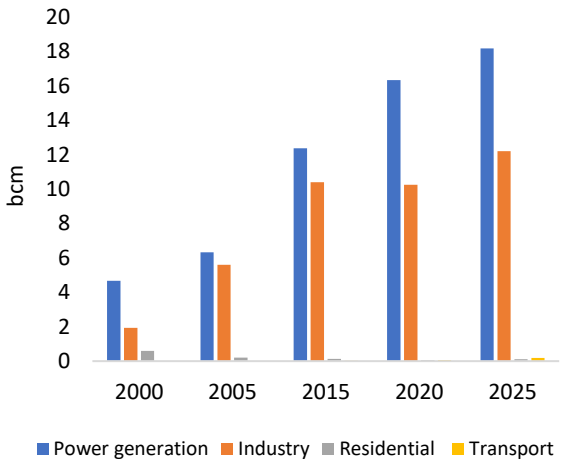


Figure iv: SSA's gas consumption by sector, 2000-2025



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

One major challenge facing SSA is striking a better balance between domestic gas consumption and exports (Figure vi). In some LNG-exporting countries, domestic gas use remains negligible, limiting the contribution of natural gas to local energy needs and economic and social development.

Figure v: Power mix in SSA by energy source, 2025

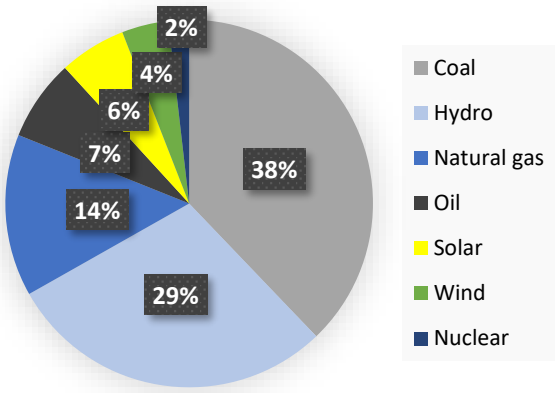
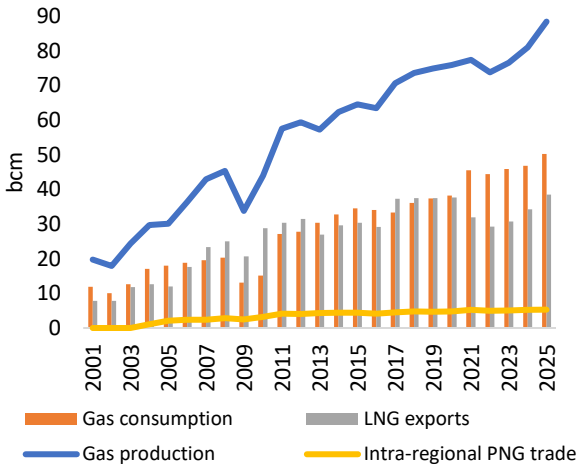


Figure vi: Trends in the SSA gas market, 2000-2025



Source: GECF Secretariat based on data from Ember and Cedigaz

Greater priority should therefore be given to domestic gas use, supported by expanding midstream and downstream infrastructure to translate the region's abundant gas resources into broader economic benefits. This requires policies that encourage investment in domestic gas markets, promote industrial development, generate employment and strengthen local supply chains.

At the same time, gas exports offer important opportunities to monetise SSA's gas resources, attract much-needed international investment and generate stable government revenues. The region's geographic location provides access to major LNG markets, with West African suppliers relatively close to Europe and East African suppliers well positioned to serve Asia. Unlike LNG exports from some Middle Eastern countries, which were severely disrupted by the 2026 crisis, SSA's LNG exports benefit from shipping routes that avoid certain major maritime chokepoints, reducing exposure to geopolitical risks. In addition, pipeline infrastructure can complement LNG exports by connecting SSA's gas-producing countries with European markets through North Africa. To translate these export opportunities into broad-based benefits, effective fiscal and governance frameworks must ensure that producing countries retain a fair share of export revenues and invest them in economic diversification and social progress.

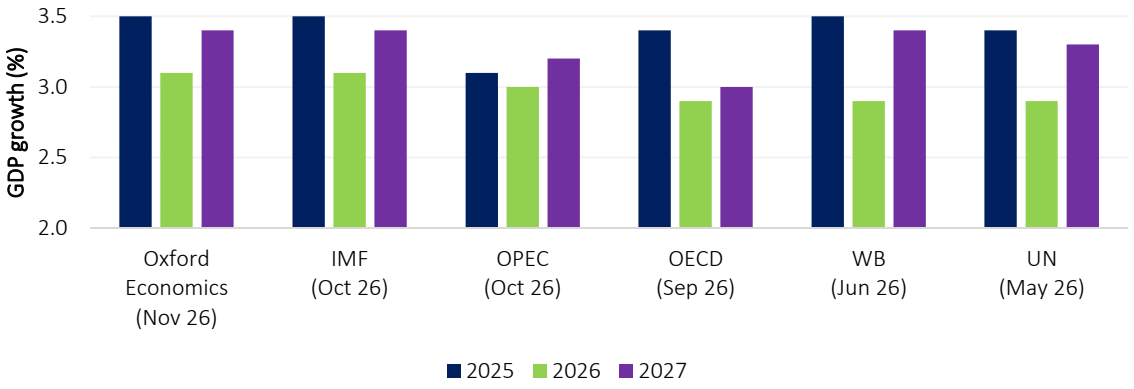
Alongside exports to overseas markets, regional gas market integration can enable the expansion of intra-regional gas trade, offering important opportunities to strengthen energy security and improve access to affordable energy across SSA. Cross-border pipelines can link resource-rich countries with neighbouring markets lacking sufficient domestic supplies, enabling gas trade at competitive prices agreed by the parties under bilateral agreements. Joint development of transboundary resources, exemplified by the Greater Tortue Ahmeyim gas field shared by Senegal and Mauritania, can enhance regional cooperation and resource utilisation. Potential gas pipeline routes under discussion, particularly along the West African coast and through the Trans-Saharan corridor, could further expand regional gas trade and strengthen market connectivity. By diversifying supplies and improving access to natural gas, regional gas market integration could advance the three dimensions of the energy trilemma: energy security, affordability and environmental sustainability.

1 GLOBAL PERSPECTIVES

1.1 Global economy

Global GDP growth forecast for 2026, based on purchasing power parity, was maintained at 3.1% by Oxford Economics in November 2026 (Figure 1). The global economic outlook remains subject to significant energy-related downside risks, with supply disruptions and persistently elevated energy prices contributing to inflationary pressures and weighing on economic activity. Nevertheless, the growth forecast for 2027 was revised upward by 0.3 percentage points to 3.4%, indicating an improved outlook despite ongoing uncertainties.

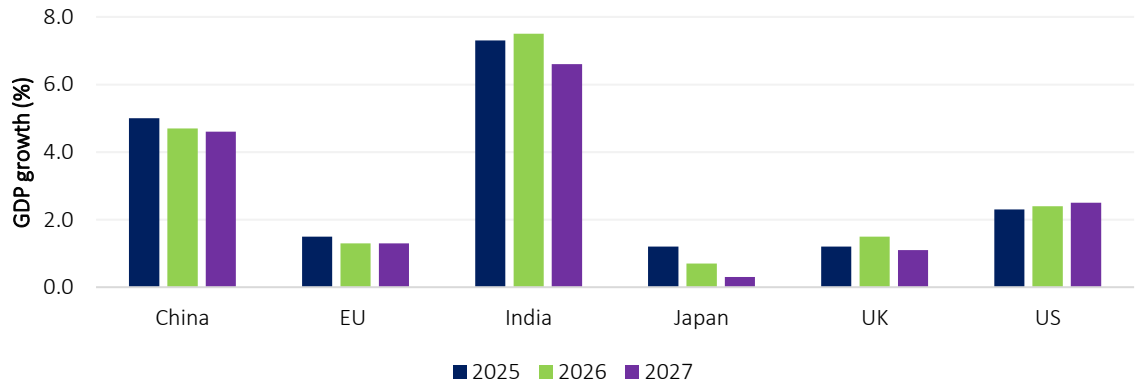
Figure 1: Global GDP growth



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

GDP growth forecasts for the US in 2026 and 2027 were maintained at 2.4% and 2.5%, respectively, supported by robust investment in AI infrastructure and a broadening industrial recovery. Similarly, the EU's growth projections remained unchanged at 1.3% for both years, as high energy prices continued to fuel inflationary pressures and weigh on economic activity. In China, the 2026 GDP growth forecast was revised upward by 0.1 percentage points to 4.7%, while the 2027 projection was raised by 0.3 percentage points to 4.6%, reflecting increased investment in AI infrastructure and a recovery in infrastructure spending. Meanwhile, India's GDP growth forecasts remained unchanged at 7.5% for 2026 and 6.6% for 2027 (Figure 2).

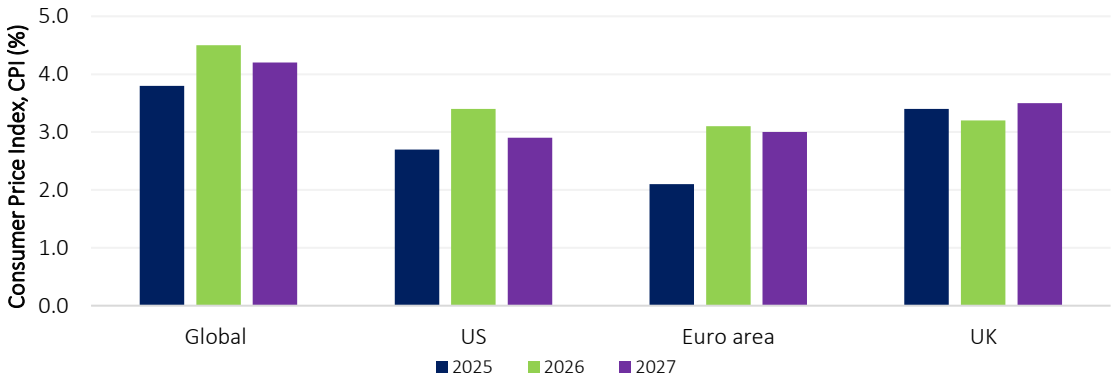
Figure 2: GDP growth in major economies



Source: GECF Secretariat based on data from Oxford Economics

The global inflation forecast for 2026 was revised downward to 4.5%, while the projection for 2027 remained unchanged at 4.2% (Figure 3). In the euro area, inflation forecasts were revised upward by 0.1 percentage points to 3.1% for 2026 and by 0.3 percentage points to 3.0% for 2027. In the UK, the 2026 inflation forecast remained unchanged at 3.2%, whereas the 2027 projection was revised upward by 0.3 percentage points to 3.5%. Similarly, the US inflation forecast for 2026 was maintained at 3.4%, while the 2027 forecast was raised by 0.2 percentage points to 2.9%. Overall, these revisions point to persistent inflationary pressures across major advanced economies.

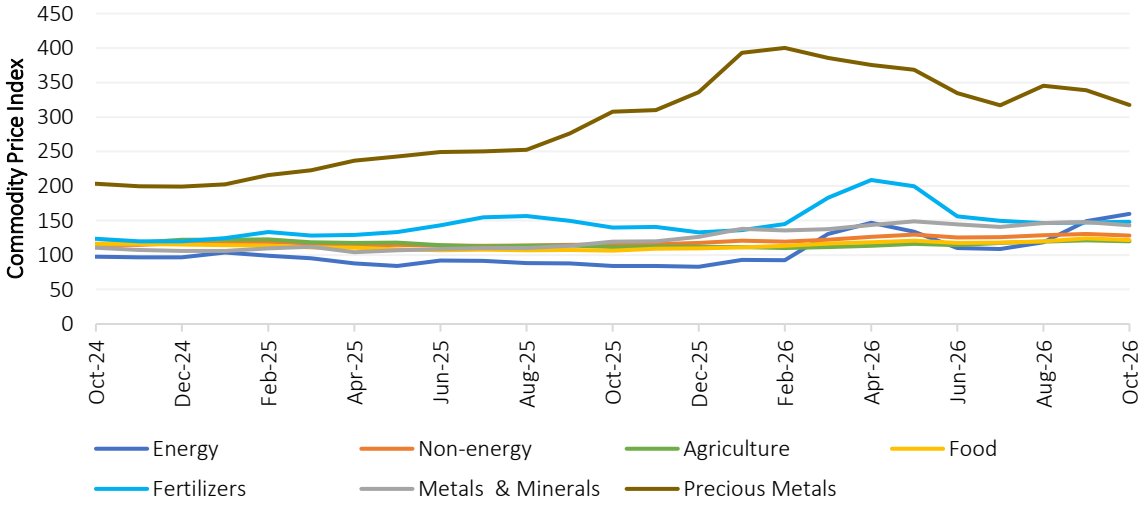
Figure 3: Inflation rates



Source: GECF Secretariat based on data from Oxford Economics

In October 2026, commodity markets displayed divergent price movements across the energy and non-energy sectors (Figure 4). The energy price index rose by 7% m-o-m and 89% y-o-y, reflecting strong upward momentum in oil, gas and coal prices. In contrast, the non-energy price index declined by 2% m-o-m, although it remained 11% higher y-o-y. Fertilizer prices edged up by 1% m-o-m and 6% y-o-y. Meanwhile, the precious metals price index fell by 6% m-o-m but remained 3% above its level a year earlier.

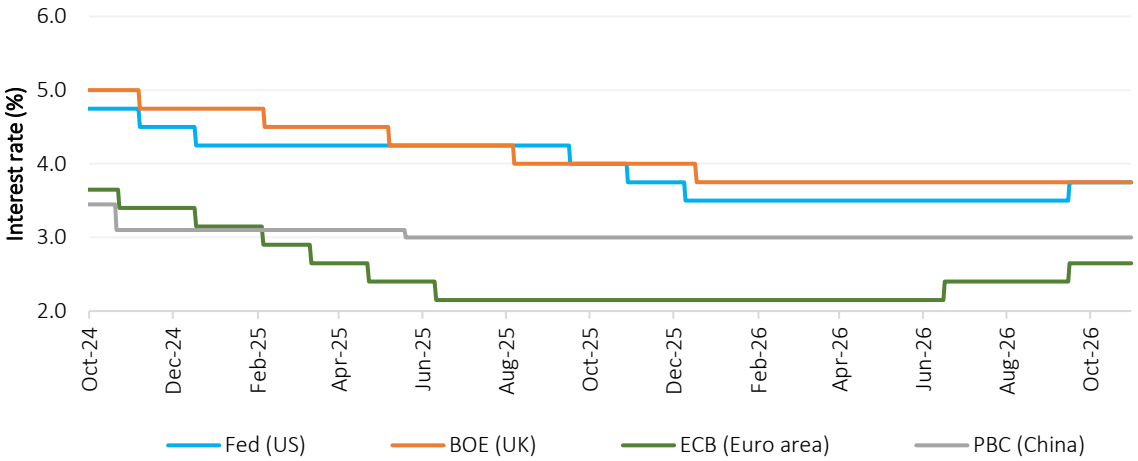
Figure 4: Monthly commodity price indices



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 October 2026, the US Federal Reserve (Fed) kept its benchmark interest rate unchanged within the range 3.75% - 4%, following a 0.25 percentage point increase in the previous month (Figure 5). The European Central Bank (ECB) likewise maintained its main refinancing operations rate at 2.65%, while the Bank of England (BOE) held its benchmark interest rate steady at 3.75% during the month. Similarly, the People's Bank of China left its one-year Loan Prime Rate (LPR) unchanged at 3.0%.

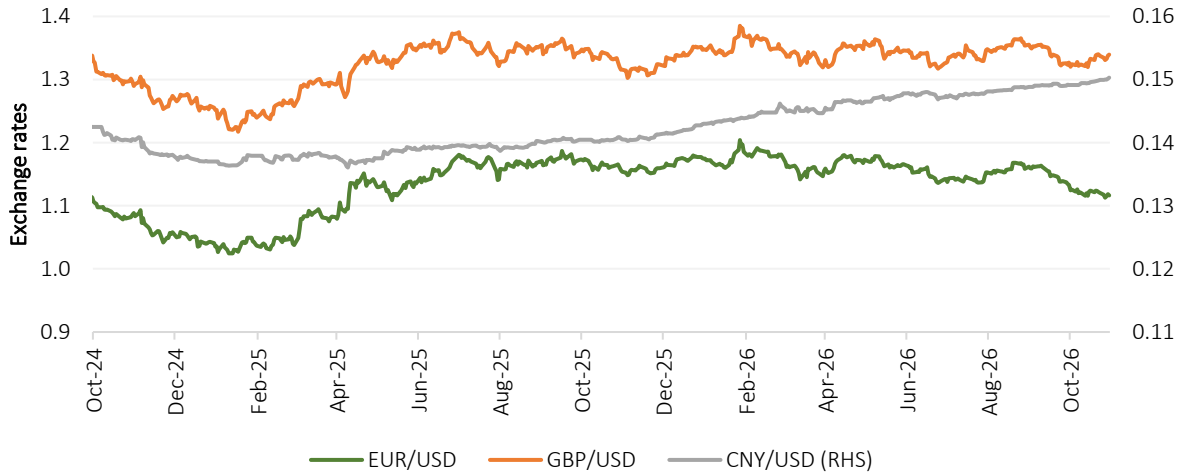
Figure 5: Interest rates in major central banks



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

In October 2026, major global currencies weakened modestly against the US dollar (Figure 6). The euro averaged $1.1204 against the US dollar, down 3% m-o-m and 4% y-o-y. Similarly, the British pound averaged $1.3297, declining by 1% m-o-m and remained at the same level as the previous year. The Chinese yuan remained relatively stable against the US dollar, averaging $0.1496, although it was 7% higher y-o-y.

Figure 6: Exchange rates



Source: GECF Secretariat based on data from LSEG

1.2 Other developments

APEC: The 33rd APEC Economic Leaders' Meeting was held on 18–19 November 2026 in Shenzhen, China, bringing together leaders of the 21 APEC member economies. Energy security featured prominently in the discussions, against the backdrop of geopolitical tensions and disruptions to international energy supply routes. In the 2026 APEC Leaders' Declaration, leaders emphasized the importance of ensuring uninterrupted, reliable and affordable energy supplies, strengthening energy supply-chain resilience, securing cross-border infrastructure, including pipelines, and enhancing emergency preparedness and strategic reserve management. They also highlighted the importance of cooperation across the energy supply chain, including between producers and consumers, and recognized the contribution of conventional and low- and zero-emission energy sources to energy security and sustainable economic growth. These commitments underscore the importance of regional energy cooperation, diversified supply sources and resilient energy infrastructure.

G20: The G20 Finance Ministers and Central Bank Governors meeting was held on 15 October 2026 in Bangkok, Thailand, on the sidelines of the IMF and World Bank Annual Meetings. Discussions focused on the economic implications of geopolitical tensions, particularly disruptions to energy and trade flows, rising inflationary pressures and elevated financing costs. Participants highlighted the importance of macroeconomic policy coordination, fiscal sustainability, stronger private investment and productivity growth, while reaffirming their commitments to market-determined exchange rates and avoiding excessive currency volatility. However, the meeting concluded without a joint communiqué or Chair's statement, reflecting differences among members on key economic policy and geopolitical issues.

IMF and WBG: The 2026 Annual Meetings of the IMF and the WBG were held on 12–18 October 2026 in Bangkok, Thailand. Discussions focused on strengthening global economic resilience, addressing rising debt vulnerabilities and mobilizing investment to support sustainable growth and job creation. Participants highlighted the risks posed by geopolitical tensions, disruptions to critical trade and energy routes, inflationary pressures and elevated borrowing costs, particularly for developing economies. Other key priorities included harnessing artificial intelligence to enhance productivity while managing associated risks, strengthening support for small businesses and expanding access to energy and essential services.

ASEAN: The 44th ASEAN Ministers on Energy Meeting (AMEM) was held on 7 October 2026 in Manila, the Philippines. In the joint media statement, ministers reaffirmed "the continued importance of oil and gas in supporting ASEAN's energy security and economic development amid heightened geopolitical and supply uncertainties" and welcomed progress under the Oil and Gas Connectivity, Security and Sustainability (OGCSS) Programme Area. Key areas of progress included enhanced LNG connectivity and regasification capacity, development of the Trans-ASEAN Gas Pipeline, upstream oil and gas cooperation, bio-LNG development and efforts to advance regional gas-market integration. Ministers also welcomed the completion of the Upstream Oil and Gas Sector Fiscal Benchmarking Study and the Gas Advocacy White Paper 2026, which provide policy analysis and recommendations to strengthen the competitiveness, transparency and investment attractiveness of the region's oil and gas sector.

2 GAS CONSUMPTION

2.1 Europe

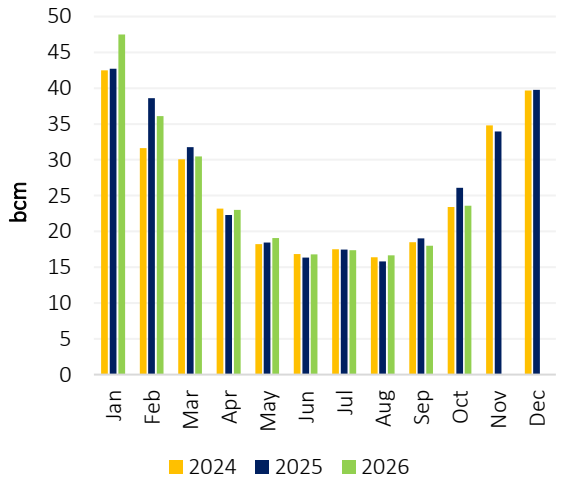
2.2.1 European Union

In October 2026, EU gas consumption declined by 10% y-o-y to 23.6 bcm (Figure 7), despite an increase in gas-fired power generation. The decline was primarily driven by lower consumption in the residential, commercial and industrial sectors. Europe's average temperature reached 11.1°C, 1.5°C above the 1991–2020 average, making October the second-warmest on record and delaying the start of the heating season. Industrial gas demand also remained subdued, further contributing to the decline in overall consumption.

EU electricity generation remained virtually unchanged y-o-y, increasing by just 0.02 TWh. However, the generation mix shifted considerably, with gas-fired power generation rising by 7% y-o-y (2.6 TWh), partly offsetting lower output from nuclear, hydropower and wind. Nuclear generation declined by 13% (6.8 TWh), hydropower by 24% (5.1 TWh) and wind by 3% (1.6 TWh). In contrast, solar generation increased by 23% (5.3 TWh), while coal-fired generation rose by 22% (4.4 TWh) (Figure 8).

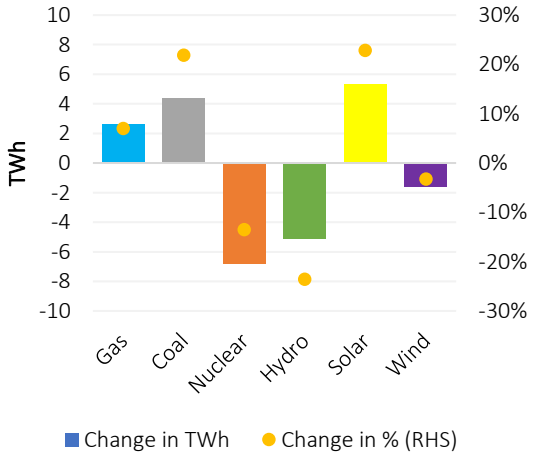
Non-hydro renewables remained the largest source of EU electricity generation, accounting for 41% of total output, followed by nuclear (21%), natural gas (19%), coal (12%) and hydropower (8%). The increase in the share of natural gas from 18% a year earlier reflects its growing contribution to electricity supply amid reduced nuclear, hydropower and wind generation. This highlights the importance of gas-fired power plants in maintaining electricity supply and balancing the generation mix when output from other sources declines.

Figure 7: Gas consumption in the EU



Source: GECF Secretariat based on data from Entsog and LSEG

Figure 8: Y-o-y changes in electricity generation by fuel in the EU, October 2026



Source: GECF Secretariat based on data from Ember

For Jan–Oct 2026, EU gas consumption remained at the same level y-o-y, totalling 248.5 bcm.

2.1.1.1 Germany

In October 2026, Germany's gas consumption declined by 8% y-o-y to 5.8 bcm (Figure 9). The decrease was driven by lower demand across the industrial, power and residential sectors. Industrial gas consumption fell by 7% y-o-y (Figure 10), reflecting continued weakness in industrial activity. Gas-fired power generation also declined by 10% y-o-y, as increased electricity generation from solar and coal more than offset the impact of lower wind output. In addition, the average temperature reached 11.3°C, around 1.3°C higher than in October 2025, reducing heating requirements at the beginning of the heating season.

Figure 9: Gas consumption in Germany

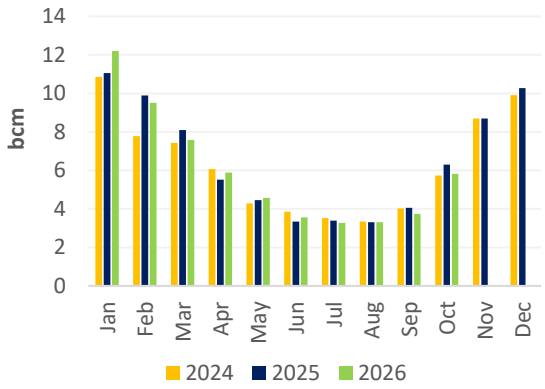
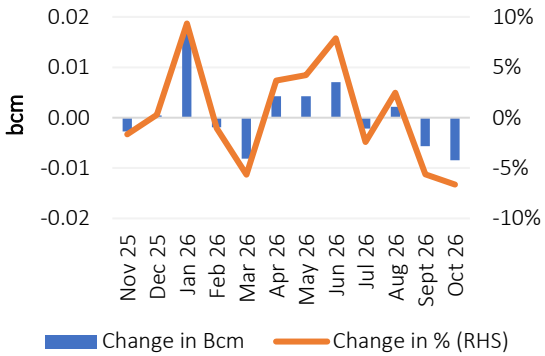


Figure 10: Trend in gas consumption in the industrial sector in Germany (y-o-y change)



Source: GECF Secretariat based on data from LSEG

Germany's electricity generation remained broadly stable in October 2026, increasing by 0.5% y-o-y (+0.2 TWh). Higher output from solar and coal-fired power plants offset declines in wind, gas-fired and hydropower generation. Solar recorded the largest increase, rising by 41% y-o-y (+1.8 TWh), supported by the continued expansion of installed capacity. Coal-fired generation also increased by 20% y-o-y (+1.6 TWh). In contrast, gas-fired generation declined by 10% y-o-y (−0.9 TWh), while wind output fell by 11% (−1.8 TWh) and hydropower generation decreased by 34% y-o-y (Figure 11). Non-hydro renewables remained the largest source of electricity generation, accounting for 57% of Germany's total output (Figure 12).

