

APERC GAS REPORT

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Foreword

The APERC Gas Report provides a comprehensive, evidence-based assessment of natural gas market developments in the APEC region, complemented by an analysis of broader global trends. In 2025, global gas demand continued to grow, albeit at a slower rate of 0.7%, bringing consumption to a record high of 4,190 bcm, while international gas imports rose by 5.7%, supported by growing LNG trade.

The APEC region remained central to these developments, accounting for around 60% of global gas demand and 62% of global gas production in recent years. It is home to many of the world's largest gas producers, consumers, exporters and importers, reflecting its diverse resources endowments and energy needs. In 2024, APEC economies accounted for almost 85% of global gas demand growth, driven largely by China, Russia, and the United States. In 2025, the region contributed nearly 90% of the increase in global gas production, while its expanding LNG exports brought APEC's share of global LNG exports to 65%. The APEC region also remained the world's largest LNG-importing region in 2025, even as European LNG imports increased significantly.

The conflict in the Middle East in early 2026 has introduced a new period of uncertainty for the global gas market. Severe disruptions to LNG shipments through the Strait of Hormuz have tightened supply and increased price volatility, with significant implications for price-sensitive gas-importing economies in Asia. These events have once again brought energy security to the forefront, underscoring the vulnerability of international gas supply chains and the importance of resilient infrastructure, diversified supply sources, and international cooperation.

Despite these near-term challenges, the longer-term structural role of gas in meeting accelerating energy demand will continue. This edition incorporates projections from the *APEC Energy Demand and Supply Outlook, 9th Edition*. By combining recent gas market developments with longer-term projections, the report aims to provide a valuable reference for policymakers and other stakeholders across APEC economies.

APERC has published APERC Gas Report since 2018 in order to supply gas market information and analysis to policymakers in the APEC region. However, with a shift in APERC's research priorities toward energy security and efficiency amid the current challenging geopolitical climate and human resource constraints, APERC will discontinue the publication of this report effective this year. Nonetheless, APERC will continue to evaluate gas market developments periodically through its other research streams, most notably the APEC Oil and Gas Security Studies (OGSS) Series.

I would like to express my sincere appreciation to the authors and contributors for their dedication and efforts in preparing this report. I am also grateful to the APEC member economies for providing updated energy data through the APEC Expert Group on Energy Data and Analysis (EGEDA).



Dr Kazutomo IRIE

Chairman & President
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Key takeaways

1. Natural gas demand: global record highs and APEC's long-term growth prospects

Global natural gas demand continued to grow in 2024 and 2025, reaching a record high

In 2024, global gas demand rose by 2.5% (over 100 bcm) to around 4,160 bcm, marking a sharp acceleration after several years of modest growth. The increase slowed to 0.7% in 2025, but consumption reached a record 4,190 bcm. Colder weather boosted gas demand in the residential and commercial sectors, while industrial demand remained subdued, particularly in Asian markets facing higher spot LNG prices.

APEC economies accounted for almost 85% of total gas demand growth in 2024, lifting their share of global gas consumption to 60%, but demand was broadly flat in 2025

APEC gas demand grew by 3.6% to 2,485 bcm in 2024, with China, Russia, and the United States being the main contributors. China led APEC growth, supported by favourable gas prices, an industrial rebound, higher gas-fired power generation, and policies promoting LNG trucks. In 2025, increased space-heating needs boosted gas use in the United States and Canada, while China recorded a much smaller increase. Declines in gas demand in Russia, Japan, and Southeast Asia offset those gains, leaving total APEC gas demand broadly unchanged.

Power generation remained the largest sector for gas use globally, accounting for 35% of total gas demand, although growth in gas-fired electricity generation slowed in 2025

In 2024, the power sector was a primary driver of gas demand growth, with gas-fired generation up 2.9%, led by North America, fast-growing Asian markets, and Eurasia. In 2025, gas-fired generation increased marginally from 7,020 to 7,042 TWh, while total electricity generation rose by 2.7% to 32,200 TWh, with renewables supplying most of the increase. Despite this modest growth, gas continued to account for 22% of the global power generation mix, providing both baseload power and dispatchable capacity to complement renewables. Furthermore, gas can could also help meet growing data centre power demand by providing reliable, around-the-clock electricity.

Looking into the future, APEC gas demand is projected to rise by almost 40% between 2022 and 2040, with power generation driving much of the growth

By 2040, APEC gas demand is expected to reach 3,300 bcm, with China, the United States, and Southeast Asia accounting for around 80% of this growth. The power generation sector accounts for over 60% of the total increase in gas usage, driven by rising electricity needs, policies to phase down coal-fired generation, and growing flexibility needs associated with renewable integration. In Southeast Asia, electricity generation is set to grow 2.5-fold, with gas becoming its largest source at 37% of the power generation mix by 2040. As domestic gas production lags behind demand, Southeast Asia is expected to rely more heavily on LNG imports, alongside an expansion of LNG-to-power projects.

2. Natural gas production: APEC's growing contribution to global supply

Global natural gas production reached record levels in 2024 and 2025, with APEC economies driving most of the increase

In 2024, global gas production rose by 1.6%, adding over 65 bcm to reach 4,145 bcm, breaking several years of stagnation. APEC economies were the main contributors to this expansion, with production growing by 3% to 2,545 bcm in 2024, exceeding the net global increase. Heightened energy security concerns and stronger oil and gas company revenues encouraged the reactivation of delayed upstream projects. Although growth slowed to 1.1% in 2025, global gas production reached a record 4,190 bcm. In this year, APEC production increased by another 40 bcm to 2,585 bcm, accounting for almost 90% of global production growth and lifting the region's share of global supply to 62%.

Unconventional natural gas production in the United States and China was a key driver of APEC supply growth in 2025

In 2025, the United States led global supply expansions as new pipeline completions resolved midstream bottlenecks, connecting gas production to processing and export hubs, and increasing total output by 4.2% to a record 1,115 bcm. China recorded a 6.1% increase to 260 bcm over the same period, supported by advanced drilling technologies that accelerated unconventional tight and shale gas production. Together, these robust unconventional gas production gains within APEC were the main driver behind global production growth.

Looking ahead, APEC's natural gas production is projected to expand by 40% between 2022 and 2040, with growth concentrated among a few key established producers

By 2040, increases in gas production will be concentrated among the largest established suppliers, allowing the dominant APEC players to expand their market share. China is projected to post the fastest growth with a 70% output surge through 2040, supported by government incentives and the development of unconventional resources. U.S. production is expected to rise by 44%, reinforcing its position as a leading global gas producer, while Russian production is projected to grow 35%, keeping Russia as the second-largest gas producer in APEC.

