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Gas Exporting Countries Forum

ANNUAL GAS MARKET REPORT 2026

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2026

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ABOUT THE GECF

The Gas Exporting Countries Forum (GECF) is an intergovernmental organisation established in 2001. It became a fully-fledged organisation in 2008, with headquarters in Doha, the State of Qatar.

As of March 2026, the GECF gathers 20 countries, including 12 Members and 8 Observer Members (hereafter referred to as GECF Member Countries) from four continents. Algeria, Bolivia, Egypt, Equatorial Guinea, Iran, Libya, Nigeria, Qatar, Russia, Trinidad and Tobago, United Arab Emirates and Venezuela have the status of Members, while Angola, Azerbaijan, Iraq, Malaysia, Mauritania, Mozambique, Peru and Senegal have the status of Observer Members.

In accordance with the GECF Statute, the organisation aims to support the sovereign rights of its Member Countries over their natural gas resources and their abilities to develop, preserve and use such resources for the benefit of their peoples, through the exchange of experience, views, information and coordination in gas-related matters.

The vision of the GECF is “to make natural gas the pivotal resource for inclusive and sustainable development”, and its mission is “to shape the energy future as a global advocate of natural gas and a platform for cooperation and dialogue, with the view to support the sovereign rights of Member Countries over their natural gas resources and to contribute to global sustainable development and energy security”.

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FOREWORD

I am honoured to present the GECF Annual Gas Market Report (AGMR) 2026. This edition provides a comprehensive review and in-depth analysis of the natural gas market developments that shaped 2025, while outlining short-term global prospects.

The global energy landscape is undergoing a notable shift in policy priorities, moving away from predominantly international climate-centric agendas toward a stronger focus on national energy security. This shift reflects a growing recognition that environmental ambitions must align with the realities of gradual and non-linear energy transitions, which require a just and orderly approach tailored to the specific socioeconomic conditions, technical capacities, and strategic priorities of individual nations. Against this backdrop, 2025 marked a turning point in the global energy discourse, as countries increasingly emphasized economic and social development underpinned by reliable and affordable energy, particularly natural gas. The narrative surrounding natural gas has evolved, moving from its characterization as a "transition fuel" to broader recognition of its long-term role as a "destination fuel," supporting the integration of intermittent renewables, ensuring grid stability, and providing a lower-carbon alternative to more emission-intensive fuels.

In 2025, gas markets demonstrated renewed resilience, with consumption rising across all major sectors and reinforcing the role of natural gas as the primary driver of global energy supply growth over the last decade. This expansion was supported by fundamental socioeconomic factors, including population growth, increasing urbanization, and ongoing industrialization, which collectively intensified global demand for reliable energy services. The strategic versatility of natural gas was particularly evident in the power sector, where it provided essential flexibility to balance intermittent renewables while simultaneously meeting the baseload requirements of expanding digital infrastructure. Beyond electricity, its impact on global stability is significant, ranging from decarbonizing heavy industry through coal-to-gas switching and providing heating and clean cooking for residential and commercial sectors, to offering a compliant alternative for transport fuels and supporting food security through fertilizer production.

The growth in gas consumption was underpinned by the affordability of natural gas, which remained broadly stable as the global market transitioned into a period of post-crisis rebalancing following the extreme volatility of the COVID-19 pandemic and the 2022 energy crisis. Although European and Asian spot gas prices experienced slight year-on-year increases compared to 2024, they remained at their second-lowest levels over the past five years, reflecting a continued phase of gradual and steady market stabilization. This sustained period of relative price relief has been critical in maintaining widespread market accessibility, even as geopolitical risks, supply uncertainties, and shifting energy policies continue to influence short-term volatility.

Looking ahead, the escalating conflict in the Middle East in early 2026 may require a downward revision of gas market projections for the year, highlighting the urgent need to safeguard critical natural gas infrastructure and evacuation routes against evolving physical, cyber and hybrid threats. Despite these short-term uncertainties, the outlook for 2027 and the medium term remains robust, driven primarily by the electricity sector, where reliable gas-fired generation meets the high-capacity baseload requirements of energy-intensive data centres. Natural gas also plays a crucial role in providing grid stability as a flexible backup for intermittent renewables. In addition, a significant wave of new LNG liquefaction capacity scheduled to come online over the next five years will further reinforce natural gas as a cornerstone for sustainable development, strengthening its role as a vital and adaptable partner for global economic, social, and environmental progress.

To support this evolving landscape and meet future energy needs, GECF Member Countries maintain their leadership in the global market by holding the largest shares of gas reserves, production, and trade. In a complex and evolving environment, they remain committed to developing these resources as reliable suppliers, ensuring global gas demand is met while promoting energy security and sustainable prosperity.

I sincerely thank all contributors to this report and share its valuable insights, key findings, and actionable recommendations with policymakers, industry leaders and stakeholders committed to fostering a secure, sustainable and inclusive energy future.

Dr Philip Mshelbila

Secretary General
Gas Exporting Countries Forum

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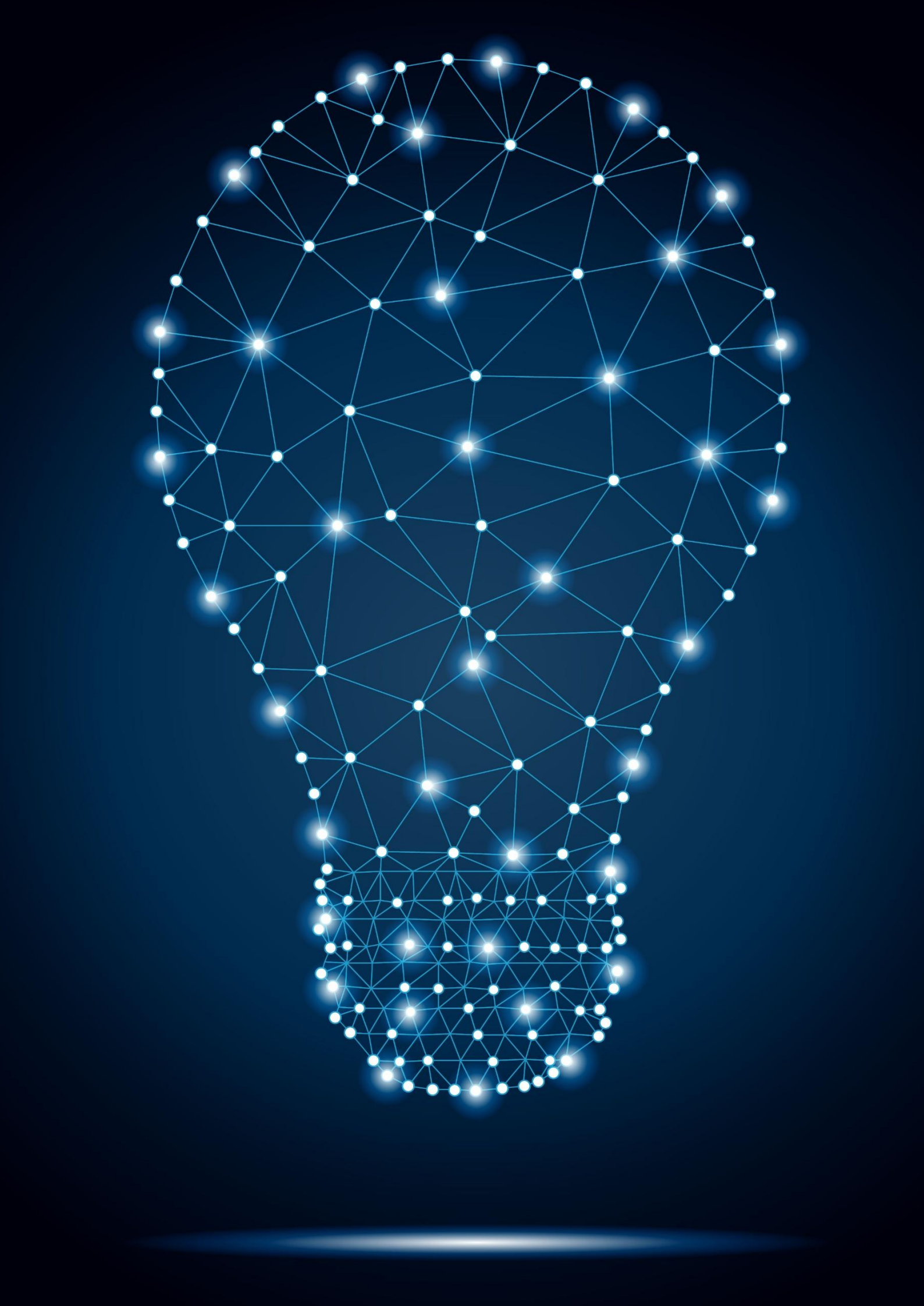


EXECUTIVE SUMMARY

Strong economic growth and focus on energy security have reshaped energy demand

Robust global GDP growth in 2025, estimated at 3.4% on a purchasing power parity basis, fuelled a surge in energy demand across both emerging and advanced economies. This expansion was supported by a notable policy shift away from predominantly international climate-centric agendas toward prioritizing national energy security and economic resilience. Consequently, many nations have increasingly prioritized natural gas as a strategic energy source to ensure reliable supply while advancing a pragmatic, balanced and low-carbon transition that underpins broader economic, social and environmental goals.

Global gas consumption reached a new record high amid growing energy requirements

Global gas consumption increased by 1.2% to reach a record 4.22 tcm in 2025, maintaining a strong growth trajectory and holding a robust 23% share of the global primary energy mix. This increase further cemented natural gas as the dominant driver of global energy expansion, accounting for roughly 30% of primary energy demand growth over the past decade, the largest share of any single energy source worldwide. By consistently providing a reliable, cost-effective, and lower-carbon fuel, natural gas has become a critical tool for navigating the energy trilemma, effectively balancing energy security, affordability and environmental sustainability.

North America and Europe re-emerged as key regional drivers of gas consumption

From a regional perspective, global gas consumption growth reflected a geographic divergence, with North America, Europe and Asia Pacific leading the expansion through additions of 15 bcm, 13 bcm, and 10 bcm, respectively. North America maintained its position as the world's largest consumer at 1,169 bcm, while Asia Pacific, which has been the primary contributor to global consumption growth in recent years, followed at 977 bcm, signalling a moderation in its momentum. These regions were followed by Eurasia at 678 bcm, the Middle East at 591 bcm, Europe at 461 bcm, Africa at 185 bcm, and Latin America and the Caribbean at 155 bcm.

Power generation and industry remained primary sectoral drivers of gas consumption

From a sectoral perspective, the power sector accounted for 39% of gas consumption, supplying essential baseload energy for diverse needs, including expanding data centres, while providing the flexible capacity required to balance renewable generation. The industrial sector followed at 28%, with gas serving as a vital fuel for high-heat processes and an indispensable feedstock for fertilizer production. Residential and commercial sectors accounted for 20%, primarily using natural gas for heating and cooking, while the transport sector maintained a steady 2% share, supported by the growing adoption of CNG and LNG in maritime and road transport.

Global gas production expanded in response to increasing gas demand

Global gas production rose by 1.2% to 4.23 tcm in 2025, driven by North America, the Middle East and Africa. At the country level, the US led growth with a 43 bcm increase, while China and Canada added 12 bcm and 8 bcm, respectively, with North American output supported by expanding LNG exports. GECF Member Countries served as a central pillar of global supply, contributing 37% of total production (1,570 bcm). By category, associated gas production reached 594 bcm, unconventional gas output 1,506 bcm, and offshore gas production 1,264 bcm.

Record number of upstream projects reached FID amid modest upstream investment

Upstream oil and gas investment reached $620 billion, marking a slight y-o-y decline. Development accounted for 89% of the total, with exploration representing the remaining 11%. In development, 160 gas projects were commissioned with an expected combined plateau output of 95 bcma, while 280 projects reached FID, the highest annual level of the past decade. In exploration, only 385 bcm of gas were discovered, the second-lowest volume of the decade, highlighting the potential for a long-term supply gap as existing reserves are gradually depleted.

Global gas trade expanded strongly amid regional market divergence

Global gas trade rose by 3% to reach 1.20 tcm in 2025, driven by a surge in LNG that offset a slight decline in pipeline gas supply. This growth brought gas trade volumes close to the record highs of 2021, highlighting the resilience of the gas markets. The global import-to-consumption ratio increased to 28.5%, the highest level in three years, reflecting easing market conditions and broader fuel availability worldwide. Import dynamics varied across regions, with Europe's total gas imports climbing 6% to 382 bcm, while Asia's imports declined 1% to 463 bcm.

Pipeline gas trade saw gradual and balanced shifts across major regions

Global pipeline gas trade, excluding regasified LNG and transit flows, declined slightly to an estimated 605 bcm, reflecting shifting regional supply and demand dynamics. Europe remained the largest importing region with 205 bcm, despite a significant drop in EU imports to 142 bcm. North America followed closely with 185 bcm, supported by rising US exports to Mexico. Asia ranked third with 92 bcm, led by China's 8% increase in imports to 81 bcm, driven primarily by higher Russian deliveries through the Power of Siberia pipeline.

LNG trade growth broadly reflected evolving flows between Asia and Europe

Global LNG trade rose by 6.5% (27 Mt) to a record 437 Mt in 2025, marking the largest annual increase since 2019. On the export side, growth was driven by the start-up and ramp-up of new liquefaction projects. On the import side, Europe led the expansion, with imports rising 29 Mt to 130 Mt, driven by weaker pipeline gas supplies and stronger injection demand, while Asia's imports dropped by 8 Mt to 273 Mt due to slower gas demand growth and higher pipeline gas flows. As a result, Asia accounted for 63% of global LNG imports, with Europe representing 30%.

New liquefaction capacity will support short- to medium-term growth in LNG markets

Global LNG liquefaction capacity surged by a record 50 Mtpa, bringing total capacity to 548 Mtpa. This growth was driven by the US, Canada and Russia, with Mauritania and Senegal joining the ranks of LNG exporters. Between 2026 and 2030, an additional 241 Mtpa of capacity is expected to come online, led by the US and Qatar and supported by Argentina, Australia, Canada, Gabon, Malaysia, Mexico and Nigeria. This rapid expansion may put downward pressure on spot prices, while also potentially stimulating demand in price-sensitive markets.

Spot LNG shipping costs fell amid carrier oversupply and changing trade routes

Spot LNG shipping costs dropped sharply, with average annual spot charter rates reaching multi-year lows of $20,000 per day for TFDE vessels and $4,600 per day for steam turbine ships. This decline was driven by the commissioning of a record 81 newbuild LNG carriers, bringing the total fleet to 831 vessels, and a shift toward shorter Atlantic-to-Europe routes, primarily from the US. The resulting reduction in tonne-mile demand, combined with excess vessel capacity relative to current liquefaction output, left the spot shipping market fundamentally oversupplied.

Gas storage efforts in the EU ensured security of supply amid declining levels

Global gas storage capacity reached 500 bcm, with underground storage accounting for 90% and LNG storage the remaining 10%. In the EU, where underground storage serves as a vital strategic buffer, a rigorous restocking effort followed the four-year high withdrawals recorded during the 2024/2025 winter season. Strong LNG imports enabled the EU to achieve a summer restocking of 51 bcm, the largest in three years. Despite this, storage levels stood at 68 bcm by late 2025, down 10 bcm from 2024, posing a significant challenge for market developments in 2026.

Spot gas prices increased with noticeable variations across key global regions

Spot gas prices rose across all major markets in 2025, although the magnitude of growth varied by region. The average European TTF spot price increased by 9% to $11.9/MMBtu, Northeast Asian (NEA) spot LNG rose by 3% to $12.1/MMBtu, and US Henry Hub prices surged by 59% to a three-year high of $3.6/MMBtu, driven primarily by record LNG feedgas demand. While TTF and NEA prices remained well below the extreme peaks observed during the 2022 energy crisis, they stayed above pre-2021 levels, suggesting a moderately higher baseline for global gas costs.

Short-term gas market projections face uncertainties from the Middle East conflict

The escalating conflict in the Middle East in early 2026, which has significantly affected the global gas market, may require a downward revision of the 2026 projections presented in this report, with the severity and duration of the conflict determining its impact. It can influence short-term gas supply, demand, trade, and broader energy patterns, but is not expected to fundamentally alter the medium-term outlook. Overall, the resilience of the global gas market suggests that prospects for 2027 and beyond remain robust despite the near-term challenges.

CHAPTER

01

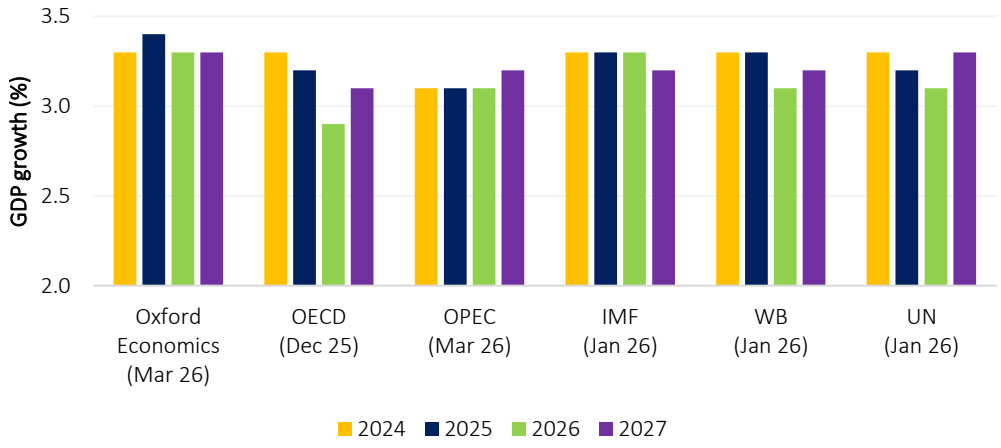
1 GLOBAL PERSPECTIVES

1.1 Global Economy

The global economy demonstrated unexpected resilience throughout 2025, sustaining solid growth momentum despite persistent trade uncertainties and heightened geopolitical tensions. Global GDP expanded by an estimated 3.4% on a purchasing power parity (PPP) basis, as estimated by Oxford Economics, increasing by 0.1 percentage points from the previous year's performance (Figure 1). Regional growth remained notably uneven: advanced economies grew by 1.9%, while emerging and developing economies accelerated to 4.4%, reinforcing their role as the primary engines of global activity. Meanwhile, global GDP growth on a market-exchange rate (MER) basis is estimated at 3.0%.

Looking ahead, global GDP growth for 2026 is projected at 3.3%, supported by moderating inflation and a gradual recovery in global trade. This strengthening of economic confidence is expected to underpin a steady expansion in energy demand throughout the year. However, the escalating conflict in the Middle East poses a significant downside risk, with the severity and duration of disruptions to energy flows ultimately determining its impact on the pace of global economic growth. Conversely, upside potential remains plausible through progress in resolving trade disputes, targeted fiscal stimulus, and significant productivity gains.

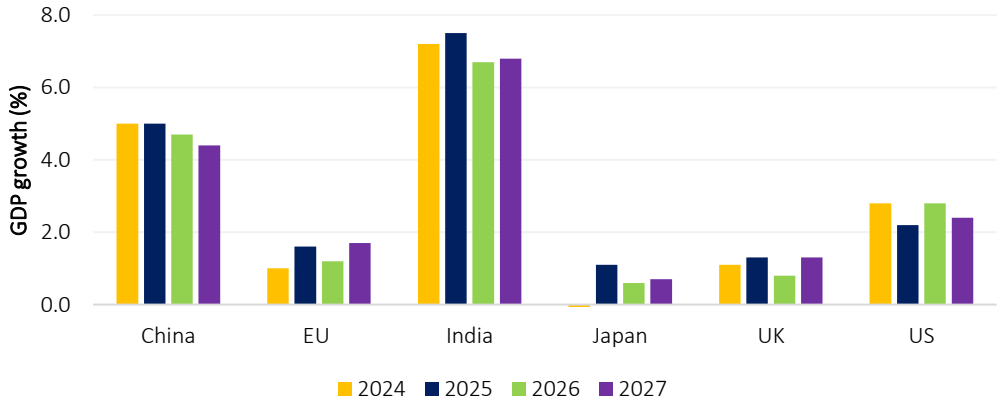
Figure 1: Global GDP growth



Source: GECF Secretariat based on data from Oxford Economics, OECD, OPEC, IMF, WB and UN
Note: Global GDP growth calculated based on purchasing power parity. Preliminary estimate for 2025 and forecast for 2026-2027, as of March 2026

Nevertheless, economic performance continues to diverge across major regions. In the US, GDP growth is estimated at 2.2% for 2025, a notable deceleration from the previous year that reflects the impact of trade tensions and new tariff policies. However, growth is projected to accelerate to 2.8% in 2026, bolstered by resilient consumer spending, easing financial conditions and a surge in business investment, particularly within AI-driven sectors. In the EU, economic activity improved modestly with 2025 GDP growth estimated at 1.6%; however, this pace is anticipated to moderate to 1.2% in 2026 due to softening investment conditions. China's GDP growth remained steady at 5.0% in 2025, as heightened uncertainty regarding US tariffs was partially offset by targeted fiscal stimulus and robust industrial output. Growth is expected to ease slightly to 4.7% in 2026, sustained by continued government support and stable external demand. Meanwhile, India remains among the world's fastest-growing economies, with GDP growth estimated at 7.5% in 2025 before moderating to a still-robust 6.7% in 2026 (Figure 2).

Figure 2: GDP growth in major economies



Source: GECF Secretariat based on data from Oxford Economics

Note: Preliminary estimate for 2025 and forecast for 2026-2027, as of March 2026

The ranking of the world's largest economies remained unchanged in 2025 when measured by PPP, with China maintaining its lead followed by the US, India, Russia and Japan (Table 1).

Table 1: GDP in top 20 largest economies in 2025

	Country	GDP (PPP) (Int$ billion)	GDP (MER) (US$ billion)		Country	GDP (PPP) (Int$ billion)	GDP (MER) (US$ billion)
1	China	41,016	19,399	*11*	Türkiye	3,767	1,565
2	US	30,616	30,616	*12*	Italy	3,720	2,544
3	India	17,714	4,125	*13*	Mexico	3,437	1,863
4	Russia	7,143	2,541	*14*	South Korea	3,363	1,859
5	Japan	6,758	4,280	*15*	Spain	2,829	1,891
6	Germany	6,154	5,014	*16*	Canada	2,723	2,284
7	Indonesia	5,016	1,443	*17*	Saudi Arabia	2,689	1,269
8	Brazil	4,973	2,257	*18*	Egypt	2,382	349
9	France	4,534	3,362	*19*	Nigeria	2,254	285
10	UK	4,455	3,959	*20*	Poland	2,020	1,040

Source: GECF Secretariat based on data from IMF

Note: Preliminary estimates for 2025, as of October 2025. GDP (PPP) is typically measured in International Dollars (Int$), a hypothetical currency that represents the purchasing power of US dollars in a given country.

Global inflation was estimated at 3.4% in 2025, down from 4.5% in 2024 and 6.1% in 2023. This was primarily driven by loosening monetary policies, as central banks shifted their focus, implementing a series of interest rate cuts over the past two years. However, the disinflation progress remains uneven across countries, influenced by the timing of monetary policy adjustments and differing supply and demand dynamics. Looking ahead, global inflation is projected to increase in 2026, to reach an average of 3.5% (Table 2).

Table 2: Inflation rates

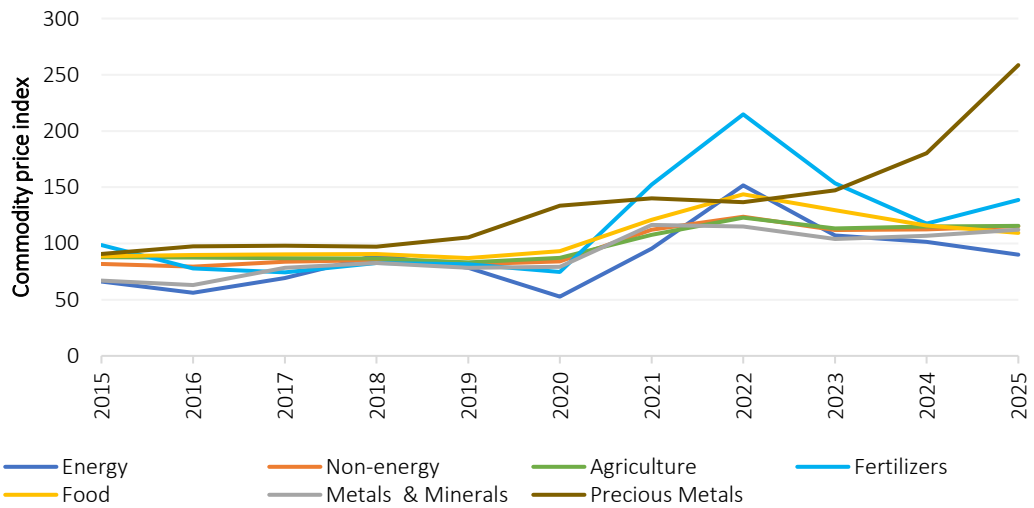
	2024	2025	2026	2027
Global	4.5	3.4	3.5	2.9
US	3.0	2.7	2.6	2.0
Euro area	2.4	2.1	2.2	1.7
UK	2.5	3.4	2.7	2.2
China	0.2	0.0	1.1	1.4
India	5.0	2.2	4.1	4.3

Source: GECF Secretariat based on data from Oxford Economics

Note: Preliminary estimates for 2025 and forecast for 2026-2027, as of March 2026

Commodity prices experienced some volatility in 2025 due to escalating geopolitical and trade tensions. The energy price index declined by 11% y-o-y, driven by lower oil, gas and coal prices, against the backdrop of broadly stable global economic growth (Figure 3). In contrast, the non-energy price index increased by 3% y-o-y. Notably, the precious metals price index surged by 44% y-o-y, while the fertiliser price index saw a sharp 18% increase y-o-y. Looking ahead to 2026, the escalating Middle East conflict may present a significant upside risk for both the energy and non-energy price indices.

Figure 3: Commodity price indices



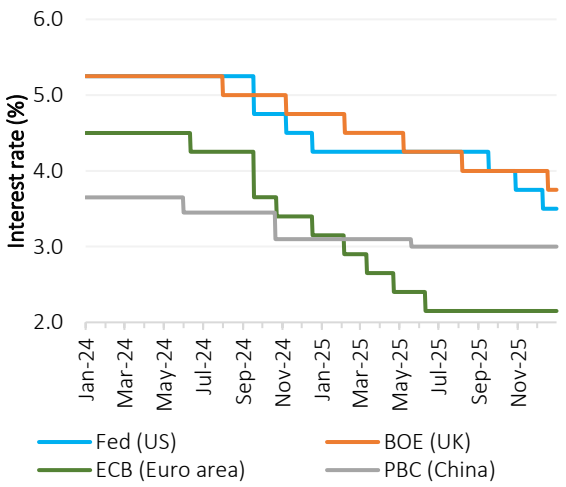
Source: GECF Secretariat based on data from World Bank Commodity Price Data

Note: Annual 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 fertilisers (3.6%)

Interest rates continued to decrease in 2025 as central banks responded to signs of easing inflation and evolving economic conditions (Figure 4). Over the past two years, major central banks have shifted their focus towards supporting economic growth, gradually implementing rate cuts, while maintaining a cautious approach. In the first half of 2025, central banks in the UK, Euro area and China started to implement their interest rate cuts. Notably, the US Federal Reserve (Fed) waited until September 2025 to implement its first rate cut. This kicked off a series of three 25-basis-point reductions across September, October and December. By year-end, the Fed's benchmark interest rate ranged from 3.5% to 3.75%. In the Euro area, the European Central Bank (ECB) reduced its key interest rates by 0.25 percentage points on four occasions, in February, March, April and June, bringing its main refinancing operations rate to 2.15% by year-end. In the UK, the Bank of England (BOE) implemented interest rate cuts of 0.25 percentage points in February, May, August and December, bringing the BOE's benchmark rate to 3.75% by the end of the year. The People's Bank of China (PBC) made one rate cut in May, reducing its one-year Loan Prime Rate (LPR) by 0.10 percentage points to 3%. Looking ahead to 2026, central banks are expected to proceed prudently, making limited further rate cuts while carefully assessing economic momentum and inflationary pressures.

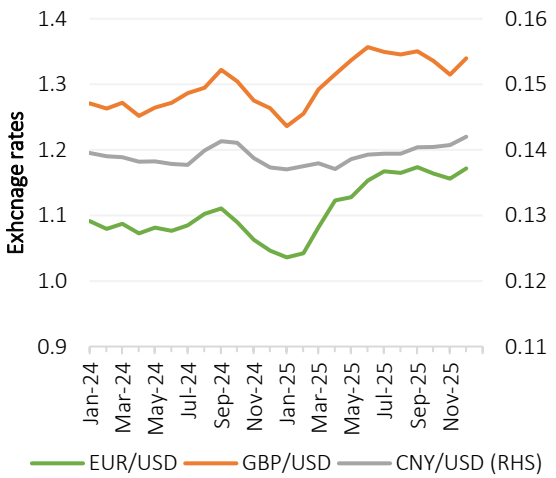
Exchange rates remained relatively stable in 2025, with minimal fluctuations observed across major currencies (Figure 5). The euro appreciated against the US dollar, averaging $1.1301, representing an increase of 4% y-o-y. The British pound also strengthened against the US dollar, averaging $1.3190, reflecting an increase of 3% y-o-y. Meanwhile, the Chinese yuan maintained its value against the US dollar, with an average exchange rate of $0.1391. Looking ahead to 2026, the US dollar may strengthen, supported by strong US economic performance and evolving geopolitical landscape.

Figure 4: Interest rates in major central banks



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

Figure 5: Exchange rates



Source: GECF Secretariat based on data from LSEG

1.2 Energy Policies

1.2.1 Global Developments

The global energy landscape underwent a definitive and calculated shift in 2025 as national governments increasingly decoupled their domestic energy policies from international, climate-centric agendas. Prioritizing national energy security over universal decarbonization targets became a cornerstone of strategic planning, largely driven by the urgent need to ensure affordability and grid reliability amidst growing geopolitical instability and economic headwinds. This pivot was most evident in the outcomes of major summits like COP30 and the G20, where the conspicuous absence of a binding fossil fuel phase-out roadmap reflected a new international consensus: that national sovereignty and economic stability must now dictate the specific pace and nature of any energy transition.

This transition toward a security-first architecture was further underscored by a radical divergence in the strategic priorities of major world powers. While the US formally withdrew from international climate frameworks to focus on maximising domestic hydrocarbon production, the EU was forced to recalibrate its green mandates to better protect industrial competitiveness and social cohesion. Consequently, natural gas has been re-emphasized as a vital, long-term strategic asset rather than a mere temporary bridge fuel. This shift signifies a move toward a more multipolar energy order, where regional pragmatism and the protection of national interests consistently outweigh the pursuit of cohesive global environmental objectives.

1.2.1.1 GECF

The 27th GECF Ministerial Meeting, held in Doha, Qatar, on 23 October 2025, concluded with a Ministerial Statement reaffirming the absolute sovereign rights of Member Countries over their natural gas resources. The Ministers emphasized that natural gas remains an essential, clean and reliable energy source required to achieve the United Nations Sustainable Development Goals, particularly in combating energy poverty and supporting global energy security. The statement stressed the critical necessity of timely and sustained investment across the entire gas value chain, alongside the continued use of long-term contracts to ensure market stability and protect the interests of both producers and consumers in the evolving energy landscape.

Furthermore, the statement expressed deep concern regarding unilateral and discriminatory trade measures, such as the EU Methane Emission Regulation and the Carbon Border Adjustment Mechanism. The GECF argued that such regulations could lead to market volatility and potentially conflict with the established principles of the WTO and the Paris Agreement. In response, the statement advocated for the promotion of all energy sources and technologies, specifically endorsing the transfer of advanced technologies and the deployment of CCUS to minimise the industry's environmental footprint and enhance overall operational efficiency.

1.2.1.2 COP30

The 30th session of the Conference of the Parties (COP30) to the United Nations Framework Convention on Climate Change (UNFCCC) was held from 10-21 November 2025 in Belém, Brazil. The event brought together representatives from nearly 200 countries, however, the world's three largest emitters (China, the US and India) all lacked head-of-state presence, with China and India sending lower-level delegations, while the US did not send any official representatives. Notably, the event also marked the 10-year anniversary of the Paris Agreement, serving as an important benchmark for assessing global climate mitigation efforts largely focused on accelerating the transition toward lower carbon energy sources.

Major COP30 outcomes with potential implications for the gas industry included agreements on climate adaptation, climate finance and climate-related trade measures.

COP30 elevated climate adaptation to an equal political footing with climate change mitigation, marking a historic shift in the trajectory of international climate summits. While the appropriate balance between these two pillars has long been a subject of rigorous debate, the conference signalled a strategic pivot toward the adaptation through the formal adoption of 59 voluntary Belém Adaptation Indicators. Established under the mandate of Article 7 of the Paris Agreement, these metrics provide a standardized, system-wide framework to monitor global progress toward the Global Goal on Adaptation (GGA). In this context, the heightened focus on climate adaptation recognizes that immediate energy security is a prerequisite for systemic resilience, reducing the pressure previously placed on natural gas and other hydrocarbon fuels, as reflected in COP28 outcomes. This approach enables natural gas to expand its role in the global energy mix, providing the reliable, sustainable energy needed for communities to withstand climate-driven disruptions.

COP30 largely preserved the status quo on climate finance, merely reaffirming the targets set at the previous COP without securing new binding commitments from developed countries. The final documents emphasized the urgent need to remain on a pathway toward mobilising at least $300 billion in public finance and scaling total financing for developing countries to at least $1.3 trillion per year by 2035. However, they provided no clear mandatory roadmap for how developed nations would fulfil these commitments. Moreover, the final documents highlighted that Parties have divergent views on whether the previous goal of developed countries to jointly mobilise $100 billion per year in climate finance for developing countries, set at COP15 in 2009, was achieved. A lack of an agreed definition of climate finance and standardized accounting methodologies continues to frustrate developing countries. The reluctance of developed nations to assume significant financial burdens in supporting developing countries' adaptation and mitigation efforts poses a major challenge to advancing renewables-oriented energy transitions. In this context, many developing countries are inclined to prioritize energy transitions that rely more on traditional low-carbon sources, particularly natural gas, which provides a balanced solution to the energy trilemma and serves as a reliable backup for intermittent wind and solar power.

COP30 marked the first time trade policies became a central component of the official negotiated outcome, formally integrating trade into the international climate agenda through a structured dialogue process aimed at ensuring that trade policies and climate objectives are mutually reinforcing. The final documents reaffirmed that climate-related trade measures, including unilateral ones, must not constitute "arbitrary or unjustifiable discrimination or a disguised restriction on international trade". To implement this, the decision mandates a three-year series of dialogues (2026–2028) involving major international organizations, including the WTO, UNCTAD and ITC, to examine opportunities and barriers for international cooperation at the intersection of climate and trade. These dialogues are intended to specifically address tensions over unilateral trade measures like the EU's Methane Emissions Regulation (MER) and Carbon Border Adjustment Mechanism (CBAM). These new EU regulations are poised to not only affect the EU but also reshape the global gas market by imposing strict requirements on international suppliers, potentially resulting in the fragmentation of global gas trade and altering supply routes, price signals and competition patterns. The establishment of the dialogues provides a formal process for exporting nations to contest border restrictions and taxes.

In addition, 2025 represented the third major cycle for Nationally Determined Contributions (NDCs 3.0) mandated by the Paris Agreement, with COP30 formally recognizing the 122 Parties whose updated 2035 targets account for 80% of global greenhouse gas (GHG) emissions. These updates are critical for the gas industry because they establish clear regulatory benchmarks through explicit methane reduction targets. For instance, China's NDC includes non-CO_2 gases for the first time, Nigeria targets a 60% reduction in fugitive methane alongside zero routine flaring by 2030, and Canada aims to cut oil and gas methane emissions by at least 75%. Furthermore, the gas industry is poised to benefit from a strategic reliance on natural gas by major emitters seeking to fulfil coal reduction commitments without compromising energy security. This trend is evident in China's updated climate strategy, which positions gas as a critical stabiliser for its 2035 absolute emission reduction goals. Similarly, India and Vietnam are accelerating plans to phase down unabated coal in favour of expanded gas capacity and LNG imports, utilising them as flexible baseload power.

The legacy of COP30 is defined by the decision to exclude a formal hydrocarbon phase-out roadmap from the final documents, despite pressure from coalitions to build on the COP28 pledge to "transition away from fossil fuels". This significant omission reflects a balanced approach that prioritizes national sovereignty over energy policy, signalling a growing fracture in global climate cooperation as short-term economic interests and energy security concerns increasingly outweigh long-term environmental goals. Following his return to office in January 2025, US President Trump rapidly dismantled US climate initiatives, withdrawing the nation from the Paris Agreement, the UNFCCC and the IPCC while notably boycotting the COP30 summit entirely. In contrast, the EU has maintained its commitment to the global climate agenda, though it carefully recalibrated its energy transition strategy following the inauguration of the new European Commission in December 2024.

1.2.1.3 G20

The G20 Summit in Johannesburg, South Africa, held on 22-23 November 2025, marked a historic milestone as the first hosted on the African continent under the theme "Solidarity, Equality, Sustainability." The South African presidency successfully centred Global South priorities, focusing on the practicalities of mobilising finance for a "Just Energy Transition" and removing structural barriers to low-cost capital. A cornerstone of the summit was the "Ubuntu Legacy Initiative", which launched the "Mission 300" partnership aimed at connecting 300 million people in Africa to electricity by 2030 through a mix of decentralised renewables and gas-to-power solutions. While leaders reaffirmed global goals to triple renewable capacity and double energy efficiency, they also introduced the "Africa Energy Efficiency Facility" to mobilise $3 billion by 2030 to combat regional grid inefficiencies.

The summit achieved significant progress on energy financing by endorsing innovative instruments like debt-for-climate swaps to support vulnerable nations without increasing their debt burdens. There was a clear consensus on a technology-neutral approach to decarbonization, explicitly acknowledging that natural gas integrated with Carbon Capture and Storage remains critical for energy security and affordability in high-carbon regions. Furthermore, the new G20 Critical Minerals Framework was unveiled to promote local processing of minerals like lithium and cobalt, ensuring resource-rich nations in the Global South become active value-chain participants. This shift toward a more multipolar energy order was underscored by the permanent membership of the African Union.

1.2.1.4 BRICS

The 17th BRICS Summit was held on 6-7 July 2025 in Rio de Janeiro, Brazil, under the theme "Strengthening Global South Cooperation for a More Inclusive and Sustainable Governance." Following the group's expansion to 11 members, including Indonesia, the summit served as a critical platform for the enlarged bloc to articulate a unified stance on energy governance and climate action. In the Rio de Janeiro Declaration, leaders reaffirmed that "just and inclusive energy transitions" must be balanced with energy security and affordable access for emerging markets. A landmark outcome was the adoption of the "Roadmap for BRICS Energy Cooperation 2025-2030", which focuses on strengthening coordination, energy security and trade, while integrating digital infrastructure and AI to optimise smart grids.

Crucially, the summit upheld the principle of technological neutrality, asserting that efficient use of all energy sources, including fossil fuels with CCS, nuclear power, natural gas and hydrogen, is essential. By rejecting one-size-fits-all models, BRICS members emphasized each nation's right to determine its own transition path based on unique socio-economic needs. To address the energy trilemma, leaders endorsed the BRICS Leaders' Framework Declaration on Climate Finance, which seeks to bridge funding gaps by encouraging the New Development Bank to provide innovative financing in local currencies. Furthermore, they prioritized the creation of resilient critical mineral supply chains that promote local value addition rather than simple raw material extraction to support industrialisation across the Global South.

1.2.1.5 G7

The 51st G7 Summit, hosted by the Canadian presidency in Kananaskis, Alberta, from 15-17 June 2025, marked a pivotal shift in the group's strategic focus under the theme "Building Energy Security and Accelerating the Digital Transition." Amidst a fragmented geopolitical landscape, the summit transitioned from a traditional joint communiqué to a "Chair's Summary", reflecting a more flexible approach to international cooperation. Central to the energy discussions was the formal recognition that long-term security requires a dual-track strategy: stabilising traditional energy markets to manage immediate economic volatility while de-risking the infrastructure necessary for a lower-carbon future in parallel.

A cornerstone of this strategy was the launch of the G7 Critical Minerals Action Plan, designed to secure the supply chains essential for the global energy transition. Leaders committed to a "Roadmap to Promote Standards-Based Markets for Critical Minerals" focusing on diversifying sources of lithium, cobalt and copper to prevent market coercion from dominant global suppliers. By establishing rigorous environmental and social governance (ESG) standards for extraction and processing, the G7 aimed to harmonize mineral trade with climate objectives, ensuring that the transition to clean energy technologies does not compromise broader sustainability or geopolitical stability.

1.2.1.6 APEC

The 2025 APEC Economic Leaders' Meeting was held in Gyeongju, Republic of Korea, from 31 October to 1 November 2025. Centred on the theme "Building a Sustainable Tomorrow: Connect, Innovate, Prosper", the summit reinforced the Putrajaya Vision 2040 through a strategic emphasis on diversified and inclusive energy pathways. A defining outcome was the explicit, consensus-based recognition of natural gas and LNG as essential pillars for regional energy security, serving as critical flexible partners to support the expansion of intermittent renewable portfolios. To address surging power demand and enhance system resilience, leaders prioritized enhanced energy connectivity across the Asia Pacific, advocating for the accelerated expansion of cross-border infrastructure including subsea power cables and smart distribution networks to build a more robust and interconnected regional power architecture.

In a significant move toward modernizing regional grids, the summit endorsed the APEC AI Initiative, focusing on the responsible adoption of artificial intelligence to optimise energy dispatching, demand management, and predictive maintenance across power systems. APEC leaders reaffirmed their collective commitment to reducing regional energy intensity by 45% by 2035 and doubling the share of modern renewables in the regional energy mix by 2030. By championing a technology-neutral framework, the Gyeongju Declaration promotes a flexible solutions set encompassing carbon capture and storage, hydrogen integration, and nuclear power to achieve regional carbon neutrality by or around mid-century. This comprehensive approach ensures that the energy transition remains a primary driver of long-term economic growth, enabling member economies to leverage innovation while meeting their ambitious international climate targets to secure a sustainable future for all.

1.2.2 Regional Developments

1.2.2.1 Europe

The EU transitioned from emergency crisis management to a formalised, structural overhaul, marking a definitive shift toward long-term strategic foresight. This period saw the expiration of emergency market intervention regulations, such as the Market Correction Mechanism and the Gas Demand Reduction Regulation. These temporary measures were replaced by a comprehensive framework designed to ensure price stability and seasonal preparedness, most notably through the extension of the Gas Storage Regulation until the end of 2027.

Market Correction Mechanism: The EU allowed the Market Correction Mechanism (MCM) to expire on 31 January 2025. Introduced in February 2023, to limit extreme price spikes at €180/MWh, the mechanism's lapse signals a return to a market-driven pricing environment following stabilised supply and decreased volatility. This expiration is considered as a signal from European regulators that the emergency phase of the 2022 energy crisis is structurally over.

Gas Demand Reduction Regulation: The EU allowed the voluntary 15% gas demand reduction mandate to expire on 31 March 2025. Originally introduced in August 2022, the regulation facilitated a structural decrease in EU gas consumption by around 18% compared to the 2017-2022 average. Its expiration signals a transition toward a normalised energy landscape where lower baseline demand is maintained through permanent efficiency gains.

Gas Storage Regulation: The EU extended the Gas Storage Regulation until 31 December 2027, transitioning it from a temporary crisis measure into a permanent structural pillar of energy security. Building on its 2022 adoption, this framework maintains the binding requirement for Member States to fill underground storage to 90% capacity before each winter, providing regulatory certainty while shielding industry from extreme price volatility. To optimise efficiency, updated rules introduced flexibility, allowing the 90% target to be met between October 1 and December 1 to prevent artificial price spikes. Member States may also deviate from these targets by up to 10 percentage points during difficult market conditions, while intermediate trajectories remain indicative to allow for more strategic, cost-effective purchasing.

Joint Purchasing: The EU launched the EU Energy and Raw Materials Platform in July 2025, transforming joint purchasing from a temporary emergency tool into a permanent, structural feature of the Energy Union. This new platform replaces the original AggregateEU mechanism, which expired on 31 March 2025, and expands its scope to include the collective procurement of natural gas, hydrogen and strategic raw materials. By leveraging the Union's massive collective market weight, the platform coordinates demand aggregation to significantly enhance bargaining power and ensure all Member States have equitable access to diversified global supplies. This permanent institutional shift is specifically designed to prevent Member States from outbidding each other during periods of market tightness, fostering long-term price stability and a more unified approach to European resource security.

FuelEU Maritime Regulation and the EU ETS: The shipping industry faced a significant regulatory shift on 1 January 2025, with the implementation of the FuelEU Maritime Regulation and the first mandatory compliance deadline for the EU Emissions Trading System (EU ETS). These frameworks create a financial stimulus for the adoption of LNG-fuelled vessels over oil-based fuel by incorporating methane slip into well-to-wake calculations, which measure emissions from fuel production through to final combustion. High pressure gas engines, which significantly reduce this methane slip, now provide the most effective pathway for shipowners to meet the initial 2% reduction mandate while mitigating rising carbon costs. This regulatory environment solidifies LNG as the premier transitional fuel, making investment in gas-ready infrastructure a strategic advantage for maintaining long-term competitiveness on global trade routes.

The Hydrogen and Decarbonised Gas Market Framework: As part of the broader Hydrogen and Decarbonised Gas Market Framework, a landmark Delegated Act officially entered into force in November 2025 to establish the specific GHG accounting methodology for low-carbon hydrogen. This regulation provides the essential legal definition for blue hydrogen, produced from natural gas with carbon capture, by setting a strict 70% GHG reduction threshold compared to fossil benchmarks. By codifying these technical standards, the EU has created the necessary investment certainty for large-scale blue hydrogen projects to support industrial decarbonization while ensuring they meet the Union's stringent climate criteria.

Methane Emission Reduction Regulation: The EU moved into the active implementation phase of the Methane Emission Reduction Regulation following its entry into force on 4 August 2024. By 5 May 2025, operators of oil and gas infrastructure were required to submit their first comprehensive leak detection and repair (LDAR) programs, while importers provided initial qualitative reports on the monitoring, reporting and verification (MRV) measures of their energy sources. This structural shift was further solidified on 5 February 2026, with the enactment of a formal ban on routine venting and flaring for existing sites, ensuring the market aligns with stricter GHG reduction targets. Furthermore, the regulation established a Methane Transparency Database to monitor the profiles of both domestic and imported energy, signalling the Union's intent to enforce future methane intensity standards for all gas entering its territory.

Corporate Sustainability Due Diligence Directive (CSDDD): The EU initiated a structural simplification of the CSDDD via the Sustainability Omnibus I package to reduce administrative burdens and enhance industrial competitiveness. While the European Parliament approved the revised text in December 2025, the package is currently awaiting final formal adoption by the European Council. Once published in the Official Journal, the new rules will significantly narrow the directive's scope to apply only to large companies with over 5,000 employees and €1.5 billion in global turnover. This pending overhaul also extends the transposition deadline for Member States to 26 July 2028, and replaces the substantive obligation for companies to put into effect climate transition plans with a simpler requirement to merely adopt them. Furthermore, the updated framework reduces the frequency of monitoring due diligence effectiveness from an annual basis to once every five years, providing the private sector with a more predictable and manageable compliance landscape.

1.2.2.2 Asia Pacific

China significantly advanced its natural gas strategy by implementing an updated National Gas Utilisation Policy on 1 August to prioritize high-efficiency users and ensure a more balanced supply-demand system. This policy shift coincided with a critical reform in gas pricing mechanisms, which for the first time successfully linked upstream and downstream prices to better reflect market realities and seasonal fluctuations. These market-based reforms were designed to complement the broader 2025 economic milestone where clean energy sectors, led by solar, wind, and electric vehicles, contributed $2.1 trillion to the national economy and reinforced the role of gas as a flexible partner to the nation's 2,159 GW of renewable capacity. Furthermore, the policy alignment supported the expansion of the national Emissions Trading System (ETS) to include heavy industries such as steel and aluminium, incentivizing high-efficiency gas utilisation over higher-emission fuels. This strategic expansion increased the system's coverage from 40% to roughly 60% of China's total greenhouse gas emissions, integrating industrial decarbonization with energy security.

India achieved 50% non-fossil electricity capacity in June 2025, reaching its national target five years early. To maintain grid stability alongside this rapid renewable growth, the government enacted the Oilfields (Regulation and Development) Amendment Act 2025, unifying gas and petroleum governance under a modernized upstream framework. This shift, supported by the Petroleum and Natural Gas Rules 2025, streamlined regulations and attracted global investment through the award of 172 exploration blocks. Concurrently, the One Nation One Gas Grid initiative expanded the operational pipeline network to over 25,400 km, while Unified Pipeline Tariff reforms ensured affordable access for industrial and household consumers.

Japan accelerated its Green Transformation (GX) strategy, positioning natural gas and LNG as indispensable pillars of energy security. A key milestone was the implementation of the Strategic LNG Reserve, allowing the government to secure emergency cargoes against global supply shocks. To meet the rising electricity demand from AI data centres and semiconductor manufacturing, the 7th Strategic Energy Plan reaffirmed gas as a vital bridge fuel while incentivizing CCS integration and ammonia co-firing. Furthermore, Japan utilised the Asia Zero Emission Community (AZEC) to promote a pragmatic transition, leveraging existing LNG infrastructure to develop future hydrogen and e-methane supply chains across the Indo-Pacific.

South Korea formally adopted the 11th Basic Plan for Electricity Supply and Demand, prioritizing a mix of nuclear, renewables and natural gas to meet surging power demand from AI data centres. A central policy shift reclassified LNG as a strategic transition fuel, incentivizing the conversion of aging coal plants into high-efficiency gas facilities with hydrogen co-firing capabilities. To bolster energy security, the government expanded KOGAS infrastructure and streamlined regulations for private LNG imports. Furthermore, the successful commissioning of the nation's first commercial-scale CCS project at an industrial hydrogen plant marked a major milestone toward decarbonizing its heavy manufacturing sector.

1.2.2.3 North America

Canada underwent a major energy policy shift under a new federal government, pivoting toward a “Climate Competitiveness Strategy” that balances decarbonization with industrial growth and consumer affordability. The government signalled the cancellation of the proposed oil and gas emissions cap, opting instead to rely on Enhanced Methane Regulations; these stricter rules target a 72% reduction in methane emissions from the oil and gas sector by 2030. To incentivize large-scale decarbonization, Budget 2025 extended the full value of the CCUS Investment Tax Credit (ITC) by five years to 2035 and expanded eligibility to include Enhanced Oil Recovery (EOR). To accelerate infrastructure, a new Major Projects Office was established to provide a "single-window" for two-year project approvals, immediately referring nation-building projects like LNG Canada Phase 2 and the Darlington New Nuclear Project for fast-tracking.

Mexico reclassified the Federal Electricity Commission (CFE) and Pemex as Public State Companies, prioritizing energy sovereignty through the National Strategy for the Electricity Sector (2025-2030). This framework mandates a 54% state share in power generation and centralises oversight under the Ministry of Energy, while allowing private participation in up to 46% of the market through new mixed-investment schemes.

The United States revised its energy and environmental trajectory following President Trump’s return to office, pivoting from a “clean energy transition” toward a policy of “American energy dominance”. This shift is characterised by a rapid return to fossil fuel prioritization and the systematic removal of climate-related regulatory barriers. On 20 January 2025, the President declared a National Energy Emergency to bypass “unduly burdensome” agency actions and announced a second formal withdrawal from the Paris Agreement, signalling a strategic retreat from international climate accords to prioritize domestic economic interests.

The administration’s “Drill, Baby, Drill” agenda translated into immediate executive actions to open vast federal tracts, including the Arctic National Wildlife Refuge and offshore areas in the Atlantic and Pacific, to oil and gas leasing. To support this surge, permitting timelines for drilling were slashed to as little as 28 days, and previous pauses on LNG export authorisations were revoked to position the US as a global energy superpower. The “One Big Beautiful Bill Act” (OBBBA), signed on 4 July 2025, fundamentally reshaped the energy tax code by pulling back billions in Inflation Reduction Act (IRA) funding and sunsetting renewable tax credits by 2027, in favour of the Energy Dominance Financing Program.

Furthermore, new executive orders signed in July 2025 fast-track the permitting of massive data centres and the essential fossil fuel infrastructure required to power them. To meet the surging electricity demands of the booming AI sector, this initiative prioritizes dispatchable baseload power, such as natural gas and coal, to ensure grid reliability for high-density computing. These measures streamline regulatory hurdles for the pipelines and transmission lines needed to support this rapid industrial expansion and ensure long-term energy security.

1.2.2.4 Latin America and the Caribbean

Argentina reinvigorated its energy sector by implementing the Incentive Regime for Large Investments, a pivotal policy designed to attract capital for large-scale energy infrastructure through 30-year regulatory stability. This legislative framework, combined with the deregulation of domestic energy markets, prioritized a transition toward market-based pricing to incentivize efficiency and stability. By establishing a predictable regulatory environment, the government shifted its policy focus toward making natural gas a central pillar of the national economy.

Bolivia aimed to revitalise production by enacting a pivotal Hydrocarbons Law reform designed to optimise fiscal terms and lure vital foreign capital for high-risk deep-well drilling. This pivot embraced a more adaptive regulatory framework to stimulate private-sector investment in frontier natural gas plays. By dismantling systemic structural barriers and introducing competitive operational incentives, the state sought to secure domestic energy reliability while fortifying its legacy as a central gas supplier for the South American market.