Figure 11: Y-o-y changes in electricity generation by fuel in Germany, October 2026

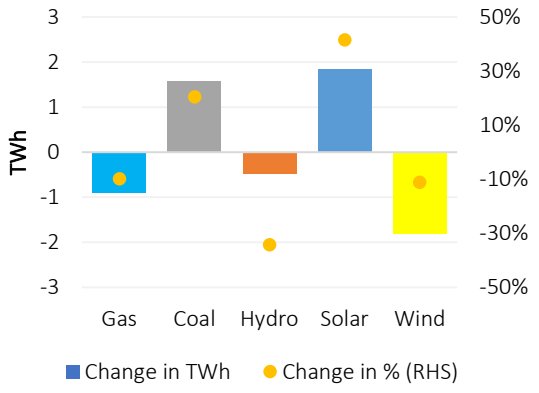
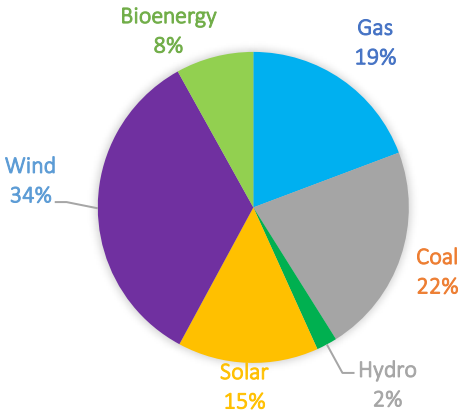


Figure 12: Germany's electricity mix, October 2026



Source: GECF Secretariat based on data from LSEG and Ember

For Jan-Oct 2026, Germany's gas consumption remained broadly unchanged y-o-y at 59.4 bcm.

2.1.1.2 Italy

In October 2026, Italy's gas consumption declined by 9% y-o-y to 4.5 bcm (Figure 13), as lower demand in the residential and industrial sectors more than offset increased gas use for power generation. Gas consumption in the power sector rose by 12% y-o-y to 2.1 bcm. In contrast, industrial gas consumption fell by 11% y-o-y to 0.93 bcm, reflecting continued weakness in industrial activity (Figure 14). Meanwhile, residential consumption decreased by 18% y-o-y to 1.36 bcm, largely due to milder weather. The average temperature reached 15.8°C, around 1.7°C higher than in October 2025, reducing heating requirements.

Figure 13: Gas consumption in Italy

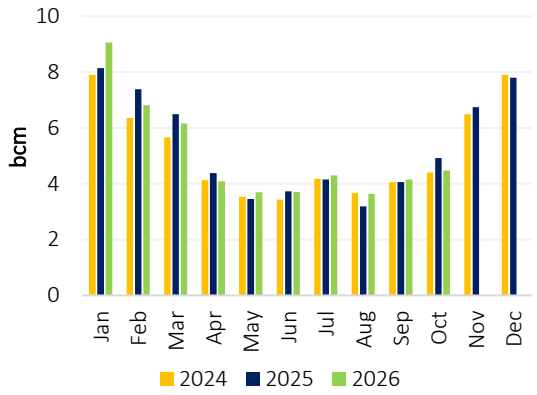
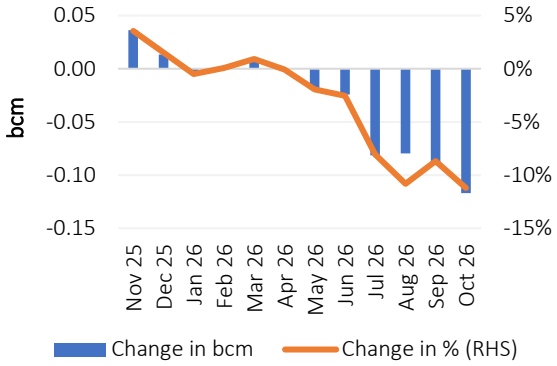


Figure 14: Trend in gas consumption in the industrial sector in Italy (y-o-y change)



Source: GECF Secretariat based on data from Snam

Italy's total electricity generation declined by 2% y-o-y (−0.5 TWh) in October 2026. Gas-fired generation recorded the largest increase, rising by 12% y-o-y (+1.2 TWh), as a sharp decline in hydropower and wind output increased the need for gas-fired generation to meet electricity demand. Hydropower generation fell by 49% y-o-y, while wind output decreased by 19%. In contrast, solar generation increased by 19% y-o-y, supported by continued capacity additions (Figure 15). Natural gas strengthened its position in the electricity mix, accounting for 54%, up from 47% a year earlier, while non-hydro renewables represented 35% (Figure 16).

Figure 15: Y-o-y changes in electricity generation by fuel in Italy, October 2026

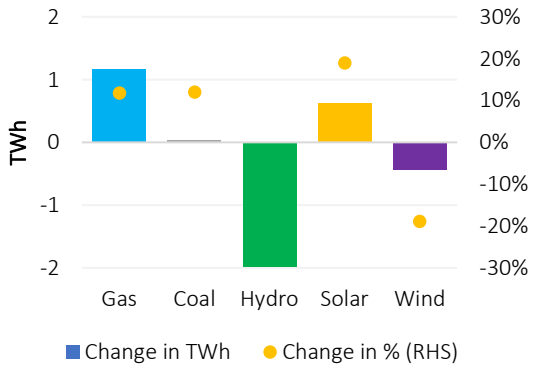
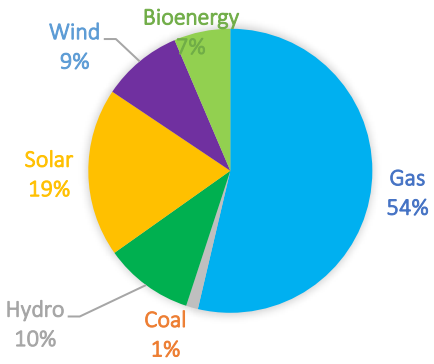


Figure 16: Italy's electricity mix, October 2026



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

For Jan-Oct 2026, Italy's gas consumption increased by 0.3% y-o-y to 50.1 bcm.

2.1.1.3 France

In October 2026, France's gas consumption declined by 8% y-o-y to 2.03 bcm (Figure 17), as lower demand in the industrial, residential and commercial sectors more than offset increased consumption for power generation. Industrial gas consumption fell by 7% y-o-y to 0.71 bcm (Figure 18). Meanwhile, residential and commercial consumption decreased by 13% y-o-y to 1.09 bcm, largely due to milder weather. The average temperature reached 15.1°C, around 0.6°C higher than in October 2025, reducing heating requirements.

Figure 17: Gas consumption in France

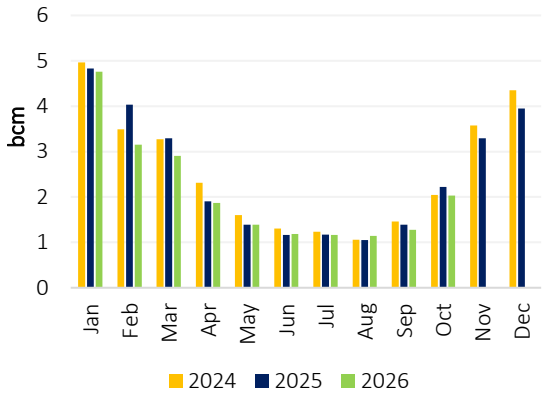
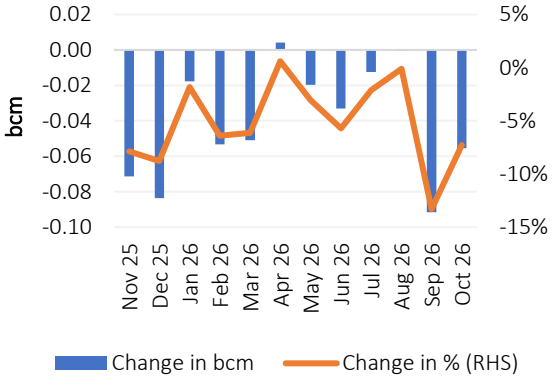


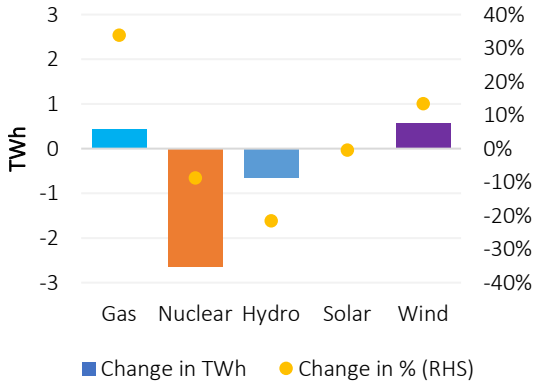
Figure 18: Trend in gas consumption in the industrial sector in France (y-o-y change)



Source: GECF Secretariat based on data from GRTgaz

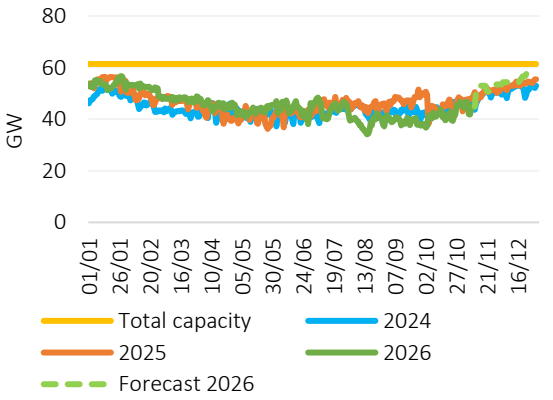
France's total electricity generation declined by 5% y-o-y (−2.2 TWh) in October 2026, primarily due to lower nuclear and hydropower output. Nuclear generation fell by 9% y-o-y (−2.6 TWh), as average nuclear capacity remained 9% below the year-earlier level, indicating continued constraints on reactor availability (Figure 20). Hydropower generation also decreased by 22% y-o-y (−0.7 TWh). In contrast, wind generation increased by 13% y-o-y (+0.6 TWh), while solar output remained unchanged. Lower nuclear and hydropower generation supported a 34% y-o-y increase in gas-fired power generation (+0.4 TWh), although this was insufficient to offset the decline in overall electricity output (Figure 19). Nuclear energy continued to dominate France's electricity mix, accounting for 70% of total generation, followed by non-hydro renewables (19%), hydropower (6%) and natural gas (4%).

Figure 19: Y-o-y changes in electricity generation by fuel in France, October 2026



Source: GECF Secretariat based on data from Ember

Figure 20: France's nuclear capacity availability



Source: GECF Secretariat based on LSEG and RTE

For Jan-Oct 2026, France's gas consumption declined by 7% y-o-y to 20.9 bcm.

2.1.1.4 Spain

In October 2026, Spain's gas consumption declined by 10% y-o-y to 2.4 bcm (Figure 21), reflecting lower demand in both the industrial and power generation sectors. Industrial gas consumption fell by 13% y-o-y to 1.3 bcm, extending the downward trend observed in recent months (Figure 22). Gas use for power generation also decreased by 5% y-o-y to 1 bcm, as higher nuclear and solar generation reduced the need for gas-fired power plants, more than offsetting the impact of lower wind and hydropower output.

Figure 21: Gas consumption in Spain

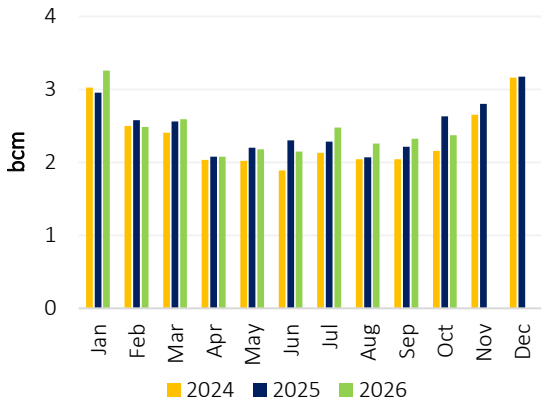
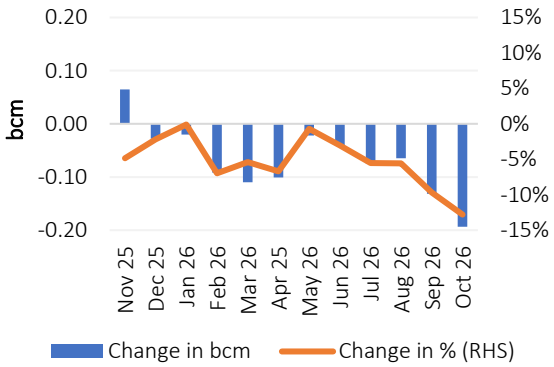


Figure 22: Trend in gas consumption in the industrial sector in Spain (y-o-y change)



Source: GECF Secretariat based on data from Enagas

Spain's electricity generation increased by 3% y-o-y (+0.6 TWh) in October 2026. Gas-fired generation declined by 11% y-o-y (−0.6 TWh), as higher nuclear and solar output outweighed lower wind and hydropower generation. Nuclear output rose by 30% y-o-y (+1.1 TWh) from a low base, recording the largest absolute increase among generation sources, while solar generation increased by 17% y-o-y (+0.7 TWh). Wind generation declined by 10% y-o-y (−0.4 TWh), while hydropower fell by 21% y-o-y (−0.3 TWh) (Figure 23). Within the electricity mix, non-hydro renewables remained the largest source, accounting for 45% of total generation, followed by natural gas (25%), nuclear (24%) and hydropower (6%) (Figure 24).

Figure 23: Y-o-y changes in electricity generation by fuel in Spain, October 2026

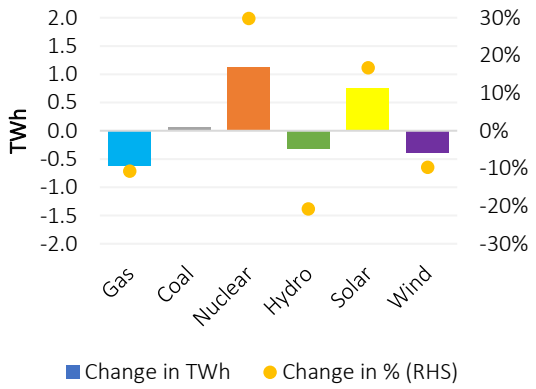
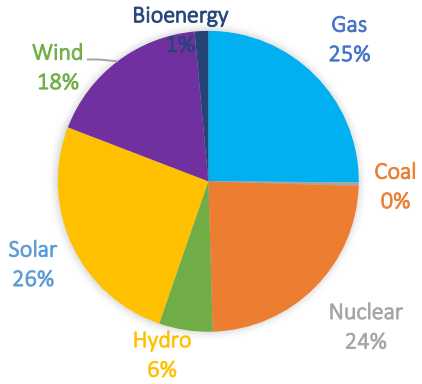


Figure 24: Spain's electricity mix, October 2026



Source: GECF Secretariat based on data from Ember and Ree

For Jan-Oct 2026, Spain's gas consumption rose by 1.2% y-o-y to 24.2 bcm.

2.1.2 United Kingdom

In October 2026, gas consumption in the UK decreased by 13% y-o-y to 4.0 bcm (Figure 25), driven by lower demand across all main sectors. Residential gas consumption decreased by 9% y-o-y to 3.0 bcm, as an average temperature of 11.6°C, around 0.4°C higher than in October 2025 and 0.8°C above the 30-year normal, limited heating requirements. Meanwhile, industrial gas demand declined by 26% y-o-y (Figure 26). Gas consumption in the power generation sector declined by 21% y-o-y to 0.97 bcm, indicating reduced reliance on gas-fired power plants. For Jan-Oct 2026, UK's gas consumption declined by 4.7% y-o-y to 41.5 bcm.

Figure 25: Gas consumption in the UK

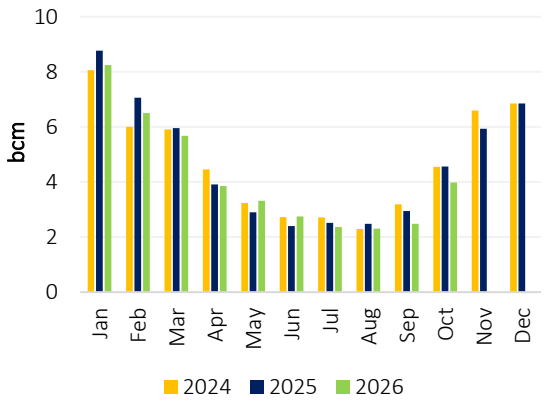
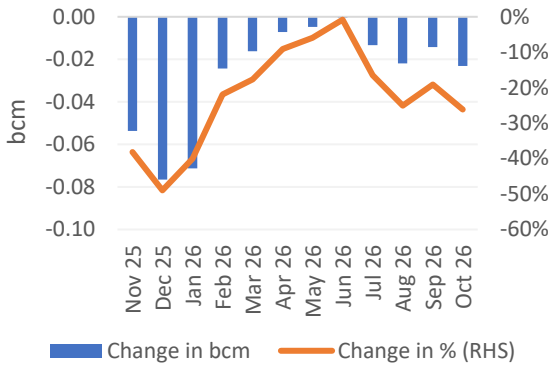


Figure 26: Trend in gas consumption in the industrial sector in the UK (y-o-y change)



Source: GECF Secretariat based on data from LSEG

For Jan–Oct 2026, combined gas consumption in the EU and the UK declined by 0.7% y-o-y (2 bcm) to 290 bcm (Figure 27). The decline was primarily driven by the UK, where gas consumption fell by 2 bcm y-o-y (Figure 28).

Figure 27: YTD EU and UK gas consumption

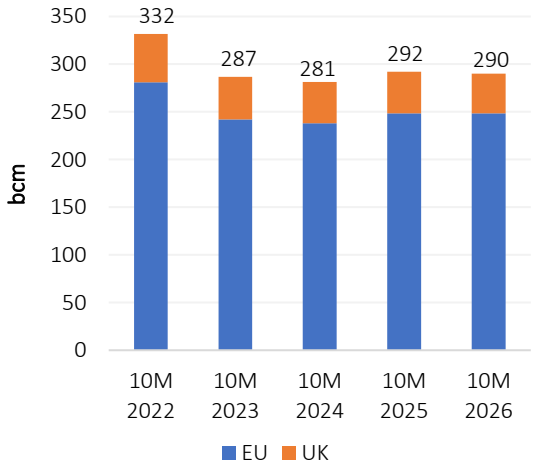
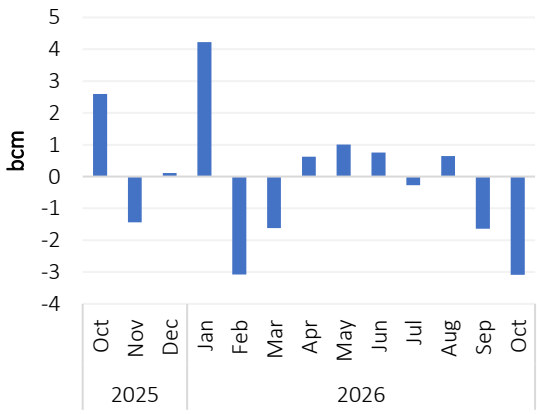


Figure 28: Y-o-y variation in EU and UK gas consumption



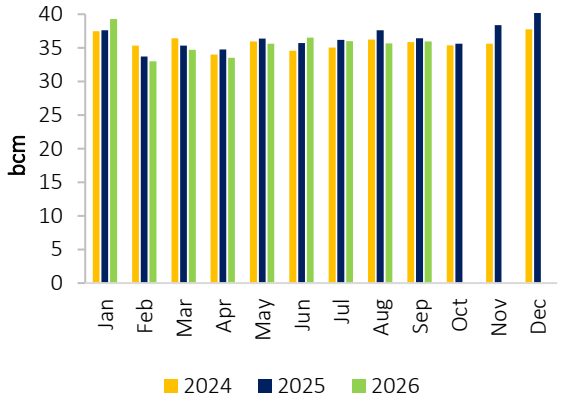
Source: GECF Secretariat based on data from LSEG

2.2 Asia

2.2.1 China

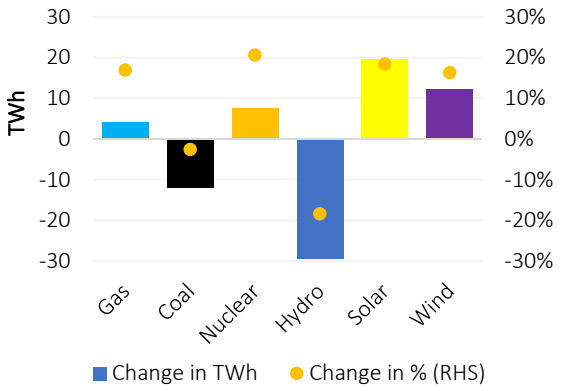
In September 2026, China's apparent gas demand (production + LNG and pipeline gas imports) declined by 1.3% y-o-y to 35.9 bcm (Figure 29). Industrial consumption remained sensitive to gas prices, while gas consumption for power generation increased by 17% y-o-y (Figure 30). For Jan–Sep 2026, gas consumption declined by 1% y-o-y to 320 bcm. Looking ahead, gas demand is projected to reach 500–570 bcm by 2030, according to the IGU, or 530–550 bcm, according to CPPEI, implying annual growth of 4–5%, primarily driven by the industrial and power sectors.

Figure 29: Gas consumption in China



Source: GECF Secretariat based on data from LSEG

Figure 30: Y-o-y changes in electricity generation by fuel in China, September 2026

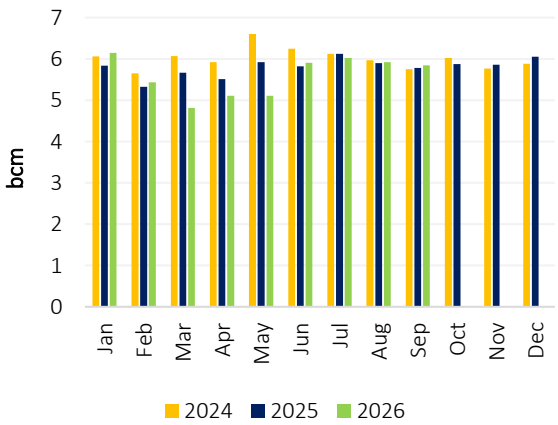


Source: GECF Secretariat based on data from Ember

2.2.2 India

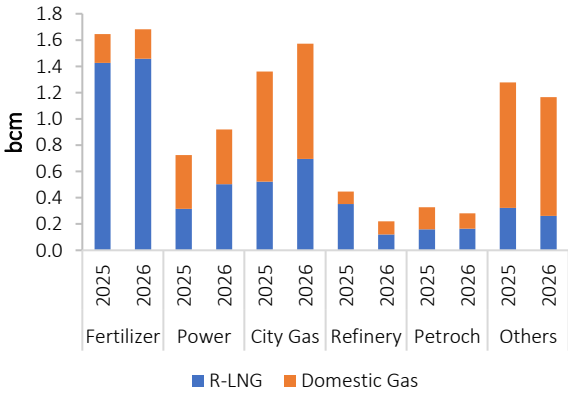
In September 2026, India's gas consumption increased by 1% y-o-y to 5.8 bcm (Figure 31), supported by higher demand in the city gas, power generation and fertilizer sectors. City gas consumption rose by 16% y-o-y (+0.21 bcm), while gas use for power generation increased by 27% (+0.19 bcm), mainly supported by higher LNG imports. Fertilizer remained the largest gas-consuming sector, accounting for 29% of total demand, followed by city gas at 27% (Figure 32). Despite the monthly increase, India's gas consumption declined by 3% y-o-y to 50.3 bcm in Jan–Sep 2026.

Figure 31: Gas consumption in India



Source: GECF Secretariat based on data from PPAC

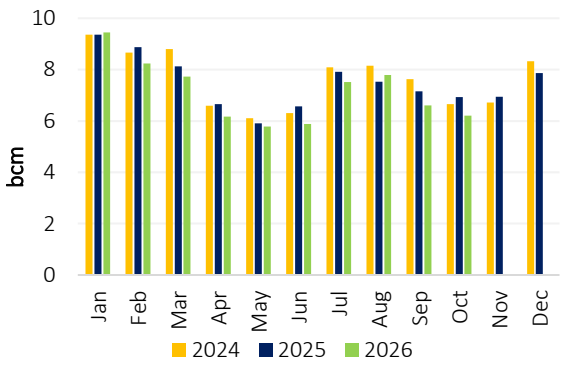
Figure 32: India's gas consumption by sector, September 2026



2.2.3 Japan

In October 2026, Japan's gas consumption declined by 10% y-o-y to 6.2 bcm (Figure 33), primarily due to lower demand in the power generation sector. Gas-fired generation fell to 18.5 TWh. The decline was driven by weaker electricity demand, which averaged 86 GW (down 2.5% y-o-y), and increased generation from coal and nuclear power plants. Coal-fired generation rose by 5% y-o-y to 18.7 TWh, while nuclear generation increased by 7% to 7.9 TWh. Despite the annual decline, electricity demand increased by 1.8% m-o-m.

Figure 33: Gas consumption in Japan

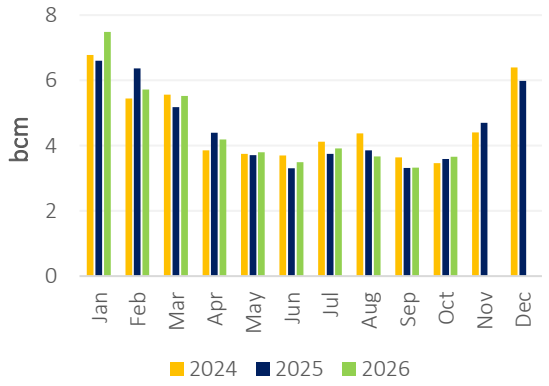


Source: GECF Secretariat based on data from LSEG

2.2.4 South Korea

In October 2026, South Korea's gas consumption increased by 2% y-o-y to 3.7 bcm (Figure 34), as a 10% increase in city gas demand to 1.6 bcm more than offset a 5% decline in gas use for power generation to 2.1 bcm. Lower gas consumption in the power sector was supported by higher nuclear availability, which averaged 19.5 GW, compared with 17.8 GW a year earlier. However, delays in the restarts of the 700 MW Wolsong 4 reactor and the 1.4 GW Saeul 3 unit limited the displacement of gas-fired output.