3. International gas trade and prices: shifting market dynamics

Global natural gas trade expanded in 2024 and 2025; however, China's reduction of LNG imports contributed to a decrease in APEC's share of global gas imports

Global gas imports rose to 1,235 bcm in 2024 and grew by 5.7% to 1,305 bcm in 2025, facilitated by new LNG import terminals and expanded pipeline interconnections. APEC economies accounted for almost half of global gas imports in 2024, totalling around 600 bcm. However, regional imports declined to 595 bcm in 2025, lowering APEC's market share to 45%, as non-APEC imports expanded, particularly in Europe. China was the main driver of APEC's decline as it reduced purchases of expensive spot LNG cargoes while increasing competitively priced pipeline gas imports from Russia and expanding its domestic production.

APEC suppliers maintained over half of the global natural gas export market in 2025, supported by expanding North American LNG capacity

APEC economies accounted for 51% of global natural gas exports in 2025, with collective exports increasing from 640 bcm in 2024 to 670 bcm. This growth relied heavily on U.S. LNG capacity expansions, which boosted LNG exports by 25% to reach 140 bcm in 2025. These rising volumes offset declining exports from other major APEC producers, including Australia, where scheduled maintenance reduced LNG output, and Russia, where the expiration of the Russia–Ukraine gas transit agreement reduced pipeline exports to Europe.

International natural gas prices normalised in 2024, tightened in early 2025, and eased later in the year

Following a post-crisis normalisation throughout 2024, international markets tightened during winter 2024-2025 as the expiry of the Russia-Ukraine gas transit agreement forced European buyers to bid aggressively against Asian utilities for flexible LNG cargoes. This cross-regional price pressure eased in late 2025 due to a new wave of destination-flexible North American LNG supplies that compressed the price gap between European and Asian benchmarks.

Between 2022 and 2040, APEC natural gas imports are projected to increase by almost 65%, with LNG playing an increasingly important role

Total gas imports into the APEC region are projected to increase by 65% between 2022 and 2040, as rising gas consumption outpaces domestic production. China will account for a substantial share of this increase, with total gas imports expected to exceed 300 bcm by 2040. APEC LNG imports are set to expand by 92%, exceeding the growth rate of total gas imports and supporting greater supply diversification and flexibility. Southeast Asia is expected to emerge as a primary growth engine for new LNG receiving infrastructure to offset domestic production deficits.

4. The 2026 Middle East crisis: LNG disruption and market implications

The Middle East conflict has disrupted global gas supply chains, with lower production and constrained LNG trade expected in 2026

The conflict in the Middle East in early 2026 severely disrupted LNG shipments through the Strait of Hormuz. The disruption affected gas production and LNG operations in this region, tightening global supply availability and increasing logistical uncertainty. Global natural gas production is projected to contract in 2026, reversing the growth recorded in the previous two years. Global LNG trade in 2026 is expected to remain broadly flat compared with 2025, as supply losses in the Middle East are projected to be largely offset by new liquefaction capacity additions in North America.

The 2026 supply shock has renewed international gas price volatility and is expected to reduce global gas demand

The disruption of LNG flows triggered sharp increases in European and Asian gas prices in March 2026, reversing the relative market stability observed in the second half of 2025. Tighter supply availability and elevated prices have particularly significant implications for price-sensitive importing economies in Asia. Against this backdrop, global gas demand is projected to decline by around 1.5% in 2026.

Chapter 1 Natural gas demand

This chapter examines recent trends and key drivers of natural gas demand globally and across APEC economies, with a focus on developments in 2024 and estimates for 2025. It then turns to the longer-term outlook for natural gas demand in APEC, based on the *APEC Energy Demand and Supply Outlook, 9th Edition*. A similar structure is followed in the subsequent chapters on natural gas production and trade, combining analysis of recent market developments with a longer-term APEC perspective.

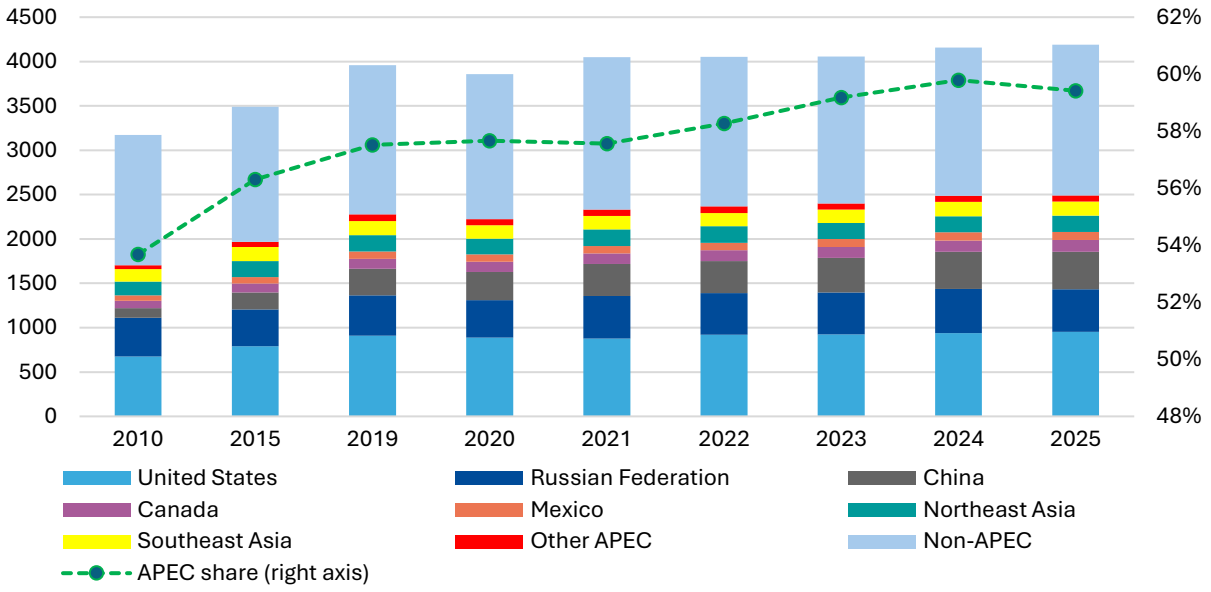
1.1 Recent trends in global natural gas demand

Global natural gas demand accelerated in 2024 as gas markets recovered from the impacts of the COVID-19 pandemic and subsequent geopolitical shifts. Global consumption rose to around 4,160 bcm in 2024, increasing by 2.5%, or over 100 bcm (Figure 1.1). This marked a clear strengthening in demand compared with the 2019-2023 period, during which global gas use grew at an average annual pace of less than 1%.