Brazil solidified its dual-track strategy, balancing record hydrocarbon output with a world-leading renewable transition under the National Energy Transition Policy (NETP). By leveraging the Fuel of the Future Law, the government expanded biofuel mandates and green hydrogen hubs while intensifying decarbonization within the oil sector. A key pillar of this effort was the commitment to Zero Routine Flaring, aiming to eliminate non-emergency gas flaring to reduce methane intensity. These initiatives, supported by pre-salt revenues, allowed renewable sources to finally meet 50% of the nation's total energy demand.

Peru centred energy policy on a strategic renewable scale-up targeting a power mix of 60% renewables and 40% gas. Under its national transition strategy, the government is accelerating over 6 GW of solar and wind capacity while integrating Battery Energy Storage Systems (BESS) to ensure grid stability. To meet its 2030 climate goals, Peru has strengthened its Zero Routine Flaring commitments and prioritized green hydrogen development via Law No. 31992, utilising tax incentives to attract the private capital necessary for deep decarbonization.

Trinidad and Tobago anchored its strategy on a dual-track approach to stabilise gas output while accelerating a transition toward 30% renewable electricity by 2030. The commissioning of the 92.2 MW Project Lara solar farms marked a pivotal shift, allowing the state to redirect gas toward high-value petrochemical exports. To meet its climate targets, the government strengthened its Zero Routine Flaring commitments and prioritized a green hydrogen roadmap, leveraging existing industrial infrastructure to attract investment for low-carbon fuel production.

Venezuela structured its energy framework around a landmark Hydrocarbons Law reform and the 7T 2025-2031 plan, expanding private-sector control to revitalise crude production. To address climate mandates, the state prioritized a 71% reduction in gas flaring by 2030, aligning with Zero Routine Flaring standards to minimise methane intensity. Concurrently, the government is facilitating a renewable expansion of 3 GW solar and 1 GW wind capacity.

1.2.2.5 Africa

Algeria concluded its first upstream licensing round in a decade, awarding five onshore blocks to international majors to boost gas output by 20 bcma. Finalized in June 2025, this bid round marks the first successful auction under the 2021 Hydrocarbon Law and is a key step toward the country's long-term goal of increasing total production capacity.

Angola launched a licensing round for the Kwanza and Benguela Basins, prioritizing natural gas exploration to maintain production above one million bpd. Under its New Gas Consortium, the state also achieved first production to monetize previously flared volumes.

Egypt concluded an international gas licensing round, awarding Mediterranean and Nile Delta blocks to industry majors. The energy expansion strategy integrates a 15 GW solar and wind rollout with upstream operations to reduce domestic gas consumption and boost export volumes. Egypt also codified its National Strategy for Low-Carbon Hydrogen.

Equatorial Guinea incentivized foreign investment by slashing corporate income tax from 35% to 25% and maintaining an “open-door” policy for 24 exploration blocks. Concurrently, the government also enhanced its Gas Mega Hub by implementing a new legal decree to ensure transparency and protection for international energy partners.

Libya launched its first international licensing round in 17 years, awarding multiple onshore and offshore exploration blocks to reach a critically important 1.6 million bpd production target. In addition, the state was also accelerating large-scale solar projects, like the 500 MW Sadada plant, to reduce domestic fuel consumption and maximise gas exports.

Mauritania inaugurated the Greater Tortue Ahmeyim gas project and ratified a Green Hydrogen Code to secure renewable investments. The administration implemented a 2025 Investment Code mandating local content participation and strengthening international arbitration rights.

Mozambique lifted force majeure on the Mozambique LNG project and the Rovuma LNG development as security stabilised. The government also launched the ASCENT project to accelerate electricity access while implementing a new National Climate Finance Strategy.

Nigeria launched an integrated licensing round for 50 blocks to hit targets of 2 million bpd of oil and 100 bcma. The state concurrently expanded its Decade of Gas initiative by mandating CNG infrastructure and ratifying a National Integrated Electricity Policy to incentivise solar, freeing up natural gas for industrial growth and lucrative global exports.

Senegal inaugurated its first offshore oil production at Sangomar and commenced LNG exports from the Greater Tortue Ahmeyim project. The state ratified a 2025 Investment Code to automate licensing through a digital window, and to guarantee stable fiscal frameworks.

South Africa ratified a R2.2 trillion Integrated Resource Plan to procure 105,000 MW from solar, wind, gas and nuclear sources while ending Eskom’s monopoly. The government concurrently advanced its Gas Master Plan to develop LNG infrastructure at Richards Bay.

*Actual Reading
004835.523 m³
Tariff: F3
ON
Qmax 6m³/h
Qmin 0,04m³/h
V 1,2dm³
pmax 0,1bar"T"
tb 20°C/tsp 20°C
tm -25°C...55°C
tg -25°C...55°C
IP55 H3
Valve Ve
0013920
SEALED
M17 0102
class 1,5
S/N: 004015943928
EI6.01
only clean with a damp cloth

CHAPTER

02

2 GAS CONSUMPTION

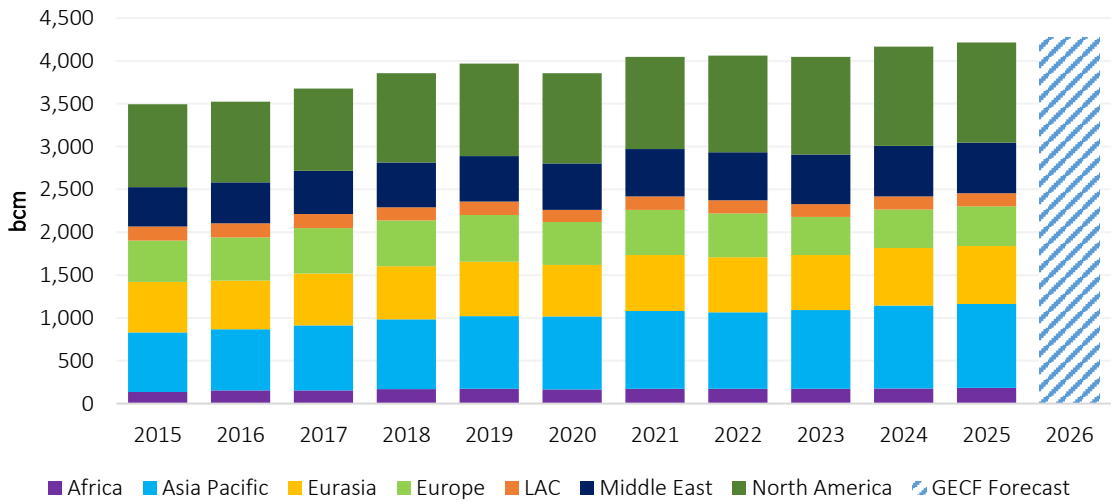
Global gas consumption is estimated to have increased by 1.2% (55 bcm) to reach 4,217 bcm in 2025, following strong growth of 2.5% in 2024 (Figure 6).

Regionally, growth was anchored by North America and Europe, while the Asia-Pacific experienced a slowdown in consumption growth after being the primary driver in previous years. This geographic divergence reflected shifting economic conditions and the significant impact of elevated spot prices on more price-sensitive emerging markets.

Sectorally, the power sector remained a primary driver of gas demand, particularly in markets compensating for weaker hydro and wind output, or where record cooling requirements were prevalent. Concurrently, industrial demand exhibited mixed regional trends, as fluctuating price dynamics and broader macroeconomic shifts heavily influenced manufacturing offtake.

Looking ahead, global gas consumption is projected to grow by 1% in 2026, nearing 4,260 bcm. This expansion is driven by a rebound in the Asia Pacific and sustained growth in North America. However, the escalating conflict in the Middle East poses a major threat to these projections.

Figure 6: Trend in global gas consumption



Source: GECF Secretariat based on Cedigaz data for 2015 to 2024, GECF estimate for 2025, GECF forecast for 2026

2.1 Gas Consumption by Region

North America maintained its largest share of the global market, with consumption rising 1% to 1,169 bcm in 2025. This growth was anchored by the US, where consumption rose by 11 bcm, and Canada, which contributed a notable 6 bcm increase to the regional total (Figure 7). These gains strengthened the continent's role as a primary engine of global gas consumption.

Asia Pacific remained an important demand driver, though its moderate 1% growth to 977 bcm signalled a cooling. While China provided the primary regional baseload demand, India faced a temporary contraction as high spot prices curtailed offtake. Southeast Asian markets exhibited mixed trends, where robust infrastructure expansion balanced stagnant demand elsewhere.

Eurasia's gas consumption climbed to 678 bcm, marking a moderate increase from a year earlier. This expansion was mainly anchored by Russia, where resilient industrial activity and domestic energy requirements continued to support overall demand levels.

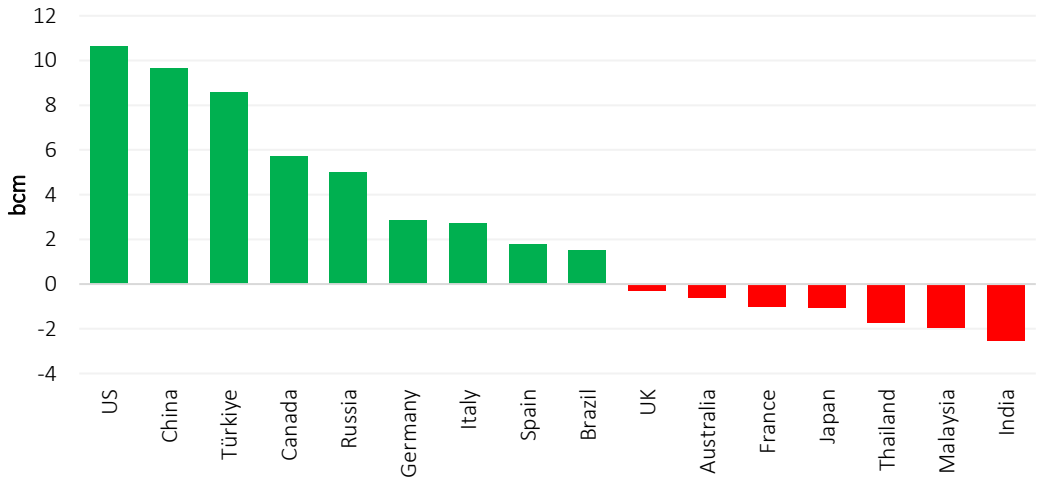
Middle East gas consumption reached 591 bcm, up slightly from a year earlier. This growth was fuelled by power and industrial expansion, especially in Saudi Arabia and the UAE, as both nations accelerated fuel-switching strategies towards natural gas for electricity output.

Europe recorded a more pronounced rebound as gas consumption rose to 461 bcm from 448 bcm a year earlier. This recovery was driven by increased gas-fired power generation and colder seasonal intervals, although total demand remains structurally below pre-crisis levels.

Africa's gas consumption expanded further to 185 bcm, supported by ongoing gas-to-power developments in key markets such as Algeria, Egypt and Nigeria, where rising electricity and residential needs continue to drive fundamental gas demand.

LAC recorded a modest increase, with gas consumption rising to 155 bcm. This recovery was largely dictated by lower hydro availability in several countries, including Brazil, which necessitated a greater role for gas-fired generation in balancing the regional power supply.

Figure 7: Y-o-y variation in gas consumption for selected major consumers in 2025



Source: GECF Secretariat based on data from national governmental organisations

2.1.1 Europe

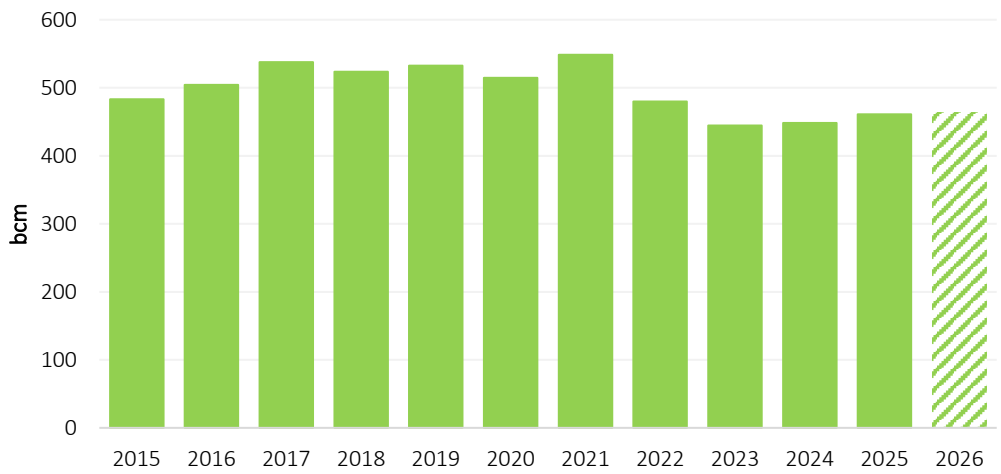
Europe's gas consumption climbed to 461 bcm in 2025, a 3% increase (+13 bcm) from the previous year (Figure 8). While this represents the most significant annual expansion since 2021, aggregate demand remains structurally depressed compared to pre-2022 levels. The growth was heavily front-loaded, with the first quarter accounting for the bulk of the gains as cold weather and intermittent renewable output necessitated higher gas burn. Although consumption moderated in subsequent months, late-autumn cold spells underscored the enduring criticality of natural gas for residential heating and grid reliability.

The power sector served as the main driver for demand growth during the year. Gas-fired generation rose to compensate for stronger electricity demand and a coinciding dip in wind and hydropower output across key markets. While solar capacity expanded at a record pace, cold weather in Northwest Europe and drought conditions in Southern Europe forced a greater reliance on the flexibility of gas-fired plants to maintain system balance.

In contrast, industrial gas consumption experienced a modest decline as persistently high prices pressured energy-intensive segments like refining and fertilizers. Although some sub-sectors have shown signs of recovery since the peak of the energy crisis, overall industrial offtake remained constrained by high input costs and broader macroeconomic headwinds across the continent, stifling a more robust return to pre-2022 activity levels.

Looking ahead to 2026, European gas consumption is projected to reach 463 bcm, reflecting a marginal 0.4% increase. Accelerated renewable integration is expected to dampen gas use in the power sector, while industrial demand is likely to stabilise as global supply conditions improve. Overall, the market is entering a period of stabilization, where natural gas maintains a critical role in providing industrial feedstocks, ensuring seasonal heating security, and offering essential flexibility to a decarbonising power grid.

Figure 8: Trend in Europe's gas consumption



Source: GECF Secretariat based on Cedigaz data for 2015 to 2024, GECF estimate for 2025, GECF forecast for 2026

2.1.1.1 EU

The EU gas market reversed its multi-year contraction in 2025, as total consumption climbed by 3% to 322 bcm, compared to 313 bcm in 2024 (Figure 9). This turnaround marks the first notable annual increase following three consecutive years of decline, primarily triggered by a resurgent power sector during the first quarter. Despite this localized recovery, aggregate demand remains structurally depressed, sitting significantly below the 2021 peak of 394 bcm and the broader pre-2022 historical averages.

The power generation served as the primary engine for this growth, with gas-fired electricity output surging by 8% to 466 TWh, up from 432 TWh a year earlier (Figure 10). This increase occurred as coal-fired generation continued its terminal decline, falling 5% to 257 TWh. While wind generation expanded strongly, a drop in hydropower and solar output necessitated a greater reliance on the dispatchable flexibility of gas-fired plants. In this context, natural gas accounted for 17% of total EU electricity generation in 2025, compared to 16% in 2024, while coal's share eroded further to 9%. Non-hydro renewables maintained their leading position in the power mix, highlighting the continued transformation of the EU's energy landscape.

The industrial sector experienced stagnant gas consumption, reflecting the enduring impact of high input costs and cautious offtake across energy-intensive manufacturing segments.

The residential and commercial sector saw an increase in gas consumption during colder periods, particularly in Q1 and late autumn. These rising heating requirements emphasized the continued importance of natural gas in ensuring the security of heat supply across the EU.

Looking ahead, the evolving energy landscape indicates that despite the aggressive expansion of renewables, the EU will require substantial dispatchable capacity to mitigate intermittency and seasonal volatility. In this context, natural gas will remain a fundamental pillar for grid stability, providing the necessary flexibility and security of supply to balance the power system.

Figure 9: Trend in EU gas consumption

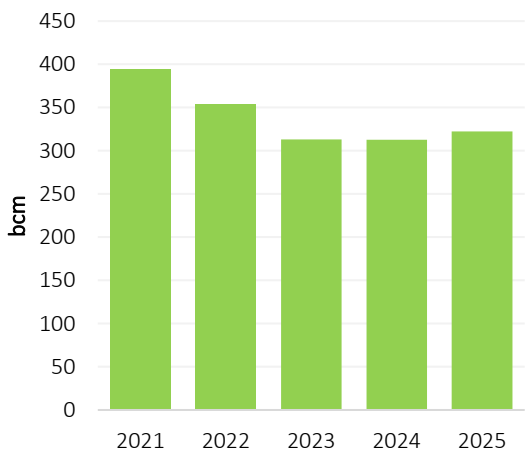
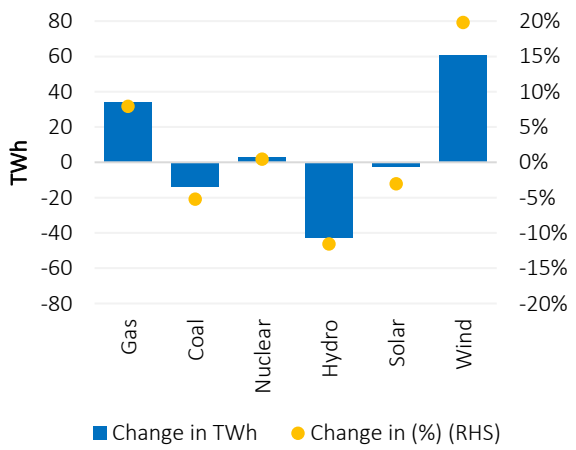


Figure 10: Y-o-y variation in EU's power generation



Source: GECF Secretariat based on data from LSEG and Ember

2.1.1.1.1 Germany

Germany's gas consumption climbed by 3.2% to 78 bcm in 2025, signalling a stabilization phase after years of intense contraction (Figure 11). This recovery was primarily driven by the residential and commercial sectors, where intake rose by 1.8 bcm to 31.4 bcm as colder temperatures in the first quarter and early autumn boosted heating demand. These weather-driven gains partially offset the structural decline in usage caused by post-2022 efficiency gains and permanent behavioural shifts. The industrial sector saw a more marginal and uneven 1.8% increase, as persistent economic headwinds and high energy costs continued to suppress a full return to historical production levels (Figure 12).

Figure 11: Trend in Germany's gas consumption

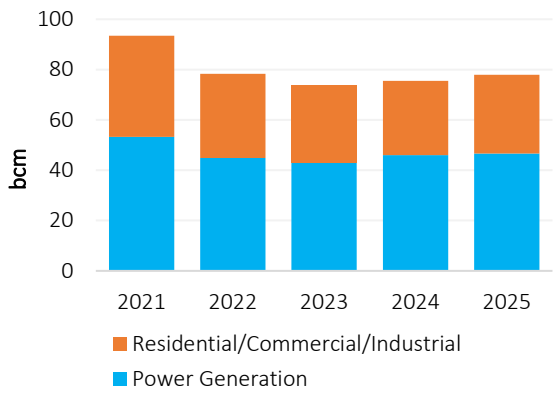
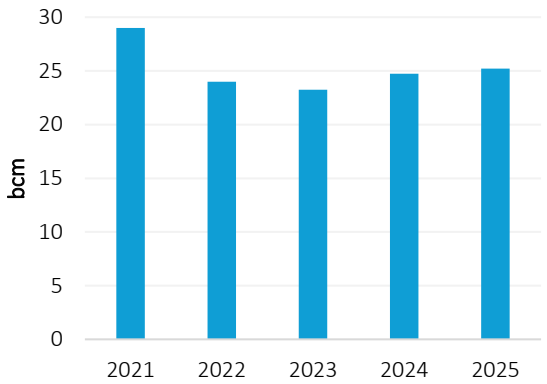


Figure 12: Germany's industrial gas consumption



Source: GECF Secretariat based on data from LSEG and Bundesnetzagentur

In the power sector, gas-fired electricity generation rose by 5.4% to 83 TWh, effectively offsetting a 3% decline in coal-fired generation, which fell to 103 TWh (Figure 13). This transition occurred as renewable expansion was led by strong gains in solar output, while wind generation saw a slight decline due to less favourable weather conditions. Despite these fluctuations, the power mix remained dominated by renewables, with non-hydro sources accounting for 58% of total output, followed by coal at 21% and natural gas at 17% (Figure 14).

Figure 13: Y-o-y variation in Germany's power output

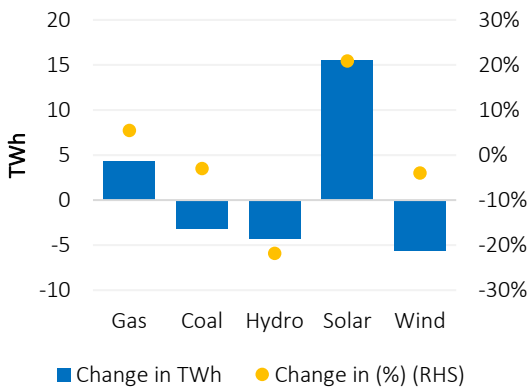
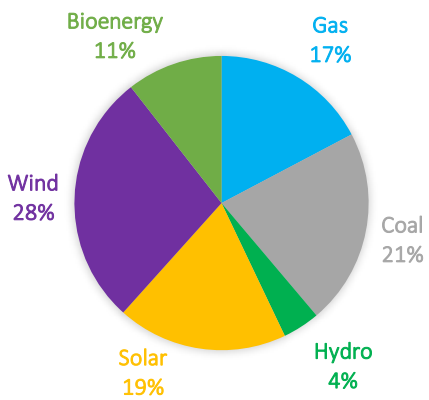


Figure 14: Germany's power mix in 2025



Source: GECF Secretariat based on data from Ember

2.1.1.1.2 Italy

Italy's gas consumption rose by 4% to 64.5 bcm in 2025, rebounding after two consecutive years of contraction (Figure 15). This recovery was primarily fuelled by the power sector, while other segments showed more stagnant trends due to unseasonably mild weather. Industrial demand edged up slightly to 12 bcm, supported by a gradual stabilization in manufacturing activity, though output remained significantly below pre-2022 benchmarks (Figure 16). In contrast, residential and commercial consumption remained broadly flat at 27 bcm. This stability reflected warmer-than-average temperatures during the critical shoulder and winter months, which effectively capped space-heating requirements.

Figure 15: Trend in Italy's gas consumption

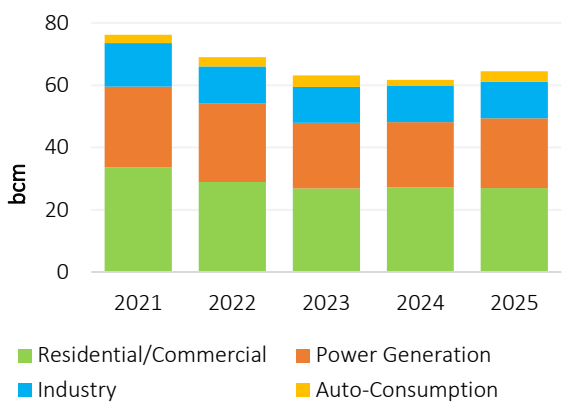
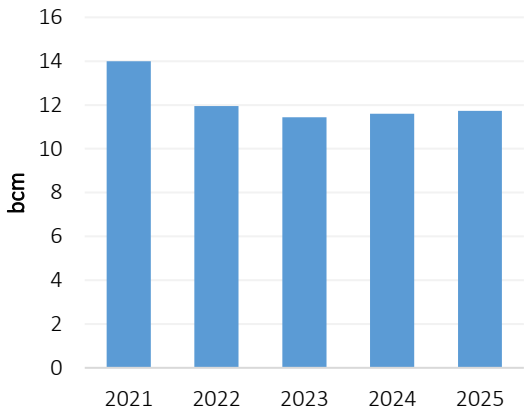


Figure 16: Italy's industrial gas consumption



Source: GECF Secretariat based on data from Snam

In the power sector, gas-fired electricity generation climbed by 5.4% to 125 TWh, primarily to bridge the deficit caused by a decline in hydropower and wind output (Figure 17). While solar generation expanded at an even faster rate, the volatility of renewable generation necessitated an increased reliance on the dispatchable flexibility of gas-fired plants. Consequently, natural gas solidified its status as the cornerstone of Italy's power mix, accounting for a dominant 50% share of total electricity generation (Figure 18).

Figure 17: Y-o-y variation in Italy's power output

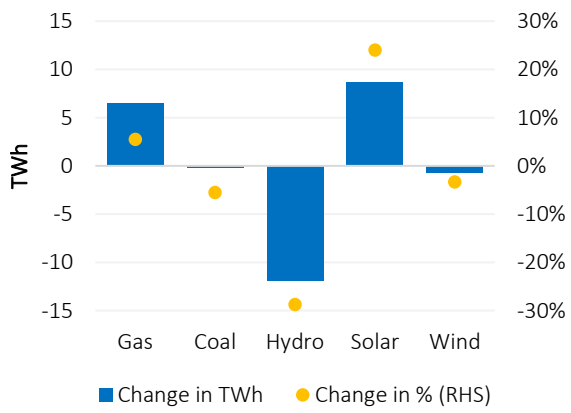
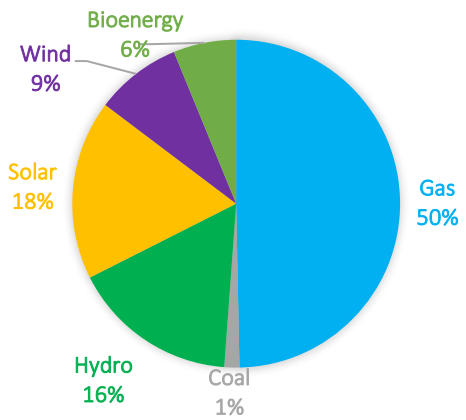


Figure 18: Italy's power mix in 2025



Source: GECF Secretariat based on data from Ember and Terna

2.1.1.1.3 France

France's gas consumption fell by 3% to 29.7 bcm in 2025, marking its third consecutive annual contraction (Figure 19). This downturn was largely dictated by a 7% slump in industrial demand, where energy-intensive sectors like chemicals, refining and paper production struggled under sustained competitive pressures (Figure 20). Meanwhile, residential and commercial requirements, which represent the largest share of national usage at 62%, slipped by 2% to 18 bcm. This decline was fuelled by a combination of ongoing efficiency improvements, deeper structural shifts in consumer behaviour since the energy crisis, and high nuclear availability.

Figure 19: Trend in France's gas consumption

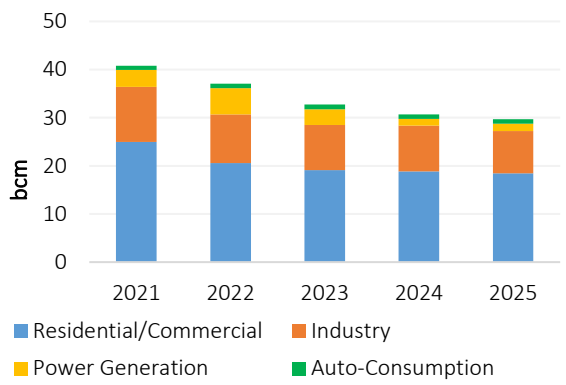
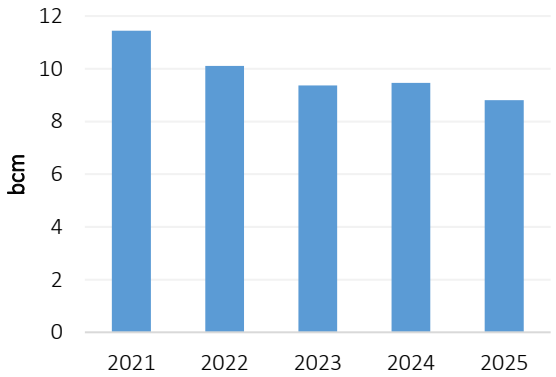


Figure 20: France's industrial gas consumption



Source: GECF Secretariat based on data from Grtgaz

In the power sector, gas-fired electricity generation decreased by 4.7% to 17 TWh (Figure 21). Although natural gas accounted for only 3% of France's total electricity generation, it performed a vital balancing function, especially during intervals of diminished hydropower output and planned nuclear maintenance during the summer months. The broader power sector was defined by a robust nuclear recovery, with generation climbing to 392 TWh and representing more than 70% of total electricity output (Figure 22). This significant resurgence in nuclear energy, bolstered by improved reactor availability, not only reduced the domestic need for thermal peaking plants but also solidified France's position as a major regional power hub, supporting higher net electricity exports to neighbouring European markets.

Figure 21: Y-o-y variation in France's power output

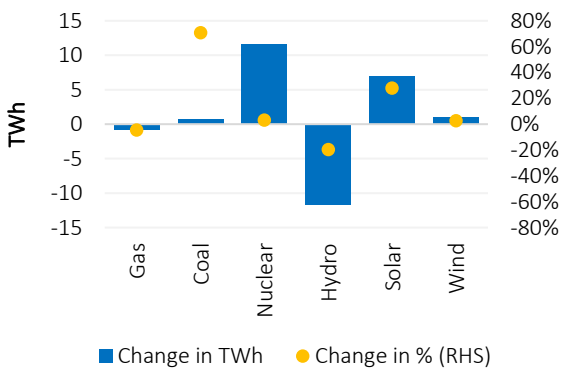
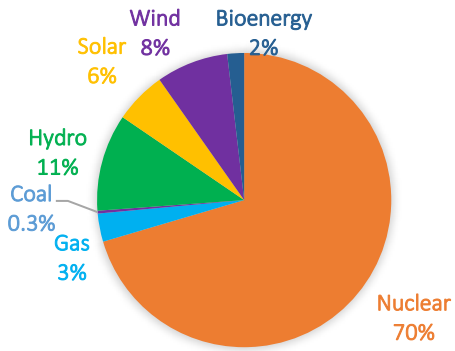


Figure 22: France's power mix in 2025



Source: GECF Secretariat based on data from Ember and EDF

2.1.1.1.4 Spain

Spain's gas consumption climbed by 6% to 30 bcm in 2025, reversing the contraction observed during the previous year. This rebound was primarily fuelled by a significant escalation in power sector intake, whereas conventional demand across the industrial and distribution segments remained largely suppressed (Figure 23). In particular, industrial consumption retreated by over 5%, as energy-intensive sectors, including refineries, metallurgy and pharmaceuticals, recorded lower usage for much of the year (Figure 24). This divergence highlights a market where thermal generation acted as the primary growth engine while manufacturing activity continued to struggle under broader economic headwinds.

Figure 23: Trend in Spain's gas consumption

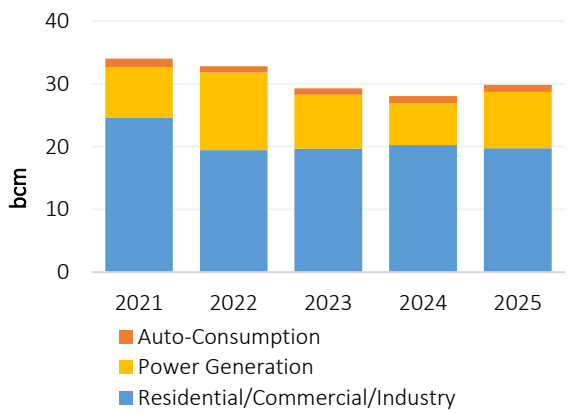
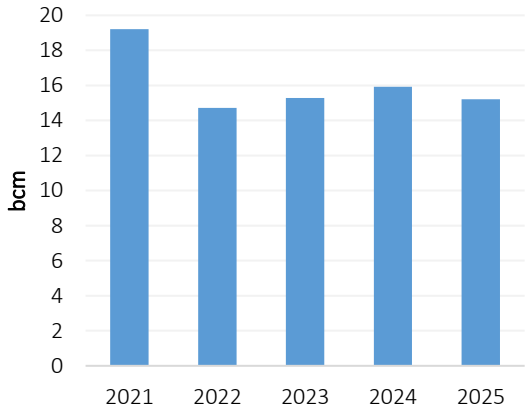


Figure 24: Spain's industrial gas consumption



Source: GECF Secretariat based on data from Enagas and LSEG

In the power sector, gas-fired generation surged by 19% to 62 TWh, driven by the necessity of balancing the power grid amid fluctuating renewable output (Figure 25). Spain emerged as the primary engine for gas-for-power demand within Southern Europe, significantly underpinning the region's broader consumption growth. This shift pushed the share of natural gas in the national electricity mix to 22%; however, renewables maintained their dominance, with solar and wind jointly accounting for 44% of total generation (Figure 26).

Figure 25: Y-o-y variation in Spain's power output

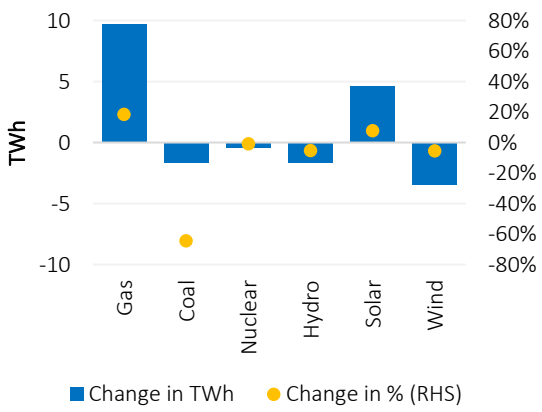
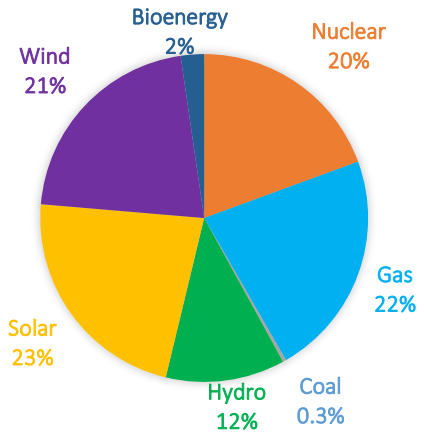


Figure 26: Spain's power mix in 2025



Source: GECF Secretariat based on data from Ember and Ree

2.1.1.2 United Kingdom

UK gas consumption declined by 0.5% to 56.3 bcm in 2025, marking its second consecutive year of marginal contraction (Figure 27). This outcome reflected significant weather-driven volatility during the first quarter, followed by subdued summer demand and a persistent structural decline in industrial offtake. Residential and commercial consumption remained broadly stable at 42 bcm, accounting for 74% of national demand and underscoring the UK's continued heavy reliance on gas for domestic heating. Conversely, industrial gas demand plummeted to just 1.1 bcm, representing a mere 2% of total consumption as the sector continues its long-term structural contraction due to exposure to high energy costs (Figure 28).

Figure 27: Trend in UK gas consumption

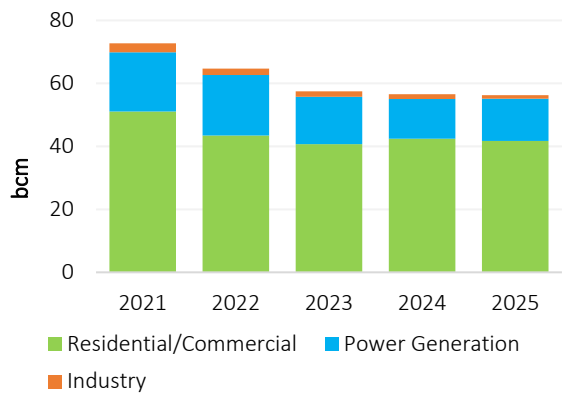
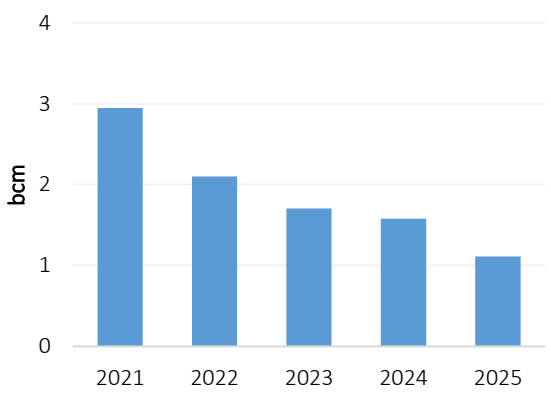


Figure 28: UK industrial gas consumption



Source: GECF Secretariat based on data from LSEG and National Grid

In the power sector, gas-fired generation rose by 5.3% to 91 TWh, supported by the final phase-out of coal-fired generation and a significant drop in nuclear output (Figure 29). Nuclear power reached its lowest level in half a century, generating only 36 TWh due to aging reactors and maintenance outages, which necessitated a rise in gas-fired output despite record renewable performance. Natural gas accounted for 32% of the power mix, while non hydro renewables remained the dominant source at 53% (Figure 30). This reliance on gas stresses its role as a flexible backstop to balance the grid during periods of low renewable availability and declining nuclear baseload.

Figure 29: Y-o-y variation in UK power output

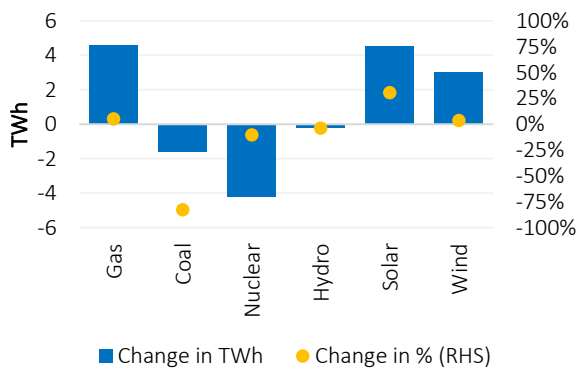
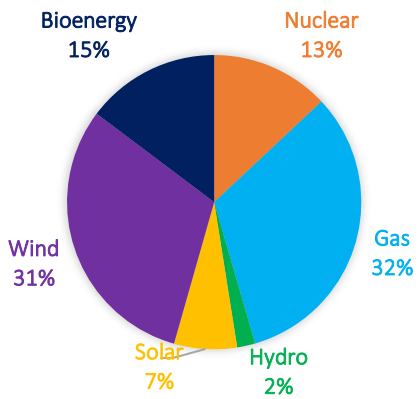


Figure 30: UK power mix in 2025



Source: GECF Secretariat based on data from Ember

2.1.1.3 Türkiye

Türkiye's gas consumption rebounded strongly by 10% to 58.5 bcm in 2025, continuing the recovery path established in 2024 following the significant contraction of 2022–2023 (Figure 31). This expansion was fuelled by a surge in demand across the power and residential sectors, whereas industrial growth remained comparatively measured. Industrial gas consumption climbed by 3% to 14 bcm, marking its second consecutive year of gradual improvement after a period of decline (Figure 32). Residential gas demand saw a marked 10% increase to 21 bcm, fully reversing the downward trend of previous years as colder weather conditions intensified space-heating requirements. Consequently, the residential sector solidified its position as Türkiye's primary gas-consuming segment, accounting for 36% of the national total.

Figure 31: Trend in Türkiye's gas consumption

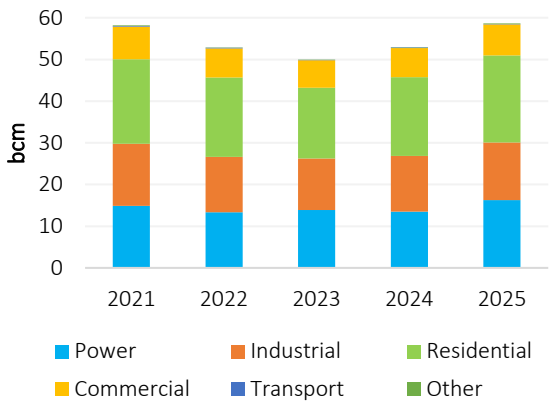
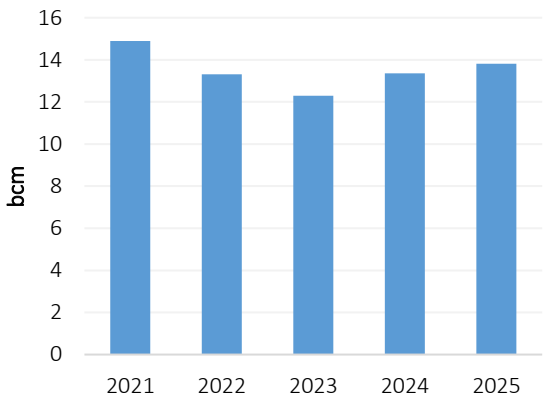


Figure 32: Türkiye's industrial gas consumption



Source: GECF Secretariat based on data from LSEG

In the power sector, gas-fired generation surged by 24% to 78 TWh to bridge a substantial deficit in hydroelectric output caused by weaker hydrological conditions (Figure 33). This underscores the critical role of dispatchable gas-fired plants in ensuring grid stability during periods of drought-induced renewable volatility. Natural gas maintained a 23% share in the power mix, ranking behind coal, even as solar and wind capacity continued to expand (Figure 34).

Figure 33: Y-o-y variation in Türkiye's power output

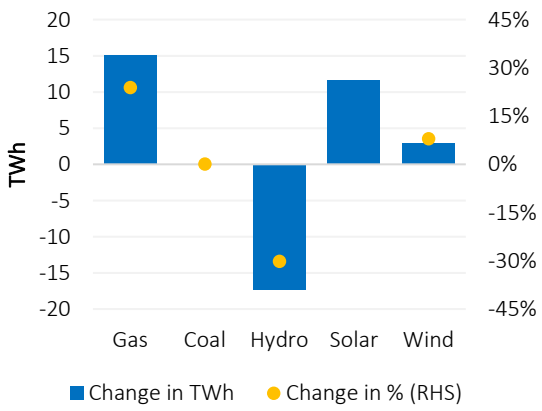
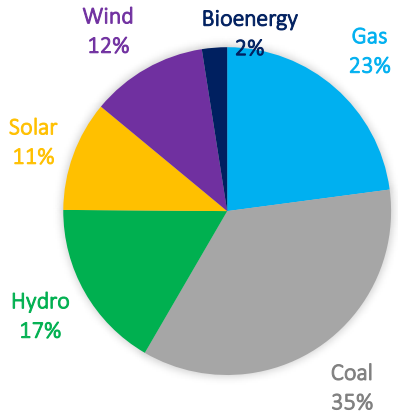


Figure 34: Türkiye's electricity mix in 2025



Source: GECF Secretariat based on data from Ember and EDPK

2.1.2 Asia Pacific

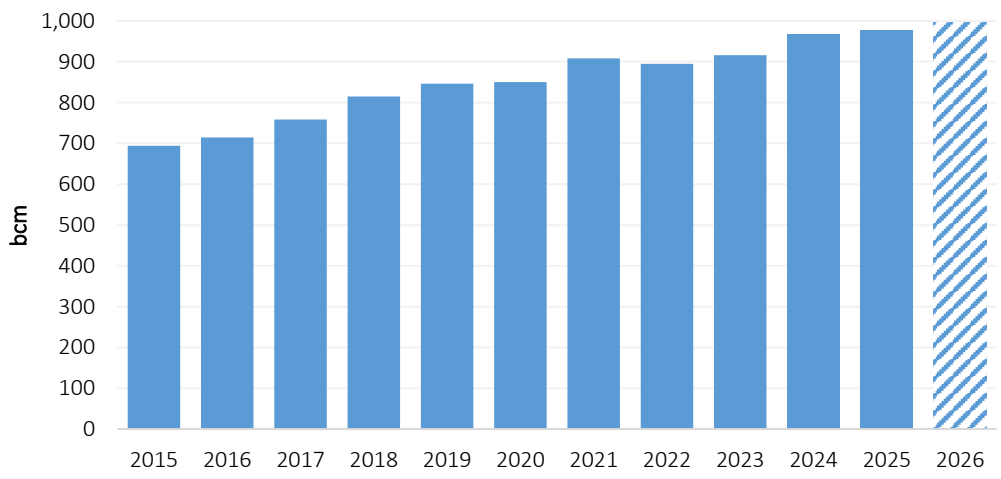
Asia Pacific gas consumption grew by 1% (10 bcm) to 977 bcm in 2025, a marked deceleration in growth from the robust 5.5% expansion seen in 2024 (Figure 35). This slowdown reflected a period of broader regional stability, with demand remaining relatively flat throughout much of the year. During the first half, consumption was tempered by a combination of cooling industrial momentum, persistently firm LNG spot prices, and unseasonably mild weather across Northeast Asia. However, a moderate improvement in gas demand emerged during the second half as market conditions stabilized.

In Northeast Asia, gas consumption showed diverging trajectories. China's demand expanded only marginally, reflecting softer heating needs early in the year and cautious industrial activity, though consumption strengthened later, supported by manufacturing and power generation. South Korea recorded an increase in gas consumption, largely driven by higher gas-fired generation to balance the grid. Conversely, Japan gas demand edged down as improved nuclear availability and higher renewable output reduced the structural necessity for gas-fired power.

In Southern and Southeast Asia, market dynamics were defined by price sensitivity and shifting supply sources. India's gas demand declined, pressured by lower utilization in the power and refining sectors and a pullback from price-sensitive industrial consumers, despite the continued expansion of city gas distribution networks. Across Southeast Asia, trends remained mixed; while some markets faced softer demand due to slower economic activity, others showed resilience. In nations facing dwindling domestic production, such as Bangladesh, stronger LNG inflows became vital to offset falling output and sustain industrial demand.

Looking ahead, regional gas demand is projected to grow by 2% in 2026, nearly crossing the 1,000 bcm milestone. This acceleration will be supported by a recovery in industrial activity and sustained infrastructure expansion across emerging Asian economies. Furthermore, more favourable market conditions and increased LNG availability are expected to improve the affordability of gas, underpinning a broader demand rebound in price-sensitive sectors.

Figure 35: Trend in Asia Pacific gas consumption



Source: GECF Secretariat based on Cedigaz data for 2015 to 2024, GECF estimate for 2025, GECF forecast for 2026

2.1.2.1 China

China's gas consumption grew by 2.1% to 439 bcm in 2025, marking a sharp deceleration from the 8.3% expansion seen in the previous year (Figure 36). This slowdown resulted from a combination of cyclical industrial weakness and a surge in renewable energy production.

The industrial sector, which accounts for 40% of China's total gas consumption, faced significant headwinds as structural growth was offset by macroeconomic volatility. Demand contracted during the first half of the year due to sluggish activity in the ceramics and glass industries, though it recovered slightly toward year-end as manufacturing margins stabilized.

The city gas sector, encompassing residential and commercial users, accounted for one-third of domestic demand. Growth was underpinned by infrastructure expansion serving 484 million people. Despite a mild winter causing an initial dip in heating requirements, a recovery in commercial activity and a fourth-quarter rebound pushed annual demand up.

The transport sector served as a vital growth engine driven by an LNG-fuelled heavy-duty truck fleet that reached approximately one million units. Favourable price spreads against diesel, government trade-in programs, and the addition of 300 new refuelling stations triggered a surge in LNG truck sales, displacing a significant portion of diesel consumption.

In the power sector, accounting for one-fourth of total gas consumption, gas-fired generation reached 297 TWh and represented 3% of China's total electricity output, while coal remained dominant at 56%. Although the sector benefited from new gas-fired capacity additions in coastal provinces like Guangdong, its growth was tempered by a massive 43% surge in solar output and a 14% increase in wind generation (Figure 37). These renewable sector gains displaced thermal output, shifting the role of gas-fired plants toward providing critical peak-shaving and grid flexibility services to balance the expanding share of intermittent energy.

Looking ahead, CNPC's ETRI projects gas demand to reach 450-455 bcm in 2026, driven by industrial fuel substitution, transport demand, and the need for gas-fired power flexibility.

Figure 36: Trend in China's gas consumption

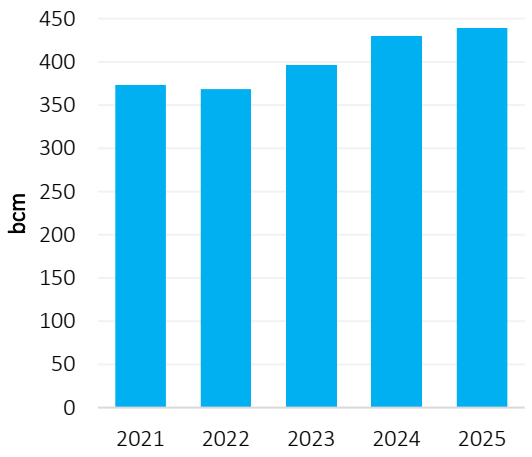
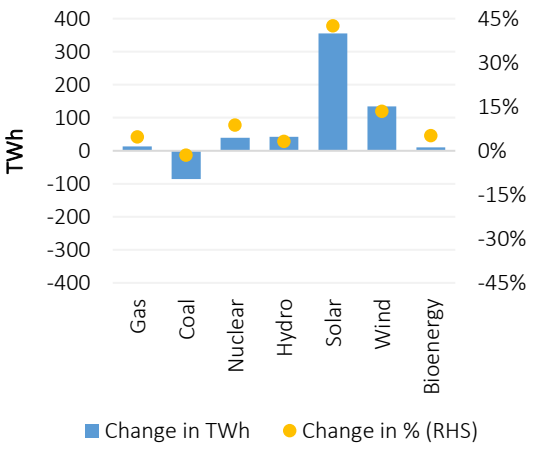


Figure 37: Y-o-y variation in China's power output



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

2.1.2.2 India

India's gas consumption declined by 3.6% to 69.5 bcm in 2025, reversing two years of strong expansion (Figure 38). This downturn was primarily driven by reduced gas utilization in the power sector, high global LNG spot prices and intense competition from cheaper domestic coal limited the economic viability of gas-fired power.

In the power sector, gas-fired generation saw a significant contraction, as high LNG prices and fuel supply constraints led to the temporary shutdown of 4.4 GW of gas-fired capacity starting in April. Total gas-fired generation fell by 8 TWh, a 24% y-o-y decline, as the fuel struggled to compete with dominant coal supplies that continued to account for over 70% of the national electricity mix. Although the government invoked Section 11 of the Electricity Act to mandate plant utilization during the early summer peak, the impact on demand was limited by adequate existing inventories and a milder seasonal climate. Overall power generation grew marginally by 1% in 2025, but this increase was driven entirely by a surge in renewable output, which displaced thermal sources across the board. Supported by favourable monsoon conditions, solar, wind and hydropower generation rose significantly, while coal and nuclear generation saw declines (Figure 39). This shift underscores a structural challenge for gas in India's power mix, where its role is increasingly squeezed by the rapid penetration of cheaper renewables and the continued dominance of domestic coal.

The city gas distribution sector remained India's primary structural growth driver, bolstered by the "one nation, one gas grid" initiative. Continued expansion of piped natural gas (PNG) and CNG infrastructure saw residential PNG increasingly displace LPG in urban areas.

Industrial demand showed mixed results. The fertilizer and petrochemical segments remained resilient, though broader industrial activity softened due to macroeconomic uncertainty and monsoon-related disruptions.

Despite this temporary dip, the long-term outlook remains positive, with structural growth in the city gas and industrial sectors expected to drive demand toward 100 bcm by 2030.

Figure 38: Trend in India's gas consumption

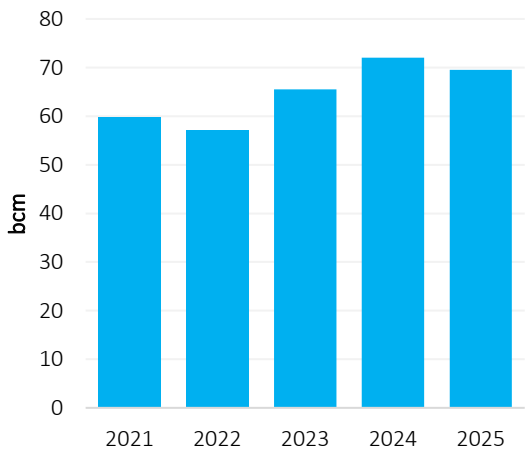
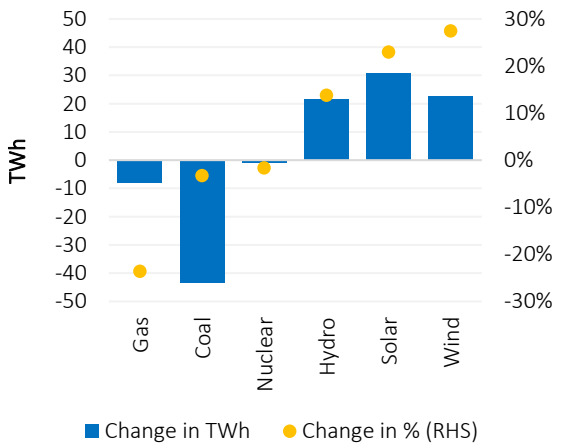


Figure 39: Y-o-y variation in India's power output



Source: GECF Secretariat based on data from PPAC and Ember

2.1.2.3 Japan

Japan's gas consumption declined by 2% to 89.5 bcm in 2025, extending the structural downtrend observed since 2020 (Figure 40). The contraction reflected lower gas burn in the power sector, relatively comfortable LNG inventories during parts of the year, and the gradual recovery of nuclear generation capacity.

In the power sector, gas consumption fell by 3% to 49 bcm, extending a long-term structural decline. While colder winter conditions in January and November temporarily boosted electricity demand, high LNG inventories mitigated the need for incremental imports. The gradual recovery of nuclear capacity continued to constrain gas burn, specifically with the December return of the 826 MW Takahama No. 1 reactor, which helped meet winter peak demand. However, with only 14 reactors currently operational and ongoing maintenance outages, nuclear output remains insufficient to fully displace natural gas (Figure 41). This is particularly evident in the Tokyo region, where gas-fired generation remains the dominant power source. Consequently, thermal capacity was repeatedly ramped up during winter peaks to ensure grid stability, highlighting that gas still plays a critical role in Japan's energy security despite the broader downward trend.

