GECF

Gas Exporting Countries Forum

MONTHLY GAS MARKET REPORT

August 2026

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Countries Forum

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About the GECF

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

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

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Project Leader

- Aydar Shakirov, Head of the Gas Market Analysis Department (GMAD)

Expert Team (in alphabetical order)

- Adrian Sookhan, Gas Market Analyst, GMAD
- Hossam ElMasry, Energy Analyst, GMAD
- Imran Mohammed, Gas Transportation and Storage Analyst, GMAD
- Rafik Amara, Senior Gas Market Analyst, GMAD
- Sandy Singh, Market Research Analyst, GMAD

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Peer Review

GaffneyCline energy advisory (GCea)

Tornado Tower, 47th & 48th Floors, West Bay, Doha, Qatar

CONTENTS

HIGHLIGHTS 1

FEATURE ARTICLE: 2

1 GLOBAL PERSPECTIVES 6

1.1 Global economy *6*

1.2 Other developments *9*

2 GAS CONSUMPTION 10

2.1 Europe *10*

2.2.1 European Union 10

2.1.2 United Kingdom 15

2.2 Asia *16*

2.2.1 China 16

2.2.2 India 16

2.2.3 Japan 17

2.2.4 South Korea 17

2.3 North America *18*

2.3.1 Canada 18

2.3.2 US 18

2.4 Other developments *19*

3 GAS PRODUCTION 21

3.1 Europe *22*

3.1.1 Norway 23

3.1.2 UK 23

3.1.3 Netherlands 23

3.2 Asia Pacific *24*

3.2.1 China 24

3.2.2 India 24

3.2.3 Australia 25

3.2.4 Indonesia 25

3.2.5 Malaysia 25

3.3 North America *26*

3.3.1 Canada 26

3.3.2 Mexico 26

3.3.3 US 27

3.4 Latin America and the Caribbean (LAC) *28*

3.4.1 Argentina 28

3.4.2 Brazil 28

3.5 Other developments *29*

3.5.1 Upstream tracker 29

3.5.2 Regional developments 30

4 GAS TRADE 31

4.1 PNG trade *31*

4.1.1 Europe 31

4.1.2 Asia 33

4.1.3 North America 34

4.1.4 Latin America and the Caribbean 34

4.1.5 Other developments ... 34

4.2 LNG trade ... 35
4.2.1 LNG imports ... 35
4.2.2 LNG exports ... 38
4.2.3 Global LNG re-exports ... 40
4.2.4 Arbitrage opportunity ... 40
4.2.5 Maintenance activity at LNG liquefaction facilities ... 41
4.2.6 LNG shipping ... 42
4.2.7 Other developments ... 44

5 GAS STORAGE ... 45

5.1 Europe ... 45

5.2 Asia ... 47

5.3 North America ... 47

6 ENERGY PRICES ... 48

6.1 Gas prices ... 48
6.1.1 Gas & LNG spot prices ... 48
6.1.2 Spot and oil-indexed long-term LNG price spreads ... 51
6.1.3 Regional spot gas & LNG price spreads ... 51
6.1.4 Gas & LNG futures prices ... 52

6.2 Cross commodity prices ... 53
6.2.1 Oil prices ... 53
6.2.2 Coal prices ... 53
6.2.3 Carbon prices ... 54
6.2.4 Fuel switching ... 54

ANNEXES ... 55

Abbreviations ... 55

References ... 58

List of Figures

Figure 1: Global GDP growth ... 6
Figure 2: GDP growth in major economies ... 6
Figure 3: Inflation rates ... 7
Figure 4: Monthly commodity price indices ... 7
Figure 5: Interest rates in major central banks ... 8
Figure 6: Exchange rates ... 8
Figure 7: Gas consumption in the EU ... 10
Figure 8: Trend in electricity production in the EU in July 2026 (y-o-y change) ... 10
Figure 9: Gas consumption in Germany ... 11
Figure 10: Trend in gas consumption in the industrial sector in Germany (y-o-y change) ... 11
Figure 11: Trend in electricity production in Germany in July 2026 (y-o-y change) ... 11
Figure 12: German electricity mix in July 2026 ... 11
Figure 13: Gas consumption in Italy ... 12
Figure 14: Trend in gas consumption in the industrial sector in Italy (y-o-y change) ... 12
Figure 15: Trend in electricity production in Italy in June 2026 (y-o-y change) ... 12
Figure 16: Italian electricity mix in June 2026 ... 12
Figure 17: Gas consumption in France ... 13
Figure 18: Trend in gas consumption in the industrial sector in France (y-o-y change) ... 13
Figure 19: Trend in electricity production in France in July 2026 (y-o-y change) ... 13
Figure 20: French nuclear capacity availability ... 13
Figure 21: Gas consumption in Spain ... 14
Figure 22: Trend in gas consumption in the industrial sector in Spain (y-o-y change) ... 14
Figure 23: Trend in electricity production in Spain in July 2026 (y-o-y change) ... 14
Figure 24: Spanish electricity mix in July 2026 ... 14
Figure 25: Gas consumption in the UK ... 15
Figure 26: Trend in gas consumption in the industrial sector in the UK (y-o-y change) ... 15
Figure 27: YTD EU and UK gas consumption ... 15
Figure 28: Y-o-y variation in EU and UK gas consumption ... 15
Figure 29: Gas consumption in China ... 16
Figure 30: Y-o-y electricity variation in China ... 16
Figure 31: Gas consumption in India ... 16
Figure 32: India's gas consumption by sector ... 16
Figure 33: Gas consumption in Japan ... 17
Figure 34: Gas consumption in South Korea ... 17
Figure 35: YTD gas consumption in North East Asia and India ... 17
Figure 36: Y-o-y variation in aggregated gas consumption of North East Asia and India ... 17
Figure 37: Gas consumption in Canada ... 18
Figure 38: Gas consumption in the US ... 18
Figure 39: Electricity production in US in June 2026 ... 18
Figure 40: Temperature forecast for July - September 2026 ... 20
Figure 41: Precipitation forecast July - September 2026 ... 20
Figure 42: Y-o-y variation in global gas production ... 21
Figure 43: Regional gas production in June 2026 ... 21
Figure 44: YTD global gas production ... 21
Figure 45: Europe's monthly gas production ... 22
Figure 46: Y-o-y variation in Europe's gas production ... 22
Figure 47: YTD Europe's gas production ... 22
Figure 48: Trend in gas production in Norway ... 23
Figure 49: Trend in gas production in the UK ... 23
Figure 50: Trend in gas production in the Netherlands ... 23
Figure 51: Trend in gas production in China ... 24
Figure 52: YTD China's gas production ... 24
Figure 53: Trend in gas production in India ... 24
Figure 54: YTD India's gas production ... 24
Figure 55: Trend in gas production in Australia ... 25
Figure 56: Trend in gas production in Indonesia ... 25
Figure 57: Trend in gas production in Malaysia ... 25
Figure 58: Trend in gas production in Canada ... 26
Figure 59: Gas rig count in Canada ... 26
Figure 60:Trend in gas production in Mexico ... 26
Figure 61: Trend in gas production in the US ... 27
Figure 62: YTD gas production in the US ... 27
Figure 63: Gas rig count in the US ... 27
Figure 64: DUC wells count in the US ... 27
Figure 65: Trend in gas production in Argentina ... 28
Figure 66: Shale gas output in Argentina ... 28
Figure 67: Marketed gas production in Brazil ... 28
Figure 68: Distribution of gross gas production ... 28
Figure 69: Trend in monthly global gas rig count ... 29
Figure 70: Monthly discovered oil and gas volumes ... 29

Figure 71: Discovered oil and gas volumes ... 29
Figure 72: Global PNG imports (-) and exports (+) by region ... 31
Figure 73: Monthly PNG imports to the EU ... 31
Figure 74: Year-to-date EU PNG imports by supplier ... 31
Figure 75: Y-o-y variation in EU PNG supply ... 32
Figure 76: EU PNG imports by entry, after 6M 2026 ... 32
Figure 77: PNG imports to the EU by supply route (7M 2026 v 7M 2025) ... 32
Figure 78: Monthly PNG imports in China ... 33
Figure 79: Year-to-date PNG imports in China ... 33
Figure 80: Monthly PNG imports in Singapore ... 33
Figure 81: Monthly PNG imports in Thailand ... 33
Figure 82: Net US PNG exports (+) and imports (-) ... 34
Figure 83: Monthly PNG exports from Bolivia ... 34
Figure 84: Trend in global monthly LNG imports ... 35
Figure 85: Trend in regional YTD LNG imports ... 35
Figure 86: Trend in Europe's monthly LNG imports ... 36
Figure 87: Top LNG importers in Europe ... 36
Figure 88: Trend in Asia's monthly LNG imports ... 36
Figure 89: LNG imports in Asia Pacific by country ... 36
Figure 90: Trend in LAC's monthly LNG imports ... 37
Figure 91: Top LNG importers in LAC ... 37
Figure 92: Trend in MEA's monthly LNG imports ... 37
Figure 93: Top LNG importers in MEA ... 37
Figure 94: Trend in global monthly LNG exports ... 38
Figure 95: Trend in YTD LNG exports by supplier ... 38
Figure 96: Trend in GECF monthly LNG exports ... 39
Figure 97: GECF's LNG exports by country ... 39
Figure 98: Trend in non-GECF monthly LNG exports ... 39
Figure 99: Non-GECF's LNG exports by country ... 39
Figure 100: Trend in global monthly LNG re-exports ... 40
Figure 101: Global YTD LNG re-exports by country ... 40
Figure 102: Price spreads & shipping costs between Asia & Europe spot LNG markets ... 41
Figure 103: Maintenance activity at LNG liquefaction facilities during July (2025 and 2026) ... 41
Figure 104: Number of LNG export cargoes ... 42
Figure 105: Changes in LNG cargo exports ... 42
Figure 106: Average LNG spot charter rate ... 43
Figure 107: Average price of shipping fuels ... 43
Figure 108: Spot shipping costs for TFDE LNG carriers ... 43
Figure 109: Monthly average UGS level in the EU ... 45
Figure 110: Net gas injections in the EU ... 45
Figure 111: UGS in EU countries as of 31 July 2026 ... 45
Figure 112: Total LNG storage in the EU ... 45
Figure 113: EU + UK monthly gas balance ... 46
Figure 114: LNG in storage in Japan and South Korea ... 47
Figure 115: Monthly average UGS level in the US ... 47
Figure 116: Daily gas & LNG spot prices ... 48
Figure 117: Daily variation of spot prices ... 48
Figure 118: Monthly European spot gas prices ... 49
Figure 119: Monthly Asian spot LNG prices ... 49
Figure 120: Monthly North American spot gas prices ... 50
Figure 121: Monthly South American spot LNG prices ... 50
Figure 122: Spot and oil-indexed LNG price spreads ... 51
Figure 123: NEA-TTF price spread ... 51
Figure 124: TTF-HH price spread ... 51
Figure 125: Gas & LNG futures prices ... 52
Figure 126: Variation in gas & LNG futures prices ... 52
Figure 127: Monthly crude oil prices ... 53
Figure 128: Monthly coal parity prices ... 53
Figure 129: EU carbon prices ... 54
Figure 130: Daily TTF vs coal-to-gas switching prices ... 54

List of Tables

Table 1: New LNG sale agreements signed in July 2026 ... 44
Table 2: EU + UK gas supply/demand balance for July 2026 (bcm) ... 46

HIGHLIGHTS

Gas consumption: Global gas consumption came under pressure during the first seven months of 2026 amid the Middle East crisis, as supply disruptions and higher spot prices weighed on demand, although trends varied across regions. In Asia, gas demand was affected by weaker industrial activity and slowing economic momentum, while North American demand declined amid broad-based weakness across major consuming sectors. In contrast, European gas demand increased, supported by elevated cooling requirements during widespread summer heatwaves.

Gas production: The closure of the Strait of Hormuz had a significant impact on global gas production, with Middle Eastern output contracting by nearly one-third year-on-year as major gas and LNG producers in the region recorded sharp production declines. The regional supply losses were partially offset at the global level by continued production growth in North America, particularly in the US, where rising gas output helped cushion the impact of the Middle Eastern supply disruption.

Gas trade: Global LNG imports fell by 2.9% y-o-y to 33.4 Mt in July 2026, as restrictions on LNG transit through the Strait of Hormuz constrained Middle Eastern supply and global trade. Europe led the decline, with imports plunging 32% y-o-y to 6.22 Mt, the lowest since September 2021. A significant Asian spot LNG premium attracted flexible US cargoes towards higher-netback Asian markets, reducing Europe's US LNG imports from 5.43 Mt in July 2025 to 3.67 Mt in July 2026. Conversely, Asia's LNG imports rose 8.8% y-o-y to 23.15 Mt, marking a second consecutive month of recovery. On the supply side, Cameroon ended eight years of LNG exports following FLNG Hilli Episeyo's departure for upgrades in Singapore ahead of its planned 20-year redeployment to Argentina.

Gas storage: Countries in the northern hemisphere continued their net gas injection seasons to prepare for the upcoming winter. In July 2026, the EU monthly average gas storage level stood at 55 bcm (53% of capacity), which is a significant decline from 66 bcm a year ago, as the region faces intense competition with Asia for available spot LNG cargoes. Meanwhile, the US maintained a stable monthly average inventory of 86 bcm, representing 65% of capacity and remaining on par with the 87 bcm recorded a year earlier. In contrast, combined LNG inventories in Japan and South Korea dropped to 8.9 bcm amidst a tight spot market and heightened summer cooling demand.

Energy prices: Gas and LNG spot prices in Europe and Asia rose sharply in July, driven by renewed geopolitical tensions in the Middle East. Average TTF prices increased by 19% m-o-m to $18.1/MMBtu, surpassing the monthly average recorded in March. Similarly, NEA spot LNG prices rose by 14% m-o-m to $19.6/MMBtu. In contrast, HH spot prices softened, decreasing by 7% m-o-m to $2.9/MMBtu. Looking ahead, competition for flexible LNG cargoes is expected to intensify as both regions prepare for the winter season, lending continued support to spot prices. Any further escalation of the Middle East conflict could exert additional upward pressure on spot prices.

FEATURE ARTICLE:

Associated gas as a driver of greater economic value and emissions reduction

Associated gas is natural gas produced together with crude oil from the same reservoir. The volume produced relative to crude oil varies depending on field geology, reservoir pressure and production maturity. Historically, it was often regarded as a by-product of oil production and, where capture and utilisation infrastructure was limited, was frequently flared. Today, it is increasingly recognised as a valuable resource that can support domestic energy supply and other productive uses. Efforts to reduce routine gas flaring and methane emissions are further strengthening incentives to capture, process and commercialise these volumes. Effective management of associated gas is therefore becoming increasingly important for maximising the value of hydrocarbon resources while reducing their environmental footprint.

Once produced, associated gas can be directed to several uses and disposition routes. Gross associated gas production can be broadly allocated among (i) marketed gas, (ii) gas used for on-site operations, (iii) gas reinjected or used for Enhanced Oil Recovery (EOR), (iv) gas flared, and (v) gas vented or released through leaks and other fugitive emissions. The balance among these pathways depends on gathering, processing and transportation infrastructure, the economics of gas utilisation, reservoir management requirements and regulatory conditions.

Global marketed associated gas production has increased significantly over the past decades, reflecting the expansion of global oil production and the growing capture and utilisation of gas produced alongside crude oil. Marketed production rose from 75 bcm in 1950 to 344 bcm in 1980 and 413 bcm in 2000, before reaching 590 bcm in 2025 (Figure i). This sustained growth highlights the increasing contribution of associated gas to overall natural gas supply, with marketed associated gas accounting for 14% of total global gas production in 2025. Unlike non-associated gas, produced from dedicated gas reservoirs and more directly influenced by market conditions, associated gas production is primarily driven by oil production. When oil prices are favourable and crude oil output expands, associated gas volumes can increase regardless of gas prices or demand. Conversely, when oil production declines, associated gas output generally falls in tandem, potentially creating supply gaps met by non-associated gas or other sources.

From a regional perspective, marketed associated gas production is highly concentrated in North America, which accounts for more than half of global marketed associated gas output. The Middle East and Eurasia follow at 12% and 11%, respectively (Figure ii).

Figure i: Global marketed associated gas production

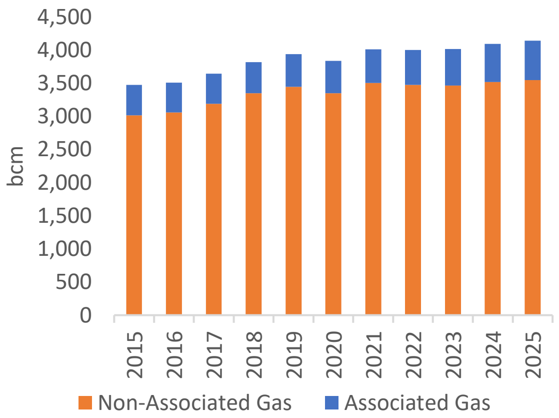
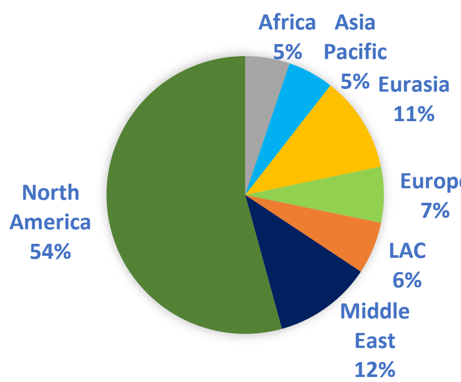


Figure ii: Regional distribution of marketed associated gas production in 2025



Source: GECF Secretariat based on data from Rystad Energy

In North America, the US dominates, accounting for 48% of global marketed associated gas production and leading by a significant margin, as the shale revolution triggered a rapid expansion of oil production from the country's shale and tight oil plays. Strong growth in US oil production, which doubled from 640 Mt in 2010 to 1,280 Mt in 2025, has translated into a substantial increase in marketed associated gas supply, rising from 90 bcm to 280 bcm over the same period and reaching 26% of total US gas output. Extensive gathering, processing, and pipeline infrastructure has enabled a large share of associated gas volumes to be captured and marketed, particularly in major oil-producing basins such as the Permian, Bakken, Eagle Ford, Anadarko, and Niobrara. The Permian Basin has emerged as the largest US source, accounting for nearly 60% of marketed associated gas output. The resulting supply of associated gas represents a structural source of relatively price-inelastic gas, which can exert downward pressure on Henry Hub prices during periods of weak gas demand and weaken the link between gas supply growth and gas-specific investment decisions and market signals.

In the Middle East, strategic midstream investments are transforming associated gas from a historical by-product of crude oil production into an increasingly important domestic energy resource. Today, marketed associated gas production amounts to nearly 10% of total regional gas output. Saudi Arabia leads the region in associated gas output, capturing 35 bcm in 2025, with the Ghawar oil field serving as its largest source. Its Master Gas System, one of the world's most extensive gas gathering and processing networks, was purpose-built to capture associated gas from major oil fields, including Ghawar, Safaniya, and Abqaiq, transforming what was historically a flared by-product into a backbone of the Kingdom's industrial energy supply. Significant volumes are also generated by other major regional oil producers, including Iran, where associated gas production is concentrated in Khuzestan Province and various offshore fields, as well as Iraq, the UAE, and Kuwait. While Iraq has historically faced challenges in capturing and processing associated gas due to infrastructure constraints and high flaring levels, ongoing investments in gas gathering and processing are increasingly allowing the country to convert these volumes into a valuable domestic energy resource.

In Eurasia, Russia is the dominant source of marketed associated gas, reflecting the scale of its oil production and extensive hydrocarbon resource base. Production is concentrated in major oil-producing regions, including Western Siberia, where extensive oil and gas infrastructure supports the gathering, processing and utilisation of associated gas. Kazakhstan and Azerbaijan also contribute significant volumes, driven by major oil-producing projects such as Tengiz and Kashagan in Kazakhstan and the Azeri-Chirag-Gunashli complex in Azerbaijan. The region's substantial oil production and gas infrastructure provide opportunities to capture and utilise associated gas for domestic energy supply, industrial applications and other productive uses, thereby increasing the value derived from oil production and supporting regional gas supply.

Beyond marketed volumes, associated gas can also be used on-site or reinjected into reservoirs, including for Enhanced Oil Recovery (EOR). Gas used for on-site operations can fuel power generation, compressors, heating and other production activities, reducing reliance on external energy supplies. This is particularly relevant in large and remote oil-producing fields, where production operations require energy inputs. Reinjection and EOR provide another important utilisation pathway, allowing gas to maintain reservoir pressure and increase oil recovery while reducing the need for flaring. These practices are particularly important in countries with mature oil fields and advanced reservoir-management systems. Where gas markets or utilisation infrastructure are limited, reinjection can also provide an alternative to flaring.

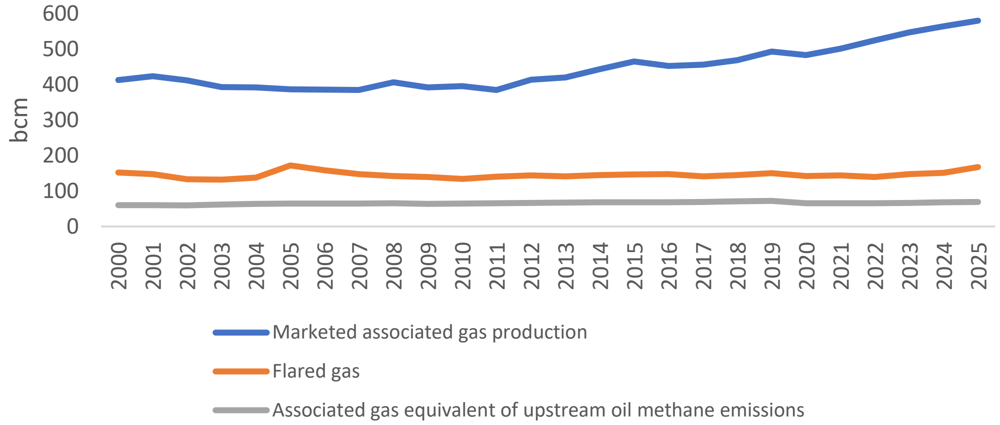
Where associated gas cannot be marketed, used on-site or reinjected, it may be flared or vented, contributing to greenhouse gas emissions and other environmental impacts. Gas flaring remains a major environmental challenge for the petroleum industry, particularly in regions where associated gas capture and utilisation infrastructure remains insufficient. According to the World Bank, global flaring volumes increased to 167 bcm in 2025, with oil production accounting for the vast majority of this volume. This was the highest level recorded since 2019 and corresponded to an estimated 429 million tonnes of CO_2 equivalent (CO_2e) emissions. Flaring converts the energy contained in associated gas into heat and CO_2, while incomplete combustion can release methane and other pollutants. It also produces black carbon, or soot, which can affect atmospheric conditions and, when deposited on snow and ice, increase heat absorption and accelerate surface melting. Beyond these direct emissions, persistent flaring can contribute to local air pollution and atmospheric impacts, particularly in areas with intensive oil production and prolonged flaring activity.

Methane emissions from upstream oil operations represent a further environmental challenge, particularly where associated gas is vented or released through equipment leaks and other fugitive sources. According to the IEA, oil operations were the largest source of energy-related methane emissions in 2025, accounting for an estimated 45 Mt of methane. These emissions arise from equipment leaks, intentional venting and other releases during oil production and associated gas handling. Given methane's high warming potential, such emissions can significantly increase the climate impact of oil production, while their dispersed and often intermittent nature makes them challenging to monitor and quantify accurately.

In this context, capturing and utilising associated gas can help address both gas flaring and methane emissions by reducing the amount of gas combusted or released at oil production sites. By recovering gas that would otherwise be flared or vented, oil producers can limit CO_2, methane and other emissions associated with these practices. This is particularly relevant in major oil-producing regions where large volumes of associated gas are generated and flaring remains widespread. Effective capture and utilisation can also reduce emissions from incomplete combustion, including methane and black carbon, while improving the overall environmental performance of oil production and associated gas management.

The evolution of marketed associated gas production, flaring and upstream oil methane emissions can be assessed by comparing their respective volumes over time. Between 2000 and 2025, global marketed associated gas production increased from 413 bcm to 590 bcm, an increase of 40%. Over the same period, gas flaring increased much more slowly, from 152 bcm to 167 bcm, while the associated-gas equivalent of upstream oil methane emissions rose from around 60 bcm to 70 bcm (Figure iii). Consequently, both flaring and methane emissions declined relative to marketed associated gas production, as their growth remained well below the increase in marketed associated gas output. Gas flaring represented 28% of marketed associated gas production in 2025, compared with 37% in 2000, while the associated-gas equivalent of upstream oil methane emissions declined from 15% to 12% over the same period. These trends indicate that, although flaring and methane emissions remain significant, their volumes have grown more slowly than marketed associated gas production. This suggests improvements in associated gas management, with increasing volumes being captured and utilised rather than flared or released.

Figure iii: Global marketed associated gas production, gas flaring and associated gas equivalent of upstream oil methane emissions



Source: GECF Secretariat based on data from the World Bank, IEA, and Rystad Energy

Associated gas also represents a significant economic opportunity for oil-producing countries because it is generated alongside crude oil production and therefore does not require separate exploration and production activities. Once the necessary gathering, processing, transportation and utilisation infrastructure is in place, associated gas can provide an additional source of energy and revenue from existing oil production, while making greater use of resources already being produced. This makes associated gas particularly attractive from an economic perspective, as the main requirement is investment in the infrastructure needed to capture, process and deliver the gas to consumers, rather than the full cost of developing a separate gas resource. This relatively low incremental resource cost can make associated gas especially valuable for countries seeking to expand domestic gas supply.

The scale of this opportunity is significant. In 2025, around 237 bcm of associated gas was flared or lost through upstream oil methane emissions, a volume exceeding the annual natural gas production of Latin America and the Caribbean and of Europe individually, and approaching the level of Africa’s gas production. This represents a substantial volume of potentially valuable gas that was not put to productive use and highlights the considerable economic potential of better associated gas utilisation. Recovering even a portion of these volumes could increase domestic gas availability and generate additional value from existing oil production. For many oil-producing developing countries, greater utilisation of associated gas could support power generation and industrialisation, reduce reliance on alternative fuels, and create opportunities for broader economic development.

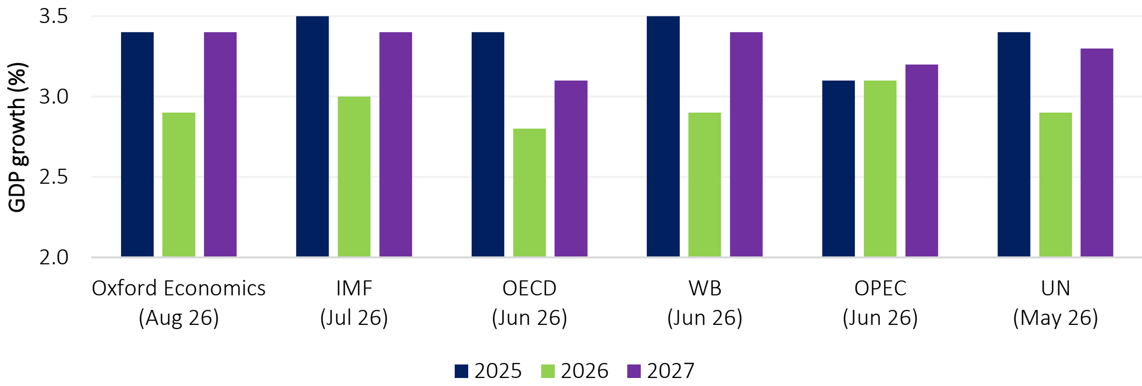
In the meantime, the severe Middle East crisis in 2026, driven by the blockade of the Strait of Hormuz, highlighted an important vulnerability of associated gas supply: its direct dependence on crude oil production. Major disruptions to regional energy infrastructure and sharp reductions in crude oil output led to significant declines in associated gas production. Unlike non-associated gas, which can be produced independently, associated gas output is closely tied to oil production and can therefore decline rapidly when crude oil extraction is disrupted. This placed additional pressure on domestic gas supplies in countries such as Saudi Arabia, Bahrain and Kuwait, where associated gas plays an important role in power generation and industrial activity, increasing the need for alternative fuel supplies. The crisis has demonstrated that reliance on associated gas can create an additional energy security risk when disruptions to oil production simultaneously constrain domestic gas availability.

1 GLOBAL PERSPECTIVES

1.1 Global economy

Global GDP growth for 2026 based on purchasing power parity was maintained at 2.9% by Oxford Economics in August 2026 (Figure 1). Despite persistent uncertainty surrounding the Middle East conflict and its adverse spillovers through higher energy prices, disrupted trade flows and tighter financial conditions, the global economy has demonstrated considerable resilience. Looking ahead, the global economic outlook is expected to improve, with GDP projected to accelerate to 3.4% in 2027.