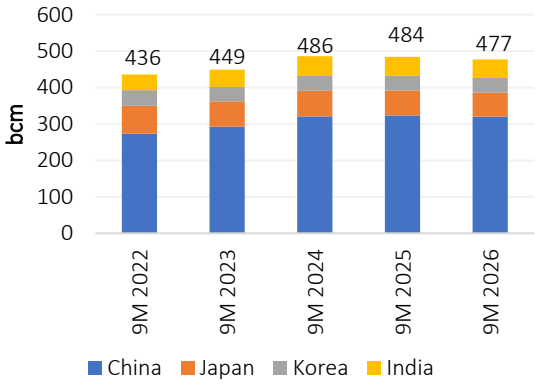
Figure 34: Gas consumption in South Korea



Source: GECF Secretariat based on data from LSEG

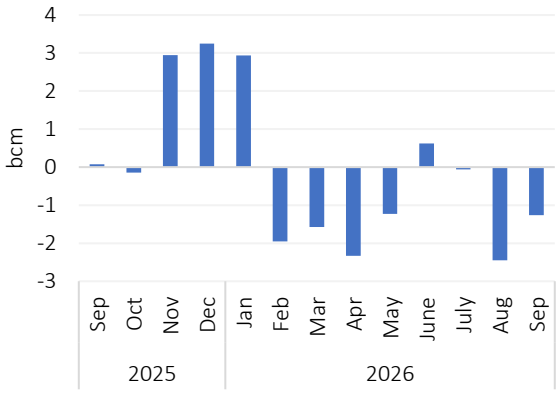
For Jan-Sep 2026, the aggregated gas consumption in major Asian gas consuming countries, namely China, India, Japan and South Korea, declined by 7.2 bcm y-o-y to reach 477 bcm (Figure 35), driven largely by a decrease of 3.4 bcm in China and 2.9 bcm in Japan (Figure 36).

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

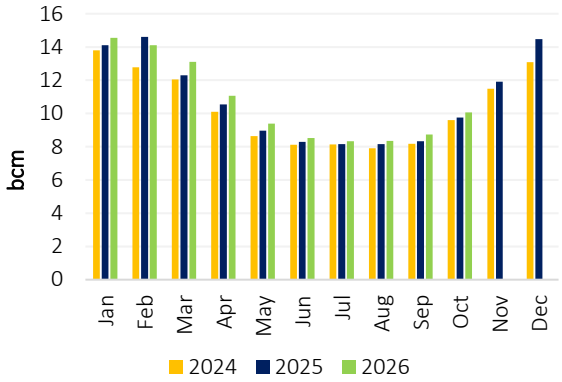


2.3 North America

2.3.1 Canada

In October 2026, Canada's gas consumption rose by 3% y-o-y to 10.1 bcm, supported by continued growth in industrial and power sectors (Figure 37). Combined gas consumption in these sectors rose by 3.3% y-o-y to 8 bcm, reflecting sustained industrial activity and steady electricity demand. Residential and commercial gas consumption also increased by 2% and 4% y-o-y, respectively, contributing to the overall growth. For Jan–Oct 2026, Canada's gas consumption increased by 3% y-o-y to 106 bcm, maintaining an upward trend.

Figure 37: Gas consumption in Canada



Source: GECF Secretariat based on data from LSEG

2.3.2 US

In October 2026, US gas consumption increased by 2% y-o-y to 70 bcm, primarily driven by stronger demand in the power generation sector (Figure 38). Gas consumption for power generation rose by 4.6% y-o-y, as higher gas-fired generation offset lower output from wind and hydropower. Industrial gas consumption also increased by 3% y-o-y, while residential and commercial consumption declined by 3% and 5% y-o-y, respectively.

Total electricity generation in the US increased by 0.7% y-o-y (+2.5 TWh) in October 2026. Gas-fired generation recorded the largest increase among generation sources, rising by 4.6% y-o-y (+6.6 TWh), as wind and hydropower output declined by 8% (−3.0 TWh) and 13% (−2.2 TWh), respectively (Figure 39). Solar generation also increased by 11% y-o-y, while nuclear output rose by 3%. In contrast, coal-fired generation declined by 8% y-o-y. Natural gas remained the largest source of electricity generation, accounting for 43% of the total, followed by nuclear (17%), coal (14%), solar and wind (10% each), hydropower (4%) and bioenergy (1%).

Figure 38: Gas consumption in the US

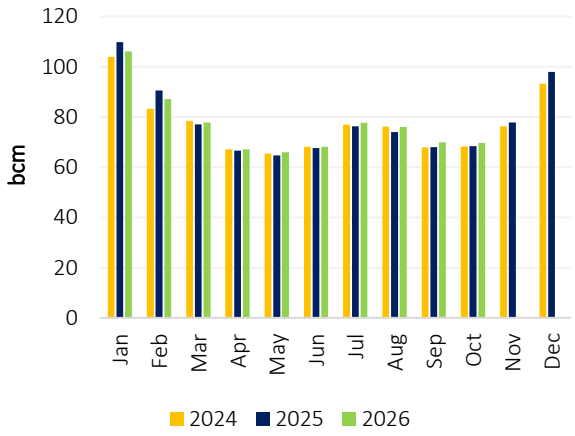


Figure 39: Y-o-y changes in electricity generation by fuel in the US, October 2026



Source: GECF Secretariat based on data from EIA and LSEG

For Jan–Oct 2026, US gas consumption increased by 0.4% y-o-y to 765 bcm.

2.4 Other developments

2.4.1 Sectoral developments

Singapore commissions 600 MW gas-fired power plant: Singapore's Sembcorp Industries commenced commercial operations at its new 600 MW combined-cycle gas turbine (CCGT) power plant on 28 October 2026. The hydrogen-ready facility, designed to accommodate lower-carbon fuels over time, will strengthen electricity supply to support Singapore's expanding digital infrastructure and energy-intensive industries, including data centres and semiconductor manufacturing. The plant is fully contracted under long-term arrangements. Its commissioning increases Sembcorp's combined gas-fired and renewable power portfolio in Singapore to 5.7 GW, reinforcing the role of gas-fired generation in meeting the country's electricity needs.

Japan's Kansai plans 1.95 GW of new high-efficiency gas-fired capacity: Kansai Electric Power plans to construct three new gas-fired power generation units at its Himeji-Daiichi power station in Hyogo Prefecture, western Japan, as part of its programme to modernise ageing generation facilities. Each unit will have a capacity of 650 MW, bringing the total planned capacity to 1.95 GW. The new facilities are expected to achieve thermal efficiency of 63%, compared with 54% for the existing units, enabling more efficient fuel utilisation and electricity generation. Their commissioning is scheduled for after FY2033–34.

Romania's 1.7 GW Mintia gas-fired power plant begins grid-connected testing: Romania's new Mintia gas-fired power plant entered the commissioning phase in October 2026. Its first 575 MW gas turbine was connected to the national electricity grid on 15 October, initially generating 135 MW during testing. The project, backed by an investment of more than €1.2 billion, is designed to provide 1.7 GW of total generation capacity through two gas turbines with a combined capacity of 1.15 GW and a combined-cycle system. Testing of the second 575 MW turbine is scheduled to begin in December 2026, with more than 1 GW of capacity expected to be connected to the national grid.

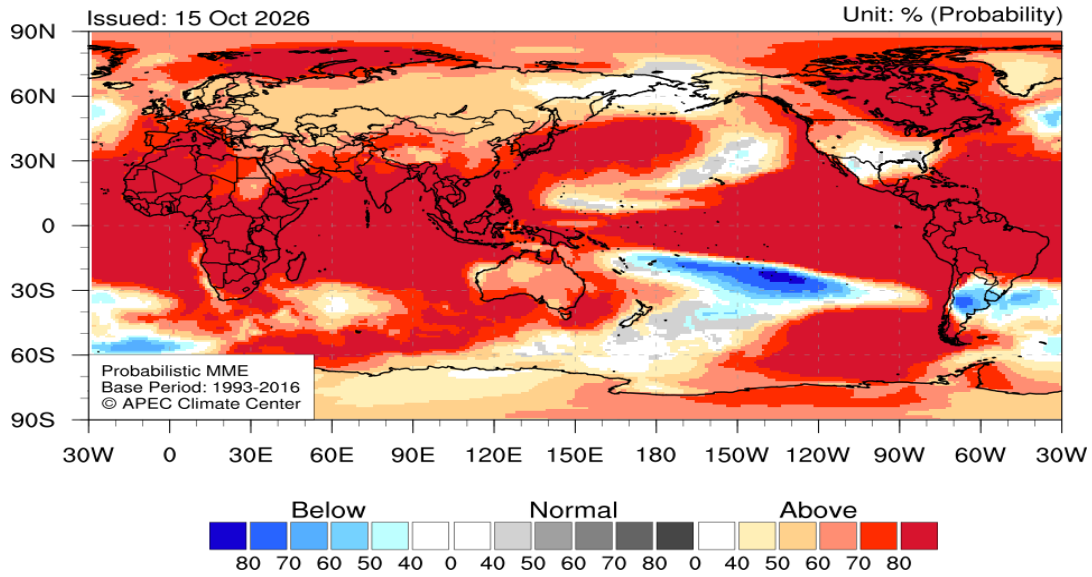
Australia's NSW considers tender for new gas-fired power capacity in 2027: New South Wales (NSW) plans to launch a tender in early 2027 to support up to 1.5 GW of additional power generation capacity, expected to come mainly from gas-fired plants, with projects required to be operational by May 2033. The initiative aims to address an anticipated capacity shortfall following the planned retirement of two coal-fired power stations. The tender will be open to different technologies, provided they can supply additional electricity to the grid, respond to demand when required and sustain output for at least eight hours. These conditions are expected to favour gas-fired peaking plants. Natural gas currently accounts for 2% of NSW's electricity generation, with its share projected to reach 4% by 2050.

China's LNG bunkering demand expected to quadruple by 2030: China's LNG bunkering market is projected to expand rapidly, driven by the growing adoption of LNG-fuelled vessels and efforts to reduce emissions in the shipping sector. According to Sinopec, demand is expected to increase from around 650,000 tonnes in 2025 to 2.5 million tonnes by 2030, reaching 7 million tonnes by 2035. Meeting this growth could require approximately 30 additional LNG bunkering vessels by 2035, compared with the five currently operated by three companies. Although alternative fuels such as ammonia and methanol are expected to gain traction, LNG is likely to retain an important role in maritime transport due to its established infrastructure, technological maturity and relative cost competitiveness.

2.4.2 Weather forecast

According to the APEC Climate Centre, an El Niño Alert is now issued for the sixth time, after three months of El Niño Watch in the last previsions. Between November 2026 and January 2027, above-normal temperatures are expected across most regions worldwide, except in some parts of the North Atlantic and central subtropical South Pacific and South America (Figure 40).

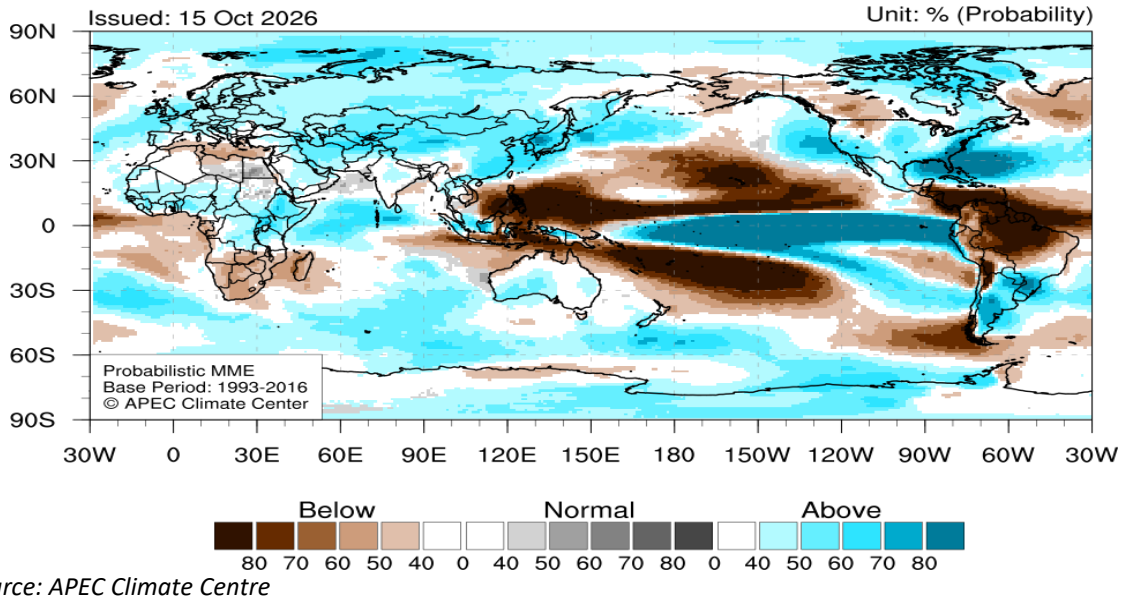
Figure 40: Temperature forecast for November 2026 - January 2027



Source: APEC Climate Center

Precipitation is expected to be above average in equatorial Pacific, part of Atlantic adjacent to the Gulf of Mexico, Arctic Sea, Great horn of Africa and equatorial Indian Ocean, West and Central Asia, parts of East Asia, southeastern South Pacific, southern North America, and southern South America. Africa and southwestern Australia. Below-average precipitation is forecast for the western tropical Pacific, part of Maritime continents and eastern tropical Indian Ocean, subtropical South Pacific, south tropical Atlantic, central America, Caribbean and northern part of South America, North Atlantic, and western Canada (Figure 41).

Figure 41: Precipitation forecast November 2026 - January 2027

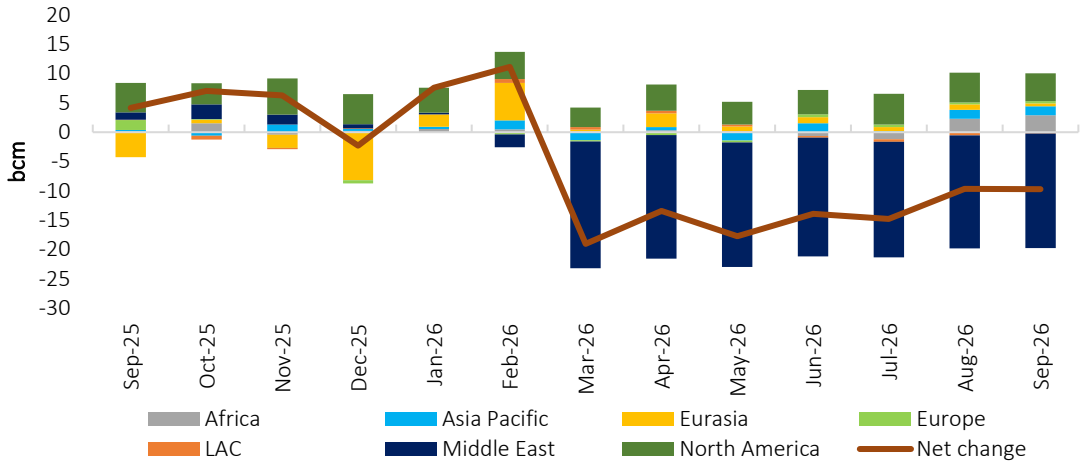


Source: APEC Climate Centre

3 GAS PRODUCTION

In September 2026, global gas production was estimated to have declined by 2.8% y-o-y to stand at 330 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, the conflict in the Middle East led to a significant shift in the geographical distribution of global gas production. North America strengthened its position as the leading producing region, accounting for 34% of global output in September 2026, up from 31% a year earlier, largely driven by US and Canadian production. Eurasia ranked second with a 19% share, followed by Asia Pacific at 17%. In contrast, the Middle East's share declined from 18% in September 2025 to 14% in September 2026. Africa, Europe, and LAC each accounted for between 4% and 7% of global gas production (Figure 43).

For Jan-Sep of 2026, global gas production is estimated to have declined by 2.6% y-o-y to stand at 3,037 bcm, mainly driven by the decline in the Middle East supply (Figure 44).

Figure 43: Regional gas production, September 2026

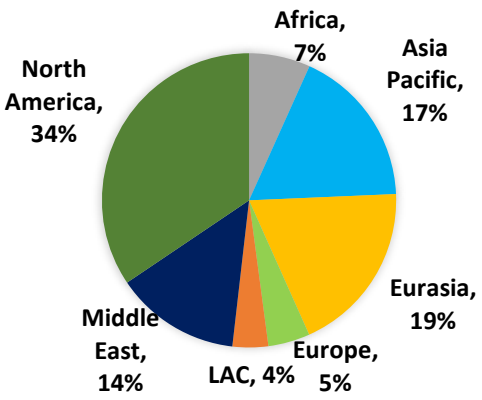
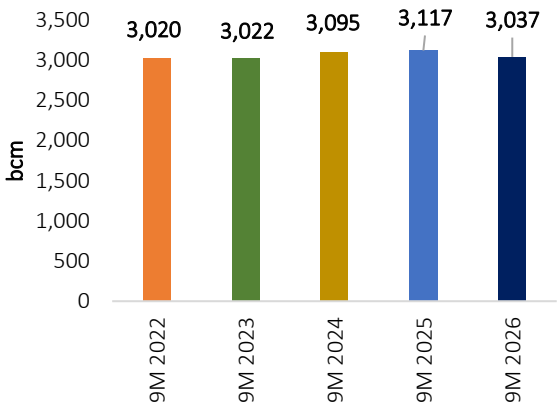


Figure 44: YTD global gas production



Source: GECF Secretariat estimation

3.1 Europe

In September 2026, gas production in Europe witnessed a 1.8% y-o-y rise, with a total output of 13.5 bcm (Figure 45). This is the fourth month in 2026 to record a y-o-y increase in the European output, mainly driven by robust Norwegian production. However, the magnitude of overall European production rise in September was limited by the decrease in gas production in the Netherlands and the UK (
Figure 46). Notably, monthly gas production in the EU stood at 2.3 bcm (2.7% higher than 2025 level), with Romania and the Netherlands maintaining their positions as top producers.

Figure 45: Trend in Europe's gas production

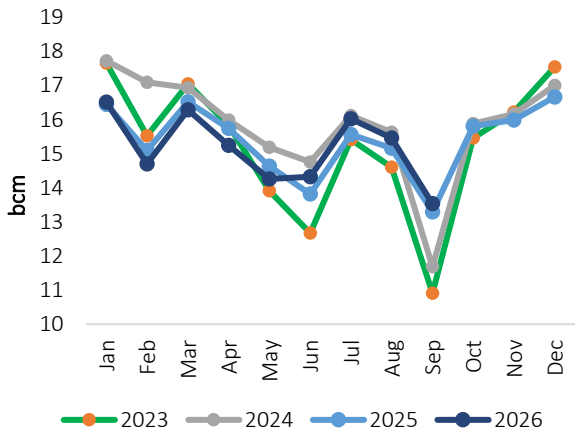
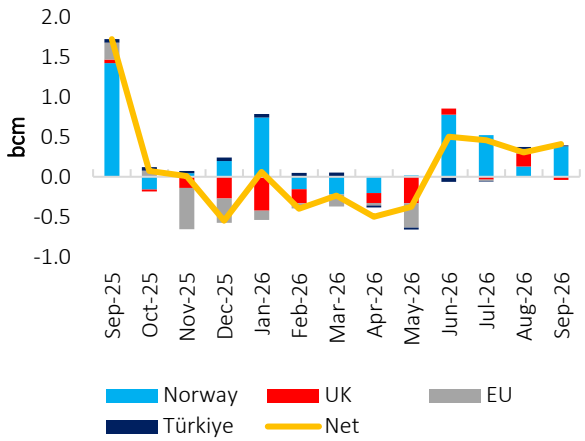


Figure 46: Y-o-y variation in Europe's gas production

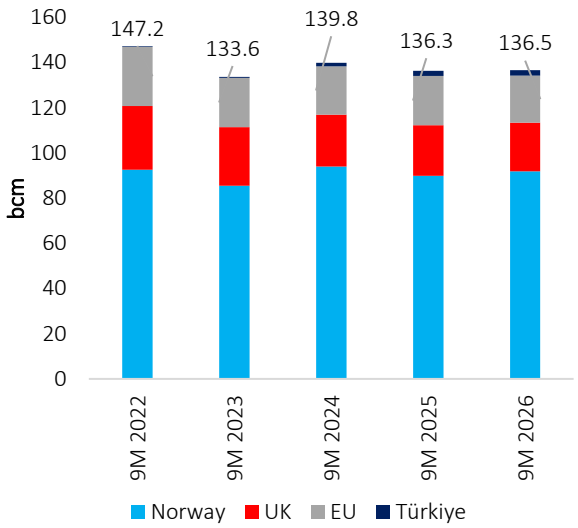


Source: GECF Secretariat based on data from LSEG, the Norwegian Offshore Directorate and JODI Gas
Note: EU countries include Austria, Denmark, Germany, Italy, Netherlands, Poland and Romania

For Jan–Sep 2026, Europe's cumulative gas production totalled 136.5 bcm, broadly in line with the level recorded in 2024, but higher than in both 2023 and 2025 (Figure 47).

This performance highlights the uncertainty surrounding Europe's full-year gas production outlook for 2026. Declining production in the UK and the Netherlands was the main factor weighing on European output over the period, while Norway, the largest European gas producer, accounting for nearly two-thirds of cumulative regional production, was able to offset these declines. Denmark is also on a positive trajectory for the full year of 2026, driven by increased production from the Tyra gas field. Romania and Türkiye are likewise expected to record production growth.

Figure 47: YTD Europe's gas production



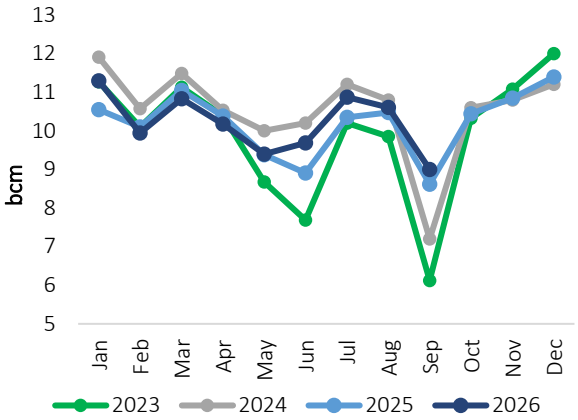
Source: GECF Secretariat based on data from Refinitiv, the Norwegian Offshore Directorate and JODI Gas

3.1.1 Norway

Norway's gas output continued its notable rise of 4.4% y-o-y, to stand at the level of 9 bcm in September (Figure 48). The growth was driven by the accurately planned maintenance period. Notably, the 124 mcm/d Troll field witnessed planned maintenance that reduced its production for 7 days. In addition, the 28.3 mcm/d Oseberg gas field underwent planned outage, which nearly ceased its production for a period of 5 days.

For Jan- Sep 2026, cumulative output reached 91.8 bcm, representing a 2.2% y-o-y growth, driven by lower planned and unplanned maintenance durations.

Figure 48: Trend in gas production in Norway



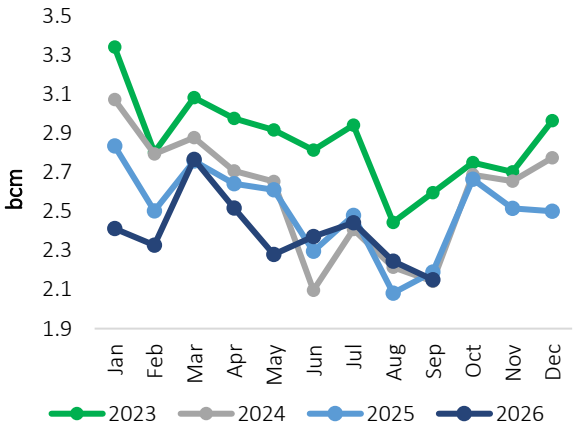
Source: GECF Secretariat based on data from the Norwegian Offshore Directorate

3.1.2 UK

UK gas production maintained its declining trend in September 2026, decreasing by 1.8% y-o-y to 2.15 bcm (Figure 49). The reduction was mainly driven by higher downtime at production facilities, which resulted in a lower output compared with September 2025. In addition, this decline reflected reduced production from mature gas fields, a lack of new gas projects coming online, as well as longer-than-expected maintenance periods at existing facilities.

For Jan– Sep 2026, cumulative gas production fell by 3.9% y-o-y to 21.5 bcm.

Figure 49: Trend in gas production in the UK



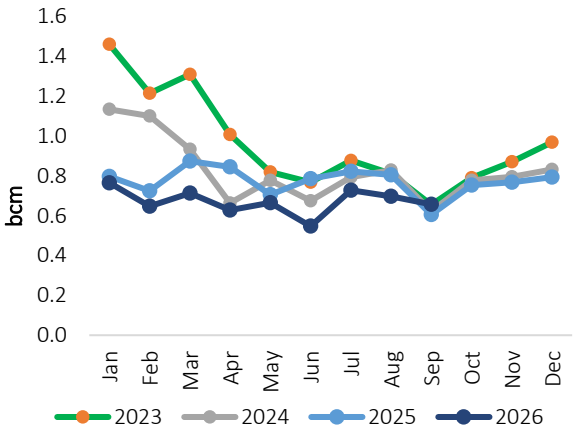
Source: GECF Secretariat based on data from LSEG

3.1.3 Netherlands

The Netherlands' gas production kept its downwards trend, decreasing by 2.7% y-o-y to 0.66 bcm in September 2026 (Figure 50).

In Jan-Sep 2026, cumulative production in the country reached 6.1 bcm, representing a 13% y-o-y reduction. In the absence of new field developments or efforts to rejuvenate existing production assets, output from ageing Dutch fields is likely to continue declining in the coming years, further reinforcing the country's long-term production challenges, with the remaining reserves expected to be depleted within approximately eight years.