City gas consumption remained broadly stable at 40 bcm, a marginal 0.4% y-o-y increase. While monthly demand was highly weather-sensitive, rising in October and November due to colder temperatures, overall sales by Tokyo Gas from April to December declined slightly. This dip was driven primarily by weaker industrial and wholesale demand rather than residential use. Throughout the period, inventory levels remained adequate, ensuring a consistent supply despite the minor fluctuations in seasonal consumption patterns.

Looking ahead, Japan's gas demand is expected to remain on a structural downtrend as more nuclear reactors return to service and renewable penetration grows. While the city gas sector offers a stable consumption base, the power sector remains highly sensitive to nuclear availability and seasonal weather.

Figure 40: Trend in Japan's gas consumption

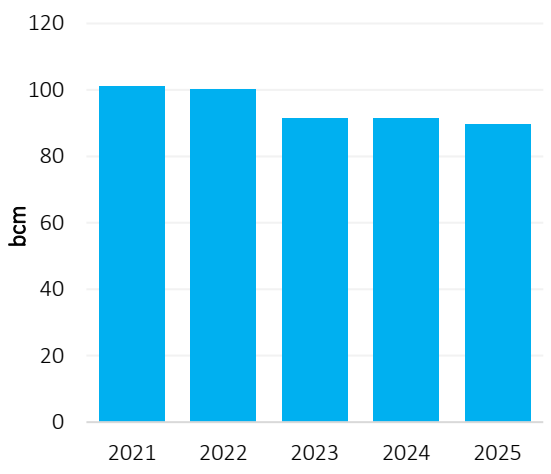
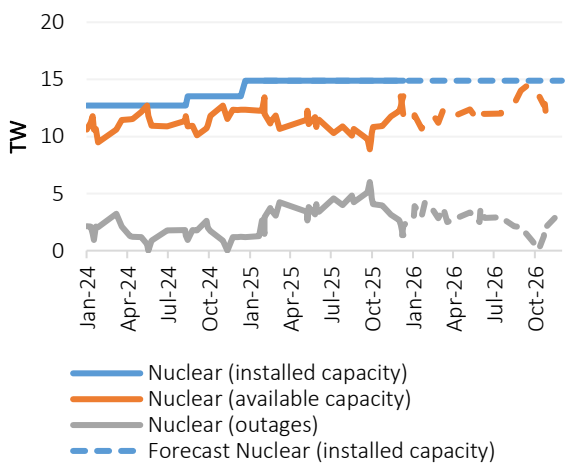


Figure 41: Japan's nuclear availability



Source: GECF Secretariat based on data from LSEG

2.1.2.4 South Korea

South Korea's natural gas consumption edged up marginally by 0.3% to 55.7 bcm in 2025, stabilizing after the sharp contraction recorded in 2023 (Figure 42). Demand resilience was primarily linked to the power sector, while city gas consumption remained broadly stable amid weather-driven fluctuations and fuel competition.

In the power sector, gas-fired generation increased by 2.7% (4.8 TWh) to 182.8 TWh in 2025, raising its share in the power mix to 29%, on par with coal (Figure 43). Total electricity output rose modestly by 1.2% y-o-y, supported by renewables expansion and stable thermal generation. Power-sector gas demand was shaped by operational and policy factors rather than pure fuel-switching economics. Throughout much of the year, coal retained a cost advantage over natural gas, limiting structural switching. However, repeated government directives restricting coal-fired output during shoulder seasons supported incremental gas burn. Grid congestion between eastern generation hubs and the Seoul metropolitan area continued to necessitate flexible gas-fired generation during peak periods.

The city gas sector recorded a notable recovery, with consumption rising by 3% to 25.6 bcm. This represents the strongest annual increase since 2021 and marks a clear reversal of the contraction seen in 2023. The expansion was primarily driven by firmer heating demand during colder periods toward year-end, which outweighed structural headwinds such as increasing competition from electric heating in new urban developments. Supported by stable underlying residential usage and a steady commercial recovery, the sector maintained its baseline momentum despite ongoing weather sensitivity. Furthermore, the government's extension of import tariff waivers helped mitigate the impact of volatile global LNG prices.

Looking ahead, South Korea's gas demand is expected to remain stable as the 11th Basic Plan for Long-Term Electricity Supply and Demand targets further LNG-fired capacity expansion. This growth aims to meet the surging power requirements of the AI and semiconductor industries, even as renewable penetration accelerates.

Figure 42: Trend in S. Korea's gas consumption

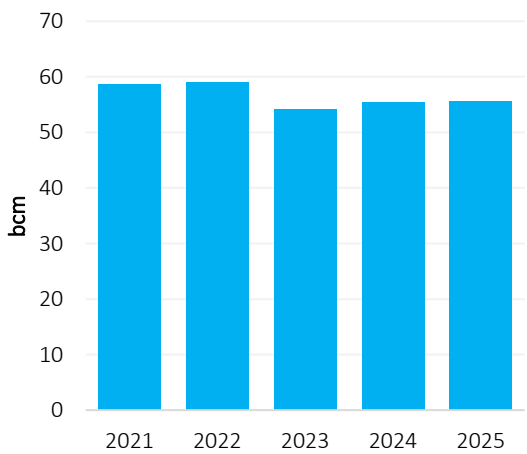
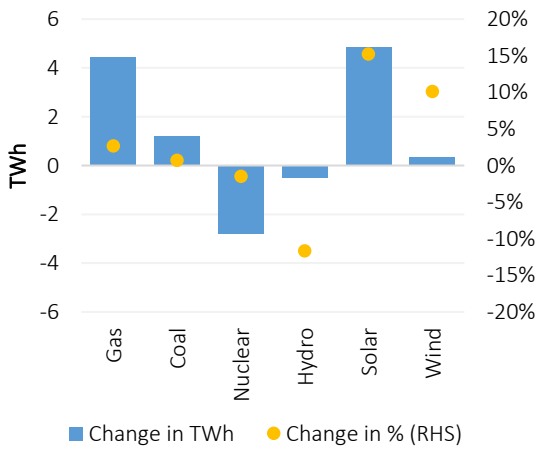


Figure 43: Y-o-y variation in S. Korea's power output

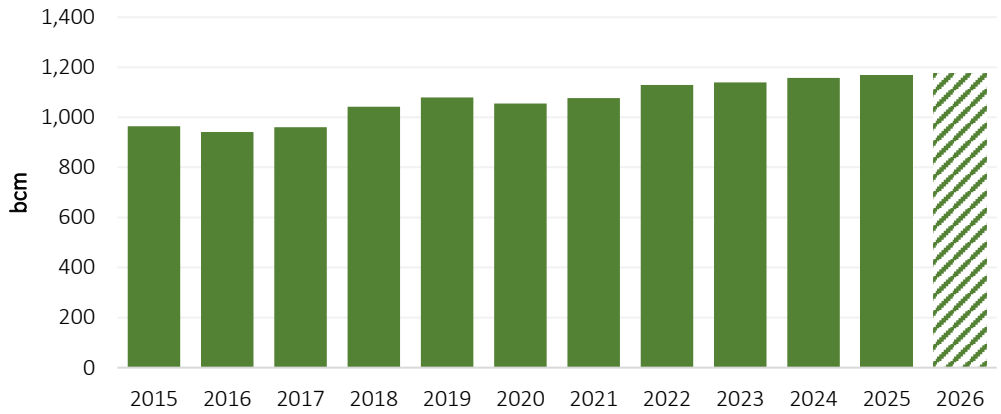


Source: GECF Secretariat based on data from LSEG and Ember

2.1.3 North America

North America's gas consumption increased by 1% (12 bcm) to 1,169 bcm in 2025 (Figure 44). This growth was primarily driven by a resilient power sector where rising electricity demand sustained gas-fired generation. Industrial demand remained firm, supported by competitive regional pricing. Looking ahead, gas consumption is projected to reach 1,175 bcm in 2026, representing a more moderate 0.5% increase. Natural gas will remain essential for ensuring grid stability and meeting the high-load requirements of expanding digital and industrial infrastructure across the region.

Figure 44: Trend in North America's gas consumption



Source: GECF Secretariat based on Cedigaz data for 2015 to 2024, GECF estimate for 2025, GECF forecast for 2026

2.1.3.1 Canada

Canada's gas consumption increased by 5% to 130 bcm in 2025, marking a strong recovery following the modest rebound observed in 2024 (Figure 45). Growth was broad-based, driven by the industrial and power sectors alongside a significant rebound in residential and commercial consumption. This residential and commercial surge was primarily a reflection of colder weather conditions compared to the previous year. In the power sector, gas-fired generation rose by 5% to 115.5 TWh, reinforcing gas's expanding role in Canada's electricity mix (Figure 46).

Figure 45: Trend in Canada's gas consumption

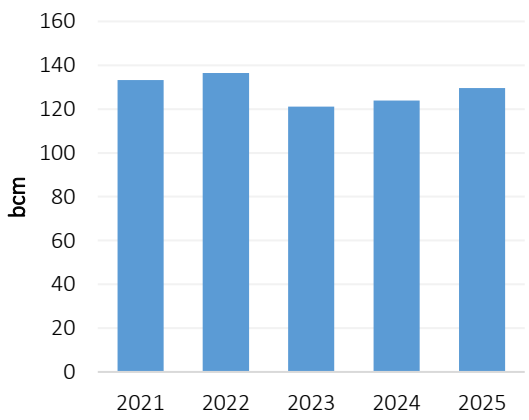
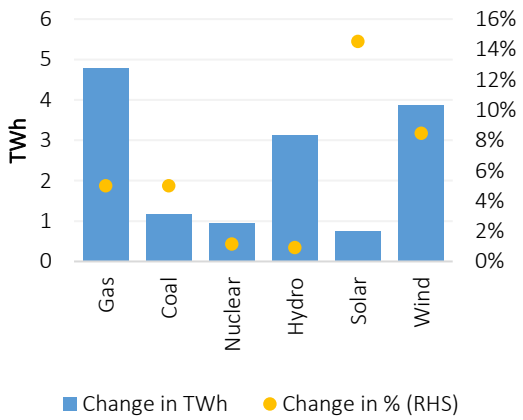


Figure 46: Y-o-y variation in Canada's power output



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

2.1.3.2 United States

US gas consumption increased by 1.5% to 940 bcm in 2025, setting a new historical high (Figure 47). The increase was primarily driven by strong growth in the residential and commercial sectors, which more than offset weaker demand from gas-fired power generation.

In the power sector, which accounts for 39% of domestic gas consumption, gas-fired electricity output fell by 3% (56 TWh) despite a 3.1% y-o-y increase in total generation (Figure 48). This decline was driven by a 13% rebound in coal generation and a 28% surge in solar output, which together captured the bulk of incremental demand. Furthermore, HH prices averaged $3.55/MMBtu, a 59% increase from 2024, eroding the cost-competitiveness of natural gas relative to coal in several regions. Despite these headwinds, natural gas maintained its position as the dominant generation source with a 40% market share.

In contrast, the residential sector recorded the largest absolute increase, with consumption rising by 14 bcm to 137 bcm. This surge was driven by colder winter conditions, including a January polar vortex that significantly elevated space-heating needs. Similarly, commercial sector demand expanded by 8 bcm to 102 bcm, a trend further amplified by the rapid proliferation of data centres. These facilities are increasingly deploying on-site gas-fired turbines to secure uninterruptible power and bypass multi-year delays plaguing traditional grid interconnection queues. As AI infrastructure continues its exponential growth, the “always-on” requirements of these digital hubs have solidified natural gas as a critical partner for meeting the immediate energy needs of the digital economy. This structural shift highlights that while renewable output is rising, the reliability of natural gas remains indispensable for supporting the massive electricity consumption of the next generation of technological innovation.

The industrial sector remained broadly stable, with consumption increasing modestly by 1.3 bcm to 241.6 bcm. Industrial gas demand continued to be supported by petrochemicals and manufacturing activity, benefiting from stable production levels and continued structural reliance on natural gas as both fuel and feedstock.

Figure 47: Trend in US gas consumption

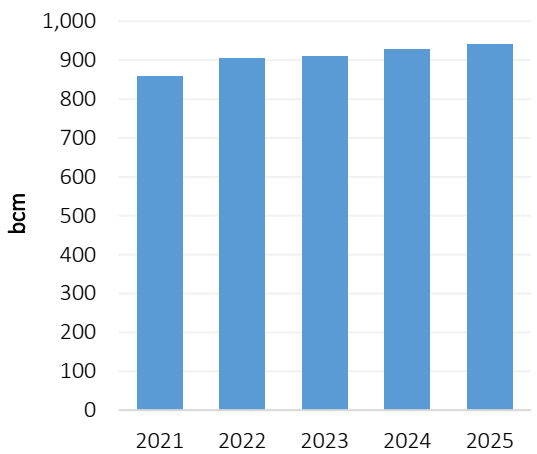
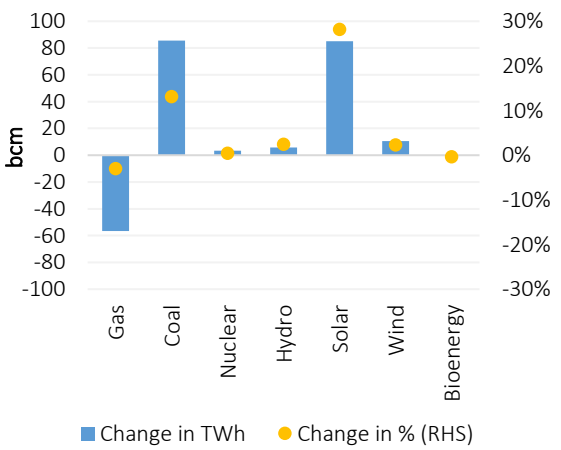


Figure 48: Y-o-y variation in US power output



Source: GECF Secretariat based on data from US EIA and Ember

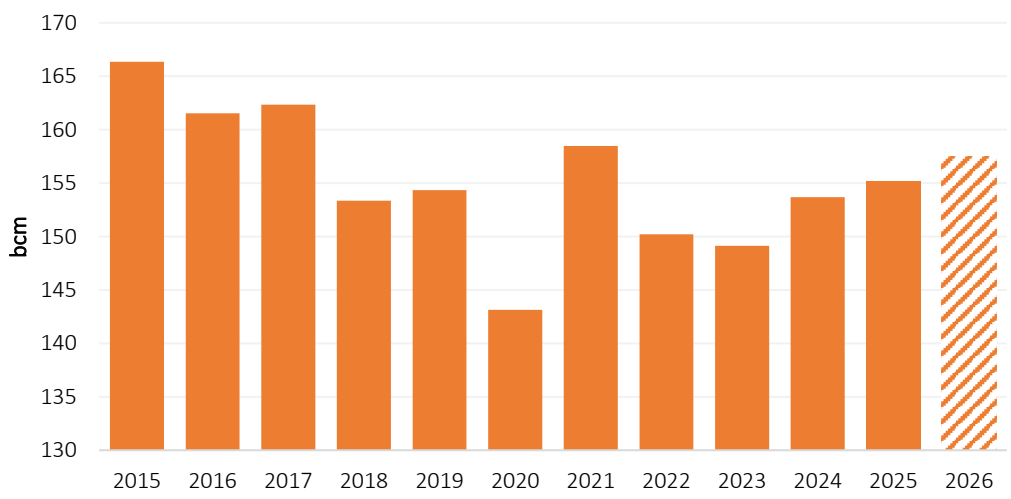
2.1.4 Latin America & the Caribbean (LAC)

Latin America and the Caribbean (LAC) gas consumption increased marginally to 155 bcm in 2025, marking a second consecutive year of growth following the contraction of 2022–2023 (Figure 49). This upward trend was primarily underpinned by firmer power-sector requirements and a gradual recovery in industrial activity across major regional economies, most notably in Brazil and Argentina. As the region's largest markets stabilized, gas demand shifted from a purely emergency backup role to a more integrated component of energy security.

Hydrological conditions remained the decisive factor for regional consumption, as natural gas continued to serve as the primary reliability backstop for hydropower-dependent grids. While lower reservoir levels necessitated significant thermoelectric ramping to prevent power shortages, the magnitude of these demand spikes was moderated by the rapid expansion of wind and solar capacity. This evolving energy mix underscores a structural shift where natural gas is repositioned as a flexible, low-carbon partner to both volatile hydro resources and intermittent renewables. Supported by new regasification terminals and expanded pipeline networks, this integrated approach is creating a more balanced demand profile that bolsters energy sovereignty and economic growth despite continued exposure to climatic volatility.

Looking ahead, natural gas demand in Latin America and the Caribbean is projected to reach 158 bcm in 2026, a 1.5% increase, driven by the power sector's dual role in meeting rising electricity needs and balancing hydropower variability. While renewable capacity is accelerating across the region, gas remains the primary reliability backstop during climatic cycles like El Niño, which frequently disrupt hydrological patterns and necessitate thermal backup. This structural dependence ensures that regional gas demand remains intrinsically linked to hydrological trends, even as industrial demand expands moderately amid gradual economic stabilization in key markets. Consequently, natural gas is solidifying its position as an essential buffer for energy security, facilitating a more resilient regional energy transition.

Figure 49: Trend in LAC's gas consumption



Source: GECF Secretariat based on Cedigaz data for 2015 to 2024, GECF estimate for 2025, GECF forecast for 2026

2.1.4.1 Argentina

Argentina's gas consumption increased by 1% to 41 bcm in 2025 (Figure 50). The growth was broad-based but moderate, with gains in industrial and residential demand.

In the power sector, gas-fired electricity generation declined by 2.5% to 80 TWh, even as total generation rose by 1% to 154 TWh (Figure 51). Despite this dip, natural gas remained the dominant fuel source, maintaining a 50% share of the electricity mix and providing essential baseload stability. The contraction in gas-fired output was primarily offset by a surge in renewable generation and a sharp rebound in coal from a historical low. Hydropower output fell by 10% due to weaker hydrological conditions, further reinforcing the role of gas as the primary flexibility option for the grid. Argentina's power sector continues to rely on domestic gas to manage renewable intermittency and compensate for fluctuating hydroelectric availability.

The residential sector rose modestly to 12 bcm, remaining the second-largest consumer, supported by stable heating demand. Consumption is heavily concentrated in the winter months, where peak space-heating requirements in urban centres like Buenos Aires necessitate significant supply prioritization. While the user base continues to expand, growth is increasingly influenced by subsidy reforms and the gradual introduction of more market-aligned pricing. Despite these economic shifts, natural gas continues to dominate space heating and cooking demand, given Argentina's extensive gas distribution network and high household penetration.

The industrial sector increased slightly to 13 bcm, with demand centred on energy-intensive segments such as petrochemicals, steel and aluminium, where it is used both as fuel and feedstock. Industrial consumption showed resilience as improved gas evacuation from the Neuquén Basin reduced the frequency of winter curtailments that historically hampered production. This stable supply environment has encouraged medium-term investments in gas-to-chemicals projects, further integrating natural gas as a vital feedstock.

The automotive sector remained stable at 2 bcm, reflecting the maturity of the domestic compressed natural gas (CNG) vehicle market. While electric mobility is gradually expanding, Argentina remains one of the world's largest CNG vehicle markets.

Figure 50: Trend in Argentina's gas consumption

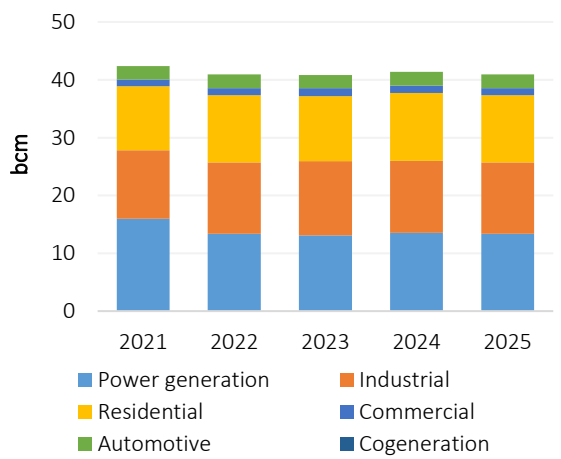
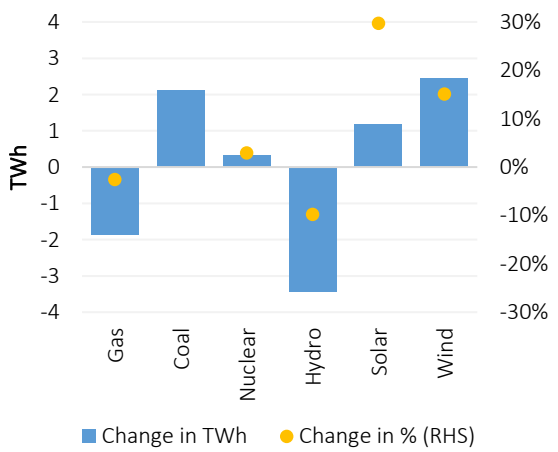


Figure 51: Y-o-y variation in Argentina's power output



Source: GECF Secretariat based on data from Enersa, Brazil's Ministry of Mines and Energy and Ember

2.1.4.2 Brazil

Brazil's gas consumption increased by 6% to 25.7 bcm in 2025, driven primarily by a stronger call on gas in electricity output (Figure 52).

In the power sector, gas-fired generation climbed by 16% to 56.6 TWh in 2025, driven by a 6% decline in hydropower output to 388 TWh (Figure 53). This shift was necessitated by tightening water availability, which forced a higher thermal dispatch to maintain grid reliability and reinforced natural gas as the critical flexibility option in a hydro-dominated system. Despite the rapid expansion of solar and wind output, the grid's structural dependence on gas remained highly hydrology-driven, particularly as intermittent renewables required firm backup. The 2025 commissioning of the 1.7 GW GNA II plant further bolstered this trend, providing several million cubic metres per day of capacity during the critical July–November dry season.

Industrial gas demand edged up to 14.5 bcm, signalling stable industrial fundamentals in contrast to the high volatility seen in the power sector. This steady performance reflects the sector's role as a consistent consumption base for the national market. Meanwhile, residential demand saw a slight increase to 0.6 bcm, and transport (automotive) demand marginally eased to 1.6 bcm, reflecting minor shifts in urban consumption patterns and fuel competition.

Looking ahead, Brazil's gas demand in 2026 is expected to remain highly power-sector driven, as below-average rainfall and declining hydro stocks could increase reliance on gas-fired generation. This potential shift, particularly during the April–October dry season, may tighten the domestic market and revive LNG import requirements if domestic supply proves insufficient. In parallel, the planned reserve capacity auction (LRCAP) and the continued build-out of gas-fired capacity are set to structurally support the gas-for-power call, especially during peak periods. Consequently, while renewable capacity is accelerating, these factors reinforce the role of natural gas as an essential reliability backstop within the Brazilian energy matrix.

Figure 52: Trend in Brazil's gas consumption

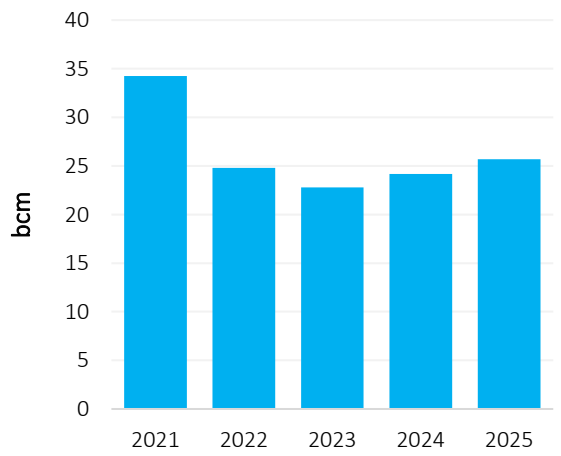
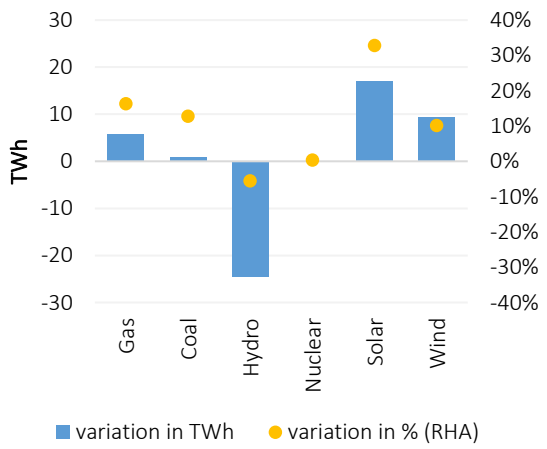


Figure 53: Y-o-y variation in Brazil's power output



Source: GECF Secretariat based on data from Brazil's Ministry of Mines and Energy and Ember

2.1.5 Africa

Africa's gas consumption increased by 4% to 185 bcm in 2025, extending an upward trend as regional demand strengthened following the volatility of 2020-2022 (Figure 54).

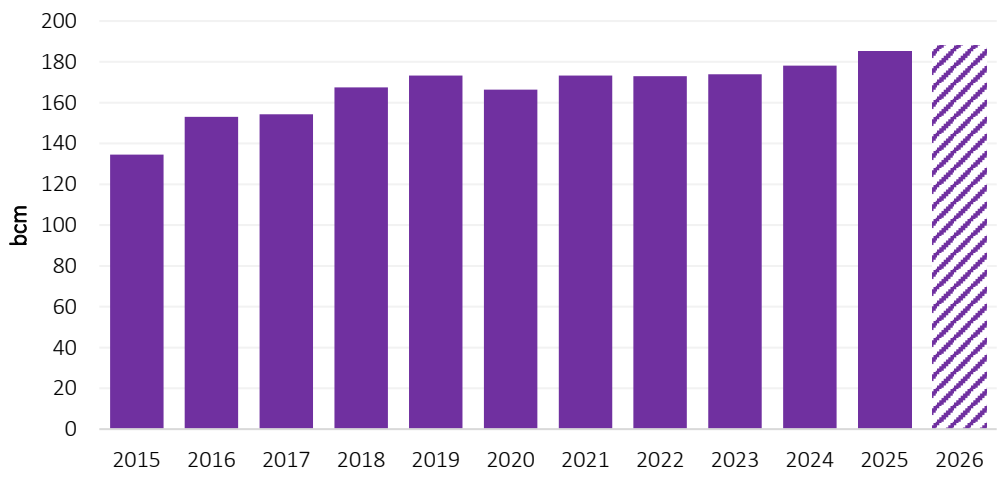
This growth remained heavily concentrated in North Africa, with Algeria and Egypt continuing to dominate continental usage. In Sub-Saharan Africa, incremental gains were recorded in Nigeria and emerging LNG-importing markets, where new regasification capacity and gas-to-power projects improved energy access despite persistent infrastructure bottlenecks.

The power sector served as the primary driver for gas demand, fuelled by rapidly rising electricity requirements, a burgeoning urban population, and concerted regional efforts to improve grid reliability. As African nations strive to bridge the persistent energy access gap, natural gas-fired generation has solidified its position as the cornerstone of the continental power mix.

Industrial demand also bolstered growth, driven by expansion in energy-intensive sectors like petrochemicals and fertilizers. In North Africa, domestic gas availability sustained industrial hubs in Algeria and Egypt that are critical for export revenues. Similarly, Nigeria is leveraging its reserves to accelerate industrialization and agricultural productivity through fertilizer output. This ensures natural gas remains a foundational feedstock for Africa's economic development.

Looking ahead, Africa's gas consumption is projected to rise further to 188 bcm in 2026. While renewable energy deployment is accelerating, natural gas is expected to retain its dual role as a reliable baseload fuel and a critical balancing source for intermittent power grids. However, the pace of this demand growth remains structurally capped by persistent near-term challenges, including significant financing constraints for large-scale projects, aging infrastructure gaps, and domestic supply limitations across several key energy-producing nations. Addressing these systemic bottlenecks will be essential for the continent to fully leverage its vast gas reserves for industrialization and energy access, ensuring that natural gas remains a foundational pillar for Africa's long-term economic development and regional energy security.

Figure 54: Trend in Africa's gas consumption



Source: GECF Secretariat based on Cedigaz data for 2015 to 2024, GECF estimate for 2025, GECF forecast for 2026

2.2 Gas Consumption by Sector

Natural gas remained a fundamental pillar of the global energy system, sustaining demand across power generation, industry, residential/commercial and transport sectors (Figure 55). Its inherent versatility and reliability, combined with a lower carbon intensity relative to other hydrocarbons, continue to underpin its adoption across diverse economies.

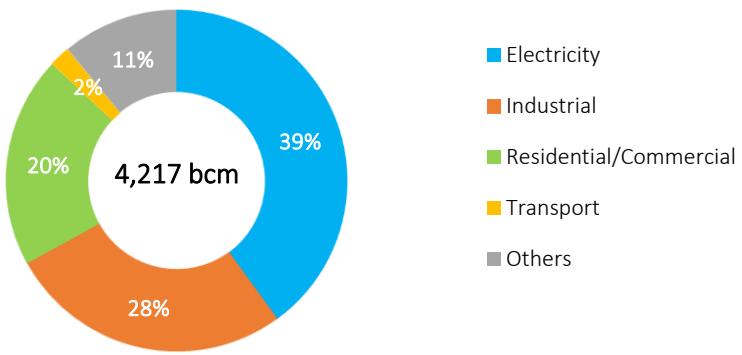
The electricity sector accounted for 39% of global gas consumption, firmly maintaining its status as the primary demand segment. Gas-fired plants remain the foundational pillar of modern energy systems, providing the critical flexibility and reliability required as renewable capacity expands at record speeds. Because of their ability to ramp output up or down almost instantaneously, these facilities are indispensable for balancing the inherent intermittency of wind and solar generation. Beyond stabilization, natural gas continues to support essential peak load requirements, ensuring grid resilience and a secure power supply.

The industrial sector accounted for 28% of global gas use, highlighting its essential role as both a primary fuel and a vital feedstock for heavy industry. Natural gas remains indispensable for energy-intensive processes in petrochemicals, steel, cement and food processing, where high-heat requirements are difficult to electrify. Its role in ammonia and fertilizer production is particularly strategic, given its direct link to agricultural productivity and global food security.

The residential and commercial sectors represented 20% of total gas consumption, primarily serving space heating, water heating and cooking needs. While demand patterns remain heavily dictated by seasonal temperature variations, particularly in colder climates, long-term growth continues to be underpinned by steady urbanization and population expansion. As gas distribution networks extend into new urban centres, natural gas provides a reliable and accessible energy source for millions of households. Furthermore, the commercial segment is seeing emerging structural demand from high-load infrastructure, such as data centres.

The transport sector accounted for 2% of global gas demand, reflecting the steady penetration of compressed natural gas (CNG) and liquefied natural gas (LNG) in road and maritime transport. Gas-powered vehicles and vessels contribute to emissions reductions and fuel diversification strategies, particularly in regions implementing stricter environmental standards.

Figure 55: Global gas consumption by sector in 2025



Source: GECF Secretariat's estimates based on data from Enerdata

2.2.1 Electricity Sector

Global gas consumption in the electricity sector increased marginally in 2025, with gas-fired power generation reaching 6,930 TWh, up from 6,900 TWh in 2024 (Figure 56). This modest growth occurred alongside a 2.8% rise in total global electricity output, which climbed to 31,830 TWh. While the pace of growth moderated compared to the previous year, electricity demand was supported by sustained economic activity, urbanization and rapid digitalization. Notably, the continued expansion of data centres has emerged as a critical structural driver, requiring the always-on reliability of gas-fired generation to supplement the evolving energy grid.

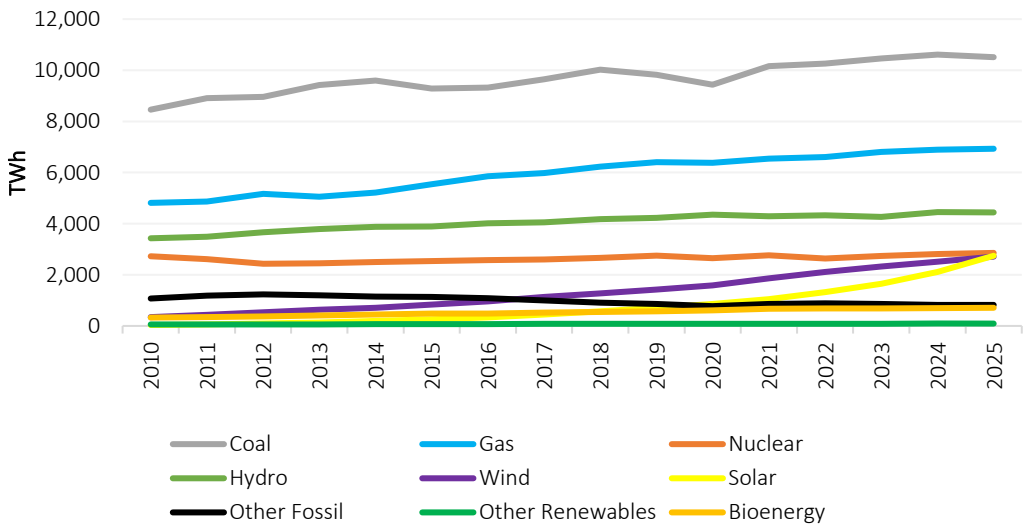
Renewable energy sources recorded another year of robust gains as global capacity additions hit record levels. Solar power generation surged by 30% (630 TWh), which was the largest absolute increase among all technologies, to reach 2,750 TWh. This exponential growth was driven by declining module costs and aggressive deployment in China and the EU. Wind generation maintained its steady upward trajectory, rising by 8% (200 TWh) to 2,710 TWh, however output additions slowed down to the lowest level since 2021.

Coal-fired generation declined marginally to 10,510 TWh, while hydropower decreased to 4,444 TWh following the strong rebound recorded in 2024. Nuclear power generation increased slightly to 2,857 TWh, supported by improved availability in several markets.

Despite these shifts, coal remained the largest single source of electricity, accounting for 33% of the global mix, followed by natural gas at 22%. Despite the steady expansion of wind and solar output, their combined share reached only 17%.

Against this backdrop, natural gas has become a dual-role cornerstone of the power mix, providing reliable baseload power for end users, including energy-intensive data centres, and dispatchable capacity to back up renewables, offering the high-ramping flexibility needed to balance the grid when solar and wind output fluctuates.

Figure 56: Trend in global electricity generation by energy source



Source: GECF Secretariat based on data from Ember and The Energy Institute Statistical Review of World Energy

2.2.2 Industrial Sector

Global gas consumption in the industrial sector increased by 1.3% to 1,186 bcm in 2025 (Figure 57), signalling a steady recovery in industrial activity. This growth was underpinned by stabilizing gas prices and improving macroeconomic conditions, which bolstered output across energy-intensive sectors. As industrial demand rebounds, gas continues to serve as a vital baseload energy source, particularly in emerging markets.

The Asia Pacific region remained the world's largest industrial gas consumer, with demand rising 3%. This growth was fuelled by robust manufacturing activity in China and India, alongside a structural shift toward coal-to-gas switching in industrial processes.

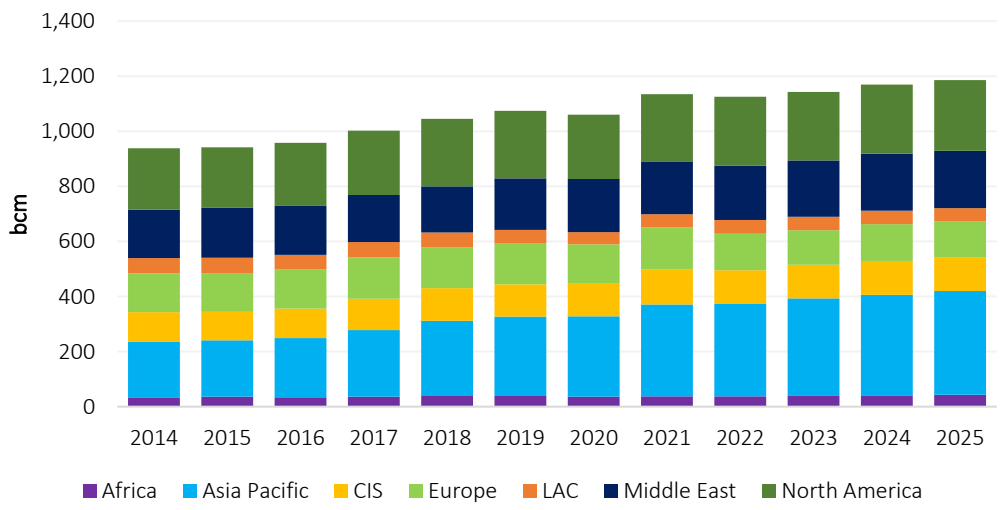
North American industrial gas demand rose 2%, reflecting resilience in petrochemicals and refining. Steady manufacturing output supported this growth, with the market expected to remain stable as energy-intensive industries maintain their competitive edge.

Europe's gas consumption declined slightly, remaining well below pre-COVID crisis levels. This downward trend reflects ongoing competitiveness challenges for energy-intensive sectors, alongside permanent structural efficiency gains and a shift toward alternative energy sources.

The Middle East recorded a slight increase in gas demand, supported by expanding petrochemical capacity and new gas-based industrial projects across the region. Africa also saw steady growth, driven by gradual industrialization and rising energy needs. Industrial gas demand in Eurasia remained broadly stable, showing little volatility despite global market shifts and uncertainties. In contrast, Latin America experienced a marginal decline, reflecting slower industrial activity and gradual changes in the regional energy mix.

Looking ahead, gas demand is projected to accelerate in 2026 as the Middle East and Asia Pacific continue their expansion, while European and North American markets stabilize.

Figure 57: Trend in gas consumption in the industrial sector by region



Source: GECF Secretariat based on data from Enerdata, Cedigaz and IEA Monthly Gas Statistics

2.2.3 Residential and Commercial Sector

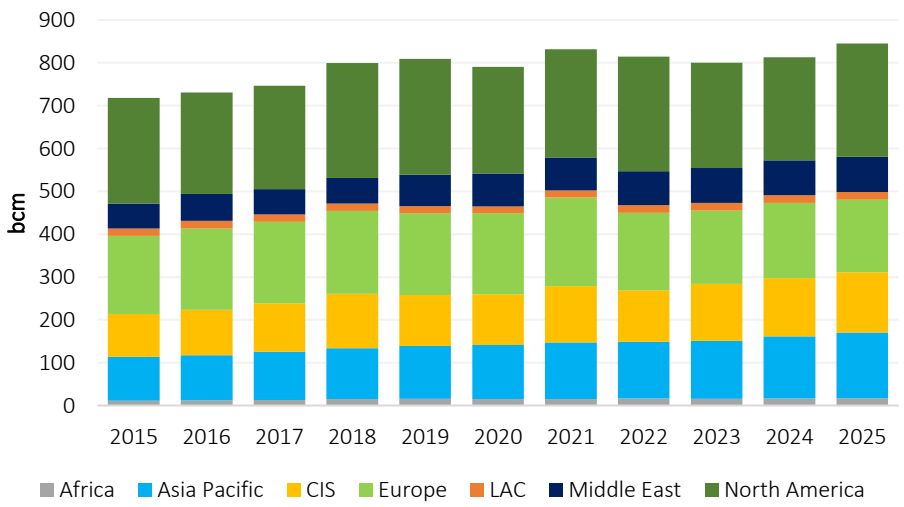
Global gas consumption in the residential and commercial sector rose by 4% to 845 bcm in 2025, marking a solid continuous recovery after the declines of 2022-2023 (Figure 58). The increase was largely driven by colder weather in key Northern Hemisphere markets, particularly during the first quarter, which boosted heating demand. This growth occurred despite ongoing improvements in building energy efficiency and the gradual electrification of heating systems, including the rollout of heat pumps.

Regionally, North America and Europe continued to hold a major share of global consumption in this sector. North America experienced a strong 10% rebound in gas demand, driven not only by colder winter temperatures but also by population growth in gas-intensive areas and increased residential and commercial usage. Conversely, Europe's demand fell by 3.6%, reflecting the combined effects of structural demand reduction measures, improvements in energy efficiency across buildings and appliances, and a continued shift toward electrified heating solutions, including the gradual adoption of heat pumps and district heating systems.

Asia Pacific maintained robust growth with a 6% increase, fuelled by the expansion of urban gas networks, ongoing coal-to-gas switching policies, and stronger demand in both residential and commercial sectors, particularly in China. The region continued to prioritize residential gas use for cooking, heating and domestic hot water, supported by infrastructure expansion, rising living standards and government initiatives to improve energy access. Meanwhile, Africa experienced growth of 5%, driven by increased urban access to natural gas and wider adoption of gas for household cooking. The Middle East recorded a marginal rise, while Latin America remained broadly stable at 18 bcm.

Looking ahead, global residential and commercial gas consumption is projected to rise further in 2026 supported by continuous demand growth in Asia Pacific, Eurasia and Africa, partially offset by efficiency improvements and electrification trends in Europe and North America.

Figure 58: Trend in gas consumption in the residential/commercial sector by region



Source: GECF Secretariat based on data from Enerdata, Cedigaz and IEA Monthly Gas Statistics

2.2.4 Transport Sector

While the transport sector is a relatively small market for natural gas, its share of global gas consumption has risen steadily, fuelled by climate mandates and cost-competitiveness. With the sector producing 25% of global GHG emissions, natural gas offers an immediate solution, cutting CO_2 by up to 25% and virtually eliminating SOx and particulate matter. Following the market stabilisation of late 2025, the significant price advantage of gas over diesel continues to drive adoption in high-mileage commercial fleets and long-haul logistics.

2.2.4.1 Automotive Industry

The global natural gas vehicle (NGV) market has reached a significant milestone as of late 2025, with around 31 million vehicles now powered by CNG or LNG. While CNG remains the standard for light-duty transport like cars, motorcycles and rickshaws, due to its mechanical simplicity and ease of engine adaptation, LNG has solidified its role as the premier fuel for heavy-duty hauling and long-range transportation. This shift is increasingly supported by the expansion of global LNG export supply throughout 2025, which stabilised fuel prices and made gas-based transport an economically superior alternative to diesel for buses, trucks and even rail transport in many regions.

China is the global leader, accounting for 7 million NGVs, with a massive shift toward LNG-powered heavy-duty trucks. By the end of 2025, the country surpassed the milestone of one million LNG-powered trucks in operation, up from 750,000 in 2024. This growth was driven by aggressive government measures, including subsidies for truck scrapping and the expansion of refuelling infrastructure, which increased LNG's share of China's heavy-duty truck market to nearly 25% in 2025. As a result, LNG is increasingly displacing diesel, although electric heavy-duty trucks are gaining traction, supported by state policies promoting clean transportation.

India also recorded rapid infrastructure growth, with its NGV fleet surpassing 5.5 million vehicles supported by a network of over 6,000 CNG stations. To further decarbonize long-haul logistics, the government plans to convert one-third of its heavy-duty truck fleet over the next decade by prioritizing domestic gas allocation for transport. This transition is underpinned by a strategic target to construct 1,000 LNG stations by 2030.

In the EU, there are roughly 1.3 million CNG-powered cars and over 13,000 LNG-powered trucks, supported by approximately 800 LNG and 4,200 CNG refuelling stations. Meanwhile, the US expanded its infrastructure to 81 LNG and 1,385 CNG refuelling stations, focusing growth on waste management and port logistics in states like California and Texas.

GECF Member Countries remain leaders in the NGV sector, with Iran ranking second globally in road transport gas utilisation, maintaining a fleet of 5 million CNG vehicles supported by over 2,500 stations. Egypt is nearing its target under the "One Million Vehicles" initiative, projected to reach 800,000 conversions by year-end 2025 while expanding its network toward 1,200 stations. Similarly, Russia has grown its fleet beyond 350,000 NGVs, supported by an expanding network of refuelling stations as part of a national strategy to increase gas consumption in the transport sector by 400% by 2035.

2.2.4.2 Maritime Industry

Although the industry remains heavily reliant on conventional oil-based fuels, which powers 98% of the global fleet, alternative fuels are steadily capturing market share. LNG has emerged as the frontrunner, accounting for 74% of the alternatively fuelled vessels, followed by LPG at 15% and methanol at 10%. The shift is most pronounced in the global ship construction pipeline, where conventional fuel's share has dropped to 85%. Within the alternatively fuelled orderbook, LNG maintains a dominant lead, particularly accounting for 80% of orders in 2025.

This evolution is driven by tightening global and regional regulations. In 2025, the IMO advanced the "Net-Zero Framework", which aims for a 20-30% reduction in emissions by 2030 and full net-zero status by 2050. Regionally, the EU's FuelEU Maritime regulation is now in effect, requiring ships to reduce GHG intensity by 2% starting in 2025, with the target tightening every five years to reach 80% by 2050. Furthermore, the integration of shipping into the EU ETS reached a new phase, with shipowners now required to cover 70% of their emissions, creating the economic incentive to replace traditional fuel oil.

By the end of 2025, the global LNG-fuelled fleet (excluding LNG carriers) grew to over 900 vessels (Figure 59). The transition is being spearheaded by the cargo ship segment, which now accounts for 50% of all active LNG-fuelled vessels. The tanker segment represents 21%, while passenger vessels (including cruise ships and ferries) comprise 15%.

Figure 59: Trend in the global LNG fuelled fleet

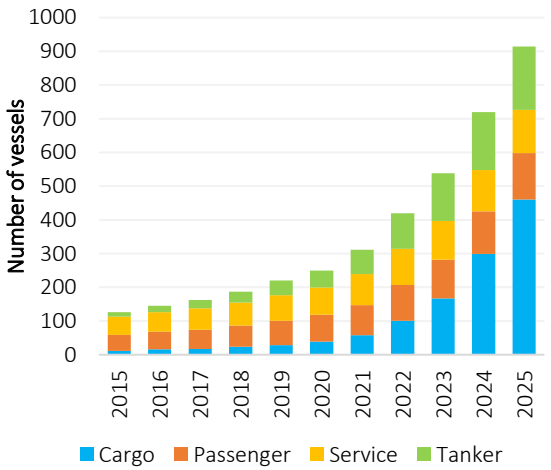
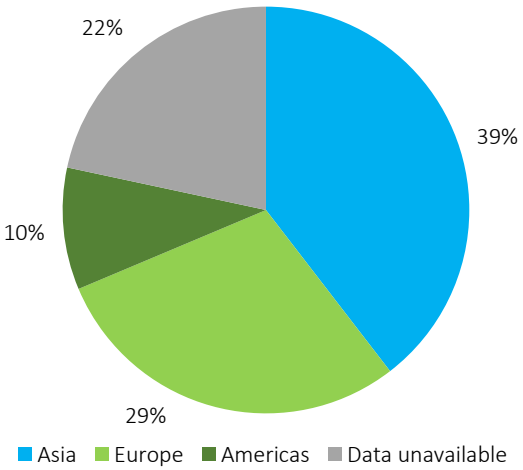


Figure 60: LNG bunker vessel distribution



Source: GECF Secretariat based on data from DNV

The physical infrastructure is supported by 83 dedicated LNG bunkering ships, which is double the number available in 2022. LNG bunkering is available in over 220 ports worldwide. The global landscape is defined by a concentration of infrastructure within high-traffic maritime corridors (Figure 60). Asia is the fastest-growing region, accounting for nearly half of global bunker sales. This growth is anchored by major hubs in Singapore, which saw record sales of over 570,000 tonnes in 2025, and China, where the bunkering network has expanded to include key ports like Shanghai and Zhoushan. Meanwhile, North America represents a sizeable portion of the fleet, with activity focused on the US Gulf Coast and Florida.

CHAPTER

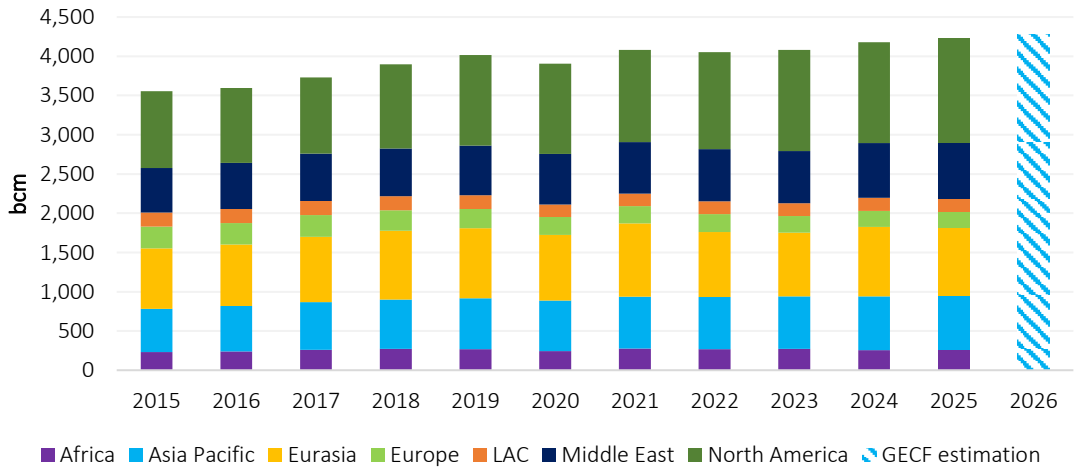
03

3 GAS PRODUCTION

Global gas production is estimated to have risen by 1.2% to reach 4,232 bcm in 2025 (Figure 61). This performance aligns with a decade of steady expansion, characterised by a compound annual growth rate (CAGR) of 1.7%, even as growth slowed from the more robust 2.5% recorded in 2024. A critical pillar of this global supply remains the contribution of the GECF Member Countries, whose output nearly mirrored the previous year's level of 1,570 bcm. By accounting for 37% of total global production, these nations continue to demonstrate resilience and maintain their pivotal role in meeting rising global demand amid evolving market conditions.

Looking ahead, global gas production is projected to increase by 1% in 2026, driven primarily by developments in North America, Asia Pacific and Africa. The expansion is underpinned largely by a significant increase in US output resulting from sustained domestic gas prices, rising domestic consumption, and expanding LNG exports. Furthermore, the commissioning of major gas projects in Saudi Arabia and China are poised to contribute to the growth. However, the escalating conflict in the Middle East poses a major threat to global gas production due to the downward revision of global gas demand projections.

Figure 61: Trend in global gas production by region



Source: GECF Secretariat based on data from Rystad Energy and Cedigaz for 2015 to 2024, GECF estimate for 2025, GECF forecast for 2026

3.1 Gas Production by Region

While most major producing regions witnessed a positive output trend in 2025, global supply growth was primarily led by North America, the Middle East and Africa.

North America emerged as the dominant driver of this expansion, recording a surge of more than 3.4%. Within the region, the US saw a 43 bcm increase in total production, spurred by rising domestic consumption, favourable Henry Hub (HH) prices and expanding LNG exports (Figure 62). Canada also sustained the growth momentum established in the previous year, supported by the commissioning of new LNG export capacity.

The Middle East achieved a 2.5% increase in production due to the development of multiple regional gas projects, with Saudi Arabia acting as the frontrunner through a 4 bcm rise alongside positive contributions from Iran, Oman and Qatar.

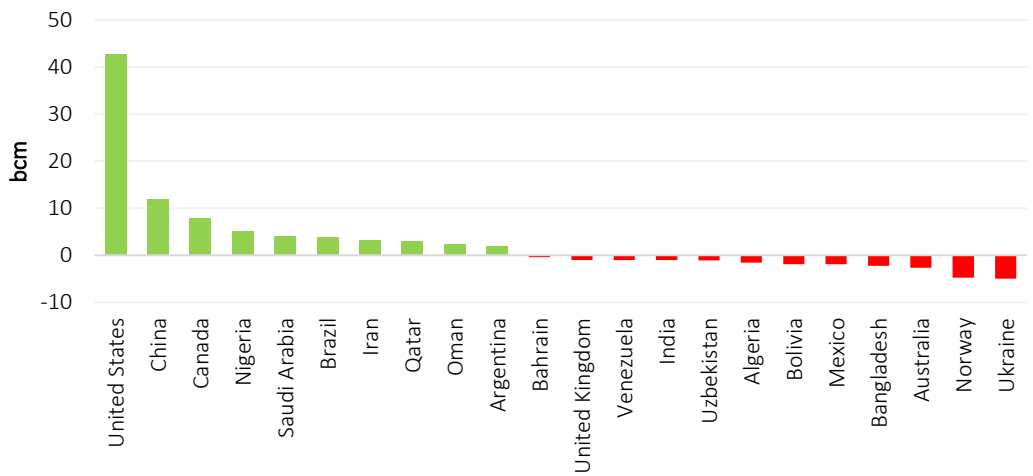
Africa similarly recorded a 2.5% rise in output, where growth in Nigeria and project ramp-ups in Mauritania and Senegal effectively offset production declines in other countries, in particular Egypt, to support a more resilient regional energy profile.

The Asia Pacific region maintained a relatively stable production level compared to 2024 as China continued with significant growth of 12 bcm, supported by the strategic expansion of its unconventional gas sector and increased domestic exploration efforts.

Latin America and the Caribbean maintained a steady output that mirrored 2024 levels, as record-high annual production in both Brazil and Argentina effectively counterbalanced declines in other regional producing countries.

Conversely, Europe and Eurasia recorded the sharpest contractions among the major gas producing regions, with y-o-y declines of 3.5% and 1.8% respectively. This downward trend primarily stemmed from reduced output across key producing nations, including Norway, the UK and Russia, reflecting broader structural shifts in the European energy landscape.