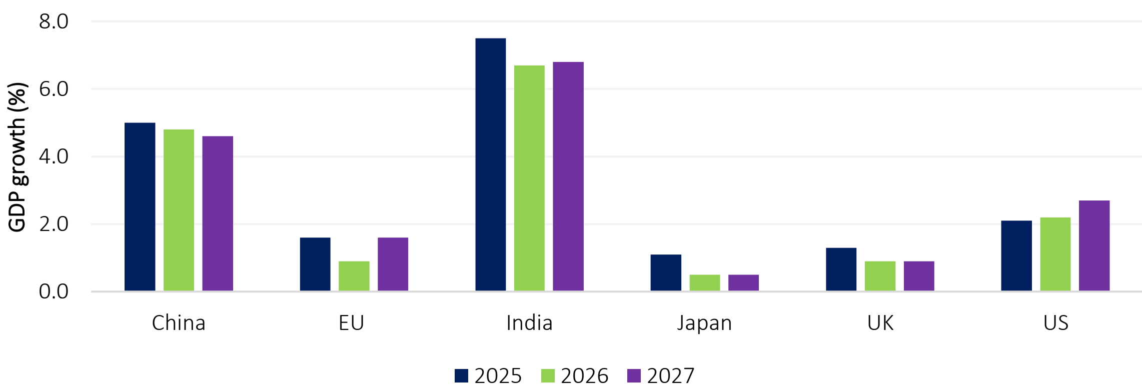
Figure 1: Global GDP growth



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

In the US, the 2026 GDP growth was revised downward by 0.1 percentage points to 2.2%, reflecting weaker-than-expected growth in the second quarter. Meanwhile, in 2027, growth is still expected to strengthen to 2.7%. In the EU, the 2026 GDP growth estimate was maintained at 0.9%, with growth projected to accelerate to 1.6% in 2027. China's 2026 GDP growth forecast was also unchanged at 4.8%, supported by resilient industrial activity, although growth is expected to moderate to 4.6% in 2027. India's GDP growth for both 2026 and 2027 remained at 6.7% and 6.8%, respectively (Figure 2).

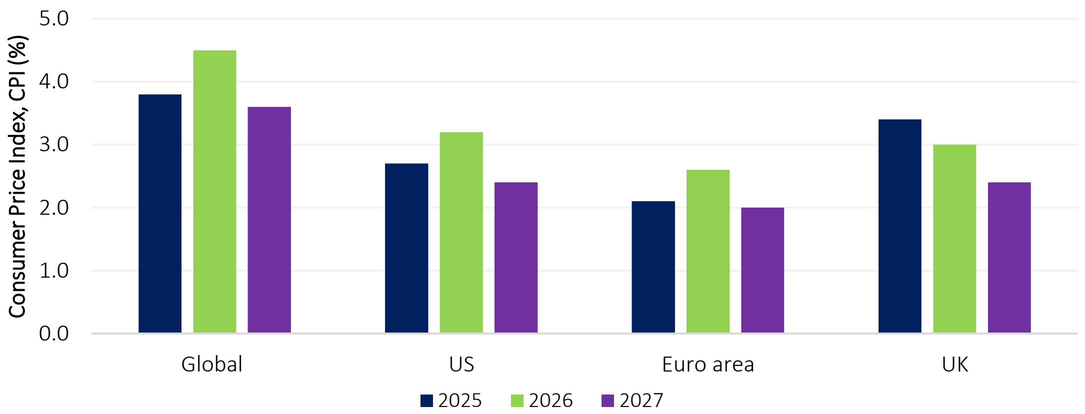
Figure 2: GDP growth in major economies



Source: GECF Secretariat based on data from Oxford Economics

In August 2026, Oxford Economics maintained its global inflation forecasts for 2026 and 2027 at 4.5% and 3.6%, respectively (Figure 3). In the Euro area, inflation projections remained the same at 2.6% in 2026 and 2.0% in 2027. The UK's inflation rate was forecast at 3.0% in 2026 and 2.4% in 2027. In the US, the 2026 inflation forecast was also maintained at 3.2% and the 2027 forecast at 2.4%.

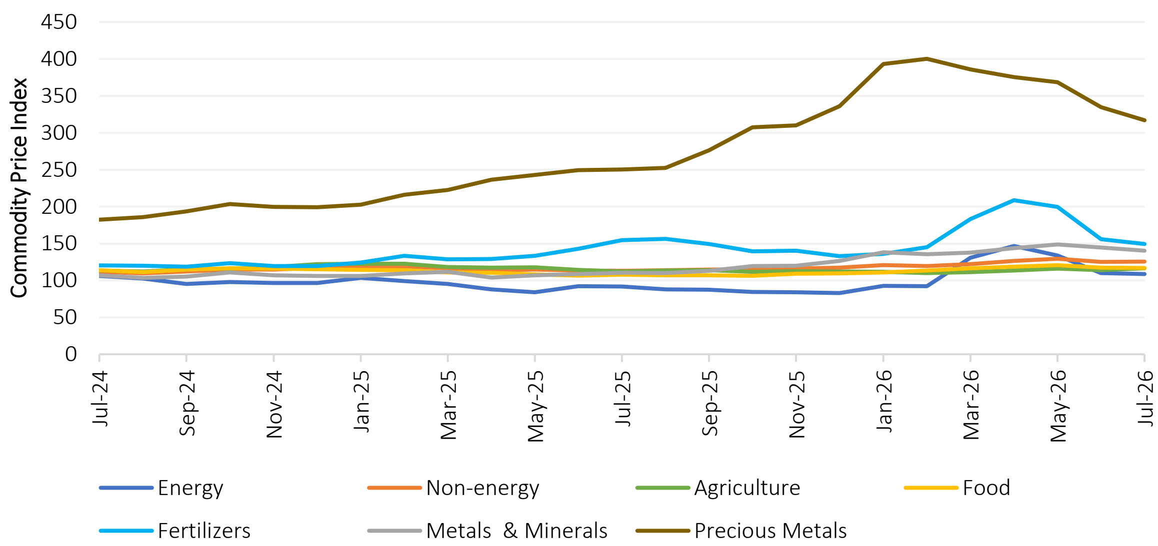
Figure 3: Inflation rates



Source: GECF Secretariat based on data from Oxford Economics

In July 2026, commodity prices across all major sectors trended lower (Figure 4). The energy price index decreased modestly by 1% m-o-m, reflecting weaker oil and coal prices, although it remained 19% higher than a year earlier. The non-energy price index was broadly unchanged from the previous month but remained 11% higher y-o-y. Fertilizer prices also softened, with the index falling 4% m-o-m and recording its first y-o-y decline since December 2024. The precious metals price index extended its downward trend, decreasing 5% m-o-m, while remaining 27% higher than a year earlier.

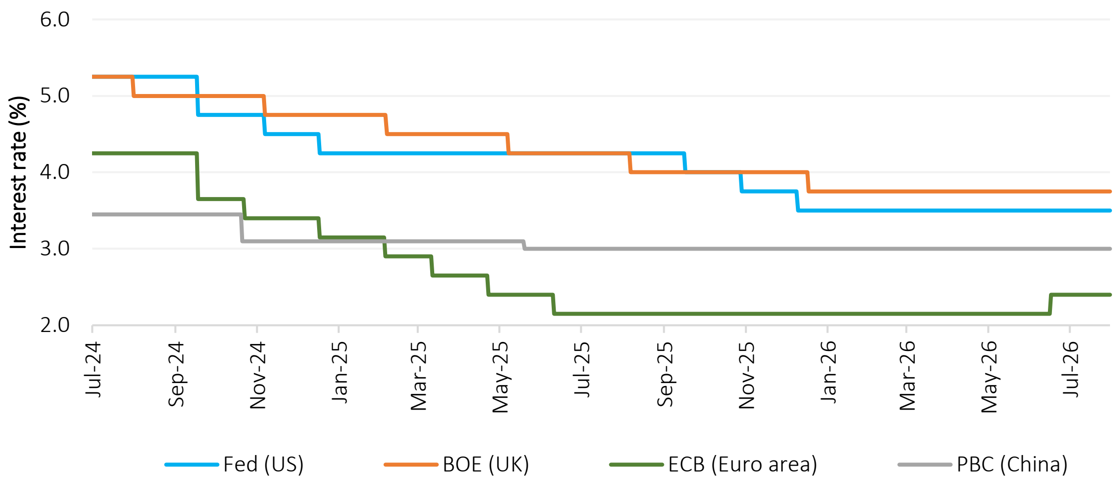
Figure 4: Monthly commodity price indices



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

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

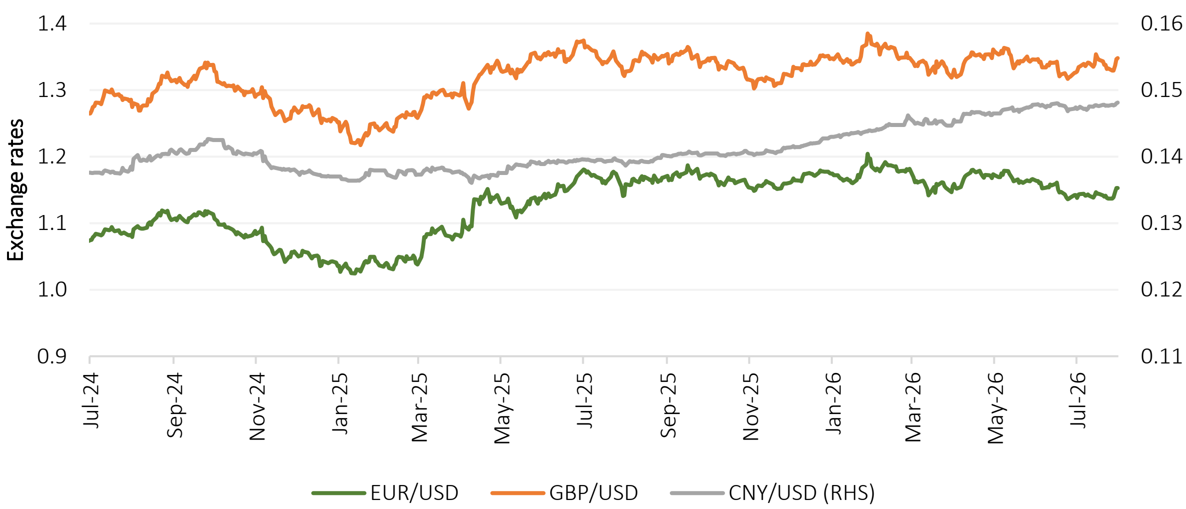
Figure 5: Interest rates in major central banks



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

In July 2026, major global currencies weakened modestly against the US dollar (Figure 6). The euro averaged $1.1425 against the US dollar, down 1% m-o-m and 2% y-o-y. Similarly, the British pound averaged $1.3388 against the US dollar, remaining broadly stable from the previous month but 1% lower than a year earlier. The Chinese yuan also remained broadly stable against the US dollar, averaging $0.1476, but was 6% higher y-o-y.

Figure 6: Exchange rates



Source: GECF Secretariat based on data from LSEG

1.2 Other developments

Global: In its July 2026 World Economic Outlook Update, the IMF projects global GDP growth of 3.0% in 2026, a downward revision of 0.1 percentage point from its April forecast, before accelerating to 3.4% in 2027. The global outlook continues to be shaped by two opposing forces: the lingering effects of the conflict in the Middle East, which are weighing on energy markets, disrupting trade and supply chains, and particularly affecting energy-importing economies; and a technology-driven investment boom, supported by strong AI-related demand, which is providing a significant boost to countries integrated into global technology value chains. The IMF notes that the impact of these forces varies considerably across economies depending on their exposure to the conflict and their position within global technology supply chains.

APEC: The 2026 APEC Digital and AI Ministerial Meeting was held on 23 July 2026 in Chengdu, China, under the theme "Digital Technologies and AI for the Empowerment of an Asia-Pacific Community". The meeting highlighted the growing role of digital technologies and artificial intelligence (AI) in enhancing productivity, efficiency, resilience and economic growth across the region. Ministers encouraged member economies to accelerate the responsible adoption of digital technologies and AI and promote their transformation across key sectors, including manufacturing, agriculture and services, while strengthening cooperation through the exchange of policies, experiences and best practices.

EU: In July 2026, the European Commission proposed a review of the EU Emissions Trading System (ETS) to strengthen its role in supporting industrial decarbonisation, competitiveness and investment, while maintaining the EU's climate objectives. The proposed revisions are intended to provide greater flexibility and predictability for industry, resulting in a more gradual decarbonisation trajectory. A key focus of the revised ETS is mobilising investment in industrial decarbonisation. The proposed Industrial Decarbonisation Bank will provide €100 billion in funding to support large-scale industrial decarbonisation projects across Europe, with the ETS Investment Booster expected to be launched before 2030 as the Bank's first phase. Member States will be required to allocate at least 50% of their national ETS revenues to investments aimed at decarbonising ETS-covered sectors.

GECF-APPO*:* The Gas Exporting Countries Forum (GECF) and the African Petroleum Producers' Organization (APPO) signed a Memorandum of Understanding (MoU) on 20 July 2026, aimed at strengthening the institutional framework for energy dialogue and cooperation between the two organizations. The MoU establishes a comprehensive framework for collaboration in areas of mutual interest, including market analysis, natural gas promotion, sustainability, research, capacity building and technical cooperation. HE Dr. Philip Mshelbila, Secretary General of the GECF, underscored the importance of strengthening collaboration among international energy organizations, emphasizing that natural gas will continue to play a critical role in enhancing energy security, expanding access to affordable and reliable energy, and supporting an orderly, balanced and just energy transition.

2 GAS CONSUMPTION

In the first half of 2026, aggregate gas consumption in major gas-consuming countries, accounting for 75% of global gas demand, decreased by 1.3% y-o-y to 1,685 bcm. Consumption declined in North America, the Middle East, and Southern Asia, while the EU recorded growth.

2.1 Europe

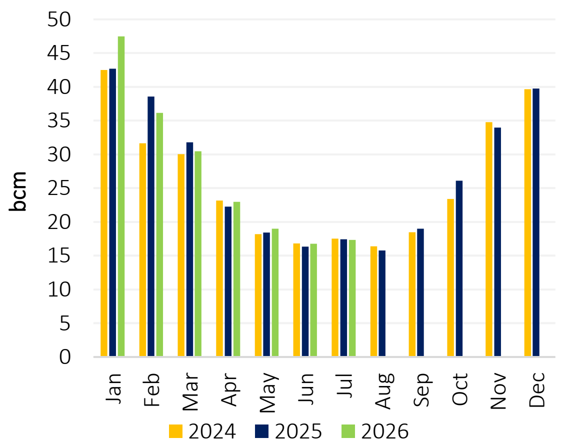
2.2.1 European Union

In July 2026, EU natural gas consumption decreased by 0.6% y-o-y to 17.4 bcm (Figure 7). The decrease was primarily driven by lower gas consumption in the industrial sector, as July marked the beginning of the holiday period. In addition, demand in the residential sector remained subdued due to seasonal factors. Although gas consumption for power generation increased slightly as an intense heatwave across much of Western Europe boosted electricity demand for cooling, higher wind and solar generation largely offset the need for gas-fired power.

EU electricity generation increased by 3.6% y-o-y to 216 TWh. Gas-fired power generation increased by 0.5% y-o-y (0.2 TWh), while nuclear generation declined by 2% y-o-y, primarily due to elevated river water temperatures, which forced several nuclear reactors to reduce output or temporarily suspend operations to comply with environmental and operational safety regulations. Solar generation continued its strong expansion, increasing by 20% y-o-y, supported by favourable seasonal conditions and the continued expansion of installed solar capacity. Likewise, wind generation rose by 13% y-o-y, while hydropower output declined by 20% y-o-y, mainly due to weaker hydroelectric availability (Figure 8).

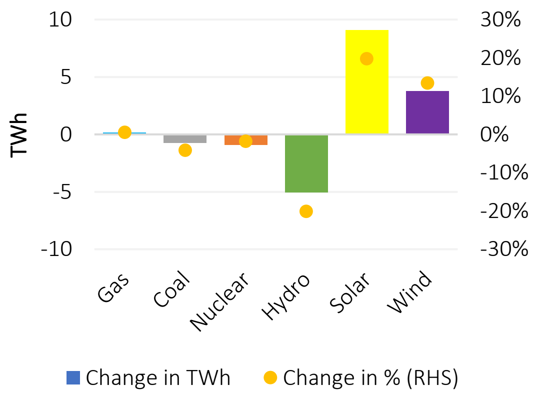
Within the power mix, non-hydro renewables remained the largest source, accounting for 44% of output, followed by nuclear (23%), natural gas (16%), hydropower (9%), and coal (8%). This generation mix reflects the continued expansion of renewable energy, particularly solar, while highlighting the complementary role of natural gas in providing system flexibility and ensuring reliable electricity supply during periods of lower wind and hydropower generation.

Figure 7: Gas consumption in the EU



Source: GECF Secretariat based on data from Entsog and LSEG

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



Source: GECF Secretariat based on data from Ember

For the period Jan-Jul 2026, the EU's gas consumption rose by 1.4% y-o-y to 190 bcm.

2.1.1.1 Germany

In July 2026, Germany's gas consumption declined to 3.3 bcm, down 3.5% y-o-y (0.12 bcm) (Figure 9). The decrease was primarily driven by lower gas demand in the power generation and industrial sectors. Although Germany experienced an intense heatwave, with the average temperature rising to 20.3°C from 18.9°C in July 2025, the resulting increase in cooling demand did not boost gas-fired electricity generation, as higher solar and wind power output met a larger share of electricity demand. Industrial gas consumption also declined by 2% y-o-y (Figure 10), while residential gas demand remained subdued owing to seasonal factors.

Figure 9: Gas consumption in Germany

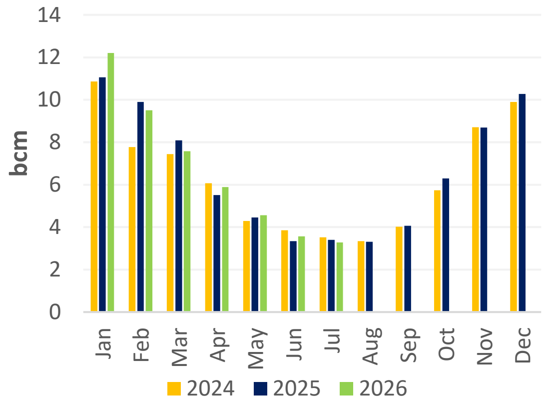
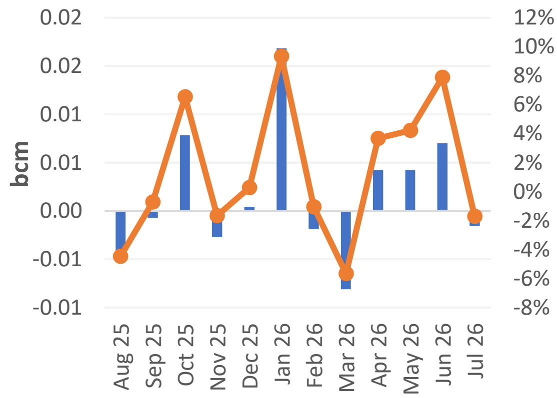


Figure 10: Trend in gas consumption in the industrial sector in Germany (y-o-y change)



Source: GECF Secretariat based on data from LSEG

Germany's electricity generation increased by 11% y-o-y to 40 TWh in July 2026, supported primarily by strong growth in renewable energy output. Solar generation recorded the largest increase, rising by 43% y-o-y (+4.39 TWh), followed by wind generation, which increased by 28% y-o-y (+2.2 TWh). In contrast, gas-fired generation declined by 20% y-o-y (−1 TWh), while coal-fired generation fell by 13% y-o-y. Hydropower output also decreased significantly, down 31% y-o-y (Figure 11). As a result, non-hydro renewables strengthened their dominant position in the power mix accounting for 70% of total generation, followed by coal (17%) and natural gas (10%) (Figure 12).

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

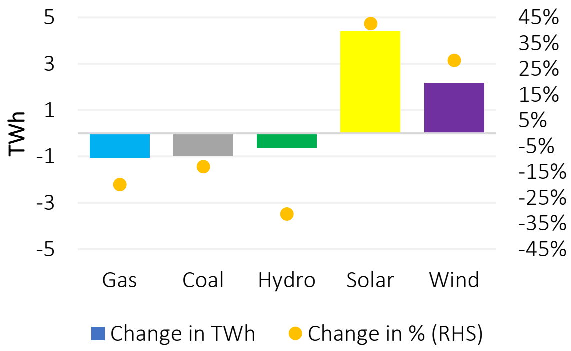
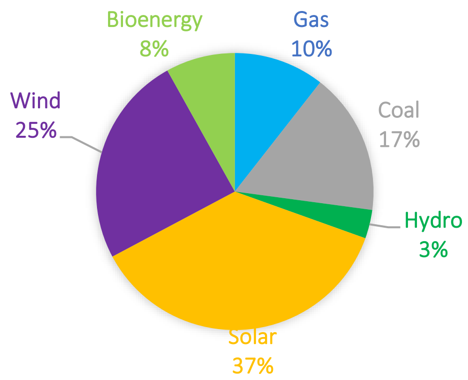


Figure 12: German electricity mix in July 2026



Source: GECF Secretariat based on data from LSEG and Ember

For the period Jan-Jul 2026, Germany's gas consumption rose by 1.8% y-o-y to 46.6 bcm.

2.1.1.2 Italy

In July 2026, Italy's gas consumption increased by 3.7% y-o-y to 4.31 bcm (Figure 13). The growth was primarily driven by higher gas demand in the power generation sector, which remained robust amid a heatwave that boosted cooling needs and electricity demand. In contrast, industrial gas consumption declined by 8% y-o-y, marking the fourth consecutive monthly contraction following the temporary recovery observed in February and March (Figure 14). Meanwhile, residential gas demand decreased by 3.7% y-o-y, reflecting seasonal factors.

Figure 13: Gas consumption in Italy

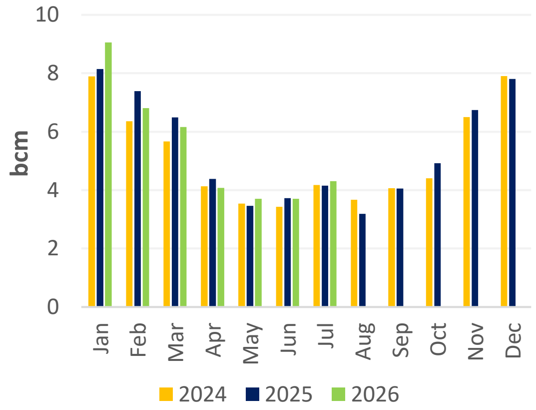
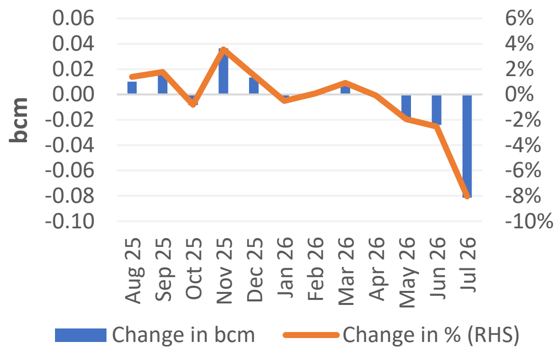


Figure 14: Trend in gas consumption in the industrial sector in Italy (y-o-y change)



Source: GECF Secretariat based on data from Snam

Italy's total electricity generation increased by 18% y-o-y to 25.8 TWh. Gas-fired power generation rose by 23% y-o-y, driven by stronger electricity demand for cooling and lower wind generation. Solar power increased by 20% y-o-y, and hydropower output rose by 21% y-o-y. In contrast, wind generation declined by 20% y-o-y (Figure 15). Natural gas remained a cornerstone of Italy's electricity system, accounting for 48% of total generation, while non-hydro renewables represented 37% of the power mix, highlighting the continued expansion of renewable energy alongside the essential role of natural gas in ensuring system flexibility and reliability during periods of weaker renewable output (Figure 16).

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

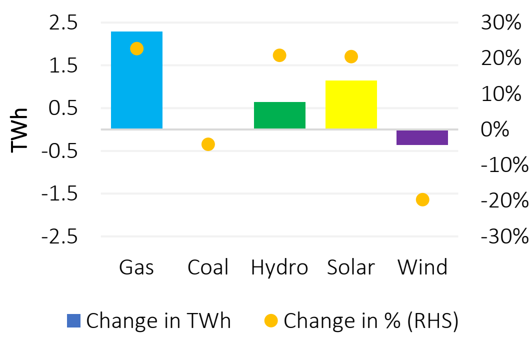
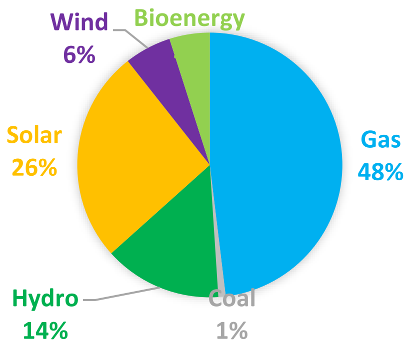


Figure 16: Italian electricity mix in July 2026



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

For the period Jan-Jul 2026, Italy's gas consumption increased by 0.2% y-o-y to 37.8 bcm.

2.1.1.3 France

In July 2026, France's natural gas consumption recorded the same level as last year to reach 1.2 bcm (Figure 17). The gas demand was primarily driven by higher demand from the power generation sector. France experienced its warmest July on record in 2026 since observations began in 1900, with an average temperature of 24.9°C, representing an anomaly of +3.8°C above the seasonal norm. The month was marked by a prolonged heatwave from 4 to 19 July—the third in history—which significantly increased cooling demand and electricity consumption. Meanwhile, industrial gas consumption continued to contract, declining by 2% y-o-y (Figure 18).

Figure 17: Gas consumption in France

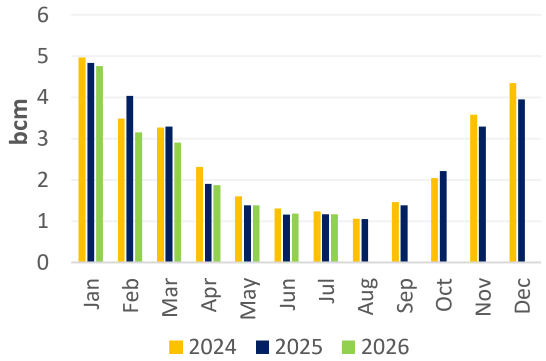
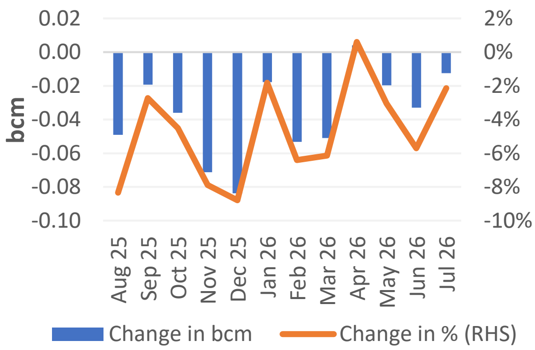


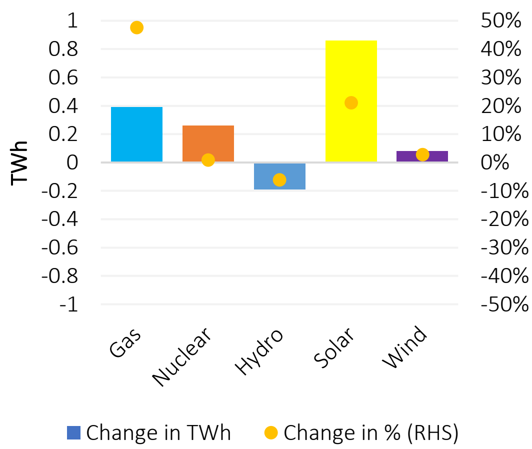
Figure 18: Trend in gas consumption in the industrial sector in France (y-o-y change)



Source: GECF Secretariat based on data from GRTgaz

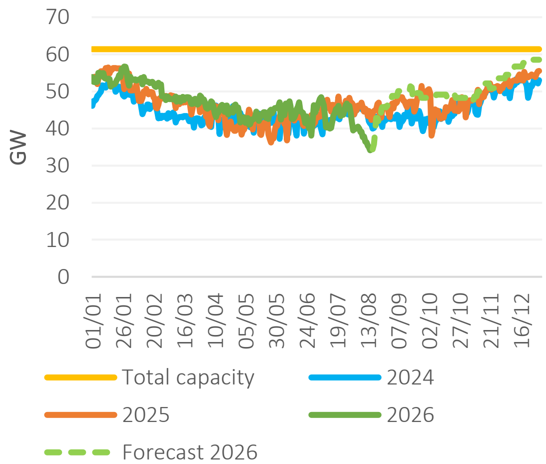
Total electricity generation in France increased by 3.5% y-o-y to 42 TWh. Gas-fired output recorded the strongest growth among all generation sources, surging by 48% y-o-y, supported by higher electricity demand for cooling during periods of elevated temperatures. Solar generation also expanded significantly, increasing by 21% y-o-y, while hydropower output declined by 6% y-o-y (Figure 19). Nuclear generation increased by 1% y-o-y. However, average nuclear capacity declined by 2.8% y-o-y during the month, as several reactors were temporarily shut down or operated at reduced output due to high river water temperatures and low water levels, which limited cooling water availability (Figure 20). Nuclear energy remained the dominant source in France's electricity mix, accounting for 70%.