The 2024 resurgence in gas demand was underpinned by strong economic performance in key regions such as Asia Pacific, North America, and Eurasia, which spurred higher electricity consumption and industrial activity. At the same time, the easing and stabilisation of gas prices (see Chapter 4 for details), compared with the exceptional levels reached in 2022, stimulated gas use across multiple sectors. Additionally, supportive energy policies encouraged fuel switching from coal and oil to gas, particularly in industry and power generation. Demand for gas-fired dispatchable generation also grew alongside the expansion of variable renewables.

These structural drivers coincided with short-term pressures from extreme weather conditions, including record-high summer temperatures and a colder-than-usual 2024/2025 winter, which influenced seasonal gas demand patterns in the residential, commercial, and power sectors.

Figure 1.1 Trends in APEC and non-APEC gas demand (bcm)



Source: APERC based on Cedigaz (2026) and EGEDA (2026)

A defining feature of gas demand increase in 2024 was its geographical concentration in APEC economies, which accounted for almost 85% of the total global increase. This was primarily

driven by growth in China, Russia, and the United States (see the following section for details). As highlighted in Figure 1.1, these demand dynamics raised APEC economies' share of global gas demand to 60% in 2024 from 59% the previous year.

Outside APEC, gas consumption growth was particularly strong in India, where demand rose by 10% in 2024. A healthy macroeconomic environment, lower spot LNG prices compared with 2023, expanding natural gas infrastructure, and higher gas-fired power generation for cooling drove an increase in gas demand in India.

The Middle East also recorded solid demand growth. This was underpinned by oil-to-gas switching in power generation and rising petrochemical feedstock use. In contrast, Europe's natural gas demand saw only a very moderate increase, shaped by continued efficiency improvements, rising renewable electricity generation, and improved nuclear availability. It is also worth noting that European natural gas consumption increased in 2024 after two consecutive years of decline, although it remained below its 2021 levels (Cedigaz, 2025).

In 2025, following a strong increase in 2024, global gas demand growth slowed markedly due to weaker industrial activity, elevated spot LNG prices in the first half of the year, and varying weather conditions. Global gas consumption is estimated to have increased by only 0.7%, reaching 4,190 bcm.

The residential and commercial sectors served as the main sources of incremental demand due to colder weather in some markets in the Northern Hemisphere. Gas demand in the power sector rose slightly, while growth in industrial gas use remained muted, with regional trends varying depending on energy prices and macroeconomic conditions. In particular, price-sensitive gas demand in some industrial sectors declined across many Asian markets (IEA, 2026; Cedigaz, 2026).

From a regional perspective, global gas consumption growth was concentrated in North America and Europe, where colder winter weather stimulated higher gas usage. In the Middle East, gas demand continued to rise, supported by expanding petrochemical capacity and oil-to-gas switching policies in the power generation sector. Africa also experienced rapid growth, driven by gas-based electrification and gradual industrialization.

In contrast, gas demand in Asia remained flat in 2025, after being the primary driver of growth the previous year. This was due to multiple factors, including reduced heating requirements and slowing industrial momentum, particularly in the first half of the year. As shown in Figure 1.1, the marked slowdown in gas demand growth across Asian APEC economies compared with 2024 contributed to the slight decline in APEC's share of global gas demand in 2025.

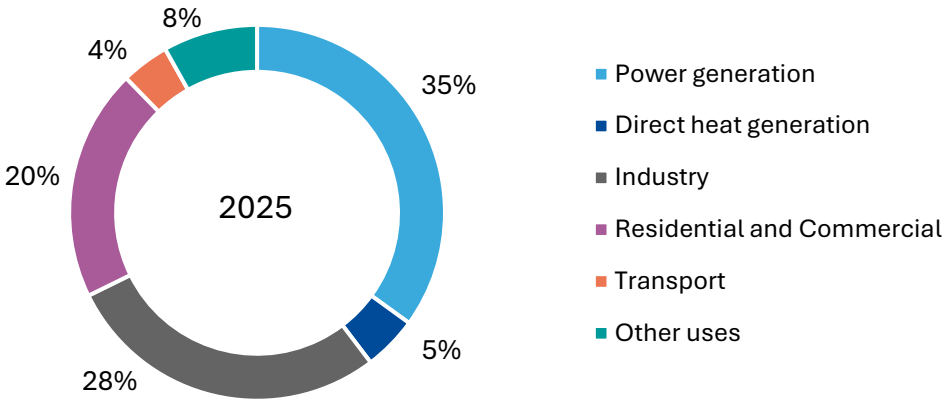
Looking ahead, APERC expects global gas demand to decline in 2026, broadly in line with the IEA's latest short-term gas market outlook, which projects a decrease of around 65 bcm, or 1.5% (IEA, 2026). The contraction is largely attributable to the conflict in the Middle East, as disruptions of LNG flows through the Strait of Hormuz have tightened the global gas balance, raised prices in key importing markets, and weighed on gas consumption. The impact of the conflict is expected to vary across regions, with declines in gas use concentrated in Asia and the Middle East. However, uncertainty surrounding the duration of the Strait of Hormuz disruption remains a key factor that could lead to revisions to gas market projections for the year.

1.1.1 Power generation sector dominates global natural gas demand

Natural gas is a central component of the global energy system, accounting for around 23% of primary global energy supply and playing a pivotal role across various sectors. Its versatility and reliability, combined with its lower carbon intensity relative to other hydrocarbons, continue to underpin its adoption across diverse economies.

In 2025, the power generation, industry, and the residential and commercial sectors together accounted for almost 85% of total natural gas demand (Figure 1.2). As aforementioned, the residential and commercial sectors saw the largest increase in absolute volumes in 2025, as cold winter weather increased heating demand. Power generation remained the single largest sector for gas use globally, accounting for around 35% of total demand, although its contribution to overall demand growth was more limited than in the previous year.

Figure 1.2 Global natural gas demand by sector[1] in 2025 (%)



Source: APERC based on IGU (2026) and GECF (2026)

By contrast, in 2024, the power sector accounted for the largest increase in incremental gas demand, driven by strong growth in gas-fired electricity generation across North America, rapidly expanding Asian markets, and Eurasia.

Global gas-fired generation increased by 2.9% in 2024, reaching 7,020 TWh, up from 6,820 TWh in 2023 (Figure 1.3). Lower natural gas prices in most major markets improved the competitiveness of gas-fired power generation, while seasonal heatwaves in economies such as China, India, and the United States provided an additional boost.

This increase took place against the backdrop of a 4.3% rise in global electricity generation, which reached 31,350 TWh in 2024 (Energy Institute, 2026). Growth in global electricity generation was driven by a range of factors, including economic expansion, rising industrial activity, urbanisation, higher cooling needs, and the rapid growth of AI data centres, which have rapidly increased electricity demand.