Figure 62: Y-o-y variation in gas production for selected major producers in 2025

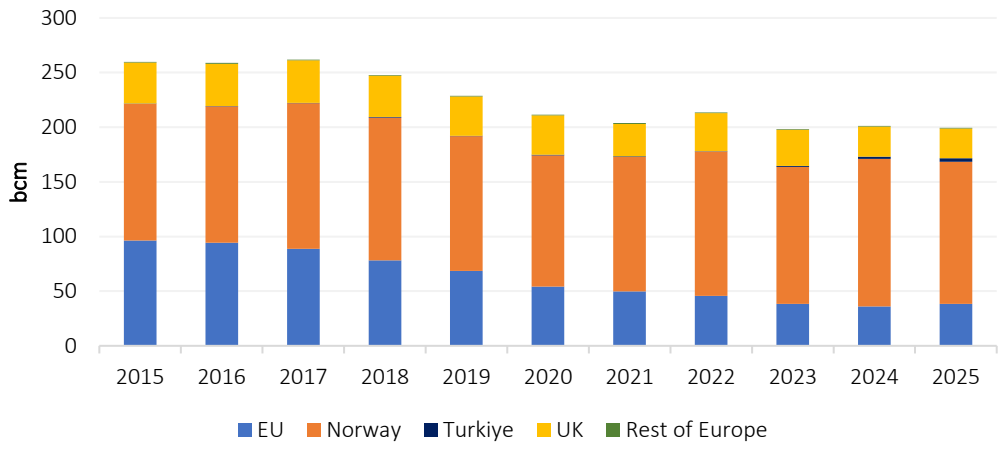


Source: GECF Secretariat based on data from Rystad Energy, Cedigaz and GECF estimation

3.1.1 Europe

European gas production witnessed the sharpest decline among the major producing regions, falling by 3.5% y-o-y to reach 200 bcm in 2025. This contraction, which reduced Europe's share of global gas output to 4.7%, was primarily driven by lower production levels in Norway, the Netherlands and the UK (Figure 63). However, the overall magnitude of this regional decline was partially mitigated by production increases in Denmark and Türkiye.

Figure 63: Trend in Europe's gas production



Source: GECF Secretariat based on data from Rystad Energy and GECF estimation for 2025

3.1.1.1 United Kingdom

The UK's gas production decreased by 1.3% y-o-y to 27 bcm in 2025, representing a significant drop from the 37 bcm recorded in 2015, which reflects a persistent lack of investment in new field developments and the natural depletion of aging assets. This downward trend aligns with recently adopted energy policies concerning North Sea production, specifically the "North Sea Future Plan" announced by the government in November 2025. This strategic plan officially halted the issuance of all new licenses for offshore and onshore exploration while concurrently introducing Transitional Energy Certificates to manage the sector's long-term decline. These certificates allow for targeted drilling in areas immediately adjacent to existing fields, provided the projects require no new exploration and can utilise a direct tie-back to current infrastructure to minimise both the environmental footprint and operational costs.

In terms of distribution, offshore gas fields on the UK Continental Shelf accounted for the entirety of British gas production, as onshore output remained negligible throughout the year. Associated gas production, which is gas extracted alongside oil, constituted 18% of the total output, representing a notable increase from its 12% share recorded in 2024. This shift highlights a changing production mix as traditional dry gas fields experience faster depletion rates than oil-linked gas assets. These internal dynamics suggest that while the UK is trying to optimise its remaining North Sea resources, the nation will increasingly rely on a diversified portfolio of imports to meet its domestic energy requirements.

3.1.1.2 Norway

Norway's gas production declined by 3.5% to 130 bcm in 2025, falling below the record set in 2024, due to extensive maintenance schedules (Figure 64). Output decreased y-o-y in 10 out of 12 months, driven by higher-than-expected planned and unplanned maintenance periods. Despite this contraction, Norway kept its position as the frontrunner gas producer in Europe, accounting for 65% of the continent's gas output. The Troll field, which typically provides one-third of the country's total gas, witnessed a 2.3% reduction to 43.7 bcm in the year, largely as a result of increased downtime at both the production field and the Kollsnes gas processing plant.

In terms of production distribution, Norway's gas supply originated entirely from offshore fields with no unconventional output. Associated gas, produced alongside oil, accounted for 23% of total production — a considerable rise from its 14% share in 2015 (Figure 65). This trend is driven by increased oil production from wells with high gas-oil ratios and infrastructure improvements that enable the recovery of associated gas instead of flaring it. Notably, Norway continues to maintain some of the world's lowest upstream emissions, achieved through strictly minimised gas flaring and the ongoing electrification of offshore platforms.

Eight relatively small new fields (Eirin, Snohvit Phase 2, Ormen Lange-Phase 3, Halten East, Andvare, Maria-Phase 2, Verdande and Smorbukk) came on stream in 2025, collectively contributing an initial production volume of 8 bcm. The most prominent of these developments is Ormen Lange Phase 3, which is expected to produce a cumulative output of 30 bcm by 2035, while medium-term output from these new fields is forecast to average 4 bcm per year. Exploration activity remained robust with 49 exploration wells drilled and 21 new discoveries made on the Norwegian Continental Shelf, estimated to hold 420 million barrels of oil equivalent in recoverable resources. Notably, gas accounts for nearly one-third of these new resources, approximately 25 bcm. According to the Norwegian Offshore Directorate, gas production is projected to stay steady at current levels over the next three to four years.

Figure 64: Trend in Norway's gas production

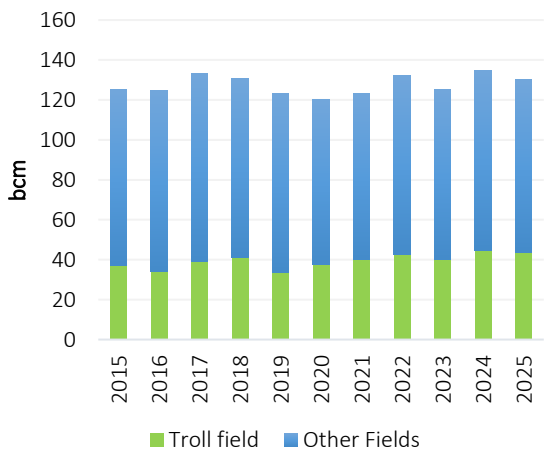
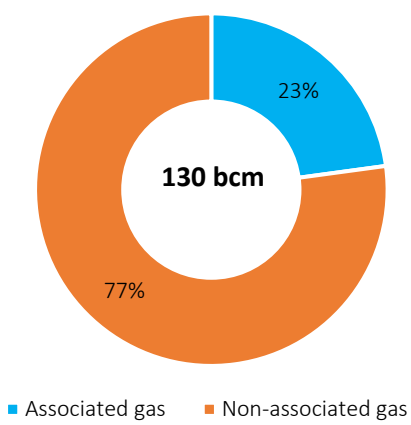


Figure 65: Norway's gas production by type in 2025



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

3.1.1.3 European Union

The EU's total gas production increased by 1.2 bcm to 38.4 bcm in 2025, as growth in Romania and Denmark successfully offset declines in the Netherlands and Germany (Figure 66).

Romania's production rose to 10.3 bcm, surpassing the Netherlands to become the EU's largest gas producer. Short-to-medium-term growth in the country will be driven by the Neptun Deep project in the Black Sea, which contains around 100 bcm of recoverable reserves. Scheduled to come online in 2027 with an anticipated annual output of 8 bcm, this field is expected to transform Romania into a key regional supplier and enhance the energy resilience of neighbouring Eastern European nations.

In the Netherlands, production fell by 0.7 bcm to 9.2 bcm in 2025, a significant drop from 54 bcm in 2015 (Figure 67). This decline was driven by the depletion of aging fields and limited investment in new developments, though the A15 offshore project slowed the trend by contributing 0.25 bcm annually. With reported proven reserves estimated at 64 bcm, the country faces potential depletion within nine years at current rates. Notably, 66% of Dutch gas production now originates from offshore fields, consisting entirely of non-associated gas.

Denmark witnessed remarkable growth, as natural gas production surged from 1.2 bcm in 2024 to 2.6 bcm in 2025. This was driven by the successful ramp-up of the Tyra II redevelopment project in the North Sea. The facility is expected to achieve a plateau production level of 2.8 bcm annually. Conversely, Germany's output fell by 0.6 bcm to 3.8 bcm, continuing a sharp and steady downward trend from the 9.4 bcm recorded in 2015. This decline is largely attributable to the natural depletion of existing fields and a regulatory environment that has limited the development of new unconventional resources. Similarly, Poland and Italy recorded modest decreases in their respective outputs as mature fields yielded lower volumes. In Italy, production declines persist despite government efforts to incentivize domestic offshore activity, while Poland's domestic production continues to face geological challenges as older reservoirs reach their terminal phase of production.

Figure 66: Trend in EU's gas production

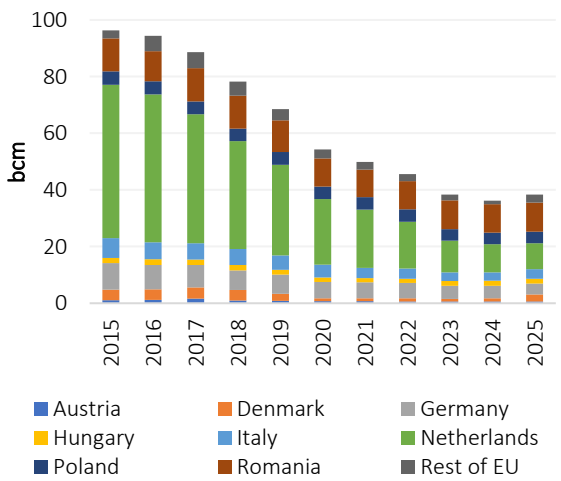
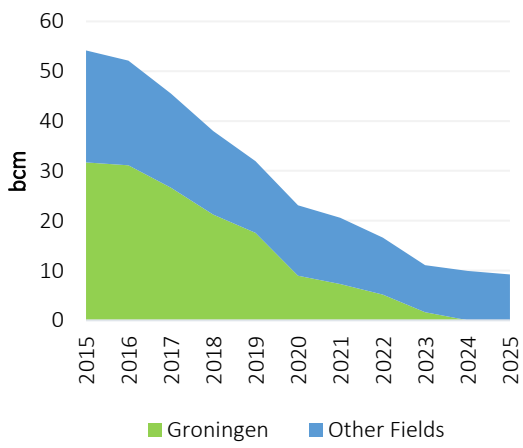


Figure 67: Trend in the Dutch gas production

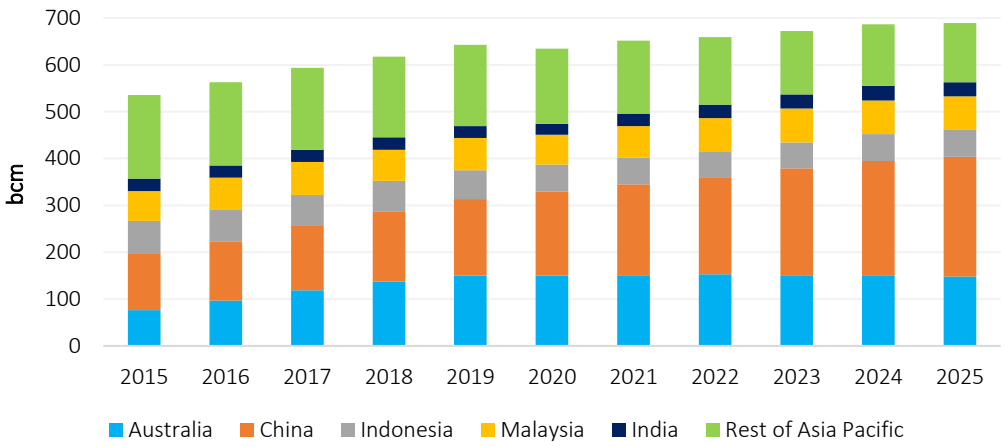


Source: GECF Secretariat based on data from Rystad Energy and LSEG

3.1.2 Asia Pacific

Gas production in the Asia Pacific region is estimated at 689 bcm in 2025, representing a marginal y-o-y increase of 0.4% (Figure 68). This relative stability was underpinned by robust growth in China, where a 12 bcm production surge successfully offset output declines across various other regional producers.

Figure 68: Trend in Asia Pacific's gas production



Source: GECF Secretariat based on data from Rystad Energy and GECF estimation

3.1.2.1 Australia

Australia's gas production in 2025 declined by 2.2% to 148 bcm (Figure 69). Unconventional production, which is primarily composed of coalbed methane CBM, accounted for 30% of the country's total output, with the CBM sector witnessing a decline of 0.6 bcm due to natural depletion. Despite this contraction, Australia maintained its status as the global leader in CBM output, supplying half of the world's total CBM volumes in 2025. Offshore production remains the backbone of the national supply, making up 70% of the country's gas output (Figure 70). The dominant offshore share has remained remarkably consistent over the past decade, reflecting the stable role of the major LNG supply projects in Western Australia and the Northern Territory.

Figure 69: Trend in Australia's gas production

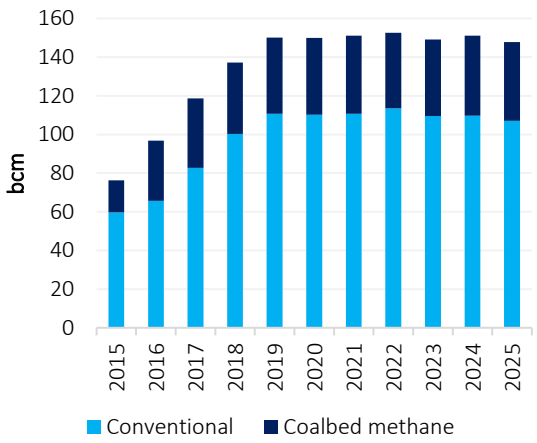
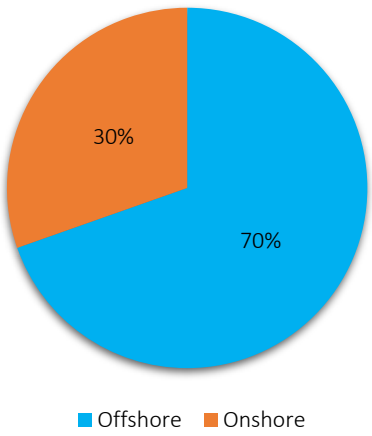


Figure 70: Australia's gas production by segment in 2025



5Source: GECF Secretariat based on data from Rystad Energy and the Australian Department of Energy

3.1.2.2 China

China's gas output rose by 12 bcm to reach 256 bcm in 2025, a steady 5% increase that positions the country as a major contributor to the expansion of global gas supply (Figure 71). This performance marks a decade of uninterrupted growth sustained by a compound annual growth rate (CAGR) of 6.4%.

Notably, unconventional sources accounted for 45% of China's total production by reaching 114 bcm, representing a significant climb from just 43 bcm ten years ago and a decadal CAGR of 10%. Within this category, shale and tight gas were the primary contributors with 70 bcm and 27 bcm of output respectively, while coal bed methane (CBM) reached a new peak of 18 bcm (Figure 72). This 8% annual surge in CBM was fuelled by the commissioning of the Shenfu Deep CBM project alongside the steady ramp-up of assets launched in 2024. Despite a strategic push for offshore expansion, the vast majority of China's supply remains onshore, which still accounts for 90% of the total national output.

In the upstream sector, nine new gas fields came online in 2025, contributing an initial combined production of 4.5 bcm with an expected average output of 9 bcm per year in the medium term. Among these developments, six conventional gas fields were commissioned, led by the Dukouhe-Qilibei Phase 1 project in the northeast Sichuan Basin, which stands as the largest with a plateau production target of 1.3 bcm per year. Additionally, the Tongnanba tight gas project in the northern Sichuan Basin emerged as the most significant development to start in 2025, carrying an anticipated plateau production of 2 bcm per year. The Qianfoya shale gas field in the southern Sichuan Basin marked the only shale-specific commissioning of the year, contributing approximately 0.8 bcm per year at its plateau. This momentum was further reinforced by 19 new gas development projects reaching the FID stage, representing a combined anticipated annual plateau production of 11 bcm to support long-term supply stability.

In the short term, China is well positioned to become the third largest gas producer globally by overtaking other major producers to trail only the US and Russia.

Figure 71: Trend in China's gas production

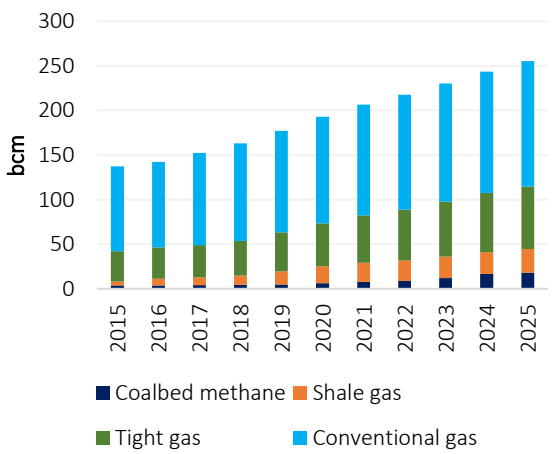
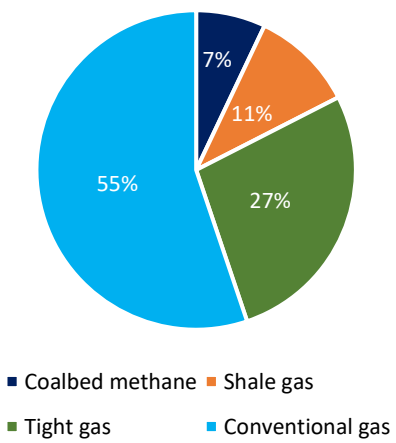


Figure 72: China's gas production by source in 2025



Source: GECF Secretariat based on data from the National Bureau of Statistics of China and Rystad Energy

3.1.2.3 India

India's gas production experienced a 3.4% decline to 30 bcm in 2025 (Figure 73). This reduction, which resulted in a total annual decrease of nearly 1 bcm, occurred because the output from aging assets fell faster than the contributions from newly commissioned development projects located primarily in India's offshore blocks.

In terms of production distribution, the vast majority of India's gas output originated from conventional fields, which accounted for 91% of the total, while tight gas and CBM projects collectively contributed the remaining 9%, with CBM production specifically concentrated in the West Bengal fields. Offshore production constituted 69% of the total gas output (Figure 74), though this share has contracted over the past decade from a level of 74% in 2015. To address this structural decline, the Indian Government is currently pursuing multiple initiatives intended to drive significant growth in offshore volumes, specifically through new licensing rounds and the strategic commissioning of deepwater projects. Additionally, associated gas production represented nearly 30% of the overall output.

In the upstream sector, 12 relatively small gas fields commenced production in 2025, contributing an initial combined output of 0.5 bcm with an expected annual plateau production of 1 bcm. All these newly commissioned assets are conventional gas fields, including two redevelopment projects specifically designed to rejuvenate mature fields. Furthermore, 12 additional small-scale development projects reached the FID stage, carrying an anticipated combined plateau production of 0.5 bcm per year over the medium term. The majority of these upcoming projects are similarly focused on the rejuvenation of old and mature existing fields to maximise recovery from the nation's brownfield assets.

In the short term, India is focused on developing its domestic resources to address the decline in proven gas reserves, which fell from 1.37 tcm in 2020 to 1.09 tcm by 2025. This contraction resulted from a lack of significant incremental additions from new discoveries. To reverse this trend, the country is looking toward its substantial unconventional potential, possessing an estimated 2.1 tcm of technically recoverable resources of shale gas.

Figure 73: Trend in India's gas production

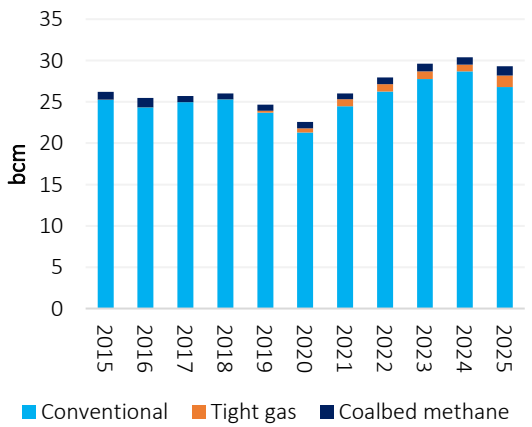
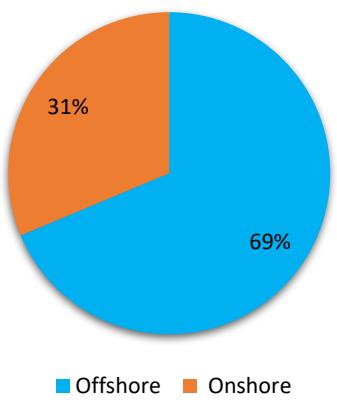


Figure 74: India's gas production by segment in 2025



Source: GECF Secretariat based on data from Rystad Energy and PPAC

3.1.2.4 Indonesia

Indonesia's gas production increased marginally to 57.2 bcm in 2025 (Figure 75). This result is viewed positively as it reverses a decade-long decline from 70 bcm in 2015 to a low of 55.3 bcm in 2022. This turnaround was driven by intensified development and the rejuvenation of aging assets, supported by a significant increase in drilling activity from 480 wells in 2021 to 980 in 2025 (Figure 76). Six new fields commenced production during the year, led by the Merakes East offshore project in the Kutei Basin with a capacity of 0.9 bcm per year. Currently, all Indonesian output originates from conventional, non-associated gas fields, with offshore production accounting for 60% of the total volume.

Figure 75: Trend in Indonesia's gas production

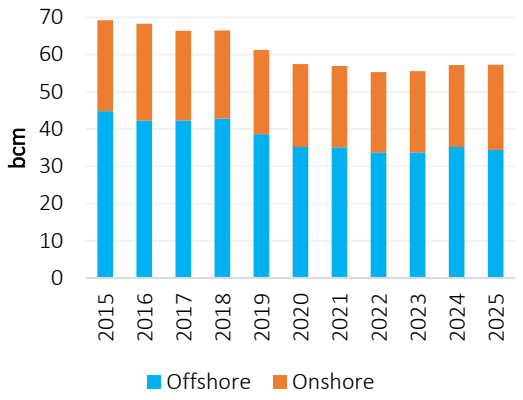
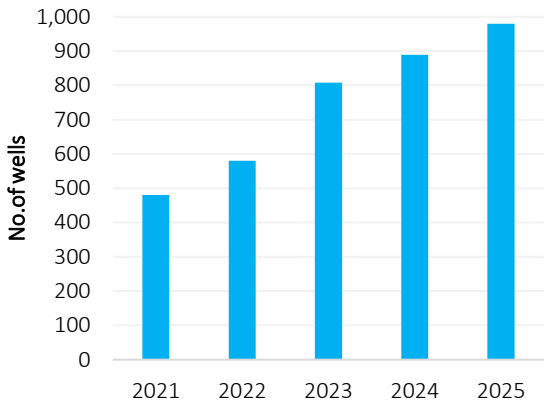


Figure 76: Indonesia's new development wells



Source: GECF Secretariat based on data from Rystad Energy and Indonesia's upstream regulator (SKK Migas)

3.1.2.5 Malaysia

Malaysia maintained its gas output at 72 bcm in 2025, a stability primarily driven by the absence of major new gas development projects (Figure 77). Only two relatively small fields, Bindu and Gansar, were brought online during the year. The country's production remains entirely offshore, with the vast majority stemming from its continental shelf (Figure 78). Furthermore, associated gas production from oil fields accounts for only 6% of the total Malaysian output, reflecting the nation's heavy reliance on dedicated non-associated gas reservoirs.

Figure 77: Trend in Malaysia's gas production

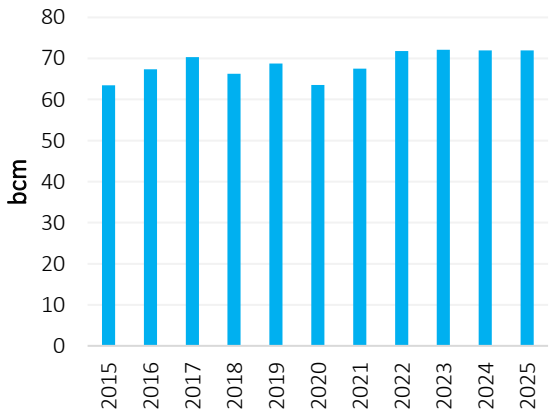
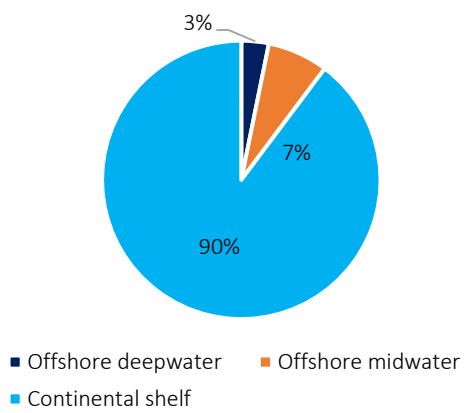


Figure 78: Malaysia's gas output by segment in 2025

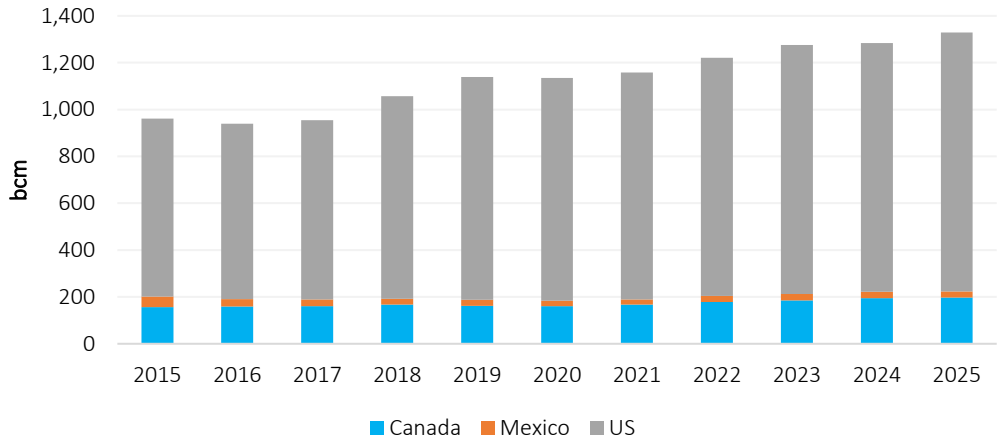


Source: GECF Secretariat based on data from Rystad Energy and JODI gas

3.1.3 North America

North America's gas production grew by 3.4% to reach 1,329 bcm in 2025, accounting for 31.5% of global gas output (Figure 79). With an incremental increase of 44 bcm, the region emerged as the primary driver of global production growth. This robust performance was underpinned by surging output in both the US and Canada as producers responded to rising demand. Looking ahead, the region is expected to maintain this positive trajectory, supported by anticipated further growth in US production levels to meet both domestic and export requirements.

Figure 79: Trend in North American gas production



Source: GECF Secretariat based on data from Rystad Energy and GECF's estimations

3.1.3.1 Canada

Canada's gas output rose by 2.5% to reach 199 bcm (Figure 80), underpinned by the strategic startup of new LNG export capacity that provided a critical outlet for increased shale and tight gas volumes. These unconventional sources together accounted for 72% of total output, while associated gas contributed 10%, with the entirety of the nation's production originating from onshore fields. Market stability was further evidenced by drilling activity, as the gas rig count in December 2025 mirrored the previous year's level of 64 active rigs (Figure 81).

Figure 80: Trend in Canada's gas production

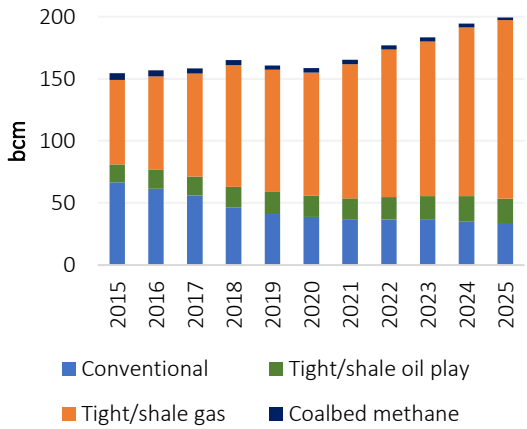
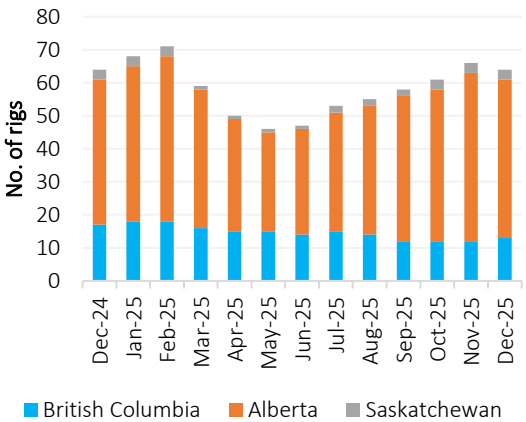


Figure 81: Gas rig count in Canada in 2025



Source: GECF Secretariat based on data from Rystad Energy and LSEG

3.1.3.2 United States

US gas production witnessed strong growth of 4% to reach an all-time high of 1,106 bcm in 2025, successfully rebounding from a year of decline in 2024 (Figure 82). This 43 bcm surge was driven by favourable market dynamics, including elevated HH gas prices and rising domestic consumption alongside rapidly expanding LNG export capacity. Furthermore, this substantial increase in US output served as the primary driver for global gas supply growth throughout 2025, reinforcing the nation's role as a cornerstone of the international energy market.

Regarding production distribution, US unconventional production reached 1,002 bcm, making up 91% of total gas output with the remaining 9% sourced from conventional reservoirs in Alaska and the Gulf of Mexico. The primary contributor was shale gas, which includes both pure gas shale plays and associated gas from shale and tight oil plays, accounting for 80% of total domestic output. This performance reinforces the nation's status as the global leader in unconventional production with a 71% share of the world's supply. Moreover, associated gas alone reached a 26% share of total output, recording a robust 8.5% CAGR over the last decade driven by rising oil production and enhanced infrastructure to recover previously flared gas.

All major producing regions in the US experienced an increase in output during 2025, led by the Permian Basin which contributed an 18 bcm rise. This expansion was primarily driven by a surge in associated gas production from shale oil plays. Among dedicated gas-producing regions, the Haynesville shale recorded the largest volume growth at 6.5 bcm, while the Eagle Ford and Appalachia regions followed with steady increases of 4.2 bcm and 8.6 bcm respectively.

Notably, the production surge was reflected in the inventory of drilled but uncompleted (DUC) wells, which fell to 5,020 in December 2025. This 778-well y-o-y decrease indicates that producers increasingly relied on their existing DUC backlog to sustain output growth. Favourable market dynamics and higher prices encouraged producers to fast-track well completions to capture market share during this period of global supply expansion (Figure 83).

In the short term, US gas production is projected to maintain its upward trajectory, reaching record highs driven by a significant expansion in LNG export capacity and a recovery in gas prices. Specifically, annual output is expected to increase by 30 bcm in 2026.

Figure 82: Trend in US gas production

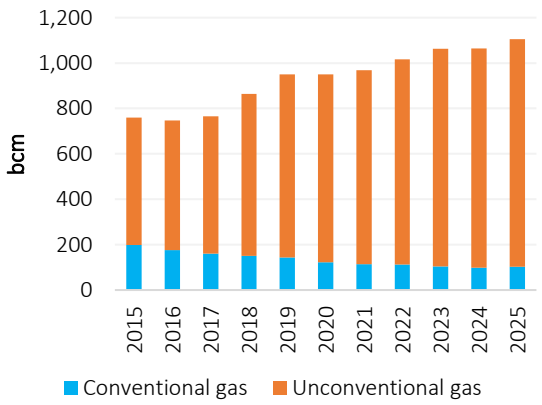
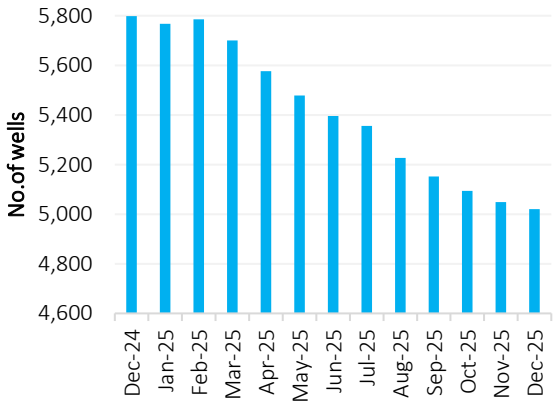


Figure 83: DUC wells count in the US

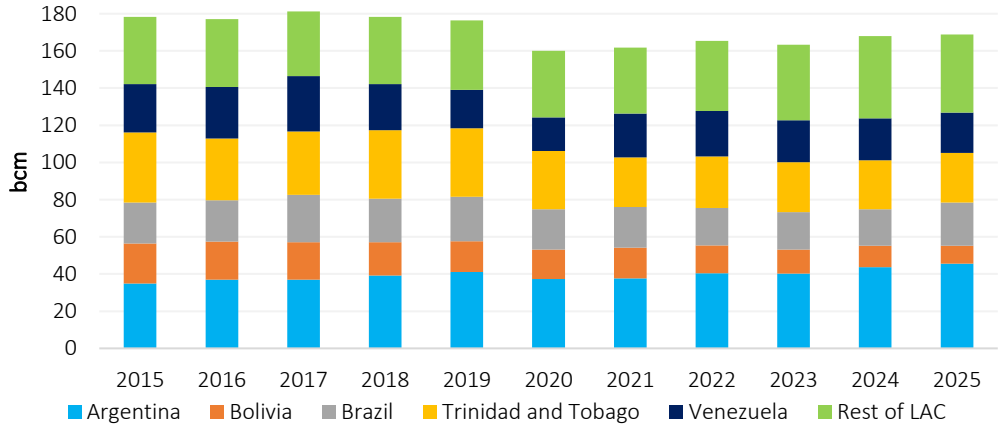


Source: GECF Secretariat based on data from Rystad Energy and the US EIA

3.1.4 Latin America and the Caribbean (LAC)

Gas production in the Latin America and the Caribbean (LAC) region grew marginally by 0.5% to reach 169 bcm in 2025 (Figure 84). This stability was largely fuelled by record annual production levels in both Argentina and Brazil, which effectively counterbalanced the output declines in other regional producers including Bolivia, Trinidad and Tobago and Venezuela.

Figure 84: Trend in LAC's gas production



Source: GECF Secretariat based on data from Rystad Energy and GECF estimation

3.1.4.1 Brazil

Brazil's marketed gas production witnessed significant growth of 18% to reach 23.1 bcm in 2025 (Figure 85). This surge was driven by a record gross output of 65 bcm alongside reduced volumes of gas being flared or internally consumed as operational fuel on the platforms. Reinjection volumes remained a critical factor, accounting for 54% of gross production, which mirrors the level recorded in 2024 (Figure 86). Notably, 81% of the marketed gas output was derived from associated gas, while offshore production represented 82% of the total supply, with pre-salt fields specifically constituting 79% of the national production.

Figure 85: Trend in Brazil's marketed gas production

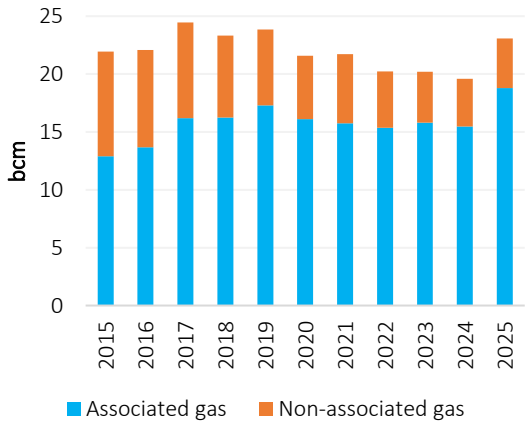
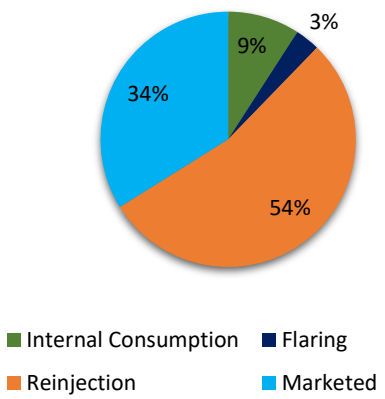


Figure 86: Brazil's gross output distribution in 2025



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

3.1.4.2 Argentina

Argentina's gas production grew by 1.5% to reach 51.5 bcm in 2025 (Figure 87). This rise was primarily driven by the continuous development of the Vaca Muerta Basin alongside the debottlenecking and expansion of associated pipeline infrastructure to meet rising domestic demand for power generation.

Argentina's gas sector is increasingly defined by unconventional sources, comprising both shale and tight gas, which collectively dominated the national landscape by accounting for 63% of total production in 2025. This structural shift was primarily driven by the robust performance of shale gas, which surged 8% annually to reach 27.4 bcm as the Vaca Muerta Basin remained the primary contributor to national output (Figure 88). In contrast, other industry segments experienced significant downturns, as tight gas production dropped by 18% to 5.3 bcm to represent just 13% of the total volume. At the same time, conventional gas fields recorded a marginal decline of 0.6% to reach 18.8 bcm, representing the remaining 37% share of the national output, as the industry continues its transition toward unconventional assets.

The production transformation in Argentina highlights both significant potential and current limitations. While the growth of the Vaca Muerta shale basin is impressive, driven by drilling advancements and infrastructure upgrades, it remains modest compared to the historical peak of the US shale sector. This disparity reflects capital boundaries, infrastructure bottlenecks, and operational scale constraints that temper unconventional growth. However, acceleration is increasing, as the 2022 to 2025 period added production faster than the 2017 to 2019 window. This trend suggests that maturing learning curves and economies of scale are delivering cumulative benefits to the basin's performance.

In the short term, Argentina's gas production is expected to sustain its consistent growth trajectory, particularly as the ongoing debottlenecking of output from Vaca Muerta enhances regional takeaway capacity. Driven by this rapid pace of expansion, Argentina is well positioned to transition into an important exporter of both LNG and pipeline gas.

Figure 87: Trend in Argentina's gas production

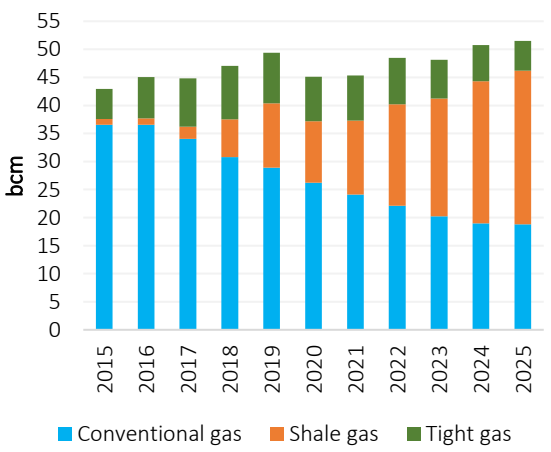
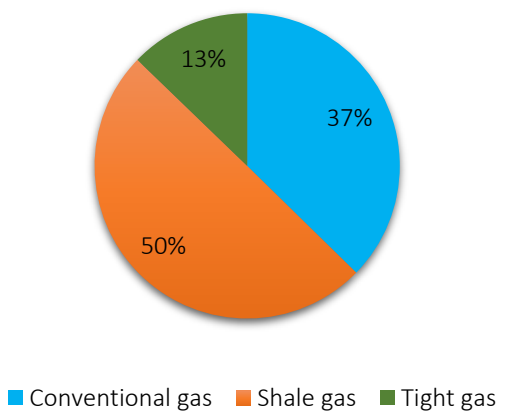


Figure 88: Argentina's gas output by source in 2025

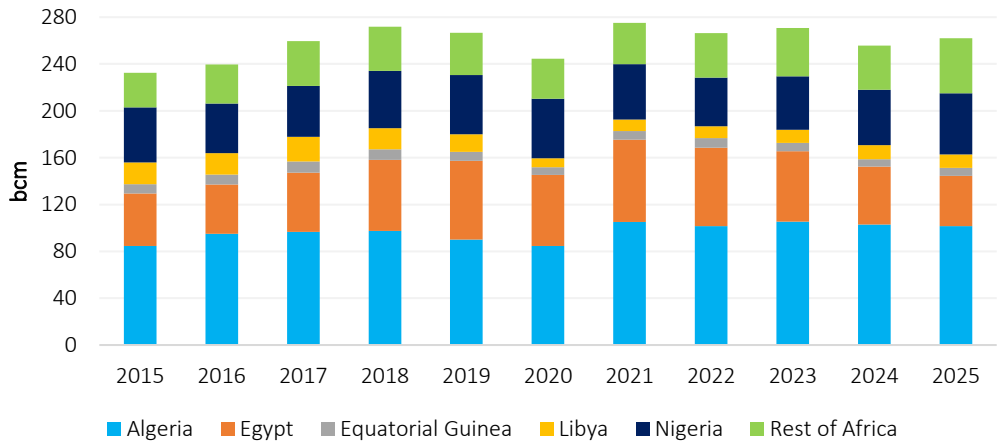


Source: GECF Secretariat based on data from Argentinian Ministry of Economy

3.1.5 Africa

Africa's gas production grew by 2.5% to reach 262 bcm in 2025, a performance that reversed the declining trend of 2024 and resulted in the continent accounting for 6.2% of global gas output (Figure 89). This expansion was primarily driven by supply growth across Sub-Saharan nations, led by Nigeria and Angola, alongside the strategic production ramp-up in West Africa through the commissioning of the Greater Tortue Ahmeyim (GTA) project in Mauritania and Senegal. Notably, these regional gains were sufficient to surpass output reductions in key North African producing countries resulting in a positive overall production variation for the continent.

Figure 89: Trend in Africa's gas production



Source: GECF Secretariat based on data from Rystad Energy and GECF estimation

Algeria, the continent's largest gas producer, recorded a robust annual output of approximately 102 bcm. This performance was underpinned by the successful ramp-up of the Ain Tsila field, which reached full operational status in August 2025 with a capacity of 4.4 bcm per year. Additionally, seven new gas projects commenced production during the year, led by the Reg Mouaded project in the Adrar province. As a critical component of the South West Gas Project, Reg Mouaded supplies the Hassi R'Mel hub via the GR-7 pipeline with facilities integrated into the Hassi Ba Hamou field. To sustain this long-term growth, Algeria approved new agreements in July 2025 for the Ahara field and the expansion of the Berkine Basin, initiatives that are expected to contribute 5.5 bcm per year of incremental production by 2028.

Angola's gas production returned to a trajectory of consistent growth after a decline in 2024, a recovery primarily driven by the startup of the Sanha Lean Gas Connection project with a first-phase capacity of 0.9 bcm per year. This project supplies natural gas from the Sanha field in Block 0 to the Soyo power plants and the Angola LNG facility. In addition to this development, the country experienced an increase in associated gas production from its offshore oil fields. Angola is recognized as a successful case study in associated gas recovery and monetization, primarily through its 5.2 Mtpa liquefaction plant in Soyo, which is one of the world's first facilities to be supplied exclusively with associated gas.

Egypt recorded a decline in gas production, primarily due to natural depletion at the Zohr field, which contributes nearly a quarter of national output. To reverse this trend, the government is implementing a strategic recovery plan to revitalise the upstream sector by incentivizing international partners through improved financial terms and the prioritized settlement of outstanding arrears. These efforts, combined with the fast-track development of newly discovered offshore blocks, are expected to introduce significant incremental volumes to the national grid and foster a more robust investment climate.

Equatorial Guinea's gas production rose by 7%, primarily driven by the Gas Mega Hub initiative, which focuses on monetizing stranded offshore resources by connecting them to existing regional infrastructure. A key driver of this growth was the commencement of Phase III of the initiative, which has successfully integrated new supply streams into the national grid. Additionally, increased feed gas from the Alen and Alba fields ensured that the LNG export facility on Bioko Island maintained high operational levels throughout the year.

Libya's gas production remained stable, yet the industry is poised for expansion as the offshore Structures A and E projects progress toward an expected startup in 2026. These strategic fields are projected to reach a plateau production of 8 bcm per year, which will at the same time strengthen domestic energy security and expand export capacity to Europe. Furthermore, the outlook for the medium term has been enhanced by the launch of the first oil and gas licensing round in over 17 years. This strategic initiative aims to attract substantial international investment and revitalise exploration activity to provide a significant near-term boost.

Mauritania and Senegal experienced a significant production ramp-up following the first gas milestone at the offshore Greater Tortue Ahmeyim project. Gas from this initial phase now flows through the floating production storage and offloading vessel to the 2.7 Mtpa FLNG facility for liquefaction. The start of LNG exports in April 2025 transformed both nations into new global market players and served as a primary driver for Africa's positive production growth.

Mozambique's gas production remained stable at 10.1 bcm. This stabilisation follows the successful integration of the Coral South floating LNG project, which transformed the country's production profile after exports commenced in November 2022.

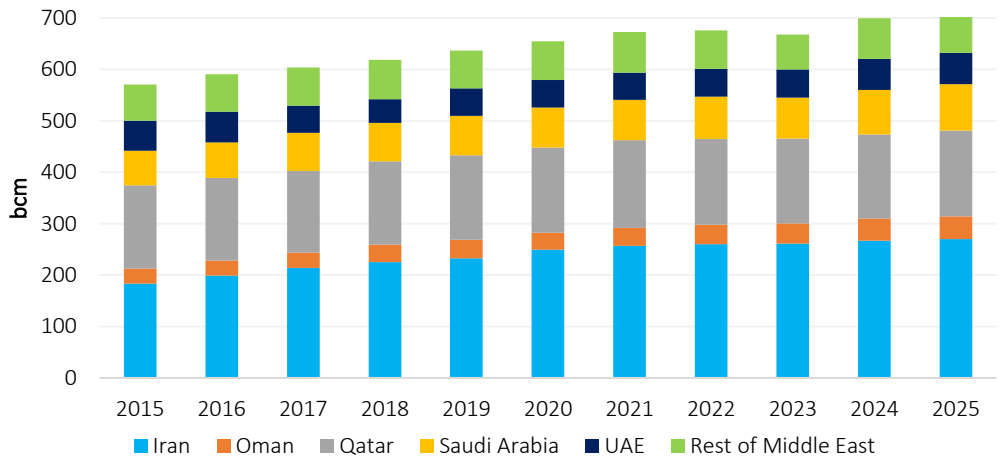
Nigeria, Africa's second-largest producer and reserve leader, recorded a 10% output increase to 52 bcm. This growth played a pivotal role in offsetting regional declines and was driven by a surge in associated gas, which now accounts for 49% of total production. Under the "Decade of Gas" initiative, the government is successfully monetizing these volumes as LNG feedstock to boost exports and reduce flaring. Continued international investment in upstream and midstream infrastructure ensures a strong production outlook for the short and medium term.

The nine GECF Member Countries mentioned above dominated Africa's gas production by representing 94% of the continent's total output, with strong short-term growth expected to be supported by rising production in Sub-Saharan Africa and a recovery in North African output levels alongside the expansion of new offshore projects.

3.1.6 Middle East

Middle East gas production grew 2.5% to 716 bcm in 2025, raising the region's global market share to 17% (Figure 90). This expansion was driven by major projects in Iran, Oman, Qatar, Saudi Arabia and the UAE. Supported by these strategic developments, the region will remain a major contributor to global production growth over the short and medium term.

Figure 90: Trend in the Middle East's gas production



Source: GECF Secretariat based on data from Rystad Energy and GECF's estimation

Iran recorded positive gas output growth driven by steady upstream progress. This expansion was supported by the commencement of the Dey onshore field. Additionally, the offshore Kish field continued its successful ramp-up following a late 2024 startup, while record performance from South Pars further reinforced national capacity to meet rising demand.

Oman's gas production grew by 3.5% to reach 44.5 bcm, with associated gas accounting for 24% of the total output. This rise was primarily driven by the commissioning of the Maradi Huraymah East processing plant alongside several associated gas recovery projects.

Qatar's gas production rose 1.8% to 167 bcm, supported by the North Field Production Sustainability (NFPS) and Al-Khaleej Gas-2 projects to maintain its output plateau. At the same time, the North Field East, South and West expansions progressed toward a 2030 target of 142 Mtpa, integrating carbon capture to reduce the carbon intensity of future exports.

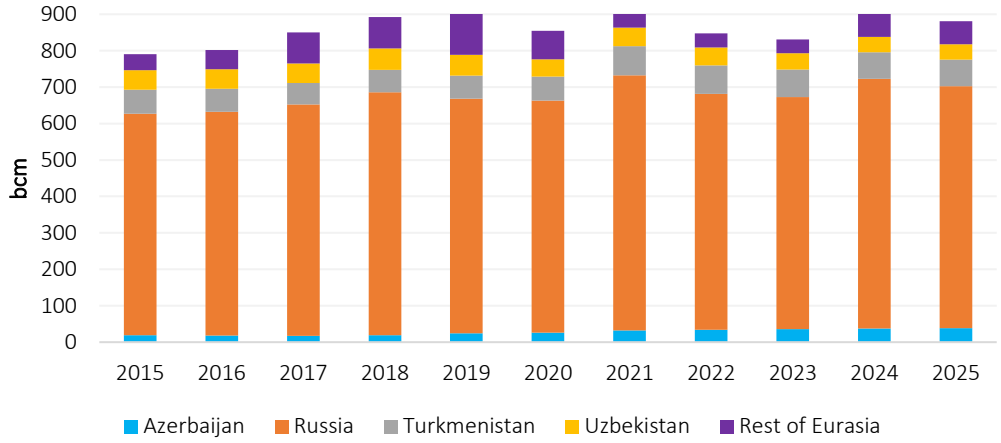
Saudi Arabia's gas production grew 4.5% to 90 bcm, primarily driven by the Fadhili processing plant expansion, which treats sour gas from the Khursaniyah and Hasbah fields, alongside the initial startup of the massive Jafurah shale gas project and the development of new infrastructure.

UAE gas production rose to 61 bcm in 2025, with further significant growth expected from the 2026 startup of the major Hail and Ghasha sour gas development. This expansion is reinforced by ADNOC's recent final investment decision for the SARB Deep Offshore project, which is designed to deliver 2.1 bcm per year by the end of the decade.

3.1.7 Eurasia

Eurasia's gas production declined by 1.8% to reach 868 bcm in 2025 (Figure 91). This reduction was primarily driven by the decrease in Russian output, which remains the second largest gas producer globally and the dominant force in the regional market by accounting for 77% of Eurasia's production. Following Russia, the regional landscape was shaped by the collective contributions of Turkmenistan, Uzbekistan, Azerbaijan and Kazakhstan.

Figure 91: Trend in Eurasia's gas production



Source: GECF Secretariat based on data from Rystad Energy and its own estimations

Azerbaijan's gas output grew by 2.4% to reach 39 bcm, a performance underpinned by the sustained output from its primary offshore fields. Production was primarily driven by the Shah Deniz field, which contributed 27.9 bcm, and the Azeri-Chirag-Deepwater Gunashli (ACG) block, which produced 3.5 bcm. Meanwhile, the Absheron gas field increased its output by 7% to reach 1.6 bcm during its initial phase.

Russia's gas output reached 664 bcm, a 3% y-o-y decline that reflects the industry's resilience as it pivots from European exports toward robust domestic consumption and expanding deliveries to China via the Power of Siberia pipeline. These strategic shifts provided a critical buffer for national production levels during a period of significant market transition. Separately, associated gas reached 101.6 bcm to represent 15% of the total output as the sector continues to prioritize resource efficiency through enhanced monetization. Looking ahead, the 2026 commissioning of the Kharasaveyskoye field on the Yamal Peninsula is expected to provide a substantial boost with a projected plateau level of 32 bcm per year.

Turkmenistan and Uzbekistan recorded production declines as maturing field yields outweighed new project gains, with output falling by 1.2% to 73 bcm and 1.1% to 42 bcm respectively. Despite these setbacks, both nations remain committed to expanding capacity through modernized infrastructure and targeted development strategies, exemplified by Turkmenistan's commencement of phase four at the massive Galkynysh field in early 2026, which is expected to eventually yield an additional 30 bcm annually.

3.2 Gas Production by Category

3.2.1 Associated Gas Production

Associated gas production increased by 3.8%, or 22 bcm, to reach 594 bcm in 2025 (Figure 92). This marks a significant rise from 462 bcm in 2015, reflecting a compound annual growth rate of 2.5% and highlighting the growing importance of associated gas within the global supply mix. Non-associated gas remained the dominant component of global production, accounting for 86% of total output and continuing to meet the majority of global gas demand.

Associated gas production offers a strategic opportunity to enhance resource efficiency and provide low-cost energy by capturing volumes naturally dissolved in oil reserves. Successfully monetizing this byproduct is essential to avoiding routine gas flaring, a practice that results in significant lost economic value and increases the industry's carbon footprint through methane and CO_2 emissions. By investing in midstream infrastructure, such as gathering pipelines and processing facilities, operators can transform what was once considered a waste stream into a reliable feedstock for power generation and petrochemicals. Effectively utilising associated gas not only supports global supply growth and energy security, but also plays a critical role in the industry's transition toward a more sustainable, circular and lower-emission energy system.

From a regional perspective, North America dominates the market, accounting for 54% of global associated gas production (Figure 93). This output is primarily driven by the prolific yields of the US Permian Basin and the Canadian Bakken shale. The Middle East holds a 12% market share, anchored by Saudi Arabia, where the Ghawar oil field remains the cornerstone of the nation's 40 bcm associated gas output. Meanwhile, Iraq is elevating its regional profile through strategic flared gas recovery projects designed to enhance resource monetization. Eurasia contributes 11% of the global total, with Russia serving as the lead producer. In Africa, Nigeria and Angola offer proven frameworks for how gas recovery can catalyse domestic production and unlock new international export opportunities.