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



Source: GECF Secretariat based on data from Ember

Figure 20: French nuclear capacity availability



Source: GECF Secretariat based on LSEG and RTE

For the period Jan-Jul 2026, France's gas consumption declined by 7.6% y-o-y to 16.4 bcm.

2.1.1.4 Spain

In July 2026, Spain's gas consumption increased by 8.4% y-o-y to 2.5 bcm (Figure 21). The growth was mainly driven by higher demand from the power generation sector. Gas consumption in the power sector increased by 23% y-o-y, primarily driven by an intense heatwave that boosted cooling demand and electricity consumption. Lower wind and nuclear generation further increased the need for gas-fired power generation to ensure system reliability. Industrial gas demand declined by 5.5% y-o-y, extending the downward trend observed in recent months and reflecting continued weakness in industrial activity mainly in the refinery (-16.5%), textile (-7.4%) and agro-food (-1.5%) (Figure 22).

Figure 21: Gas consumption in Spain

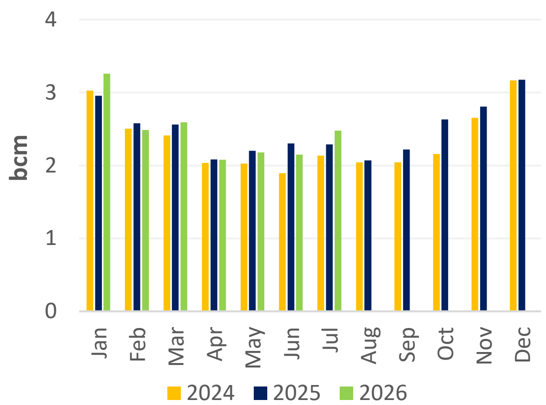
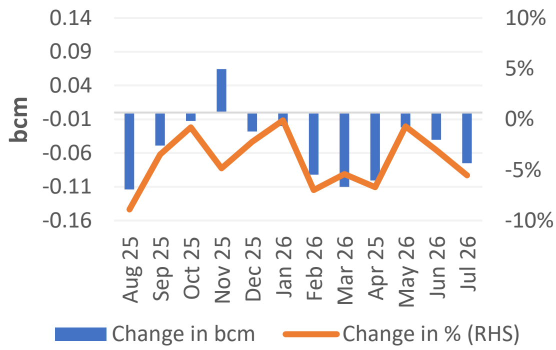


Figure 22: Trend in gas consumption in the industrial sector in Spain (y-o-y change)



Source: GECF Secretariat based on data from Enagas

Spain's electricity generation increased by 3.7% y-o-y to 25 TWh. Gas-fired output recorded the largest growth among the major generation sources, growing by 23% y-o-y (Figure 23). In contrast, wind generation decreased by 17% y-o-y, supported by unfavourable wind conditions, while solar generation rose by 7% y-o-y. Hydropower generation, however, rose by 7% y-o-y. Within the electricity mix, non-hydro renewables remained the largest source of generation, accounting for 49% of total output, followed by natural gas (24%), nuclear (20%) and hydropower (7%) (Figure 24).

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

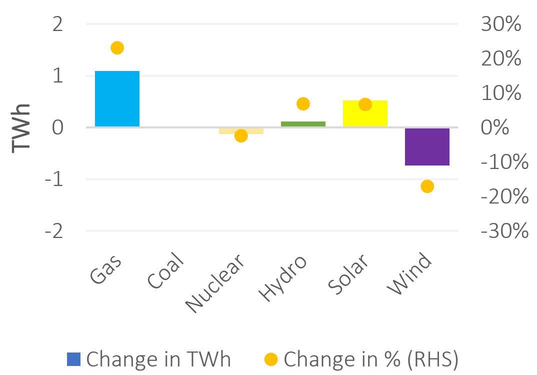
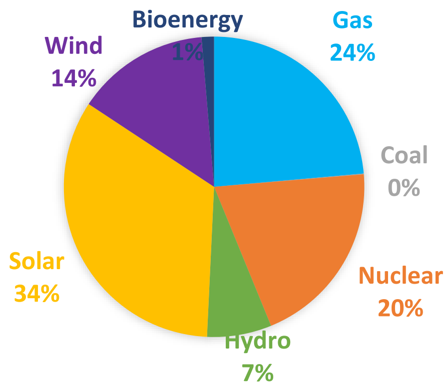


Figure 24: Spanish electricity mix in July 2026



Source: GECF Secretariat based on data from Ember and Ree

For the period Jan-Jul 2026, Spain's gas consumption rose by 1.5% y-o-y to 17.2 bcm.

2.1.2 United Kingdom

In July 2026, gas consumption in the UK decreased by 6.1% y-o-y to 2.37 bcm (Figure 25), driven by lower demand from the industrial and power generation sectors. Gas consumption in power generation fell by 2.6% y-o-y to 1 bcm, despite electricity demand increasing by 13%. Strong growth in renewable generation, with both solar and wind output rising by 32% y-o-y, offset the need for additional gas-fired output. Residential gas consumption decreased by 8% y-o-y to 1.4 bcm, while industrial gas demand declined by 16.5% y-o-y (Figure 26). For the period Jan-Jul 2026, UK's gas consumption declined by 2.5% y-o-y to 32.7 bcm.

Figure 25: Gas consumption in the UK

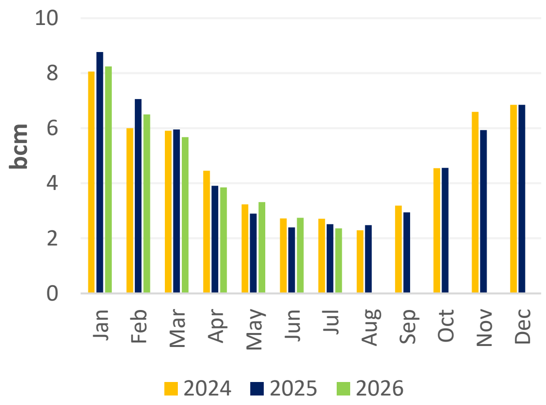
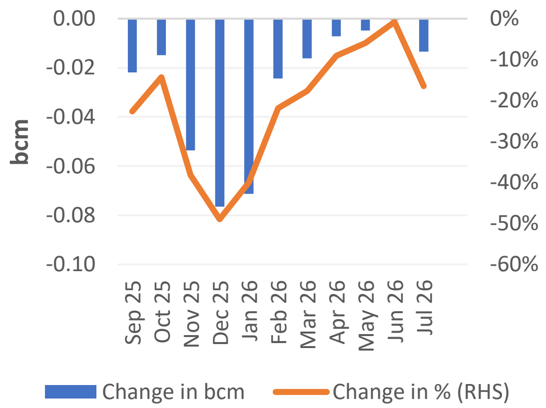


Figure 26: Trend in gas consumption in the industrial sector in the UK (y-o-y change)



Source: GECF Secretariat based on data from LSEG

For the period Jan-Jul 2026, aggregated gas consumption in the EU and UK increased by 0.8% y-o-y (1.8 bcm) to reach 223 bcm (Figure 27). The EU was the main contributor to this growth, with a y-o-y increase of 2.6 bcm (Figure 28).

Figure 27: YTD EU and UK gas consumption

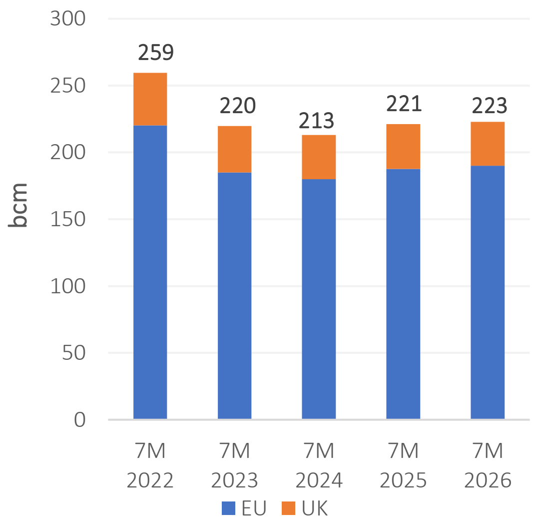
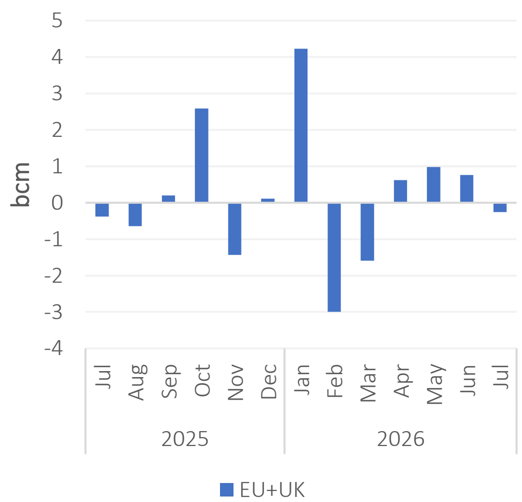


Figure 28: Y-o-y variation in EU and UK gas consumption



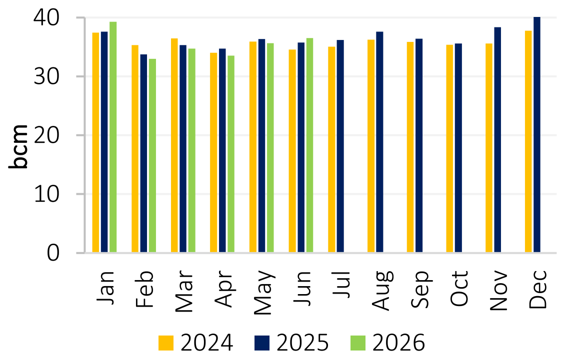
Source: GECF Secretariat based on data from LSEG

2.2 Asia

2.2.1 China

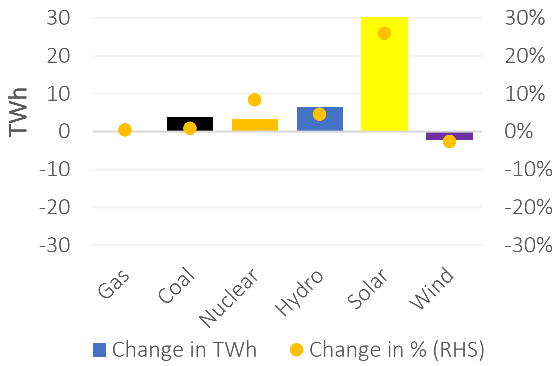
In June 2026, China's apparent gas demand (production + LNG and pipeline gas imports) rose by 2.2% y-o-y to 36.5 bcm (Figure 29). According to the National Energy Administration's China Natural Gas Development Report 2026, China's natural gas consumption is projected to reach 435 bcm in 2026, up 1% y-o-y, signalling slower market growth. Demand growth continues to be supported by city gas and LNG-fuelled transport, while industrial consumption remains weak. China's electricity generation increased by 4.8% y-o-y to 914 TWh in June supported by robust economic activity and rising seasonal electricity demand (Figure 30). For the period Jan–Jun 2026, Chinese gas consumption declined by 0.4% y-o-y to 213 bcm.

Figure 29: Gas consumption in China



Source: GECF Secretariat based on data from LSEG

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

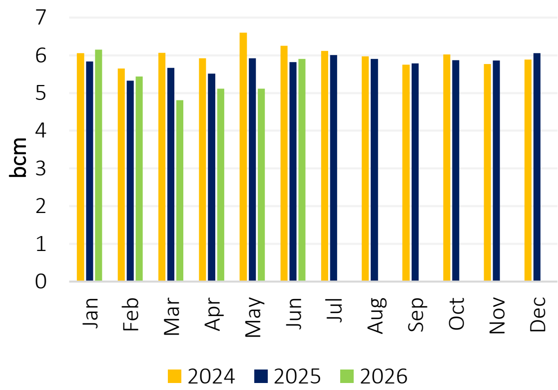


Source: GECF Secretariat based on data from Ember

2.2.2 India

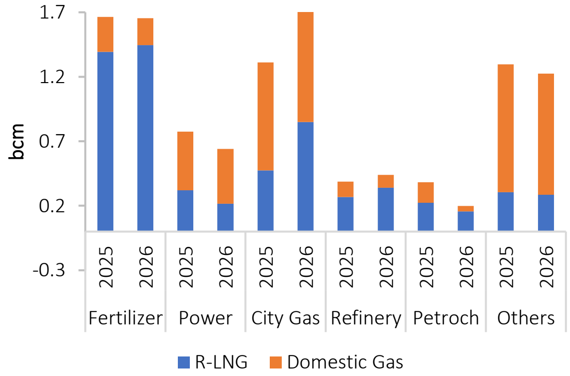
In June 2026, India's gas consumption increased by 1.5% y-o-y to 5.9 bcm, driven by the city gas sector (Figure 31). The growth was primarily driven by higher gas consumption in the city gas and refinery sectors with a rise of 33% (+0.44 bcm) and 13% (0.05 bcm) respectively. Consumption in the petrochemical, power generation and fertilizer sectors fell by 48% (0.2 bcm), 17% (0.13 bcm) and 0.5% (0.1 bcm) y-o-y, respectively. City gas was the largest source of gas consumption with a 30% share of total demand, followed by the fertilizer sector with a 28% share (Figure 32). For the period Jan–Jun 2026, India's gas consumption declined by 4.5% y-o-y to 32.5 bcm.

Figure 31: Gas consumption in India



Source: GECF Secretariat based on data from PPAC

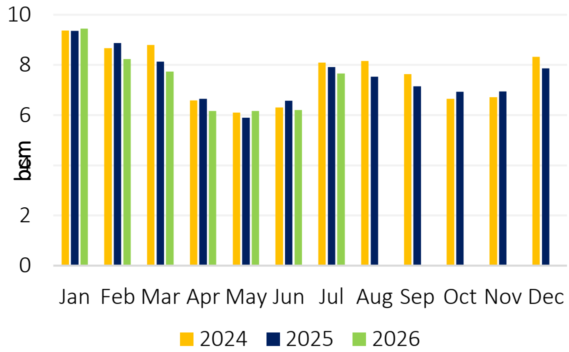
Figure 32: India's gas consumption by sector in June 2026



2.2.3 Japan

In July 2026, Japan's gas consumption declined by 3.5% y-o-y to 7.7 bcm (Figure 33). Japan's gas demand for power generation declined as gas-fired electricity output fell 6.9% y-o-y to 24.9 TWh. The decrease was driven by cooler weather and a 4% y-o-y decline in electricity demand, which more than offset the impact of a mid-month heatwave. As a result, gas consumption in the power sector declined significantly during the month.

Figure 33: Gas consumption in Japan

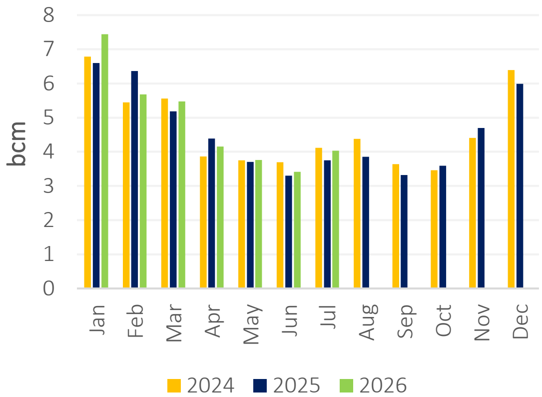


Source: GECF Secretariat based on data from LSEG

2.2.4 South Korea

In July 2026, South Korea's gas consumption increased by 7.6% y-o-y to 4 bcm (Figure 34). South Korea's Ministry of Trade, Industry and Resources (MOTIE) projects natural gas demand to decline from 45.9 Mt in 2026 to 41 Mt by 2038, averaging -0.9% annually. Rising city gas demand will be offset by lower gas-fired power generation. The plan also strengthens energy security through expanded LNG storage, diversified supply sources, longer-term contracts, AI-based demand forecasting, and additional pipeline infrastructure.

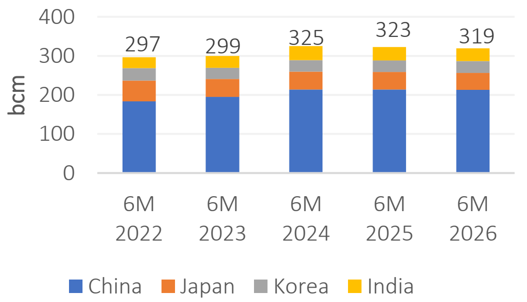
Figure 34: Gas consumption in South Korea



Source: GECF Secretariat based on data from LSEG

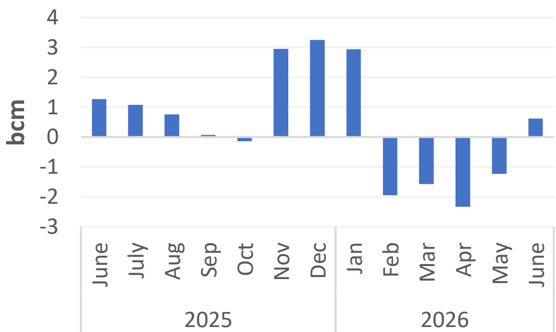
The regional aggregated gas consumption data for the period January-June 2026 in major Asian gas consuming countries, namely China, India, Japan and South Korea, declined by 3.6 bcm y-o-y to reach 319 bcm (Figure 35), driven largely by a decrease of a total of 1.5 bcm each for both Japan and India (Figure 36).

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



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

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

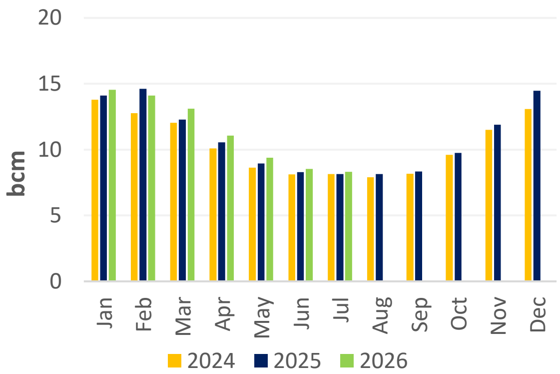


2.3 North America

2.3.1 Canada

In July 2026, Canada's gas consumption rose by 2.1% y-o-y to 8.3 bcm, supported by continued growth in industrial and power sectors (Figure 37). Gas demand from these sectors increased by 2.5% y-o-y to 7.5 bcm, reflecting sustained industrial activity and steady electricity demand. Residential and commercial gas consumption also recorded a decline of 2% and 1.9% y-o-y, respectively. For the period Jan–Jul 2026, Canada's gas consumption increased to 79 bcm, up 2.7% y-o-y.

Figure 37: Gas consumption in Canada



Source: GECF Secretariat based on data from LSEG

2.3.2 US

In July 2026, US natural gas consumption declined by 1.9% y-o-y to 74.8 bcm (Figure 38), reflecting lower demand across all major consuming sectors. Residential and commercial gas consumption fell by 6.3% y-o-y, as milder weather reduced space-cooling and heating requirements in several regions. Industrial gas demand remained relatively stable, declining by just 0.2% y-o-y, while gas consumption in the electric power sector decreased by 1.3% y-o-y, reflecting increased competition from renewable energy sources and nuclear generation.

Total electricity generation in the US increased by 2.2% y-o-y to 462 TWh. Despite remaining the largest source of electricity generation, gas-fired output declined by 0.2% y-o-y (Figure 39). Natural gas continued to dominate the electricity mix with a 44% share, followed by coal (16%), nuclear (15%), solar (12%), wind (7%), hydropower (5%), and bioenergy (1%).

Figure 38: Gas consumption in the US

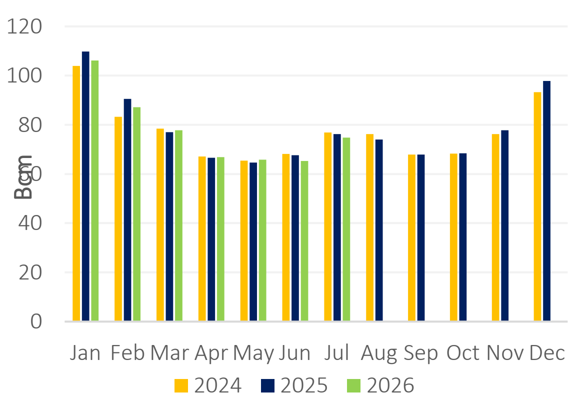
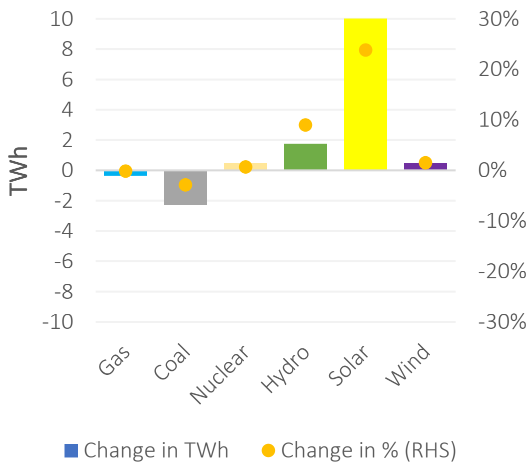


Figure 39: Electricity production in US in July 2026



Source: GECF Secretariat based on data from EIA and LSEG

For the period Jan–Jul 2026, US gas consumption declined by 1.5% y-o-y to 543 bcm.

2.4 Other developments

2.4.1 Sectoral developments

US data centres turn to Texas gas infrastructure for AI power growth: The rapid expansion of AI in the US is driving the development of at least 74 dedicated gas-fired power projects, as technology companies seek to secure reliable, around-the-clock energy for data centres. Texas leads this industrial surge with 32 proposed projects, representing 43% of the national total. Technology developers are increasingly opting to build these massive on-site generation facilities directly alongside new data centres rather than rely on increasingly constrained utility grids. This shift ensures the uninterrupted, massive computing power required for AI workloads while positioning Texas at the epicentre of the changing energy infrastructure.

Global AI and data centre demand sparks 50% Siemens manufacturing expansion: The explosive global expansion of artificial intelligence infrastructure and energy-intensive data centres is driving a historic surge in power technology markets, prompting Siemens Energy to execute a massive 50% capacity expansion. Record-breaking order backlogs for heavy-duty gas turbines have triggered extreme shortages in foundational electrical grid components. To directly counter severe multi-year equipment bottlenecks and clear a staggering €51 billion infrastructure backlog through 2030, manufacturing executives are radically scaling up global industrial output. This strategic industrial ramp-up centres on rapidly accelerating the production of large power transformers and specialized gas-insulated switchgear.

Germany launches landmark gas-fired capacity auctions under the new law: The German Parliament officially passed the highly anticipated Electricity Supply Security and Capacity Act (StromVKG) on 10 July 2026, setting the stage for a historic expansion of the country's natural gas-fired backup fleet. To directly combat soaring equipment costs and ensure a robust supply of dispatchable energy, the legislative framework immediately increased maximum long-term capacity tender caps by over 40% to a record €244,000 per MW. This massive regulatory overhaul effectively forces the development of multi-day repeatable output gas turbines over battery storage, cementing natural gas as Germany's core transitional power source.

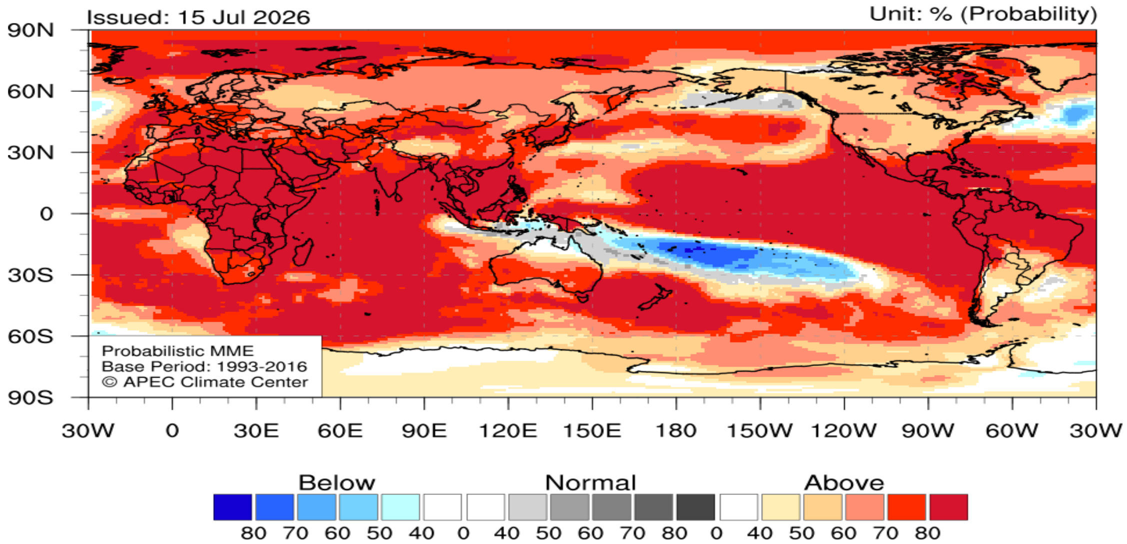
Kazakhstan hybrid infrastructure project achieves major gas power milestone: Energy developers Eni and KazMunaiGas (KMG) have successfully generated the first industrial electricity from their new 120 MW gas-fired unit in Zhanaozen, Kazakhstan. This newly operational gas turbine serves as the foundational baseline anchor for a broader 247-megawatt hybrid power infrastructure site designed to provide stable and reliable energy. By integrating flexible gas-fired generation directly alongside renewable assets, the facility ensures a continuous, around-the-clock electricity supply to protect local operations from grid instability. The entire industrial project remains on track for full commercial commissioning by the third quarter of 2026.

Vietnam approves new generation price framework to accelerate gas power builds: The Ministry of Industry and Trade of Vietnam officially issued a landmark regulatory decree on 23 July 2026, establishing the national electricity generation price framework for large-scale combined-cycle gas turbine facilities. To attract heavy foreign capital and clear development backlogs for massive fuel infrastructure, the government set a firm wholesale electricity price ceiling of 3,410.64 Vietnamese Dong per kWh ($0.13/kWh) based on a 1,008-MW baseline reference plant. This critical policy shift provides clear financial visibility for multinational developers racing to build out localized gas networks, ensuring that gas-fired generation remains the bedrock of Vietnam's rapid industrialization while the country transitions away from coal assets.

2.4.2 Weather forecast

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

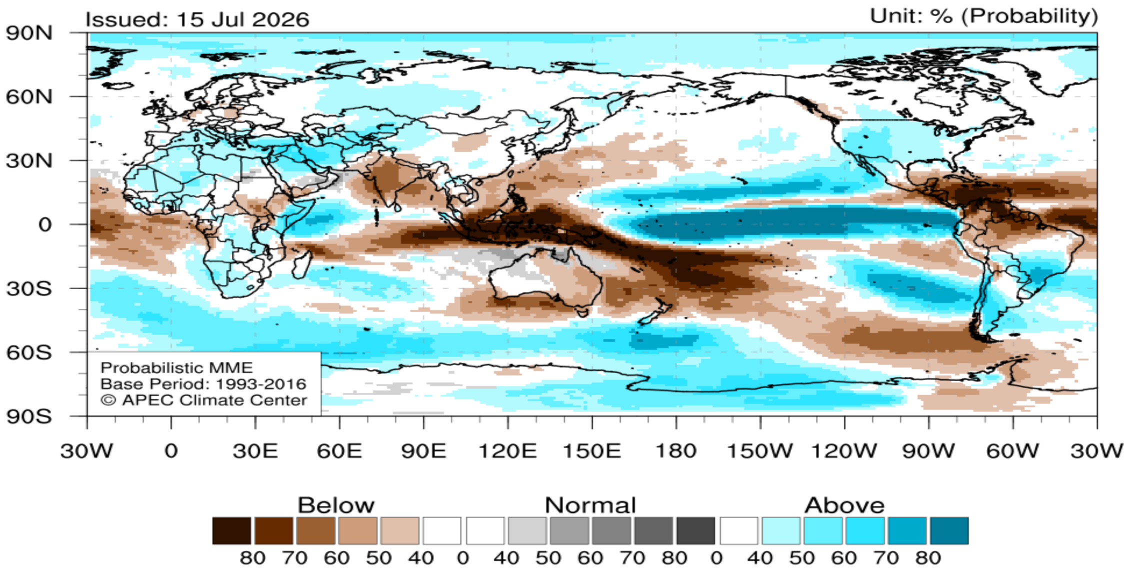
Figure 40: Temperature forecast for August- October 2026



Source: APEC Climate Center

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

Figure 41: Precipitation forecast August- October 2026

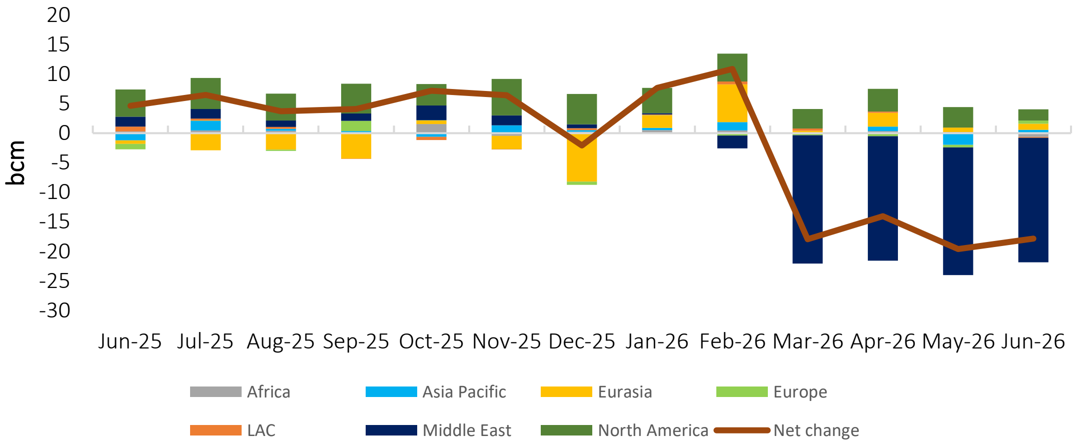


Source: APEC Climate Centre

3 GAS PRODUCTION

In June 2026, global gas production was estimated to have declined by 5.2% y-o-y to stand at 323 bcm. The contraction was primarily driven by the supply shock in the Middle East resulting from the ongoing geopolitical conflict and the closure of the Strait of Hormuz, which reduced the region's gas production by nearly one-third compared with a year earlier, largely owing to lower LNG output. By contrast, continued growth in North American gas production partially mitigated the global supply decline, with increased output in the US and Canada providing a significant offset to the disruption in the Middle East (Figure 42).