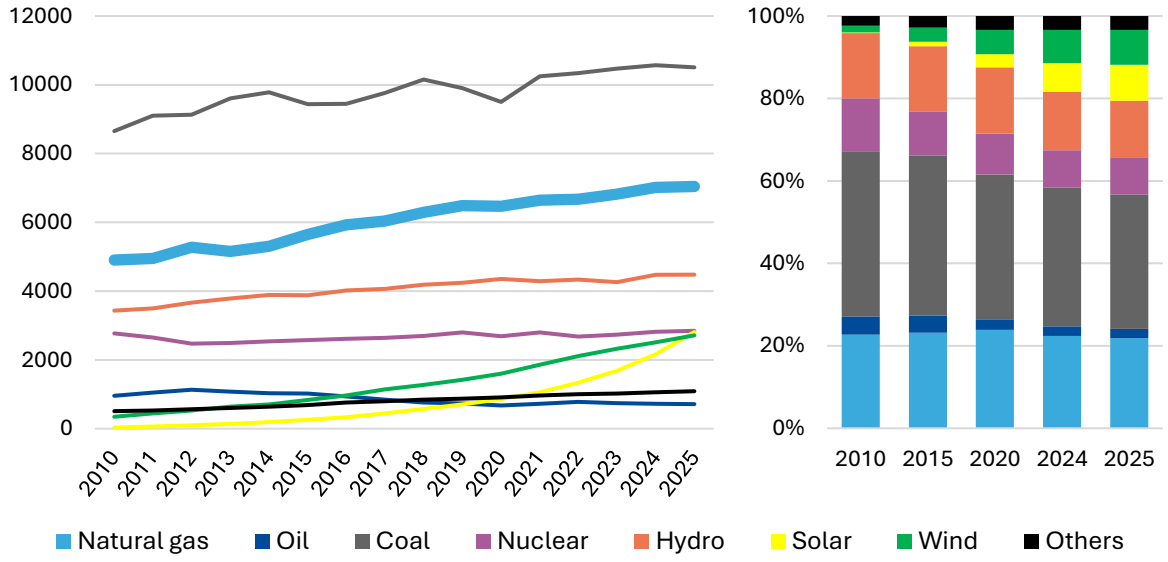
[1] Power generation covers gas used as fuel in the electric power sector (including combined heat and power plants). Direct heat generation refers to gas used in boilers and pumps for district heating. Industry includes gas directly used as fuel and feedstock, as well as input for refineries. Residential sector covers gas used in private dwellings for heating, air-conditioning, cooking, water heating, and other household uses. Commercial sector includes gas used in the sale of goods or services for the same purposes as for the residential sector. Transport encompasses road transport, marine bunkers, rail transport, and pipeline operations. Other uses include gas consumed for the energy sector's own use, together with distribution losses.

In parallel to an increase in gas-fired generation, solar PV, wind, and hydropower also experienced significant growth. In 2024, solar PV accounted for an additional 490 TWh, almost 40% of the total increase in power generation. Wind expanded by about 190 TWh in 2024, as new projects were brought online. Hydropower generation increased strongly, rebounding from 2023 declines amid improved precipitation in key regions. Nuclear power generation rose by 80 TWh, boosted by new projects and reactivated operations at several reactors in France and Japan. Coal-fired power generation also contributed to the total increase in power generation in 2024, adding 95 TWh.

In 2025, global electricity generation rose by 2.7%, or 850 TWh, to 32,200 TWh. Although economic expansion, urbanisation, and digitalisation continued to drive power generation output, growth slowed compared to the previous year. This reflected the absence of a weather-related boost (as temperatures remained at or above 2024 levels), and a weaker electricity demand increase in manufacturing and industry, particularly in China (Ember, 2026). Notably, the expansion of data centres has emerged as an important structural driver of electricity demand, with potentially significant implications for gas-fired generation prospects (Box 1.1).

As shown in Figure 1.3, in 2025, global gas-fired generation increased marginally to 7,042 TWh. The largest gains occurred in Chinese Taipei, following the shutdown of its last operating nuclear reactor, and in Türkiye, amid a shortfall in hydropower output. The steepest decline was recorded in the United States, where higher natural gas prices reversed the coal-to-gas switching trend observed in recent years.

Figure 1.3 Trends in global electricity generation by energy source (TWh) and generation mix (%)



Source: APERC based on data from the Energy Institute Statistical Review of World Energy (2026)

Solar and wind generation continued to grow robustly. 2025 was another record year for global solar growth, surging by 30%, or 645 TWh, driven by declining technology costs and large-scale deployment in China and Europe. Wind generation rose by 200 TWh. Nuclear output increased slightly owing to improved availability in several markets. Global coal-fired generation fell by 60 TWh, driven by declines in China and India, which outweighed an increase in the United States.

Despite these shifts, coal remained the largest source of global electricity generation in 2025, although its share declined to around 33% (Figure 1.3). Natural gas ranked second, accounting for 22%, while wind and solar together reached 17%. These trends highlight the continued transformation of the global power generation system towards cleaner energy sources, as well as the growing need for flexible generation to support system reliability. In this context, natural gas plays a critical role in power generation by providing both reliable baseload power for end users, including energy-intensive data centres, and dispatchable capacity to back up renewables.

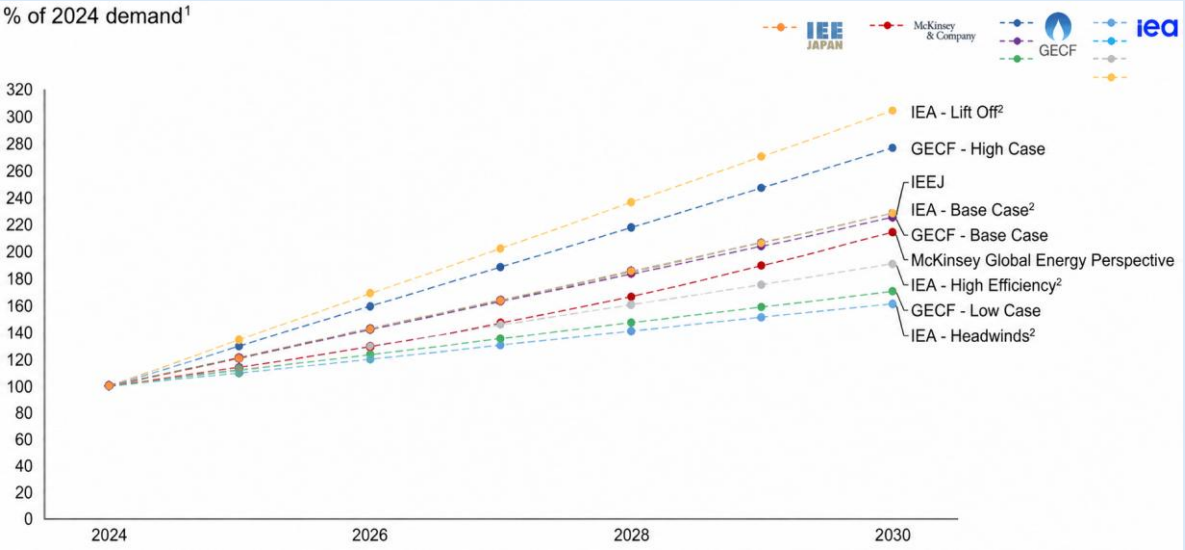
Box 1.1 The role of natural gas in meeting data centres' growing electricity demand