Figure 92: Global gas production by type

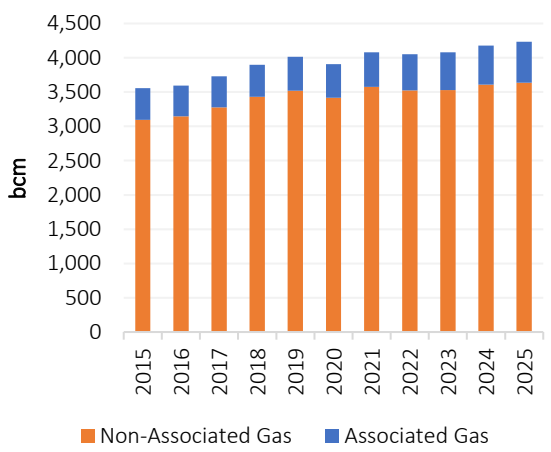
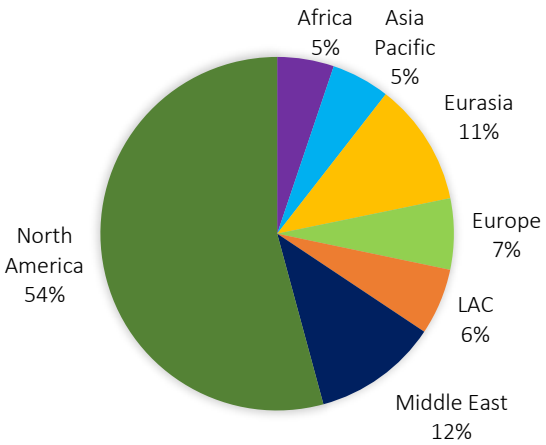


Figure 93: Associated gas output by region in 2025



Source: GECF Secretariat based on data from Rystad Energy and GECF estimation

3.2.2 Unconventional Gas Production

Unconventional gas production increased by 4.4% (63 bcm) to reach 1,506 bcm in 2025 (Figure 94). The annual growth rate is consistent with last year's performance but trails the previous decade's average CAGR of 6.4%. Since 2015, the global market share of unconventional gas has climbed from 23% to 35.5%. This steady rise, most notable in the US, is the result of advanced hydraulic fracturing, horizontal drilling, and favourable market conditions that have reduced breakeven costs through economies of scale and increased investment.

From a regional perspective, North America continues to dominate the unconventional gas landscape, commanding an 83% market share fuelled by the sustained US shale boom and rising tight gas output from Canada. The Asia Pacific region follows with an 11% share, propelled by China's aggressive expansion into shale and CBM, which together now constitute 45% of its domestic production, alongside Australia's world-leading CBM operations. Meanwhile, Latin America holds a 3% share, with Argentina's Vaca Muerta Basin serving as the primary catalyst for regional growth. The Middle East accounts for the remaining 2.5%, led by Saudi Arabia's development of the North Arabia and South Ghawar fields and the strategic commencement of the Jafurah shale project (Phase I) in late 2025.

Shale gas constituted 56% of the global unconventional gas supply, with the US serving as the primary source of this volume. The market share of associated gas from shale oil formations reached 22%, a rise largely attributed to surging output from the US Permian Basin. Tight gas accounted for a further 12% of production, sourced mainly from the Montney Basin in Canada and various Chinese plays. Finally, CBM made up 5% of the total, with growth spearheaded by established operations in Australia and China (Figure 95).

In the short term, unconventional gas production is set to play a key role in driving global gas supply growth. This expansion will be fuelled by the continuous rise in US shale gas output under favourable market dynamics, alongside the strategic ramp-up of Saudi Arabia's shale production.

Figure 94: Trend in global gas production by source

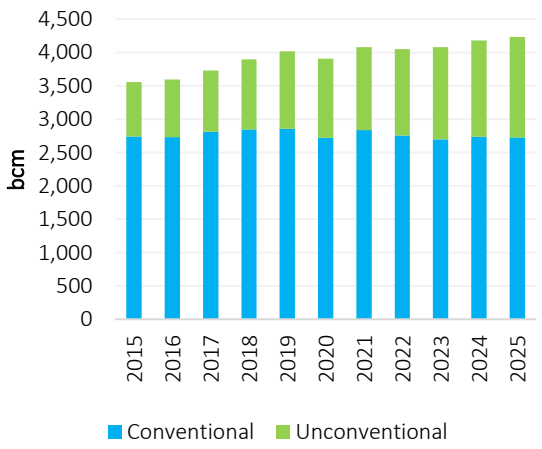
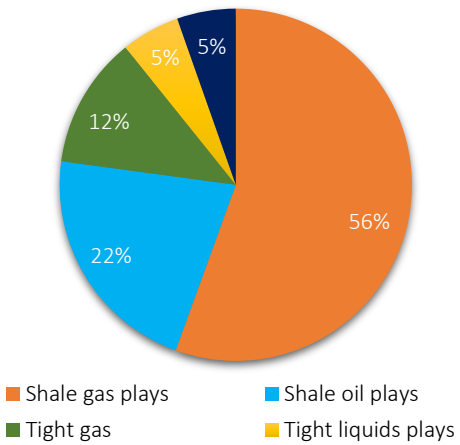


Figure 95: Unconventional gas output by type in 2025



Source: GECF Secretariat based on data from Rystad Energy and GECF estimation

3.2.3 Offshore Gas Production

Offshore gas production increased by 2.2% (26 bcm) to reach 1,264 bcm in 2025 (Figure 96). This sector, which encompasses operations across the continental shelf, deepwater and ultra-deepwater, has maintained a steady 30% share of global output over the last decade. Strategic new investments have successfully balanced natural declines in mature areas such as the North Sea, ensuring the sector's stability. Consequently, onshore production continues to serve as the industry's primary pillar, supplying the remaining 70% of global gas.

From a regional perspective, the Middle East held the largest portion of offshore gas production at 40%, marking a significant increase over the last decade (Figure 97). This growth was predominantly driven by the phased expansion of Iran's South Pars field and increased output from Qatar's North Field, which together represent the largest offshore production hub globally. The Asia Pacific region followed with a 26% share, fuelled by rising production in Australia and China alongside steady contributions from Malaysia and Indonesia, where offshore activities account for 100% and 60% of national output respectively. Conversely, Europe's share plummeted from 26% in 2015 to just 14% in 2025, a sharp decline resulting from dwindling output in the UK and Netherlands' North Sea sectors.

In the short and medium term, offshore gas production is poised to be a primary catalyst for global supply growth as a significant wave of new projects prepares to come online. High-profile developments such as Qatar's North Field Expansion, the Neptune Deep and Sakarya Phase II and III projects in the Black Sea and various Mediterranean fields including Nargis, Aphrodite and Cronos underscore this momentum. This shift toward the offshore is driven by the maturation of onshore reserves and rising energy demand, which have rendered previously marginal offshore prospects commercially viable. The strategic importance of the offshore sector is further validated by a decade of exploration trends where offshore findings have consistently outpaced onshore discoveries.

Figure 96: Trend in global gas production by segment

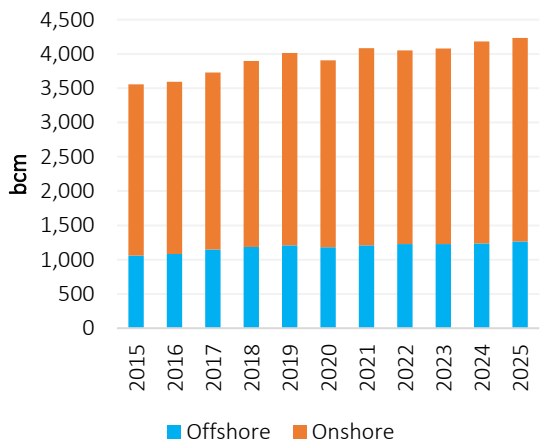
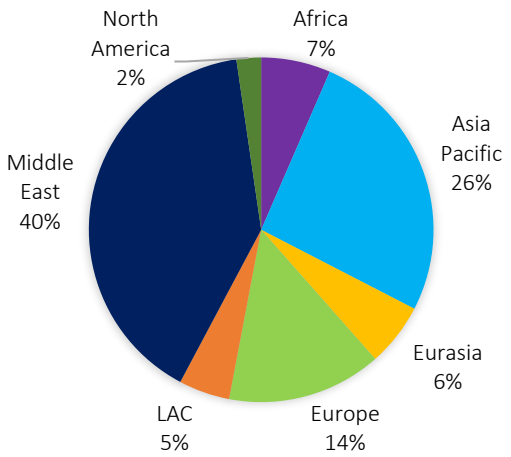


Figure 97: Offshore gas output by region in 2025



Source: GECF Secretariat based on data from Rystad Energy and GECF estimation

3.3 Upstream Developments

3.3.1 Development Activity

The number of upstream gas projects commissioned in 2025 totalled 160. These projects are expected to reach a collective plateau production of 95 bcma and unlock 2.5 tcm of technically recoverable resources over their operational lifetimes (Figure 98). Regionally, North America contributed 31% of this plateau, driven by a high volume of relatively small shale fields, while Asia Pacific accounted for 20%, led by Australia's Barossa project and multiple startups in China. The Middle East remains a strategic contributor through Qatar's North Field expansion and Iraq's associated gas recovery initiatives, while Africa's output is headlined by Egypt's Raven Field Phase II and Algeria's Reg Mouaded project. Of the total anticipated production, offshore developments will account for 26%, while associated gas projects will comprise 20%.

The number of upstream gas projects reaching FID in 2025 totalled 280, marking the highest level of sanctioned projects in a single year over the last decade (Figure 99). Collectively, these projects are expected to reach a plateau production of 100 bcma and unlock 2.6 tcm of technically recoverable resources over their operational lifetimes. This surge was primarily driven by two regions: North America, where favourable market dynamics made numerous small-scale US shale projects economically feasible, and the Middle East, which contributed significantly to the global volume. A primary driver in the Middle East was Qatar's North Field Production Sustainability (NFPS) Offshore Compression Program (COMP 4 and COMP 5). As the largest FID of the year, it carries a combined investment of $5.8 billion and is designed to sustain and gradually increase output from the North Field reservoir. Similarly, the UAE's ADNOC reached FID for the first phase of its $5 billion Rich Gas Development (RGD) project, marking a major milestone in the company's capital investment strategy.

Figure 98: Annual plateau gas production from commissioned projects

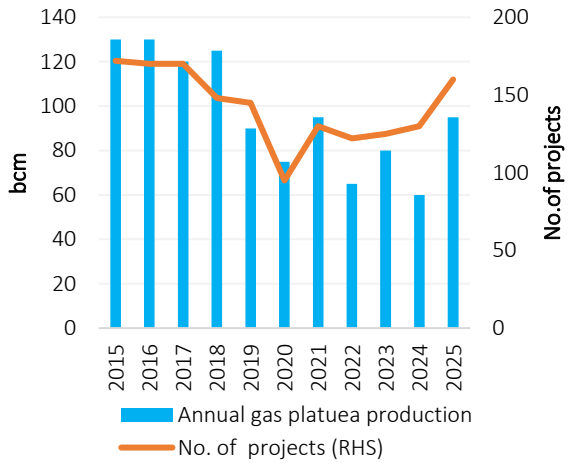
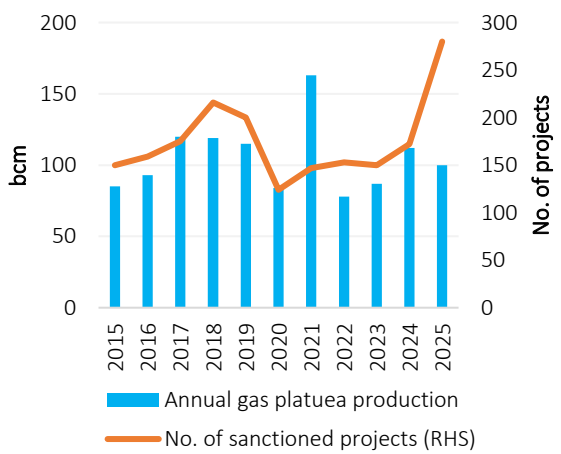


Figure 99: Annual plateau gas production from projects that reached FID



Source: GECF Secretariat based on data from Rystad Energy
Note: Annual plateau production is calculated over a 10-year period from approval date

3.3.2 Exploration Activity

Global oil and gas discoveries totalled 5.4 billion barrels of oil equivalent (boe) in 2025. Natural gas accounted for 42% (385 bcm) of this volume, while oil comprised the remaining 58% (3.1 billion boe). This reflects an 8% annual decline in discovered gas compared to the 420 bcm found in 2024, though volumes remained above the record lows of 2023 (Figure 100). These results underscore the growing difficulty of securing significant gas volumes through high-risk wildcat exploration. This challenge is compounded by several high-impact prospects failing to meet resource projections, sparking concerns over long-term supply stability. Such a trend heightens risks related to reserve replacement, market price volatility and global energy security.

These low discovery levels kept exploration costs elevated for a third consecutive year. In 2025, the marginal cost of finding natural gas reached $9.7/boe, or $1.6/MMBtu (Figure 101).

Figure 100: Global oil and gas volumes discovered

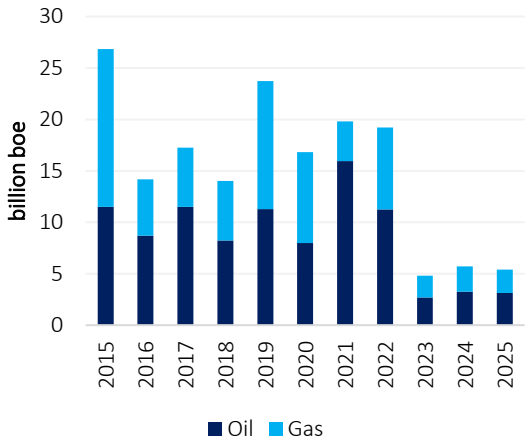
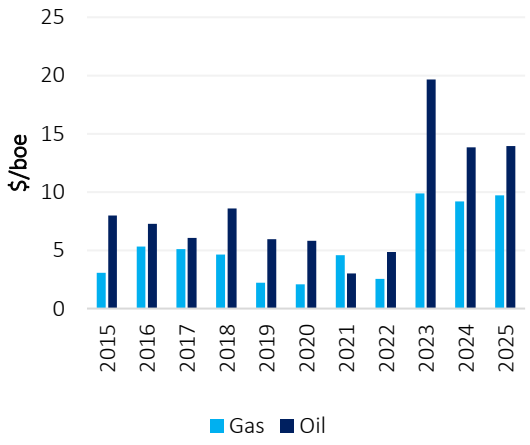


Figure 101: Gas and oil marginal cost of finding



Source: GECF Secretariat based on data from Rystad Energy

Offshore discoveries remained the cornerstone of global exploration in 2025, accounting for 86% (4.7 billion boe) of total volumes. This segment was dominated by deepwater prospects (60%), followed by continental shelf finds at 25%, while onshore projects contributed the remaining balance. This concentration in deepwater highlights a shifting exploration frontier; as the industry pivots toward more remote and technically demanding environments, it faces a structural increase in both operational complexity and finding costs compared to traditional onshore or shallow-water plays.

From a regional perspective, exploration success was led by Latin America and the Caribbean (LAC) with a 35% share of discovered volumes, driven by high-impact offshore finds in Brazil, followed by Asia Pacific (18%) due to continued momentum in Malaysia, Vietnam and China. The remaining discoveries were distributed across Europe (17%), Africa (16%) and the Middle East (14%), highlighted by several strategic offshore projects: the massive Pegasus discovery in Cyprus, Egypt's Nefertari field, the Gajajeira field in Angola, Kuwait's Al-Julaiah offshore discovery and ongoing infrastructure-led successes on the Norwegian Continental Shelf.

3.3.3 Gas Reserves and Resources

Global proven gas reserves are estimated at around 200 tcm. According to some sources, conventional gas dominates, while unconventional sources represent 32%, led by shale gas (53%), followed by associated gas from shale oil (25%) and tight gas/oil (17%), with the remainder from CBM. Offshore gas accounts for 30% of global reserves, divided between continental shelves (70%) and deep offshore prospects (30%). Associated gas contributes 15% of total reserves. GECF Member Countries hold 68% of global proven gas reserves.

From a regional perspective, the Middle East maintains its global leadership with a 39% share of reserves, anchored by Iran, Qatar and Saudi Arabia. Eurasia follows with 30%, supported by the vast resource bases of Russia and Turkmenistan. Meanwhile, North America accounts for 10% of the world total (Figure 102).

Global technically recoverable gas resources (TRR) are estimated at 725 tcm. Regional distribution is led by Eurasia, North America and Latin America & the Caribbean (LAC), which hold respective shares of 24%, 19% and 18%. The remaining TRR are distributed across the Asia Pacific (16%), Africa (11%), the Middle East (9%) and Europe (3%). In terms of resource type, conventional gas accounts for 490 tcm, while unconventional gas totals 235 tcm, with shale gas serving as the primary component of the unconventional category. Global offshore geological settings contain 35% of these total TRR, with deep-offshore prospects representing 38% of the offshore total.

The gas reserve replacement ratio (RRR) fell to 47% in 2025 from 53% in 2024, the lowest level in a decade (Figure 103). This decline was primarily driven by disappointing exploration results and low volumes of discovered gas. Consequently, this trend raises concerns about medium to long-term supply security and highlights the urgent need for sufficient upstream investment.

Figure 102: Proven gas reserves by region in 2025

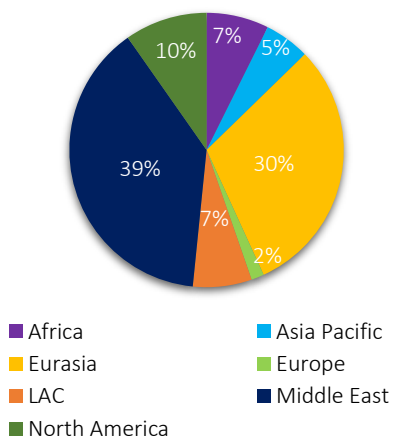
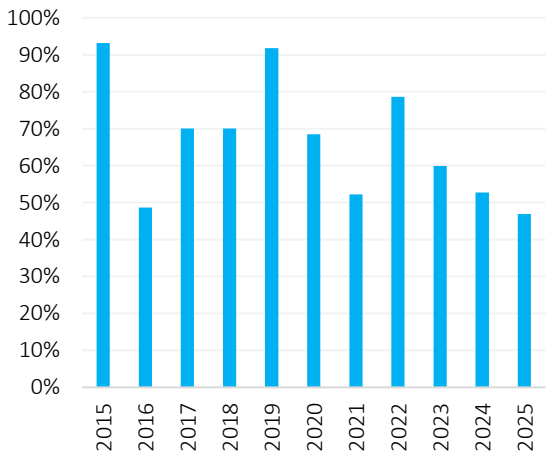


Figure 103: Gas reserve replacement ratio (RRR)



Source: GECF Secretariat based on Rystad Energy, Cedigaz and Enerdata
Note: RRR% is calculated as the ratio between added reserves (discoveries+development) over total production

3.3.4 Developments in Decarbonisation Projects

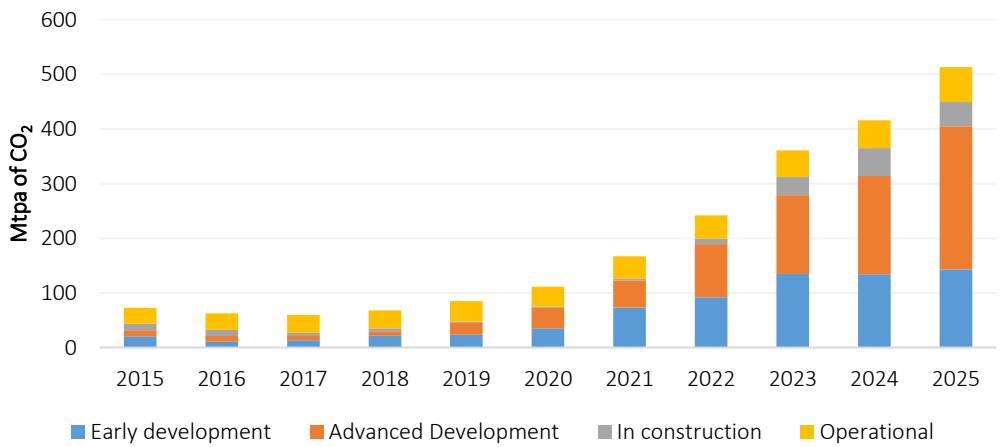
3.3.4.1 Carbon Capture, Utilisation and Storage (CCUS)

The deployment of Carbon Capture, Utilisation and Storage (CCUS) has accelerated as a critical strategy for meeting decarbonization goals. According to the Global Status of CCS 2025 report, the project pipeline has expanded to 734 facilities with a total capture potential of 513 Mtpa of CO_2 (Figure 104). A key milestone was reached in 2025 with 77 commercial projects now operational, representing a 54% y-o-y increase and capturing a combined 64 Mtpa. Furthermore, 47 projects currently under construction will add 44 Mtpa of capacity, set to increase the operating total by 70% upon completion. The remaining pipeline includes 297 projects in advanced development and 313 in early planning, representing 405 Mtpa of capacity.

North America continues to lead CCUS deployment, driven in the US by enhanced 45Q tax incentives and the integration of carbon capture with gas power to meet electricity demand from AI data centres, such as a pioneering project in Wyoming. Europe is also expanding rapidly, with dedicated CO_2 transport and storage projects doubling between 2023 and 2024, while the UK advances integrated industrial hubs like the East Coast Cluster through sequenced government funding. Meanwhile, China has transitioned to large-scale operations, highlighted by the 1.5 Mtpa Huaneng project and the May 2025 launch of its first offshore CO_2-EOR project at the Enping 15-1 field. The global progress is increasingly defined by transnational cooperation, exemplified by the late 2025 delivery of specialised CO_2 transport ships to Norway's Northern Lights project, signalling a maturing international market for carbon management.

The rapid expansion of CCUS underscores its vital role in global decarbonization, specifically for hard-to-abate sectors. In 2025, the industry reached a new phase of financial maturity as projects secured non-recourse debt financing. Key examples include Net-Zero Teesside and the Northern Endurance Partnership, where robust policies enabled this project finance milestone. As regulations strengthen and technology advances, CCUS is set to become a critical decarbonization enabler across the entire energy value chain.

Figure 104: Global capacity of operational, under construction and planned CCUS projects



Source: GECF Secretariat based on data from Global CCS Institute 2025 Status Report

3.3.4.2 Hydrogen

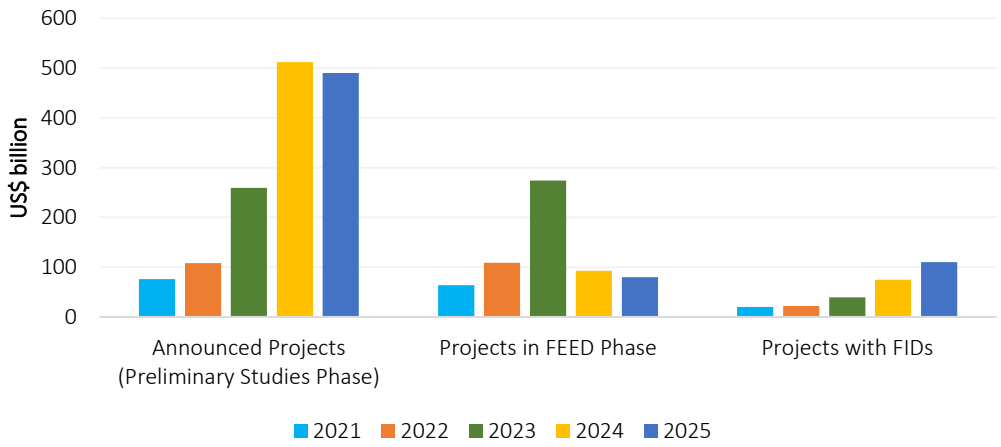
The hydrogen industry has transitioned toward disciplined execution and project maturation, moving beyond initial speculative announcements. According to the Hydrogen Council, total committed investment in clean hydrogen has surpassed $110 billion, an annual increase of $35 billion. Currently, over 500 projects have reached FID, entered construction, or become operational. This shift reflects a strategic "pipeline clean-up," where less viable ventures are sidelined in favour of projects with robust business cases and secured offtake (Figure 105).

Total committed production capacity now exceeds 6 Mtpa, with 1 Mtpa already fully operational. While early projections were more aggressive, the industry now anticipates a more realistic deployment of 9 to 14 Mtpa by 2030 due to project attrition. China has emerged as the global leader in renewable hydrogen, accounting for over 50% of committed green capacity and increasing its operational volume sixfold since 2022. Conversely, North America remains the leader in low-carbon (blue) hydrogen, which currently represents 70% of global operational capacity compared to renewable hydrogen's 30% share.

Project success increasingly hinges on securing binding offtake agreements. To date, 3.6 Mtpa of offtake has been secured globally, covering 60% of total committed capacity. Demand remains dominated by traditional industrial sectors, with 70% offtake linked to refining and ammonia production, while emerging sectors like steel, mobility and power account for the remaining 30%. Effective policy execution in the EU, US, Japan and Korea is estimated to unlock an additional 8 Mtpa of clean hydrogen demand by 2030.

Despite high interest rates and rising equipment costs, the industry is prioritizing pragmatism and infrastructure. Addressing the $190 billion gap in transport and storage remains essential for connecting production centres to end-users. Moving forward, success will depend on policy stability, scaled manufacturing supply chains, and coordinated public-private efforts to translate announced projects into operational capacity.

Figure 105: Investment in hydrogen projects



Source: GECF Secretariat based on data from Hydrogen Council 2025 Report

3.3.4.3 GHG Emissions Reduction

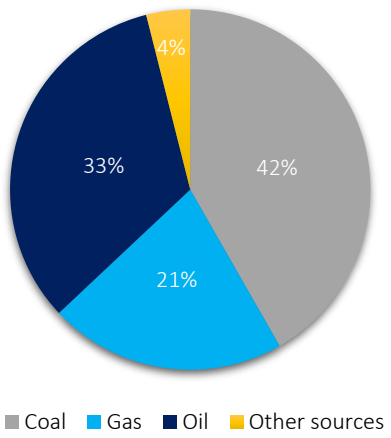
While the global momentum for emission reductions has slowed down, the primary focus remains on CO_2. Cutting carbon dioxide is essential to tackling the climate crisis, as it is the leading driver of global warming. Global energy-related greenhouse gas (GHG) emissions are estimated to have reached 42.7 Gt CO_2-equivalent in 2025, with CO_2 accounting for 90%, methane-related emissions representing 9% and the remaining 1% attributed to other GHGs.

Global energy-related CO_2 emissions reached a record high of 38.1 Gt in 2025. While coal and oil remain the primary drivers, accounting for 42% (15.9 Gt) and 33% (12.6 Gt) of the total respectively, natural gas persists as the least carbon-intensive hydrocarbon. It contributed 21% (8.1 Gt) of energy-related emissions (Figure 106).

Likewise, energy-related methane emissions are estimated to have reached 144 Mt (4.2 $GtCO_2eq$) in 2025, a significant increase from previous years due to record production levels and the inclusion of newly tracked sources like abandoned facilities. Oil and gas operations remain the largest source of these emissions, accounting for approximately 51% (74 Mt), while coal accounts for roughly 29% (42 Mt). Notably, natural gas accounted for the least methane emissions among the fossil fuels. Bioenergy and other energy sources contribute the remainder, including roughly 20 Mt from biomass and 8 Mt from abandoned wells and mines (Figure 107). Venting, leaks and flaring continue to be the primary causes of emissions in the oil and gas sector. The US remains the largest emitter from oil and gas operations, while China continues to be the highest emitter in the coal sector, though both nations have introduced new regulatory frameworks in 2025 to curb emission levels.

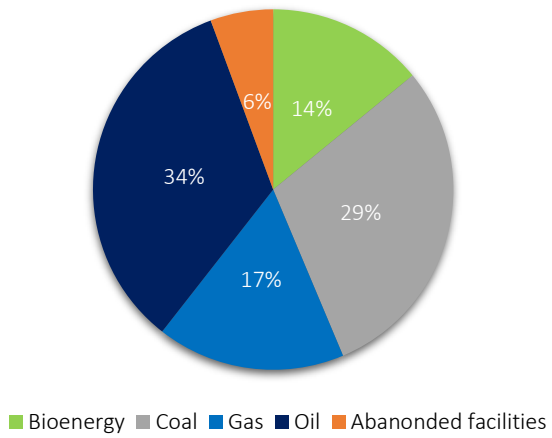
These figures underscore the environmental potential of natural gas within the global energy mix. As the cleanest-burning fossil fuel, natural gas provides a lower-carbon alternative to coal and oil. Consequently, implementing policies that encourage a transition from coal and oil to gas presents a major opportunity for immediate emission reductions.

Figure 106: Energy-related CO_2 emissions in 2025



Source: GECF Secretariat based on data from Global Carbon Budget 2025 report

Figure 107: Energy-related methane emissions in 2025



Source: GECF Secretariat estimations based on the IEA Global Methane Tracker 2025

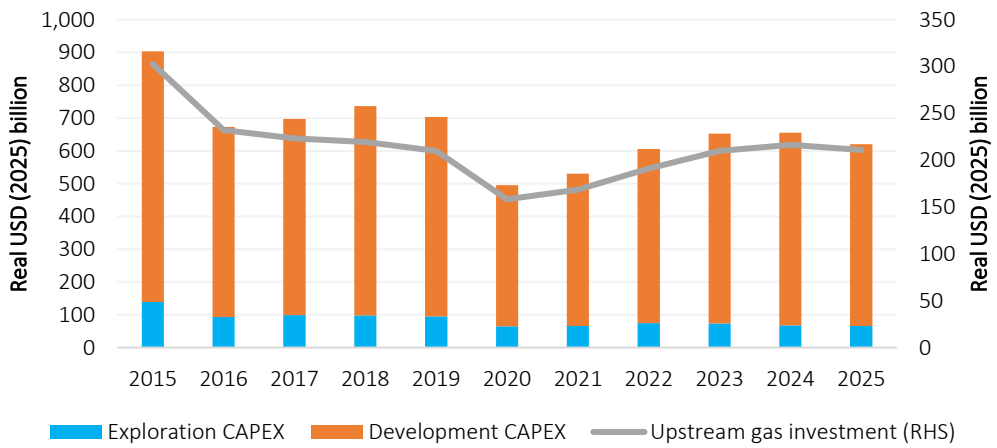
3.3.5 Upstream Investment in the Oil and Gas Industry

Upstream oil and gas investment in 2025 was estimated at $620 billion in real terms, representing a 5.4% y-o-y decline (Figure 108). This contraction was driven by shifting energy policies, economic headwinds, heightened operational costs due to inflationary pressures and escalating geopolitical tensions. Despite these hurdles, investment levels remained the third highest since the COVID-19 pandemic, bolstered by easing monetary policies and favourable energy prices. In nominal terms, spending remained relatively stable, highlighting how inflation has eroded real purchasing power within the sector. Of the total expenditure, 89% was allocated to development CAPEX, specifically for production facilities, processing plants and well completion, while exploration CAPEX accounted for 9%, totalling $66 billion. Notably, upstream gas investment proved resilient, holding steady at $211 billion.

North America led global upstream oil and gas investment, accounting for 36% of total spending at $223 billion. This leading position was driven by rising shale production activity and boosted by favourable market dynamics. The Middle East followed with 19% of global investment at $118 billion and recording the highest annual growth rate among all regions. This surge in spending was predominantly driven by national oil companies' expansion strategies and several massive development projects. Asia Pacific ranked third, securing 16% of total investment at $100 billion. Meanwhile, other regions including Africa, Europe, Eurasia and South America each accounted for less than 10% of the global upstream total.

Global gas investment is expected to rebound in 2026, catalysed by a major wave of new LNG projects across the Middle East and North America. This resurgence will be supported by easing monetary policies, which reduce capital costs, and favourable natural gas prices that strengthen project economics. As national oil companies and international majors reach final investment decisions on deferred ventures, expanding liquefaction capacity will become the primary engine for upstream and midstream growth, ensuring long-term global supply security.

Figure 108: Upstream oil and gas investment



Source: GECF Secretariat based on data from Rystad Energy

NATURAL GAS

CHAPTER

04

4 GAS TRADE

Global gas trade rose by an estimated 3% to reach circa 1.2 tcm in 2025, driven by a surge in LNG that effectively offset a marginal decline in pipeline natural gas (PNG) deliveries (Table 3). The rebound brought global trade volumes remarkably close to the record highs of 2021. Furthermore, the global import-to-consumption ratio rose to 28.5%, reaching its highest level in three years; this serves as a clear indicator of easing market conditions and greater fuel availability worldwide.

Table 3: Global gas trade

Year	2019	2020	2021	2022	2023	2024	2025
PNG imports (bcm)	685	643	695	622	571	608	605
LNG imports (bcm)	481	487	514	541	553	557	594
Total gas imports (bcm)	1,166	1,130	1,209	1,164	1,124	1,166	1,198
Gas consumption (bcm)	3,957	3,857	4,047	4,062	4,055	4,157	4,207
Import-to-consumption ratio	29.5%	29.3%	29.9%	28.6%	27.7%	28.0%	28.5%

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

Import dynamics showed a notable split between the major regions. Europe saw its total gas imports climb by 6% to 382 bcm, as LNG shipments successfully compensated for a reduction in pipeline gas (Figure 109). Meanwhile, despite a marginal 1% decline in total imports to 463 bcm, Asia retained its position as the world's leading gas-importing region (Figure 110).

Figure 109: Gas imports in Europe

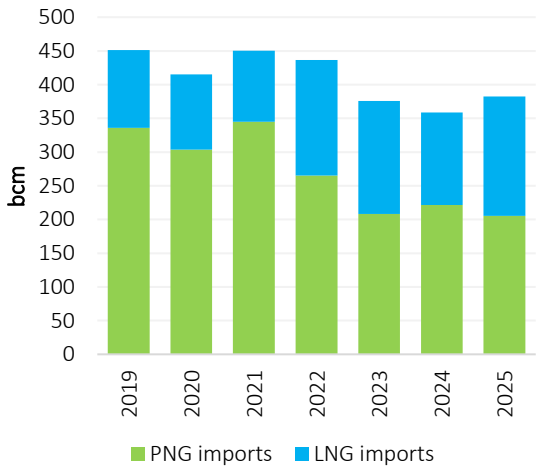
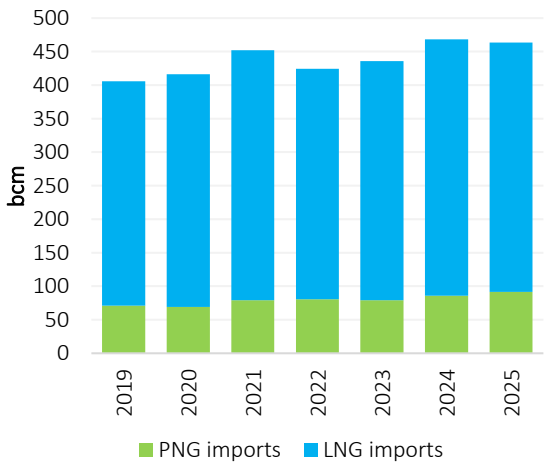


Figure 110: Gas imports in Asia



Source: GECF Secretariat based on data from GACC, ICIS, JODI and LSEG

In China, total gas imports declined by 9 bcm to 174 bcm as rising PNG imports failed to compensate for a significant decrease in LNG shipments. This decline was driven by record domestic production growth that outpaced the rise in consumption, reducing the immediate need for external supply. Despite this dip, the volume remained the second-largest in the country's history, surpassed only by the peak levels seen in 2024 (Figure 111). In the EU, total gas imports increased by 18 bcm to 289 bcm to meet growing consumption, highlighting a continued reliance on external suppliers. 2025 marked a historic pivot as LNG displaced PNG as the region's leading import source for the first time (Figure 112).

Figure 111: Gas balance of China

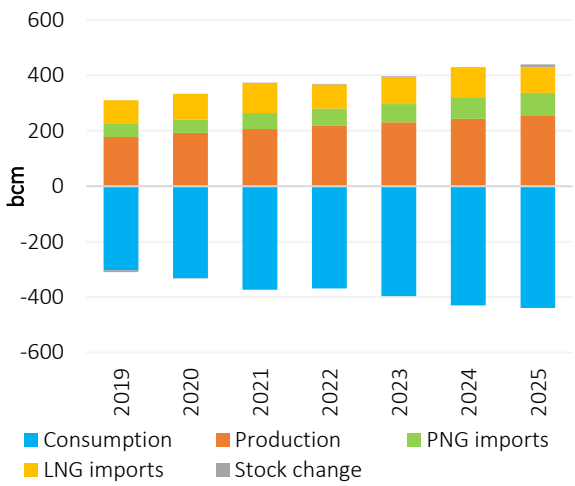
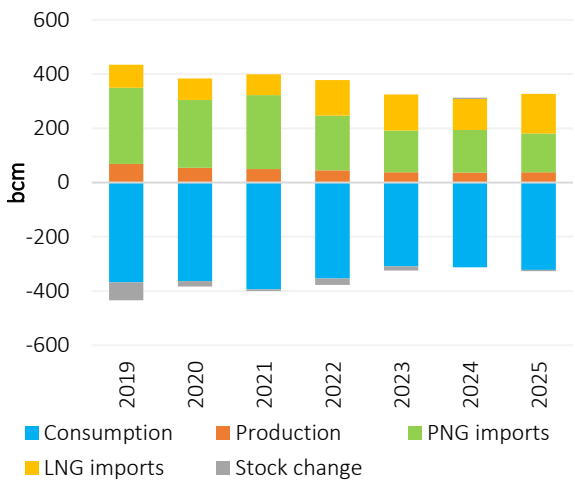


Figure 112: Gas balance of the EU



Source: GECF Secretariat based on data from Cedigaz, GACC, ICIS, LSEG and Rystad Energy

Export dynamics showed that the GECF and the US maintained their positions as the two largest gas exporters worldwide. GECF Member Countries' PNG exports declined marginally to 225 bcm, while their LNG exports slightly increased to 265 bcm, with total gas exports reaching 490 bcm (Figure 113). In the meantime, the US saw record growth across gas production, consumption and exports. Notably, LNG exports surged to 153 bcm, supported by growing shale output and the commissioning of new liquefaction capacity (Figure 114).

Figure 113: GECF countries' aggregated gas balance

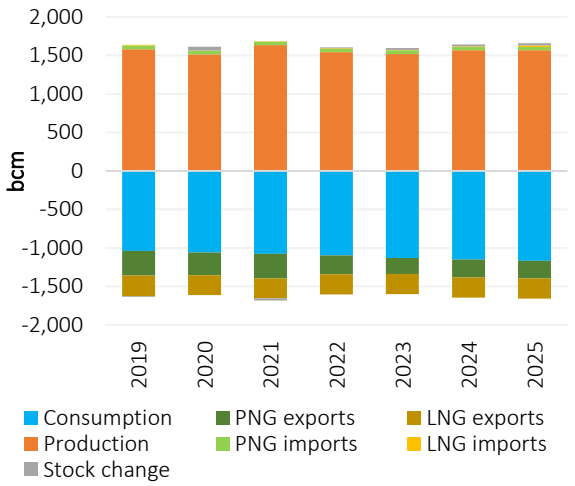
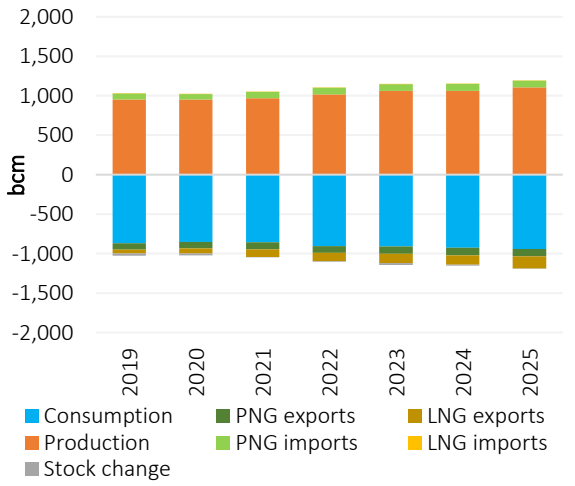


Figure 114: Gas balance of the US



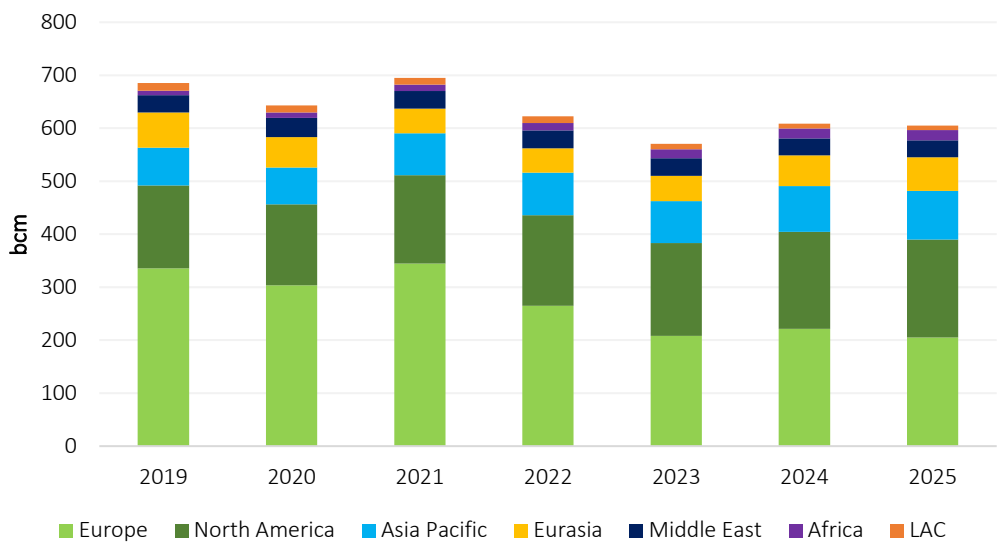
Source: GECF Secretariat based on data from Cedigaz, EIA, GECF ASB 2025, ICIS, JODI, LSEG and Rystad Energy

4.1 Pipeline Gas Trade

Global pipeline gas trade contracted by 1% to total an estimated 605 bcm in 2025 (Figure 115). This figure reflects direct export volumes to final destinations and excludes flows of regasified LNG as well as transit pipeline gas flows.

On the import side, Europe maintained its position as the leading PNG consuming region with a 34% market share, despite an overall 17 bcm decline in its import flows. North American countries followed closely, accounting for 31% of global imports; in this market, a significant rise in US-to-Mexico volumes successfully compensated for the reduced flows observed from Canada to the US. In contrast, Asian PNG imports grew by 6 bcm to reach a 15% global share, a surge primarily fuelled by increased supply from Russia to China as the Power of Siberia pipeline reached its full design capacity. This geographical shift reflects a broader global trend where traditional Western pipeline dominance is gradually being balanced by the rapid expansion of cross-border energy infrastructure in the East.

Figure 115: Global pipeline gas imports by region



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

On the export side, Eurasia continued to lead the market, accounting for 33% of total pipeline gas flows, followed by intra-North American trade at 31% and European exports at 17%. North America distinguished itself as the only region to register year-on-year export growth, while volumes from other major regions remained largely stable.

Looking ahead to 2026, global pipeline gas trade may experience a moderate increase, driven by a reorientation of some gas importing countries towards pipeline gas imports, where possible, to compensate for lost LNG volumes or to avoid buying high-priced spot LNG cargoes amidst the escalating conflict in the Middle East. At the same time, the growth may be supported by Russia's continued pivot to China via the Power of Siberia, alongside Argentina's significant ramp-up in exports to Brazil through newly commissioned infrastructure.

4.1.1 Europe

Europe remains the world's leading gas importing hub, accounting for over a third of global pipeline trade. This market is anchored by the EU, the UK and Türkiye, with the region's supply architecture primarily supported by five external partners: Algeria, Azerbaijan, Libya, Norway and Russia. To mitigate market volatility and ensure supply-chain resilience, the European mainland and the UK are linked by dual bidirectional interconnectors. These pipelines allow for the strategic redirection of regasified LNG between regions, providing the operational flexibility necessary to balance supply and demand across the continent.

The EU's pipeline gas landscape was characterized by a structural contraction, with total cumulative pipeline imports falling by 10% (15 bcm) to 142 bcm in 2025 (Figure 116). This downturn was primarily catalysed by the expiration of major long-term transit agreements in January, which altered traditional supply routes into Eastern and Central Europe. While the market had achieved a relative equilibrium in 2024, the start of 2025 introduced new volatility; January imports immediately dropped 13% m-o-m as historical Russia-originated transit corridors closed. At the same time, colder temperatures in the UK necessitated the diversion of Norwegian supplies away from the EU mainland to prioritize British domestic demand. Throughout 2025, these combined factors kept monthly PNG imports in a persistent year-on-year deficit, highlighting a permanent shift in the region's supply-chain architecture.

Figure 116: EU pipeline gas imports by supplier

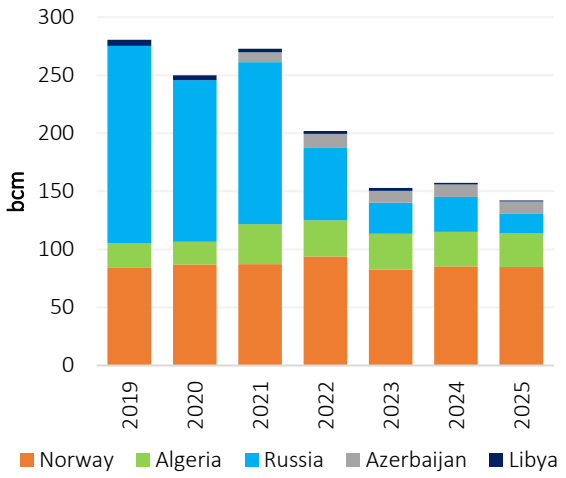
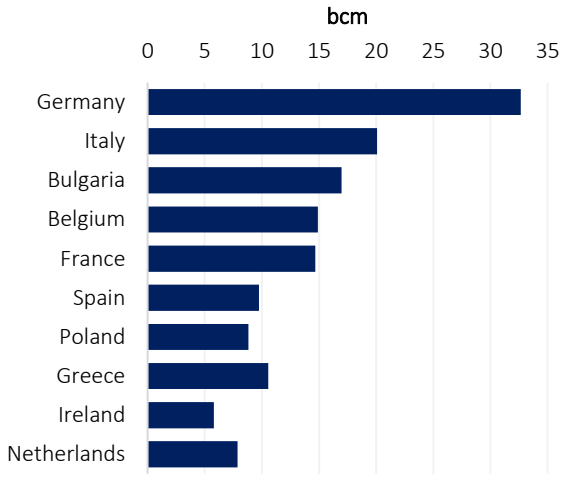


Figure 117: EU PNG imports by entry country



Source: GECF Secretariat based on data from LSEG

Germany ranked as the EU's largest entry point for pipeline gas, accounting for 23% of total inflows, equivalent to 33 bcm (Figure 117). This leading position was anchored by the high utilization of the Norwegian-German corridor, which delivered stable volumes through the Europipe I and II, Norpipe and Zeepipe systems. Throughout the year, Germany functioned as an important transit hub for Central Europe, redistributing these North Sea volumes to neighbouring markets to compensate for shifting supply dynamics elsewhere. Following Germany, Italy solidified its role as the second-largest gateway, contributing 14% of total pipeline inflows. This was primarily supported by high utilization of the Trans-Mediterranean Pipeline from Algeria and consistent volumes via the Trans Adriatic Pipeline (TAP) from Azerbaijan.

Norway solidified its role as the EU's primary energy partner, accounting for circa 60% of the bloc's total pipeline gas supply in 2025. Despite this dominant market share, Norwegian deliveries were characterized by planned maintenance and unplanned technical constraints that tested the region's supply elasticity. During the early months of the year, substantial volumes were frequently redirected toward the UK and Ireland to satisfy surging residential heating demand, a shift that necessitated careful coordination across the North Sea transit network. Furthermore, the summer and autumn periods were defined by extensive scheduled maintenance cycles across major offshore platforms and processing terminals, such as the Kollsnes and Nyhamna facilities. These essential infrastructure upgrades, while necessary for long-term reliability, caused temporary but sharp dips in daily exports, forcing European grid operators to rely more heavily on storage withdrawals. This operational volatility highlighted the critical importance of Norway's transparency and coordination in maintaining continental energy security during a period of broader structural shifts in the global gas market.

Algeria served as a vital stabilizer within the Mediterranean energy landscape, distinguishing itself during the first half of the year as the only major supplier to record consistent year-on-year growth. This reliable performance effectively buffered the region against broader supply-chain volatility, particularly during periods when northern supply routes faced technical constraints. Over the full duration of the year, Algeria maintained steady export growth to Spain while sustaining high-utilization volumes to Italy via the Trans-Mediterranean pipeline.

Russia maintained its position as a top-three PNG supplier to the EU, providing a consistent baseload to markets across Central and South-eastern Europe. This supply architecture was increasingly defined by the TurkStream pipeline, which saw an 8% increase in supply, serving as the primary corridor for delivering stable volumes into the region. Russia's overall contribution to the European energy mix remained a relevant component of the regional supply balance, particularly for nations with historically integrated infrastructure.

Libya continued to provide a localized baseload to the Italian market via the GreenStream pipeline, ensuring a stable contribution to the North African-European supply corridor.

Azerbaijan reinforced its role as a key diversification partner for South-eastern Europe, maintaining consistent flows through the Trans-Adriatic Pipeline (TAP).

The 2026 outlook for Europe's pipeline gas imports focuses on bolstering supply stability within a structurally transformed market. Import volumes are projected to recover modestly, supported by record flows through the TurkStream pipeline and the phased expansion of the Trans Adriatic Pipeline (TAP). This growth is primarily necessitated by the requirement to refill Europe's underground storage to mandatory regulatory levels. Concurrently, Europe is expected to prioritize pipeline gas deliveries as a strategic hedge against volatile spot LNG prices, particularly as the escalating conflict in the Middle East intensify competition with the Asia-Pacific region for available spot LNG cargoes.

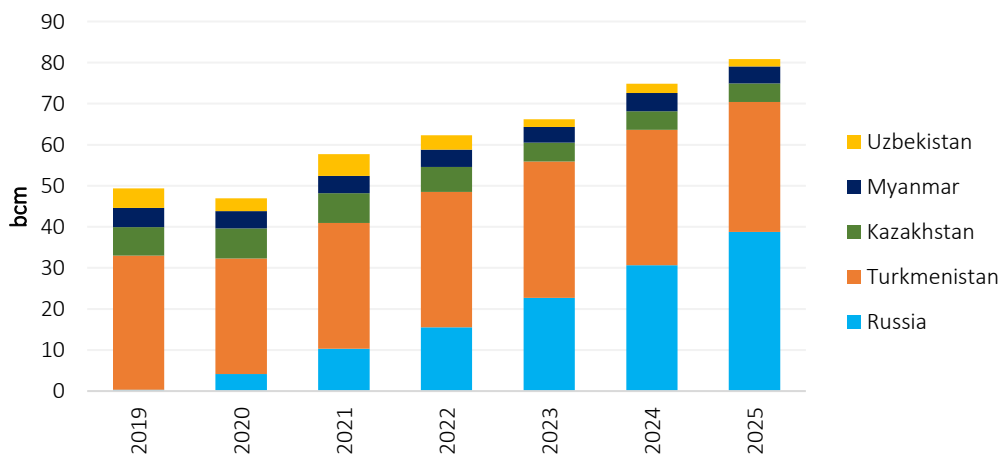
4.1.2 Asia

China has solidified its status as a central pillar of the Asian gas market, which now accounts for 15% of global PNG imports, by leveraging the full maturation of its infrastructure to meet rapidly growing energy needs. Its PNG supply is strategically anchored by a multi-directional network originating from Russia to the north, Myanmar to the south and the Central Asian nations of Kazakhstan, Turkmenistan and Uzbekistan to the west. In 2025, this market underwent a landmark expansion characterized by record-breaking volumes, specifically as the Power of Siberia pipeline reached its full 38 bcm annual capacity, signalling a fundamental shift in the national energy import mix as stable pipeline flows began to displace more volatile LNG imports.

Total PNG imports to China rose by 8% to reach 81 bcm in 2025, sustaining the momentum of the 13% growth recorded the previous year (Figure 118). The defining narrative of the year was the unwavering upward trajectory of supply; by December, China achieved 20 consecutive months of year-on-year increases. The expansion was not merely a matter of volume but of geographical reach. The extension of the northern trunk lines into high-demand urban centres in eastern China allowed pipeline gas to penetrate industrial hubs that were previously reliant on coastal LNG terminals. This structural shift has rewired China's internal logistics, ensuring that midstream infrastructure can now handle record-breaking monthly flows.

2025 was characterized by a series of unprecedented milestones. Monthly import records were shattered repeatedly, eventually peaking at a historic 7.5 bcm in August. Moreover, the year marked a shift in the long-standing competition between PNG and LNG. In February 2025, monthly pipeline imports surpassed LNG volumes for the first time in seven years, driven by a combination of high pipeline throughput and milder winter temperatures that dampened LNG demand. This dominance intensified during the second quarter, with PNG's share of total imports reaching 52% in April and May. This shift highlights China's deliberate pivot toward cost-competitive pipeline volumes as an alternative to higher-priced LNG cargoes. By the end of the year, PNG had successfully claimed a larger stake in the national energy balance, with its share of total gas imports rising from 42% in 2024 to 46% in 2025.

Figure 118: Pipeline gas imports to China by supplier



Source: GECF Secretariat based on data from Cedigaz and GACC

The primary engine for this growth was the successful ramp-up of the Power of Siberia 1 pipeline, which reached full operational capacity in December 2024. Consequently, Russia emerged as China's leading strategic energy partner in 2025 by delivering 39 bcm of gas. This volume represented a 27% y-o-y increase and accounted for nearly half of the country's total PNG supply. The long-term trajectory points toward a massive scale-up to establish a 106 bcma supply corridor, bolstered by the pivotal September 2025 signing of a binding memorandum for the Power of Siberia 2 project, which will deliver 50 bcma from Russia's Arctic fields via Mongolia. This expansion is further supported by agreements to boost the original Power of Siberia 1 capacity from 38 to 44 bcma, alongside the Far East Route, which is scheduled to commence in 2027 and scale to 12 bcma.