Figure 50: Trend in gas production in the Netherlands



Source: GECF Secretariat based on data from LSEG

3.2 Asia Pacific

In September 2026, gas output in Asia Pacific was estimated to stand at 58 bcm, representing a 2.7% y-o-y growth. This increase was driven by the rise in China's gas output which offset the decline output in some regional Asia Pacific producers. For Jan-Sep 2026, the cumulative regional production is estimated to have reached 530 bcm, which represents a 0.8% rise y-o-y.

3.2.1 China

In September 2026, China's gas production increased by 0.8% y-o-y to stand at 21 bcm (Figure 51). This increase was mainly driven by the restart of some major offshore production platforms after maintenance activities. Coal bed methane production continued its annual growth as well, with 6.5% y-o-y rise, to stand at 1.25 bcm. For Jan-Sep 2026, cumulative production in China reached 196.8 bcm, representing a 1% y-o-y growth (Figure 52).

Figure 51: Trend in gas production in China

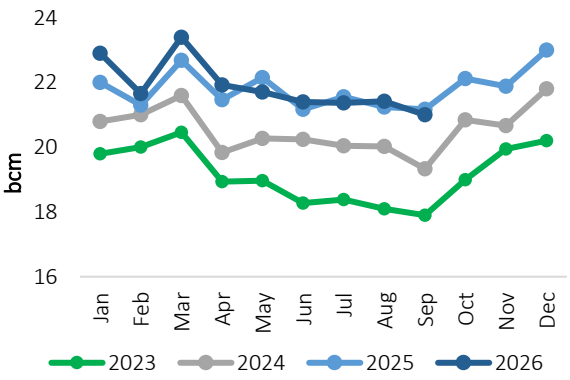
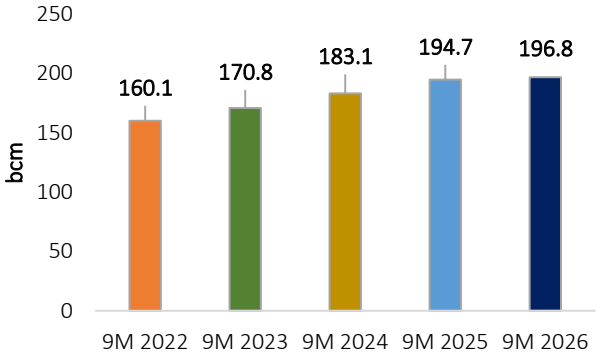


Figure 52: YTD China's gas production



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

3.2.2 India

In September 2026, India's gas production continued its negative trend, declining by 4.5% y-o-y to stand at 2.7 bcm (Figure 53). The decrease was driven by a reduction in offshore gas output, which represented 75% of Indian production. Meanwhile, the CBM gas fields recorded a growth of 5.1% y-o-y growth, mainly from the West Bengal fields. For Jan-Sep 2026, the cumulative production amounted to 24.9 bcm, representing a 4.5% y-o-y decline (Figure 54).

Figure 53: Trend in gas production in India

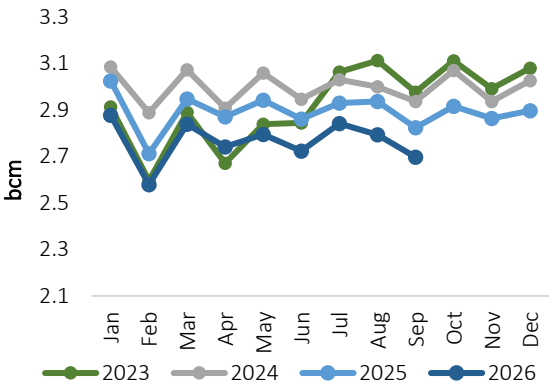
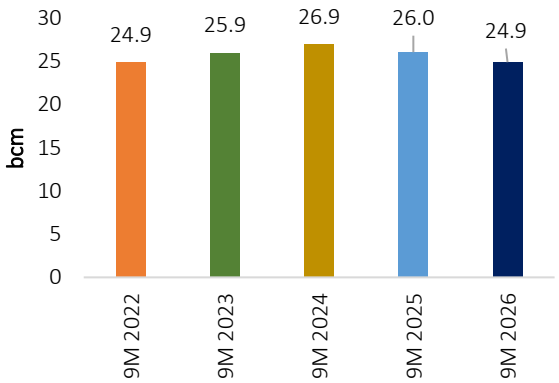


Figure 54: YTD India's gas production

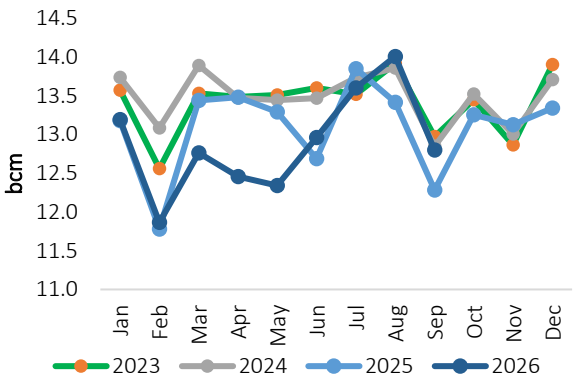


Source: GECF Secretariat based on data from the Ministry of Petroleum and Natural Gas (PPAC)

3.2.3 Australia

In September 2026, Australia's gas production rose by 4.2% y-o-y, to stand at 12.8 bcm (Figure 55). Gas production from CBM fields amounted to 3.45 bcm, representing a 1.4 % y-o-y growth and accounted for 27% of 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 Jan-Sep 2026, the cumulative production amounted to 116 bcm, representing a 1.2% y-o-y reduction.

Figure 55: Trend in gas production in Australia

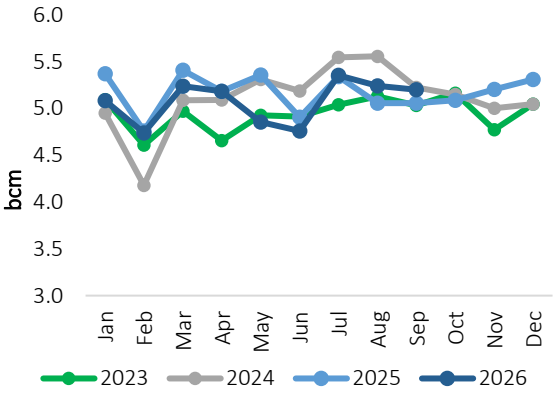


Source: GECF Secretariat based on data from the Australian Department of Energy

3.2.4 Indonesia

In September 2026, Indonesia's gas output rose by 2.8% y-o-y to 5.2 bcm (Figure 56). This increase was driven by an extensive development drilling campaign, with 75 new development wells drilled during the month. Their incremental production was sufficient to exceed the natural decline in output from existing producing fields. In addition, three new exploration wells were drilled in September, indicating an acceleration in exploration activity and continued efforts to replenish the country's resource base. For January–September 2026, cumulative output decreased by 1.7% y-o-y to 45.7 bcm.

Figure 56: Trend in gas production in Indonesia

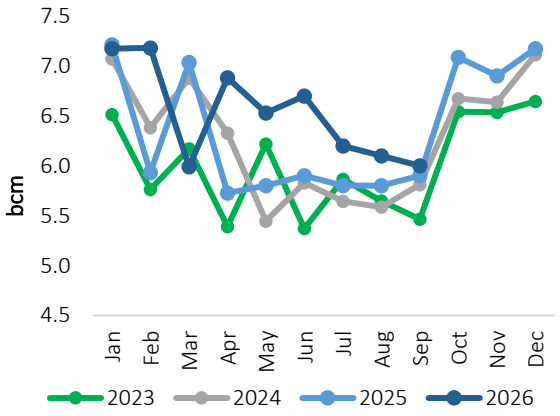


Source: GECF Secretariat based on data from SKK Migas and JODI Gas

3.2.5 Malaysia

In September 2026, Malaysia's gas output was estimated at 6 bcm, representing a 1.7% y-o-y growth (Figure 57). This reflected higher domestic gas output, supported by improved production performance across key producing assets. For Jan–Sep 2026, cumulative output grew by 6.6% to reach 58.8 bcm. The stronger output highlights the positive momentum in Malaysia's gas production, supporting the availability of natural gas for domestic consumption and export markets, while reinforcing its position as a major regional gas supplier.

Figure 57: Trend in gas production in Malaysia



Source: GECF Secretariat based on data from the JODI

3.3 North America

In September 2026, gas production in North America (including Mexico) rose by 3.2% y-o-y to reach 114 bcm, driven largely by strong gas supply growth in the US. For Jan-Sep 2026, cumulative production in North America reached 1,032 bcm, representing a 4% y-o-y growth.

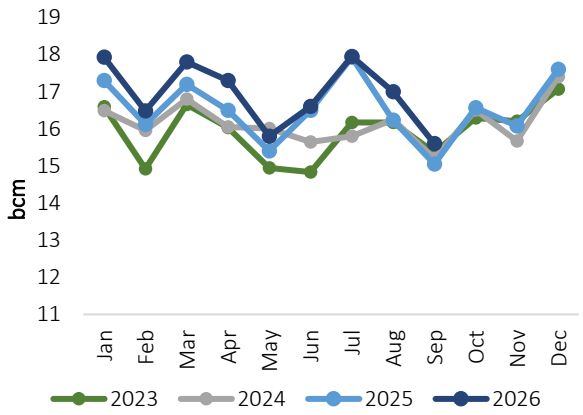
3.3.1 Canada

In September 2026, Canada's gas production grew by 3.7% y-o-y to 15.6 bcm (Figure 58), supported by an LNG export rise. From a regional perspective, Alberta was responsible for 9.5 bcm of the production, mainly originating from the Bakken shale production, whilst British Columbia accounted for 5.7 bcm, stemming from tight gas production from the Montney Basin.

For Jan-Sep 2026, the cumulative production amounted to 148 bcm, representing a 2.9% y-o-y rise. In this context, Canada is well poised to continue strong production growth, driven by the rising LNG exports and favourable market conditions.

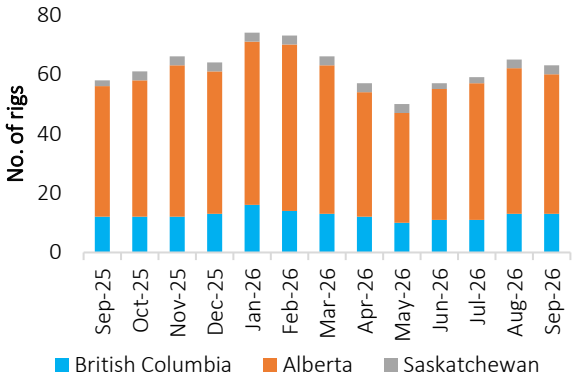
In terms of gas drilling activity, there was an overall 2-rig decrease in September 2026, with Alberta releasing 2 drilling rigs. Moreover, this represented a 5-rig-increase in the number of drilling rigs compared to September 2025 (Figure 59).

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

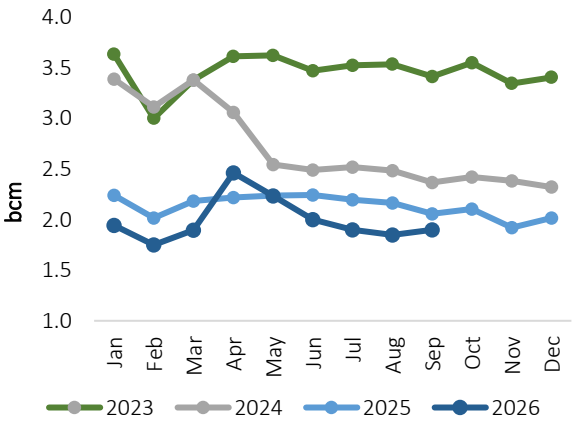


Source: GECF Secretariat based on data from LSEG

3.3.2 Mexico

In September 2026, Mexico's gas output was estimated at 1.9 bcm, representing a production decrease of 7.6% y-o-y (Figure 60). This reduction was driven by the natural decline in mature producing fields and the lack of new gas field developments. Associated gas production from oil fields represented 38% of total Mexican production, at 0.72 bcm, highlighting the country's continued reliance on hydrocarbon co-production. For Jan–Sep 2026, cumulative production in Mexico declined by 8.3% y-o-y to 17.9 bcm, reflecting persistent structural challenges in the domestic gas sector.

Figure 60:Trend in gas production in Mexico



Source: GECF Secretariat based on data from the JODI

3.3.3 US

In October 2026, US total gas production kept its consistent growth trend, with a monthly output of 100.4 bcm, rising by 7% y-o-y (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%, while conventional gas and associated gas production from shale oil represented the remaining 19%. In terms of field type, associated gas production accounted for 24% of total gas output. From a regional perspective, the Appalachian region accounted for 33% of total production, followed by the Permian region output with 25% and Haynesville with 15%.

For Jan-Oct 2026, cumulative gas production rose by 5% y-o-y to 966 bcm (Figure 62).

Figure 61: Trend in gas production in the US

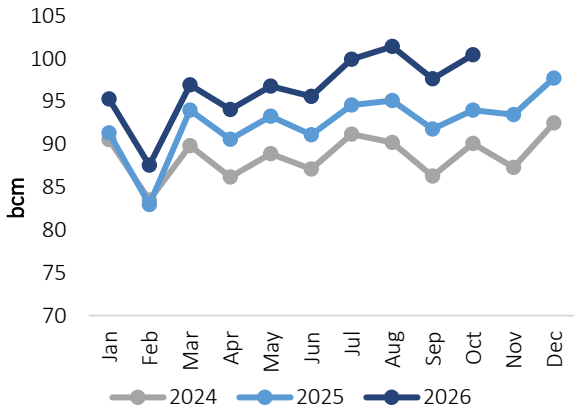
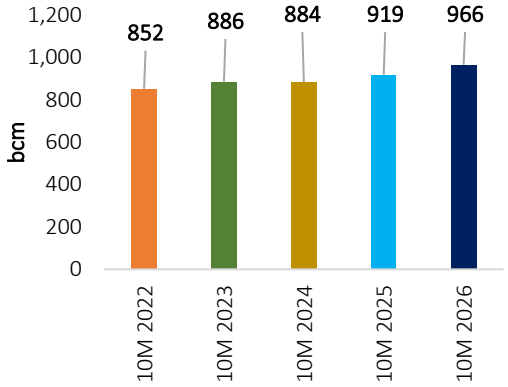


Figure 62: YTD gas production in the US



Source: GECF Secretariat based on data from the US EIA

As of October 2026, the number of gas drilling rigs operating in the US stood at 132, marking a 1-rig decrease compared to September 2026, and an 11-rig rise, compared to October 2025 (Figure 63), showing the current robust upstream activity in the US. Additionally, in October 2026, the total number of drilled but uncompleted (DUC) wells in the US onshore regions amounted to 4,752, a 25-well m-o-m decrease and 632 wells lower than October 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

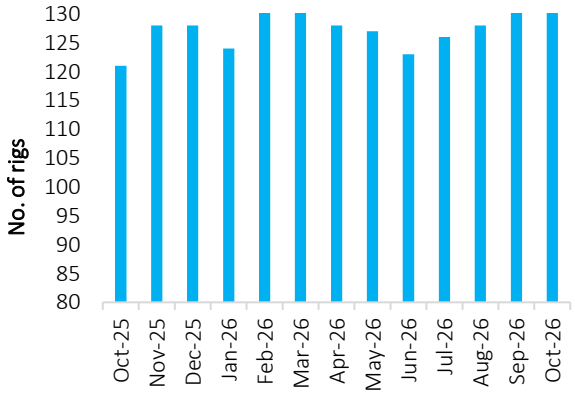
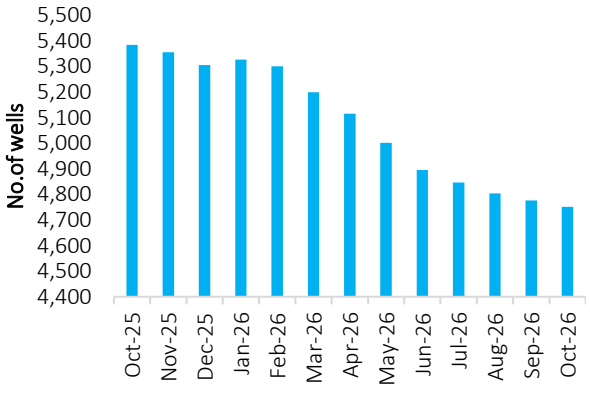


Figure 64: DUC wells count in the US



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 September 2026, gas production in LAC was estimated at 13 bcm (1.5% y-o-y decline). For Jan-Sep 2026, cumulative production reached 118 bcm, nearly mirroring last year level.

3.4.1 Argentina

In September 2026, Argentina's gas production rebounded by 6.2% y-o-y growth (Figure 65). Shale gas production from the Vaca Muerta Basin accounted for 52% of total output (Figure 66), while tight gas contributed 8% and conventional gas accounted for the remaining 34%. For Jan- Sep 2026, cumulative production in Argentina reached 40.1 bcm, a 0.3% y-o-y rise.

Figure 65: Trend in gas production in Argentina

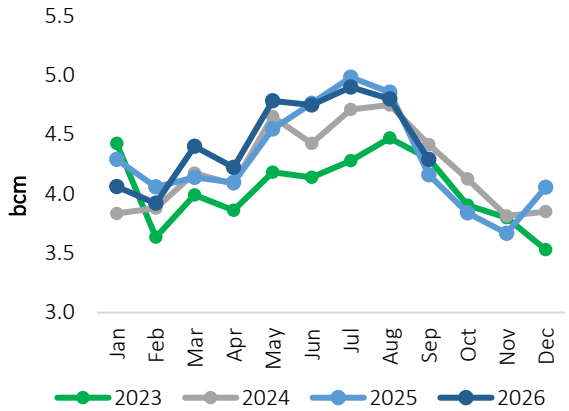
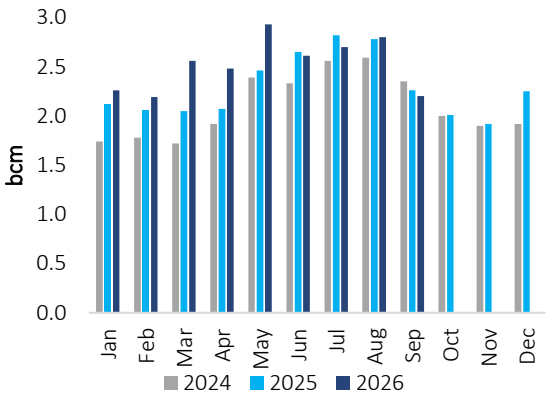


Figure 66: Shale gas output in Argentina



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

3.4.2 Brazil

In September 2026, Brazil's marketed gas production witnessed a marginal uptick of 0.2%, to achieve an output level of 2 bcm, driven by high gross gas production at 6.7 bcm (17 % y-o-y rise) and large reinjection volumes (Figure 67), with the pre-salt fields representing 79% of the total production. Notably, 88% of production originated from offshore fields. In terms of distribution, 59% of gross gas production was reinjected into reservoirs, while there was an 8% m-o-m and 14% y-o-y reduction in flaring (Figure 68). For Jan- Sep 2026, cumulative production reached 17.8 bcm, a 13% y-o-y growth.

Figure 67: Marketed gas production in Brazil

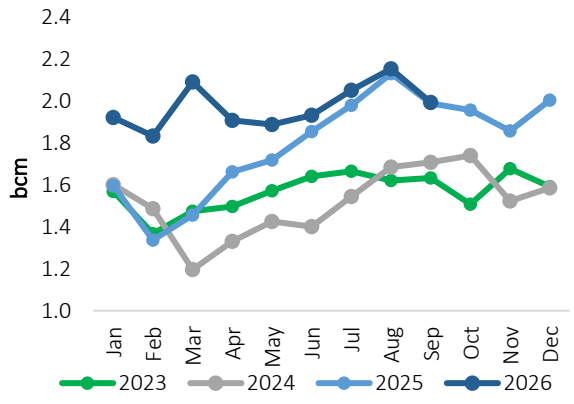
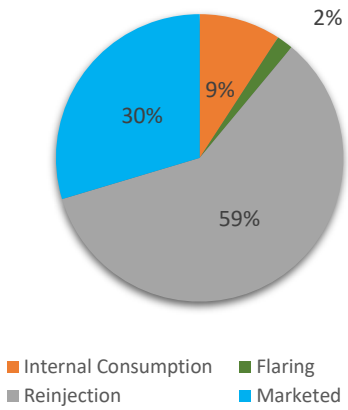


Figure 68: Distribution of gross gas production



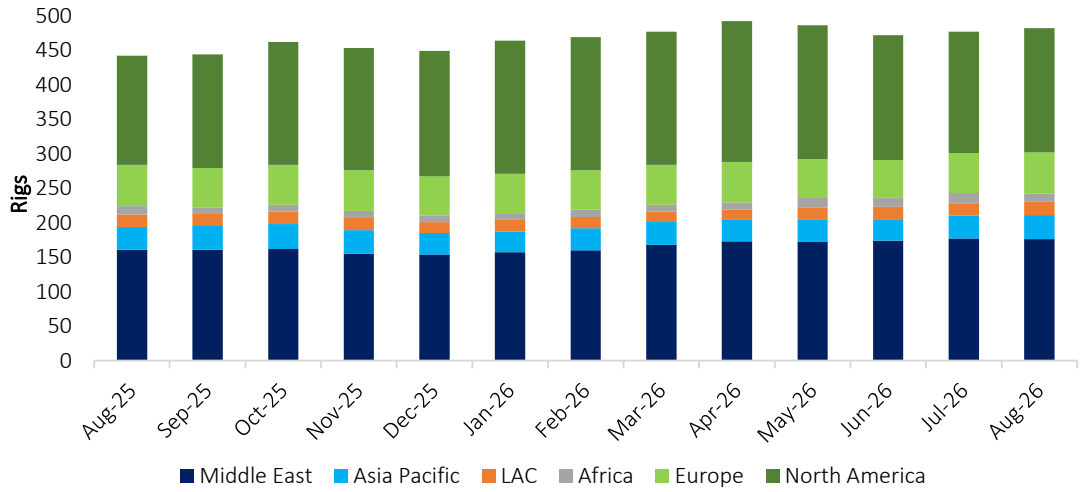
Source: GECF Secretariat based on data from the Brazilian National Agency of Petroleum (ANP)

3.5 Other developments

3.5.1 Upstream tracker

In September 2026, the number of gas drilling rigs globally accelerated by 8 additional units m-o-m, reaching 503 rigs (Figure 69). This was driven mainly by the increased drilling activity in North America and Middle East, specifically in the US and Saudi Arabia. Onshore drilling accounted for the majority with 470 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 September 2026, global exploration activity resulted in the total volume of discovered gas and liquids amounting to 380 million barrels of oil equivalent (boe) (Figure 70), with oil representing the majority share with 82% (310 million bbl), while gas accounted for 12 bcm. Seven new discoveries were announced in September and five of them were offshore. In terms of regional distribution, LAC (79%) dominated the new discoveries mainly in Guyana and Brazil, followed by Europe with 9% (Norway) and Africa with 8% (Tanzania) (Figure 71). The Kasa discovery, offshore Tanzania, which represents Tanzania's first reported new gas find in over a decade, was the most significant gas discovery during the month. For the period Jan-Sep of 2026, cumulative discovered volumes reached 3.9 billion boe.

Figure 70: Monthly discovered oil and gas volumes

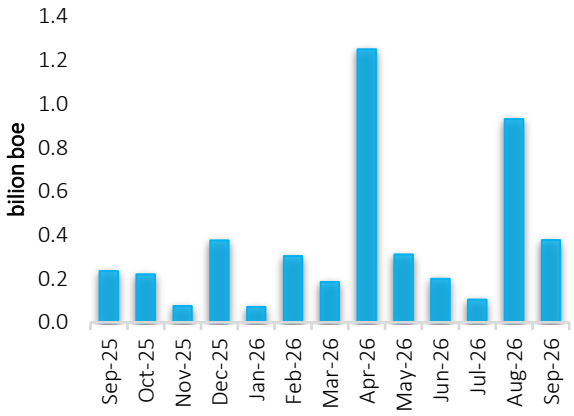
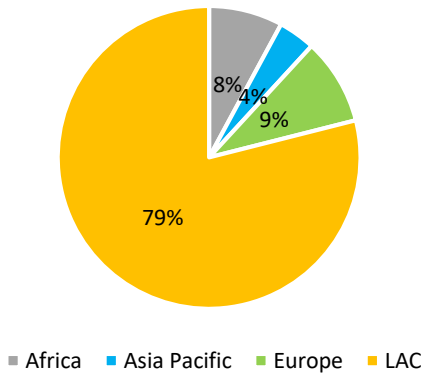


Figure 71: Discovered oil and gas volumes by region, September 2026



Source: GECF Secretariat based on data from Rystad

3.5.2 Regional developments

Egypt makes 200 bcf (5.66 bcm) gas discovery in Tiba concession: Egypt has announced a Mediterranean gas discovery at the Nasseem-1X exploratory well in the Tiba concession, with estimated gas in place of 5.7 bcm. Further assessments will determine recoverable reserves and potential daily production. Eni operates the concession alongside Woodside, with Petrobel undertaking drilling on their behalf. Development plans include a 22-km pipeline linking the well to the existing Abu Madi-El Gamil pipeline to accelerate production. The discovery supports Egypt's efforts to increase domestic supply and reduce import dependence.

Eni launches subsea bid process for big Libyan project: A joint venture between Eni and Libya's National Oil Corporation (NOC) has launched a bid process for a subsea production system linked to its huge Structures A&E project off the North African nation. Structure A is being developed by a large wellhead platform, while Structure E is set to be tapped via subsea wells tied back to a tension-leg platform, after the Mellitah Oil & Gas joint venture recently announced plans to use a massive, fixed steel platform due to cost, technical and logistics challenges. The overall development aims to pipe natural gas, liquids and carbon dioxide from block NC 41 to an upgraded onshore terminal at Mellitah, with the gas used in Libya and exported to Italy, and carbon dioxide piped back offshore for reinjection.

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.