The rapid expansion of AI, cloud computing, and other digital services is becoming an increasingly important source of electricity demand growth. Data centres require large volumes of reliable electricity for computing equipment and cooling systems.

Many new facilities are expected to move into the 100 MW to 1 GW range, particularly as hyperscale campuses expand to support AI training and the use of AI models (IGU, 2026). As a result, the scale and concentration of new data centre loads are becoming a key consideration for electricity system planning, particularly in locations where generation or grid capacity is already constrained.

The magnitude of future electricity demand remains uncertain, reflecting differences in assumptions about AI adoption, computing efficiency, and the pace at which announced data centre projects are completed. Nevertheless, available outlooks consistently point to substantial growth through 2030, although the magnitude varies considerably across projections (Figure 1.4). Global data centre electricity consumption rose from 270 TWh in 2020 to 416 TWh in 2024 (IEA, 2026), and several outlooks indicate that demand reach around 1,000 TWh or more by 2030.

Figure 1.4 Forecasts for global data centre electricity demand, 2024-2030



Source: APERC based on IGU (2026) and projections from IEA, IEEJ, GECF, McKinsey

Note: 1) projections were normalised to a 2024 baseline (set as 100%) for comparability;
2) IEA scenarios: Headwinds (slower buildout), Base case (expected growth), High efficiency (adoption partly offset by efficiency gains), Lift-off (AI-driven surge).

Natural gas could play an important role in supplying part of this additional electricity demand. Data centres operate continuously and place a high value on power reliability, while the rapid development of new facilities can outpace the expansion of electricity networks and generation infrastructure.

In the United States, for example, data centres can often be developed within a few years, whereas transmission infrastructure and grid connections may take considerably longer. This emerging "time-to-power" constraint is encouraging some developers to consider dedicated or behind-the-meter gas-fired generation, which can provide and dispatchable generation where grid access is delayed or constrained. Recent examples include Duke Energy's plans for new combined-cycle and peaking capacity in the Carolinas linked to hyperscale load growth, and Entergy's gas-backed project supporting Meta's data centre in Louisiana.

At the same time, the role of natural gas should be viewed as part of a broader portfolio of electricity supply options rather than as a stand-alone solution. Renewable electricity is expected to provide a growing share of power used by data centres, while nuclear power is also attracting attention. Natural gas can complement these resources by providing flexible and dispatchable generation, particularly where variable renewable generation is expanding or where grid capacity is insufficient to accommodate new large loads. Recent project announcements also show increasing interest in co-locating data centres with dedicated power generation or combining renewable procurement with firm generation capacity.

The potential implications are particularly relevant for several APEC economies. North America remains the largest hub of data centre development, with the United States accounting for more than 40% of global data centre capacity. The availability of domestic natural gas, coupled with an expanding gas-fired power fleet, positions natural gas to meet part of the incremental electricity demand from data centres in several U.S. states, including through dedicated generation. Elsewhere, the role of natural gas will depend on the existing power mix and availability of gas infrastructure. In China, for example, gas is likely to play a more targeted role for powering data centres, alongside rapid additions of renewables and expanding coal and nuclear power generation.

The extent to which additional data centre demand translates into higher natural gas consumption will ultimately depend on regional electricity market conditions, fuel prices, access to gas infrastructure, technology costs, and climate policies. Environmental performance will also remain important. While modern gas-fired generation has a lower emissions intensity than coal-fired generation, additional gas use would still raise emissions unless accompanied by decarbonisation technologies, such as carbon capture, utilisation and storage (CCUS).

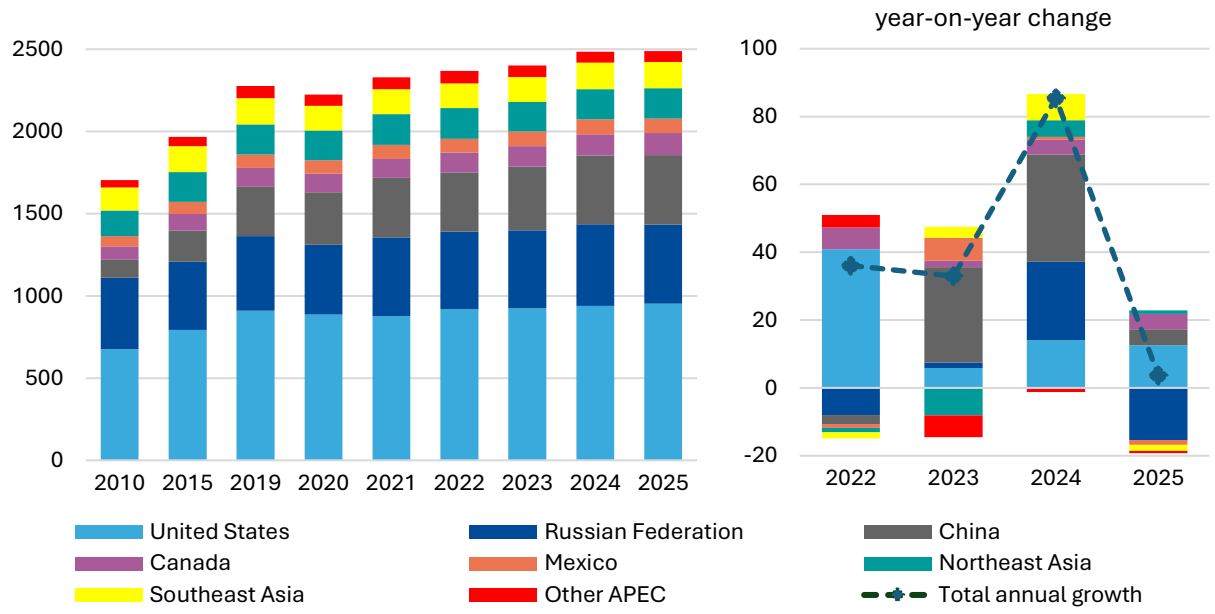
Overall, the emerging relationship between natural gas and data centres is likely to be strong, as gas-fired generation can simultaneously address reliability and flexibility, while also helping to speed data centre deployment.