In contrast, the Central Asian corridor, historically China's largest supply source, experienced a year of transition as regional exporters prioritized domestic energy security. While Central Asia still accounted for 47% of China's total PNG imports, with Turkmenistan alone supplying 32 bcm or 39% of the national total, contributions from Kazakhstan and Uzbekistan dwindled to 6% and 2% respectively. This decline was driven by a strategic reorientation within these nations to meet surging internal demand, particularly during peak winter heating months. Consequently, the Central Asian PNG outlook is defined by a push for incremental growth against a backdrop of infrastructure delays and rising domestic needs. Turkmenistan's exports remain capped by the 55 bcm capacity of existing lines as the proposed 30 bcma Line D expansion faces ongoing setbacks. Meanwhile, Kazakhstan is attempting to maximize its contribution, signing a February 2025 agreement to increase flows beyond its initial 5 bcma target despite the persistent challenge of balancing export commitments with high internal consumption.

Singapore's PNG imports from Indonesia and Malaysia experienced a recovery in 2025, reaching 6.6 bcm, a robust 7% increase (Figure 119). In contrast, Thailand saw a continued decline in its PNG imports from Myanmar, which fell by 14% to 4.4 bcm (Figure 120). This divergence highlights Singapore's effective management of its legacy PNG contracts, whereas Thailand is forced to increasingly rely on the LNG market to offset the substantial drop in its PNG inflows.

Figure 119: Pipeline gas imports to Singapore

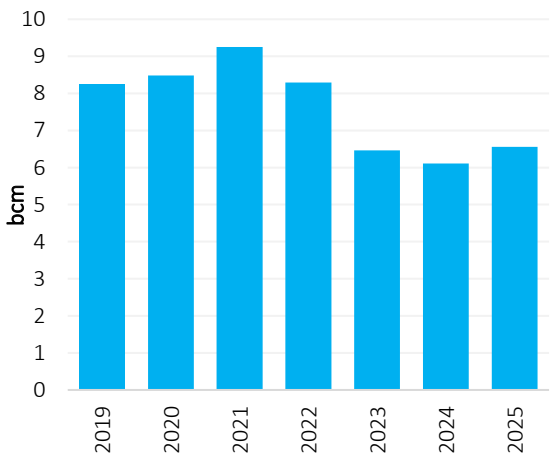
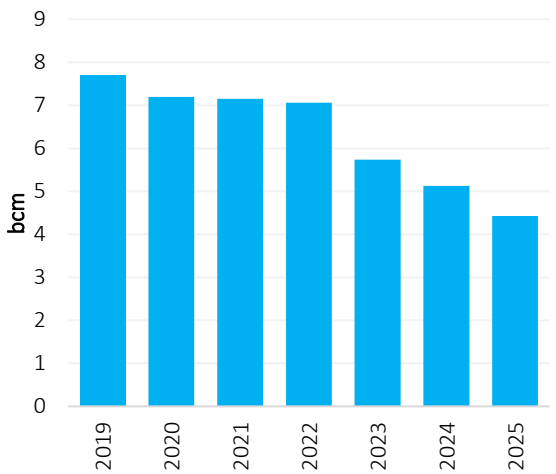


Figure 120: Pipeline gas imports to Thailand



Source: GECF Secretariat based on data from JODI Gas

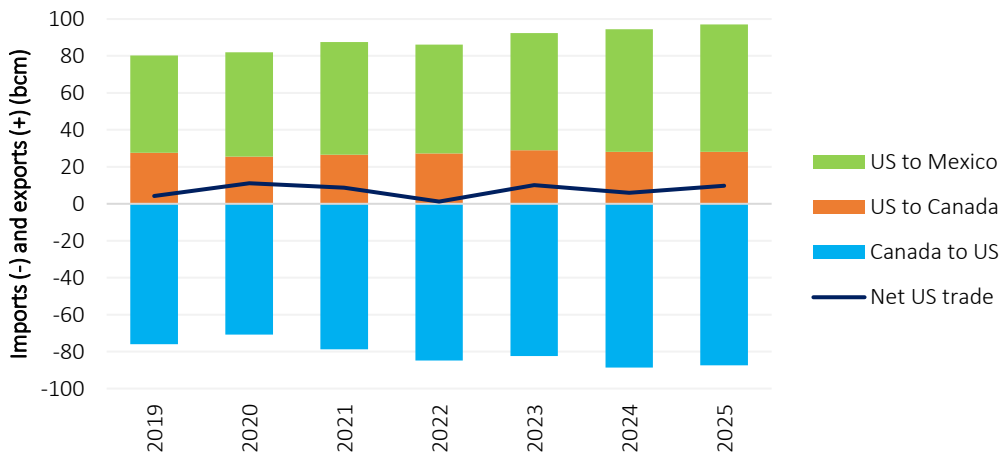
4.1.3 North America

North America functions as a closed-circuit pipeline gas market characterized by robust cross-border trade between the US, Canada and Mexico. Driven by rising regional flows, the US has firmly established itself as a consistent net exporter, although it continues to import supply from Canada to fuel states across its Midwest and Northwest regions. Developments in PNG trade in 2025 were defined by record-breaking export volumes from the US to Mexico and a resilient, though seasonally volatile, interconnection between the US and Canada (Figure 121).

US PNG exports to Mexico reached a historic 69 bcm for the year, a 4% increase fuelled by Mexico's expanding electric power sector and its increasing reliance on low-cost Permian Basin supply. This growth was underpinned by the continued build-out of Mexico's internal pipeline network, which improved the distribution of Waha Hub gas to industrial hubs in central and western Mexico. US exports now account for over 70% of Mexico's total gas consumption, serving as the primary engine for its industrial and electrical infrastructure.

The US-Canada gas trade corridor remained critical for regional energy security in 2025, particularly during peak winter months when cross-border synchronization is most vital. Net flows from Canada to the US totalled 59 bcm, representing a slight 2% decrease from 2024 despite hitting record-breaking levels in January 2025 to satisfy surging heating demand across the Northwestern United States. This trade relationship navigated a complex backdrop of geopolitical friction, including persistent tariff war threats and declining hub prices, yet the necessity for Canadian supply endured as production in Western Canada continued to rise.

Figure 121: Net pipeline gas trade in the US



Source: GECF Secretariat based on data from US EIA

The 2026 outlook centres on a structural shift as regional flows are increasingly diverted to support global LNG exports. Mexico's imports from the US are expected to be driven by the ramp-up of its LNG exporting terminals on the Pacific coast. At the same time, net exports from Canada to the US may decline as LNG Canada begins to prioritise Western Canadian volumes for direct shipment to Asian markets, reconfiguring the continent's internal trade dynamics.

4.1.4 Latin America and the Caribbean

Latin America and the Caribbean (LAC) remained the world's smallest arena for PNG trade, accounting for 1% of global imports in 2025. This relatively self-contained market is anchored by two primary export routes: the long-standing corridor from Bolivia to Brazil and the expanding interconnection between Argentina and Chile. Despite the region's latent potential, total internal trade volumes contracted by 10% to 8 bcm in 2025. This downturn was defined by a major structural shift as Bolivia's historical role as a multi-country exporter diminished, while Argentina concurrently moved to expand its influence across South America.

Total Bolivian exports fell by 21% to 5 bcm, a decline driven almost entirely by the expiration of its foundational supply contract with Argentina in late 2024 (Figure 122). While flows from Bolivia to Brazil remained stable, the loss of the Argentine market, which plummeted from 1.2 bcm in 2024 to a negligible interruptible supply of just 0.1 bcm in 2025, has reduced Bolivia's export profile to a single-buyer model focused almost exclusively on Brazil.

In contrast, Argentina solidified its status as a rising regional supplier by leveraging record-breaking domestic production from the Vaca Muerta Basin to fill the void left by declining Bolivian exports. Exports from Argentina to Chile surged by 23% to 3.1 bcm in 2025 (Figure 123), providing consistent baseload supply that has allowed Chilean power generators to significantly reduce their reliance on expensive, seaborne LNG. Following the completion of the Gasoducto Norte reversal and other key midstream improvements, Argentina officially initiated gas exports to Brazil in April 2025. This strategic shift utilizes existing Bolivian infrastructure as a high-capacity transit corridor, with initial shipments facilitated by a tripartite agreement designed to maximize existing regional pipeline connectivity. This milestone transition is further supported by a robust suite of new commercial frameworks, including a bilateral Memorandum of Understanding targeting long-term volume growth, alongside firm supply deals with Uruguay that ensure regional energy security. In this context, Argentina is poised to increase its pipeline gas exports and drive South American energy integration.

Figure 122: Pipeline gas exports from Bolivia

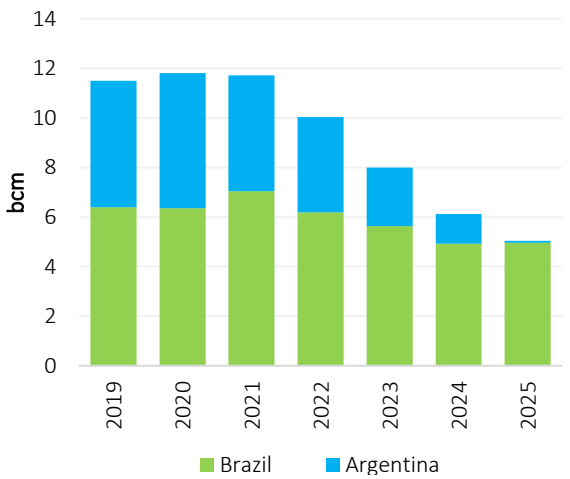
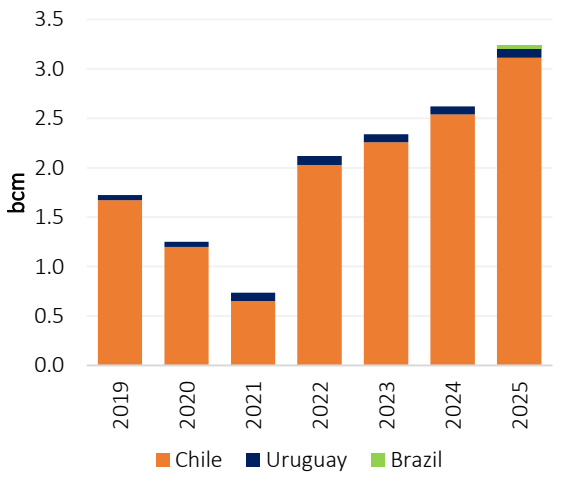


Figure 123: Pipeline gas exports from Argentina



Source: GECF Secretariat based on data from JODI Gas

4.2 Liquefied Natural Gas (LNG) Trade

4.2.1 LNG Supply

4.2.1.1 Global LNG Exports

In this report, LNG exports refer to the volumes delivered to importing countries, excluding deliveries via ISO containers, trucks and rail. The export volumes also do not represent the exact volumes loaded at LNG export facilities as the reported delivered LNG volumes exclude boil-off gas and losses incurred during loading, shipping and offloading. Global LNG exports encompass both exports from LNG-producing countries and LNG re-exports.

Global LNG exports surged by 6.7% y-o-y (28 Mt) to a record high of 438 Mt in 2025 (Figure 124), marking the largest annual addition since 2019 and signalling the onset of the next wave of LNG supply through 2030. Growth was driven primarily by the start-up and ramp-up of new liquefaction projects, debottlenecking at existing facilities, improved feedgas availability and lower maintenance activity in some producing countries.

Non-GECF countries accounted for most of the incremental growth, while GECF Member Countries contributed to a lesser extent and LNG re-exports declined slightly. As a result, non-GECF exporters strengthened their lead with a 54% share of global exports, compared with 45% for GECF Member Countries and 1% from LNG re-exports.

The US solidified its dominance as the world's premier LNG exporter in 2025, reaching a historic 113 Mt and becoming the inaugural nation to surpass the 100 Mt annual threshold (Figure 125). This record-breaking performance placed the US firmly ahead of other major producers, including Qatar (83 Mt), Australia (76 Mt), Russia (31 Mt) and Malaysia (27 Mt). The global exporter landscape also experienced a notable diversification as Canada, Mauritania and Senegal officially entered the global market with their first shipments.

Figure 124: Trend in global LNG exports by supplier

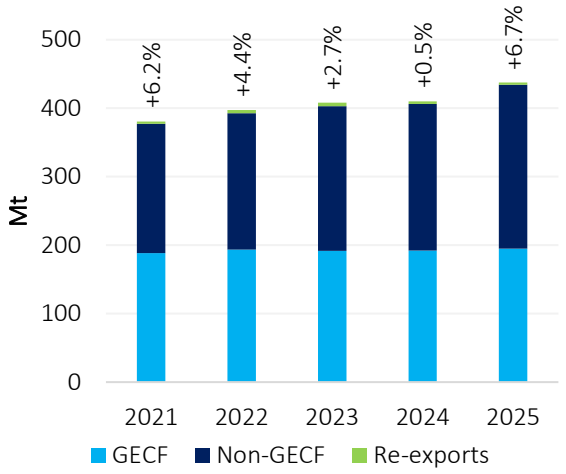
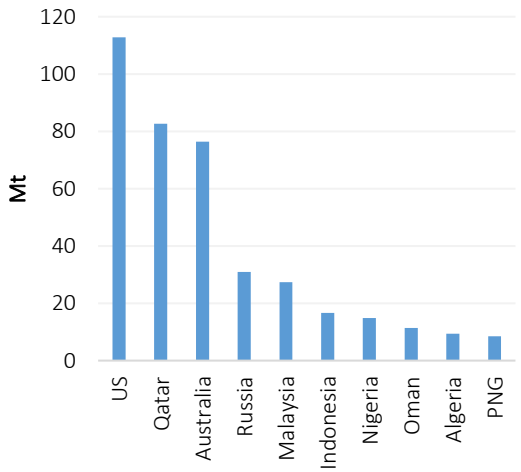


Figure 125: Top 10 LNG exporting countries in 2025



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.1.1 GECF LNG Exports

LNG exports from GECF Member Countries reached a multi-year high of 195 Mt in 2025, representing a 1.5% increase that signalled a notable acceleration in growth compared to the previous year. This upward trajectory was primarily driven by the strategic commissioning of new liquefaction capacity and significantly improved feedgas availability across key producing nations, including Angola, Nigeria and Trinidad and Tobago (Figure 126). In Qatar, volumes were further bolstered by an optimized maintenance schedule at the massive Ras Laffan LNG complex, which allowed for higher facility utilization rates throughout the year.

Notably, Mauritania and Senegal officially joined the global club of LNG exporters in April 2025 with the inaugural shipment from the Greater Tortue Ahmeyim (GTA) project. This innovative offshore development, situated on the maritime border between the two nations, utilizes a floating liquefied natural gas (FLNG) vessel with a nameplate capacity of 2.7 Mtpa. The first LNG cargo was successfully loaded onto the British Sponsor LNG carrier and departed the hub terminal on 15 April 2025, marking a milestone in regional energy development.

In terms of LNG exports by market, Asia remained the dominant destination for GECF volumes in 2025, absorbing 68% of total exports, followed by Europe at 25% (Figure 127). Smaller shares were delivered to the Middle East and Africa (MEA) at 4%, Latin America and the Caribbean (LAC) at 2% and North America at less than 1%. This regional distribution remained broadly unchanged from 2024, reflecting the deeply entrenched long-term contractual ties that bind GECF producers to the Asia Pacific region. At the same time, the high European share was sustained by consistent GECF deliveries aimed at compensating for lower piped gas inflows and meeting aggressive storage injection targets across the continent.

Figure 126: GECF's LNG exports by country (2024 & 2025)

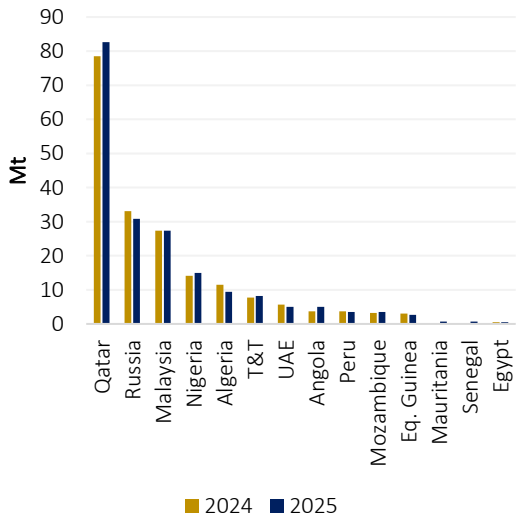
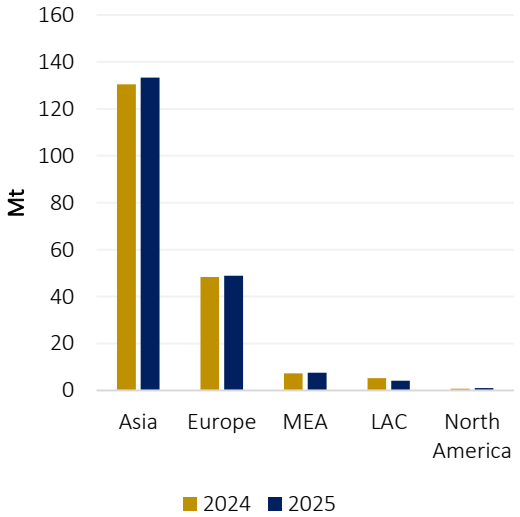


Figure 127: GECF's LNG exports to regional markets (2024 & 2025)



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.1.2 Non-GECF LNG Exports

LNG exports from non-GECF countries continued to set new records in 2025, surging by 12% to reach 240 Mt. This represents a massive 25 Mt annual increase, the largest single-year rise in the history of the industry. This extraordinary growth was primarily fuelled by the aggressive start-up and rapid ramp-up of new liquefaction capacity, alongside successful debottlenecking projects at existing facilities and a strategic reduction in scheduled maintenance activity.

The US was the main driver of global LNG export growth, accounting for most of the non-GECF increase as exports rose by 25 Mt (Figure 128). This was underpinned by ramp-ups at Corpus Christi LNG Stage 3 and Plaquemines LNG Phases 1–2, alongside more stable operations at Freeport LNG following reduced maintenance and debottlenecking. Europe emerged as the largest destination for US LNG, the share of total US LNG exported to Europe rising from 54% in 2024 to 68% in 2025, while the share of US LNG in Europe's total imports increased from 46% to 57%. This LNG trade underscores the growing mutual dependence between the US and Europe. In contrast, the share of total US LNG to Asia fell sharply from 32% to 16%.

Conversely, these gains were partly offset by a decline in Australian LNG exports, driven by reduced feedgas availability, most notably at the ageing North West Shelf (NWS) facility. Asia remained the dominant destination for Australia's LNG, reflecting geographic proximity to key importing markets and the prevalence of long-term contractual arrangements in the region. Beyond the traditional powerhouses, additional gains were recorded in Canada and Mexico, following the landmark start-up of LNG Canada Trains 1 and 2 and increased output from Mexico's Altamira FLNG 1, marking the emergence of a new North American export corridor.

Non-GECF LNG exports increasingly rebalanced from Asia towards Europe. Although Asia Pacific remained the largest market, its share of non-GECF LNG exports declined from 70% in 2024 to 58% in 2025 (Figure 129). Conversely, Europe's share rose from 24% to 34%, reflecting weaker LNG deliveries to Asia and a strong increase in US LNG exports to Europe.

Figure 128: Non-GECF's LNG exports by country (2024 & 2025)

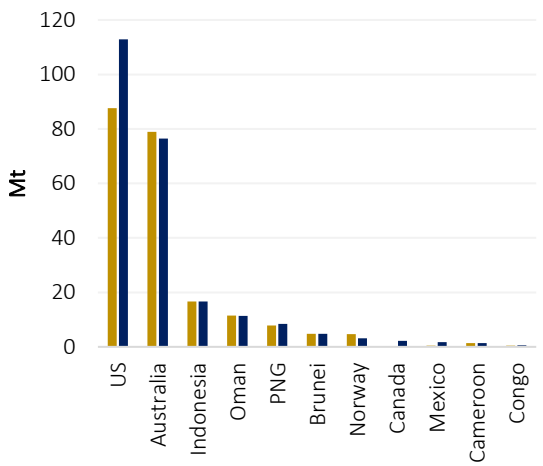
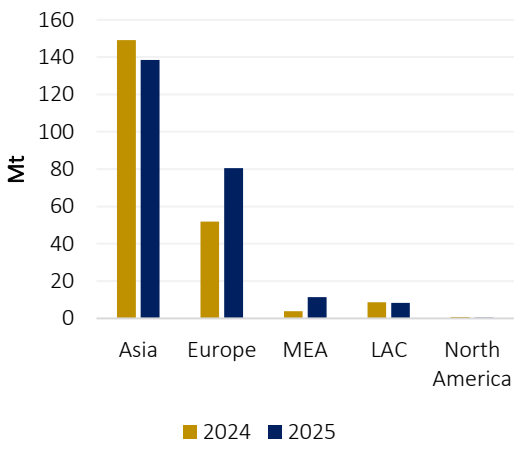


Figure 129: Non-GECF's LNG exports to regional markets (2024 & 2025)



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.1.3 LNG Re-Exports

Global LNG re-exports contracted by 15% to 3.1 Mt in 2025, marking the lowest activity level for this niche trade segment since 2020 (Figure 130). This decline was characterized by a sharp reduction in volumes from traditional transit hubs like Spain and the US Virgin Islands, which outweighed modest gains in China and Singapore.

China emerged as the world's largest LNG re-exporter in 2025 with 0.9 Mt, effectively leveraging its expansive terminal infrastructure to rebalance an oversupplied domestic market and optimise its long-term contractual portfolio. This surge in re-export activity served as a critical strategic response to tepid domestic demand, which compelled state-owned enterprises to divert surplus cargoes toward higher-priced regional markets in Japan and South Korea. By transforming from a pure consumer into a flexible regional swing market, China has successfully mitigated the financial burden of "take-or-pay" contracts while simultaneously enhancing its influence over Asian spot market liquidity. This operational pivot highlights a maturing energy strategy where massive storage capacity and diverse supply tranches are utilised not just for energy security, but as arbitrage tools to capture favourable price spreads across the Pacific basin.

The contraction in Spanish re-exports reflected a realignment of Atlantic Basin flows, as surging direct US supply to LAC reduced the need for European intermediaries. Similarly, the US Virgin Islands' regional role diminished as direct LNG routes were established from the US mainland to Puerto Rico. These shifts indicate that small-scale carrier growth is replacing distribution hubs with direct logistics.

Meanwhile, Singapore solidified its status as a regional energy pivot; its increased re-exports to emerging buyers in Southeast Asia, such as Vietnam and the Philippines, more than offset a decline in shipments to China (Figure 131). This highlights the growing intra-regional liquidity of the Asian gas market, where Singapore acts as a critical balancing agent between established giants and emerging importers.

Figure 130: Global LNG re-exports by country (2024 and 2025)

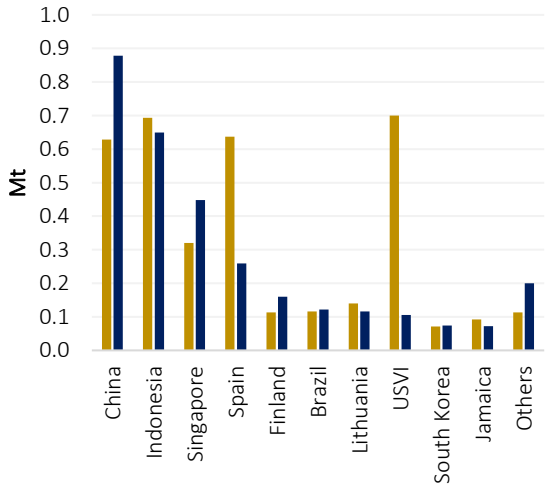
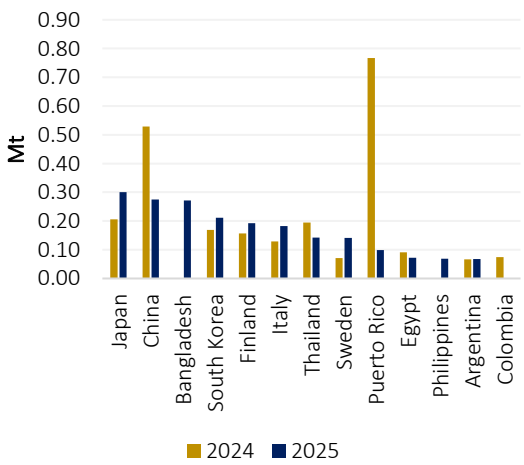


Figure 131: Major markets for re-exported LNG (2024 and 2025)



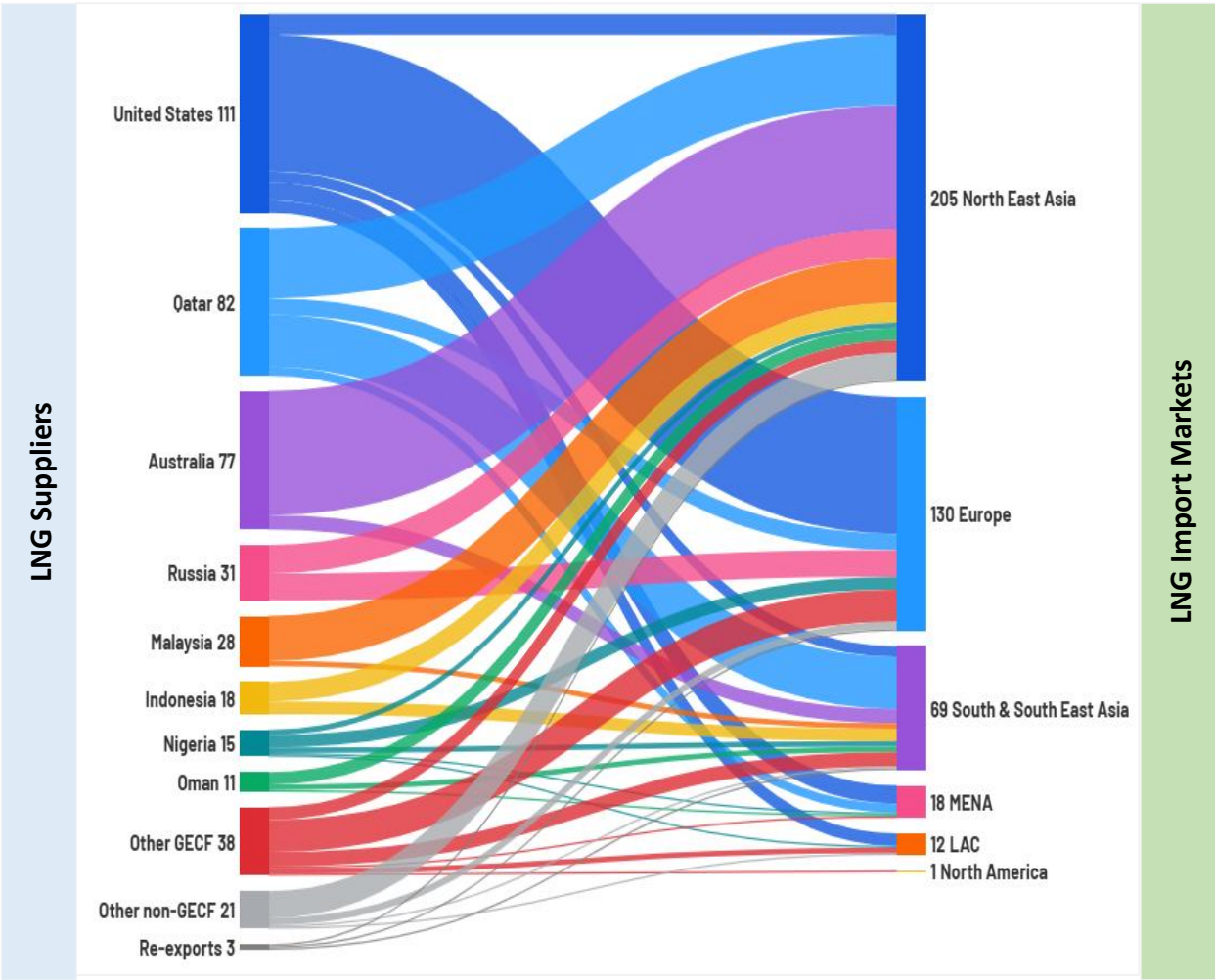
Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.2 Major LNG Trade Routes

In 2025, the US–Europe corridor was the largest LNG trade route at around 76 Mt (Figure 132), driven by Europe's role as the premium spot market for Atlantic Basin cargoes amid lower pipeline gas imports. Australia–North East Asia was the second-largest flow at 69 Mt, reflecting geographic proximity and long-term contracts. Qatar also maintained a strong position in Asia, supplying 39 Mt to North East Asia and 29 Mt to South and South East Asia. In this context, the US remained the dominant supplier to Europe, Australia led in North East Asia, and Qatar was the largest supplier to South and South East Asia.

Overall, LNG trade flows are increasingly influenced by gas demand growth, the geographic proximity of exporters and importers, shipping economics, the continued dominance of long-term contracts, a rising share of destination-flexible cargoes, and Asia-Europe spot price differentials.

Figure 132: Export country to import market LNG trade flows in 2025 (Mt)



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.3 Start-up of New LNG Liquefaction Capacity

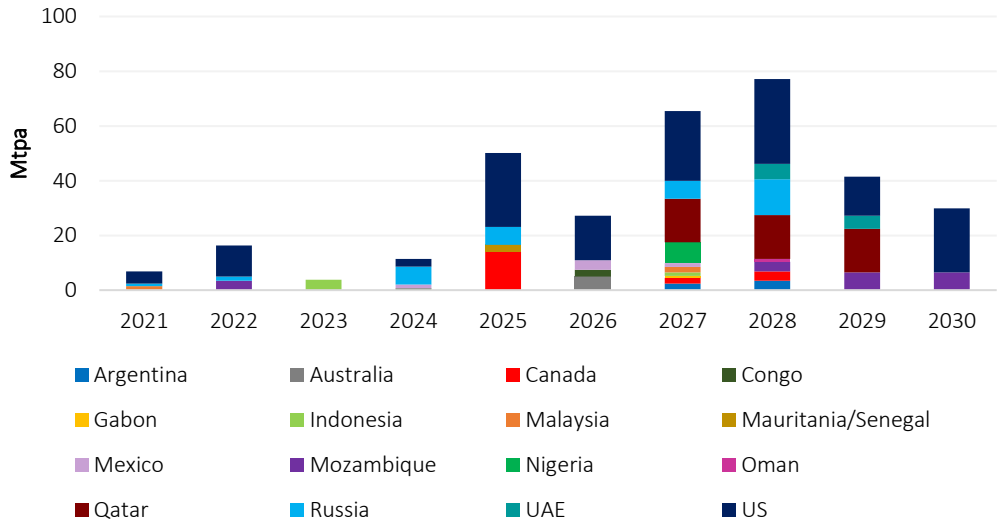
In 2025, global LNG liquefaction capacity additions reached a record 50.1 Mtpa, the largest annual increase and a sharp rise from 11.4 Mtpa in 2024 (Figure 133). The US led this expansion with 27 Mtpa, driven by Plaquemines LNG Phases 1 and 2 and Corpus Christi LNG Stage 3. Additional capacity came from Canada with the start-up of LNG Canada Trains 1 and 2 (14 Mtpa), Russia with Arctic LNG 2 Train 2 (6.6 Mtpa) and Mauritania and Senegal through the commissioning of the Greater Tortue Ahmeyim (GTA) FLNG project (2.5 Mtpa). As a result, global liquefaction capacity increased to 548 Mtpa by end-2025, while average utilisation declined slightly to around 80%, reflecting the ramp-up of new facilities and below-nameplate operations at some existing plants.

Between 2026 and 2030, 241 Mtpa of new liquefaction capacity is expected to start operation.

In particular, the capacity addition will likely reach 27 Mtpa in 2026. The Congo FLNG 2 facility started operations in January 2026, while several projects are scheduled to come online later in the year, including Pluto LNG Train 2 in Australia, Energia Costa Azul Phase 1 in Mexico and multiple new trains in the US at Golden Pass and Corpus Christi stage 3.

In addition, around 214 Mtpa of additional liquefaction capacity is expected to be commissioned globally between 2027 and 2030, led by the US and Qatar and supported by new projects in Argentina, Gabon, Canada, Indonesia, Malaysia, Mexico, Nigeria, Russia and the United Arab Emirates, with Argentina and Gabon to join the club of LNG exporters. This rapid expansion raises the risk of LNG market oversupply and downward pressure on spot prices, although lower prices could stimulate demand in price-sensitive markets and help rebalance the global gas market. However, the impact of the escalating conflict in the Middle East on the regional LNG supply is expected to tighten the global market in the short term.

Figure 133: Start-up of new LNG liquefaction capacity from export projects by country



Source: GECF Secretariat based on data from Argus, ICIS LNG Edge, LSEG, Rystad Energy and project updates

4.2.1.4 FIDs on New LNG Export Projects

Around 66 Mtpa of LNG liquefaction capacity reached final investment decision (FID) in 2025, the second-highest annual total after 71 Mtpa in 2019 and a sharp rebound from just 16 Mtpa in 2024. The US accounted for the bulk of FIDs, with seven projects totalling 56 Mtpa (Table 4), followed by two projects in Argentina (6 Mtpa) and one in Mozambique (3.6 Mtpa). This marked a record high for US LNG FIDs and a significant turnaround in US LNG project approvals, after no projects reached FID in 2024 due to the temporary pause on new LNG export authorisations to non-free trade agreement (non-FTA) countries introduced by the Biden administration in January 2024. Following the change in administration in January 2025, the Trump Administration lifted the pause on authorisations and eased regulatory constraints, restoring momentum to US LNG project development.

Table 4: LNG export projects that took FID in 2025

Date of FID	Project	Capacity (Mtpa)	Country
Apr-25	Louisiana LNG Phase 1	16.5	US
May-25	Southern Energy FLNG1	2.45	Argentina
Jun-25	Corpus Christi Midscale Trains 8 & 9	3	US
Jun-25	Corpus Christi & Sabine Pass Debottlenecking	3	US
Jul-25	CP2 LNG Phase 1	14.4	US
Aug-25	Southern Energy FLNG1	3.5	Argentina
Sep-25	Rio Grande LNG Train 4	6	US
Sep-25	Port Arthur LNG Phase 2	13	US
Oct-25	Coral North FLNG	3.6	Mozambique
Oct-25	Rio Grande LNG Train 5	6	US

Source: GECF Secretariat based on data from Argus, ICIS LNG Edge, LSEG and project updates

By the end of March 2026, Qatar's North Field West expansion and Phase 2 of the CP2 LNG facility in the US, with a combined capacity of 25 Mtpa, had reached FID. Looking ahead, around 158 Mtpa of new LNG liquefaction capacity from export projects is targeting FID in the short term, between April 2026 and December 2027. The US accounts for around half of this capacity, at 78 Mtpa. Significant expansions are also planned in Mexico (19 Mtpa), Mozambique (15 Mtpa), Argentina (12 Mtpa), Canada (12 Mtpa), Indonesia (9.5 Mtpa), Papua New Guinea (5.6 Mtpa), Oman (3.8 Mtpa) and Nigeria (2.8 Mtpa).

While there are potential risks of LNG oversupply in the medium term, the post-2030 period could see a tightening of supply as gas demand continues to rise. Given that LNG export projects typically require four to six years of construction following FID, most of the above-mentioned capacity targeting FID is unlikely to come online before 2030. In this context, the planned wave of liquefaction investments supports longer-term market balance, highlighting the importance of sustained investment to underpin gas market stability and ensure security of supply for importing countries.

4.2.1.5 LNG Liquefaction Plant Outages

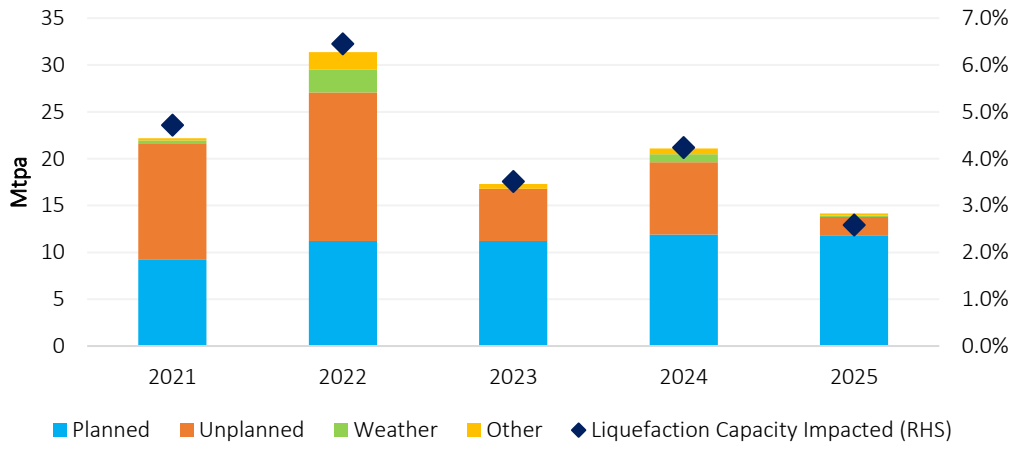
Liquefaction facility utilisation is affected by a range of factors, including planned maintenance, unplanned outages, weather-related disruptions and other unforeseen incidents, all of which can constrain LNG supply. However, the analysis of liquefaction plant outages does not capture feedgas constraints or economic considerations, which may also influence capacity utilisation. The impacted LNG volumes refer to liquefaction capacity that is either temporarily offline or operating at reduced utilisation rates.

The total impact on global liquefaction capacity from planned maintenance, unplanned outages, weather-related disruptions and other unforeseen events amounted to 14.2 Mtpa in 2025, down 33% from 21.1 Mtpa in 2024 (Figure 134). Overall, these factors affected just 2.6% of global liquefaction capacity, compared with 4.2% in 2024. The decline was driven primarily by fewer unplanned outages, while the impact of planned maintenance, weather-related disruptions and other factors also eased compared to the previous year.

The reduction in unplanned outages was largely attributable to improved operations at Bintulu LNG (Malaysia), Freeport LNG (US), Lumut LNG (Brunei), Sabine Pass LNG (US) and Tangguh LNG (Indonesia). In contrast, unplanned outages increased notably at Cameron LNG (US), Gorgon LNG (Australia) and Ichthys LNG (Australia). In addition, weather-related disruptions at Freeport LNG declined following hurricane-related impacts in July 2024.

Planned maintenance activity was significantly lower at Arzew LNG (Algeria), Atlantic LNG (Trinidad and Tobago), Calcasieu Pass LNG (US), Freeport LNG (US), Ras Laffan (Qatar) and Sakhalin 2 LNG (Russia). Conversely, planned maintenance increased at Bintulu LNG (Malaysia), Das Island LNG (United Arab Emirates), Hammerfest LNG (Norway), Ichthys LNG (Australia) and Qalhat LNG (Oman).

Figure 134: Global LNG liquefaction plant outages



Source: GECF Secretariat based on data from Argus, ICIS LNG Edge and LSEG
Note: "Other" refers to activities not associated with the LNG facility, such as pipeline and upstream maintenance and industrial action by workers

4.2.2 LNG Demand

4.2.2.1 Global LNG Imports

Global LNG imports reached a new record of 437 Mt in 2025, rising by 6.5% (27 Mt) (Figure 135). Growth was driven primarily by stronger LNG demand in Europe and the Middle East and Africa (MEA), which more than offset declining imports in Asia Pacific and Latin America and the Caribbean (LAC) (Figure 136). The LNG market remained relatively tight during the year, with TTF prices trading at a sustained premium for several months to draw flexible US LNG cargoes away from Asia Pacific to Europe.

Figure 135: Global LNG imports by region

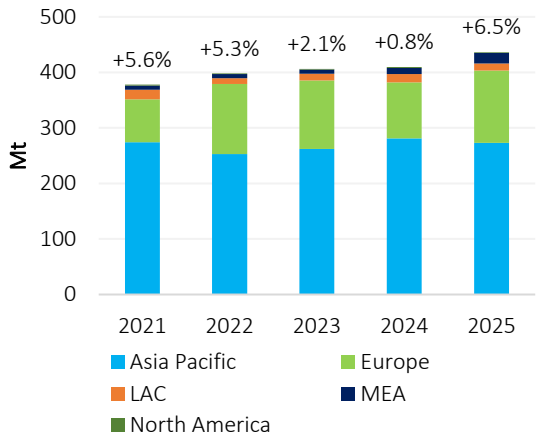
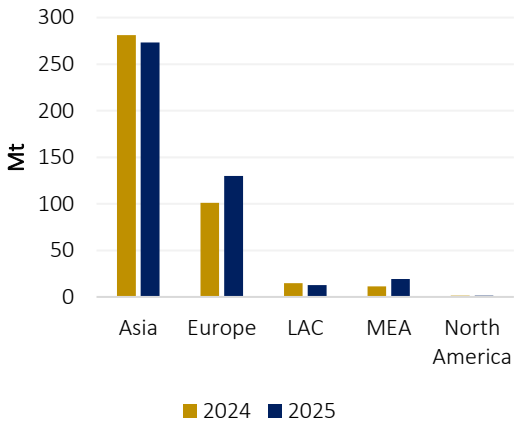


Figure 136: Regional LNG imports (2024 & 2025)



Source: GECF Secretariat based on data from ICIS LNG Edge

Although Asia remained the largest LNG market in 2025, its share of global LNG imports declined from 69% in 2024 to 63% in 2025 (Figure 137). Meanwhile, Europe's share of global LNG imports rose from 25% to 30% during the same period while MEA's share also rose from 2.7% to 4.4%, overtaking LAC. Despite the decline in China's LNG imports, it remained the largest LNG importer globally followed by Japan, South Korea, India and Taiwan (Figure 138).

Figure 137: Share of regional LNG imports in 2025

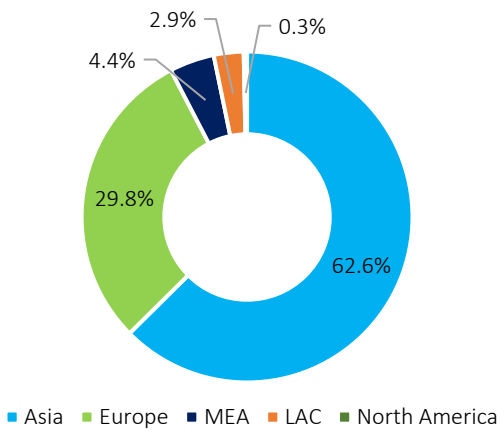
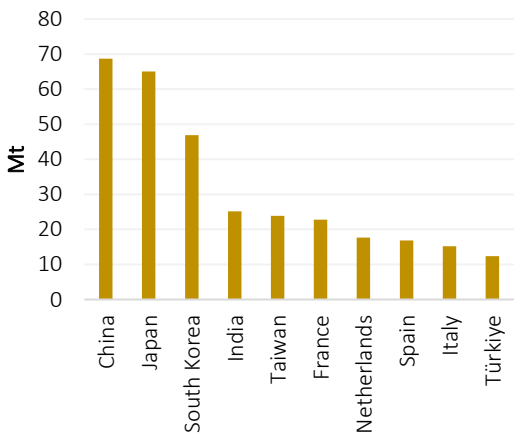


Figure 138: Top 10 LNG importing countries in 2025



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.1.1 Europe

Europe's LNG imports rose by 29% (29 Mt) to a record high of 130 Mt in 2025, surpassing the previous peak of 126 Mt recorded in 2022. The increase was driven by weaker pipeline gas imports, resilient gas demand, and stronger requirements for injections into underground gas storage. France remained the region's largest LNG importer, followed by the Netherlands, Spain, Italy and Türkiye. Import growth was concentrated in Belgium, Italy, France, the Netherlands, Türkiye, Spain, Germany, the UK and Poland (Figure 139).

The EU accounted for the bulk of the increase in LNG imports. The bloc exited the 2024/2025 winter season with lower underground gas storage levels than a year earlier, necessitating higher LNG imports to support storage replenishment. Beyond storage injections, increased LNG imports in Belgium, France, Germany, Italy, the Netherlands and Poland were primarily driven by reduced pipeline gas imports. These countries also served as key entry points for the onward export of regasified LNG to neighbouring markets, to compensate for lower regional pipeline gas availability. In addition, stronger LNG imports in Germany, Italy, Poland and Spain were supported by higher domestic gas consumption, while the ramp-up of recently commissioned LNG import terminals in Germany and Italy further contributed to the increase.

Among non-EU countries, Türkiye's higher LNG imports were mainly underpinned by stronger gas consumption. In the UK, declining domestic gas production, lower pipeline gas imports, and favourable arbitrage conditions for exports of regasified LNG to mainland Europe supported higher LNG import volumes.

The US remained the dominant source among LNG suppliers to Europe, with its exports to the region rising by 62% to 76 Mt in 2025 (Figure 140). This surge solidified the US as the provider of over half of Europe's total LNG imports, primarily driven by the ramp-up of new Gulf Coast facilities. Russia, Qatar, Algeria and Nigeria also ranked among the region's leading suppliers, collectively reinforcing Europe's diversified and resilient energy security strategy.

Figure 139: Europe's LNG imports by country (2024 & 2025)

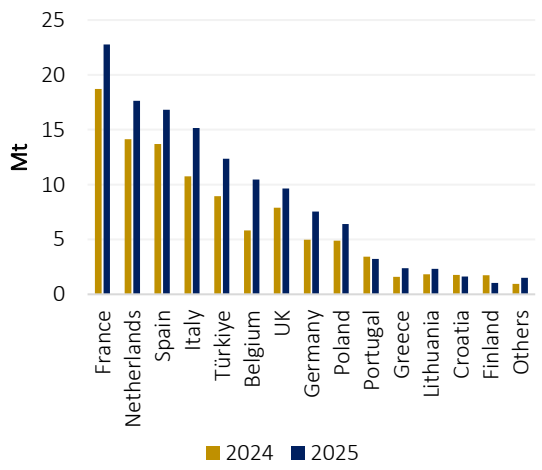
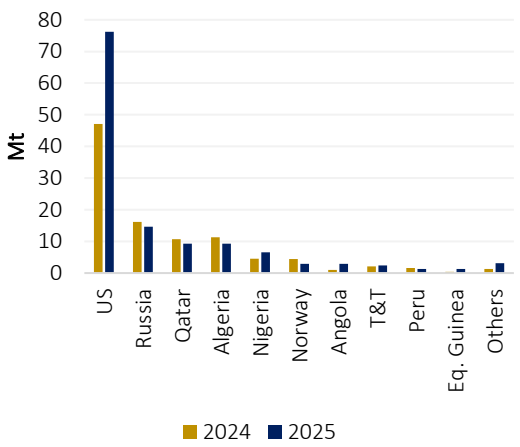


Figure 140: Europe's main LNG suppliers (2024 & 2025)



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.1.2 Asia

Asia's LNG imports declined by 2.9% (8.0 Mt) to 273 Mt in 2025, marking the region's first contraction since 2022. The narrow spot price spread between Asian LNG and TTF gas prices diverted flexible US LNG cargoes toward Europe rather than Asia Pacific. Despite a fall in its imports, China remained the region's largest LNG importer, followed by Japan, South Korea, Taiwan and India. China accounted for the bulk of the regional decline, followed by India and Pakistan, while Taiwan and Bangladesh recorded notable increases (Figure 141).

China's LNG imports fell sharply by 14% to 69 Mt, the first decline since 2022 and the lowest level since that year. This reflected rising domestic gas production, stronger pipeline gas inflows and weaker industrial gas demand. In India, high spot LNG prices dampened demand in the price-sensitive market, while an earlier-than-usual monsoon reduced gas consumption in the power sector. Pakistan's LNG imports also declined as weaker power sector gas demand, amid a shift toward cheaper coal, resulted in an oversupplied LNG market, leading to widespread cargo cancellations and deferrals in 2026 and 2027.

In contrast, Taiwan's LNG imports increased on the back of stronger gas demand in the power sector following the country's nuclear phase-out, with the final reactor shutdown in May 2025, driving imports to a record 23.9 Mt. In Bangladesh, higher LNG imports were supported by improved regasification capacity availability and declining domestic gas production. This upward trend was mirrored in South Korea, where LNG imports reached a historic high of 46.7 Mt in 2025, defying earlier forecasts that gas would be displaced by nuclear power.

Among LNG suppliers to Asia Pacific, Australia remained the largest source due to its proximity to the region, followed by Qatar, Malaysia, the US and Indonesia (Figure 142). US LNG exports to Asia Pacific fell sharply by 36% in 2025, as Europe absorbed more flexible US cargoes. Notably, China has not imported any LNG cargoes from the US since February 2025 amid ongoing trade tensions between the two countries.

Figure 141: Asia Pacific's LNG imports by country (2024 & 2025)

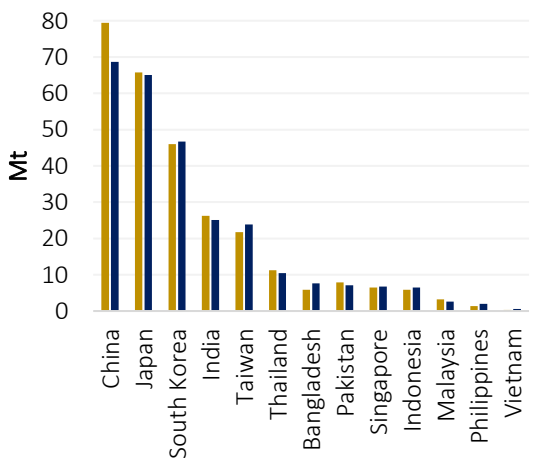
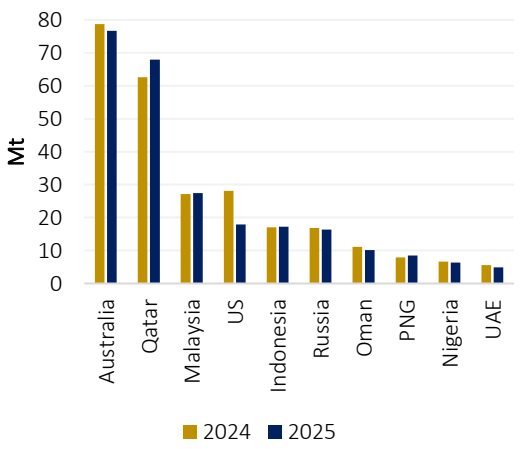


Figure 142: Asia Pacific's main LNG imports (2024 & 2025)



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.1.3 Latin America and the Caribbean (LAC)

LAC's LNG imports declined by 15% (2.2 Mt) to 12.7 Mt in 2025, reversing the growth seen in 2024. Puerto Rico became the region's largest LNG importer, overtaking Brazil, followed by the Dominican Republic, Chile and Colombia. The regional decline was driven mainly by lower imports in Brazil, the US Virgin Islands (USVI), Argentina and Jamaica, which outweighed higher imports in Puerto Rico (Figure 143). Argentina and Brazil's LNG imports fell due to higher domestic gas production, which reduced their LNG needs. Imports into the USVI declined as direct US LNG exports to Puerto Rico reduced its role as a Caribbean break-bulking hub. In Jamaica, weaker power sector gas demand following Hurricane Melissa in October 2025 curtailed LNG imports, whereas stronger power sector gas consumption boosted LNG demand in Puerto Rico, reshaping regional energy trade flows throughout the year.

4.2.2.1.4 Middle East and Africa (MEA)

LNG imports in the MEA region surged to a record high of 19.1 Mt in 2025, up 70% (7.9 Mt), making it the world's third-largest LNG importing region. Egypt overtook Kuwait to become the region's largest LNG importer, followed by Jordan, Bahrain, the United Arab Emirates and Senegal (Figure 144). Bahrain also resumed LNG exports, while Senegal entered the LNG import market with the start-up of the Karmol LNGT Powership Africa. Egypt drove most of the regional import growth, as it became a net LNG importer to meet domestic gas demand amid declining domestic production. Egypt's LNG imports nearly quadrupled in 2025, reaching a record level and ranking the country as the world's 14th largest LNG importer.

Figure 143: LAC's LNG imports by country (2024 & 2025)

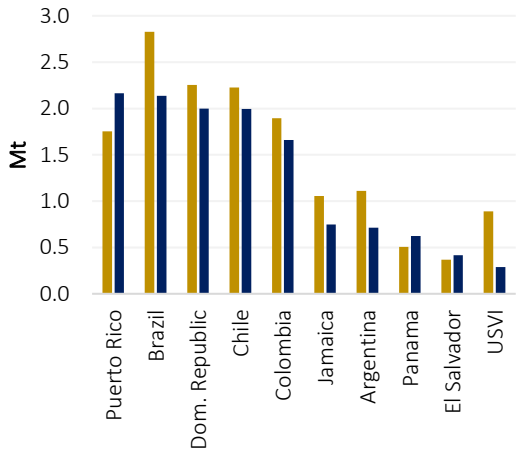
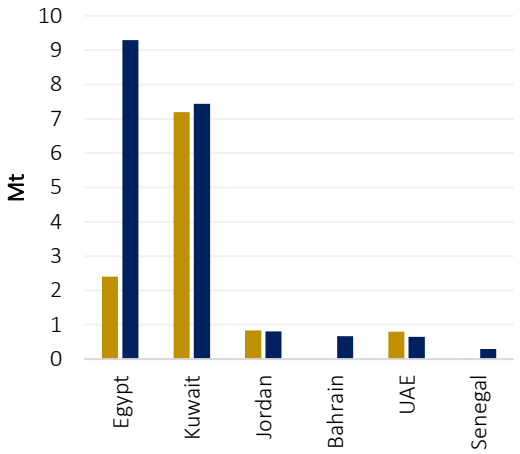


Figure 144: MEA's LNG imports by country (2024 & 2025)



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.1.5 North America

North America's LNG imports declined by 7.2% (0.1 Mt) to 1.4 Mt in 2025, driven by lower imports in the US and Mexico, partly offset by an increase in Canada. US LNG imports fell as record-breaking domestic production and strategic midstream debottlenecking reduced the need for seasonal peak-shaving cargoes. At the same time, stronger pipeline gas flows from the US to Mexico further diminished Mexico's LNG import requirements.