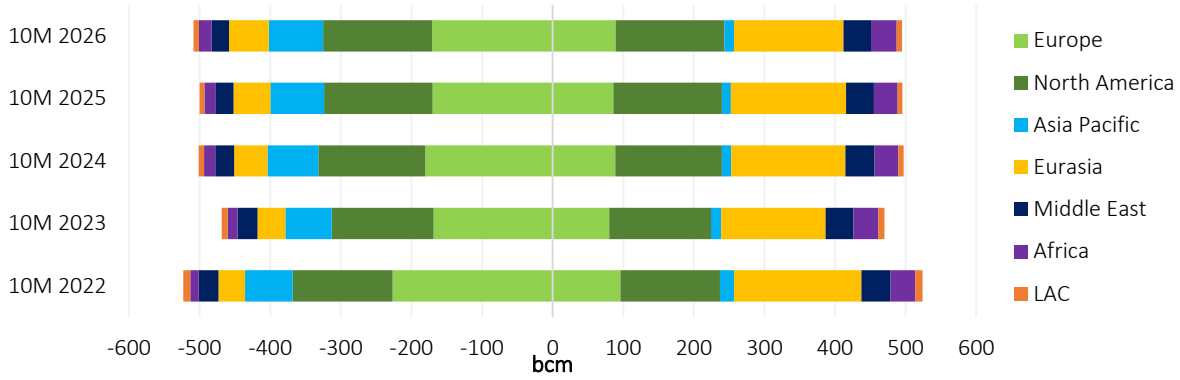
Malampaya Phase 4 achieves first gas from two deepwater wells offshore Philippines: The Malampaya Phase 4 (MP4) project has delivered first gas from the Malampaya East-1 and Camago-3 wells into the existing Malampaya production system offshore Palawan, adding an estimated 222 Bcf of recoverable natural gas reserves. The two new wells were connected to the existing Malampaya production platform through new subsea infrastructure, and the investment totalled close to $1 billion. MP4 was completed 27 months after final investment decision, about five months ahead of its original schedule. It was also the Philippines' first offshore drilling campaign in more than a decade.

4 GAS TRADE

4.1 PNG trade

During the first ten months of 2026, cumulative global PNG imports expanded by an estimated 2% y-o-y, reaching approximately 509 bcm (Figure 72). This growth was driven by increased imports into the EU, Kazakhstan, and Canada, which more than offset declining inflows into the US and Türkiye. Eurasia and North America dominated as the primary exporting regions, each capturing a 31% share of total global exports. Europe posted a 4% y-o-y surge in PNG exports, supported by robust production output from Norway.

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

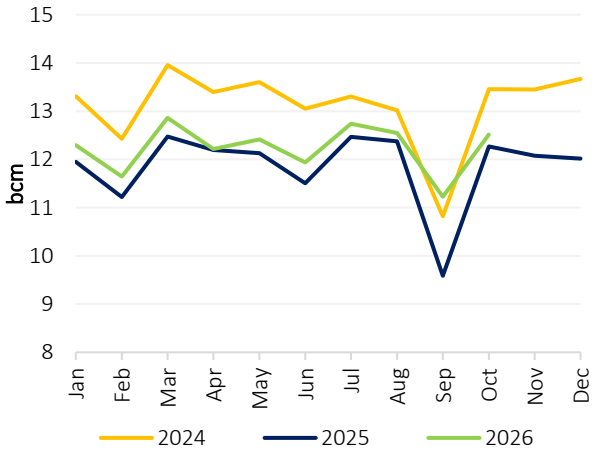


Source: GECF Secretariat based on data from Cedigaz, ENARGAS, Eurostat, GACC, JODI, LSEG and US EIA

4.1.1 Europe

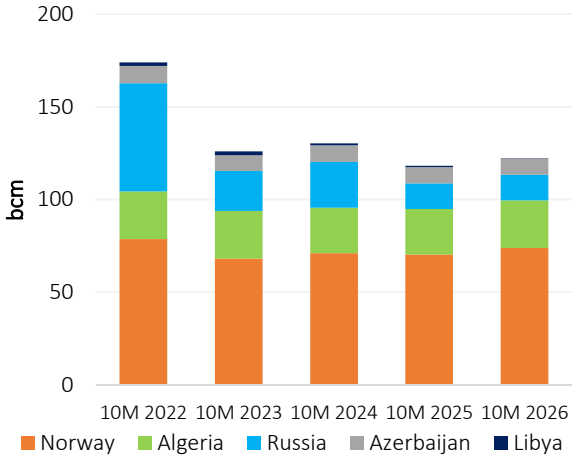
During October 2026, PNG imports into the EU reached 12.5 bcm, marking a 2% increase y-o-y (Figure 73). The average delivery rate rose to 404 mmcmd, which was an 8% increase m-o-m, driven primarily by a post-maintenance recovery following the completion of Norway's annual upstream works. This lifted cumulative EU PNG imports for 2026 to 122 bcm, representing a 4% increase y-o-y, underpinned by sustained strong supplies from Norway and Algeria (Figure 74).

Figure 73: Monthly PNG imports to the EU



Source: GECF Secretariat based on data from LSEG

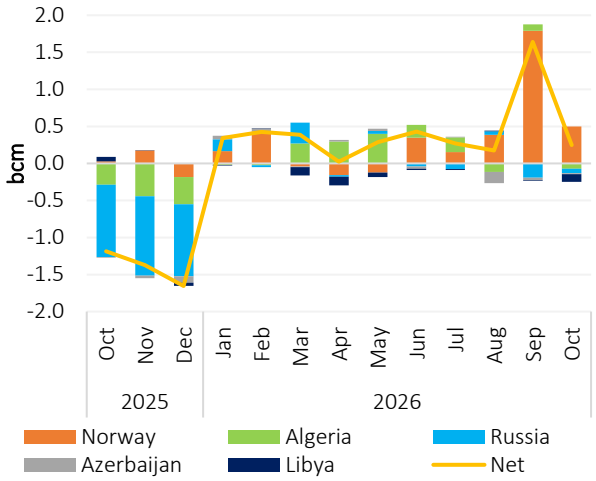
Figure 74: Year-to-date EU PNG imports by supplier



Source: GECF Secretariat based on data from LSEG

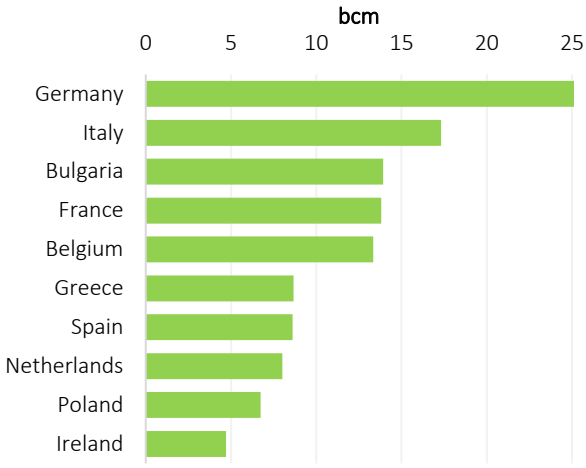
EU PNG imports achieved positive net y-o-y growth every single month in 2026, most notably in September 2026 due to lighter maintenance activity compared to the previous year (Figure 75). Germany maintained its position as the leading entry point across the bloc throughout 2026, while Greece surpassed Spain in the regional rankings for the year (Figure 76).

Figure 75: Y-o-y variation in EU PNG supply



Source: GECF Secretariat based on data from LSEG

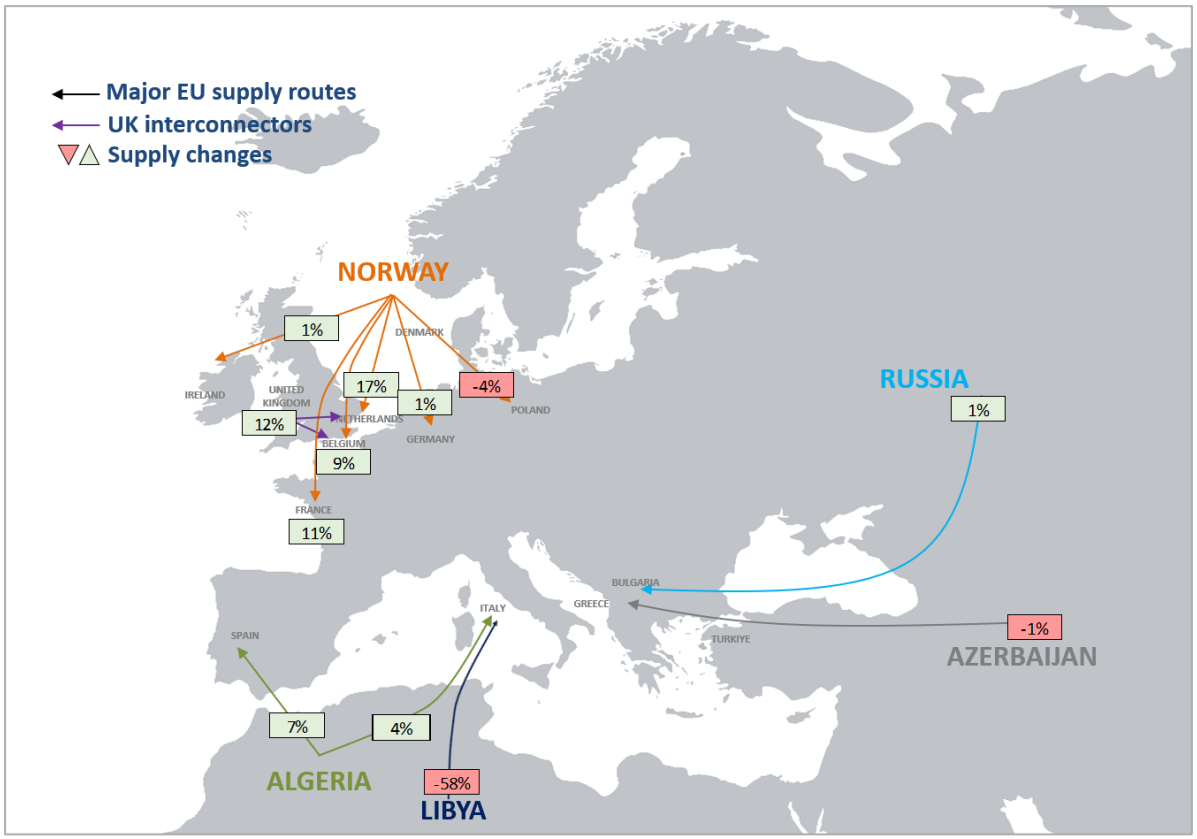
Figure 76: EU PNG imports by entry, after 10M 2026



Source: GECF Secretariat based on data from LSEG

Figure 77 shows the PNG imports to the EU via the major supply routes during the 10M 2026 period, relative to the same period in 2025. Norway particularly increased pipeline deliveries over the period to the Netherlands and France, each recording double-digit percentage growth, underpinned by expanded supply commitments and strong pre-winter production efforts. Similarly, Algeria ramped up exports via both Spain (up by 7%) and Italy (up by 4%), strengthening the vital Mediterranean supply routes. Furthermore, the UK interconnectors delivered 7.1 bcm of regasified LNG, a 12% y-o-y increase as mainland Europe drew on gas via the UK to build up its seasonal gas storage reserves.

Figure 77: PNG imports to the EU by supply route (10M 2026 v 10M 2025)



Source: GECF Secretariat based on data from LSEG

4.1.2 Asia

In September 2026, China imported 7.1 bcm of PNG, a 1% decline y-o-y, driven by subdued industrial demand during the month (Figure 78). However, daily deliveries averaged 238 mmcmd, a 5% m-o-m rise as flows ramped up toward month end to replenish storage. PNG comprised 48% of total September gas imports, representing only the fourth month in 2026 where PNG imports trailed LNG imports. This reflects buyers' structural preference for cheaper PNG contract pricing relative to spot LNG alternatives when global spot markers face elevated volatility. Nevertheless, PNG and LNG sustained equal shares of total gas imports across the year-to-date. Cumulative PNG imports in 2026 totalled 61 bcm, down 2% y-o-y (Figure 79).

Figure 78: Monthly PNG imports in China

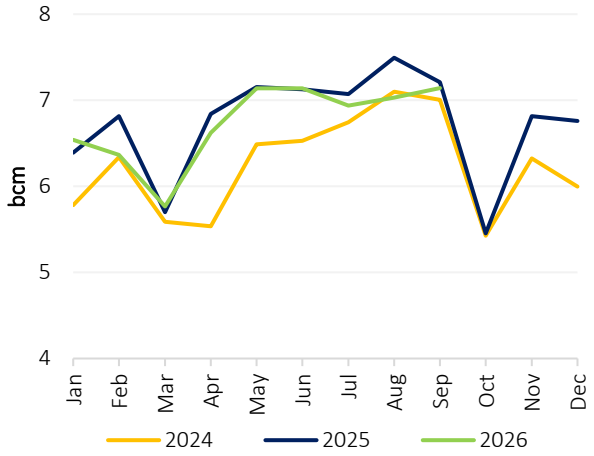
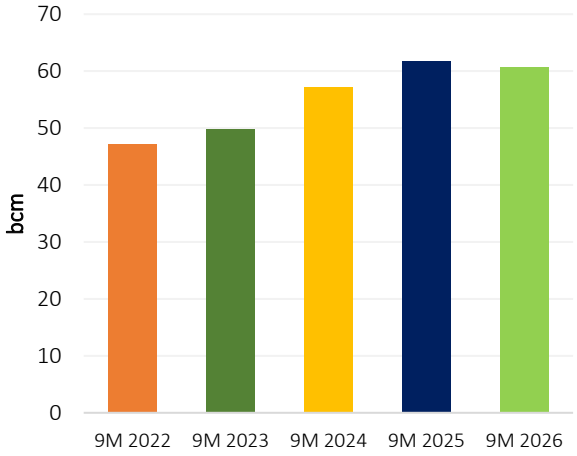


Figure 79: Year-to-date PNG imports in China



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

In August 2026, Singapore imported 0.65 bcm of PNG from Indonesia and Malaysia, a 13% increase y-o-y and a 6% increase m-o-m (Figure 80). This lifted cumulative PNG imports for the first eight months of the year to 4.9 bcm, up 22% y-o-y. During the same month, Thailand imported an estimated 0.34 bcm of PNG from Myanmar, dropping 14% y-o-y and 7% m-o-m (Figure 81). This decline reflects continuing natural depletion and upstream technical constraints. Consequently, Thailand's cumulative 2026 PNG imports reached 2.8 bcm, a 21% decrease y-o-y and compelling the country to increasingly turn to spot LNG imports.

Figure 80: Monthly PNG imports in Singapore

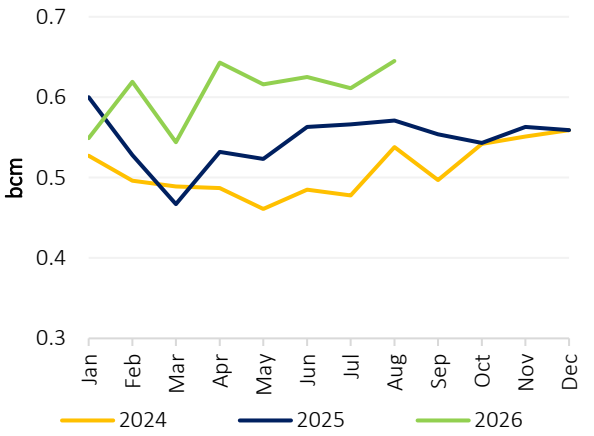
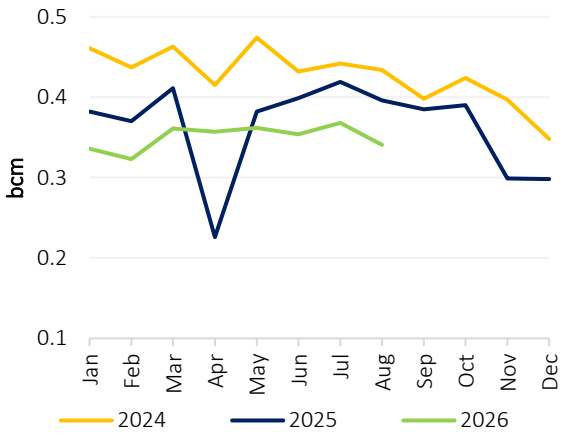


Figure 81: Monthly PNG imports in Thailand

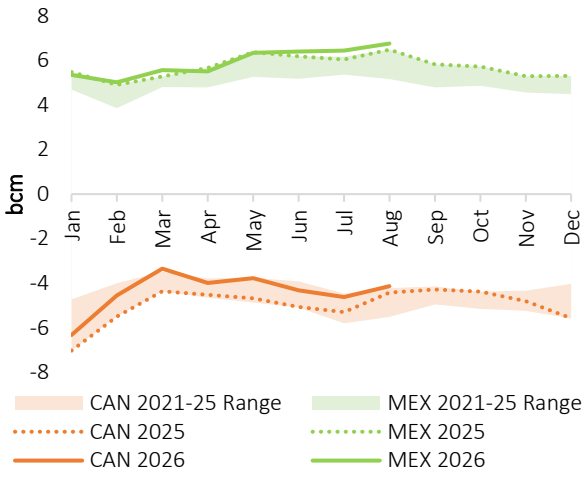


Source: GECF Secretariat based on data from JODI Gas

4.1.3 North America

In August 2026, Mexico imported 6.8 bcm of PNG from the US, a 4% increase y-o-y and a 5% gain m-o-m (Figure 82). This growth was driven by sustained robust demand from Mexico's power generation sector and expanding industrial gas consumption, lifting cumulative imports for the first eight months of the year up 2% y-o-y to 47 bcm. Net PNG flows from Canada to the US totalled 4.1 bcm, down 7% y-o-y and 11% m-o-m. Gross exports from Canada to the US declined m-o-m to 6.6 bcm, while reverse flows increased m-o-m to 2.5 bcm. Cumulative net flows from Canada to the US in 2026 contracted 14% y-o-y to 35 bcm.

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

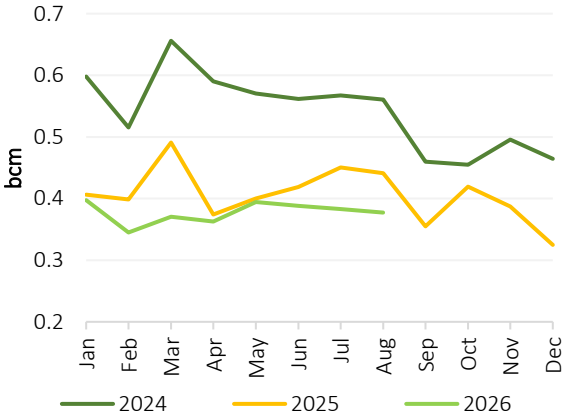


Source: GECF Secretariat based on data from US EIA

4.1.4 Latin America and the Caribbean

In August 2026, Bolivia exported an estimated 0.38 bcm of PNG, declining by 14% y-o-y, with daily flows also decreasing 1% m-o-m (Figure 83). This brought cumulative exports for the first eight months of the year to 3.0 bcm, an 11% reduction y-o-y. Argentina exported an estimated 0.30 bcm of PNG during the same month, a 14% increase y-o-y and a 13% m-o-m rise in daily delivery. This was bolstered by rising production from Vaca Muerta and expanding regional export capacity, lifting Argentina's total exports through the first eight months of 2026 by 33% y-o-y to 2.5 bcm.

Figure 83: Monthly PNG exports from Bolivia



Source: GECF Secretariat based on data from JODI Gas

4.1.5 Other developments

Revival of the Antonio Ricaurte pipeline: With growing interest in addressing Colombia's domestic gas needs by tapping into Venezuela's reserves, energy stakeholders are exploring the repair and reopening of the 400-km Antonio Ricaurte pipeline. The scope for initial restoration requires an estimated $60–62 million to ready a critical 2-km section for an initial flow of 1.7 to 2.8 mmcmd, potentially providing additional supplies to help ease domestic market tightness.

Cyprus sets 2028 target for Kronos gas exports to Egypt: Cyprus is finalising plans to export natural gas from the Kronos field to Egypt by early 2028, utilising existing infrastructure via the Zohr field, with the initial output slated for the European market. Parallel developments are moving forward for the Aphrodite and Isai deposits, which will involve new subsea pipelines to meet Egypt's high domestic demand. While local infrastructure for Cypriot consumption remains sidelined due to market size, the focus has shifted to establishing Cyprus as a regional supplier through these established Mediterranean transit corridors.

4.2 LNG trade

4.2.1 LNG imports

In October 2026, global LNG imports fell by 4.4% (1.60 Mt) y-o-y to 34.94 Mt, although they reached their highest monthly level since March 2026 (Figure 84). The decline was driven primarily by lower imports into Europe, with a smaller reduction recorded in the Middle East and Africa (MEA). These decreases were partially offset by higher imports into Asia and Latin America and the Caribbean (LAC). Global LNG trade continued to be impacted by the ongoing Middle East conflict, as restrictions on transit through the Strait of Hormuz disrupted LNG exports from Qatar and the UAE.

Between January and October 2026, global LNG trade decreased by 1.5% (5.35 Mt) y-o-y to 350.74 Mt, primarily reflecting reduced LNG supplies from the Middle East, which weighed heavily on imports into Asia and Europe (Figure 85).

Figure 84: Trend in global monthly LNG imports

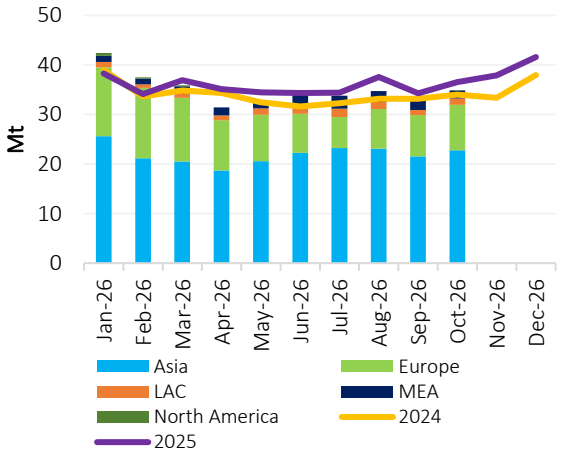
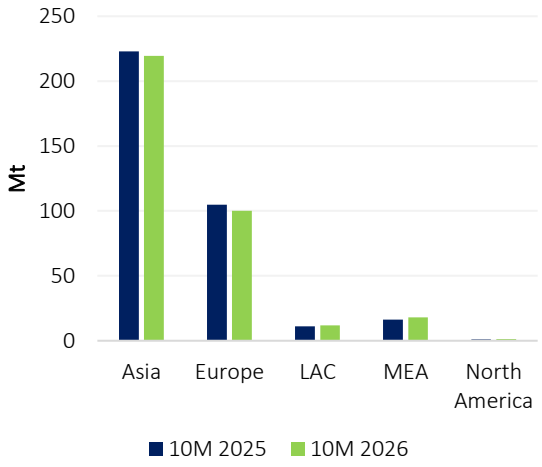


Figure 85: Trend in regional YTD LNG imports



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.1 Europe

In October 2026, Europe's LNG imports dropped sharply by 16% (1.77 Mt) y-o-y to 9.18 Mt but was still at the highest level since May 2026 (Figure 86). The decline was mainly due to the impact of the Middle East conflict, which reduced Qatari LNG supply to the region, as well as a partial shift in LNG supply from Russia's Yamal LNG facility away from Europe to Asia. At the country level, Belgium, Germany, Italy, Poland, Türkiye and the UK recorded the largest declines, partially offset by higher imports in France, the Netherlands and Portugal (Figure 87).

The decline in LNG imports across several European countries was primarily driven by reduced deliveries from key suppliers. Belgium recorded lower imports from Qatar, Russia and the US, while Germany's decline was mainly attributable to reduced US LNG deliveries. Similarly, lower LNG imports from Qatar weighed on imports into Italy and Poland. In Türkiye, elevated spot LNG prices discouraged spot purchases, contributing to the decline in imports. Meanwhile, the UK recorded lower deliveries from Algeria and the US. Conversely, France's LNG imports increased, supported by stronger deliveries from Algeria and Norway, while higher US LNG supplies drove import growth in the Netherlands and Portugal. Overall, LNG trade flows from Algeria and the US have shifted across European markets driven by pricing dynamics.

From January to October 2026, Europe's LNG imports fell by 4.5% (4.72 Mt) y-o-y to 100.13 Mt.

Figure 86: Trend in Europe's monthly LNG imports

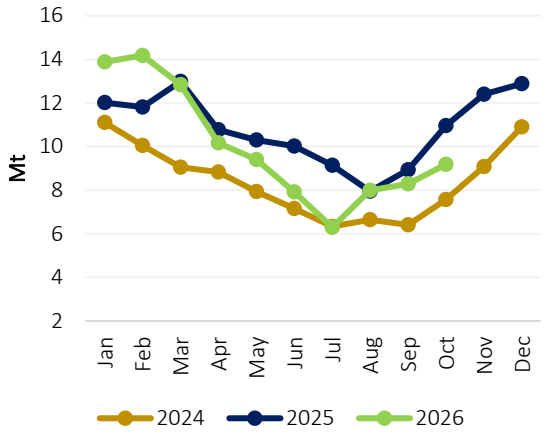
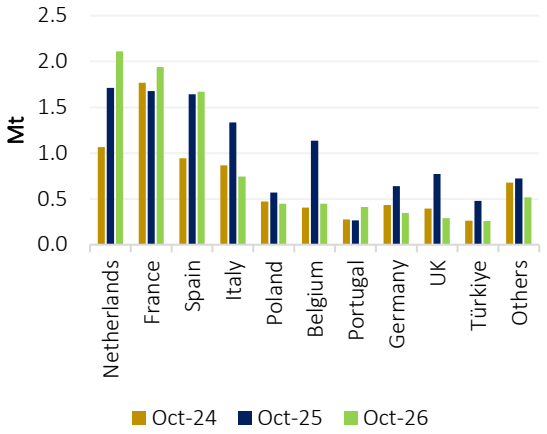


Figure 87: LNG imports in Europe by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.2 Asia

In October 2026, Asia's LNG imports increased by 1.3% (0.28 Mt) y-o-y to 22.75 Mt, reversing the declines recorded in August and September 2026 (Figure 88). Despite reduced Middle Eastern LNG supplies and multi-year high spot prices, stronger deliveries from North America, Russia and West Africa supported increased imports for winter stockpiling. At the country level, significant increases in LNG imports into China, Indonesia, South Korea and Vietnam more than offset lower imports into Japan, Pakistan and Taiwan (Figure 89).