1.2 Recent trends in APEC natural gas demand

In 2024, natural gas demand in APEC increased by 3.6% to 2,485 bcm, following a modest 1.4% increase in 2023 (Figure 1.5). This growth was primarily driven by China, Russia and the United States, together adding around 70 bcm and accounting for over 80% of the total increase. China led the regional growth, benefiting from policy-driven switching, the expansion of its LNG import capacity, and the ramp-up of pipeline gas deliveries from Russia via the Power of Siberia pipeline.

After rapid growth in 2024, APEC natural gas demand slowed significantly in 2025 and remained broadly flat, reflecting contrasting regional trends. In Asia, demand was constrained by weaker industrial activity, elevated spot LNG prices, mild weather in northern China, and increased nuclear power availability in Japan. Russia recorded a sharp decline in gas consumption, partly owing to a mild winter in the first quarter of 2025. By contrast, demand growth in North America was sufficient to offset declines elsewhere in the region, supported by higher residential and commercial gas consumption as colder temperatures in the first and fourth quarters increased space-heating needs in Canada and the United States (IEA, 2026; Cedigaz, 2026).

Figure 1.5 Trends in APEC natural gas demand (bcm)



Source: APERC based on Cedigaz (2026) and EGEDA (2026)

China

In **China**, natural gas demand expanded strongly in 2024, rising by over 8% and marking the second consecutive year of growth. Following a contraction in 2022, driven by record-high spot LNG prices and weaker economic activity, demand increased by 28 bcm in 2023 and a further 32 bcm in 2024. This growth was mainly supported by favourable gas prices, a rebound in the industrial sector, higher gas-fired power generation, and policy measures promoting gas as a cleaner alternative in transport, particularly in heavy-duty trucking.

In 2024, extreme summer heatwaves and rising air-conditioning needs drove a surge in gas-fired power generation, reaching 321 TWh, up 7.7% year-on-year (Energy Institute, 2026). Despite this increase, the share of gas in China's power generation mix remained broadly unchanged at around 3%, as coal continued to dominate at 58%. Industrial gas consumption also rose strongly

amid economic recovery and a structural shift toward cleaner fuels, while gas demand in the residential and commercial sectors was stable, influenced by seasonal weather conditions.

At the same time, China's transport sector emerged as a key driver of gas demand growth in 2024. With both favourable energy policies and economics, China saw a strong increase in LNG-powered truck sales, which reached 178,200 units in 2024, a 17% increase compared to 2023, contributing to lower diesel consumption (Shell, 2025). It is worth mentioning that this upward trend persisted into 2025, with sales rising to about 198,700 units, up 11.6% year-on-year (ICIS, 2026). As a result, the number of LNG-powered trucks in operation in China grew to around one million units in 2025 (GECF, 2026).

In 2025, China's gas consumption decelerated, growing by only 1.1%, adding 5 bcm. This overall slowdown resulted from muted industrial activity, lower heating needs in the first part of 2025, and a surge in renewables generation (Cedigaz, 2026).

In the power sector, China's gas demand continued to grow, supported by additions of new gas-fired capacity in coastal provinces, including Guangdong, Jiangsu, and Zhejiang. Overall, around 19 GW of new gas-fired capacity was added in 2025 (Oxford, 2026). However, the increase in gas consumption for power generation in 2025 was significantly lower than in 2024, as growth was tempered by a 40% surge in solar generation and a 13% increase in wind generation. These gains in renewable generation constrained thermal power output, increasingly shifting the role of gas-fired plants toward providing peak shaving and grid flexibility services.

Notably, 2025 was the first year since 2015 in which China recorded a decline in fossil-fuel-based power generation, as the decrease in coal-fired generation more than outweighed the increase in gas-fired generation (Ember, 2026).

Russia

Natural gas demand in **Russia** increased significantly in 2024, rising by 5% or around 23 bcm. This growth was driven by stronger consumption in the industrial and residential sectors. Higher gas use in electricity generation also contributed to the overall increase.

Industrial demand was supported by energy-intensive industries. In 2024, Russian fertiliser manufacturers purchased record-high gas volumes. More than 63 million tonnes of all types of mineral fertilizers were produced, up 6.5% year-on-year, while exports reached a historic high of 40 million tonnes in 2024, boosted by increased supplies to Asian markets (Interfax, 2024). In parallel, residential gas demand also experienced a notable rise as more households were connected to gas distribution networks under the continued implementation of Russia's gasification programme.

The strong growth observed in 2024 was reversed in 2025, when Russia's gas demand is estimated to have declined by around 15 bcm. The contraction reflected a mild winter during the first quarter of the year, which reduced heating demand. In addition, weaker macroeconomic conditions weighed on gas consumption in both the industrial and power sectors (Cedigaz, 2026).

APEC North America

North America remained the largest gas-consuming subregion within APEC, accounting for almost 1,160 bcm in 2024, or 47% of total APEC gas demand. In 2024, North American economies together increased gas demand by 19 bcm, with the majority of the growth coming

from the United States. This increase was underpinned by robust growth in the power generation sector, while industrial gas demand recorded a moderate increase. Gas use in the residential and commercial sectors declined, as milder weather conditions reduced heating requirements.

North American gas consumption continued to increase in 2025, rising by around 16 bcm. Unlike in 2024, however, growth was largely driven by the residential and commercial sectors due to colder winter weather, which boosted heating needs. In contrast, gas use in the power sector declined as higher gas prices reduced the competitiveness of gas-fired generation (IEA, 2026).

At the economy level, in **Canada**, natural gas demand increased by 3.5% in 2024, or around 4 bcm, driven by rising industrial gas consumption. Higher gas use in oil sands operations was a key contributor, supported by growing oil sands extraction volumes and increased crude takeaway capacity following the completion of the Trans Mountain pipeline expansion in May 2024 (Statistics Canada, 2025).

In 2025, Canada's natural gas consumption increased by 3.5%, the same rate as in 2024. Higher gas use in the industrial and power sectors was accompanied by a strong growth in residential and commercial demand. Similar to the United States, colder weather conditions in the first and fourth quarters of 2025 boosted heating needs.

In **Mexico**, gas demand across sectors remained relatively flat in 2024, before declining by an estimated 1.6%, or around 1.5 bcm, in 2025. The contraction was largely driven by lower gas use in the power sector.