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



Source: GECF Secretariat estimation

From a regional perspective, there was a fundamental shift in the regional distribution of the global gas supply, driven by the conflict in the Middle East, with North America keeping its extending position as the frontrunner producing region (dominated by US production), accounting for 35% of global gas production (rising from 31% in June 2025), followed by Eurasia with 19%, and Asia Pacific with 17%, whilst the Middle East share declined to 14% down from 18% in June 2025. Africa, Europe, Latin America and the Caribbean (LAC) held shares ranging from 4% to 6% (Figure 43).

For the first half of 2026, global gas production was estimated to have declined by 2.2% y-o-y to stand at 2,039 bcm (Figure 44). This decline was mainly driven by the reduction in the Middle East supply; however, it was partially counterbalanced by the strong production growth in North America and Eurasia.

Figure 43: Regional gas production in June 2026

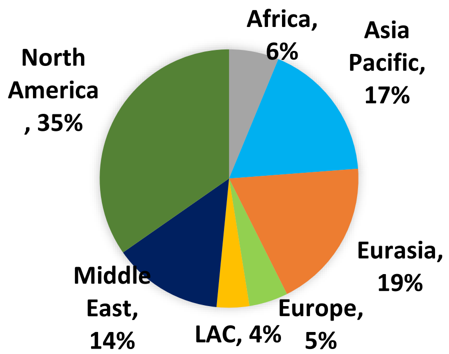
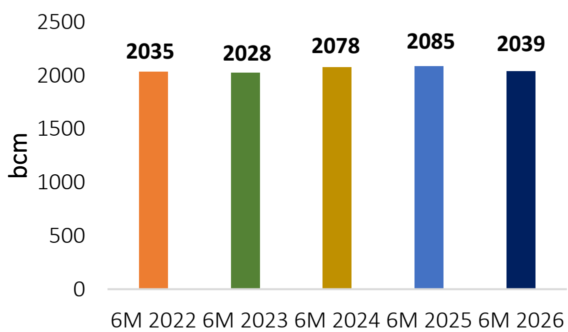


Figure 44: YTD global gas production



Source: GECF Secretariat estimation

3.1 Europe

In June 2026, gas production in Europe witnessed a 3.7% y-o-y uptick, with a total output of 14.3 bcm (Figure 45). This is the second month in 2026 to record a y-o-y increase in the European output, mainly driven by higher Norwegian production. However, the magnitude of overall European production rise in June was limited by the decrease in gas production in the Netherlands (Figure 46). Notably, monthly gas production in the EU stood at 2 bcm (13% decline compared to 2025 level), with the Netherlands and Romania maintaining their positions as top producers.

Figure 45: Europe's monthly gas production

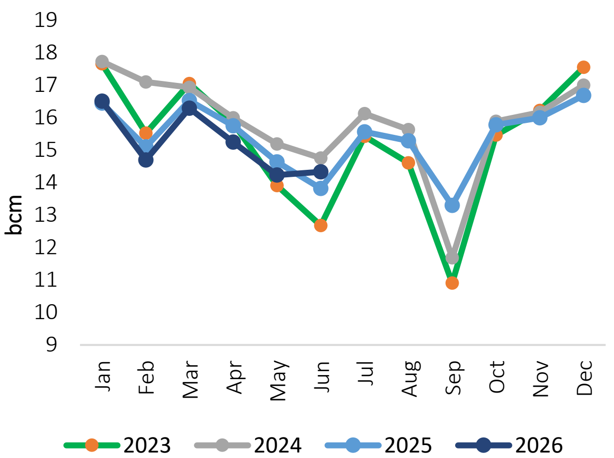
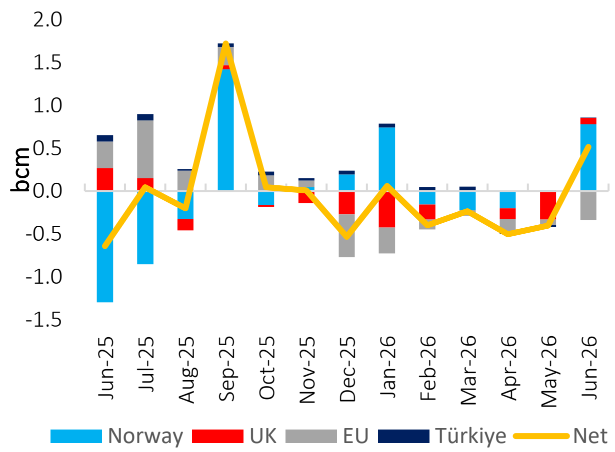


Figure 46: Y-o-y variation in Europe's gas production



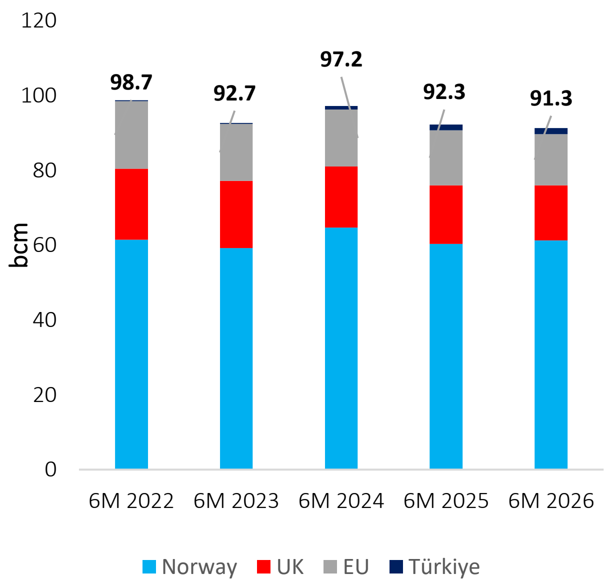
Source: GECF Secretariat based on data from LSEG, the Norwegian Offshore Directorate and JODI Gas
Note: EU countries include Austria, Denmark, Germany, Italy, Netherlands, Poland and Romania

For the first half of 2026, the aggregated gas output in Europe amounted to 91.3 bcm (Figure 47), representing a 1% y-o-y decline, compared with the production level during the same period in 2025, and recording the lowest output in the last 5-year period.

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

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

Figure 47: YTD Europe's gas production



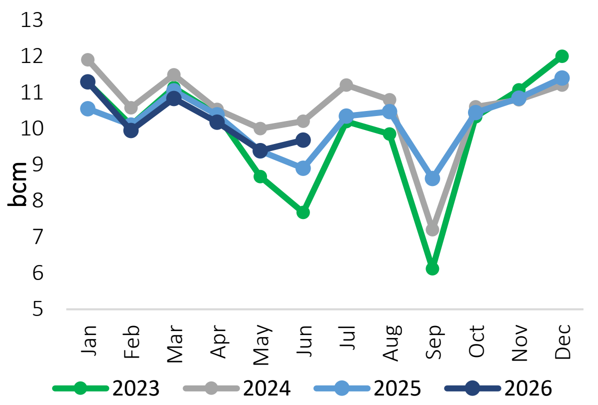
Source: GECF Secretariat based on data from Refinitiv, the Norwegian Offshore Directorate and JODI Gas

3.1.1 Norway

Norway's gas output recorded a notable rise of 8.7% y-o-y, to stand at the level of 9.7 bcm (Figure 48). This was mainly driven by the reduced maintenance period in June, along with the base year effect. Notably, the 130 mcm/d Troll gas field witnessed reduced production for only 1 day, as a result of planned activity. In addition, the 31.9 mcm/d Oseberg gas platform underwent planned maintenance, which ceased its output for the entire month.

For the first half of 2026, cumulative output amounted to 61.3 bcm, representing a 1.6% y-o-y growth, driven by lower planned and unplanned maintenance durations.

Figure 48: Trend in gas production in Norway



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

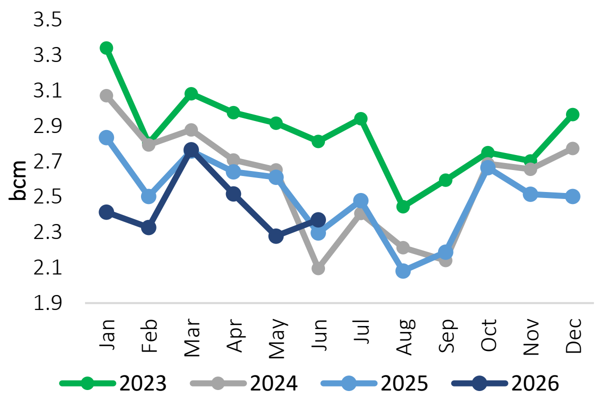
3.1.2 UK

UK gas production recorded its first increase in the year with a 3.2% y-o-y rise to stand at 2.37 bcm (Figure 49).

This is in contradiction to the declining trend over the past period, as a result of reduced output from the UK's mature fields, lack of new gas projects and longer than expected maintenance periods.

For the first half of 2026, cumulative output declined by 6.2% y-o-y to 14.7 bcm.

Figure 49: Trend in gas production in the UK



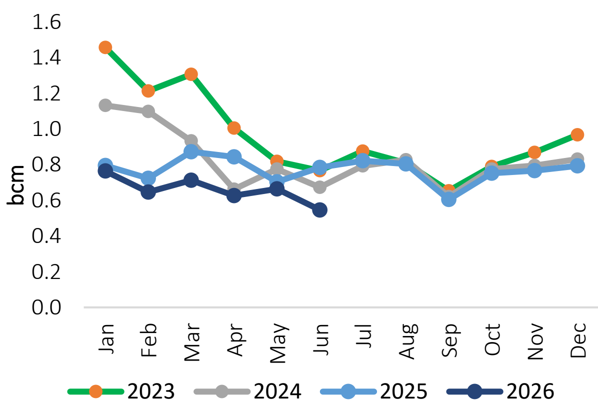
Source: GECF Secretariat based on data from LSEG

3.1.3 Netherlands

The Netherlands' annual gas production kept its downwards trend, with a 30% y-o-y decrease, to stand at 0.55 bcm (Figure 50).

For the first half of 2026, cumulative production in the Netherlands reached 4 bcm, representing a 16.2% y-o-y reduction. With the absence of new field development or rejuvenation, this production drop from the ageing Dutch fields is likely to continue in the coming years, with the remaining reserves expected to be depleted in 8 years.

Figure 50: Trend in gas production in the Netherlands



Source: GECF Secretariat based on data from LSEG

3.2 Asia Pacific

In June 2026, gas output in Asia Pacific was estimated to stand at 57 bcm, representing a 1% y-o-y increase. This increase was driven by the rise in the Chinese gas output that offset the decline output in some regional Asia Pacific producers. For the first half of 2026, the cumulative regional production reached 352.1 bcm, nearly mirroring last year level.

3.2.1 China

In June 2026, China's gas production continued its consistent growth, after a decline in May 2026, to stand at 21.4 bcm, representing a 1.1% y-o-y rise (Figure 51). This increase was mainly driven by the restart of some main offshore production platforms after maintenance activities. Coal bed methane production continued its annual growth as well, with 9% y-o-y rise, to stand at 1.25 bcm. For the first half of 2026, cumulative production in China reached 133 bcm, representing a 1.7% y-o-y growth (Figure 52).

Figure 51: Trend in gas production in China

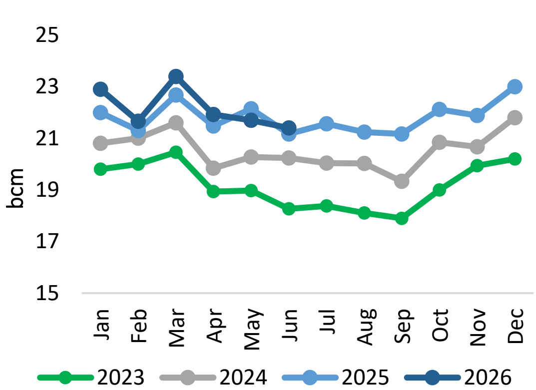
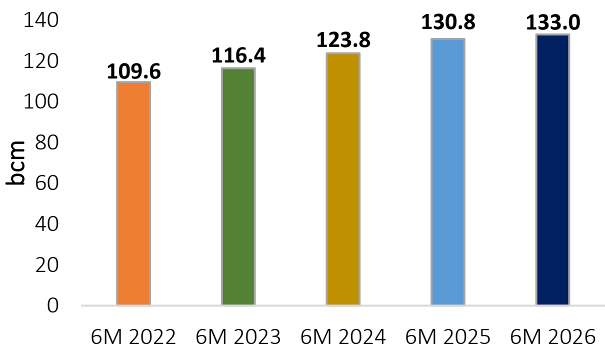


Figure 52: YTD China's gas production



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

3.2.2 India

In June 2026, India's gas production continued its negative trend, declining by 4.8% y-o-y to stand at 2.72 bcm (Figure 53). The decrease was driven by a reduction in offshore gas output, which represented 73% of Indian production, along with reduced production from the onshore Tamil Nadu field. Meanwhile, the CBM gas fields recorded a 0.5% y-o-y growth, mainly from the West Bengal fields. For the first half of 2026, the cumulative production in India amounted to 16.6 bcm, representing a 4.6% y-o-y decline (Figure 54).

Figure 53: Trend in gas production in India

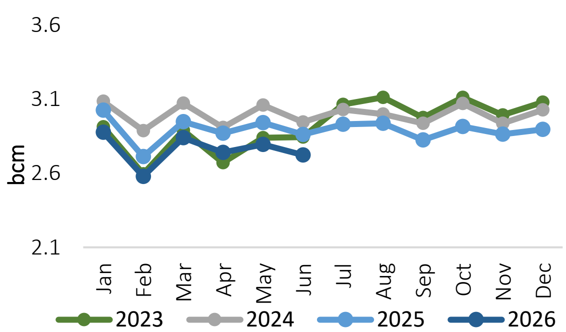
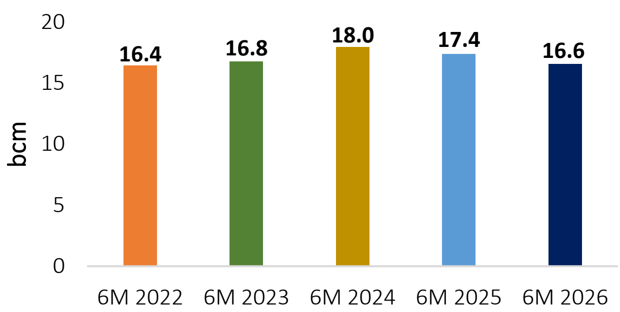


Figure 54: YTD India's gas production

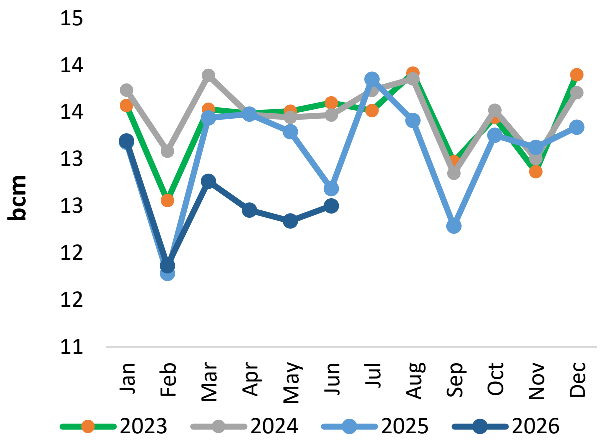


Source: GECF Secretariat based on data from the Ministry of Petroleum and Natural Gas (PPAC)

3.2.3 Australia

In June 2026, Australia's gas production declined by 1.5% y-o-y, to stand at 12.5 bcm (Figure 55). Gas production from CBM fields amounted to 3.4 bcm, representing a 1 % y-o-y rise and accounted for 27% of the domestic production. Notably, Australia kept its position as the global leader in terms of CBM production, with sustained growth in the past years and CBM being used as feedstock for LNG export terminals. For the first half of 2026, the cumulative production in Australia amounted to 75.1 bcm, representing a 3.5% y-o-y reduction.

Figure 55: Trend in gas production in Australia

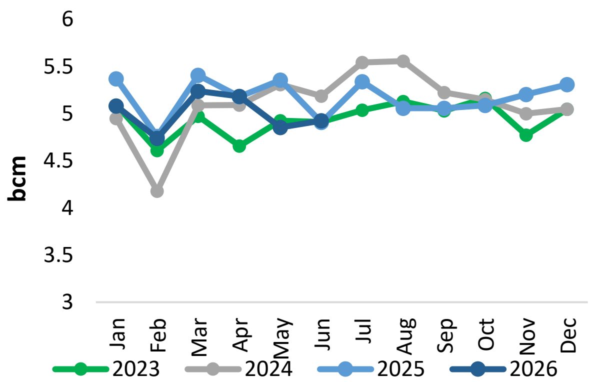


Source: GECF Secretariat based on data from the Australian Department of Energy

3.2.4 Indonesia

In June 2026, Indonesia's gas output rose by 0.4% y-o-y to 4.9 bcm (Figure 56). This was driven by an extensive development drilling campaign, with 57 new development wells drilled during the month. Their incremental production was able to exceed the natural decline in the producing fields. In addition, 4 new exploration wells were drilled in June, which represented an acceleration for the exploration activity. For the first half of 2026, the cumulative production reached 30 bcm, representing a 3.1% y-o-y decline

Figure 56: Trend in gas production in Indonesia



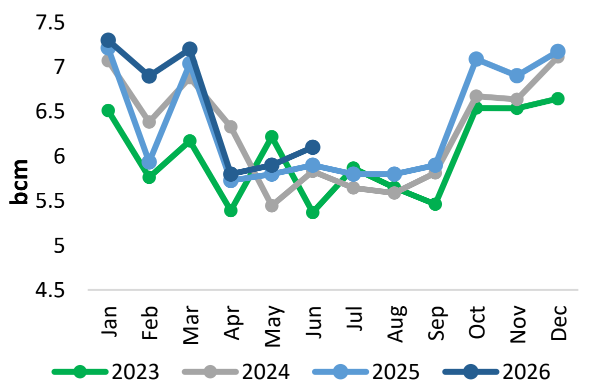
Source: GECF Secretariat based on data from SKK Migas and JODI Gas

3.2.5 Malaysia

In June 2026, Malaysia's gas output was estimated at 6.1 bcm, representing a 3.4% y-o-y production growth (Figure 57).

For the first half of 2026, the cumulative production in Malaysia reached 39.2 bcm, representing a 4.2% y-o-y growth.

Figure 57: Trend in gas production in Malaysia



Source: GECF Secretariat based on data from the JODI

3.3 North America

In June 2026, gas production in North America (including Mexico) rose by 3.6% y-o-y to reach 112.7 bcm, driven by strong gas supply growth in the US and Canada. For the first half of 2026, cumulative production in North America reached 678 bcm, representing a 3.5% y-o-y growth.

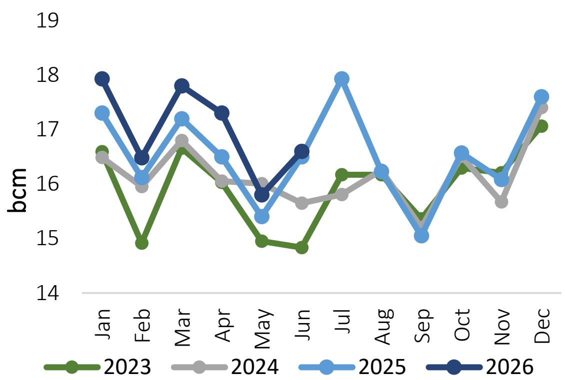
3.3.1 Canada

In June 2026, Canada's gas production grew by 0.6% y-o-y to 16.6 bcm (Figure 58), supported by an LNG export rise. From a regional perspective, Alberta was responsible for 9.8 bcm of the production, mainly originating from the Bakken shale production, whilst British Columbia accounted for 6.4 bcm, stemming from tight gas production from the Montney Basin.

For the first half of 2026, the cumulative production amounted to 102 bcm, representing a 2.9% y-o-y uptick. In this context, Canada is well poised to continue strong production growth, driven by the rising LNG exports and favourable market conditions.

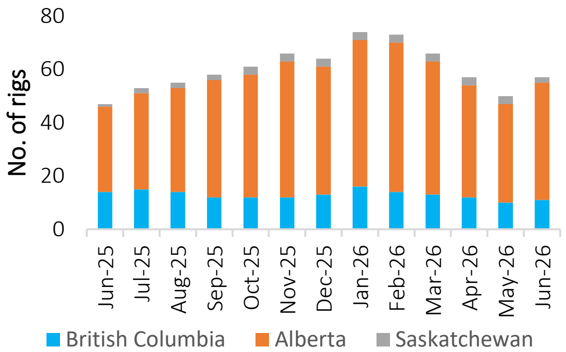
In terms of gas drilling activity, there was an overall 7-rig-increase in June 2026, with Alberta and British Columbia releasing 7 and 1 drilling rigs, respectively, while Saskatchewan released one drilling rig. Moreover, this represented a 10-rig-increase in the number of drilling rigs, as compared to June 2025 (Figure 59).

Figure 58: Trend in gas production in Canada



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

Figure 59: Gas rig count in Canada



Source: GECF Secretariat based on data from LSEG

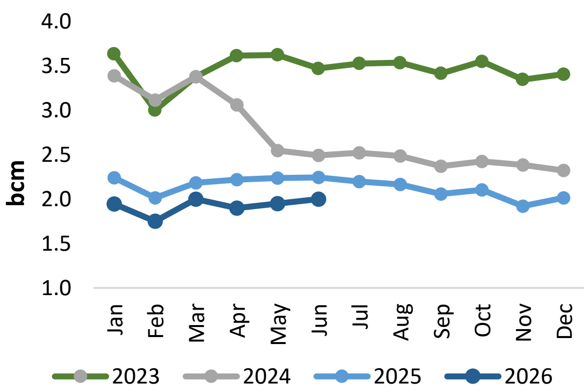
3.3.2 Mexico

In June 2026, Mexico's gas output was estimated at 2 bcm, representing a production decrease of 10.9% y-o-y (Figure 60). This reduction was driven by the natural decline in the Mexican legacy fields and lack of new gas field developments.

Associated gas production from oil fields represented 38% of the total Mexican production, at 0.76 bcm.

For the first half of 2026, the cumulative production in Mexico amounted to 11.5 bcm, representing a 12.1% y-o-y decline.

Figure 60:Trend in gas production in Mexico



Source: GECF Secretariat based on data from the JODI

3.3.3 US

In July 2026, US total gas production kept its consistent growth trend, with monthly output rising by 2.6% y-o-y to 97 bcm (Figure 61). This growth reflected the favourable market dynamics, driven by the increased Henry Hub gas prices, rising gas demand, along with the increased feed gas directed to LNG exports terminals.

In terms of supply distribution, shale dry gas production sustained its frontrunner position in the US dry gas output, accounting for 82% and represented the main driver for the growth, with a 3.4% rise, while conventional gas and associated gas production from shale oil represented the remaining 18%. In terms of field type, associated gas production accounted for about 24.5% of total gas output. From a regional perspective, the Appalachian region accounted for 33% of total production, followed by the Permian region output with 24% and Haynesville with 14%.

For the period Jan-Jul 2026, cumulative gas production in the US reached 661 bcm (Figure 62), representing 3.6% y-o-y growth and therefore provided evidence on the positive trajectory of the US gas supply for the full year.

Figure 61: Trend in gas production in the US

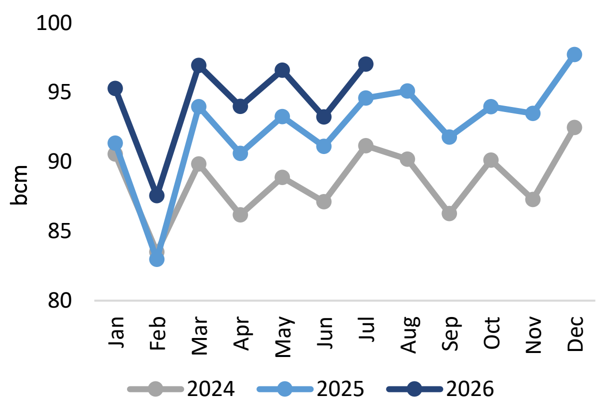
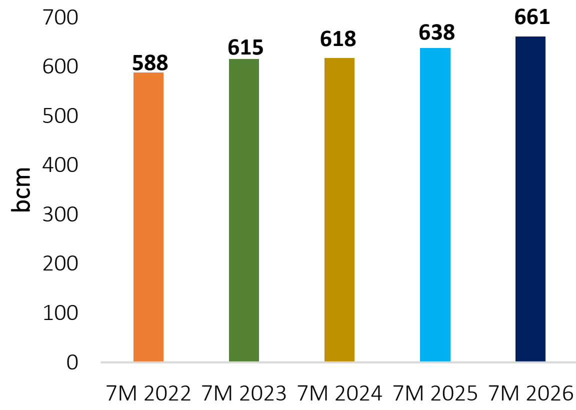


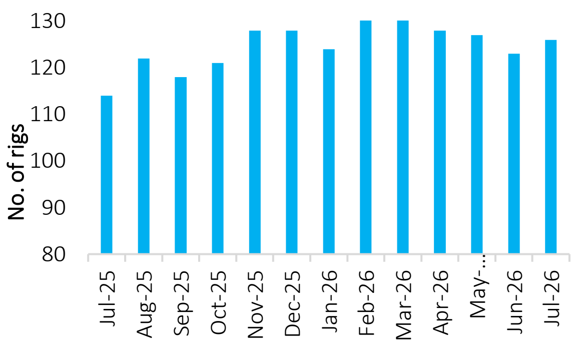
Figure 62: YTD gas production in the US



Source: GECF Secretariat based on data from the US EIA

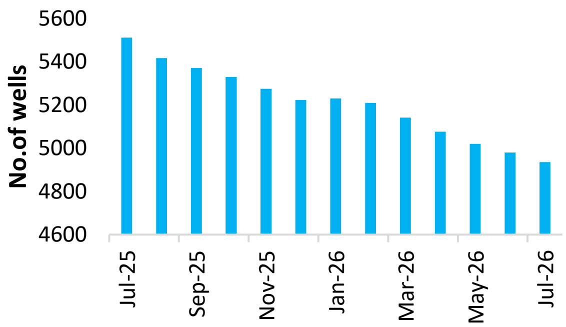
As of July 2026, the number of gas drilling rigs operating in the US stood at 126, marking a 3-rig increase compared to June 2026, and a 12-rig rise, compared to July 2025 (Figure 63), giving evidence of accelerated upstream activity in the US. Additionally in July 2026, the total number of drilled but uncompleted (DUC) wells in the US onshore regions amounted to 4,935, marking a 44-well m-o-m decrease and 576 wells lower than July 2025 (Figure 64). This reduction in DUCs reflected the reliance of the operators on their inventory of drilled wells, targeting the benefits of bringing the gas to market, during favourable conditions.

Figure 63: Gas rig count in the US



Source: GECF Secretariat based on data from Baker Hughes

Figure 64: DUC wells count in the US



Source: GECF Secretariat based on data from the US EIA

3.4 Latin America and the Caribbean (LAC)

In June 2026, gas production in LAC was estimated at 13.2 bcm (0.6% y-o-y rise), mainly driven by higher output in Argentina. For the first half of 2026, cumulative production reached 63.8 bcm, representing a 2% y-o-y growth.