China's LNG imports reached their highest monthly level since January 2026, with the y-o-y increase driven by stronger stockpiling ahead of the winter season. Similarly, winter stockpiling supported higher LNG imports into South Korea, while increased intra-country LNG trade boosted Indonesia's imports. In Vietnam, stronger gas demand led to an increase in spot LNG purchases. Conversely, elevated LNG inventories in Japan reduced the need for additional imports, while Pakistan's LNG imports declined due to lower deliveries from Qatar. Meanwhile, LNG importers in Taiwan adopted a wait-and-see approach in anticipation of easing market tightness, resulting in reduced LNG purchases.

From January to October 2026, Asia's LNG imports dropped by 1.5% (3.36 Mt) y-o-y to 219.50 Mt.

Figure 88: Trend in Asia's monthly LNG imports

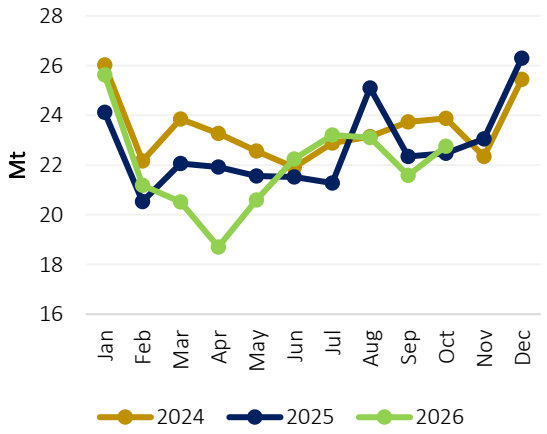
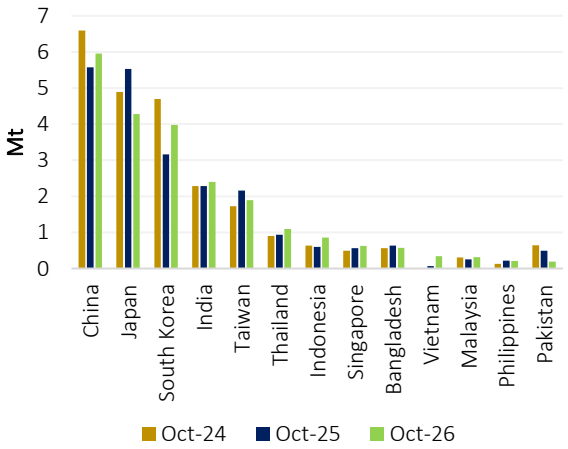


Figure 89: LNG imports in Asia Pacific by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.3 Latin America & the Caribbean (LAC)

In October 2026, LNG imports in Latin America and the Caribbean (LAC) jumped by 30% (0.30 Mt) y-o-y to 1.31 Mt (Figure 90). Colombia accounted for the bulk of the regional increase, more than offsetting lower imports in the US Virgin Islands (USVI) (Figure 91).

The increase in Colombia's LNG imports was driven by stronger gas demand for power generation, amid reduced hydropower availability associated with El Niño conditions and declining domestic gas production. Conversely, LNG imports into the USVI declined following the cessation of its operations as a breakbulking LNG transhipment facility in the Caribbean.

From January to October 2026, LAC's LNG imports increased by 7.0% (0.78 Mt) y-o-y to 11.84 Mt.

Figure 90: Trend in LAC's monthly LNG imports

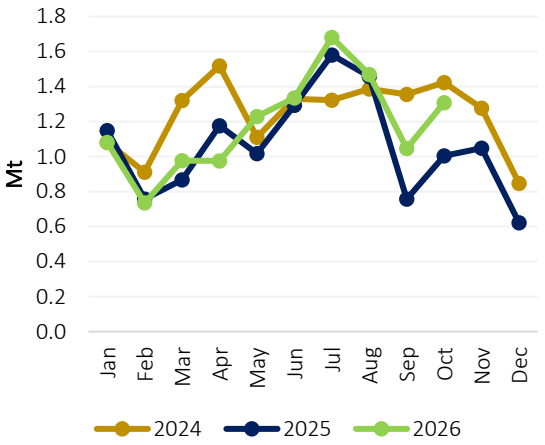
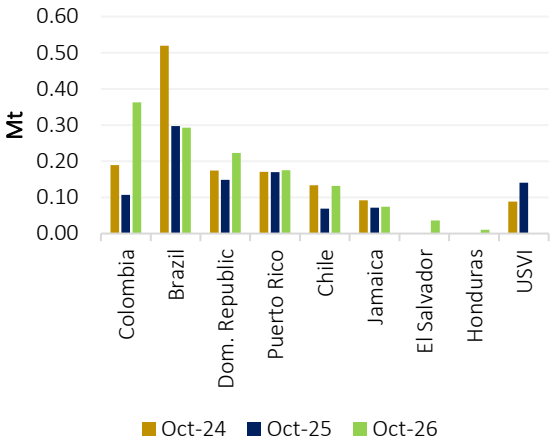


Figure 91: LNG imports in LAC by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.4 Middle East and Africa (MEA)

In October 2026, LNG imports into the MEA recorded its third consecutive monthly y-o-y decline, declining by 22% (0.47 Mt) y-o-y to 1.65 Mt (Figure 92). Egypt accounted for the bulk of the decline in the region's LNG imports, while the UAE recorded a smaller reduction (Figure 93). Lower LNG imports into Egypt were likely driven by elevated global spot LNG prices, which encouraged fuel-switching towards cheaper fuel oil for electricity generation.

From January to October 2026, MEA's LNG imports rose by 10% (1.70 Mt) y-o-y to 18.00 Mt.

Figure 92: Trend in MEA's monthly LNG imports

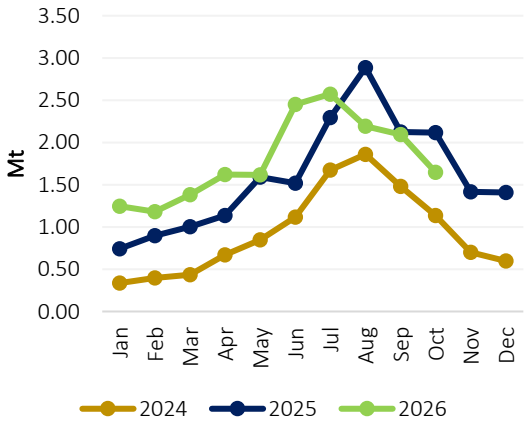
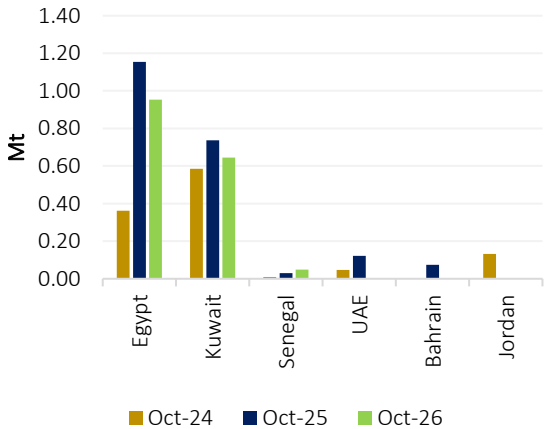


Figure 93: Top LNG importers in MEA



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2 LNG exports

In October 2026, global LNG exports declined by 3.8% (1.46 Mt) y-o-y to 36.81 Mt, although they reached their highest monthly level since February 2026 (Figure 94). The ongoing Middle East conflict continued to constrain global LNG supply, as restrictions on transit through the Strait of Hormuz disrupted LNG exports from the region. Despite higher exports from non-GECF countries and an increase in LNG re-exports, these additional volumes could not fully offset the decline in exports from GECF Member Countries. The US, Australia and Russia remained the world's three largest LNG exporters during the month.

Reflecting these shifts in global LNG supply, the market share of non-GECF countries increased from 54.3% in October 2025 to 62.0% in October 2026, while the share of LNG re-exports rose from 0.4% to 1.9%. Conversely, GECF Member Countries' share decreased significantly from 45.3% to 36.1% over the same period.

From January to October 2026, global LNG exports fell by 1.4% (5.02 Mt) y-o-y to 351.78 Mt, primarily driven by reduced exports from GECF Member Countries (Figure 95).

Figure 94: Trend in global monthly LNG exports

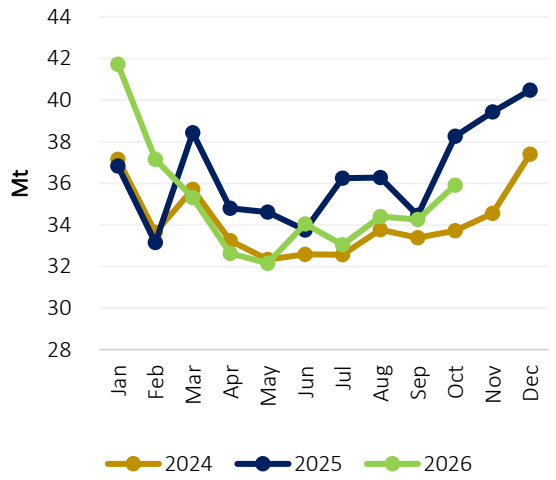
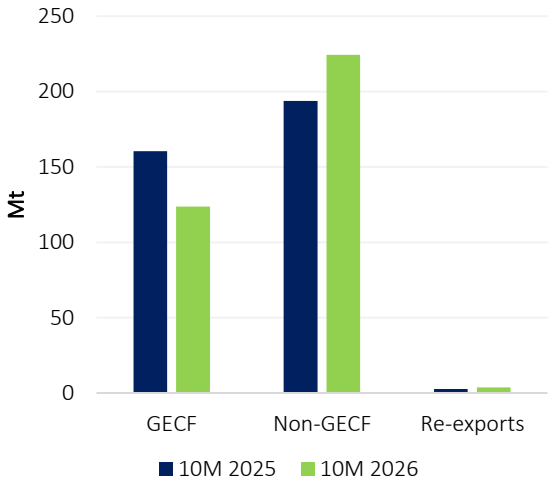


Figure 95: Trend in YTD LNG exports by supplier



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.1 GECF

In October 2026, LNG exports from GECF member countries reached 13.28 Mt, representing a decline of 23% (4.05 Mt) y-o-y (Figure 96), primarily driven by reduced exports from the Middle East amid restrictions on LNG transit through the Strait of Hormuz (Figure 97). Qatar accounted for the bulk of the decline, with smaller reductions recorded in Angola and Equatorial Guinea. These decreases were partially offset by higher LNG exports from Malaysia, Nigeria and Russia.

Qatar's LNG exports remained constrained by ongoing restrictions on transit through the Strait of Hormuz amid the Middle East conflict. Nevertheless, the country's exports reached their highest monthly level since the onset of the conflict. Similarly, despite the transit restrictions, the UAE recorded an increase in LNG exports in October 2026. Elsewhere, improved feedgas availability supported higher LNG exports from Malaysia and Nigeria, while increased production at the Arctic LNG 2 facility boosted Russia's LNG exports.

For the period January to October 2026, LNG exports from GECF member countries fell by 23% (36.69 Mt) y-o-y to 123.70 Mt.

Figure 96: Trend in GECF monthly LNG exports

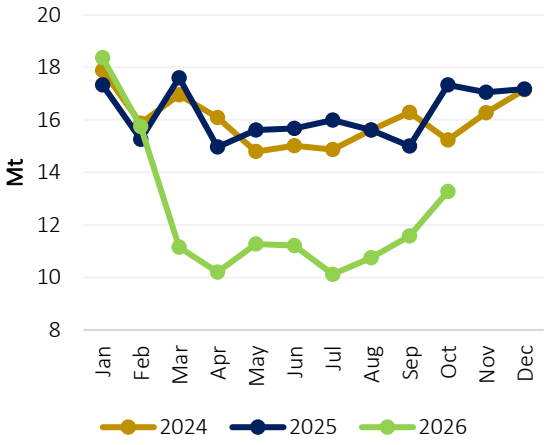
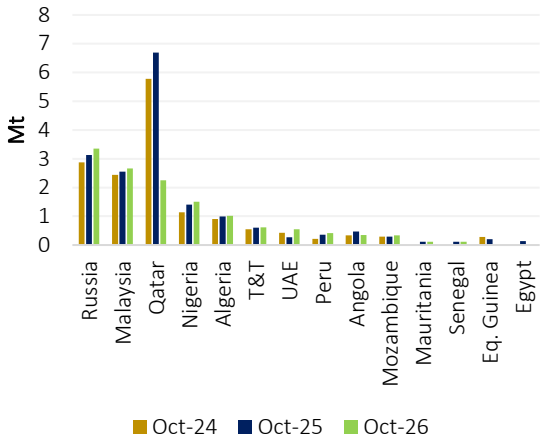


Figure 97: GECF's LNG exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.2 Non-GECF

In October 2026, LNG exports from non-GECF countries increased by 10% (2.13 Mt) y-o-y to 22.92 Mt, marking the smallest incremental increase since May 2026 (Figure 98). The growth was primarily driven by the ramp-up of new LNG export projects and improved feedgas availability in several countries. The US remained the main contributor to the increase in non-GECF LNG exports, supported by smaller gains in Australia, Canada and the Republic of the Congo. These increases more than offset lower exports from Cameroon and Mexico (Figure 99).

US LNG exports surpassed 11 Mt in October 2026, supported by the ramp-up of production at the Corpus Christi and Golden Pass LNG facilities. In Australia, higher exports were driven by increased output from the Darwin LNG facility following its recent restart, alongside reduced maintenance activity at the Ichthys LNG facility. Similarly, the ramp-up of production at the LNG Canada and Congo FLNG facilities boosted exports from Canada and the Republic of the Congo, respectively. Conversely, an unplanned outage at the Altamira FLNG facility constrained Mexico's LNG exports.

For the period January to October 2026, non-GECF LNG exports increased by 16% (30.66 Mt) y-o-y to 224.39 Mt.

Figure 98: Trend in non-GECF monthly LNG exports

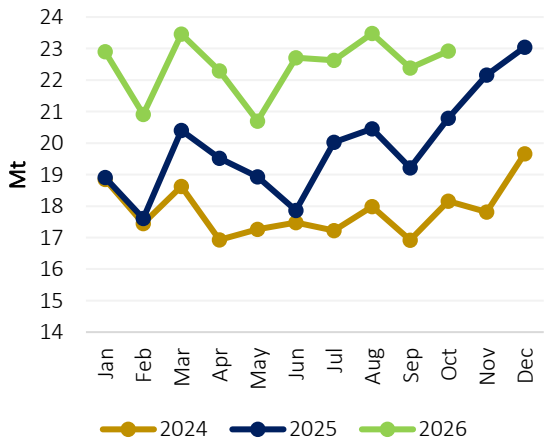
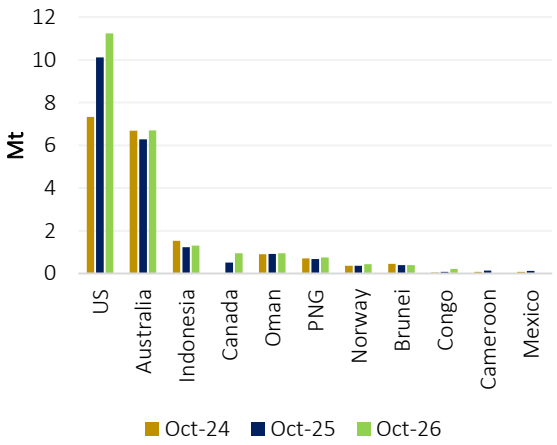


Figure 99: Non-GECF's LNG exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.3 Global LNG re-exports

In October 2026, global LNG re-exports increased five-fold, rising by 0.56 Mt y-o-y to reach 0.70 Mt (Figure 100). The increase was driven primarily by stronger re-export activity in China, as well as Indonesia, Singapore and Türkiye.

China re-exported LNG cargoes to South Korea, Bangladesh and Thailand, capitalising on elevated regional spot LNG prices. With its domestic gas market well supplied, Chinese LNG importers took advantage of arbitrage opportunities by redirecting surplus LNG volumes to other Asian markets. Meanwhile, Indonesia and Singapore continued to serve as regional LNG trading hubs, with traders and portfolio players leveraging their LNG infrastructure and strategic locations to optimise cargo flows across Asia. Outside the region, Türkiye re-exported two LNG cargoes to Spain, marking its first LNG re-exports since 2023.

From January to October 2026, global LNG re-exports surged by 42% (1.12 Mt) y-o-y to 3.76 Mt, exceeding the total annual volume recorded in 2025. The increase was primarily driven by stronger LNG re-export activity from China. (Figure 101).

Figure 100: Trend in global monthly LNG re-exports

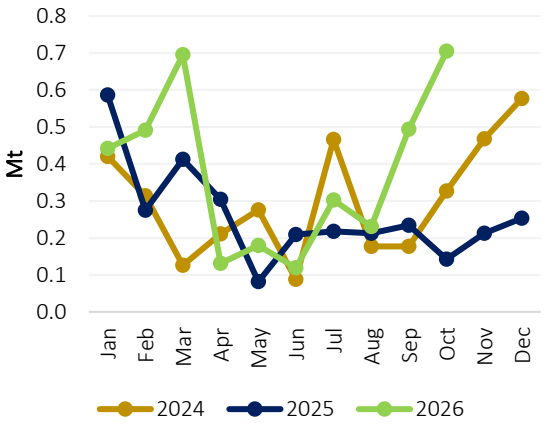
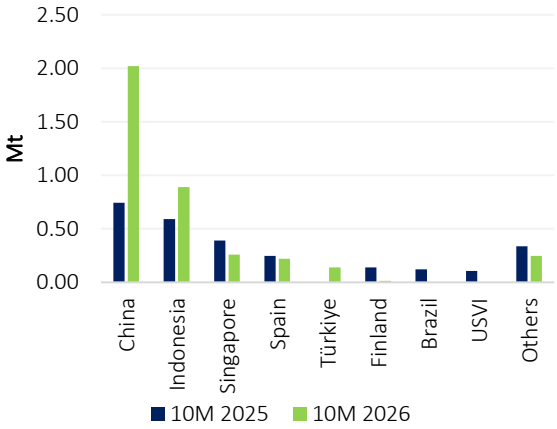


Figure 101: Global YTD LNG re-exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

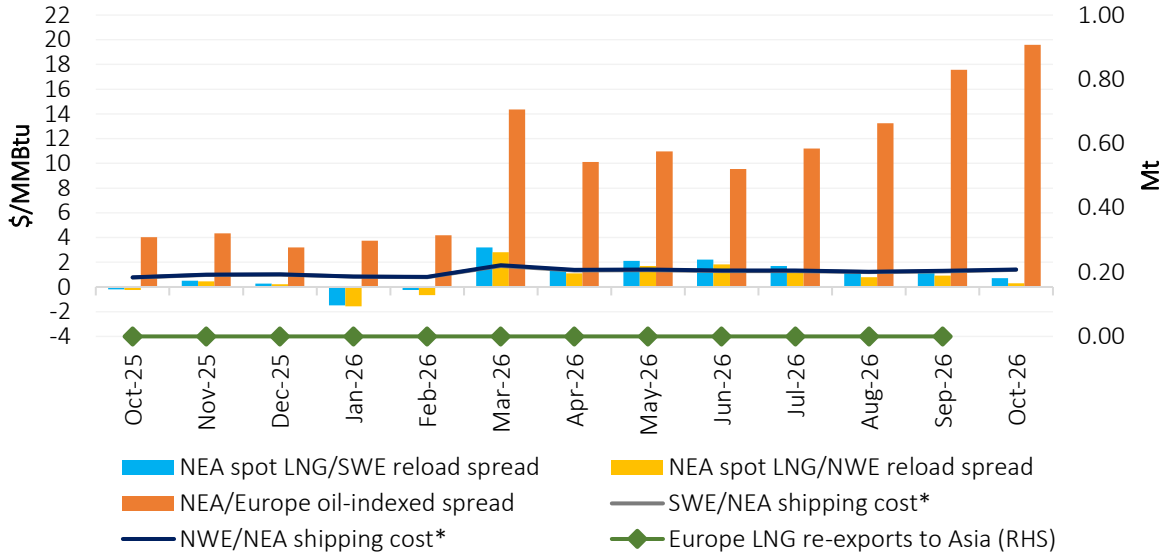
4.2.4 Arbitrage opportunity

In October 2026, arbitrage opportunities for LNG re-exports from Europe to Asia became economically unviable, as the premium of Northeast Asian (NEA) spot LNG prices over European LNG reload prices narrowed significantly, falling below the one-way spot shipping costs from Europe to Asia (Figure 102). Conversely, the NEA spot LNG premium over European oil-indexed LNG prices widened further, remaining substantially above shipping costs.

The NEA–Southwest Europe (SWE) and NEA–Northwest Europe (NWE) price spreads narrowed from $1.33/MMBtu and $0.93/MMBtu in September to $0.71/MMBtu and $0.31/MMBtu in October, respectively. This reflected a sharper increase in European LNG reload prices compared with NEA spot LNG prices. Meanwhile, the NEA premium over European oil-indexed LNG prices widened from $17.57/MMBtu to $19.60/MMBtu, while one-way spot shipping costs from Europe to Asia increased from $1.29/MMBtu to $1.40/MMBtu.

These unfavourable arbitrage economics discouraged LNG re-exports from Europe to Asia during October. Despite the substantial premium over European oil-indexed LNG prices, the availability of such volumes for re-export remained dependent on contractual flexibility and access to LNG supplies.

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

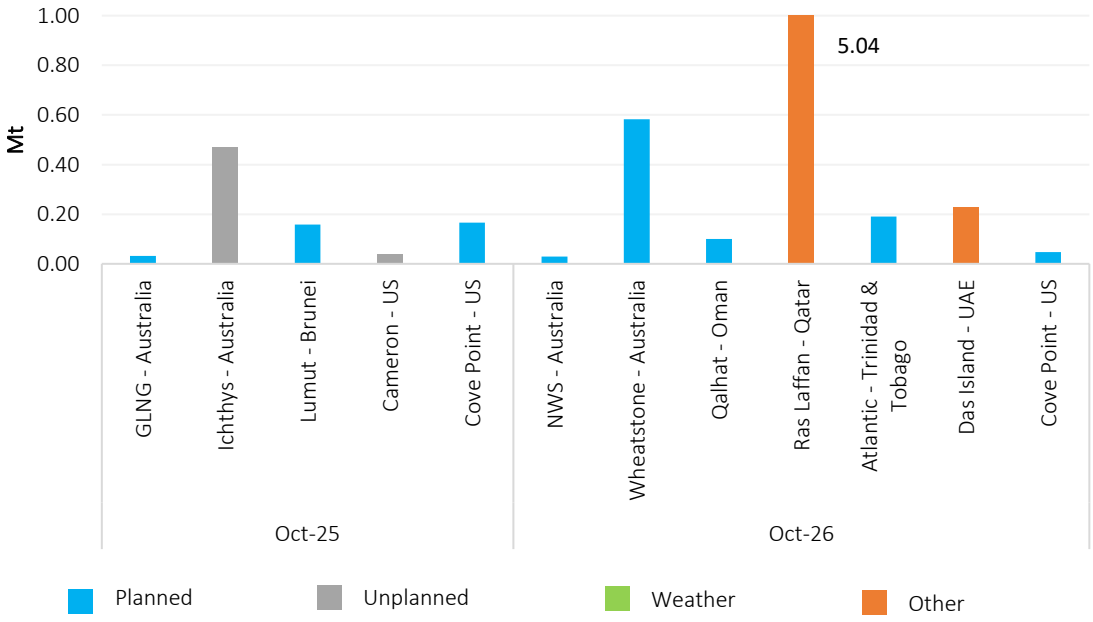


Source: GECF Secretariat based on data from GECF Shipping Model, Argus and ICIS LNG Edge
(*): One-way spot shipping costs

4.2.5 Maintenance activity at LNG liquefaction facilities

In October 2026, disruptions at global LNG liquefaction facilities, including planned maintenance, unplanned outages and other operational issues, remained significantly elevated compared with a year earlier, surging from 0.86 Mt in October 2025 to 6.22 Mt (Figure 103). The sharp increase was primarily driven by restrictions on LNG shipments through the Strait of Hormuz amid the ongoing Middle East conflict, which severely constrained operations at Qatar's Ras Laffan and the UAE's Das Island LNG facilities. Planned maintenance at several LNG liquefaction facilities in Australia, Oman, Trinidad and Tobago and the US further contributed to the elevated level of disruptions.