The **United States** is the largest natural gas consumer, accounting for about 38% of total natural gas demand in APEC and more than 81% of demand in North America. In 2024, U.S. natural gas consumption continued its upward trajectory, increasing by 1.5%, or 14 bcm, to reach 940 bcm.

In the U.S. power generation sector, gas demand increased amid higher electricity consumption, supported by the rapid expansion of energy-intensive data centres and increased cooling demand during the summer. Low natural gas prices throughout 2024 also encouraged coal-to-gas switching in the power sector. The share of gas in the power generation mix rose to 43% in 2024, strengthening its role as the dominant source of the U.S. power system (Energy Institute, 2026).

In 2025, U.S. gas consumption increased further by an estimated 1.3%, adding 13 bcm. The increase was primarily driven by strong growth in the residential and commercial sectors amid colder winter conditions, including a January polar vortex that significantly elevated space-heating needs. Natural gas demand in industry and the energy supply-side sector also increased, partly supported by stronger gas use associated with the economy's expanding LNG liquefaction capacity (Cedigaz, 2026; EIA, 2026).

However, gas-to-power demand in the United States declined in 2025 due to stronger renewable power output and price-driven gas-to-coal switching. Solar generation surged by 28% in 2025, while coal-fired generation rebounded by 13%, together accounting for the bulk of incremental electricity generation. Henry Hub prices averaged $3.52/MMBtu, a 56% increase from the 2024 annual average, weakening the cost-competitiveness of natural gas relative to coal in several regions (EIA, 2026; GECF, 2026). Consequently, the share of gas in the U.S. power generation mix declined from 43% in 2024 to 41% in 2025. Nevertheless, gas-fired generation is set to remain central to supporting electricity demand growth and grid reliability as renewable generation rises.

APEC Northeast Asia

In Northeast Asia, gas demand in 2024 increased by 5 bcm, or 2.8%, mainly due to higher consumption in the power sector in Korea and Chinese Taipei. In 2025, as illustrated in Figure 1.5, total gas demand in Northeast Asia increased only marginally, reaching 185 bcm. While gas consumption continued to rise in Korea and Chinese Taipei, lower gas use for power generation in Japan largely offset these gains (Cedigaz, 2026).

In **Korea**, gas demand growth was particularly strong in 2024, leading to a 4% increase in LNG imports. Several factors contributed to this increase, including nuclear power curtailments and higher-than-normal summer temperatures, which drove up electricity demand for cooling. In 2025, Korea had a modest 1% increase in gas use, driven by higher gas-fired power generation to support grid stability, along with gas demand increases in the residential and commercial sectors.

In **Chinese Taipei**, gas demand rose strongly in both 2024 and 2025, with a cumulative increase of around 4.5 bcm. Higher gas use in the power sector to compensate for the decommissioning of nuclear capacity was a key driver of this trend. In July 2024, Unit 1 of the Maanshan Nuclear Power Plant was shut down. Then, in May 2025, Maanshan Unit 2, the economy's final operating nuclear reactor, ceased operations following the expiration of its 40-year operating licence (Taipower, 2025).

Japan's demand for gas remained relatively stable in 2024. The economy's gas consumption was shaped by temperature variations, continued efforts to diversify the power generation mix, and fluctuations in nuclear power availability. In particular, the restart of idle nuclear reactors, such as Onagawa Unit 2 and Shimane Unit 2, together with stronger renewable energy output, helped limit the need for additional gas consumption in the power sector (JAIF, 2026; GECF, 2025).

In 2025, Japan's gas demand decreased by an estimated 2.2%, or around 2 bcm, to 90 bcm. Higher renewable output and the gradual recovery of nuclear capacity continued to reduce gas requirements in the power sector, with the return of the 826 MW Takahama No. 1 reactor in December 2025 providing additional capacity during the winter peak (Cedigaz, 2026).

APEC Southeast Asia

Natural gas demand in Southeast Asia increased by 5%, or 8 bcm, in 2024. This was driven by increased gas use in the power generation and industrial sectors. Growth was largely concentrated in the region's gas-rich markets, particularly Indonesia and Malaysia, where rising domestic gas production continued to support higher consumption. At the same time, Thailand and Singapore also contributed to the regional upward trend.

In 2025, Southeast Asia's gas consumption fell by around 1%, or 2 bcm, to slightly below 160 bcm. Trends at the economy level remained mixed, depending on infrastructure expansion, upstream gas availability, and gas price competitiveness.

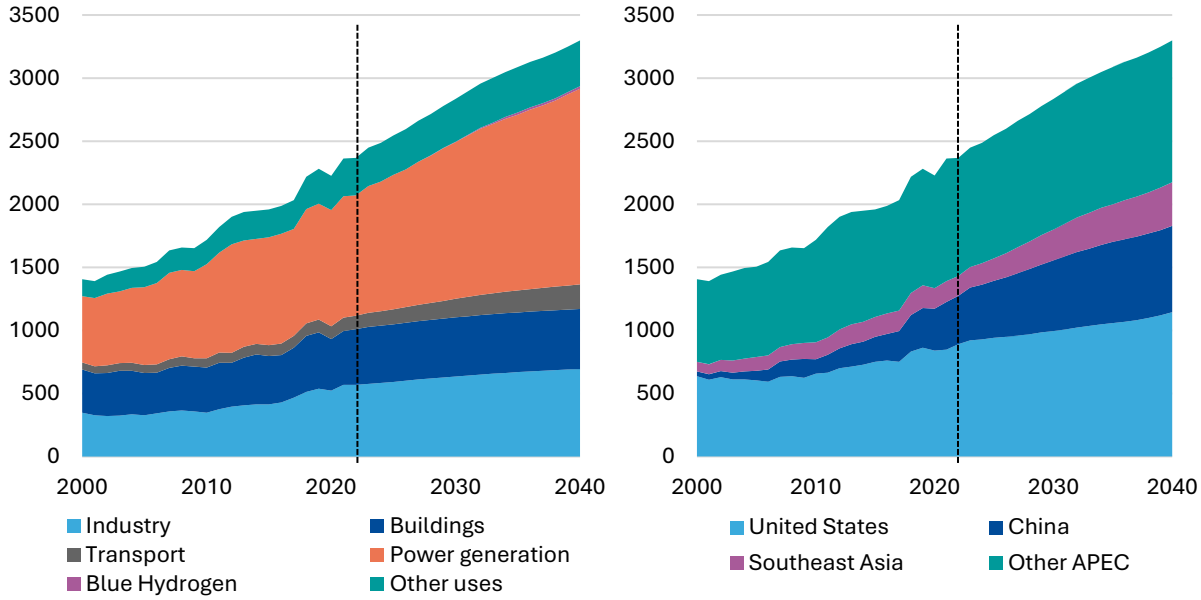
In the long term, Southeast Asia is expected to emerge as a key centre of gas demand growth within APEC, as economies ramp up investments in gas-based infrastructure, including LNG import facilities, to support growing gas use as a lower-emissions alternative to coal and as a critical enabler of renewable energy integration. These projections are discussed in the following section.