3.4.1 Argentina

In June 2026, Argentina's gas production stood at 4.75 bcm, representing a marginal decline of 0.3% y-o-y (Figure 65). Most of the gas output originated from the Vaca Muerta (shale gas) Basin, however the conventional gas fields witnessed an 8% the growth. Notably, shale gas production witnessed a 1.5% y-o-y decline to stand at 2.61 bcm, accounting for 55% of total gas production (Figure 66). Moreover, tight gas production reached 0.38 bcm representing an 8% share of the total production, whilst the remaining output was produced from conventional fields. For the first half of 2026, cumulative production in Argentina reached 26.1 bcm, a 1% y-o-y rise.

Figure 65: Trend in gas production in Argentina

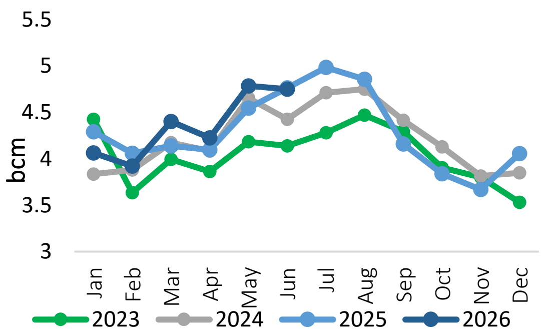
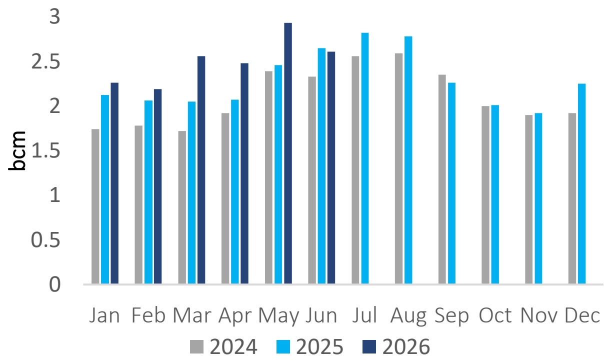


Figure 66: Shale gas output in Argentina



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

3.4.2 Brazil

In June 2026, Brazil's marketed gas production witnessed a decline of 2.7%, to achieve an output level of 1.8 bcm, driven by high gross gas production that stood at 6.5 bcm (20 % y-o-y rise) and large reinjection volumes (Figure 67), with the pre-salt fields representing 79% of the total production. Notably, 89% of production originated from offshore fields. In terms of distribution, 58% of gross gas production was reinjected into reservoirs, while there was a 12.9% increase in flaring compared to the previous month, and a 10.1% increase compared to June 2025. The increase in flaring was mainly due to the commissioning of the P-79 platform in the Búzios field. (Figure 68). For the first half of 2026, cumulative production reached 10.9 bcm, a 13.6% y-o-y growth.

Figure 67: Marketed gas production in Brazil

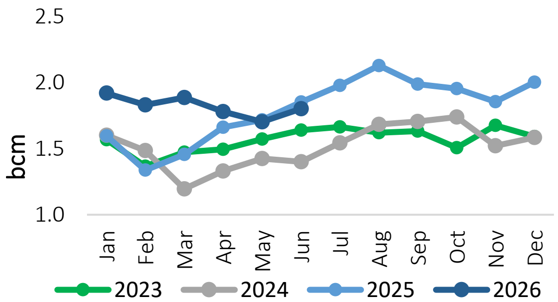
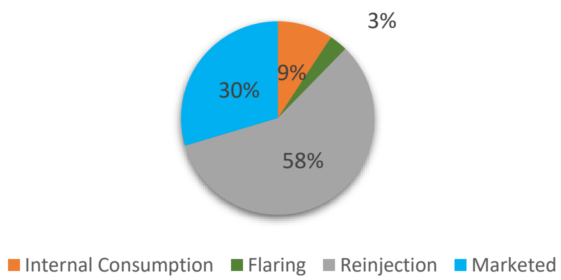


Figure 68: Distribution of gross gas production



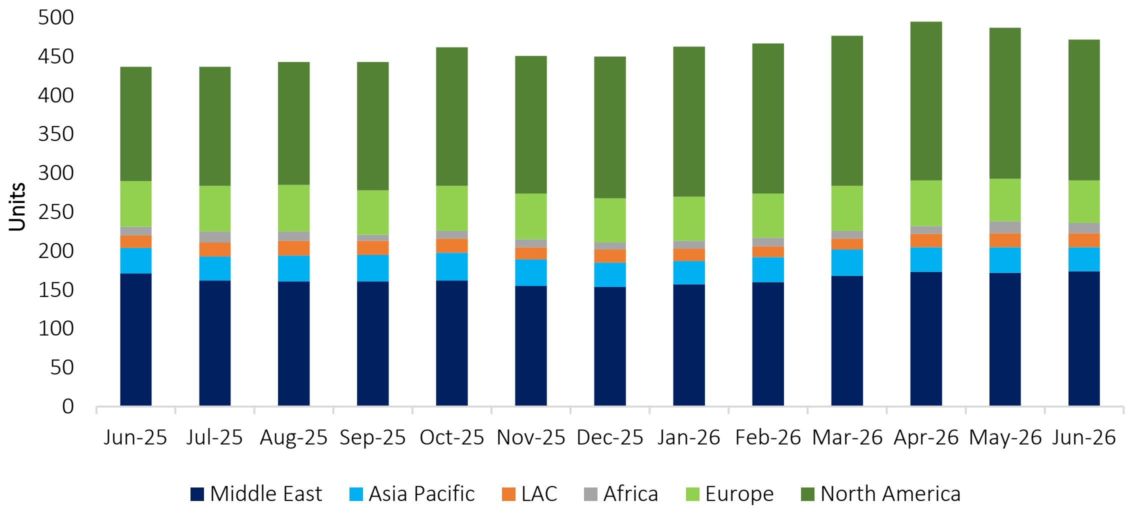
Source: GECF Secretariat based on data from the Brazilian National Agency of Petroleum (ANP)

3.5 Other developments

3.5.1 Upstream tracker

In June 2026, the number of gas drilling rigs globally accelerated by 14 additional units m-o-m, reaching 481 rigs (Figure 69). This was driven mainly by the increased drilling activity in North America, specifically in Canada. Onshore drilling accounted for the majority with 448 units, while offshore accounted for 33 rigs.

Figure 69: Trend in monthly global gas rig count



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

In June 2026, global exploration activity resulted in the total volume of discovered gas and liquids amounting to 200 million barrels of oil equivalent (boe) (Figure 70). with equal shares of liquids (100 million Bbl) and gas (17 bcm). Three new discoveries were announced in June, two of them were offshore. In terms of regional distribution, discoveries spread across Africa, LAC and Asia Pacific. LAC (Suriname) dominated the new discovered volumes with 75%, Africa (mainly Cote d Ivoire) followed by 23% (Figure 71). The Swartzia Aspasia Complex discovery, which is located 8 km east of the Sloanea-1 gas discovery, offshore Suriname, was the most significant gas discovery during the month. For the first half of 2026, cumulative discovered volumes reached 2.4 billion boe.

Figure 70: Monthly discovered oil and gas volumes

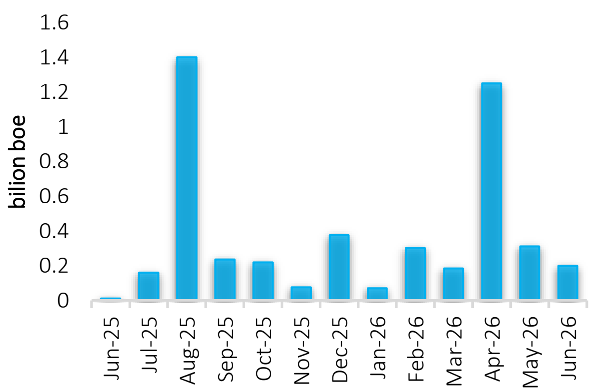
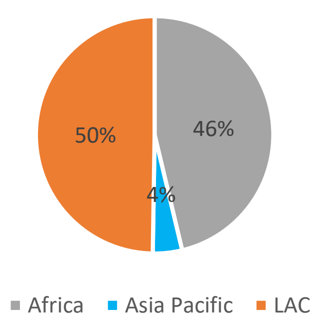


Figure 71: Discovered oil and gas volumes in June 2026 by region



Source: GECF Secretariat based on data from Rystad

3.5.2 Regional developments

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

ADNOC approved Umm Shaif Gas Cap development: ADNOC and its partners, TotalEnergies, Eni and China National Petroleum Corporation (CNPC), have approved a final investment decision (FID) for the USD6.2bn Umm Shaif Gas Cap project offshore Abu Dhabi, the company announced on 21 July 2026. The development is expected to produce more than 600 mscf/d (17 mcm/day) of natural gas and associated gas liquids by 2030, equivalent to nearly 10% of the UAE's current daily gas consumption. The project includes USD5.1bn in offshore EPC contracts and a USD365m drilling programme covering 14 wells. The investment strengthens ADNOC's gas growth strategy, following the Bab Gas Cap award, and supports its ambition to expand LNG exports and achieve 47 Mtpa of marketable LNG capacity by 2035.

Halliburton awarded unconventional gas project contract from Aramco: Halliburton has secured a multi-year contract from Aramco to provide integrated stimulation and completion services for unconventional gas development in Saudi Arabia. The contract forms part of a wider multibillion-dollar agreement linked to one of the largest unconventional gas development initiatives in the world. Halliburton currently supplies a range of drilling and completion services across Saudi Arabia's unconventional fields. The company uses an integrated service model designed to support intensive development and improve operational efficiency and reliability.

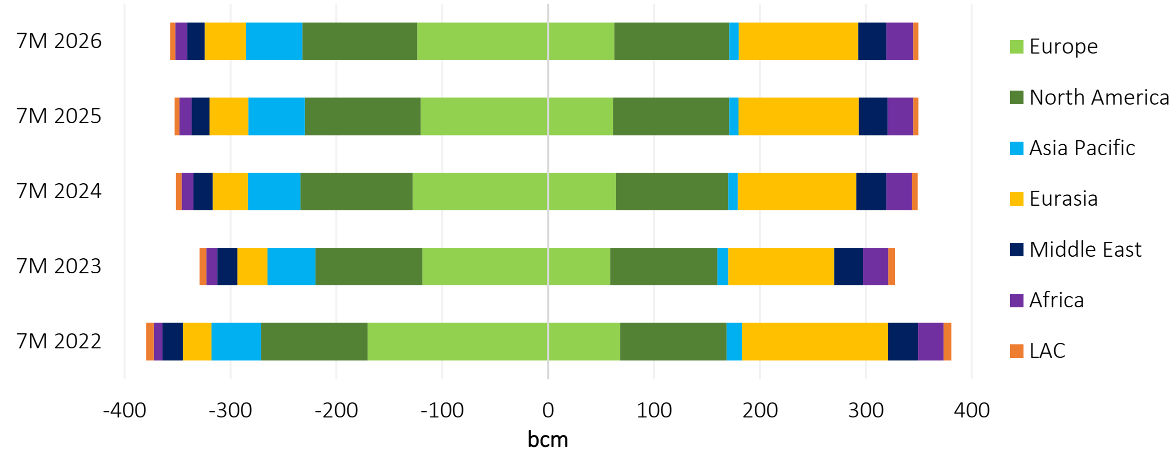
QatarEnergy signs commercial discovery declaration for Block 10 offshore Cyprus: QatarEnergy has signed a commercial discovery declaration for the Glaucus and Pegasus fields in Block 10, offshore Cyprus, as well as a collaboration statement, together with the Government of Cyprus and ExxonMobil. Signed in Nicosia, the declaration represents an important milestone in advancing the development of Cyprus' offshore resources. It also reflects the strong and constructive relationship between the parties and their shared commitment to continued collaboration and long-term strategic engagement, encompassing both the development of Block 10 and broader future opportunities. Under the declaration, the parties will work together to advance regulatory engagement and approvals, as well as development and production planning, in support of the next phase of Block 10 activities.

4 GAS TRADE

4.1 PNG trade

Cumulative global PNG imports between January and July 2026 grew by 1% y-o-y, reaching an estimated 357 bcm (Figure 72). This expansion was primarily driven by higher import volumes in Canada, the EU, and Kazakhstan, which more than offset lower inflows into the US, China, and the UAE. Eurasia retained its position as the leading exporting region, with a 32% share of global exports in 2026, while exports from African countries recorded a 4% y-o-y increase.

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

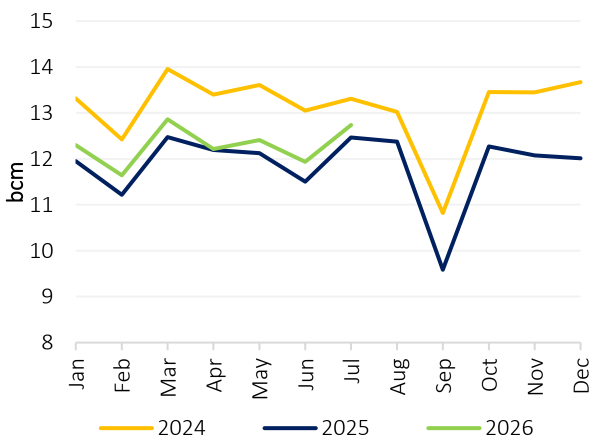


Source: GECF Secretariat based on data from Cedigaz, ENARGAS, Eurostat, GACC, JODI, LSEG and US EIA

4.1.1 Europe

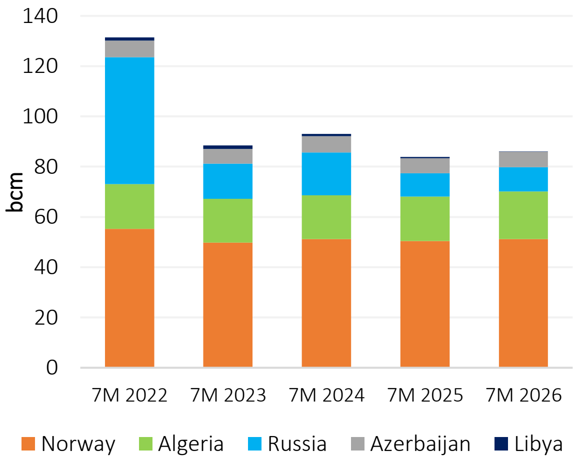
In July 2026, EU PNG imports rose 2% y-o-y to 12.7 bcm (Figure 73). Furthermore, the daily rate of 411 mmcmd reflected a 3% increase m-o-m, bringing the EU cumulative PNG imports for the first seven months of the year to 86 bcm, up by 3% y-o-y. This expansion was characterised by increased flows from all major suppliers with the exception of Libya (Figure 74).

Figure 73: Monthly PNG imports to the EU



Source: GECF Secretariat based on data from LSEG

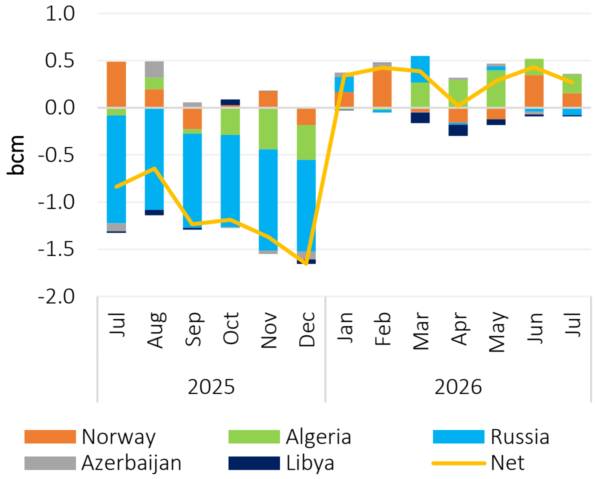
Figure 74: Year-to-date EU PNG imports by supplier



Source: GECF Secretariat based on data from LSEG

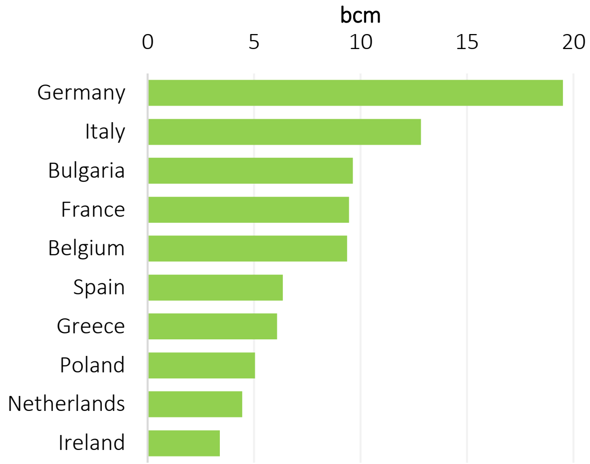
Throughout 2026, EU PNG imports posted a positive net y-o-y variation each month, driven primarily by supplies from Algeria (Figure 75). From January to July, imports increased across nearly all regional entry points, with the exception of the Netherlands. Additionally, France overtook Belgium in the ranking of EU PNG entry points in 2026 thus far (Figure 76).

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



Source: GECF Secretariat based on data from LSEG

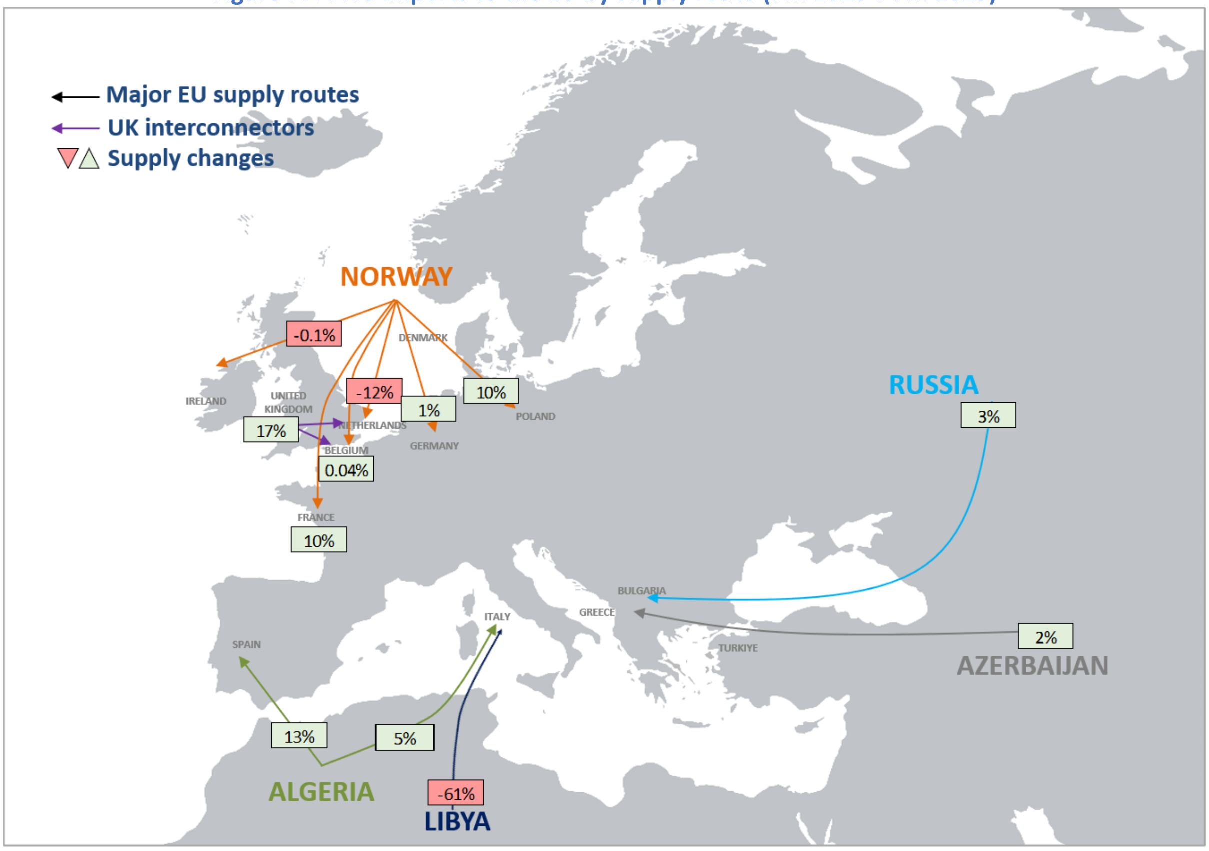
Figure 76: EU PNG imports by entry, after 6M 2026



Source: GECF Secretariat based on data from LSEG

Figure 77 shows the PNG imports to the EU via the major supply routes during the 7M 2026 period, relative to the same period in 2025. Norwegian pipeline deliveries to France and Poland each scaled up by 10% y-o-y, while Algerian exports to Spain grew by 13%. Similarly, Russian pipeline gas transported through TurkStream increased by 3% y-o-y. Over the same period, the cross-border interconnectors with the UK delivered nearly 5 bcm of regasified LNG into mainland Europe, marking a 17% y-o-y surge.

Figure 77: PNG imports to the EU by supply route (7M 2026 v 7M 2025)



Source: GECF Secretariat based on data from LSEG

4.1.2 Asia

In June 2026, China imported 7.1 bcm of PNG, remaining virtually unchanged y-o-y (Figure 78). However, this volume equated to 238 mmcmd, representing a 3% increase m-o-m. PNG accounted for 48% of total gas imports in June, marking only the second month of 2026 in which LNG imports exceeded pipeline supplies. Across the year to date, however, PNG maintained a 50% share of total gas imports, with cumulative volumes for the first half of 2026 reaching 39.6 bcm, down 1% y-o-y (Figure 79).

Figure 78: Monthly PNG imports in China

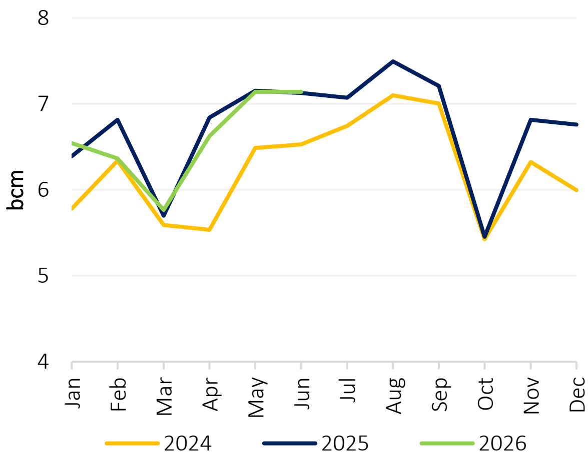
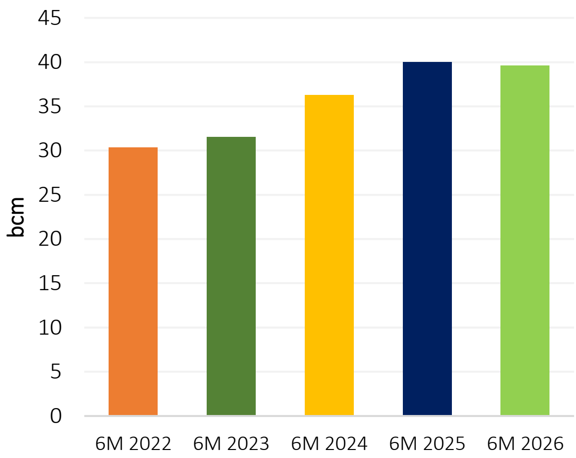


Figure 79: Year-to-date PNG imports in China



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

Singapore imported 0.62 bcm of PNG from Indonesia and Malaysia in May 2026, marking an 18% increase y-o-y despite a 4% decline m-o-m (Figure 80). This brought cumulative PNG imports for the first five months of the year to 3 bcm, up 21% y-o-y.

Meanwhile, Thailand imported 0.36 bcm of PNG from Myanmar during May, down 5% y-o-y but up 1% m-o-m (Figure 81). This placed Thailand's cumulative 2026 PNG imports at 1.7 bcm, representing a 23% decrease y-o-y.

Figure 80: Monthly PNG imports in Singapore

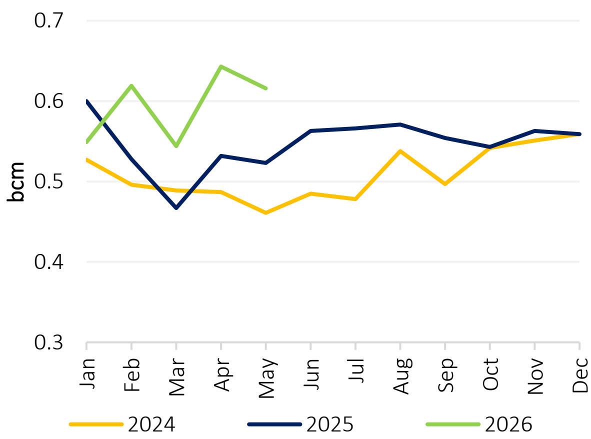
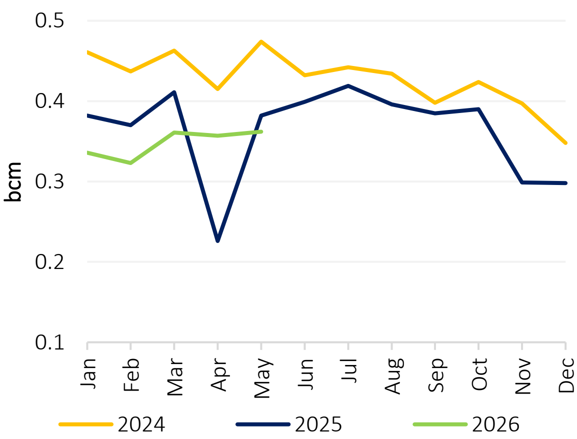


Figure 81: Monthly PNG imports in Thailand



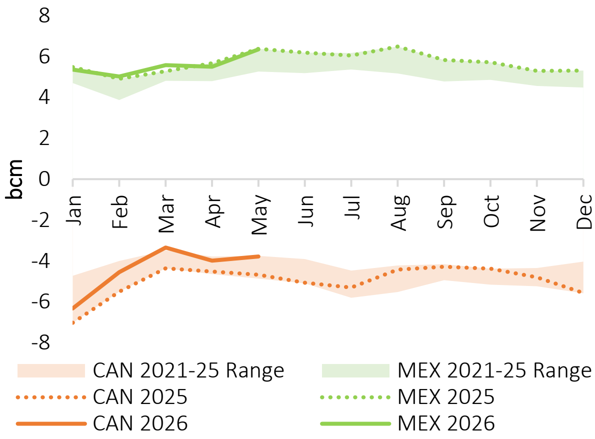
Source: GECF Secretariat based on data from JODI Gas

4.1.3 North America

In May 2026, Mexico imported 6.3 bcm of PNG from the US, down 1% y-o-y but up 15% m-o-m (Figure 82). This brought Mexico's total imports for the first five months of the year to 28 bcm, which was unchanged y-o-y.

In the same month, net PNG flows from Canada to the US totalled 3.8 bcm, falling 19% y-o-y and 5% m-o-m. Gross flows from Canada to the US ticked up m-o-m to 6.3 bcm, while flows from the US to Canada also increased m-o-m to 2.5 bcm. For the year to date, cumulative net flows from Canada to the US dropped 16% y-o-y to 22 bcm.

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



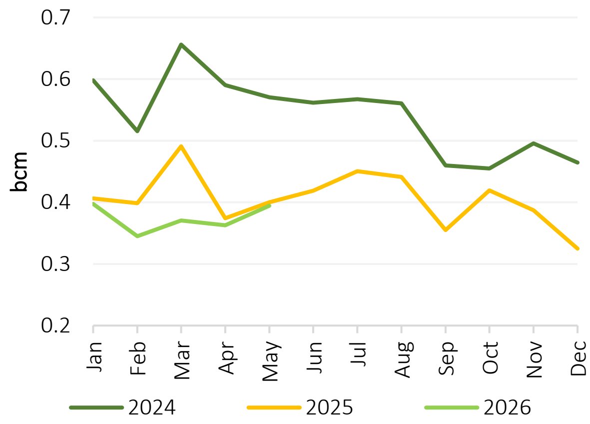
Source: GECF Secretariat based on data from US EIA

4.1.4 Latin America and the Caribbean

Bolivia exported 0.39 bcm of PNG in May 2026, marking a 1% decline y-o-y (Figure 83). On a daily basis, however, exports ticked up 5% m-o-m to 13 mmcmd. This brought cumulative Bolivian exports for the first five months of the year to 1.9 bcm, down 10% y-o-y.

In the same month, Argentina exported 0.29 bcm of PNG to Brazil, Chile, and Uruguay, representing a 12% increase y-o-y. Although the daily export rate fell 19% m-o-m to 9 mmcmd, cumulative Argentine PNG exports for the first five months rose 21% y-o-y to reach 1.7 bcm.

Figure 83: Monthly PNG exports from Bolivia



Source: GECF Secretariat based on data from JODI Gas

4.1.5 Other developments

Sonatrach advances Trans-Sahara project: In a move to bolster energy ties between Africa and Europe, Algeria dispatched a specialist technical team from state energy giant Sonatrach to the transit country Niger to revive the long-stalled $13 billion Trans-Sahara Gas Pipeline. Once operational, the 4,100 km pipeline will carry 30 bcm of natural gas annually from Nigeria’s Niger Delta to Algerian export hubs, serving European markets and integrating regional energy infrastructure.