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

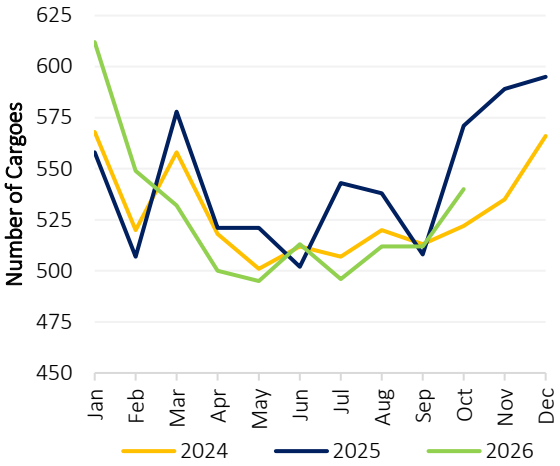


Source: GECF Secretariat based on information from Argus, ICIS LNG Edge and LSEG

4.2.6 LNG shipping

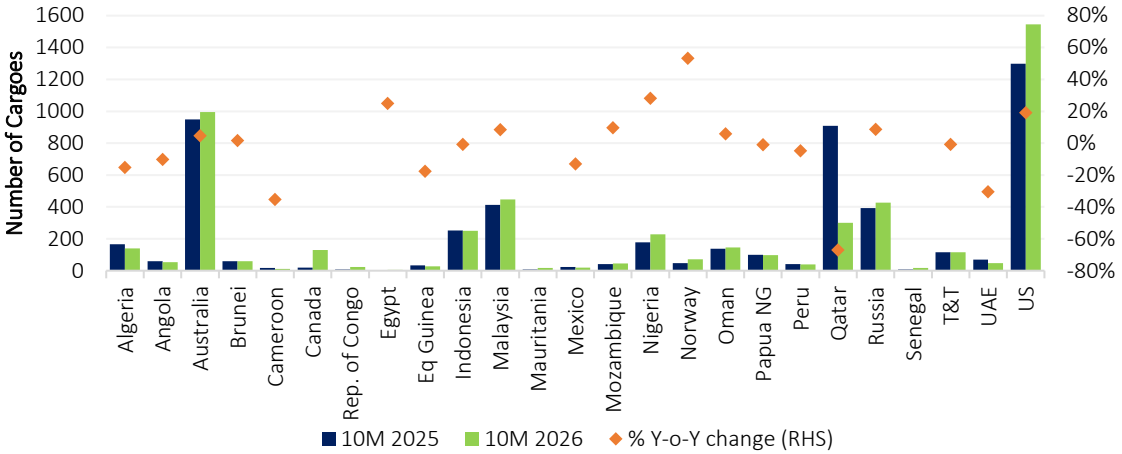
In October 2026, global LNG cargo loadings reached 540, an increase of 28 cargoes compared to the previous month (Figure 104). However, this represented a 5% decline y-o-y, as curtailed exports from Qatar and the UAE continued to constrain the global LNG market heading into the typically high-demand final quarter of the year. Across 2026, cumulative shipments declined by 86 to total 5,261 cargoes. GECF Countries accounted for 36% of these, led by Malaysia, Russia, and Qatar. The US and Nigeria registered the largest increases in cargo exports, whereas the Republic of the Congo and Norway posted 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



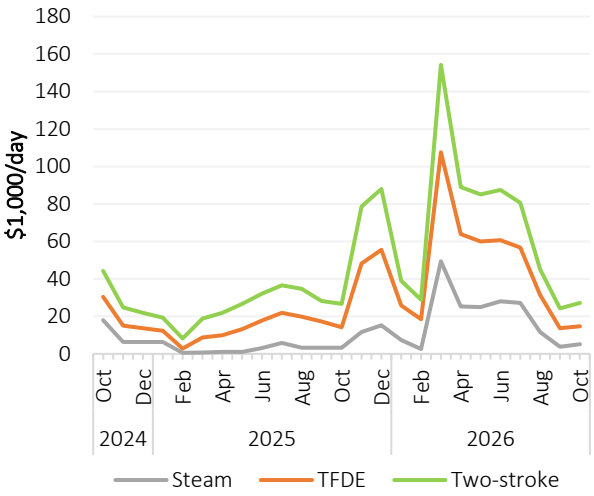
Source: GECF Secretariat based on data from ICIS LNG Edge

In October 2026, LNG carrier spot charter rates remained significantly depressed, defying typical expectations for a fourth-quarter seasonal surge (Figure 106). Monthly average spot rates for TFDE carriers rose by 7% m-o-m to stand at $14,600 per day, which was up 4% y-o-y, but $106,700 per day below the five-year average. Similarly, average spot rates for two-stroke vessels jumped by 12% m-o-m to $27,100 per day, though they remained 83% lower than their five-year average. Meanwhile, steam turbine carrier rates increased by 38% m-o-m to average just $5,100 per day, while staying 94% below the five-year average.

The charter market continues to be shaped by shifting inter-basin arbitrage economics and seasonal supply dynamics. The month initially saw firming in the Atlantic basin as participants anticipated winter demand and potential voyages to Asia. However, rates retreated as November requirements proved slow to materialize. Mid-month highlighted muted enquiries; although Chinese buyers sought winter deliveries, insufficient premiums in Asia meant that most US export volumes continued flowing to Europe. By late October, the inter-basin arbitrage for uncommitted cargoes shut due to rising European delivered prices, eliminating the incentive to divert vessels toward Asia. Ultimately, fluctuating regional spreads and unfavourable freight economics kept market fundamentals constrained, ensuring that any spikes in spot charter rates remained short-lived.

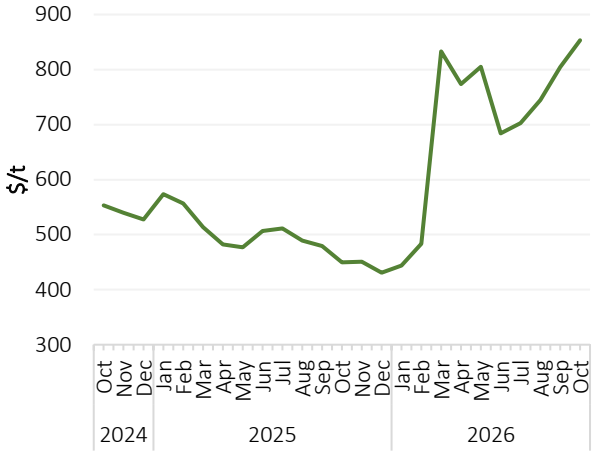
In October 2026, the global average price of shipping fuels increased by 6% m-o-m, reaching $850 per tonne (Figure 107). This price was 89% higher y-o-y and 47% above the five-year monthly average, primarily driven by surging crude oil benchmarks, alongside heightened geopolitical risk premiums impacting global bunker hubs.

Figure 106: Average LNG spot charter rate



Source: GECF Secretariat based on data from Argus

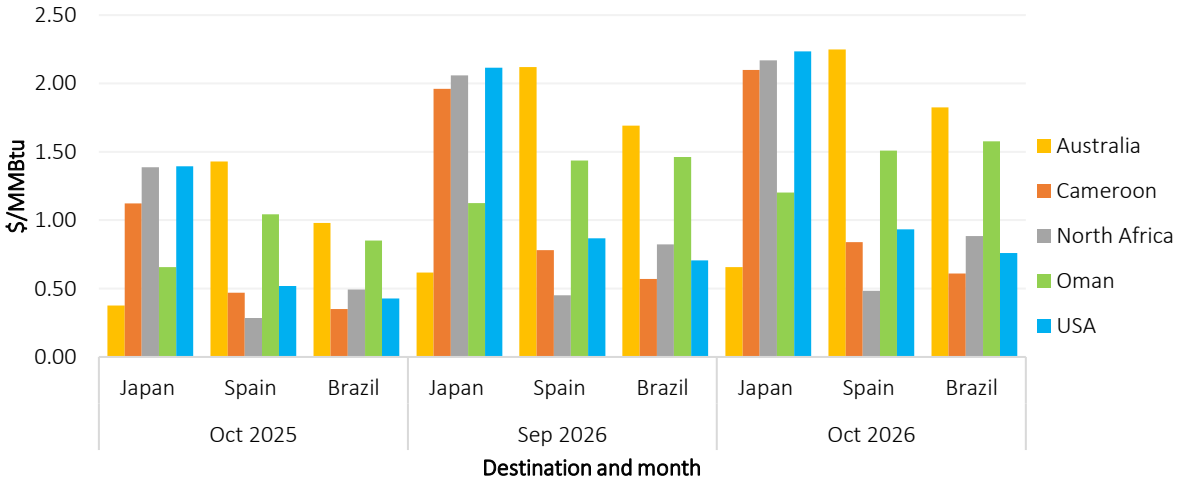
Figure 107: Average price of shipping fuels



Source: GECF Secretariat based on data from Argus and Platts

As a result, spot shipping costs for TFDE LNG carriers in October 2026 experienced an increase of up to $0.14/MMBtu m-o-m on certain routes, driven by increases in monthly average spot charter rates, bunker fuel costs, and delivered spot LNG prices (Figure 108). Moreover, compared to one year ago, spot LNG shipping costs rose by up to $0.97/MMBtu y-o-y on certain routes, as a result of higher shipping fuel prices and delivered spot LNG prices than in October 2025, coupled with similar monthly average spot charter rates.

Figure 108: Spot shipping costs for TFDE LNG carriers



Source: GECF Shipping Cost Model

4.2.7 Other developments

Germany Stade FSRU receives first LNG cargo: Germany's new floating storage and regasification unit (FSRU) in Stade received its first LNG cargo on 2 November 2026, delivered by the Lech Kaczyński carrier from the US Plaquemines LNG facility. The shipment, comprising approximately 160,000 cubic metres of LNG, was transferred to the Energos Force floating storage and regasification unit (FSRU). The delivery marks a significant milestone towards the terminal's commissioning, with initial gas send-out expected during the month of November. The terminal could supply up to 3.2 bcm of natural gas in 2027.

Costs continue to rise for Norway's Hammerfest LNG emissions reduction project: Equinor has raised the estimated cost of its Hammerfest LNG electrification and lifetime extension project in Norway by over 30%, from NOK20 billion to NOK26.5 billion ($2.77 billion), citing unforeseen technical challenges and greater operational complexity. The project involves replacing gas-fired power generation with electricity from the mainland grid and installing additional compression capacity to extend gas production. Currently 60% complete, the project is expected to reduce annual emissions by 850,000 tonnes, with compression facilities operational by 2029 and full electrification scheduled for 2030.

Gate LNG terminal commissions fourth LNG storage tank: The fourth LNG storage tank at Gate Terminal in Rotterdam, Netherlands was completed as scheduled and commissioned in early October 2026, following three years of construction. The expansion adds 180,000 cubic metres of LNG storage capacity and 4 bcm per year of regasification capacity, increasing the terminal's total regasification capacity to 20 bcm per year, equivalent to approximately two-thirds of Dutch gas demand. The project strengthens LNG import infrastructure and enhances gas supply security in the Netherlands and Northwest Europe.

MOL and Chevron advance wind-assisted LNG carrier: Mitsui OSK Lines (MOL) has named the *FUJIN SAILOR* at Hanwha Ocean's South Korean shipyard, a groundbreaking milestone as the world's first LNG carrier equipped with two Wind Challenger hard sail systems. Set for delivery to Chevron Corporation, the vessel harnesses wind power to significantly reduce fuel consumption and greenhouse gas emissions. Moreover, this marks the fourth MOL vessel to feature this advanced technology, supporting the company's corporate strategy which aims to deploy 25 Wind Challenger-equipped ships by 2030 and achieve net-zero greenhouse gas emissions across the entire fleet by 2050.

In October 2026, LNG contracting activity declined compared with September, with six agreements signed, down from 10 in the previous month (Table 1).

Table 1: New LNG sale agreements signed in October 2026

Contract Type	Exporting Country	Project	Seller	Importing Country	Buyer	Volume (Mtpa)	Duration (Years)
SPA	US	Portfolio	Venture Global	Portfolio	ConocoPhillips	1	20
SPA	Portfolio	Portfolio	ADNOC Trading	Thailand	Gulf Group	2	N/A
SPA	US	Sabine Pass	Cheniere	Portfolio	QatarEnergy	2	23
SPA	US	Corpus Christi	Cheniere	Portfolio	QatarEnergy	2	23
SPA	Canada	Ksi Lisims LNG	Ksi Lisims LNG	Germany	SEFE	1	20
SPA	US	Louisiana LNG	Woodside Energy	Portfolio	QatarEnergy	3	20

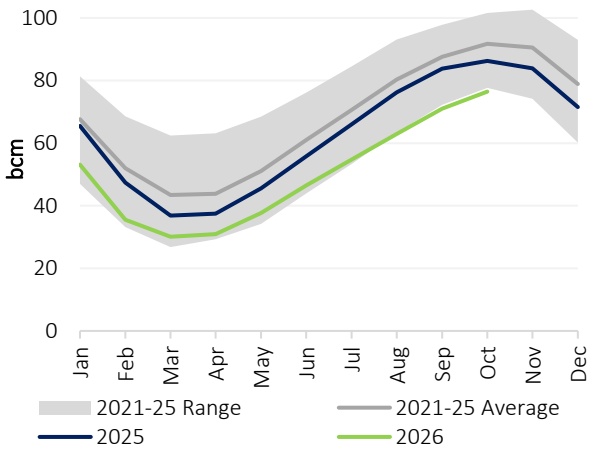
Source: GECF Secretariat based on Project Updates and News
N/A: Not Available

5 GAS STORAGE

5.1 Europe

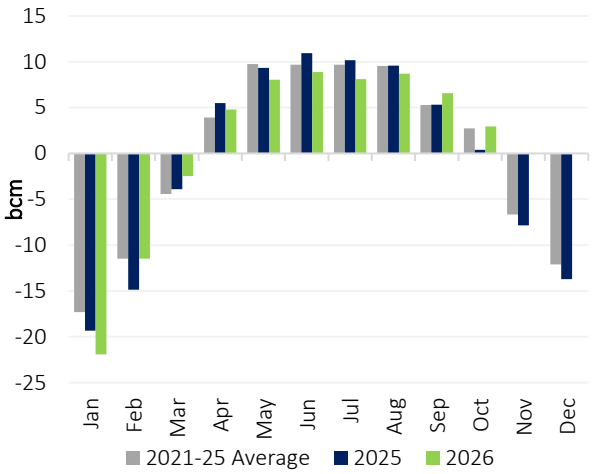
October 2026 marked the final month for net gas injections in the EU. The average daily storage level increased to 76.5 bcm, up from 71.0 bcm in the previous month (Figure 109); however, inventories still trailed the storage level of one year ago by 10 bcm and the five-year average by 15 bcm. Total EU stocks rose from 74.0 bcm on 30 September to 77.1 bcm on 31 October. This year's maximum stock level of 75% was achieved on 27 October, which while similar to the peak date of previous filling cycles, defied expectations that the region might continue net gas injections into the first week of November. Moreover, this marks the lowest peak storage percentage heading into the start of the winter heating season since records began in 2011.

Figure 109: Monthly average UGS level in the EU



Source: GECF Secretariat based on data from AGSI+

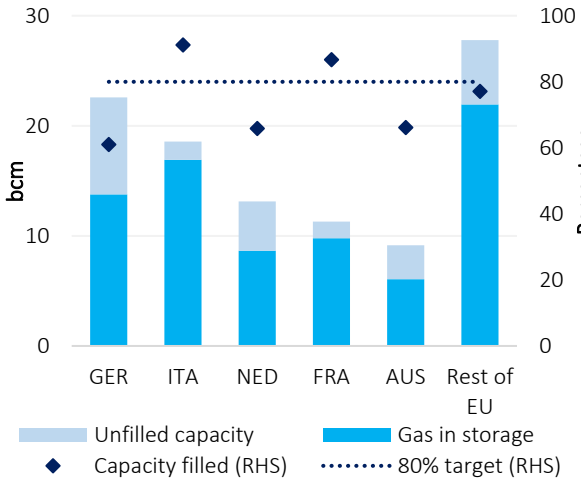
Figure 110: Net gas injections in the EU



Source: GECF Secretariat based on data from AGSI+

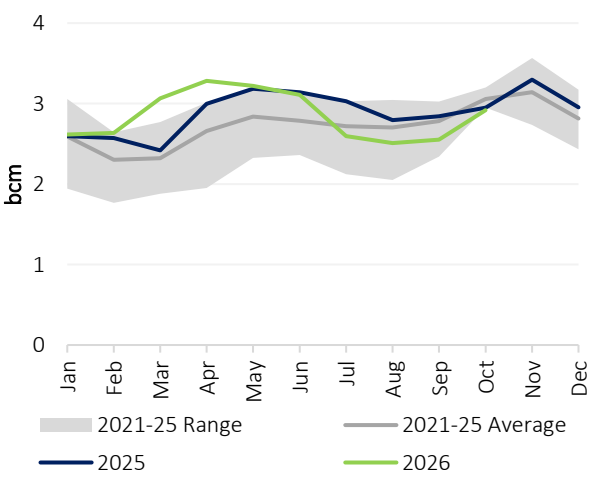
During October, the bloc recorded a notable 2.9 bcm in net gas injections, up sharply from 0.4 bcm a year earlier and even surpassing the five-year October benchmark by 7% (Figure 110). National trajectories varied widely: while Italy and France successfully pushed storage levels to roughly 90%, Germany (61%) and the Netherlands (66%) continued to lag behind with severely constrained reserves (Figure 111). EU LNG storage averaged 2.9 bcm (51% of capacity), slipping 1% y-o-y and standing 5% below the five-year average (Figure 112).

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



Source: GECF Secretariat based on data from AGSI+

Figure 112: Total LNG storage in the EU

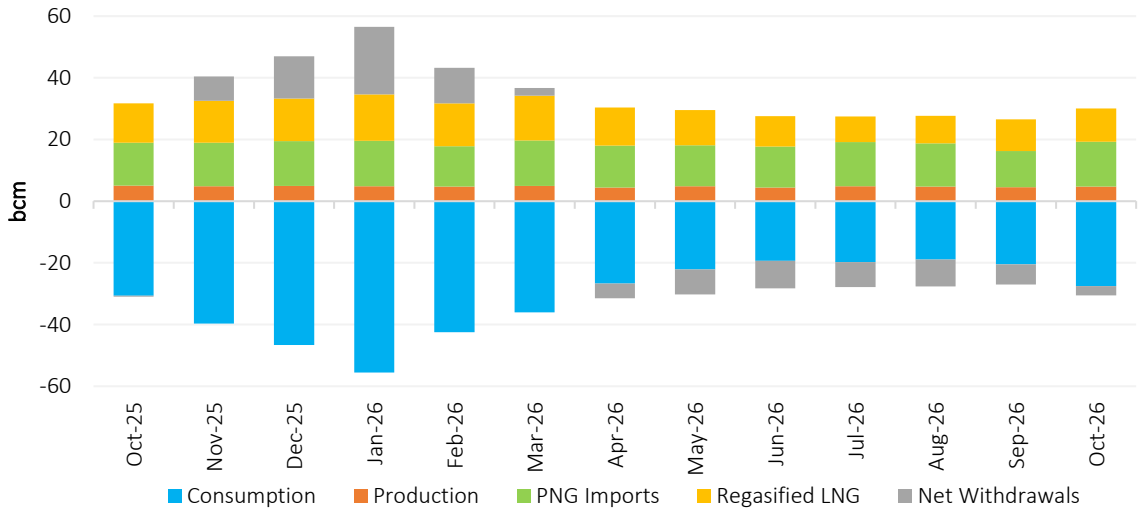


Source: GECF Secretariat based on data from ALSI

European wholesale gas prices escalated sharply across October 2026, driven by tightening global LNG balances, heightened geopolitical risk, and lingering disruptions across key maritime routes. This upward price momentum flattened the winter-summer spread, increasing competition for flexible LNG and pulling potential shipments away from Asian destinations. Against this backdrop, European authorities intensified monitoring of regional storage, stressing that navigating the heating season would demand rigorous demand-side restraint and seamless cross-border supply coordination.

In October 2026, external imports accounted for 84% of the combined EU and UK gas supply, matching the level from one year prior, with domestic production covering the remaining 16% (Figure 113). PNG increased its market share from 44% to 49%, solidifying its position as the primary supply source. In contrast, regasified LNG send-out fell from 40% in October 2025 to 36%.

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 October 2026.

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

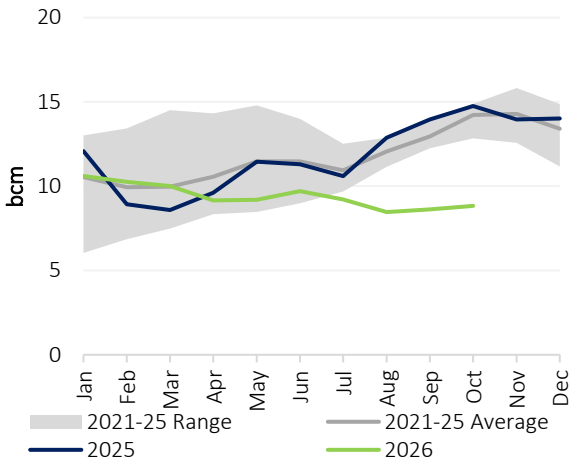
	2025	Oct-25	Oct-26	10M 2025	10M 2026	Change* y-o-y	Change** 2026/2025
(a) Gas Consumption	378.23	30.60	27.57	291.91	289.04	-10%	-1%
(b) Gas Production	58.90	5.07	4.72	49.01	46.80	-7%	-5%
Difference (a) - (b)	319.33	25.53	22.85	242.90	242.24	-11%	0%
PNG Imports	162.14	13.91	14.60	133.59	137.75	5%	3%
Regasified LNG	147.08	12.76	10.77	119.66	115.22	-16%	-4%
Net Withdrawals	8.46	-0.39	-2.93	-13.10	-12.13	654%	-7%
Variation	1.64	-0.75	0.41	2.75	1.39		

Source: GECF Secretariat based on data from AGSI+, JODI Gas and LSEG
(*): y-o-y change for October 2026 compared to October 2025
(**): y-o-y change for 10M 2026 compared to 10M 2025

5.2 Asia

In October 2026, combined LNG inventories in Japan and South Korea rose by 2% m-o-m to an estimated 8.8 bcm (Figure 114). These reserves sat 40% lower y-o-y and lagged 5.4 bcm behind the five-year average. In Japan, storage levels stood 33% lower y-o-y at 4.6 bcm, driven by accelerated domestic power generation requirements and high spot LNG prices that deterred opportunistic inventory replenishment. South Korea experienced a similar 47% decline y-o-y to stand at an estimated 4.2 bcm, driven by robust industrial gas use and early-season heating demand amidst constrained spot cargo arrivals.

Figure 114: LNG in storage in Japan and South Korea

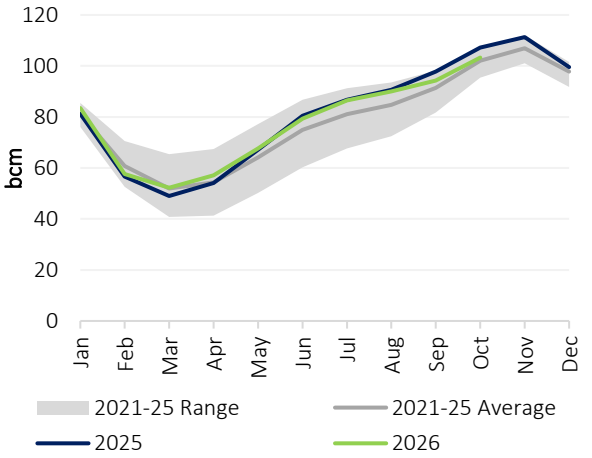


Source: GECF Secretariat based on data from LSEG

5.3 North America

Net gas injections continued in the US through October 2026, with average UGS volumes climbing to 103.3 bcm up from 94.3 bcm in the previous month (Figure 115). This level was down 3.9 bcm lower than one year prior but stood 1.3 bcm above the five-year historical average. The average UGS capacity utilization reached 77%. There were 10.9 bcm of net restocking during the month, which was greater than both the 10.0 bcm injected in October 2025 and the five-year October average of 10.4 bcm. This brought cumulative summer restocking for 2026 to 56 bcm, compared to 63 bcm accumulated by the same point last year.

Figure 115: Monthly average UGS level in the US



Source: GECF Secretariat based on data from US EIA

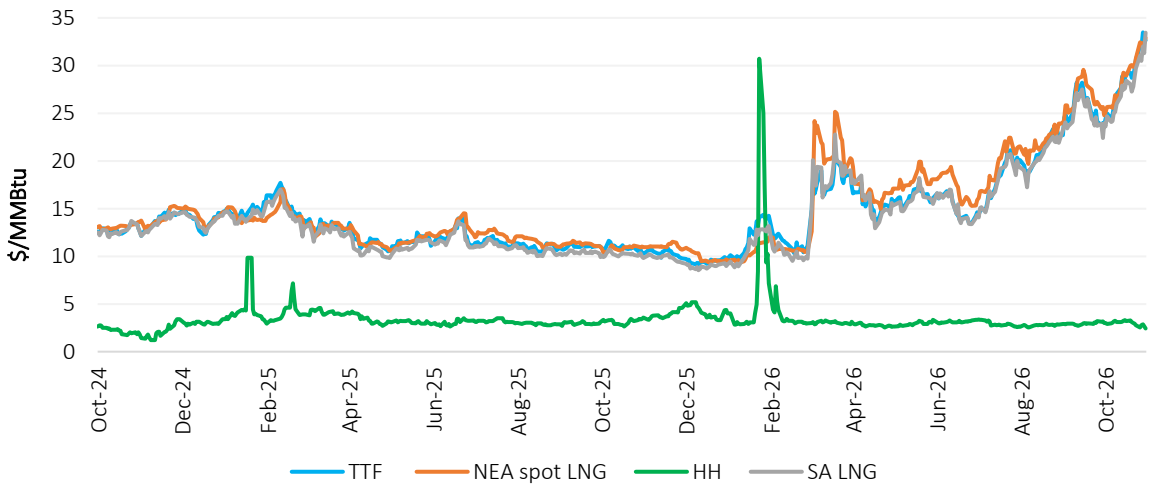
6 ENERGY PRICES

6.1 Gas prices

6.1.1 Gas & LNG spot prices

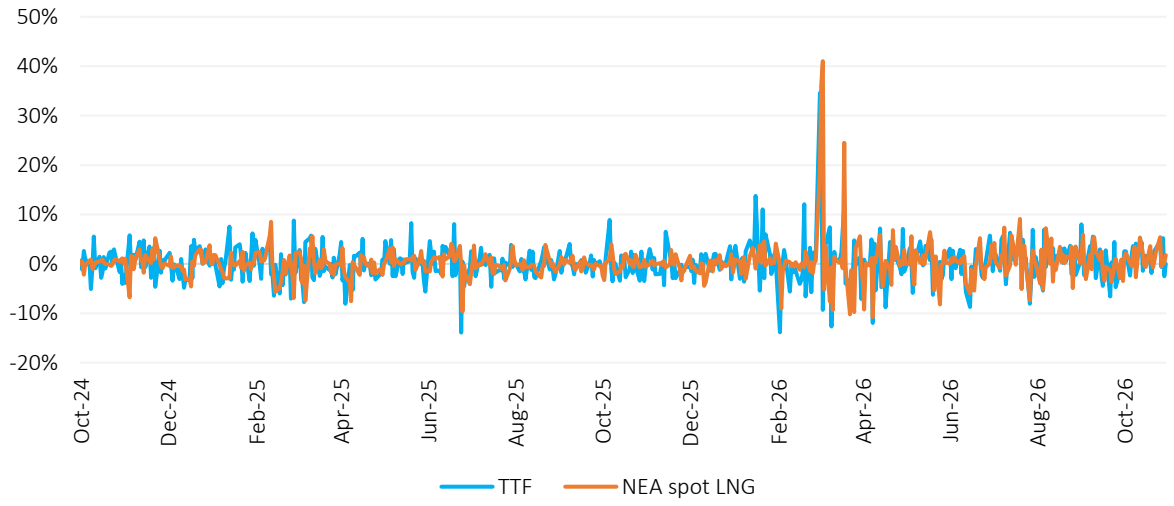
In October 2026, European and Asian gas and LNG spot prices surged to new multi-year highs amid heightened market volatility (Figure 116 and Figure 117). Persistent uncertainty surrounding transit through the Strait of Hormuz provided significant upward price pressure. In Europe, market fundamentals also tightened due to unplanned outages at several Norwegian facilities, reduced wind power generation and low gas storage inventories. Asian LNG spot prices closely tracked gains in European benchmarks, although elevated prices continued to dampen buying interest, keeping many buyers on the sidelines. Looking ahead, prolonged supply constraints, combined with colder-than-normal temperatures, could further tighten market balances and trigger additional price spikes.