4.2.2.2 Start-up of New LNG Regasification Capacity

New LNG regasification capacity additions eased to 48 Mt in 2025, down from 67 Mt in 2024, bringing global regasification capacity to 1,055 Mtpa (Figure 145). Around half of the new capacity came from floating storage regasification units (FSRUs).

Asia led global capacity growth with 20 Mtpa, followed by Africa (15 Mtpa) and Europe (13 Mtpa). Average global LNG import terminal utilisation stood at 41%, unchanged from 2024 and roughly half that of LNG export terminals. At the country level, Egypt recorded the largest regasification capacity additions with 15 Mtpa, followed by China (9.3 Mtpa), India (5.0 Mtpa), Italy (3.7 Mtpa), Germany (3.3 Mtpa), Taiwan (3.0 Mtpa) and Vietnam (3.0 Mtpa) (Figure 146). Key terminals commissioned in 2025 included the Ain Sokhna FSRU, Ain Sokhna Sumed FSRU 2 and Damietta FSRU in Egypt, Chhara LNG in India, Ravenna FRU in Italy, Taoyuan LNG in Taiwan and Cai Mep LNG in Vietnam. In China, several projects were delayed due to weaker LNG demand, with only two new terminals and two expansions coming online.

As a result, Asia remained the largest regasification market with 658 Mtpa, followed by Europe (241 Mtpa), MEA (64 Mtpa), LAC (62 Mtpa) and North America (30 Mtpa). By end-2025, LNG import capacity from FSRUs and floating storage units (FSUs) reached 203 Mtpa, representing around 20% of global LNG import capacity. Brazil held the largest share of FSRU/FSU capacity at 36 Mtpa, followed by Egypt (21 Mtpa), Türkiye (15 Mtpa), Germany (13 Mtpa), Pakistan (12 Mtpa), the United Arab Emirates (11 Mtpa) and Italy (11 Mtpa).

Looking ahead, around 95 Mtpa of new regasification capacity is expected to start operations in 2026. China accounts for the majority with 54 Mtpa, including projects delayed from 2025, followed by India (14 Mtpa), Jordan (5.3 Mtpa), Brazil (3.8 Mtpa), Iraq (3.8 Mtpa), Germany (3.5 Mtpa) and Honduras (3.5 Mtpa). Cyprus, Honduras and Iraq are set to join the ranks of LNG importing countries in 2026.

Figure 145: Start-up of new LNG regasification capacity by region

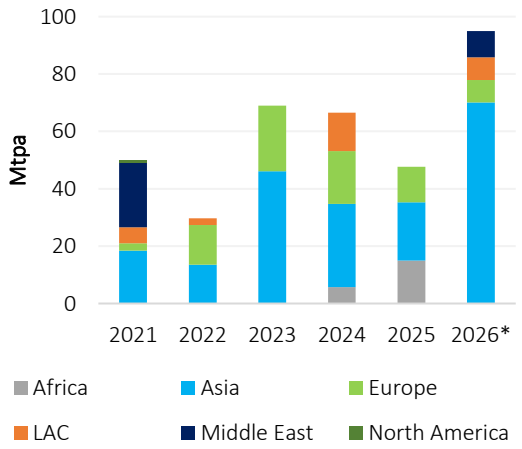
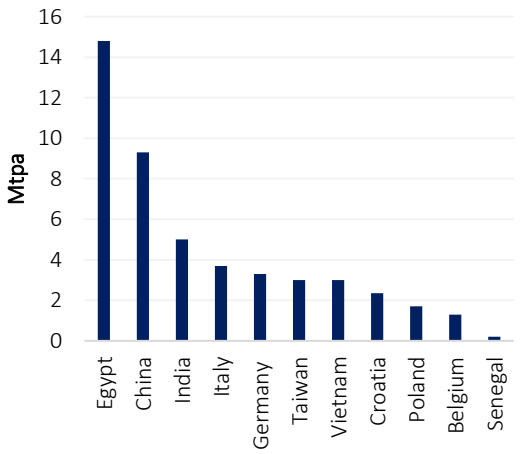


Figure 146: Start-up of new LNG regasification capacity by country in 2025



(*): GECF Secretariat's forecast for 2026

Source: GECF Secretariat based on data from Argus, ICIS LNG Edge, LSEG, Rystad Energy and project updates

4.2.3 Trend in Global LNG Trade by Duration

LNG cargoes traded were categorised into spot and short-term (spot|ST) or medium-term and long-term (MT|LT). Spot and short-term LNG trade encompasses LNG cargoes traded under contracts of two years or less. However, for several cargoes, the sales basis data was unavailable, leading to their classification as "others". Consequently, the actual spot|ST and MT|LT trade may be higher than the data provided in this report.

Medium and long-term LNG trade continued to dominate in 2025, accounting for at least 60% of global LNG trade (Figure 147). Global spot and short-term LNG trade rose to a record 115 Mt in 2025, up 6% y-o-y, while its share of total LNG trade remained stable at 26%. Growth was driven by Europe, where spot and short-term LNG imports increased sharply from 29 Mt in 2024 to 44 Mt in 2025, lifting their share of total LNG imports from 28% to 34% (Figure 148) and helping offset weaker pipeline gas supplies.

By contrast, Asia's spot and short-term LNG imports declined from 72 Mt to 60 Mt as Europe attracted more flexible US cargoes, reducing Asia's share from 26% to 22%. At the country level, higher spot imports were led by Egypt, Türkiye, the Netherlands, France and the UK. Egypt's shift from a net LNG exporter to importer, combined with the lack of long-term contracts, increased its reliance on the spot market. Meanwhile China and India recorded sharp declines amid elevated prices and weaker spot demand.

On the supply side, the US emerged as the largest source of spot and short-term LNG, accounting for the majority of the incremental growth in this segment. In 2025, the US supplied around 44% of global spot and short-term LNG cargoes, with volumes rising from 38 Mt in 2024 to about 50 Mt. This increase was largely driven by the early start-up of exports from Plaquemines LNG, where commissioning cargoes were marketed on a spot basis. In addition, the US LNG tolling model enabled portfolio players and traders to trade volumes flexibly, allowing significant quantities of US LNG to be placed into Europe's premium spot market.

Figure 147: Global LNG trade by contract duration (2021-2025)

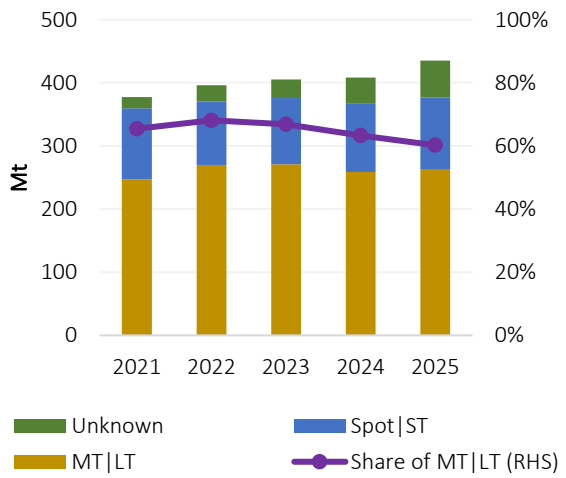
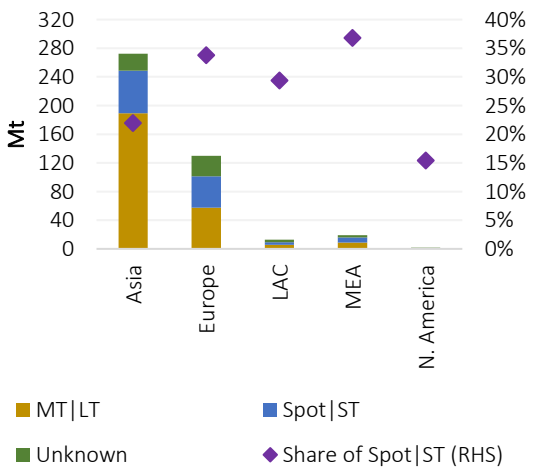


Figure 148: Regional LNG imports by contract duration in 2025



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.4 Expiration of Global LNG Contracts

The analysis of LNG contract expirations for importing countries focuses solely on sale and purchase agreements (SPAs) with a specified destination market, excluding memorandums of understanding (MoUs), heads of agreements (HoAs) and SPAs involving portfolio players or traders without defined destinations.

Between 2026 and 2030, a total of 78 Mtpa of contracted LNG volumes are due to expire. Asia accounts for the largest share at 53 Mtpa, followed by Europe (14 Mtpa), North America (7.3 Mtpa), LAC (2.5 Mtpa) and MEA (1.7 Mtpa). Contract expirations are expected to peak at 25 Mtpa in 2027, before gradually declining to 10 Mtpa by 2030 (Figure 149).

At the country level, Japan faces the largest volume of LNG contract expirations, with 17 Mtpa set to end by 2030, followed by South Korea (13 Mtpa), India (11 Mtpa), Mexico (7.3 Mtpa), China (6.8 Mtpa), Türkiye (6.0 Mtpa) and Belgium (5.5 Mtpa) (Figure 150). While Japan's appetite for long-term LNG contracts has been uncertain amid nuclear restarts and expanding renewable capacity, energy security remains a key pillar of its LNG strategy, as reflected in the recent 27-year, 3 Mtpa agreement between JERA and QatarEnergy. South Korea and India have also been actively securing LNG contracts, likely driven by contract expirations, supply diversification and energy security considerations.

Figure 149: LNG import contract expirations by region in 2026-2030

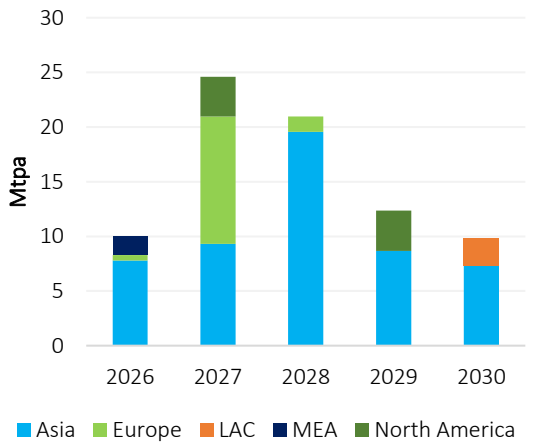
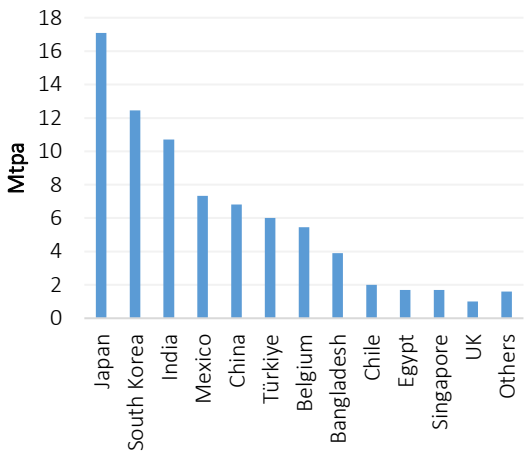


Figure 150: LNG import contract expirations by country (2026-2030)



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

On the supply side, nearly 100 Mtpa of contracted LNG volumes are due to expire between 2026 and 2030. The higher volume compared with the import side reflects the inclusion of LNG SPAs with portfolio players and traders, which typically have no specified destination and are largely traded on the spot market. GECF Member Countries account for the largest share of expiring LNG contracts, with around 50 Mtpa set to end, followed by non-GECF countries (34 Mtpa) and portfolio players or traders (14 Mtpa). Australia, Indonesia, Qatar and Russia hold the largest volumes of LNG under existing contracts expiring by 2030.

4.2.5 LNG Shipping

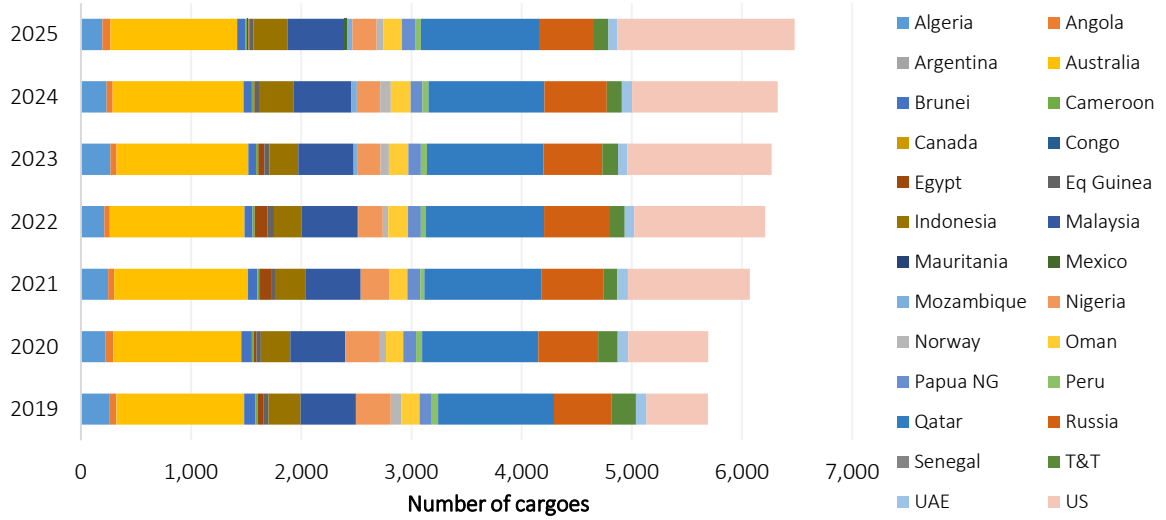
4.2.5.1 LNG Shipments

Global LNG shipments continued its multi-year upward trajectory in 2025, with the total cargo count rising by 3% (an addition of 188 shipments) to reach 6,527 cargoes. While the sector has maintained consistent growth, the 2025 expansion marks a notable acceleration compared to the marginal 1% growth rates observed in 2023 and 2024.

The market remains highly concentrated among three dominant suppliers, namely the US, Australia and Qatar, each of which surpassed the 1,000-cargo threshold for the fifth consecutive year (Figure 151). Collectively, these three accounted for 59% of global shipments, a three-percentage-point increase from 2024 levels. The US was the primary driver of this uptick, increasing its output by 287 cargoes (a 22% surge compared to the previous year), while Qatar recorded a steady 3% increase. Notably, Angola recorded the highest relative growth among established players at 33%, and the market welcomed new supply from Canada and the Senegal/Mauritania joint project, which contributed a combined 49 cargoes.

There were six GECF countries within the top ten global exporters: Qatar, Malaysia, Russia, Nigeria, Algeria and Trinidad & Tobago. The group's aggregate market share declined from 48% in 2024 to 45% in 2025, due to the growth in non-GECF output.

Figure 151: Number of LNG cargoes by exporting country



Source: GECF Secretariat based on data from ICIS LNG Edge

In 2026, the number of LNG shipments is expected to rise, driven by a substantial wave of new liquefaction capacity entering the market, led by the scale-up of output in North Field in Qatar and of certain US projects. This growth will be further bolstered by the full-year output from Canada and Senegal/Mauritania, and supported by the record delivery of over 100 new LNG carriers scheduled to enter service. This influx of supply may stimulate increased demand across price-sensitive Asian markets and maintain energy security in Europe, ultimately pushing the global cargo count toward new historic highs.

4.2.5.2 LNG Carriers

The global LNG carrier fleet underwent significant transformation in 2025, expanding to a total of 831 vessels driven by record-breaking shipbuilding. While 764 of these ships served as active carriers, 67 were utilised in specialised roles as FSRUs, FSUs or floating power ships. The fleet expansion was spearheaded by the commissioning of 81 new carriers, surpassing the previous record of 69 set in 2024, which added 14 million cubic metres of shipping capacity. This 12% jump in capacity represents a substantial acceleration in growth compared to the early 2020s, bringing the total active fleet capacity to 126 million cubic metres by year-end.

The fleet is categorised by three main propulsion types: steam turbine, Tri-Fuel Diesel Electric (TFDE) and two-stroke engines (Figure 152). The year 2025 solidified a major shift in this technological landscape; two-stroke vessels, which are primarily utilised for long-term charters, became the dominant segment, rising from 26% of the fleet in 2020 to 48% by the end of 2025. Conversely, over the same period, the first-generation steam turbine vessels saw their share dwindle from 37% to 25%. As their economic viability continues to deteriorate, these older steam turbine carriers are increasingly being converted to FSRUs, sold for scrap, or even simply laid up idle, having surrendered their former leading role in the spot LNG trade to the more efficient TFDE segment as global carbon regulations tighten.

The fleet modernization is further reflected in vessel dimensions as the conventional size class averaging 174,000 m^3 now accounts for almost three-fifths of the total global fleet (Figure 153). These larger and more efficient ships are now nearly twice as common as legacy vessels which average 150,000 m^3 highlighting the industry's push for greater economies of scale to lower unit transport costs. The transition to this 174,000 m^3 standard has been accelerated by the need to optimize berth slot capacity at major liquefaction terminals in the US Gulf Coast and Qatar where larger parcels are essential for long-haul efficiency.

Figure 152: Distribution of the LNG carrier fleet by build year and propulsion system

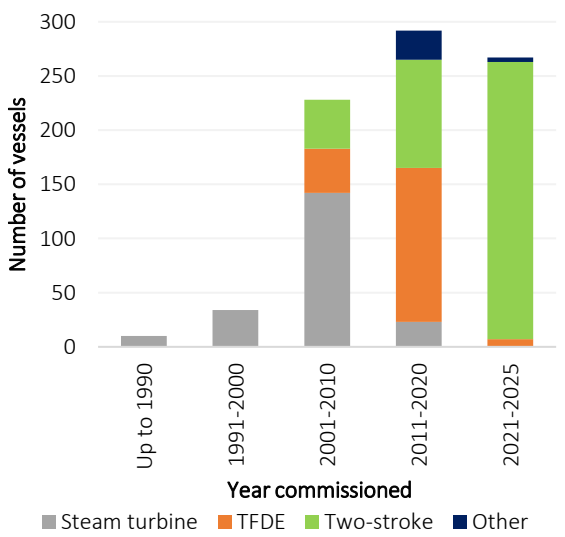
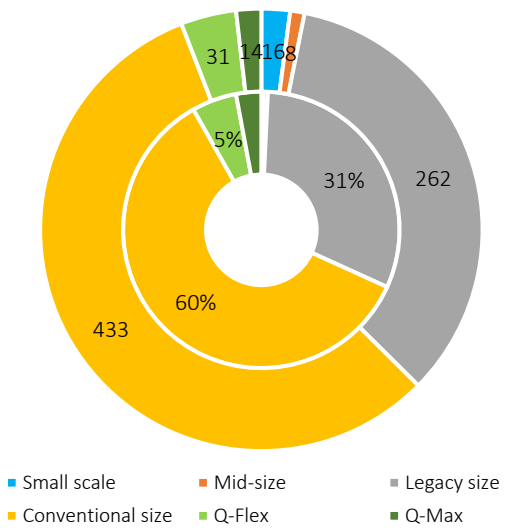


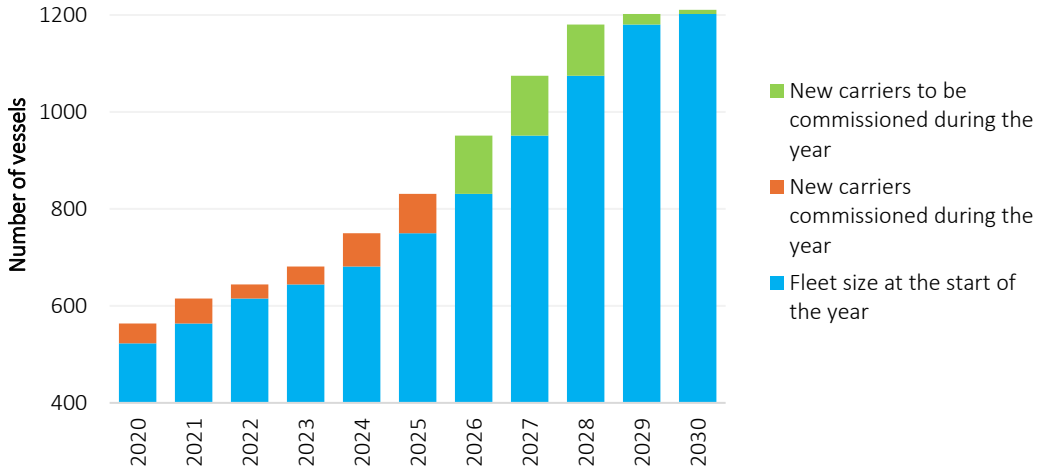
Figure 153: Active LNG carrier fleet by number of vessels (outer) and capacity (inner)



Source: GECF Secretariat based on data from Argus, ICIS LNG Edge, IGU, LSEG and Rystad Energy

The global LNG export sector is also in the midst of a rapid expansion, with a massive 233 Mtpa increase in liquefaction capacity projected through 2030. To support this surge, an unprecedented building cycle is underway: since 2024, nearly 550 new carriers have been slated for delivery by the end of the decade, a move that will expand the global fleet by 80% (Figure 154). This supply wave is set to peak between 2026 and 2028, with over 100 vessels expected to be commissioned annually, repeatedly shattering previous delivery records. While the newbuild market booms, the legacy fleet is facing a rapid exodus; a record 14 steam turbine vessels were sold for scrap in 2025, nearly triple the five-year average, as they became increasingly obsolete. With 30 vessels already exceeding 25 years of age, and some 120 set to come off-charter shortly, steam turbine owners are increasingly opting for the scrapyard over the prohibitive costs of dry-dock maintenance.

Figure 154: Growth of the LNG carrier fleet



Source: GECF Secretariat based on data from Argus, ICIS LNG Edge, IGU, LSEG and Rystad Energy

The geography of shipbuilding is also shifting. While South Korean shipbuilding giants maintain their leadership, China has emerged as a formidable challenger. By the end of 2025, China's share of the global orderbook climbed to 32%, up from 27% the previous year, driven by lower labour costs and the successful scaling of its technical expertise. Meanwhile, the US is attempting to re-enter the arena; under the Trump administration, the USTR has implemented tariffs on foreign-built tankers to jumpstart domestic shipbuilding. Although the threat to revoke export licenses was dropped, the 2025 acquisition of Philly Shipyard by South Korea's Hanwha Ocean signals an effort to localise the US-built carrier sector.

GECF Member Countries are at the forefront of the fleet expansion, led by QatarEnergy's massive renewal program, which is expected to reach 200 vessels within the next five years. Qatar has ordered 128 new LNG carriers; 24 of these will be constructed under a new size class, the QC-Max, which will be the world's largest at 271,000 m³. Notably, Qatar has selected China's Hudong-Zhonghua Shipyard to construct these ultra-large QC-Max vessels. Other countries, such as Algeria, Nigeria, Russia and the UAE, are likewise ordering new vessels to modernise their fleets and support the commissioning of upcoming LNG export projects.

4.2.5.3 LNG Shipping Cost

LNG shipping costs are a function of the vessel charter rate, the cost of shipping fuel, and the distance between the origin and destination ports. In 2025, spot charter rates for all segments of the global fleet recorded historical lows (Figure 155). The annual average for the TFDE segment, which is the dominant vessel option for spot LNG trade, fell to $20,000/day, a 50% decrease from the 2024 average and a large decline from the $110,000 seen in 2022. In addition, the annual average rate for steam turbine carriers fell by 82% to just $4,600/day, while the rate for two-stroke vessels fell by 36% to $35,000/day.

The LNG spot charter market experienced extreme volatility in 2025. The year opened with a severe downturn as charter rates for all vessel segments continued a slide that began in mid-2024 (Figure 156). By February, the market hit a historic nadir; monthly average spot rates for steam turbine carriers plummeted to just $500/day, with daily assessments in the Atlantic Basin reaching $0/day. This collapse was driven by a record influx of newbuild LNG carrier deliveries outpacing the startup of new liquefaction capacity, while high European storage levels and a preference for shorter Atlantic-to-Europe voyages (prompted by a price premium over Asia) drastically reduced the number of vessels required for long-haul transport.

Throughout the spring and summer, vessel availability tightened intermittently due to maintenance at European regasification terminals and a temporary spike in June caused by the escalating conflict in the Middle East and threats to the Strait of Hormuz. Despite these, the market remained structurally oversupplied. The narrative shifted dramatically in the final months of 2025 as a rapid and sustained rally took hold in November, driven by record-high loading demand from the US Gulf Coast and West Africa, alongside scheduling disruptions from French strikes and Egyptian cargo deferrals. The year concluded with a bearish sentiment, as the continued steady arrival of newbuilds reinforced expectations that the market would remain oversupplied well into 2026.

Figure 155: LNG carrier annual spot charter rates

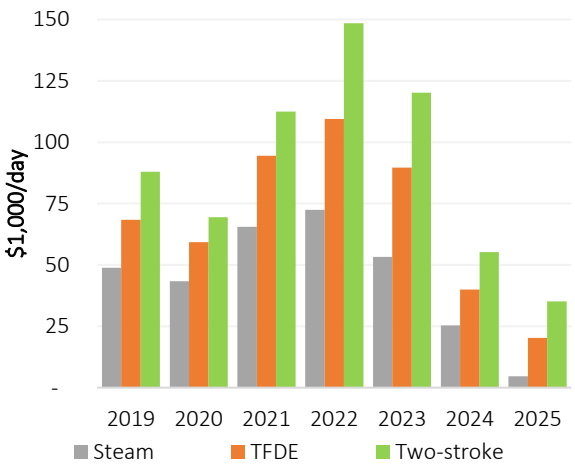
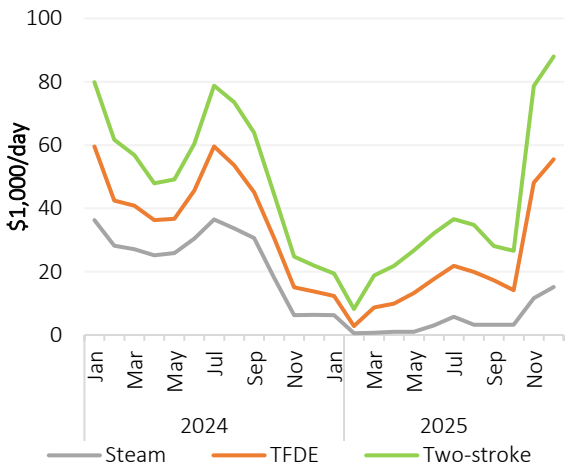


Figure 156: LNG carrier monthly spot charter rates



Source: GECF Secretariat based on data from Argus

Shipping fuel oil prices followed a predominantly bearish trajectory in 2025; the annual average of circa $490/t stood in stark contrast to the five-year high of approximately $760/t recorded in 2022, providing shippers relief in operational expenditures (Figure 157). The year began at the annual peak of $560/t before entering a sustained decline that mirrored the softening of global crude oil prices (Figure 158). Although a brief rebound in June pushed costs back up to $520/t, the recovery was short-lived as prices steadily eroded throughout the second half of the year. By the fourth quarter, prices had reached an annual floor of $425/t, representing a 19% decrease compared to the previous year and sitting significantly below the five-year average.

Figure 157: Annual price of shipping fuel oil

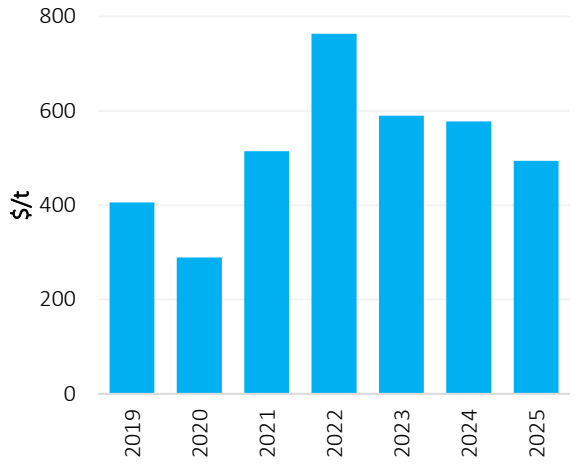
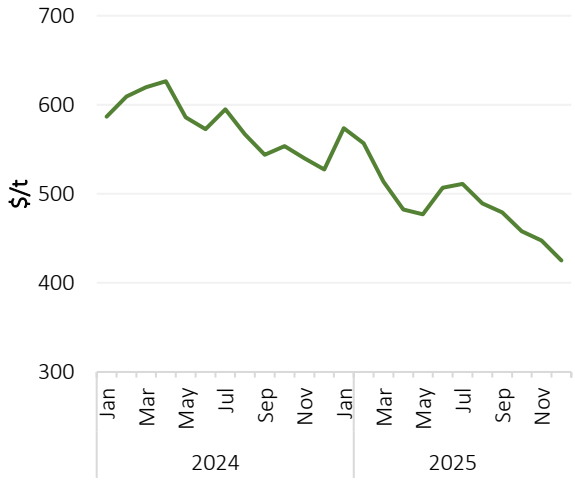


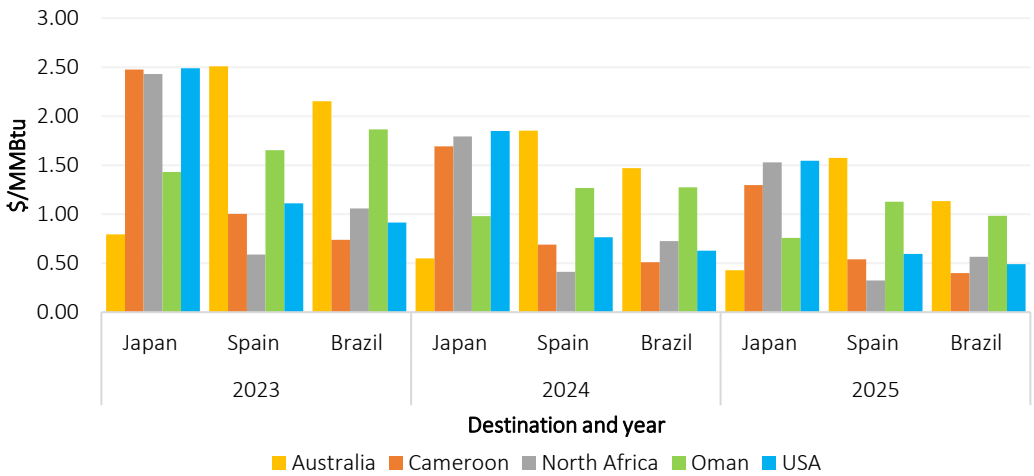
Figure 158: Monthly price of shipping fuel oil



Source: GECF Secretariat based on data from Argus and Platts

There was a decrease in the spot shipping costs for TFDE LNG carriers in 2025 compared with the previous year, by up to $0.39/MMBtu on certain routes (Figure 159). This was driven by the decreases in the LNG carrier spot charter rate and the cost of shipping fuels, despite the small increase in delivered spot LNG prices.

Figure 159: Spot shipping costs for TFDE LNG carriers



Source: GECF Secretariat based on the GECF Shipping Cost Model

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CHAPTER

05

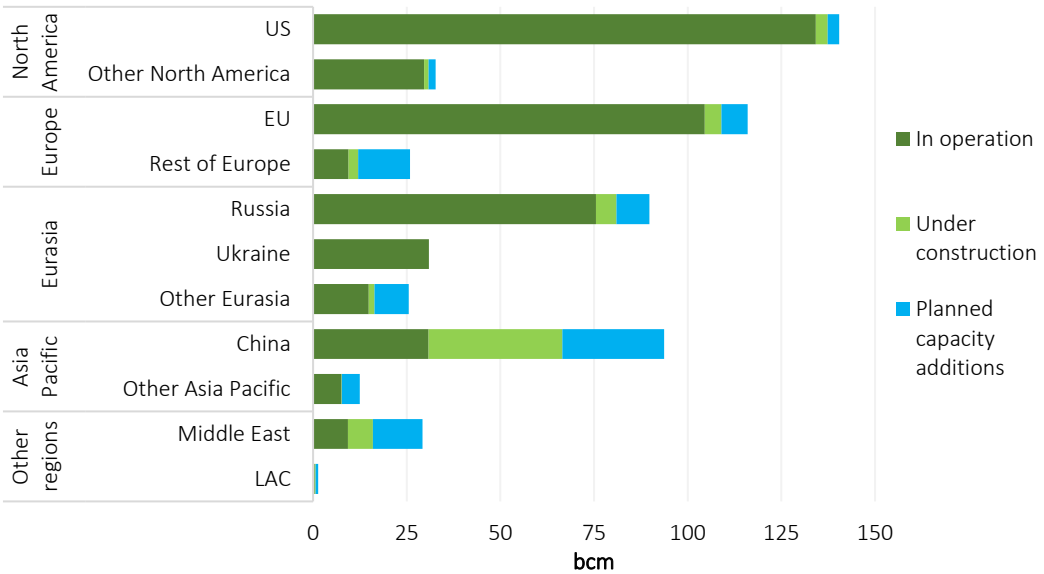
5 GAS STORAGE

Gas storage acts as the primary stabiliser for global gas supply chain by buffering the volatility inherent in both supply and demand. On the supply side, it mitigates risks from geopolitical disruptions and infrastructure failures, while on the demand side, it balances extreme weather shifts and provides essential backup for intermittent renewable energy. This stability is maintained through two core functions: seasonal balancing, which manages the large-scale shift between summer injection and winter withdrawal, and short-term balancing, which provides the rapid flexibility needed for daily or hourly peaks. Of the 500 bcm total storage capacity, 90% is held in underground gas storage (UGS) including depleted fields, aquifers and salt caverns, while the remaining 10% is provided by LNG storage tanks for localised flexibility.

5.1 Underground Gas Storage

Global UGS capacity increased by 1.2% to reach 447 bcm in 2025. While North America (37%), Eurasia (27%) and Europe (26%) maintain historical dominance, China has emerged as the primary catalyst for growth, surging over 500% since 2010. With 31 bcm of active capacity and 36 bcm currently under construction, China is fundamentally shifting the gas storage landscape (Figure 160).

Figure 160: Present and future UGS capacity by region/country



Source: GECF Secretariat based on data from Cedigaz, GIE, IGU and Snam

5.1.1 Europe

The EU's UGS landscape in 2025 was characterised by a return to more aggressive seasonal cycles. Following two consecutive mild years, a colder 2024/2025 winter triggered the second largest storage depletion in seven years, necessitating a vigorous restocking effort throughout the summer. Consequently, European gas storage levels in 2025 remained consistently lower than 2024 figures and below the five-year historical average for much of the year (Figure 161).

Despite beginning the 2024/2025 winter at the top of the five-year range, an early onset of cold weather prompted stronger-than-average gas withdrawals in late 2024. This aggressive drawdown intensified in January 2025, which recorded 19 bcm of net withdrawals (the highest for that month since 2021), driven by surging heating demand and reduced pipeline imports from Norway. By the end of March, storage levels in Germany, France and the Netherlands dipped below 30%, placing these major markets in a precarious position. Total winter withdrawals reached 65 bcm, significantly exceeding the five-year average of 50 bcm and highlighting the grid's vulnerability following a harsh winter season.

Figure 161: Monthly average UGS level in the EU

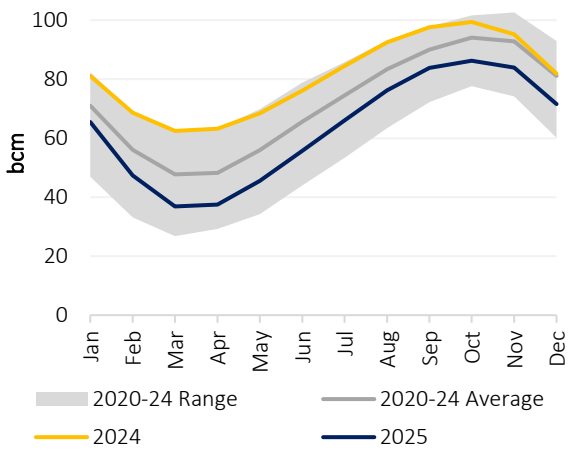
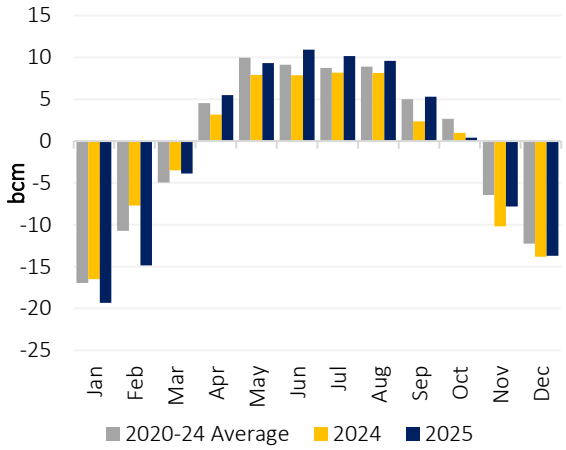


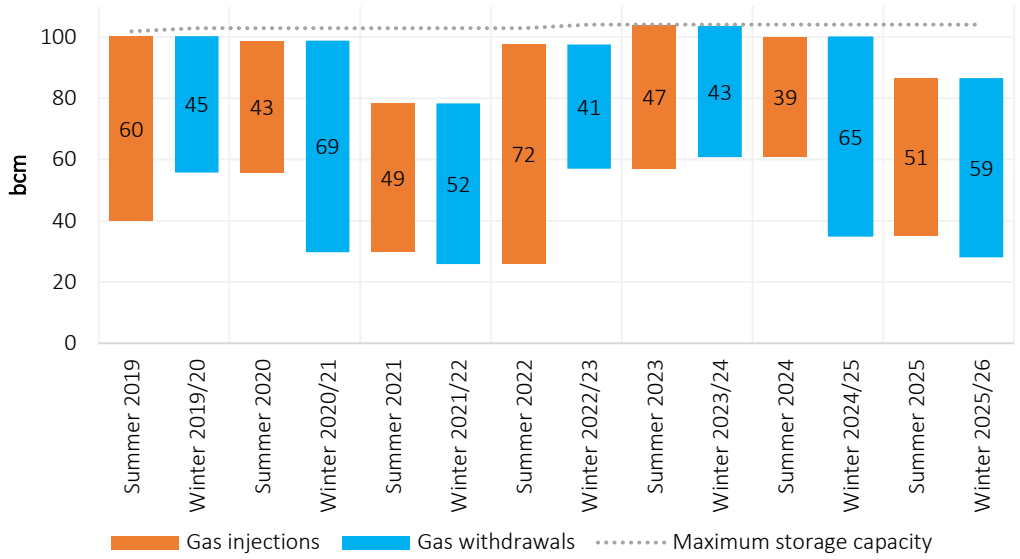
Figure 162: Net gas injections in the EU



Source: GECF Secretariat based on data from AGSI+

To recover from depleted spring levels, the EU aggressively ramped up injections into UGS facilities, supported by a sustained influx of high-volume LNG imports between April and August that facilitated higher-than-usual injection rates (Figure 162). This operational surge was reinforced by the European Parliament's July decision to extend the Gas Storage Regulation until 2027, which introduced critical flexibility by allowing the mandatory 90% filling target to be met at any point between 1 October and 1 December. This strategic shift enabled the region to replenish a three-year high of 51 bcm by the conclusion of the injection season (Figure 163). However, the year ended with an early transition back to withdrawals as unseasonal cold triggered premature heating demand. With further build-up stymied by the lowest average October temperatures since 2021, EU storage peaked at only 83% capacity on 12 October and plummeted to 62% by year-end, leaving the market to navigate a tightening reserve margin for the remainder of the winter.

Figure 163: UGS injections and withdrawals in the EU



Source: GECF Secretariat based on data from AGSI+

Throughout 2025, the massive withdrawals of the preceding winter forced the EU into an accelerated and costly refilling cycle that significantly tightened the global gas market as European buyers maintained a persistent premium over the JKM benchmark to secure flexible LNG cargoes. A defining feature of this period was the disruptive inverted seasonal spread, where intense mandatory filling during the first half of the year caused Summer 2025 contracts to trade higher than Winter 2025/2026 contracts. This backwardation eroded the normal seasonal commercial incentive for storage by forcing operators to purchase expensive summer gas for lower-priced winter resale, creating a high risk of financial loss. This market imbalance was resolved with the introduction of storage deadline flexibility, allowing member states to meet the 90% target anytime between 1 October and 1 December, easing the buying imperative and restoring the functional spreads necessary for sustainable injections.

The start of 2026 was marked by a severe winter shock as temperatures plunged significantly below seasonal norms across Northern and Eastern Europe. As a result of growing heating demand, the gas withdrawals reached 59 bcm during the 2025/2026 winter season, with UGS levels dropping to a minimum of 27% of storage capacity by the end of the 2025/2026 winter season, the lowest level since the end of the 2021/2022 winter season. This will necessitate another intense and costly restocking season starting in April 2026, with approximately 65 bcm of gas required for injection, which is a substantial 14 bcm increase over the volume replenished during the previous year. This massive injection requirement is expected to exert strong upward pressure on spot gas prices throughout the summer, fuelled by intensified global competition and the urgent need for European buyers to attract high-priced, flexible LNG cargoes away from Asian markets to fulfil the EU's 2026 energy security mandates. The situation has been further aggravated by the escalating conflict in the Middle East in early 2026, as LNG deliveries to Europe, critical for restocking UGS inventories, may be challenged by global supply disruptions.

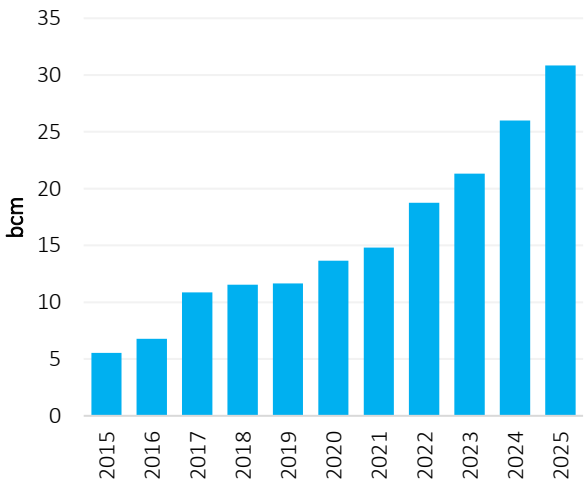
5.1.2 Asia Pacific

Although the Asia Pacific region leads the world in gas consumption, it accounts for only 9% of global working underground gas capacity, with China (31 bcm) and Australia (7 bcm) serving as the primary contributors.

China currently ranks as the world's fourth-largest holder of underground storage capacity, trailing only the US, Russia and Ukraine. Driven by record domestic production and steady pipeline imports via the Power of Siberia, China entered the 2025/2026 winter with storage levels at record highs of 90% to 100%. This significant inventory depressed spot LNG demand and contributed to a notable softening of regional gas prices. In alignment with national goals to increase storage to 13% of annual demand, China has aggressively expanded its infrastructure in recent years (Figure 164). The country aims to reach a combined underground and LNG storage capacity of 55 to 60 bcm by the end of 2026. Furthermore, China is pursuing an ambitious long-term target to scale its underground capacity alone to 100 bcm by 2035, fundamentally reshaping its energy security profile.

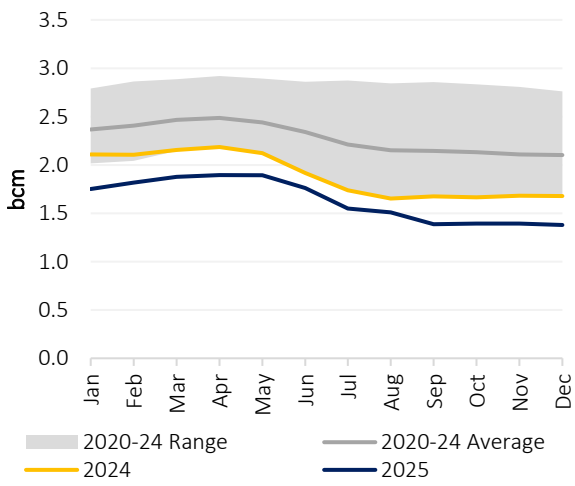
Underground storage in Australia follows a distinct seasonal cycle, with stocks typically building ahead of the Southern Hemisphere winter from June to August. Throughout 2025, storage levels remained consistently below the five-year range, a deficit driven by declining production from mature fields and a sharp increase in gas-fired power generation during periods of low renewable output (Figure 165). Consequently, winter withdrawals in 2025 were 50% higher than the five-year average, a surge that underscores the intensifying supply tightness within the domestic market.

Figure 164: UGS capacity growth in China



Source: GECF Secretariat based on data from Cedigaz

Figure 165: Monthly average UGS level in Australia



Source: GECF Secretariat based on data from AEMO

India is developing its first dedicated UGS facility, targeting an initial capacity of 4 bcm. Currently in the feasibility and site-selection phase, the project evaluates the geological suitability of depleted oil fields and salt caverns. This initiative marks a strategic shift toward establishing a national gas reserve, designed to provide a buffer against global price volatility and support the firm power generation needed to integrate growing renewable energy capacity.

5.1.3 North America

Unlike the previous year, the UGS levels in the US in 2025 kept relatively close to the five-year average (Figure 166). The year began with a sharp drawdown as colder temperatures reduced capacity utilisation to the yearly low of 37%. The market transitioned early to net injections by mid-March, initiating a period of aggressive restocking that consistently outpaced historical averages (Figure 167). In May, record injections restored storage to a surplus against the five-year average, a trend that continued throughout the summer. As a result, 64 bcm were restocked over summer 2025, compared to the average 56 bcm of the previous five years (Figure 168).

Figure 166: Monthly average UGS level in the US

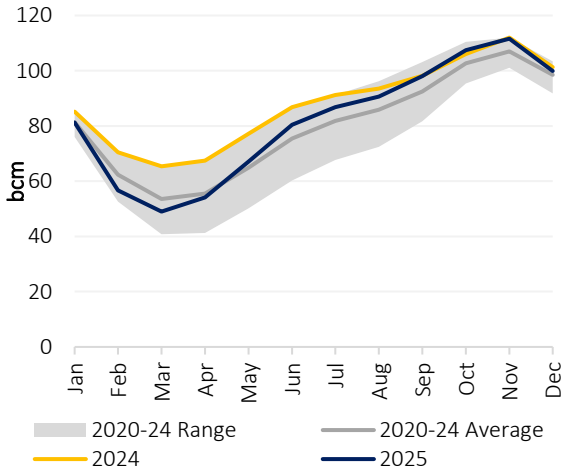
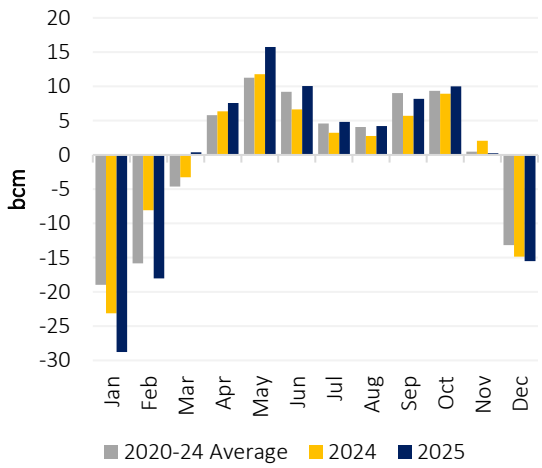


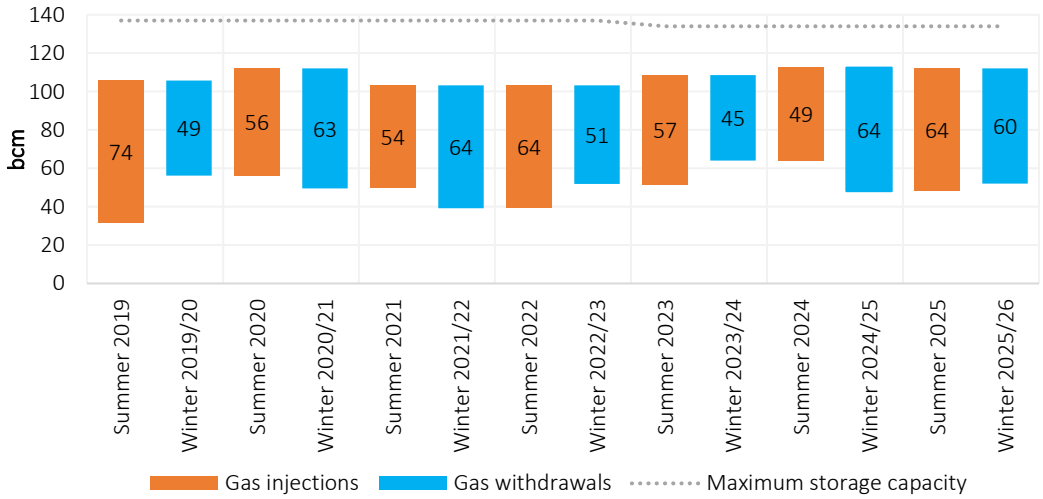
Figure 167: Net gas injections in the US



Source: GECF Secretariat based on data from US EIA

The year concluded with a shift back to net withdrawals by November, ending with an average capacity utilisation of 70% despite the heavy demand seen earlier in the year. Driven by massive heating demand and production freeze-offs caused by winter storms, the outlook for Q1 2026 anticipates a much tighter market than previously expected, with inventories projected to end the withdrawal season as low 52 bcm.

Figure 168: UGS injections and withdrawals in the US



Source: GECF Secretariat based on data from US EIA

5.2 LNG Storage

5.2.1 Europe

Globally, LNG-importing countries maintain a combined 52 bcm of LNG storage capacity, a critical infrastructure segment that remains heavily dominated by the Asia Pacific region. In stark contrast, Europe accounts for only 15% of this global total, largely because the continent relies on its vast and historically established UGS infrastructure to perform the bulk of its large-scale seasonal balancing. LNG storage in Europe serves a more specialised, secondary role within the broader energy value chain. Rather than functioning as a primary seasonal reserve to bridge the gap between summer and winter, these European facilities are strategically focused on optimising terminal operations and ensuring the smooth regasification of incoming shipments. They act as essential shock absorbers, aligning short-term cargo timing misalignments and providing immediate flexibility to manage unforeseen technical disruptions or sudden spikes in local demand without depleting the more massive underground reservoirs.

By the end of 2025, daily EU LNG storage capacity reached 5.7 bcm, up from 5.4 bcm at the start of the year. Spain maintains the largest share of this capacity at 37%, followed by France at 16%. Throughout 2025, inventory levels remained mostly at or above the five-year average. Between April and July, inventories hit the upper end of their historical range as record LNG imports were fast-tracked to refill depleted UGS sites (Figure 169). Unlike the rigid seasonal cycles of UGS, EU LNG storage does not follow a strict pattern, though stocks typically rise ahead of winter (Figure 170). In late 2025, regional LNG withdrawals totalled 0.35 bcm, approximately 30% below the five-year average, reflecting a well-buffered system.

Figure 169: Monthly average LNG storage in the EU

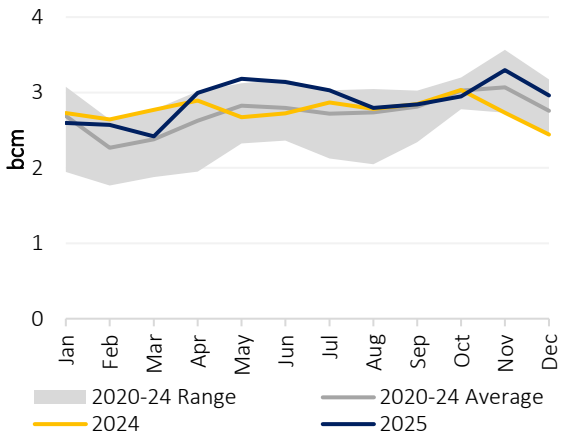
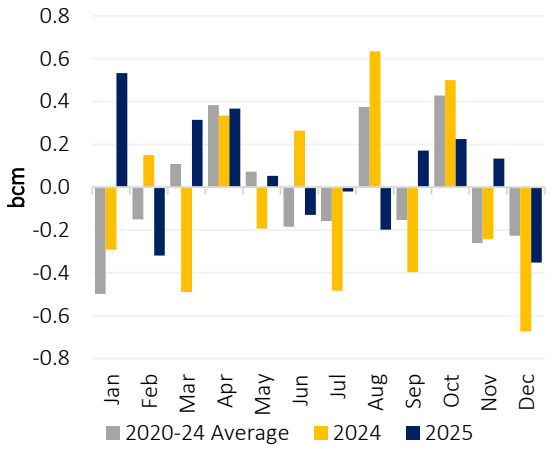


Figure 170: LNG stock changes in the EU



Source: GECF Secretariat based on data from ALSI

Looking ahead, LNG storage will remain critical to the operation of the EU gas market as the region continues to adapt to reduced pipeline imports. These facilities are essential for balancing domestic demand and providing the flexibility needed to support the massive replenishment of UGS sites. By ensuring a steady flow of regasified supply, LNG storage infrastructure will serve as a primary defence against short-term market volatility.

5.2.2 Asia Pacific

The Asia Pacific region dominates the global LNG storage landscape with a 75% share of total capacity, stemming from a historical structural deficit in large-scale UGS facilities. Unlike Europe or North America, which rely on vast geological formations for seasonal balancing, key Asian economies must utilise high-deliverability LNG tanks for their primary energy reserves storage. LNG storage is indispensable for managing the sharp spikes of peak winter heating demand, as well as for maintaining the constant operational stability required at major LNG receiving terminals. This regional reliance has spurred an aggressive infrastructure build-out, with China emerging as the clear leader by operating 27 bcm of working gas capacity. Japan and South Korea follow with 12 bcm and 8.0 bcm respectively, maintaining some of the highest tank-to-consumption ratios in the world to mitigate their vulnerability to maritime supply chain disruptions. India, while still developing its UGS potential, has bolstered its terminal-based capacity to 1.7 bcm to support its growing natural gas mandate.