TAPI pipeline moves ahead: The Chairman of the People's Council of Turkmenistan visited Afghanistan to launch the latest phase of the $10 billion Turkmenistan-Afghanistan-Pakistan-India (TAPI) gas pipeline project, which aims to transport 33 bcm of gas annually from the Galkynysh field. The meeting inaugurated the construction of the 153 km Serhetabat-Herat section in Afghanistan, which follows the completion of the Turkmen section in 2024. Once operational, the pipeline will supply 42% of its gas each to Pakistan and India, while generating over $1 billion in annual revenue for Afghanistan.

4.2 LNG trade

4.2.1 LNG imports

In July 2026, global LNG imports continued to trend lower, falling by 2.9% (1.01 Mt) y-o-y to 33.40 Mt (Figure 84). Europe led the decline in LNG imports, partially offset by higher imports in Asia. Reduced LNG supply from the Middle East, due to restrictions on LNG transit through the Strait of Hormuz, weighed on global LNG trade. Furthermore, the significant premium of Asian spot LNG prices over European prices incentivised the diversion of some LNG cargoes from Europe to Asia.

For the period January to July 2026, global LNG imports edged up by 0.4% (0.99 Mt) y-o-y to 248.65 Mt driven by stronger LNG imports in Asia and the MEA (Figure 85).

Figure 84: Trend in global monthly LNG imports

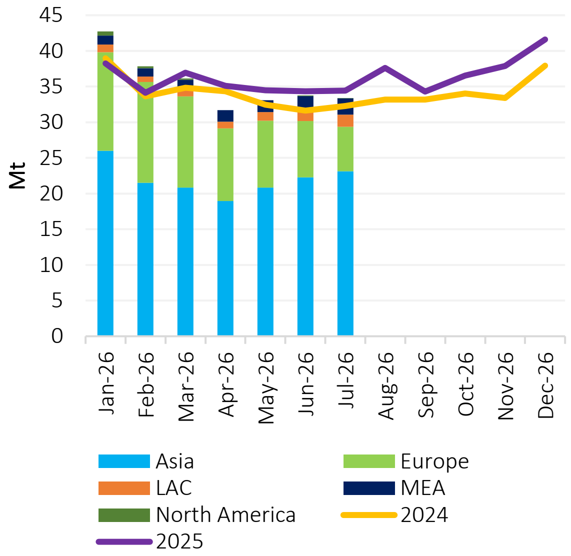
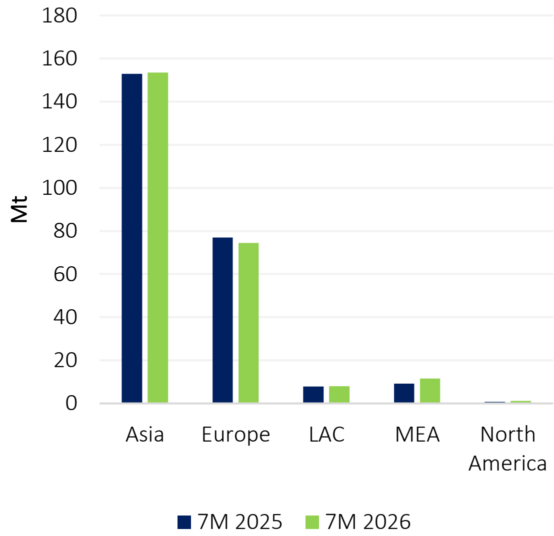


Figure 85: Trend in regional YTD LNG imports



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.1 Europe

In July 2026, Europe's LNG imports fell sharply by 32% (2.91 Mt) y-o-y to 6.22 Mt, the lowest monthly level since September 2021 (Figure 86). The decline was driven by tighter global LNG supply amid restrictions on LNG transit through the Strait of Hormuz. At the same time, Asian spot LNG prices averaged a significant premium of around $1.70/MMBtu over European prices, attracting a substantial number of flexible US LNG cargoes away from Europe towards higher-netback Asian markets. Higher spot LNG prices in Egypt also diverted some US LNG cargoes away from Europe. At the country level, Belgium, Finland, France, Germany, the Netherlands, Spain and the UK accounted for the bulk of the regional decline (Figure 87).

The decline in LNG imports across these countries was driven primarily by lower imports from the US, while reduced Russian LNG deliveries also contributed to the decline in France. Europe's imports of US LNG fell from 5.43 Mt in July 2025 to 3.67 Mt in July 2026, with the largest declines recorded in Belgium, France, Germany and the Netherlands. Conversely, Italy increased its imports of US LNG, partially offsetting lower supplies from Qatar.

For the period Jan-Jul 2026, Europe's LNG imports declined by 3.4% y-o-y (2.58 Mt) to 74.43 Mt.

Figure 86: Trend in Europe's monthly LNG imports

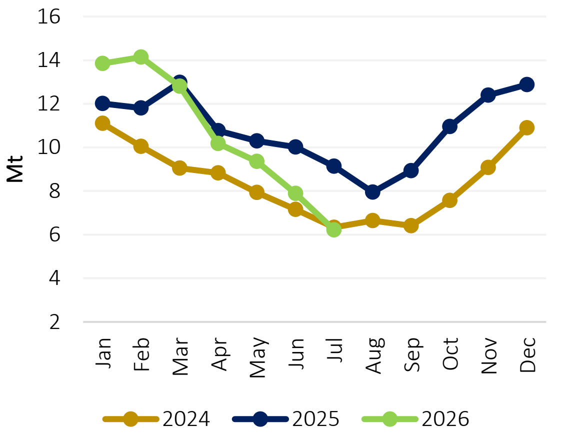
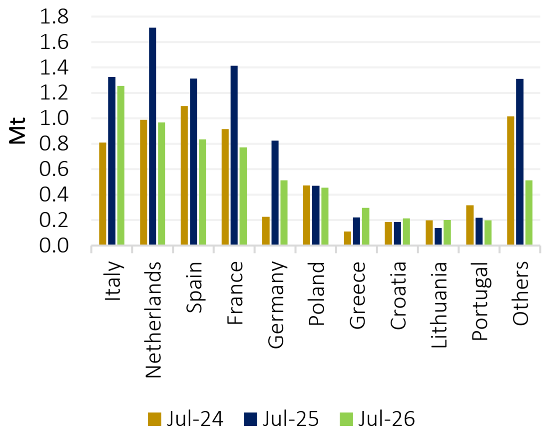


Figure 87: Top LNG importers in Europe



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.2 Asia

In July 2026, Asia's LNG imports continued to recover, rising by 8.8% (1.87 Mt) y-o-y to 23.15 Mt (Figure 88). Despite reduced LNG supply from the Middle East, Asia's LNG imports increased for the second consecutive month. The growth in Asia's LNG imports was driven mainly by higher imports in India, Indonesia, Japan, Malaysia, South Korea, Taiwan and Thailand, which more than offset declines in China, Pakistan and Singapore (Figure 89).

Stronger LNG imports in India, Taiwan and Thailand were supported by higher gas consumption in the power sector. In Taiwan, LNG restocking requirements provided additional support to imports. In Indonesia and Malaysia, increased intra-country trade to meet stronger gas demand boosted LNG imports. Japan and South Korea also increased their LNG imports to maintain sufficient inventory levels, despite lower gas consumption in the power sector. Meanwhile, China's LNG imports declined following the increase recorded in June 2026, driven mainly by lower supplies from Indonesia and Qatar. In Pakistan and Singapore, LNG imports continued to be constrained by reduced supplies from Qatar amid restrictions on LNG transit through the Strait of Hormuz.

For the period January to July 2026, Asia's LNG imports grew by 0.4% (0.60 Mt) y-o-y to 153.56 Mt.

Figure 88: Trend in Asia's monthly LNG imports

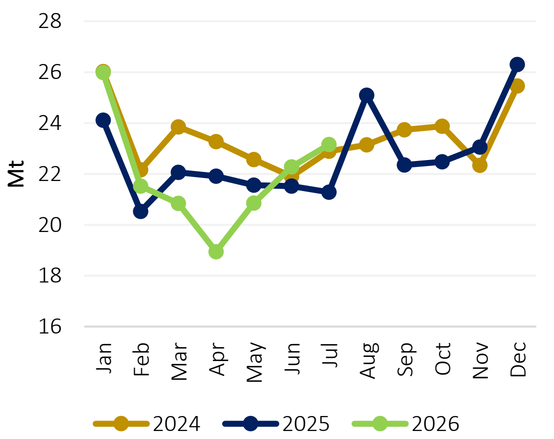
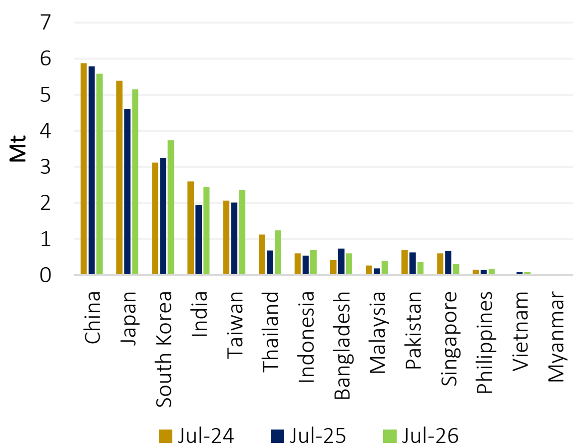


Figure 89: LNG imports in Asia Pacific by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.3 Latin America & the Caribbean (LAC)

In July 2026, LNG imports in Latin America and the Caribbean (LAC) increased by 6.3% (0.10 Mt) y-o-y to 1.68 Mt (Figure 90). Higher imports in Argentina and Colombia drove the regional increase, more than offsetting declines in Jamaica and the Dominican Republic (Figure 91).

Argentina's LNG imports rose sharply, supported by a colder-than-usual winter that boosted gas demand for heating and increased the need for LNG supply. In Colombia, declining domestic gas production, combined with stronger gas-fired power generation amid lower hydropower output and the risk of El Niño-induced drought conditions, supported higher LNG imports. Conversely, Jamaica did not import any LNG cargoes in July, following a sharp increase in imports in June. Meanwhile, the decline in the Dominican Republic's LNG imports was primarily attributable to lower imports from the US.

For the period January to June 2026, LAC's LNG imports rose by 1.7% (0.14 Mt) y-o-y to 7.98 Mt.

Figure 90: Trend in LAC's monthly LNG imports

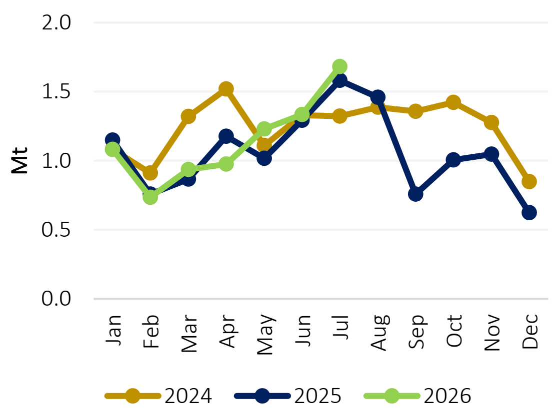
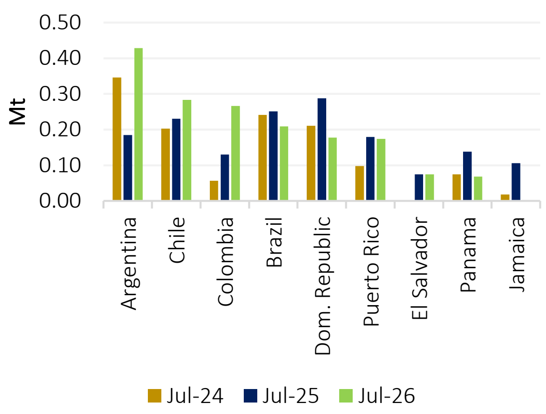


Figure 91: Top LNG importers in LAC



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.1.4 Middle East and Africa (MEA)

In July 2026, LNG imports in the MEA remained broadly stable at 2.29 Mt, unchanged from July 2025 (Figure 92). Sharp increase in Egypt's LNG imports offset weaker imports in Kuwait (Figure 93). Egypt's higher LNG imports were driven by lower domestic gas production and robust gas demand, while Kuwait's imports were impacted by the impact of the Middle East conflict.

For the period January to July 2026, MEA's LNG imports grew by 26% (2.36 Mt) y-o-y to 11.54 Mt.

Figure 92: Trend in MEA's monthly LNG imports

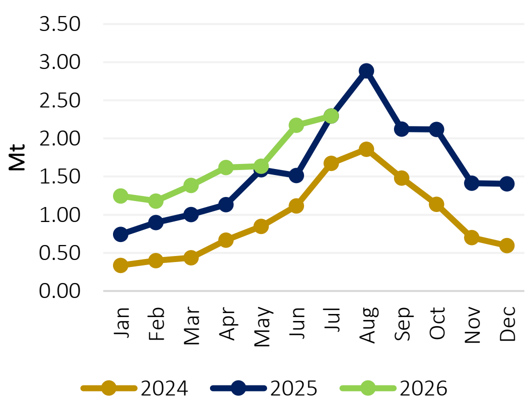
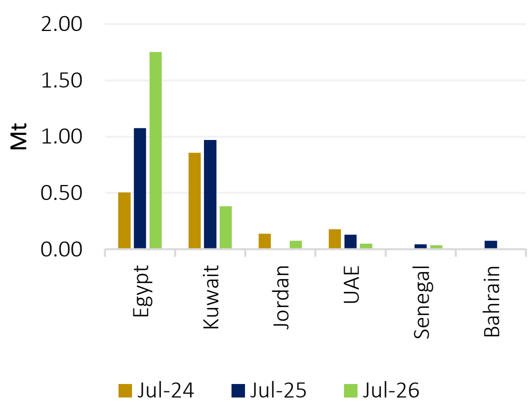


Figure 93: Top LNG importers in MEA



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2 LNG exports

In July 2026, global LNG exports fell sharply by 9.5% (3.46 Mt) y-o-y to 32.78 Mt, marking the steepest monthly y-o-y decline on record (Figure 94). The contraction was primarily driven by restrictions on LNG transit through the Strait of Hormuz amid the Middle East conflict. Lower LNG exports from GECF member countries more than offset higher exports from non-GECF countries. The US, Australia and Malaysia were the world's three largest LNG exporters.

Consequently, non-GECF countries' share of global LNG supply rose from 55.3% in July 2025 to 69.7% in July 2026, while the share of LNG re-exports edged up from 0.6% to 0.8%. Conversely, the share of GECF member countries fell from 44.1% to 29.5% over the same period.

For the period January to July 2026, global LNG exports declined marginally by 0.4% (1.09 Mt) y-o-y to 246.72 Mt, driven by lower exports from GECF member countries (Figure 95).

Figure 94: Trend in global monthly LNG exports

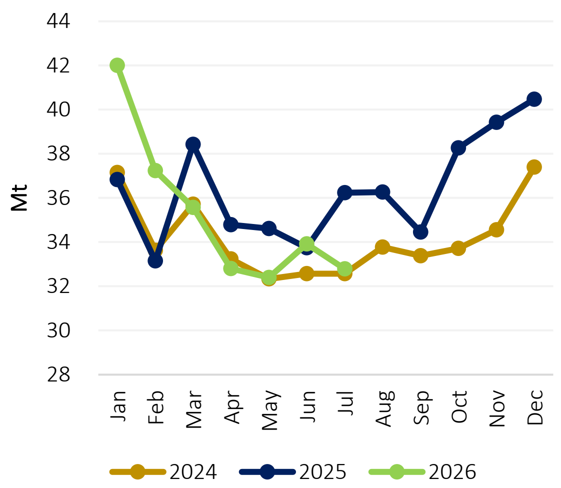
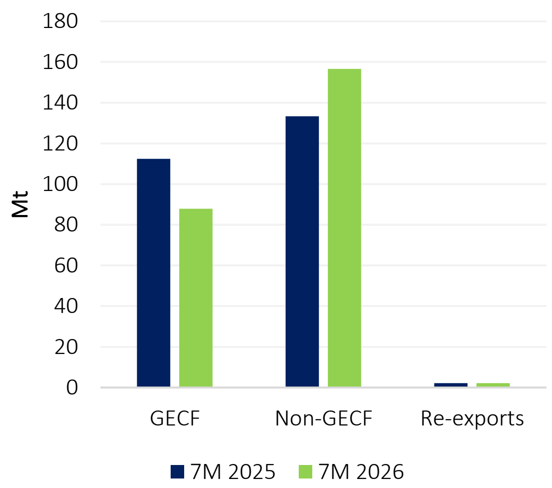


Figure 95: Trend in YTD LNG exports by supplier



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.1 GECF

In July 2026, LNG exports from GECF member countries fell sharply by 40% (6.32 Mt) y-o-y to a multi-year low of 9.67 Mt (Figure 96). The decline was driven primarily by continued restrictions on LNG transit through the Strait of Hormuz, which severely constrained exports from the Middle East (Figure 97). Qatar accounted for the bulk of the decline, while Algeria, Angola and the United Arab Emirates (UAE) also recorded lower exports. Conversely, LNG exports from Malaysia and Russia increased.

Qatar and the UAE's LNG exports remained significantly constrained by disruptions to LNG transit through the Strait of Hormuz, with exports from both countries declining further from June amid heightened geopolitical tensions in the region. In Algeria, lower feedgas availability weighed on LNG exports, while maintenance activity at the Angola LNG facility reduced output. Conversely, higher feedgas availability boosted higher LNG exports from Malaysia, while increased cargo loadings from the Arctic LNG 2 facility drove Russia's LNG exports higher.

For the period January to July 2026, LNG exports from GECF member countries fell by 22% (24.50 Mt) y-o-y to 87.95 Mt.

Figure 96: Trend in GECF monthly LNG exports

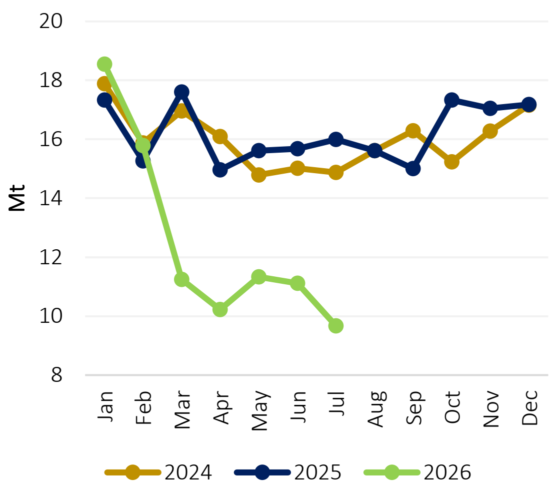
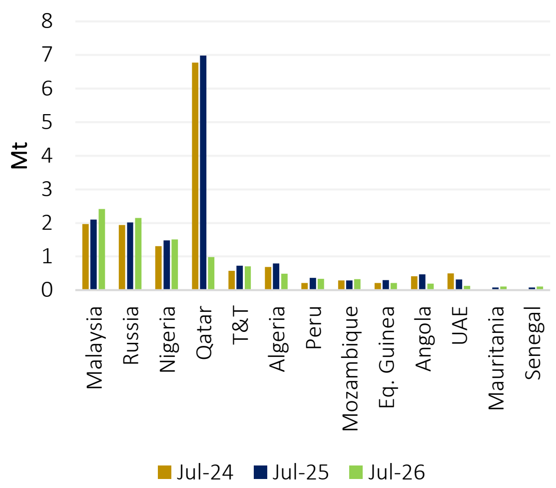


Figure 97: GECF's LNG exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.2.2 Non-GECF

In July 2026, LNG exports from non-GECF countries jumped by 14% (2.82 Mt) y-o-y to reach 22.86 Mt (Figure 98). The stronger LNG exports was driven by a combination of the ramp-up in production from new facilities, increased feedgas availability and lower maintenance activity, which came mainly from US, as well as Australia, Canada, Congo and Norway (Figure 99).

The increase in US LNG exports was driven primarily by the ramp-up in production at the Corpus Christi, Golden Pass and Plaquemines LNG facilities. Similarly, rising production from the LNG Canada and Congo FLNG 2 facilities supported higher LNG exports from Canada and the Republic of the Congo, respectively. In Australia, the ramp-up in production at the Darwin LNG facility following its recent restart, combined with lower maintenance activity at the APLNG and Gorgon LNG facilities, boosted LNG exports. Likewise, reduced maintenance activity at the Hammerfest LNG facility supported higher LNG exports from Norway.

For the period January to July 2026, non-GECF LNG exports increased by 18% (23.30 Mt) y-o-y to 156.57 Mt.

Figure 98: Trend in non-GECF monthly LNG exports

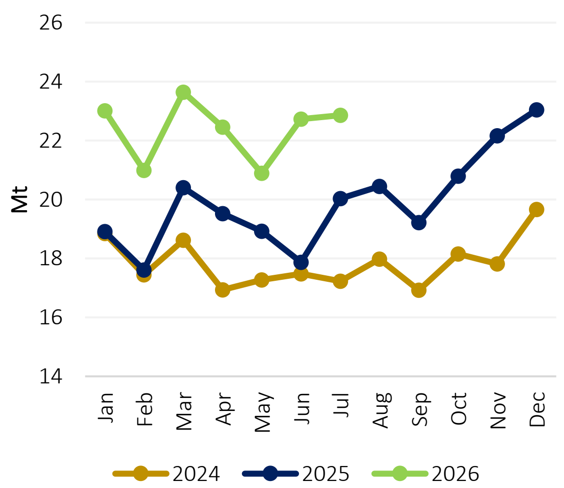
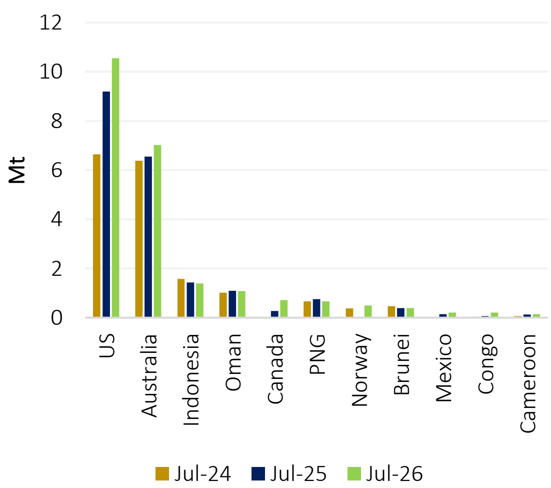


Figure 99: Non-GECF's LNG exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

4.2.3 Global LNG re-exports

In July 2026, global LNG re-exports increased by 18% (0.04 Mt) y-o-y to 0.26 Mt, the highest monthly level since March 2026 (Figure 100). The increase was driven primarily by stronger re-export activity from China.

China's LNG re-exports rose sharply during the month, supported by increased intra-regional LNG trade. The country re-exported three LNG cargoes, with one cargo each delivered to Japan, South Korea and Thailand, compared with only one cargo re-exported to South Korea in July 2025. The cargo re-exported to Thailand was likely a bonded LNG cargo originating from the US, representing the first US LNG cargo imported into China since February 2025.

For the January to July 2026 period, global LNG re-exports increased by 5.7% (0.12 Mt) y-o-y to 2.20 Mt. The growth was driven primarily by higher re-exports from China, which more than offset declines in Brazil, Finland, Singapore and the US Virgin Islands (USVI) (Figure 101).

Figure 100: Trend in global monthly LNG re-exports

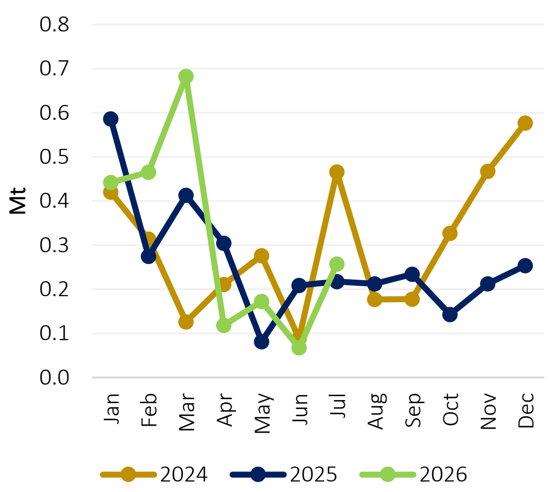
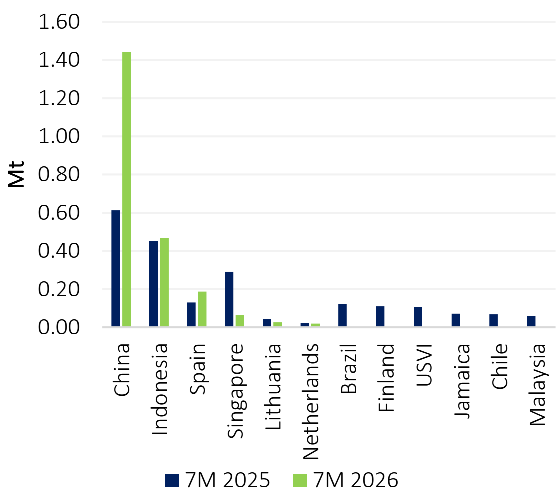


Figure 101: Global YTD LNG re-exports by country



Source: GECF Secretariat based on data from ICIS LNG Edge

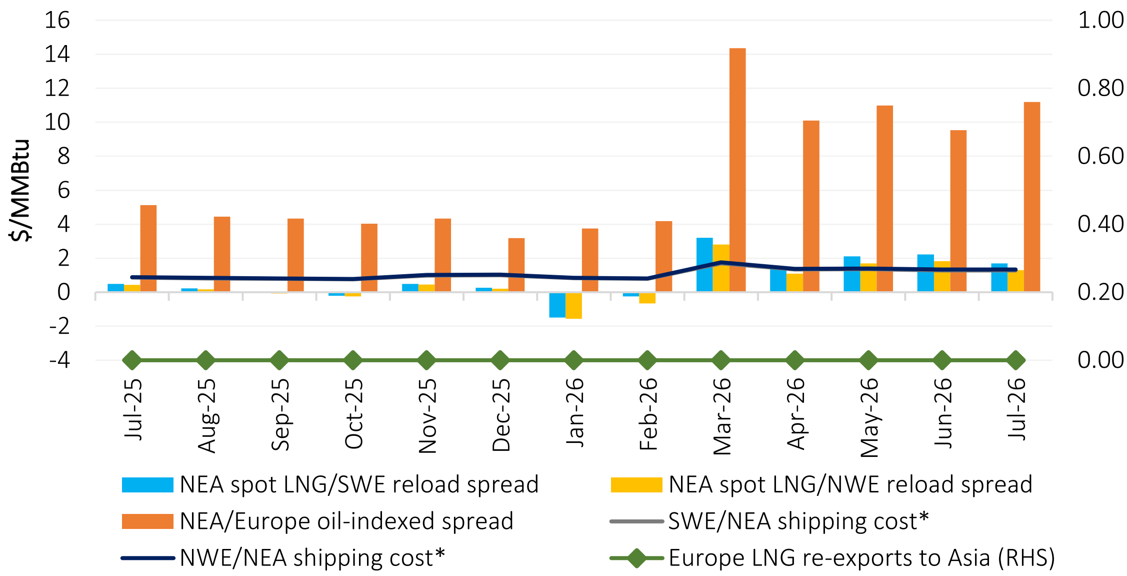
4.2.4 Arbitrage opportunity

In July 2026, arbitrage opportunities for LNG re-exports from Europe to Asia remained relatively favourable, as the North East Asia (NEA) spot LNG price maintained a significant premium over European LNG reload prices, with the spreads exceeding one-way spot shipping costs from Europe to Asia (Figure 102). Similarly, the premium of the NEA spot LNG price over European oil-indexed LNG remained well above the corresponding shipping costs.

The NEA–Southwest Europe (SWE) and NEA–Northwest Europe (NWE) spreads narrowed from $2.22/MMBtu and $1.82/MMBtu in June to $1.69/MMBtu and $1.29/MMBtu in July, respectively, reflecting a stronger decline in European LNG reload prices relative to the NEA spot LNG price. Conversely, the premium of the NEA spot LNG price over European oil-indexed LNG widened from $9.54/MMBtu to $11.20/MMBtu, while one-way shipping costs from Europe to Asia remained stable at $1.31/MMBtu.

Despite favourable arbitrage economics, no LNG cargoes were re-exported from Europe to Asia in July. This reflected continued tightness in the global LNG market, the diversion of some US LNG cargoes towards higher-priced Asian markets, and Europe's continued need to refill underground gas storage from multi-year low levels.