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



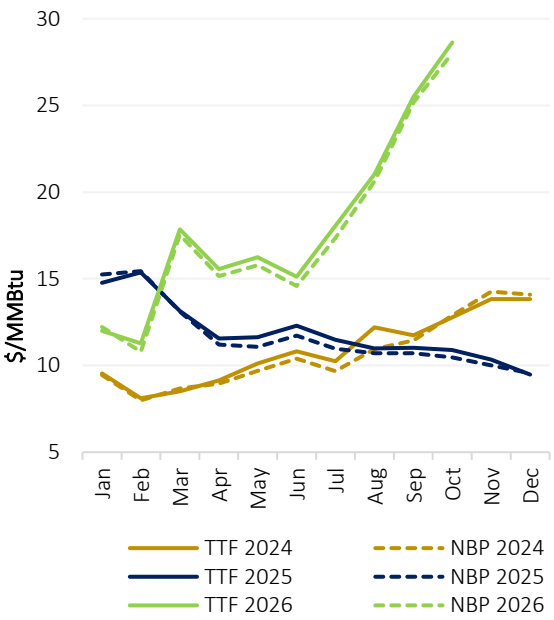
Source: GECF Secretariat based on data from Argus and LSEG

6.1.1.1 European spot gas and LNG prices

In October 2026, TTF spot gas price averaged $28.63/MMBtu, increasing by 12% m-o-m and 163% y-o-y. Similarly, NBP spot price averaged $28.02/MMBtu, increasing 11% m-o-m and 168% y-o-y (Figure 118). Daily TTF prices peaked at $33.48/MMBtu, the highest level recorded since December 2022. Spot prices surged to new highs amid heightened uncertainty surrounding transit through the Strait of Hormuz. From a market fundamentals perspective, the supply-demand balance in Northwest Europe also tightened, driven by unplanned outages at Norwegian facilities and reduced wind power output. In addition, low gas storage levels provided further upward pressure on prices.

For Jan-Oct 2026, TTF and NBP prices increased by 47% y-o-y to average $18.13/MMBtu and $17.72/MMBtu.

Figure 118: Monthly European spot gas prices



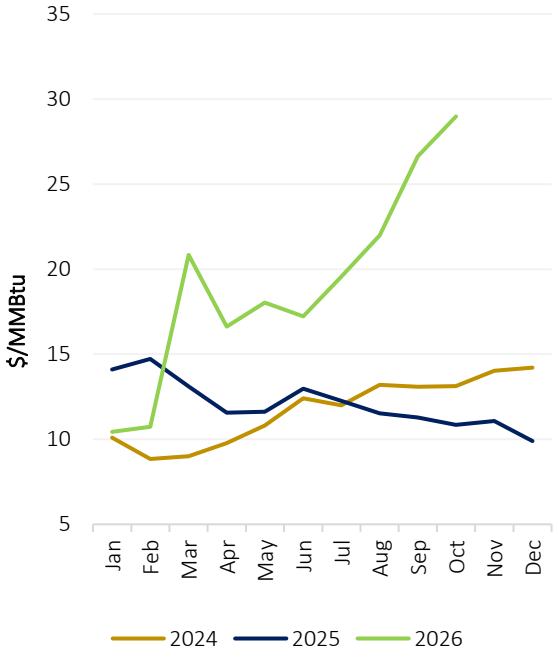
Source: GECF Secretariat based on data from LSEG

6.1.1.2 Asian spot LNG prices

In October 2026, the average North East Asia (NEA) spot LNG price averaged $28.98/MMBtu, reflecting increases of 9% m-o-m and 167% y-o-y (Figure 119). The daily NEA spot LNG price soared to $32.92/MMBtu, its highest level since December 2022. Asian LNG spot prices mirrored gains in European gas prices, reflecting increasingly interconnected regional market dynamics. Heightened tensions in the Middle East continued to underpin bullish market sentiment, while feedgas supply issues at the US Freeport LNG terminal provided additional support. However, elevated spot prices dampened buying interest, particularly among price-sensitive Asian importers.

For Jan-Oct 2026, NEA spot LNG price averaged $19.11/MMBtu, reflecting an increase of 54% y-o-y.

Figure 119: Monthly Asian spot LNG prices



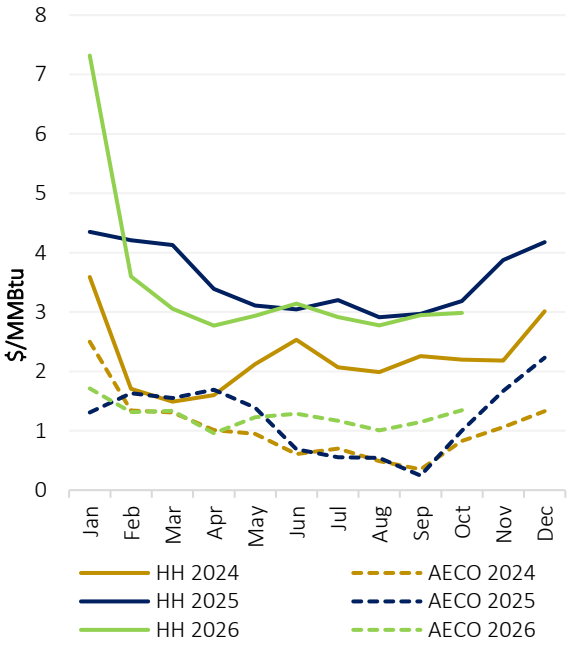
Source: GECF Secretariat based on data from Argus

6.1.1.3 North American spot gas prices

In October 2026, the Henry Hub (HH) spot gas price averaged $2.99/MMBtu, increasing by 1% m-o-m, although remaining 6% lower y-o-y (Figure 120). Daily HH prices reached a three-month high of $3.30/MMBtu towards the end of the month. Despite this upward movement, price gains remained limited by milder-than-expected weather and robust natural gas production, which ensured comfortable supply availability. Similarly, AECO spot prices averaged $1.35/MMBtu, increasing by 18% m-o-m and 34% y-o-y, reflecting a stronger price recovery in the Canadian market.

For Jan–Oct 2026, HH spot prices averaged $3.45/MMBtu, remaining relatively stable compared with the previous year, while AECO spot prices averaged $1.25/MMBtu, increasing by 18%.

Figure 120: Monthly North American spot gas prices



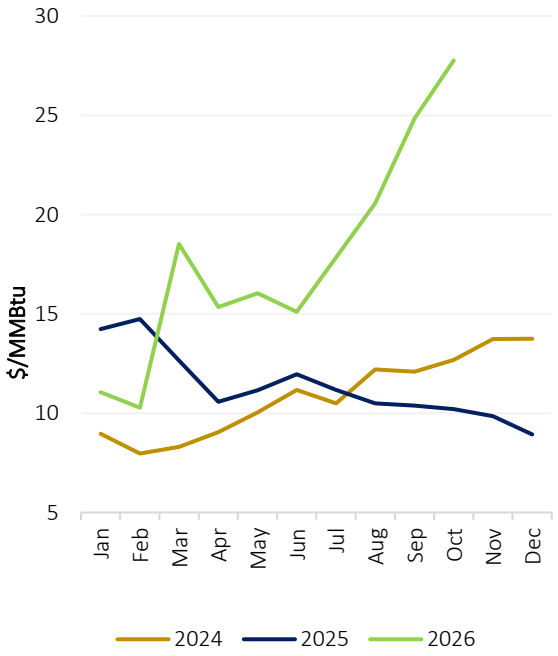
Source: GECF Secretariat based on data from LSEG

6.1.1.4 South American spot LNG prices

In October 2026, the South America (SA) spot LNG price averaged $27.76/MMBtu, increasing by 12% m-o-m and 172% y-o-y (Figure 121). During the month, daily SA spot LNG prices rose to a high of $33.45/MMBtu, their highest level since December 2022, reflecting heightened competition for flexible LNG supplies amid tighter global market conditions. 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 $27.77/MMBtu, $27.59/MMBtu and $27.93/MMBtu, respectively. These elevated prices increased import costs across the region, potentially placing pressure on domestic gas markets and import-dependent economies.

For Jan-Oct 2026, the SA spot LNG price averaged $17.74/MMBtu, up 51% y-o-y.

Figure 121: Monthly South American spot LNG prices

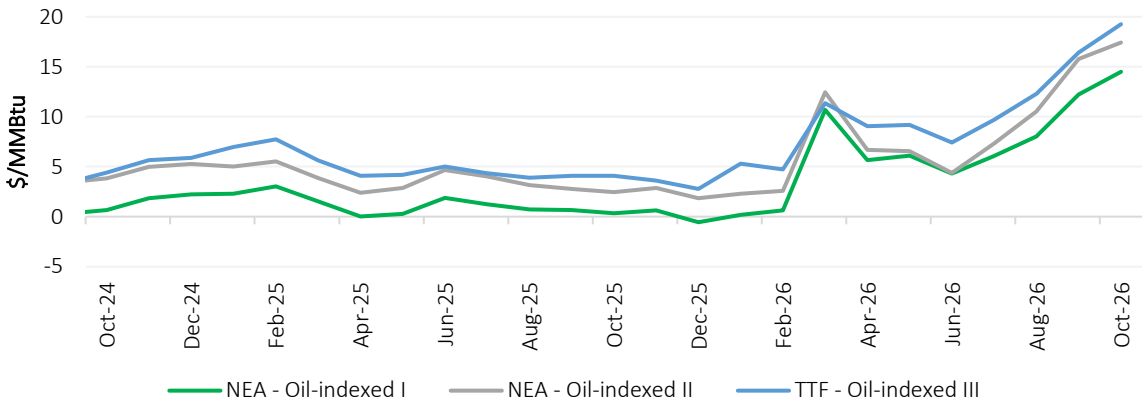


Source: GECF Secretariat based on data from Argus
Note: SA LNG price is an average of the LNG delivered prices for Argentina, Brazil and Chile based on Argus assessment

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

In October 2026, the Oil-Indexed I LNG price averaged $14.49/MMBtu, relatively stable compared to the previous month, but was 38% higher y-o-y. Meanwhile, the Oil-Indexed II LNG price averaged $11.56/MMBtu, increasing by 7% m-o-m and 38% y-o-y. In Europe, the Oil-Indexed III LNG price averaged $9.38/MMBtu, reflecting increases of 3% m-o-m and 38% y-o-y. During the month, the premium of NEA spot LNG over Oil-Indexed I and Oil-Indexed II prices increased to $14.5/MMBtu, and $17.4/MMBtu, respectively. Similarly, the TTF spot gas premium over Oil-Indexed III widened to $19.3/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 October 2026, the NEA–TTF price spread narrowed to $0.35/MMBtu, reflecting intense competition for flexible LNG cargoes ahead of the winter season (Figure 123). Meanwhile, the TTF–HH price spread widened to $25.65/MMBtu (Figure 124).

Figure 123: NEA-TTF price spread

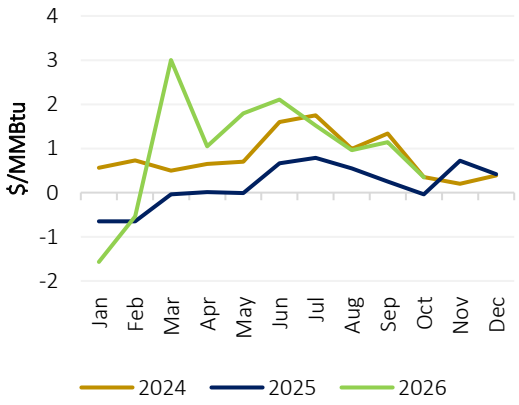
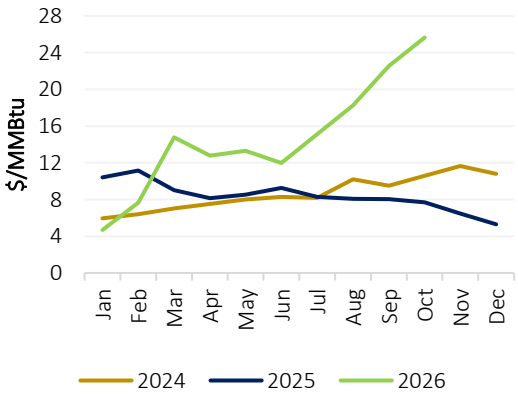


Figure 124: TTF-HH price spread



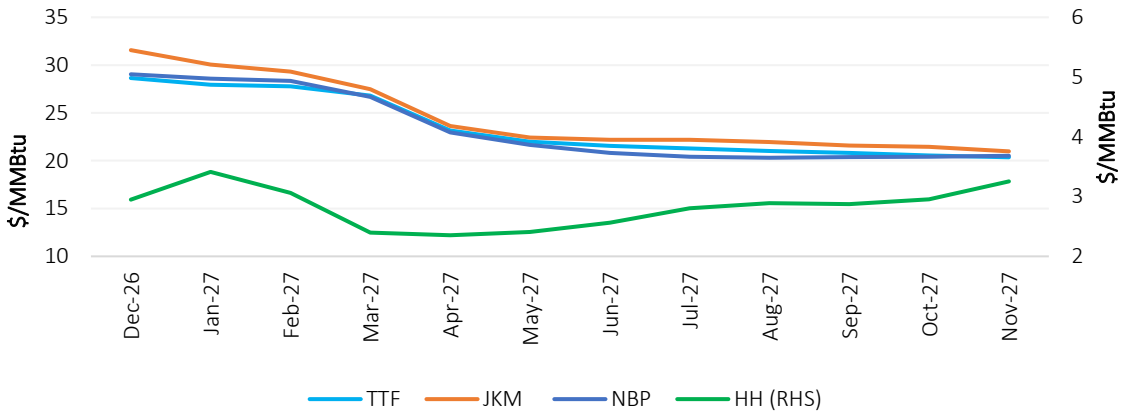
Source: GECF Secretariat based on data from Argus and LSE

6.1.4 Gas & LNG futures prices

As of 6 November 2026, the average futures prices for the 12-month period from December 2026 to November 2027 stood at $23.50/MMBtu for TTF, $23.35/MMBtu for NBP, and $24.57/MMBtu for JKM (Figure 125). Notably, all three benchmark prices were higher than the previous expectations presented in the GECF MGMR October 2026 assessment on 5 October 2026. Over the same period, Henry Hub futures averaged $2.83/MMBtu, around 8% lower than previous expectations (Figure 126).

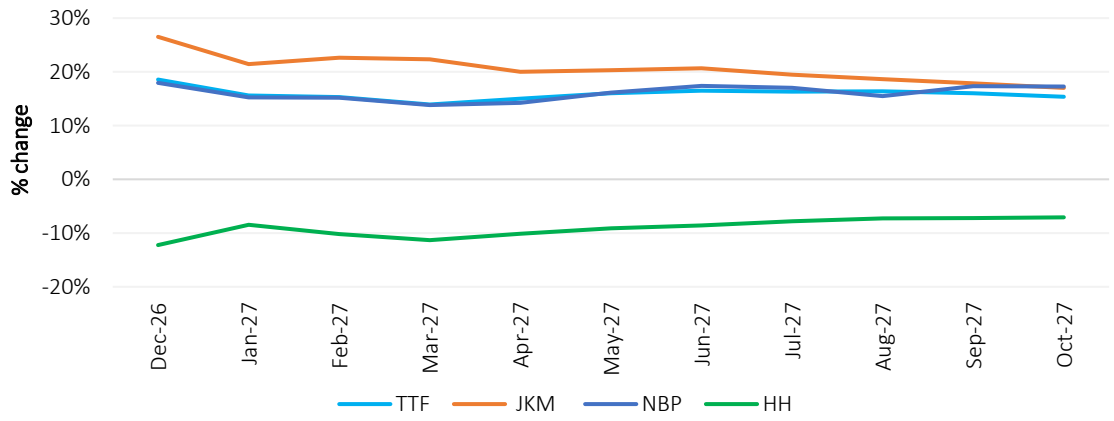
Looking ahead, the JKM–TTF spread is expected to average $2.9/MMBtu in December 2026, after which it narrows to $2.1/MMBtu in January 2027.

Figure 125: Gas & LNG futures prices



Source: GECF Secretariat based on data from LSEG
Note: Futures prices as of 6 November 2026

Figure 126: Variation in gas & LNG futures prices



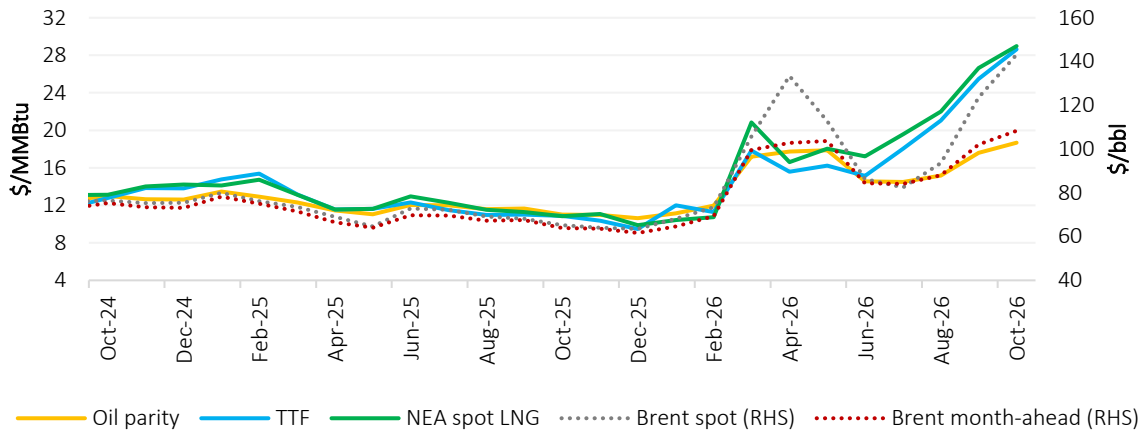
Source: GECF Secretariat based on data from LSEG
Note: Comparison with the futures prices as of 5 October 2026, as reported in GECF MGMR October 2026

6.2 Cross commodity prices

6.2.1 Oil prices

In October 2026, the average Brent crude spot price averaged $143.18/Bbl, increasing by 16% m-o-m and 120% y-o-y. Similarly, the month-ahead Brent price averaged $108.34/Bbl, increasing by 6% m-o-m and 69% y-o-y. Furthermore, both TTF and NEA LNG spot prices traded at a premium of $10/MMBtu to the oil parity price (Figure 127).

Figure 127: Monthly crude oil prices

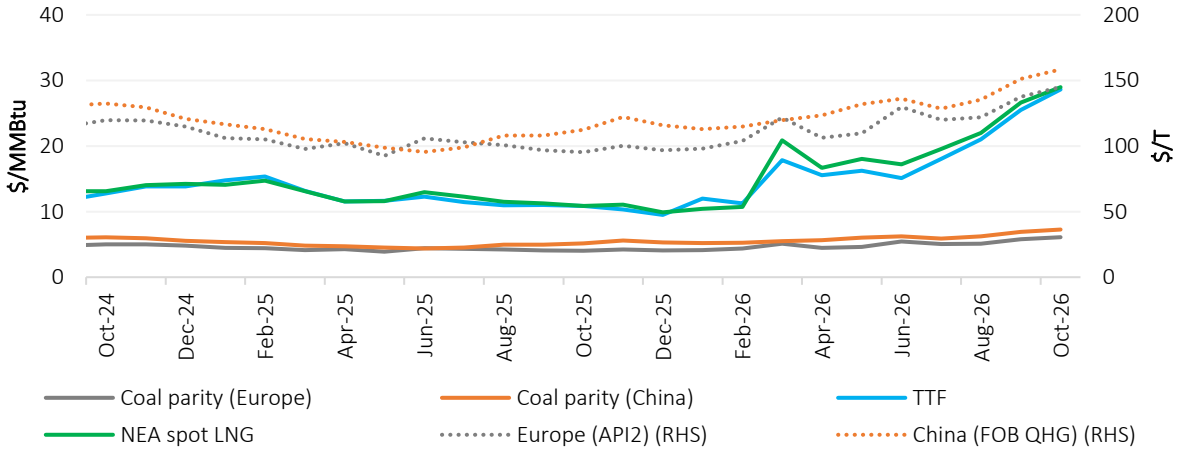


Source: GECF Secretariat based on data from Argus and LSEG
Note: Conversion factor of 5.8 was used to calculate the oil parity price in $/MMBtu based on the ICE Brent month-ahead price.

6.2.2 Coal prices

In October 2026, the European coal price (API2) averaged $145.05/t, increasing by 5% m-o-m and 52% y-o-y. The premium of TTF spot gas over API2 parity widened compared to the previous month to $22.5/MMBtu. Similarly, in China, the Qinhuangdao (QHG) coal price averaged $158.44/t, increasing by 5% m-o-m and 41% y-o-y. The premium of NEA spot LNG over QHG parity increased to $21.7/MMBtu (Figure 128).

Figure 128: Monthly coal parity prices

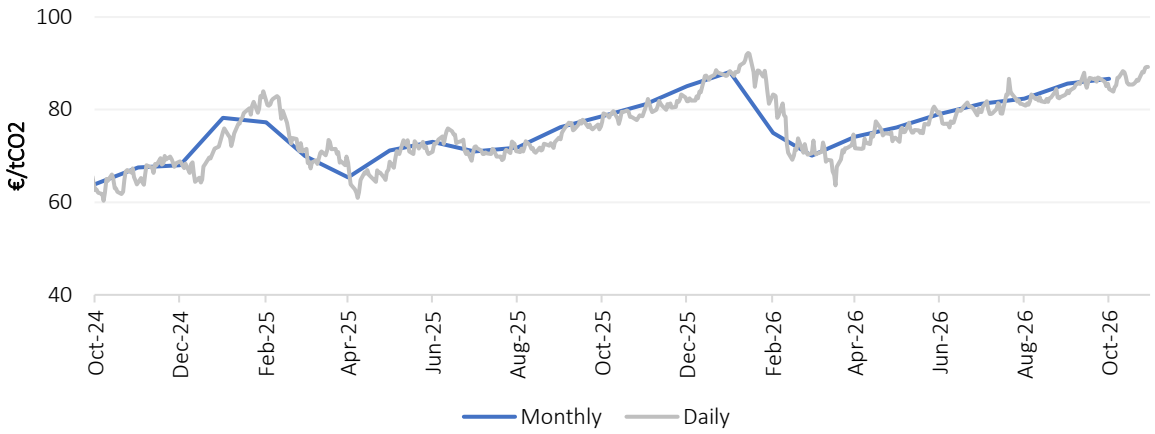


Source: GECF Secretariat based on data from Argus and LSEG
Note: Conversion factors of 23.79 and 21.81 were used to calculate the coal prices in $/MMBtu for Europe (API2) and China (QHG) respectively.

6.2.3 Carbon prices

In October 2026, the EU carbon price averaged €86.64/tCO_2, reflecting increases of 1% m-o-m and 10% y-o-y (Figure 129). During the month, the daily EU carbon price climbed to a peak of €89.20/tCO_2.

Figure 129: EU carbon prices

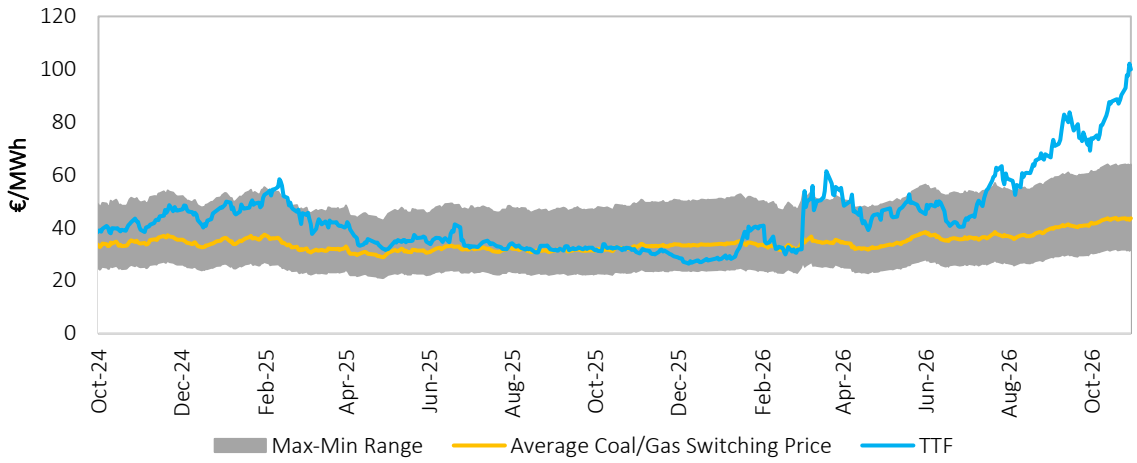


Source: GECF Secretariat based on data from LSEG

6.2.4 Fuel switching

In October 2026, TTF spot prices climbed significantly above the upper bound of the coal-to-gas switching range during the month (Figure 130). Furthermore, the average monthly price spread widened considerably to €43/MWh, further reinforcing the relative cost competitiveness of coal over natural 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, CO_2 emissions prices, operation costs and power plant efficiencies. The efficiencies considered for gas plants are max: 56%, min: 46%, avg: 49.13%. The efficiencies considered for coal plants are max: 40%, min: 34%, avg: 36%.

ANNEXES

Abbreviations

Abbreviation	Explanation
AE	Advanced Economies
AECO	Alberta Energy Company
Bbl	Barrel
bcm	Billion cubic metres
bcma	Billion cubic metres per annum
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
tCO_2	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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