Throughout 2025, LNG storage in Japan and South Korea followed a volatile trajectory, beginning with a sharp winter drawdown that saw combined stocks fall from 12 bcm in January to a seasonal low of 8.6 bcm by March, dipping 1.9 bcm below the five-year average (Figure 171). While spring restocking briefly restored levels, a major July heatwave triggered a 6% m-o-m depletion as cooling demand surged (Figure 172). However, a robust late-year recovery, driven by aggressive South Korean imports and unseasonably warm temperatures, allowed inventories to conclude the year at 15 bcm. This year-end position sat 11% higher than 2024 levels and 2.7 bcm above the five-year average, providing a substantial buffer entering the 2026 heating season.

Figure 171: Monthly average LNG storage level in Japan and South Korea combined

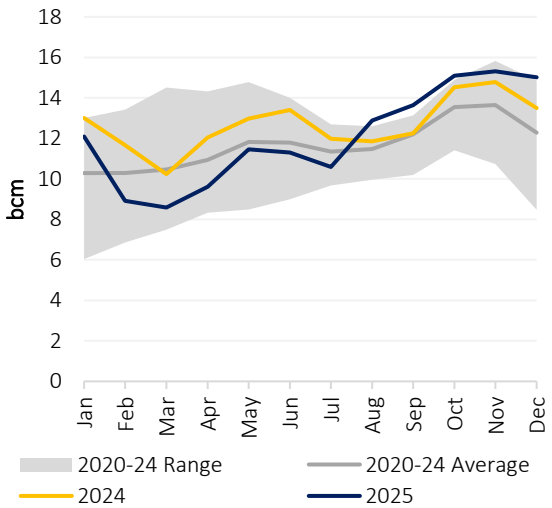
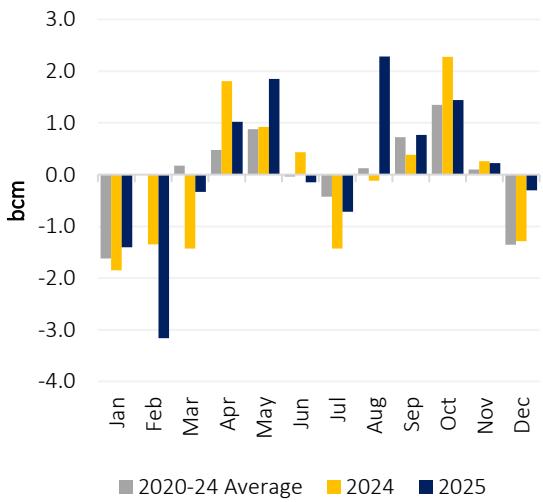


Figure 172: LNG stock changes in Japan and South Korea combined



Source: GECF Secretariat based on data from LSEG

In 2026, the regional market is expected to remain soft despite the demands for winter heating and summer cooling, as ample availability and a looming supply wave from Qatar and North America is forecast to keep spot JKM prices stabilised.

CHAPTER

06

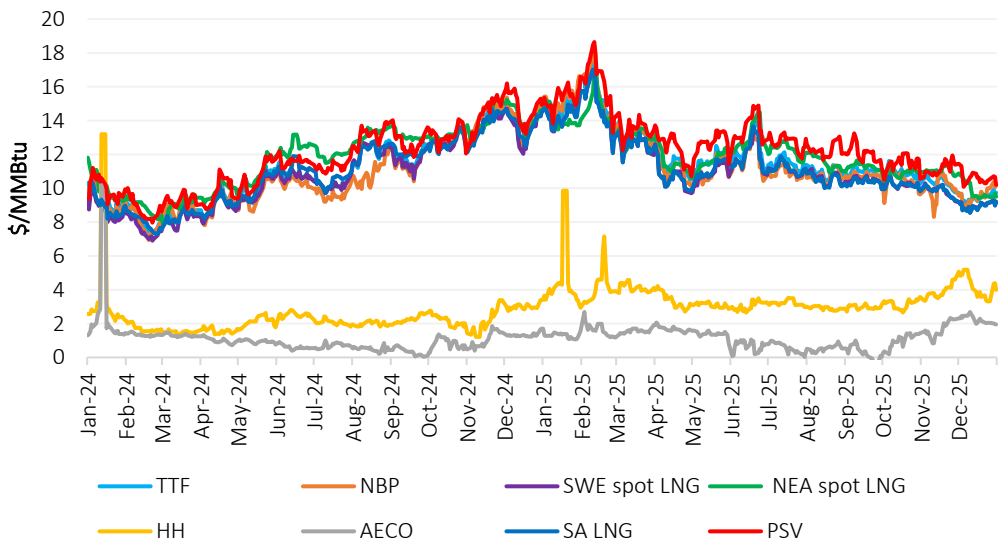
6 ENERGY PRICES

6.1 Gas Prices

6.1.1 Gas & LNG Spot Prices

Global spot gas and LNG prices increased in 2025, reversing the decline recorded in 2024 (Figure 173). Despite higher prices, daily price volatility remained relatively stable and broadly in line with 2024 levels, contrasting with the pronounced fluctuations observed during 2021–2023. Europe was the main driver of higher spot gas and LNG prices, with other importing regions largely tracking movements in TTF prices. The price increase reflected a relatively tight LNG market, despite record export growth, as strong competition between Asia and Europe for spot cargoes coincided with lower pipeline gas inflows to Europe and reduced gas and LNG storage levels. Among the key global gas and LNG benchmarks, the PSV spot gas price traded at the highest level relative to other benchmarks. In addition to market fundamentals, geopolitical developments also influenced prices, triggering short-lived price spikes.

Figure 173: 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 in Argentina, Brazil and Chile based on Argus assessment

Q1 2025 saw winter tightness lift prices before late-quarter easing, as European gas and Asian LNG spot prices initially climbed due to colder temperatures and significant supply constraints. Market volatility was driven by low wind output and unplanned Norwegian production outages, while the decline of pipeline gas flows from 1 January due to the expiration of a major transit contract further lifted prices and spilled over into Asian LNG markets through arbitrage. Asian spot prices broadly tracked European hubs despite ample supply and high inventories, supported by colder conditions in parts of Northeast Asia. By March, prices in both regions declined as warmer weather reduced heating demand and robust LNG supply weighed on markets. Expectations of eased EU gas storage targets, alongside contained volatility, reinforced bearish sentiment, while rising trade tensions and global growth concerns added further downward pressure.

Q2 2025 witnessed bearish fundamentals dominate despite episodic disruptions, as spot prices in Europe and Asia generally declined, reflecting loose market conditions throughout the spring. April extended the bearish trend as subdued demand and ample LNG supply outweighed geopolitical concerns, including new US tariffs that raised fears of weaker global growth and potentially reduced industrial gas consumption. In May, prices stabilised and edged higher on scheduled maintenance at key gas and LNG facilities in Norway, Malaysia and the US, though stronger wind generation in Europe and weak Asian demand, particularly in China, effectively capped these gains. In June, prices rebounded amid heightened volatility, driven by growing Middle East tensions and rising seasonal temperatures that lifted cooling demand across both hemispheres, before eventually easing toward month-end as supply stability returned.

Q3 2025 experienced ample LNG supply cap prices amid summer demand, as spot prices softened across Europe and Asia, reflecting robust availability that outweighed weather-driven consumption. Prices retreated in July despite Norwegian outages and strong European power-sector gas demand, while in Asia, higher cooling requirements were offset by abundant LNG availability. Prices weakened further in August, falling below year-earlier levels for the first time in 2025 as ample supply and high inventories capped weather-driven demand. In September, European prices stabilised as balanced fundamentals offset disruptions from French regasification strikes and Norwegian facility maintenance, while Asian prices continued to ease amid weak demand and strong LNG inflows.

Q4 2025 underwent a period where strong supply and mild weather weighed on year-end prices, as European and Asian spot prices trended lower amid robust LNG availability. In October, prices edged down despite higher gas demand for power generation in Europe, as record LNG inflows dominated market fundamentals, while Asian prices continued to soften amid weak industrial demand. In November and December, prices declined further, pressured by unseasonably mild weather and ample supply, even as European storage levels declined significantly by late December. Asian LNG prices received only brief support from a spike in charter rates driven by increased floating storage and temporary logistical constraints. By year-end, spot prices reached their lowest levels since mid-2024, potentially encouraging renewed spot buying if colder conditions emerge in early 2026.

All major global gas price indices recorded annual increases in 2025, though the magnitude varied significantly across regions. The NEA spot LNG price rose modestly by 3% to $12.1/MMBtu, while the European TTF spot gas price increased more sharply by 9% to $11.9/MMBtu. In contrast, Henry Hub (HH) spot gas prices strengthened significantly, surging by 59% to a three-year high of $3.6/MMBtu, driven largely by record LNG feedgas demand. Despite these gains, both TTF and NEA LNG spot prices remained below the extreme annual levels recorded during the 2021–2023 energy crisis, yet they remained notably elevated compared to historical spot prices prior to 2021 (Table 5).

Table 5: Annual gas and spot LNG prices (2015-2025)

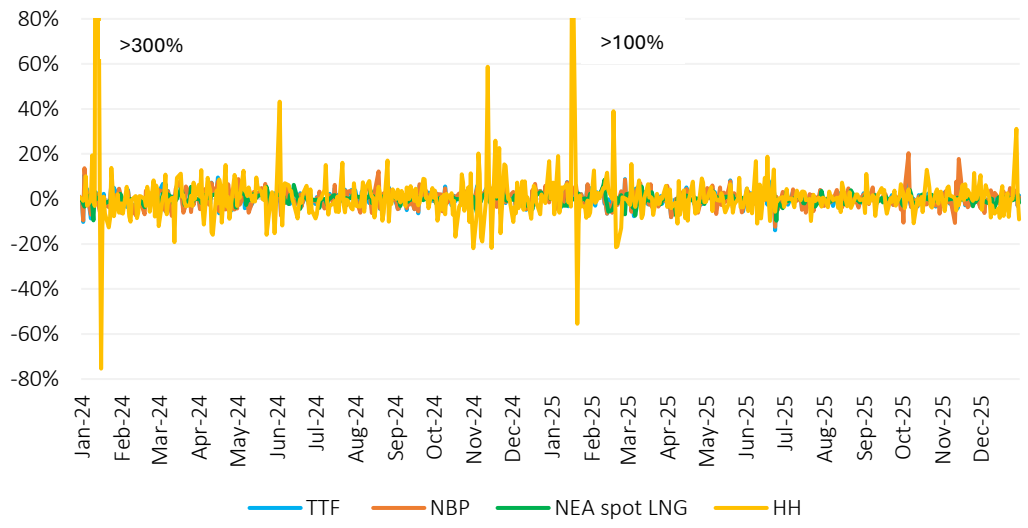
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
TTF spot gas	6.4	4.5	5.7	7.9	4.5	3.2	15.9	37.6	12.9	10.9	11.9
NEA spot LNG	7.6	5.8	7.2	9.8	5.4	4.4	18.6	33.2	13.5	11.7	12.1
HH spot gas	2.6	2.5	3.0	3.2	2.6	2.0	3.9	6.4	2.5	2.2	3.6

Source: GECF Secretariat based on data from Argus and LSEG

Spot price volatility in Europe and Asia in 2025 remained broadly in line with 2024 levels. Daily movements in TTF spot prices ranged from –14% to 9%, while NEA LNG spot prices fluctuated between –10% and 9%. NBP daily fluctuations ranged from –12% to 20%. In contrast, HH spot prices saw a decline in volatility, with daily swings narrowing to a range of –55% to 129%.

Cumulative annual price variability, defined as the sum of absolute daily price changes, provides a clear indicator of price volatility. In 2025, annual variability for TTF and NBP spot prices stood at 69 and 78, respectively, remaining broadly stable compared with 2024. HH spot price variability was also unchanged at 51. In Asia, however, annual variability in NEA LNG spot prices rose slightly to 45, up from 38 in 2024 (Figure 174).

Figure 174: 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

TTF and NBP spot gas prices each rose by 9% in 2025, averaging $11.9/MMBtu and $11.7/MMBtu, respectively (Figure 175). Meanwhile, spot LNG prices in South West Europe (SWE) and North West Europe (NWE) each increased by 7% to average $11.4/MMBtu, trading at a discount to TTF.

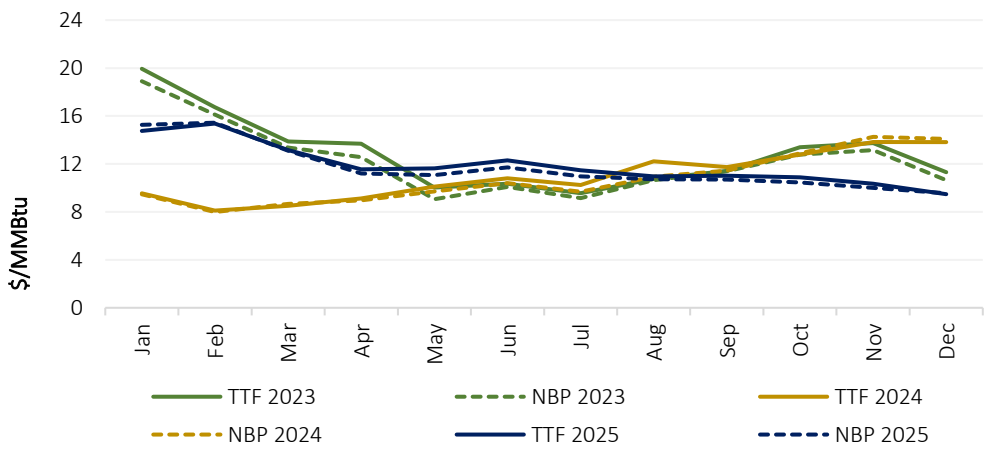
The TTF and NBP spot gas prices followed a clear seasonal and fundamentals-driven pattern throughout the year, rising sharply in the first quarter before trending lower for the rest of the year. Prices strengthened in January and February amid colder-than-normal weather, low wind generation and unplanned outages at Norwegian gas fields/facilities. The decline of pipeline gas flows from 1 January due to the expiration of a major transit contract further tightened markets, while relatively low storage levels pushed daily prices to above $17/MMBtu in February.

From March, prices declined as warmer weather reduced heating demand and LNG supply remained ample. Expectations of eased EU gas storage requirements reinforced bearish sentiment, while subdued demand and strong LNG inflows extended the downturn into April, alongside concerns over a global economic slowdown following new US tariffs. Prices rebounded modestly in May and June, supported by maintenance downtime at Norwegian gas fields/facilities and LNG facilities and higher temperatures boosting cooling demand, with Middle East tensions also briefly lifting prices in June.

In summer, prices softened as robust global LNG supply outweighed weather-driven demand. Despite heatwaves, low wind output and reduced French nuclear availability, ample LNG imports and high inventories capped price gains, pushing prices lower in August. In September, prices stabilised as balanced fundamentals offset maintenance and strike-related disruptions.

In the final quarter, strong LNG supply and generally mild weather drove prices lower, with abundant LNG availability pushing spot prices to their lowest monthly averages since mid-2024.

Figure 175: Monthly European spot gas prices



Source: GECF Secretariat based on data from LSEG

6.1.1.2 Asian Spot LNG Prices

The NEA spot LNG price averaged $12.1/MMBtu in 2025, representing an increase of 3% from 2024 (Figure 176). The NEA spot LNG price followed a clear seasonal and market-driven pattern, marked by early-year strength followed by a sustained decline in the second half.

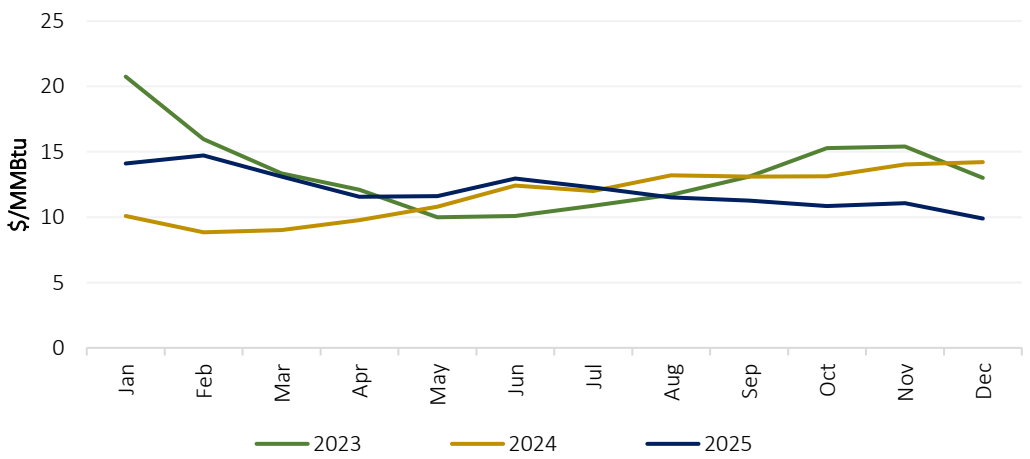
Prices began the year elevated, averaging $14.1/MMBtu in January, supported by winter demand and colder temperatures in parts of the region. However, weaker Chinese demand during the Lunar New Year, combined with ample LNG supply and high inventory levels, limited upside. In February, prices rose further to $14.7/MMBtu, tracking the bullish momentum in European hub prices. Nevertheless, subdued regional demand and abundant supply capped further gains.

From March, NEA spot LNG prices declined sharply, mirroring the easing of European gas prices amid warmer weather and robust LNG availability. The downturn extended into April, as muted demand and sustained oversupply pushed prices to multi-month lows. A modest stabilisation in May reflected temporary supply disruptions in Malaysia and the United States, although weak demand, particularly from China, continued to weigh on prices.

In June, prices rebounded amid heightened geopolitical tensions in the Middle East and rising temperatures in Japan and South Korea, boosting cooling-related gas demand. These gains proved short-lived, as prices softened again over the summer months. From July to October, NEA spot LNG prices declined for four consecutive months, driven by robust global LNG supply, high inventories and persistently weak regional demand, reaching a 17-month low in October.

In November, prices recorded a modest rebound, supported by higher charter rates that increased the cost of attracting LNG cargoes. However, this recovery was short-lived, and prices fell sharply in December to $9.9/MMBtu amid mild weather, ample supply and elevated inventories, ending the year well below early-2025 levels.

Figure 176: Monthly North East Asia (NEA) spot LNG prices



Source: GECF Secretariat based on data from Argus and LSEG

6.1.1.3 North American Spot Gas Prices

The HH spot gas price increased by 59% to average $3.6/MMBtu in 2025, marking its highest annual average since 2022 (Figure 177). Meanwhile, in Canada, the Alberta Energy Company (AECO) spot gas price also strengthened, rising by 31% to average $1.2/MMBtu, although it remained at multi-year lows.

HH spot gas prices were marked by sharp volatility throughout the year, driven by weather conditions, shifting production trends and robust LNG export growth. Prices surged early in the year, averaging above $4/MMBtu in January and February as colder-than-normal weather boosted heating demand, with daily prices briefly spiking to nearly $10/MMBtu. From March to June, prices declined steadily as strong domestic gas production outpaced relatively flat demand, pushing HH prices to multi-month lows. A modest rebound emerged in July, fuelled by stronger power-sector demand and record-breaking feedgas deliveries to new LNG export terminals, before prices softened again in August due to elevated production and inventories. From September onward, HH prices strengthened significantly, supported by rising seasonal demand, colder weather and the sustained ramp-up of US LNG export capacity, ending the year above $4/MMBtu and well above 2024 levels.

Meanwhile, the AECO spot gas price recovered from its record low in 2024. Over the past two years, Canada's gas market was oversupplied due to strong growth in domestic gas production. However, the start-up of the LNG Canada project increased gas demand and, together with a colder-than-usual winter toward the end of 2025, contributed to a rise in the spot gas price.

6.1.1.4 South America Spot LNG Prices

The South America (SA) spot LNG price rose by 5% to $11.4/MMBtu in 2025, despite weaker LNG imports. SA spot LNG prices largely tracked movements in TTF spot gas and NEA spot LNG prices. Average annual delivered LNG prices reached $11.4/MMBtu in Argentina, $11.2/MMBtu in Brazil and $11.5/MMBtu in Chile (Figure 178).

Figure 177: Monthly North American spot gas prices

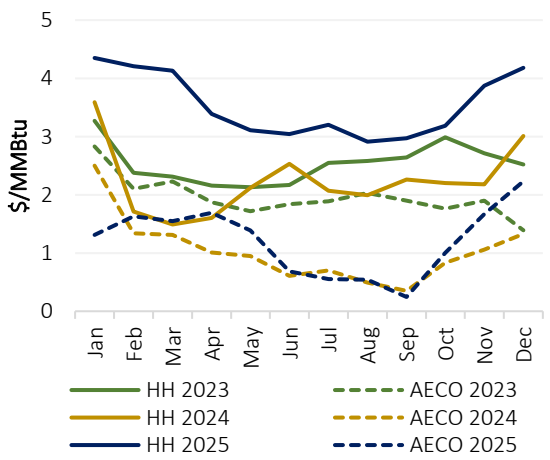
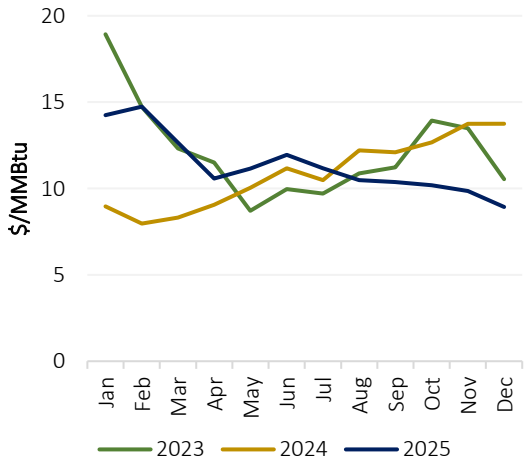


Figure 178: Monthly SA spot LNG prices



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

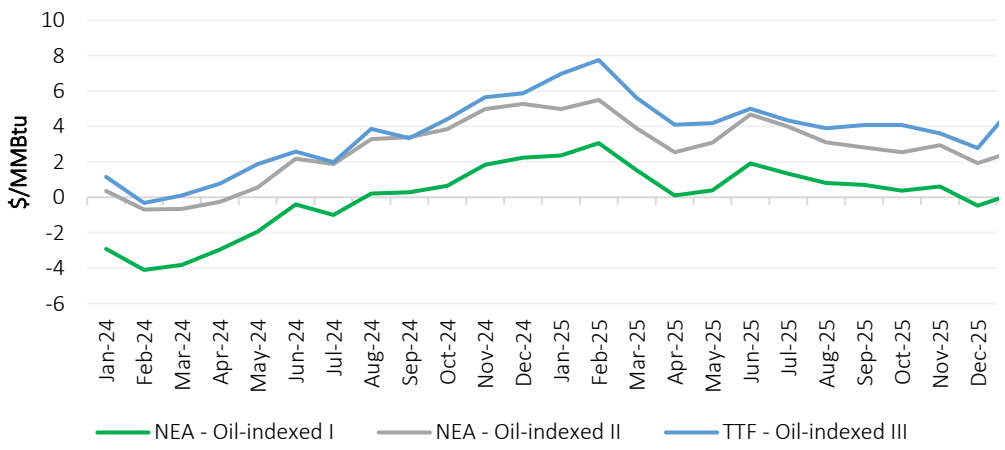
6.1.2 Spot and Oil-Indexed Long-Term LNG Price Spreads

The Oil-Indexed I and Oil-Indexed II LNG prices each declined by 13% in 2025 to average $11.0/MMBtu and $8.6/MMBtu, both at their lowest since 2021. This downward trend was primarily driven by weaker global oil prices, which directly influenced the indexed formulas governing LNG supplies to Asia. The two indices represent different generations of pricing strategies. Oil-Indexed I reflects traditional long-term contracts, using an average slope of 14.9% and a six-month historical Brent price average. In contrast, Oil-Indexed II, applied to more recent contracts, recalculates the slope annually based on a five-year historical average from long-term agreements; in 2025, this formula used a slope of 11.6% and a three-month Brent price average.

In terms of price spreads, Oil-Indexed I LNG prices traded at a discount to NEA spot LNG prices for most of 2025, except in December when they briefly shifted to a small premium (Figure 179). The discount averaged $2.3/MMBtu in Q1, narrowed during April–May and widened again to around $1.6/MMBtu in June–July. Overall, Oil-Indexed I prices averaged a discount of $1.1/MMBtu in 2025, compared with an average premium of $1.0/MMBtu in 2024. The flip from a premium to discount was driven by a rise in the NEA spot LNG price while Asia oil-indexed prices fell sharply. For Oil-Indexed II, the average discount to NEA spot LNG prices widened from $2.0/MMBtu in 2024 to $3.5/MMBtu in 2025.

In Europe, the Oil-Indexed III LNG price, based on Argus' assessment of long-term contracts, fell by 13% to average $7.2/MMBtu in 2025. It continued to trade at a discount to TTF spot gas prices, with the discount widening from $2.6/MMBtu in 2024 to $4.7/MMBtu in 2025, reflecting increasing divergence between oil-indexed and hub-based pricing.

Figure 179: Spot gas and oil-indexed price spreads



Source: GECF Secretariat based on data from Argus and LSEG
Note: Oil-indexed I (using traditional LTC slope): 14.9% X Brent (6 0 1) + 0.5
Oil-indexed II (using 5-year historical average LTC): (2023 – 11.1%; 2024 – 11.4%) % X Brent (3 0 1) + 0.5
Oil-indexed III: Argus assessment for European LTC.

6.1.3 Regional Spot Gas and LNG Price Spreads

The NEA–TTF inter-basin price spread narrowed sharply to just $0.2/MMBtu in 2025, falling from $0.8/MMBtu in 2024. This spread is a key indicator of the directional flow of spot and destination-free LNG cargoes, particularly from the US, between Europe and Asia, as it reflects relative netback economics driven by regional supply–demand balances.

When the NEA–TTF spread is below $1/MMBtu, deliveries of US LNG typically favour Europe over Asia. The persisting trend of narrow price spreads between Europe and Asia further intensified in 2025, once again incentivising record US LNG exports to European markets. This 2025 pattern mirrored the dynamics of 2024, where spreads averaging below $1/MMBtu supported high European intake relative to Asia.

During January–February 2025, the spread briefly turned negative as TTF prices surged to a premium over NEA spot LNG prices, reflecting strong European demand and supply constraints. From March to April, prices in both markets converged, after which NEA prices held a modest average premium of $0.6/MMBtu for most of the year (Figure 180).

As Europe became increasingly reliant on LNG to meet domestic gas demand amid structurally lower pipeline gas supplies, it emerged as the premium LNG market, particularly against a backdrop of weaker demand in Asia. As a result, Europe increasingly acted as the price setter for global spot LNG, with NEA spot LNG prices closely tracking movements in TTF as both regions competed for flexible US LNG cargoes. These dynamics highlight the growing interconnectivity of European and Asian gas markets, where shifts in one region can rapidly influence prices and trade flows in the other, especially during periods of market tightness.

Furthermore, the average TTF–HH price spread narrowed slightly in 2025, declining from $8.70/MMBtu in 2024 to $8.40/MMBtu. This reflected the sharper increase in HH spot gas prices relative to TTF. During 2025, the TTF–HH spread followed a downward trajectory, falling from a peak of $11.20/MMBtu in February to $5.3/MMBtu by December (Figure 181). This narrowing underscore the tightening price margins faced by US LNG exporters.

Figure 180: NEA-TTF price spread

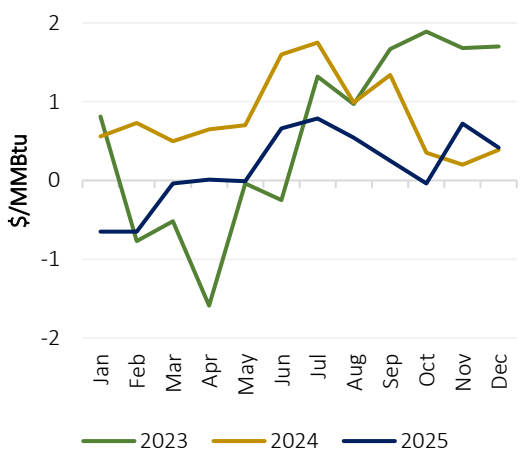
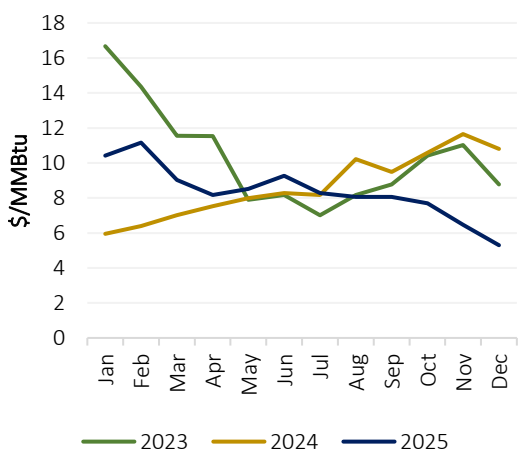


Figure 181: TTF-HH price spread



Source: GECF Secretariat based on data from Argus and LSEG

6.1.4 Gas & LNG Futures Prices

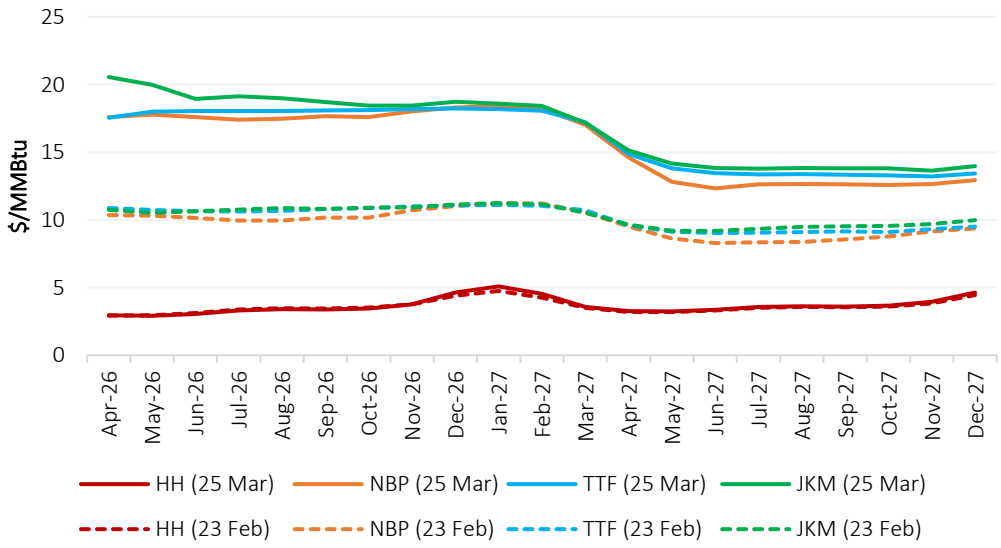
In 2026, European gas and global LNG prices were initially expected to soften amid strong growth in global LNG supply, led by new LNG export capacity. A looser spot LNG market was anticipated to improve supply availability across key importing regions, resulting in lower spot prices. However, the escalating conflict in the Middle East, which disrupted LNG flows from the region, has reversed this outlook, driving a sharp increase in futures prices.

Based on January–March 2026 spot prices and futures prices as of 25 March 2026, TTF, NBP and JKM annual prices in 2026 were projected to average $16.9/MMBtu, $16.7/MMBtu and $17.6/MMBtu, respectively. Compared with futures on 23 February 2026, prior to the escalating conflict, the projected annual average prices represented increases of 54%, 61% and 63%, respectively (Figure 182). The conflict has also widened the JKM premium over TTF, particularly for the period April to September 2026, reflecting Asia's need to attract flexible LNG cargoes from the Atlantic basin to compensate for contractual LNG volumes lost due to the conflict.

In the meantime, the HH average annual price was forecast to rise modestly to $3.7/MMBtu, supported by stronger LNG exports and colder-than-usual winter weather, with limited direct impact from the escalating conflict given the US's position as a net gas exporter.

In 2027, regional gas and LNG prices were projected to ease driven by the new wave of LNG supply. TTF, NBP, JKM and HH prices were projected to average $14.6/MMBtu, $14.1/MMBtu, $15.0/MMBtu and $3.8/MMBtu, respectively, still around 50% higher than pre-escalation expectations. While the JKM–TTF spread is likely to remain positive, narrower differentials could again support the redirection of US LNG toward Europe. Meanwhile, the TTF–HH spread is expected to remain elevated, supporting strong export margins for US LNG suppliers.

Figure 182: Gas & LNG futures prices



Source: GECF Secretariat based on data from LSEG
Note: Futures prices as of 25 March 2026

6.2 Cross Commodity Prices

6.2.1 Oil Prices

Brent oil prices declined by 15% in 2025, with the spot and month-ahead prices averaging $69.9/bbl and $68.2/bbl, respectively, at their lowest levels since 2020 (Figure 183).

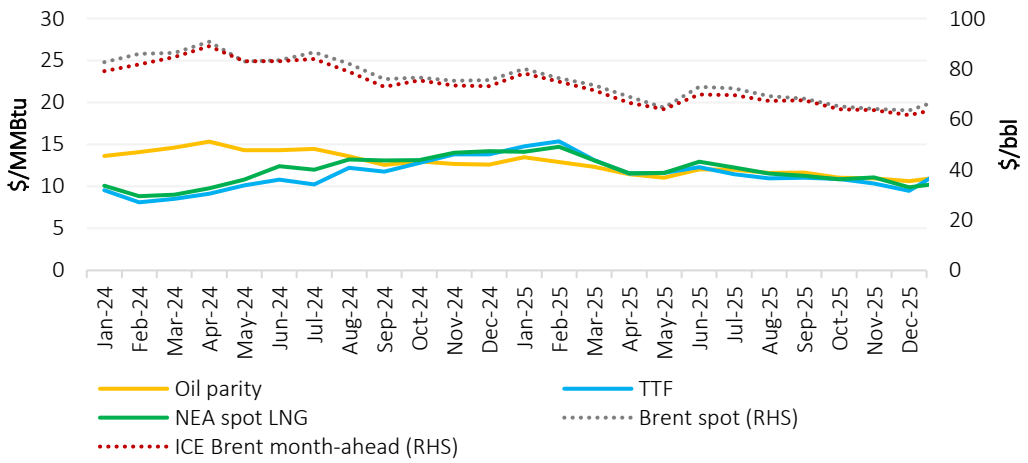
Brent crude prices exhibited pronounced volatility, shaped by geopolitical risks, futures sentiment and evolving physical fundamentals. Prices rebounded in January as supply concerns resurfaced, supported by falling US crude stocks and strong spot buying. However, gains proved short-lived, with prices retreating through May as futures selloffs, easing risk premiums and rising inventories weighed on sentiment. Growing trade tensions further dampened risk appetite, pushing Brent to multi-year lows by April.

Prices stabilised and rebounded in June, driven by heightened geopolitical tensions in the Middle East and Europe, stronger physical demand ahead of the summer driving season and sizeable draws in US crude stocks. Through July and September, Brent followed a mixed trajectory, underpinned by robust refinery runs and strong middle-distillate margins, but capped by futures market uncertainty and macroeconomic headwinds.

From October to December, Brent prices trended lower again as refinery intakes declined, supply risk premiums eased and futures markets faced persistent selling pressure from money managers. Despite this, firm physical fundamentals, particularly in the Atlantic Basin, helped limit downside risks toward year-end. Strong refinery demand, stock draws and regional supply disruptions provided intermittent support, but overall market sentiment remained cautious amid continued geopolitical uncertainty and volatile financial conditions.

TTF and NEA spot LNG prices broadly converged with oil parity in 2025, trading at small premiums of $0.2/MMBtu and $0.3/MMBtu, respectively.

Figure 183: Monthly crude oil prices



Source: GECF Secretariat based on data from 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

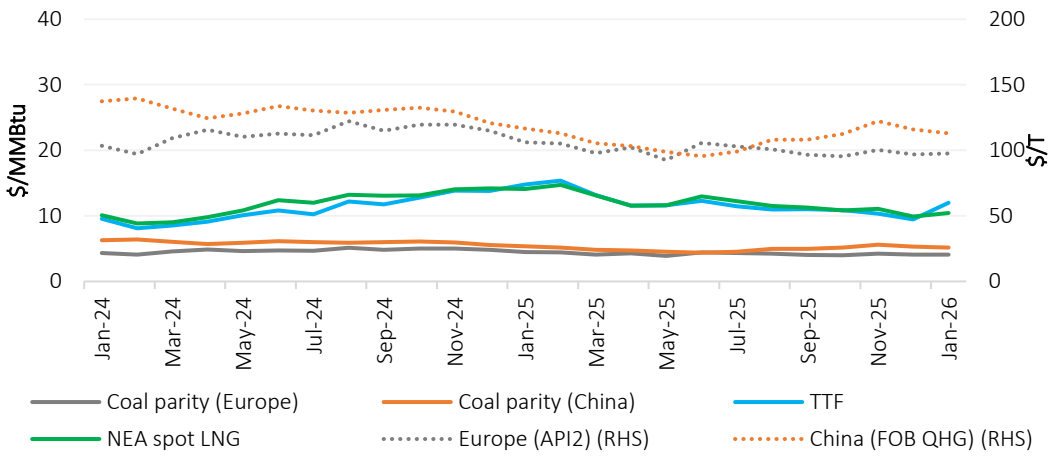
Global coal prices remained under downward pressure in 2025, marking a third consecutive annual decline and reaching their lowest levels since 2020. Europe's API2 coal price averaged $100.2/t, down 11% y-o-y, while China's Qinhuangdao (QHG) coal price fell more sharply by 17% y-o-y to $108.2/t (Figure 184).

In Europe, API2 prices followed a largely bearish trajectory, reflecting weakening demand fundamentals and ample supply. Prices were relatively firm early in the year, supported by winter heating demand and precautionary procurement. However, from early spring, milder weather reduced coal burn in the power sector, while lower gas prices improved coal-to-gas switching economics. Elevated inventories and limited restocking interest further weighed on prices. A brief mid-year rebound, driven by temporary supply tightness and firmer international coal market conditions, proved short-lived. Prices softened again in the second half of the year amid strong renewable generation, high stock levels and structurally declining coal use, with only modest year-end support from seasonal restocking and colder weather.

In China, QHG coal prices also trended lower, reflecting soft demand and strong domestic supply. After a relatively firm start to the year, prices weakened from spring as mild weather, high inventories at ports and power plants and robust coal output reduced procurement needs. Weaker steel production further dampened coal demand, reinforcing oversupply concerns. Although seasonal power demand and restocking provided intermittent support, rising renewable and hydropower generation and cautious buying limited any sustained recovery.

In terms of price spreads, the premium of TTF over the API2 parity price widened to $7.7/MMBtu, while the premium of the NEA spot LNG price over the QHG parity price increased to $7.1/MMBtu. This reflected a growing divergence between spot gas/LNG prices relative to coal prices.

Figure 184: 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.

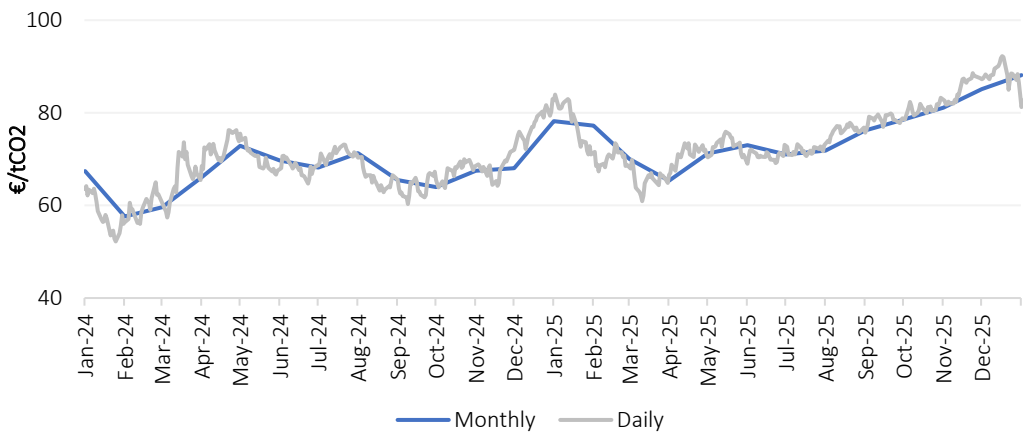
6.2.3 Carbon Prices

Globally, there are around 40 emissions trading systems (ETS's), covering nearly 20% of global greenhouse gas emissions, with the EU ETS being the first and largest carbon market. In 2025, the EU carbon price averaged €74.9/tCO_2 representing an increase of 13% compared to the average of €66.5/tCO_2 in 2024 (Figure 185). The EU ETS carbon prices were highly volatile, reflecting the interaction between tightening climate policy, energy-market fundamentals and elevated macroeconomic uncertainty. Overall, prices in 2025 followed a somewhat U-shaped trajectory, weakening in the first half of the year before recovering strongly toward year-end.

Prices opened the year near €78/t, supported by elevated gas prices, colder weather, lower wind output and speculative positioning ahead of new compliance obligations. Structural policy drivers remained firmly supportive. The accelerated cap reduction under the Fit for 55 reforms continued to constrain supply, while 2025 marked the first year of maritime sector compliance, adding a new source of demand. At the same time, anticipation of the phase-out of free allocations from 2026 and the conclusion of the CBAM transitional phase encouraged forward-looking buying. However, concerns over affordability and industrial competitiveness gained prominence, with growing expectations that the launch of ETS2 would be delayed to 2028, tempering near-term sentiment without undermining confidence in the ETS framework.

Prices fell sharply in spring, reaching a year-low of around €65/t in April, as milder weather, strong renewable generation, easing gas prices and rising global trade tensions weighed on power demand and industrial activity. From late spring, prices stabilised and gradually recovered, trading mostly in the low-to-mid €70/t range through summer. Support came from intermittent heatwaves, nuclear constraints, compliance buying ahead of the September deadline and renewed fund accumulation in anticipation of tighter supply in 2026. Momentum strengthened in autumn, with prices moving above €80/t and ending the year close to €85/t, supported by colder weather, lighter auction supply and strong speculative net-long positions.

Figure 185: EU carbon prices



Source: GECF Secretariat based on data from LSEG

6.2.4 Coal-to-Gas Switching

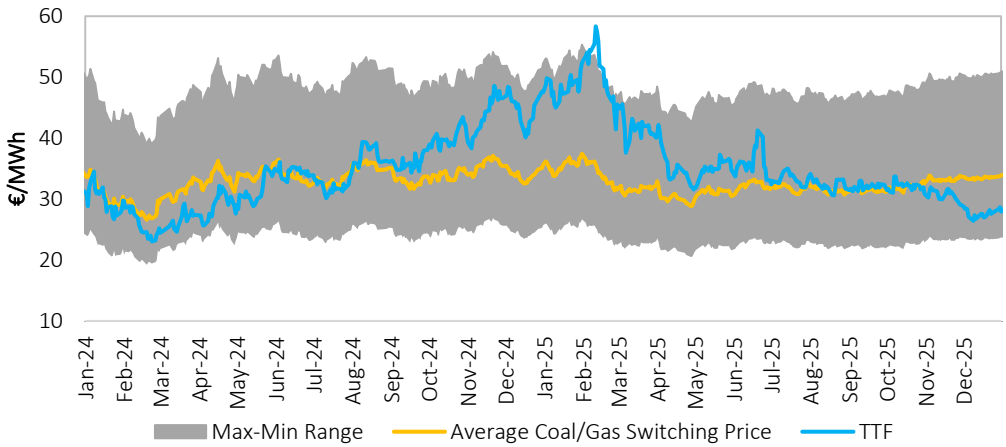
Daily TTF spot gas prices generally remained within the coal-to-gas switching range in 2025, except for a brief spike in February when prices exceeded the upper threshold. The average coal-to-gas switching price declined by 2% to €32.35/MWh, while the TTF spot price averaged €36.31/MWh (Figure 186). Consequently, the TTF premium over the switching price widened sharply from €1.15/MWh in 2024 to €3.96/MWh in 2025, weakening incentives for coal-to-gas switching, particularly for less efficient coal-fired power plants.

During the first half of the year, TTF gas prices remained consistently above the average coal-to-gas switching price. This was most pronounced in the first quarter, when colder weather, supply tightness and elevated gas demand pushed TTF prices to a peak premium of around €17/MWh over the average switching price in February. Under these conditions, coal retained a relative cost advantage in power generation over gas.

From mid-year, market conditions shifted. Between July and October, TTF spot price gradually converged with the coal-to-gas switching price. This convergence improved the competitiveness of gas-fired generation relative to coal, encouraging higher gas utilisation in the power sector, particularly among more efficient combined-cycle gas turbine plants. Toward year-end, the incentive structure strengthened further. In November and December, TTF prices fell below the average coal-to-gas switching price, creating a clear economic signal in favour of gas over coal.

Looking ahead to 2026, the expected easing of TTF spot prices amid rising LNG supply is likely to keep gas prices within, or below, the coal-to-gas switching range, reinforcing incentives for greater gas use in the EU power sector.

Figure 186: 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

Gas Market Data

Region	2019	2020	2021	2022	2023	2024	2025
Gas consumption (bcm)							
Global	**3,957**	**3,857**	**4,047**	**4,062**	**4,048**	**4,166**	**4,217**
Africa	173	166	173	173	174	178	185
Asia Pacific	847	850	909	895	916	967	977
Eurasia	635	603	654	641	645	672	678
Europe	548	500	525	513	446	448	461
LAC	154	143	158	150	149	154	155
Middle East	533	540	551	562	580	589	591
North America	1,079	1,055	1,076	1,129	1,139	1,157	1,169
Gas production (bcm)							
Global	**4,016**	**3,905**	**4,082**	**4,052**	**4,080**	**4,181**	**4,232**
Africa	267	244	275	266	271	256	262
Asia Pacific	651	645	663	666	670	687	689
Eurasia	904	847	944	842	825	884	868
Europe	232	215	206	214	199	202	200
LAC	176	160	162	165	163	167	168
Middle East	630	644	657	661	665	698	716
North America	1,155	1,150	1,174	1,237	1,287	1,287	1,329
Total gas imports (bcm)							
Global	**1,166**	**1,130**	**1,209**	**1,164**	**1,124**	**1,166**	**1,198**
Africa	9	11	13	14	17	22	33
Asia Pacific	406	416	452	424	436	469	464
Eurasia	66	58	47	46	48	58	64
Europe	451	415	450	436	376	358	382
LAC	28	27	36	27	27	29	25
Middle East	42	46	43	43	43	44	45
North America	164	157	169	173	177	185	187

Region/Market	2019	2020	2021	2022	2023	2024	2025
Pipeline gas imports (bcm)							
Global	**685**	**643**	**695**	**622**	**571**	**608**	**605**
Africa	9	11	12	14	17	19	20
Asia Pacific	71	69	79	81	79	86	92
Eurasia	66	58	47	46	48	58	64
Europe	336	304	345	265	208	222	205
LAC	14	13	13	12	10	9	8
Middle East	32	36	33	34	33	32	32
North America	156	153	166	171	175	183	185
LNG imports (bcm)							
Global	**481**	**487**	**514**	**541**	**553**	**557**	**594**
Africa	0	0	0	0	0	3	13
Asia Pacific	334	347	373	344	357	382	372
Europe	115	112	106	171	168	137	177
LAC	13	14	23	15	17	20	17
Middle East	10	10	10	9	10	12	13
North America	8	4	2	2	2	2	2
Gas & LNG spot prices ($/MMBtu)							
TTF	4.5	3.2	15.9	37.6	12.9	10.9	11.9
North East Asia (NEA) LNG	5.4	4.4	18.6	33.2	13.5	11.7	12.1
HH	2.6	2.0	3.9	6.4	2.5	2.2	3.6

Source: GECF Secretariat based on data from Argus, Cedigaz, ICIS LNG Edge, LSEG and Rystad Energy

Regional Grouping

Term	Meaning
Advanced Economies (AEs)	Australia, Austria, Belgium, Canada, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hong Kong, Iceland, Ireland, Israel, Italy, Japan, Korea, Latvia, Lithuania, Luxembourg, Macau (China), Malta, Netherlands, New Zealand, Norway, Portugal, Puerto Rico, San Marino, Singapore, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Taiwan (Province of China), United Kingdom, United States
Africa	Algeria, Angola, Benin, Central African Rep., Congo, Democratic Republic of the Congo, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Ghana, Gabon, Ivory Coast, Kenya, Libya, Mali, Mauritania, Morocco, Mozambique, Namibia, Niger, Nigeria, Senegal, South Africa, South Sudan, Sudan, Tanzania, Togo, Tunisia, Uganda, Zambia, Zimbabwe
Asia Pacific	Afghanistan, Australia, Bangladesh, Bhutan, Brunei Darussalam, Cambodia, China, Cook Islands, Democratic People's Republic of Korea, Fiji, French Polynesia, Hong Kong, India, Indonesia, Japan, Kiribati, Korea, Lao People's Democratic Republic, Macau (China), Malaysia, Maldives, Mongolia, Myanmar, Nepal, New Caledonia, New Zealand, Pakistan, Palau, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan (Province of China), Thailand, Timor-Leste, Tonga, Vanuatu, Vietnam
BRICS	Brazil, Russia, India, China and South Africa
Emerging Markets and Developing Economies (EMDEs)	All other countries not included in "Advanced Economies"
Eurasia	Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, Russia, Tajikistan, Turkmenistan, Ukraine, Uzbekistan
Europe	European Union and Albania, Bosnia and Herzegovina, Gibraltar, Iceland, Macedonia, Moldova, Montenegro, Norway, Serbia, Switzerland, Türkiye, United Kingdom
European Union	Austria, Belgium, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden

Euro area	Austria, Belgium, Croatia, Cyprus, Estonia, Finland, France, Germany, Greece, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Portugal, Slovakia, Slovenia, Spain
G7	Canada, France, Germany, Italy, Japan, United Kingdom, United States
G20	Argentina, Australia, Brazil, Canada, China, EU, France, Germany, India, Indonesia, Italy, Japan, Mexico, Russia, Saudi Arabia, South Africa, South Korea, Türkiye, United Kingdom, United States
GECF Members	Algeria, Bolivia, Egypt, Equatorial Guinea, Libya, Iran, Nigeria, Qatar, Russia, Trinidad and Tobago, United Arab Emirates, Venezuela
GECF Observer Members	Angola, Azerbaijan, Iraq, Malaysia, Mauritania, Mozambique, Peru, Senegal
Latin America and the Caribbean (LAC)	Antigua and Barbuda, Argentina, Aruba, Bahamas, Barbados, Belise, Bermuda, Bolivia, Brazil, British Virgin Islands, Cayman Islands, Chile, Colombia, Costa Rica, Cuba, Dominica, Dominican Republic, Ecuador, El Salvador, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Montserrat, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Saint Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, Saint Vincent and the Grenadines, Suriname, Trinidad and Tobago, Turks and Caicos Islands, Uruguay, Venezuela
Middle East	Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, United Arab Emirates, Yemen
Middle East and Africa (MEA)	Algeria, Angola, Bahrain, Benin, Central African Rep., Congo, Democratic Republic of the Congo, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Ghana, Gabon, Iran, Iraq, Israel, Ivory Coast, Jordan, Kenya, Kuwait, Lebanon, Libya, Mali, Mauritania, Morocco, Mozambique, Namibia, Niger, Nigeria, Oman, Qatar, Saudi Arabia, Senegal, South Africa, South Sudan, Sudan, Syria, Tanzania, Togo, Tunisia, Uganda, United Arab Emirates, Yemen, Zambia, Zimbabwe
North America	Canada, Mexico, United States
South America	Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador, French Guyana, Guyana, Paraguay, Peru, Suriname, Uruguay, Venezuela

Abbreviations

Abbreviation	Explanation
ACQ	Annual contracted quantity
AE	Advanced economies
AECO	Alberta Energy Company
bcm	Billion cubic metres
bcma	Billion cubic metres per annum
BOE	Bank of England
bbl	Barrel
bpd	Barrel per day
CAGR	Compound annual growth rate
CBAM	Carbon border adjustment mechanism
CBM	Coal bed methane
CCGT	Combined cycle gas turbine
CCS	Carbon, capture and storage
CCUS	Carbon capture, utilisation and storage
CNG	Compressed natural gas
CO_2	Carbon dioxide
CPI	Consumer price index
EC	European Commission
ECB	European Central Bank
EEXI	Energy efficiency existing ship index
EMDE	Emerging markets and developing economies
EU	European Union
EU ETS	European Union emissions trading system
EUA	European Union allowance
Fed	Federal Reserve

FEED	Front end engineering design
FID	Final investment decision
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 Organisation
JKM	Japan Korea Marker
LNG	Liquefied natural gas
LAC	Latin America and the Caribbean
LT	Long-term
MEA	Middle East and Africa
MENA	Middle East and North Africa
MER	Market exchange rates
METI	Ministry of Trade and Industry in Japan
MMBtu	Million British Thermal Unit
m-o-m	month-on-month
Mt	Million tonnes
Mtpa	Million tonnes per annum
MWh	Megawatt hour
NEA	North East Asia
NBP	National balancing Point
NDC	Nationally determined contribution
NGV	Natural gas vehicle

NZBA	Net-Zero Banking Alliance
OECD	Organisation for Economic Co-operation and Development
PBC	People's Bank of China
PPAC	Petroleum Planning & Analysis Cell
PPP	Purchasing power parity
PSV	Punto di Scambio Virtuale (Virtual Trading Point in Italy)
QHG	Qinhuangdao
R-LNG	Regasified LNG
SA	South America
SPA	Sales and purchase agreement
SWE	South West Europe
T&T	Trinidad and Tobago
TANAP	Trans-Anatolian Gas Pipeline
tcm	Trillion cubic metres
tCO_2	Ton 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
USTR	Office of the United States Trade Representative
y-o-y	year-on-year

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