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

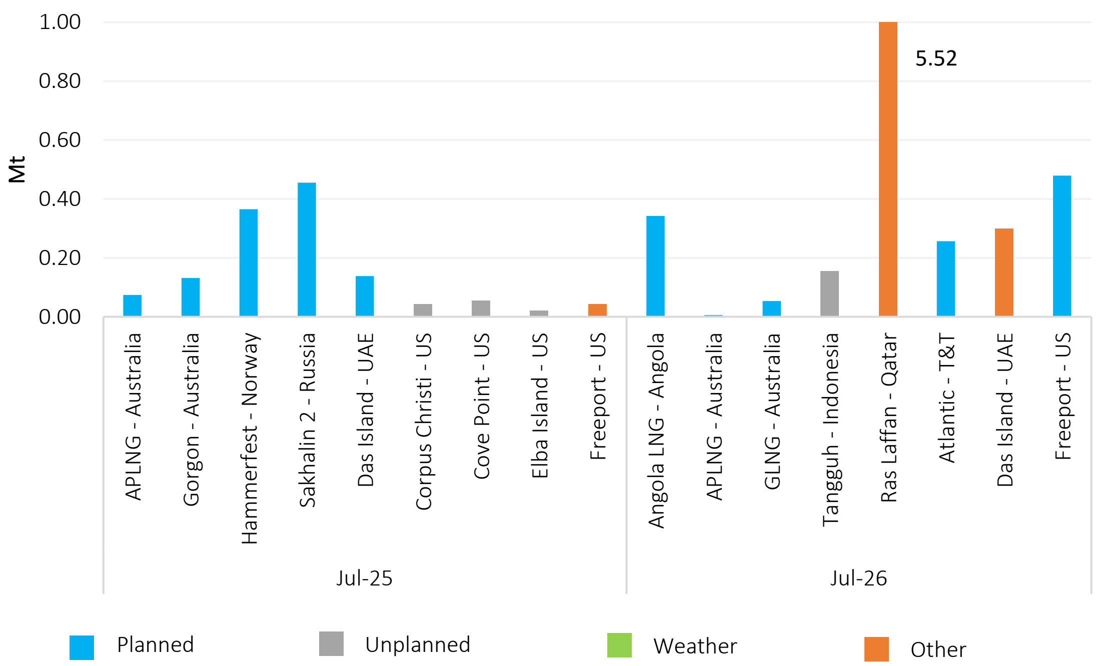


Source: GECF Secretariat based on data from GECF Shipping Model, Argus and ICIS LNG Edge
(*): One-way spot shipping costs

4.2.5 Maintenance activity at LNG liquefaction facilities

In July 2026, disruptions at global LNG liquefaction facilities, including planned maintenance, unplanned outages and other operational issues, rose sharply to 7.11 Mt, compared with 1.33 Mt in July 2025 (Figure 103). The significant increase was driven by the impact of the Middle East conflict on operations at Qatar's Ras Laffan and the UAE's Das Island LNG facilities. Further disruptions were caused by planned maintenance at several LNG facilities in Angola, Australia, Trinidad and Tobago and the US, as well as an unplanned outage in Indonesia.

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

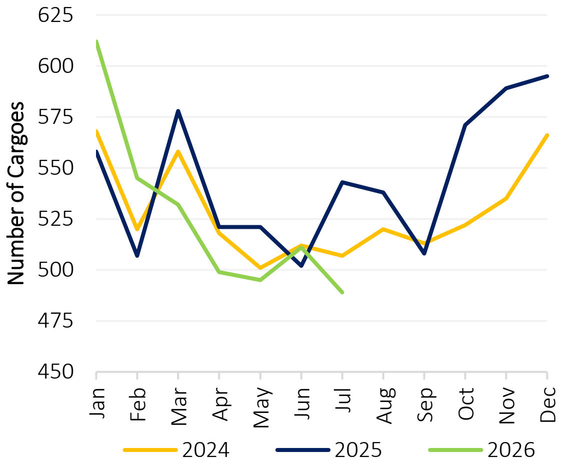


Source: GECF Secretariat based on information from Argus, ICIS LNG Edge and LSEG

4.2.6 LNG shipping

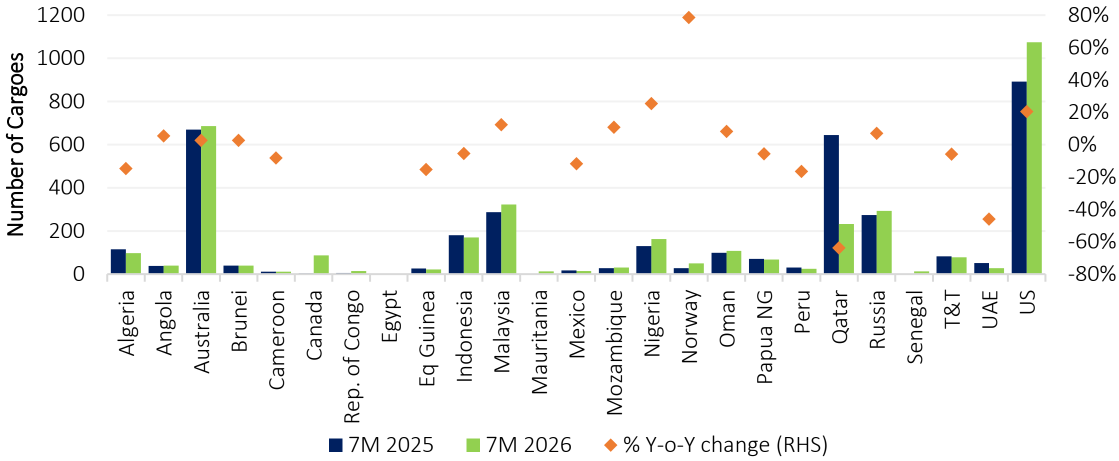
Global LNG cargo loadings fell by 22 shipments m-o-m to reach 489 in July 2026. This represented a 10% decrease y-o-y, as a result of seasonal factors as well as lower output from Qatar and the UAE (Figure 104). Over the first seven months of the year, total shipments fell by 47 cargoes to 3,683. GECF countries accounted for 37% of these loadings, led by Malaysia, Russia, and Qatar. Year-to-date, the US (+182) and Malaysia (+35) recorded the largest increases in cargo exports, whilst the Republic of the Congo and Egypt registered the highest percentage growth, with both countries tripling exports (Figure 105).

Figure 104: Number of LNG export cargoes



Source: GECF Secretariat based on data from ICIS LNG Edge

Figure 105: Changes in LNG cargo exports



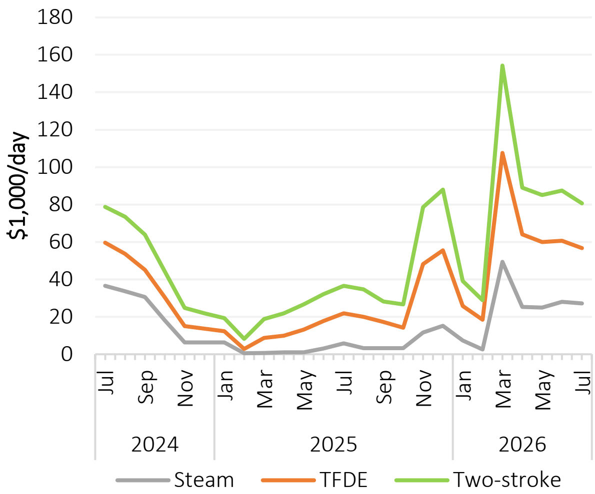
Source: GECF Secretariat based on data from ICIS LNG Edge

In July 2026, the spot charter market for LNG carriers sustained the stability observed since the early-March spike subsided (Figure 106). Monthly average rates for TFDE carriers fell 7% m-o-m to $56,700 per day, staying 160% higher y-o-y and standing $2,400 per day above the five-year average. The average spot rate for two-stroke vessels decreased 8% m-o-m to $80,500 per day, though it remained 120% above the previous year. Steam turbine carriers experienced a 3% m-o-m decline to average $27,200 per day, holding 369% higher y-o-y.

During July, the LNG carrier spot charter rates shifted from early-to-mid-month firmness to a significant late-month decline. Initially, rising Middle East conflicts prompted long-length firms to withdraw offers, anticipating a sustained inter-basin arbitrage, while firm Atlantic basin requirements and surging LNG prices kept the market tight and stable. However, rates dropped sharply toward the end of July. This downward correction was driven by expectations that the inter-basin arbitrage for uncommitted US Gulf Coast cargoes would remain closed for the rest of the second half of the year, forcing vessels into shorter European voyages and releasing global freight supply. Looking ahead, there is market uncertainty on fourth-quarter rates, considering the balance between seasonal demand upticks and the ongoing Middle East conflict, against quick newbuild deliveries and a closed arbitrage.

In July 2026, the average price of shipping fuels fell 13% m-o-m to an estimated $590 per tonne (Figure 107). Although this price remained 16% higher y-o-y, it stood 4% below the five-year monthly average, driven by softening global crude oil prices.

Figure 106: Average LNG spot charter rate



Source: GECF Secretariat based on data from Argus

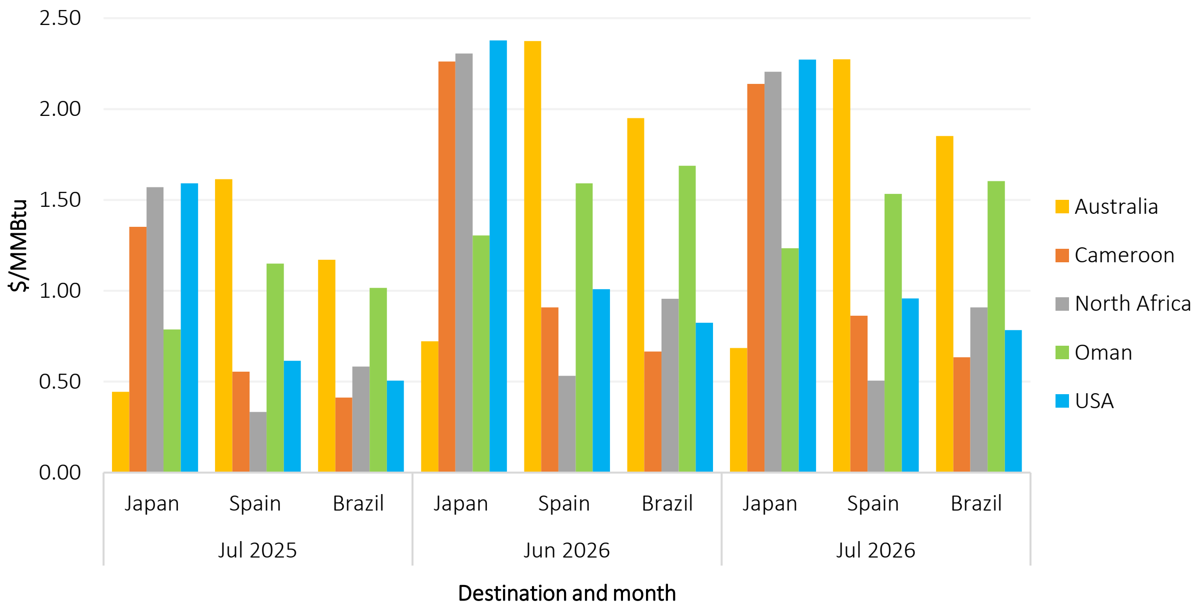
Figure 107: Average price of shipping fuels

Source: GECF Secretariat based on data from Argus and Platts

There was a decrease in spot shipping costs for TFDE LNG carriers in July 2026 compared to the previous month, by up to $0.12/MMBtu on certain routes (Figure 108). This was driven by the decreases in the monthly average spot charter rates and in the cost of shipping fuels, despite the increase in the delivered spot LNG prices.

Compared to one year ago, in July 2026 the monthly average LNG carrier spot charter rate, the cost of shipping fuels, and the delivered spot LNG prices were also all higher. As a result, spot LNG shipping costs were up to $0.79/MMBtu higher than in July 2025.

Figure 108: Spot shipping costs for TFDE LNG carriers



Source: GECF Shipping Cost Model

4.2.7 Other developments

UAE's ADNOC establishes global LNG marketing and trading platform: On 6 July 2026, ADNOC announced the consolidation of the LNG marketing activities of ADNOC Gas and XRG with ADNOC Trading into a new integrated global LNG marketing and trading platform based in Abu Dhabi. The platform aims to enhance commercial flexibility, shipping optionality and portfolio optimisation while strengthening access to global customers. It will support ADNOC Gas' expanding LNG portfolio, including Ruwais LNG, alongside XRG's international gas and infrastructure growth. With combined marketable LNG volumes targeted to reach 47 Mtpa by 2035, the platform is expected to position ADNOC and XRG among leading global LNG players and reinforce UAE's role as a global energy trading hub.

Cameroon exits LNG export market following the Hilli Episeyo FLNG departure: Golar LNG's Hilli Episeyo FLNG departed Cameroon in August 2026 after completing eight years of LNG production offshore Kribi, ending Cameroon's status as an LNG exporter. Following the expiry of its production tolling contract with Perenco and SNH, the vessel is heading to Singapore's Seatrium shipyard for upgrades ahead of its redeployment to Argentina under a 20-year contract. The modifications will include life-extension works, winterisation and installation of a new mooring system. The FLNG will subsequently be deployed in the Gulf of San Matias, marking Golar LNG's strategic shift towards expanding its operations in Latin America.

Shell takes FID on Bahamas LNG import terminal: On 14 July 2026, Shell took a final investment decision (FID) on a small-scale LNG regasification terminal at Clifton Pier, New Providence, supporting The Bahamas' transition from diesel and fuel oil to natural gas for power generation. The project will be developed by New Providence Gas Ltd., in which Shell Bahamas Power Company holds a 40% stake. Shell will supply LNG from its US portfolio. The phased terminal will initially support more than 170 MW of power generation, with first gas targeted for Q1 2027 and regasification capacity of around 55 MMscf/d.

Japan to resume LNG carrier construction: Japan plans to revive its domestic LNG carrier construction industry by 2035, with major shipbuilders aiming to build 3 to 5 LNG carriers annually. The government is considering subsidies to help domestic vessels compete with lower-cost South Korean and Chinese ships and plans to include the initiative in its Public-Private Investment Roadmap. Because Japan halted LNG carrier construction in 2019, it is reportedly seeking technological cooperation from South Korean shipbuilders to regain critical expertise, particularly the production of membrane-type LNG tanks.

In July 2026, LNG contracting was robust with five (5) LNG agreements signed (Table 1).

Table 1: New LNG sale agreements signed in July 2026

Contract Type	Exporting Country	Project	Seller	Importing Country	Buyer	Volume (Mtpa)	Duration (Years)
HOA	US	Texas LNG	Glenfarne	Portfolio	BGN	1	20
SPA	Portfolio	Portfolio	Shell Eastern LNG	Vietnam	PV Gas		5
SPA	UAE	Ruwais LNG	ADNOC Gas	Portfolio	INPEX	1	15
SPA	Portfolio	Portfolio	Petronas	Japan	Shizuoka Gas	0.84	7
SPA	Canada	Ksi Lisims LNG	Ksi Lisims LNG	Germany	Uniper	2	20

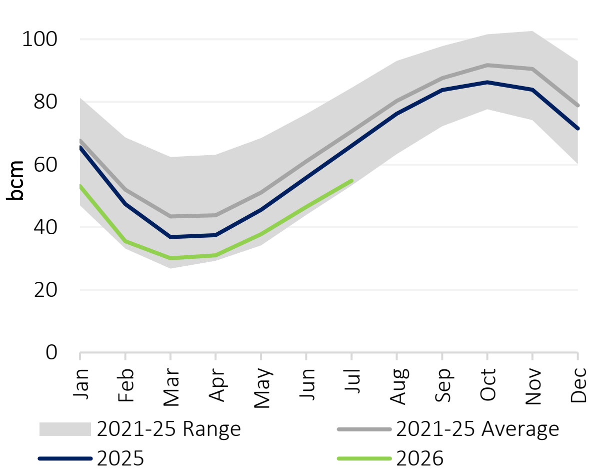
Source: GECF Secretariat based on Project Updates and News
N/A: Not Available

5 GAS STORAGE

5.1 Europe

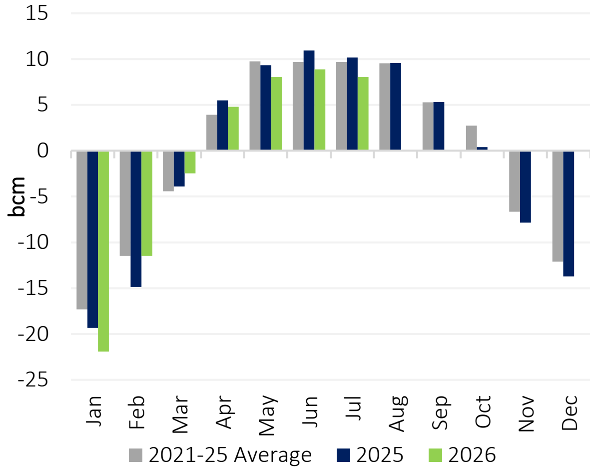
Europe’s net gas injection season continued through July 2026, although the restocking pace has slowed this year amid ongoing tight global LNG supply and unfavourable storage economics. The average daily volume of gas in EU underground storage rose to 54.8 bcm, up from 46.5 bcm a month prior (Figure 109). Nevertheless, this inventory level was 11 bcm lower y-o-y as well as 16 bcm below the five-year average, marking the lowest average stock level for July since 2021. Total EU stocks advanced from 50.7 bcm on 30 June to 58.7 bcm on 31 July, bringing the average regional storage fill level to 56%.

Figure 109: Monthly average UGS level in the EU



Source: GECF Secretariat based on data from AGSI+

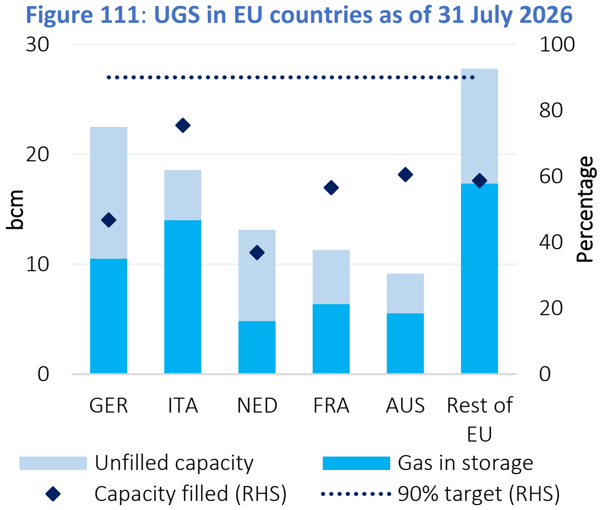
Figure 110: Net gas injections in the EU



Source: GECF Secretariat based on data from AGSI+

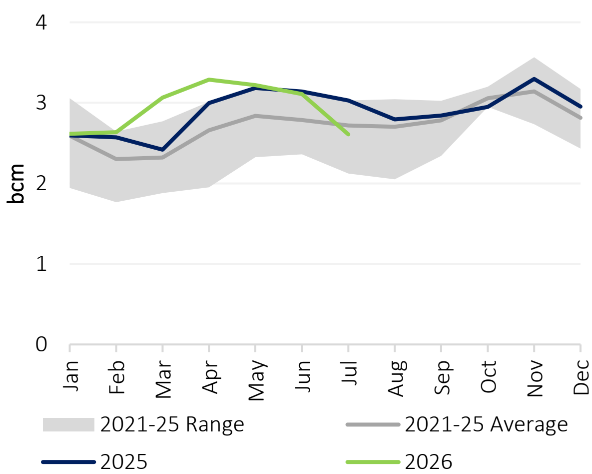
Net gas injections across the EU totalled 8.1 bcm in July, down from 10.2 bcm a year earlier and tracking 17% below the five-year historical average for that month (Figure 110). Although the Netherlands continued to lag behind other major EU nations, a robust monthly build lifted its storage fill level to 37% by month-end (Figure 111). Italy led the bloc with storage at 75% capacity, followed by Austria at 61%. Meanwhile, EU LNG storage averaged 2.6 bcm during the month, representing 46% of total capacity, which was down 14% y-o-y and 4% below the five-year monthly average (Figure 112).

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



Source: GECF Secretariat based on data from AGSI+

Figure 112: Total LNG storage in the EU

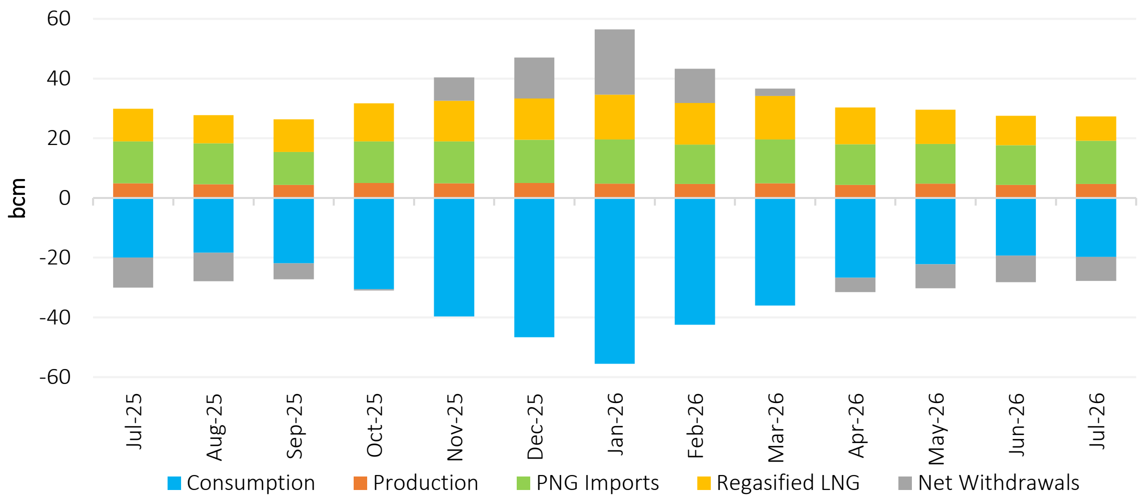


Source: GECF Secretariat based on data from ALSI

The market dynamics have been similar over the recent few weeks, with an unfavourable winter-summer price spread eroding the commercial margins for gas injections across the continent, while a wide JKM-TTF price differential is diverting flexible global LNG cargoes away from Europe towards lucrative Asian markets. This dual market pressure severely suppressed storage refill velocities again during July 2026, leaving EU inventories at multi-year lows during the peak of summer. Consequently, the outlook for the remainder of the refilling season points to persistent supply vulnerability, forcing the EU to rely on flexible regulatory mechanisms and face a high cost to secure adequate winter reserves.

In July 2026, external gas imports accounted for 83% of combined EU and UK gas supply, remaining stable y-o-y (Figure 113), while domestic production covered the remaining 17%. PNG solidified its position as the primary import channel, accounting for 53% of total gas supply, representing an increase from 47% one year prior. Conversely, regasified LNG send-out supplied 30% of the regional market in July 2026, down from 37% in July 2025, as European buyers faced sustained, intensive competition with Asian markets to secure flexible, uncommitted spot cargoes.

Figure 113: EU + UK monthly gas balance



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

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

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

	2025	Jul-25	Jul-26	7M 2025	7M 2026	Change* y-o-y	Change** 2026/2025
(a) Gas Consumption	378.23	19.90	19.72	221.11	222.04	-1%	0%
(b) Gas Production	58.90	4.94	4.70	34.96	32.73	-5%	-6%
Difference (a) - (b)	319.33	14.96	15.02	186.15	189.31	0%	2%
PNG Imports	162.14	13.97	14.42	94.90	97.37	3%	3%
Regasified LNG	147.08	11.02	8.23	86.57	85.25	-25%	-2%
Net Withdrawals	8.46	-10.17	-8.05	2.19	6.14	-21%	181%
Variation	1.64	0.14	0.42	2.49	0.56		

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

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

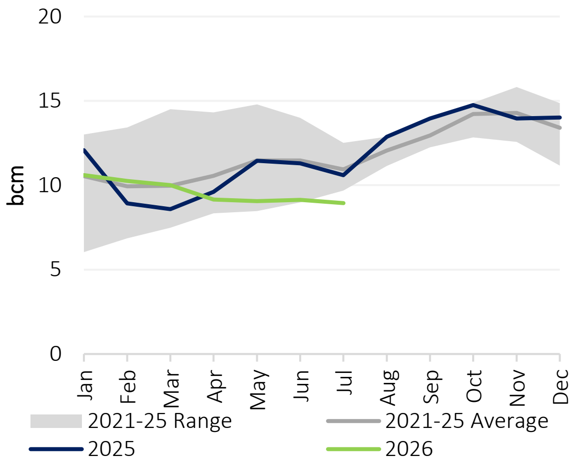
(**): y-o-y change for 6M 2026 compared to 6M 2025

5.2 Asia

In July 2026, combined LNG inventories in Japan and South Korea declined by 2% m-o-m to an estimated 8.9 bcm (Figure 114). Driven by sustained cooling demand across the region, as well as tight spot LNG procurement, these reserves sat 16% lower y-o-y and lagged 2.0 bcm behind the five-year average.

In Japan, estimated storage levels fell 6% y-o-y to reach 5.6 bcm, reflecting supply adjustments to meet power needs. South Korea experienced a steeper 28% decline y-o-y to stand at an estimated 3.3 bcm, driven by heightened power generation demands and competitive bidding in the global spot market that rapidly depleted domestic reserves.

Figure 114: LNG in storage in Japan and South Korea



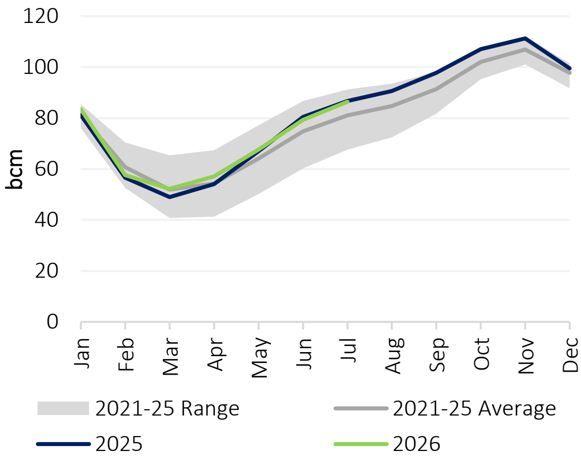
Source: GECF Secretariat based on data from LSEG

5.3 North America

In July 2026, the US continued its natural gas injection season, with average UGS volumes rising to 86.4 bcm, up from 79.3 bcm in June (Figure 115). Although this total was a marginal 0.3 bcm lower y-o-y, it remained 5.4 bcm above the historical five-year average, pushing average UGS capacity utilisation to 65%.

Net gas restocking for the month reached 5.5 bcm, outpacing both the 4.8 bcm injected in July 2025 and the five-year average July injection of 4.4 bcm. This brought total summer restocking for 2026 to 37 bcm, compared to 41 bcm by the same point one year ago.

Figure 115: Monthly average UGS level in the US



Source: GECF Secretariat based on data from US EIA

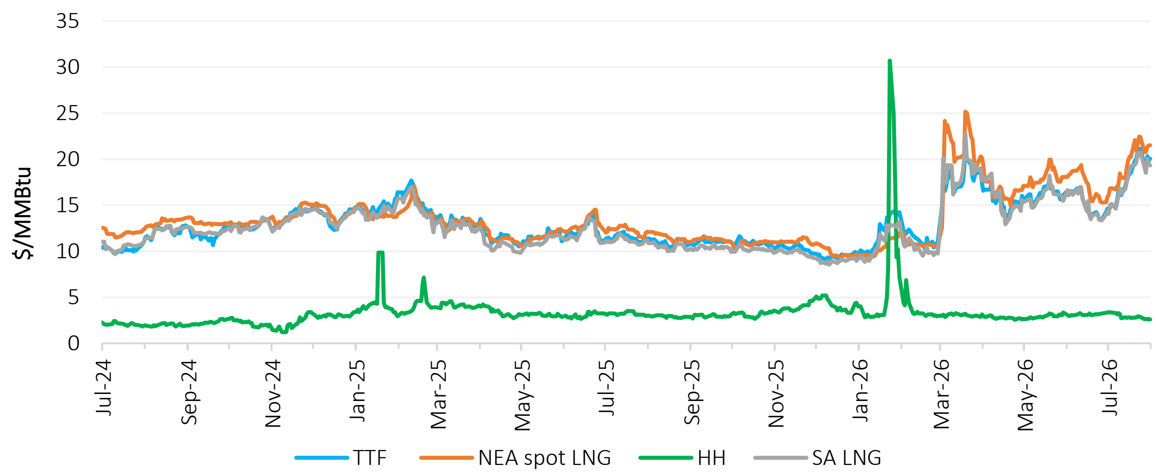
6 ENERGY PRICES

6.1 Gas prices

6.1.1 Gas & LNG spot prices

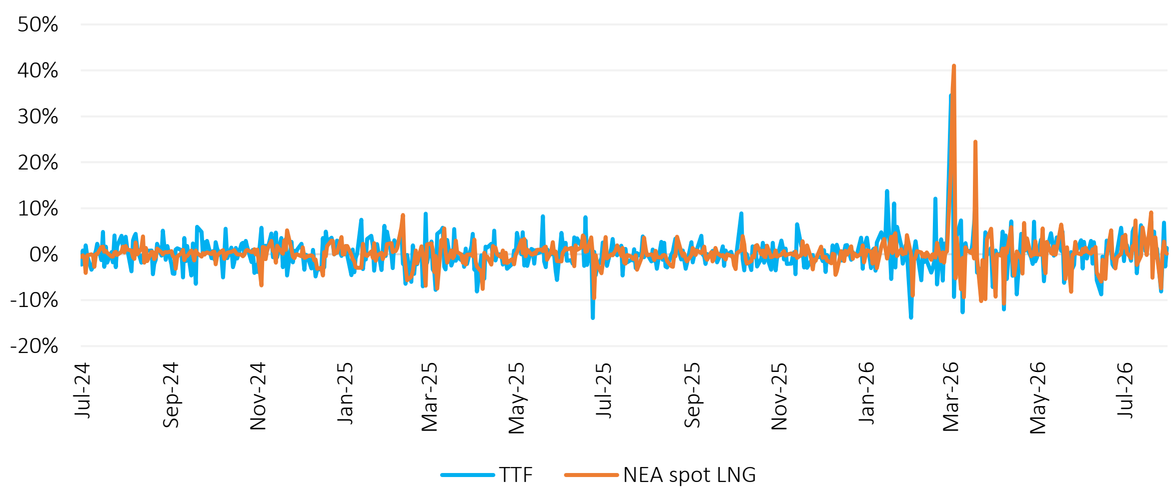
In July 2026, gas and LNG spot prices in Europe and Asia rose sharply, accompanied by heightened market volatility (Figure 116 and Figure 117). The rally was fuelled by renewed geopolitical tensions in the Middle East, with daily TTF spot prices climbing above $21/MMBtu, surpassing the levels recorded at the onset of the conflict. Warmer-than-usual weather also sustained strong gas-fired power generation, providing additional support to prices. In Asia, buying interest from emerging importers, particularly in Southeast Asia, further underpinned LNG prices, although buyers remained cautious. Looking ahead, competition for flexible LNG cargoes is expected to intensify as both regions prepare for the winter season, lending continued support to spot prices. Any further escalation of the Middle East conflict could further disrupt LNG trade flows and exert additional upward pressure on spot prices.

Figure 116: Daily gas & LNG spot prices



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

Figure 117: Daily variation of spot prices



Source: GECF Secretariat based on data from Argus and LSEG

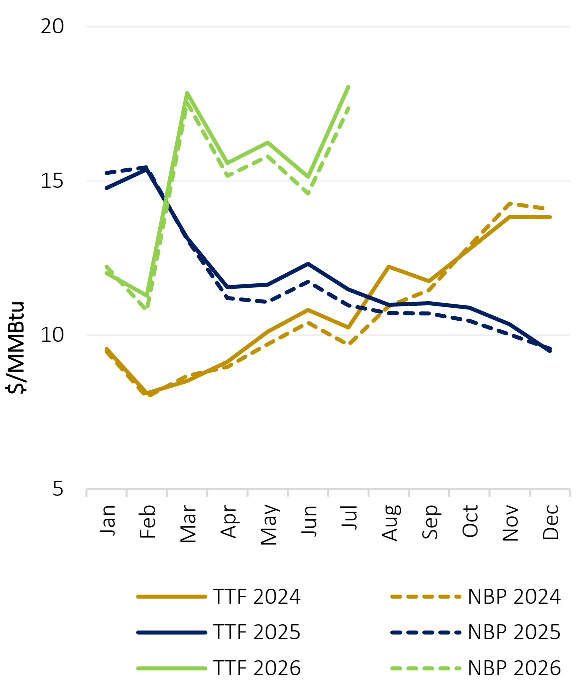
6.1.1.1 European spot gas and LNG prices

In July 2026, the TTF spot gas price averaged $18.05/MMBtu, increasing sharply by 19% m-o-m and 52% y-o-y. Similarly, the NBP spot price averaged $17.35/MMBtu, increasing 19% m-o-m, and 58% y-o-y (Figure 118). During the month, daily TTF prices peaked at $21.12/MMBtu, the highest level recorded since January 2023.

European gas and LNG prices rose sharply, exceeding the levels recorded earlier in March 2026, as renewed tensions in the Middle East eroded optimism over the resumption of LNG carrier transits through the Strait of Hormuz. At the same time, warmer-than-usual weather sustained strong gas-fired power generation, providing additional support to prices.

For the period January to July 2026, TTF and NBP prices averaged $15.16/MMBtu and $14.78/MMBtu, increasing by 18% and 17% y-o-y, respectively.

Figure 118: Monthly European spot gas prices



Source: GECF Secretariat based on data from LSEG

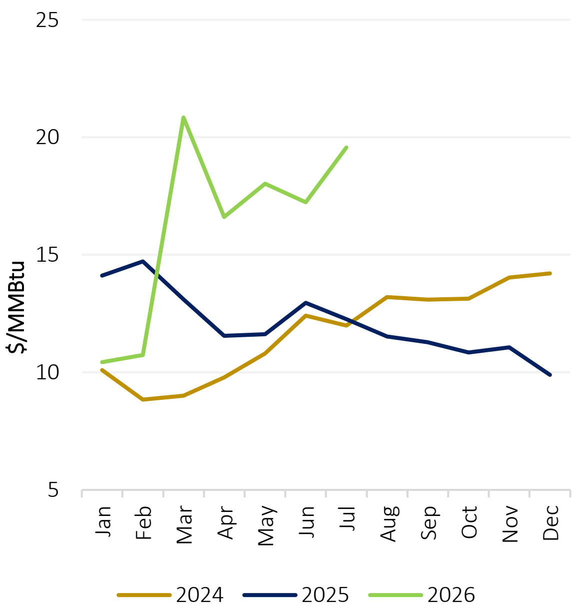
6.1.1.2 Asian spot LNG prices

In July 2026, the average North East Asia (NEA) spot LNG price averaged $19.56/MMBtu, reflecting increases of 14% m-o-m and 60% y-o-y (Figure 119). Daily NEA spot LNG price climbed to a four-month high of $22.45/MMBtu.

Asian LNG prices also extended their rally, closely tracking gains at European gas hubs amid heightened geopolitical uncertainty. Buying interest from emerging importers, particularly in Southeast Asia, further supported prices, although buyers remained cautious amid elevated price levels and market volatility.

For the period January to July 2026, NEA spot LNG price averaged $16.21/MMBtu, reflecting an increase of 26% y-o-y.

Figure 119: Monthly Asian spot LNG prices



Source: GECF Secretariat based on data from Argus

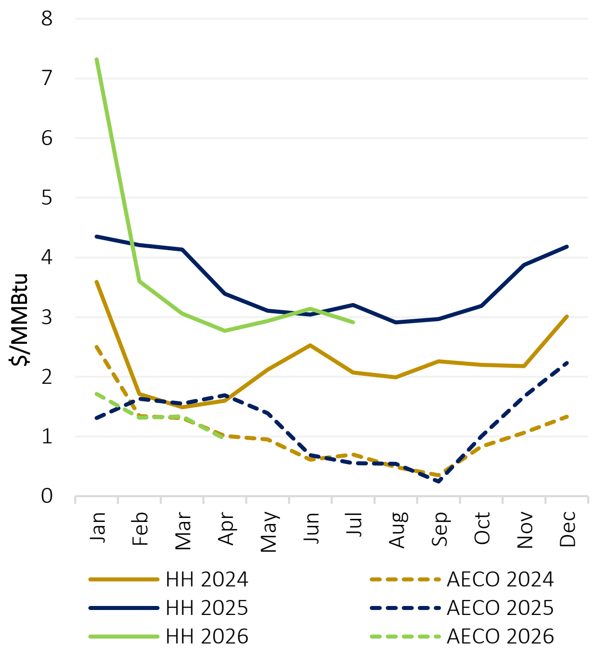
6.1.1.3 North American spot gas prices

In July 2026, the Henry Hub (HH) spot gas price averaged $2.92/MMBtu, decreasing by 7% m-o-m and 9% y-o-y. Similarly, the AECO spot prices averaged $1.17/MMBtu decreasing by 9% m-o-m, but was 110% higher y-o-y (Figure 120). Daily HH prices fell to a low of $2.58/MMBtu at the end of the month.

In the US, HH spot prices eased modestly as milder-than-normal summer weather curbed gas demand for cooling. Strong domestic gas production and above-average storage inventories further reinforced bearish market sentiment, contributing to downward pressure on prices.

For the period January to July 2026, HH and AECO spot prices averaged $3.68/MMBtu and $1.29/MMBtu, decreasing by 1% and 2%, respectively.

Figure 120: Monthly North American spot gas prices



Source: GECF Secretariat based on data from LSEG

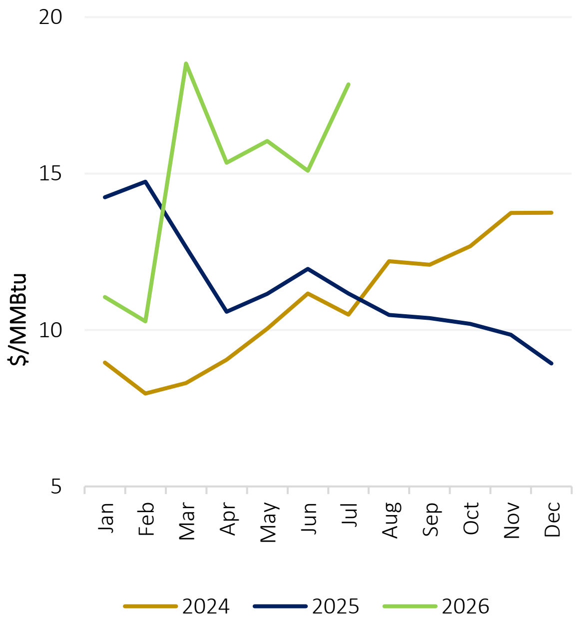
6.1.1.4 South American spot LNG prices

In July 2026, the South America (SA) spot LNG price averaged $17.85/MMBtu, increasing by 18% m-o-m and 60% y-o-y (Figure 121). During the month, daily SA spot LNG prices rose to a high of $20.74/MMBtu.

The SA spot LNG prices continued to align with broader global LNG market trends, tracking substantial gains in European and Asian prices. Delivered LNG prices in Argentina, Brazil and Chile averaged $17.94/MMBtu, $17.55/MMBtu and $18.05/MMBtu, respectively.

For the period January to July 2026, the SA spot LNG price averaged $14.88/MMBtu, up 20% y-o-y.

Figure 121: Monthly South American spot LNG prices

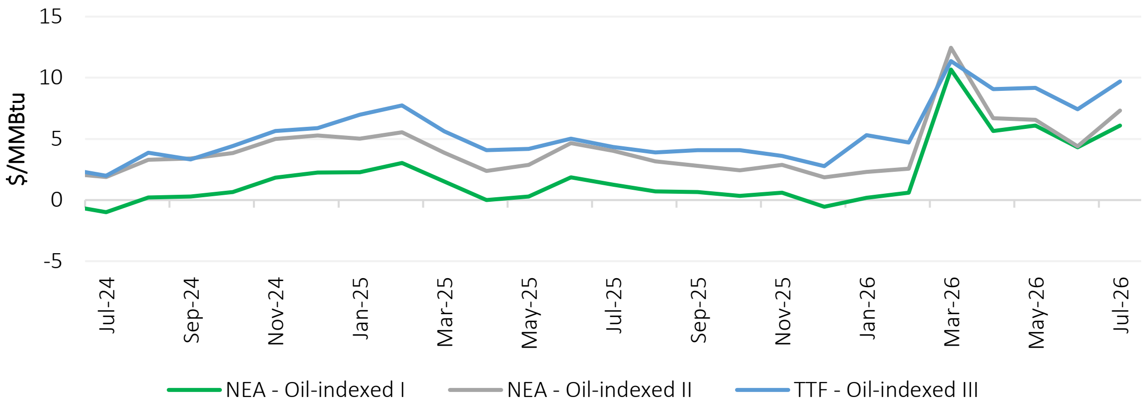


Source: GECF Secretariat based on data from Argus
Note: SA LNG price is an average of the LNG delivered prices for Argentina, Brazil and Chile based on Argus assessment

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

In July 2026, the Oil-Indexed I LNG price averaged $13.48/MMBtu, rising modestly by 4% m-o-m and 22% y-o-y. Meanwhile, the Oil-Indexed II LNG price averaged $12.23/MMBtu decreasing by 5% m-o-m, but was 48% higher y-o-y. In Europe, the Oil-Indexed III LNG price averaged $8.36/MMBtu, reflecting increases of 9% m-o-m and 17% y-o-y. During the month, the premium of NEA spot LNG over Oil-Indexed I and Oil-Indexed II prices increased to $6.1/MMBtu, and $4.4/MMBtu, respectively. Similarly, the TTF spot gas premium over Oil-Indexed III widened to $9.7/MMBtu (Figure 122).

Figure 122: Spot and oil-indexed LNG price spreads



Source: GECF Secretariat based on data from Argus and LSEG
Note: Oil-indexed I LNG prices are calculated using the traditional LTC slope (14.9%) and 6-month historical average of Brent. Oil-indexed II LNG prices are calculated using the 5-year historical average LTC slope (12.1% for 2026) and 3-month historical average of Brent. Oil-indexed III LNG prices are based on Argus' assessment for European oil-indexed long-term LNG prices.

6.1.3 Regional spot gas & LNG price spreads

In July 2026, the NEA–TTF price spread narrowed slightly to $1.52/MMBtu. TTF spot prices experienced a sharper uptick than the NEA spot LNG prices during the month (Figure 123). Meanwhile, the TTF–HH price spread widened to $15.13/MMBtu (Figure 124).

Figure 123: NEA-TTF price spread

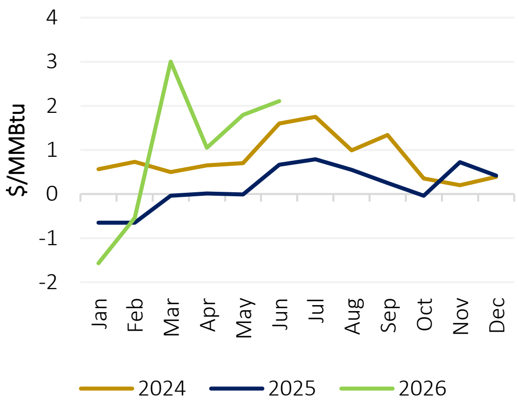
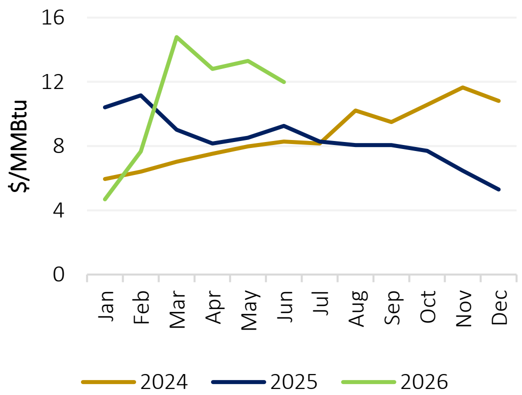


Figure 124: TTF-HH price spread



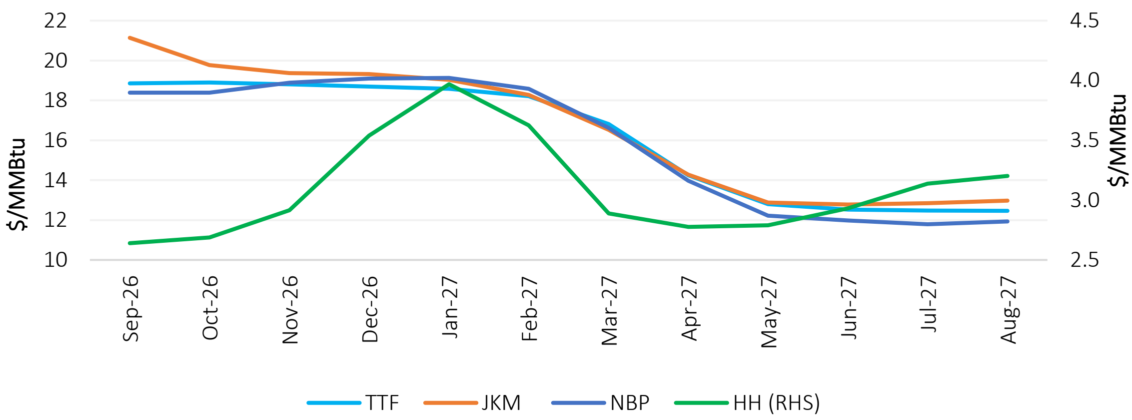
Source: GECF Secretariat based on data from Argus and LSE

6.1.4 Gas & LNG futures prices

As of 7 August 2026, the average futures prices for the 12-month period from September 2026 to August 2027 stood at $16.12/MMBtu for TTF, $15.91/MMBtu for NBP, and $16.60/MMBtu for JKM (Figure 125). Notably, all three benchmark prices were around 6% higher than the previous expectations presented in the GECF MGMR July 2026 assessment on 6 July 2026. Over the same period, Henry Hub futures averaged $3.09/MMBtu, around 9% lower than previous expectations (Figure 126).

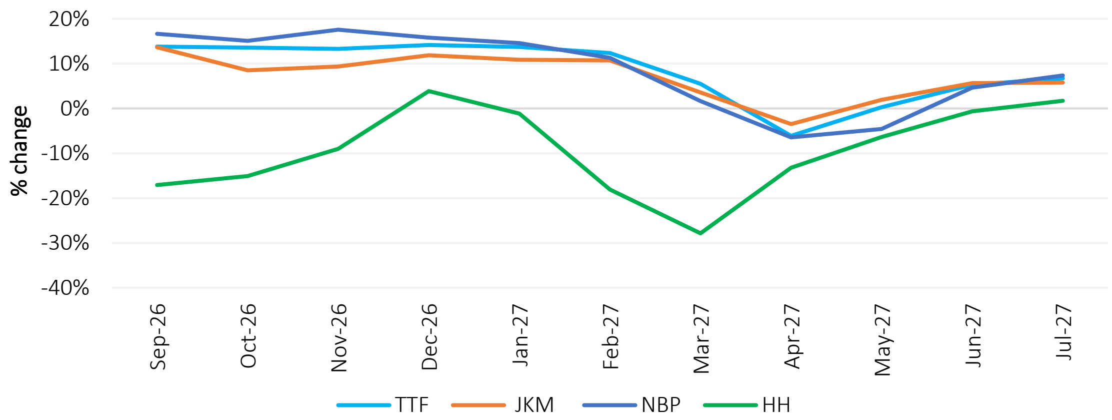
Looking ahead, the JKM–TTF spread is expected to average $2.3/MMBtu in September 2026, before tightening further to less than $1/MMBtu during the fourth quarter of the year.

Figure 125: Gas & LNG futures prices



Source: GECF Secretariat based on data from LSEG
Note: Futures prices as of 7 August 2026

Figure 126: Variation in gas & LNG futures prices



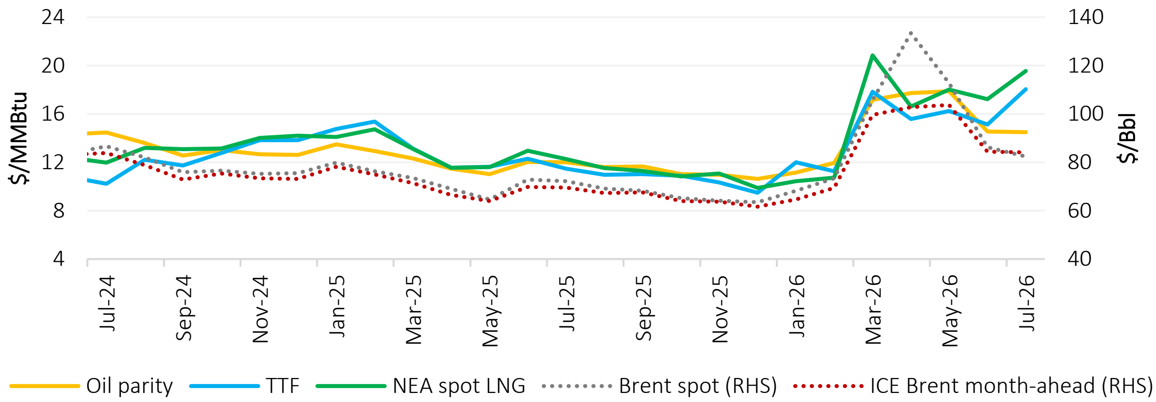
Source: GECF Secretariat based on data from LSEG
Note: Comparison with the futures prices as of 6 July 2026, as reported in GECF MGMR July 2026

6.2 Cross commodity prices

6.2.1 Oil prices

In July 2026, the average Brent crude spot price declined by 4% m-o-m to $82.41/Bbl. However, it remained 14% higher y-o-y. Similarly, the month-ahead Brent price averaged $84.06/Bbl, relatively stable compared to the previous month, but was 21% higher y-o-y. Furthermore, TTF spot prices traded at a premium of $3.6/MMBtu to the oil parity price, while NEA spot LNG prices traded a $5.1/MMBtu premium (Figure 127).

Figure 127: Monthly crude oil prices

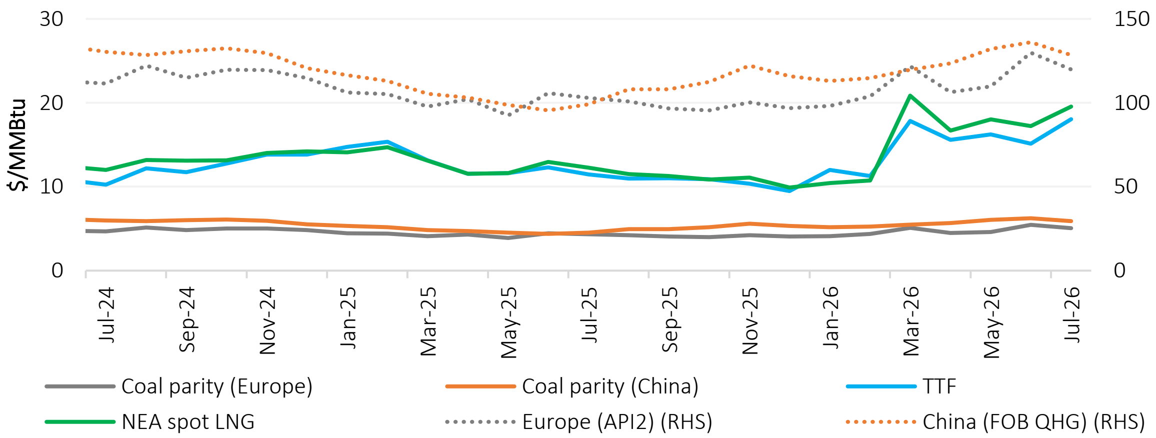


Source: GECF Secretariat based on data from Argus and LSEG
Note: Conversion factor of 5.8 was used to calculate the oil parity price in $/MMBtu based on the ICE Brent month-ahead price.

6.2.2 Coal prices

In July 2026, the European coal price (API2) averaged $119.92/t, decreasing modestly by 8% m-o-m, but was 16% higher y-o-y. The premium of TTF spot gas over API2 parity widened compared to the previous month to $13.01/MMBtu. Similarly, in China, the Qinhuangdao (QHG) coal price averaged $128.53/t, decreasing by 6% m-o-m, but was 30% higher y-o-y. The premium of NEA spot LNG over QHG parity increased to $13.67/MMBtu (Figure 128).

Figure 128: Monthly coal parity prices

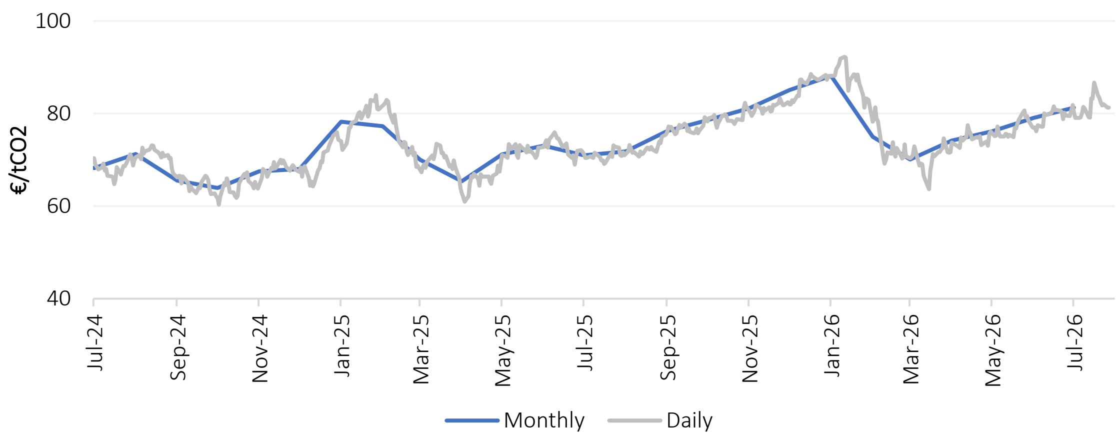


Source: GECF Secretariat based on data from Argus and LSEG
Note: Conversion factors of 23.79 and 21.81 were used to calculate the coal prices in $/MMBtu for Europe (API2) and China (QHG) respectively.

6.2.3 Carbon prices

In July 2026, the EU carbon price averaged €81.25/tCO_2, reflecting increases of 3% m-o-m and 14% y-o-y (Figure 129). During the month, the daily EU carbon price climbed to a peak of €86.63/tCO_2.

Figure 129: EU carbon prices

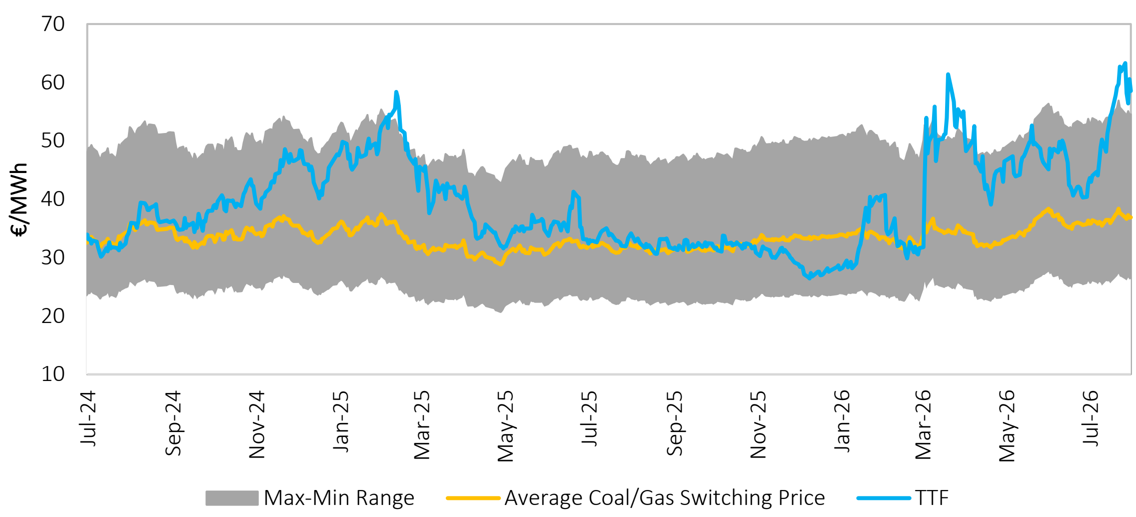


Source: GECF Secretariat based on data from LSEG

6.2.4 Fuel switching

In July 2026, TTF prices remained above the average coal-to-gas switching price and soared above the upper bound of the switching range at the end of the month (Figure 130). Furthermore, the average monthly price spread increased significantly to €16.6/MWh, indicating that coal likely remained relatively more competitive over gas in the power generation sector.

Figure 130: Daily TTF vs coal-to-gas switching prices



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

ANNEXES

Abbreviations

Abbreviation	Explanation
AE	Advanced Economies
AECO	Alberta Energy Company
Bbl	Barrel
bcm	Billion cubic metres
bcma	Billion cubic metres per annum
CBAM	Carbon Border Adjustment Mechanism
CBM	Coal bed methane
CCS	Carbon, Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CDD	Cooling Degree Days
CNG	Compressed Natural Gas
CO_2	Carbon dioxide
CO_{2e}	Carbon dioxide equivalent
CPI	Consumer Price Index
DOE	Department of Energy
EC	European Commission
ECB	European Central Bank
EMDE	Emerging Markets and Developing Economies
EU	European Union
EU ETS	European Union Emissions Trading Scheme
EUA	European Union Allowance
Fed	United States Federal Reserve
FID	Final Investment Decision
FSU	Floating Storage Unit
FSRU	Floating Storage Regasification Unit
G7	Group of Seven

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

PNG	Pipeline Natural Gas
PPAC	India's Petroleum Planning & Analysis Cell
PSV	Punto di Scambio Virtuale (Virtual Trading Point in Italy)
QHG	Qinhuangdao
R-LNG	Regasified LNG
SA	South America
SPA	Sales and Purchase Agreement
SWE	South West Europe
T&T	Trinidad and Tobago
Tcm	Trillion cubic metres
tCO_2	Tonne of carbon dioxide
TFDE	Tri-Fuel Diesel Electric
TTF	Title Transfer Facility
TWh	Terawatt hour
UGS	Underground Gas Storage
UAE	United Arab Emirates
UK	United Kingdom
US	United States
y-o-y	year-on-year

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GECF

Gas Exporting Countries Forum , GECF
GECF Headquarters
P.O.Box 23753, Tornado Tower
47th & 48th Floors, West Bay, Doha

www.gecf.org