1.3 APEC natural gas demand outlook

According to the *APEC Energy Demand and Supply Outlook, 9th Edition*, the Reference Scenario (REF) projects natural gas demand in the APEC region to increase by almost 40% between 2022, the Outlook's base year, and 2040, reaching 3,300 bcm (Figure 1.6). China, the United States, and Southeast Asia economies collectively represent the main growth centres, together accounting for around 80% of the total increase over the forecast period.

This rise is underpinned by population growth, robust economic expansion, rising electrification, and the continued expansion of gas infrastructure. New LNG regasification facilities, expanded pipeline networks, city gas distribution systems, and gas-fired power plants are creating the foundation for wider natural gas use across the region. Policy measures encouraging switching from coal and oil to gas, particularly in APEC's Asian economies, accelerate demand growth as economies seek to reduce emissions and improve air quality.

Figure 1.6 APEC natural gas demand outlook by sector (a) and by subregion (b) (bcm)



Source: APEC Energy Demand and Supply Outlook, 2025
Note: Buildings include residential and commercial sectors

The power generation sector plays a frontline role in APEC's natural gas demand growth, accounting for more than 60% of the total increase between 2022 and 2040. Rising electrification across the buildings, industry, and transport sectors will increase the need for gas-fired power generation. The continued expansion of data centres is also emerging as an important structural driver for gas power demand, given the need for reliable, around-the-clock electricity supply.

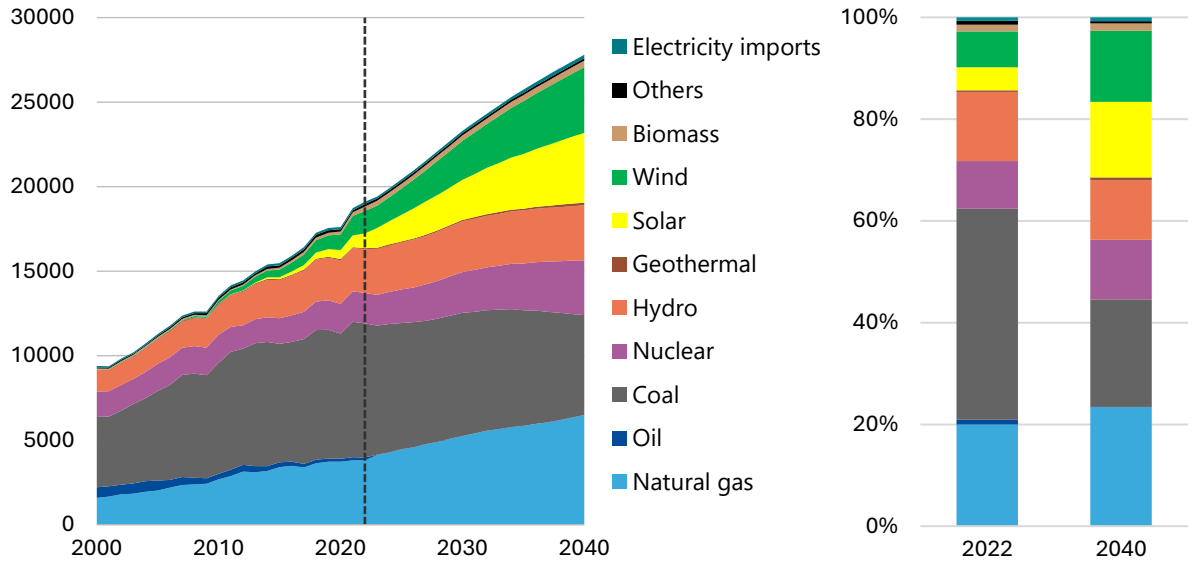
Demand for gas-fired generation is further driven by policies aimed at phasing down coal-fired power generation. At the same time, gas-based power generation will be in demand for dispatchable capacity, supporting the growing integration of variable renewables. While gas continues to displace coal, its role is also expected to evolve gradually from baseload generation toward system balancing and flexibility provision.

As Figure 1.7 indicates, amid rising electricity demand and continued renewable expansion, the share of gas-fired generation in APEC's power generation mix is projected to increase from 20% in 2022 to 23% by 2040. This occurs despite an overall decline in total thermal generation, where

the share is expected to fall from 62% to 45%, with coal generation falling rapidly and being largely displaced by natural gas. Regionally, China is projected to contribute most to the decline of coal-based generation. However, the regional trend is partially offset by increased fossil fuel-fired generation, mainly gas-fired generation, in fast-growing Southeast Asian economies.

Although abundant and affordable coal resources continue to play an important role in energy security and affordability, many economies are placing greater emphasis on expanding natural gas and renewable energy capacity to support sustainability objectives and meet rapidly rising electricity demand. This trend is particularly evident in APEC Southeast Asia, where natural gas demand growth is projected to be primarily power-driven. The Special Focus section presented in this chapter provides further insight into the evolving role of cleaner energy sources such as natural gas in Southeast Asia's power generation mix.

Figure 1.7 Electricity generation trends in APEC by fuel (TWh) and fuel shares (%)



Source: APEC Energy Demand and Supply Outlook, 2025

From a sectoral perspective, industry represents the second-largest source of demand growth, accounting for around 15% of additional gas volumes. Policy-driven initiatives to reduce emissions act as an important catalyst, favouring coal- and oil-to-gas switching. Gas is set to play an increasing role in providing heat and steam across energy-intensive industries, particularly in petrochemical production, non-metallic minerals, iron and steel, and a broad range of light manufacturing.

In industry, gas is expected to remain particularly important for high-temperature processes that are difficult to electrify, as well as for ammonia and fertiliser production, where it serves as a key feedstock and contributes to agricultural productivity and food security. Moreover, many industries using natural gas are expected to initiate the deployment of CCUS that are critical for decarbonising industrial processes.

The buildings sector is expected to contribute to around 5% of total gas demand growth between 2022 and 2040, with gas used primarily for space heating, water heating, and cooking. Although demand in this sector remains highly seasonal, future growth potential continues to be supported by ongoing urbanisation, population growth, and the expansion of gas distribution networks.

Finally, over the outlook horizon, the transport sector emerges as an additional avenue for natural gas demand growth in APEC, accounting for around 9% of the total increase. This also includes increased natural gas consumption in pipeline operations.

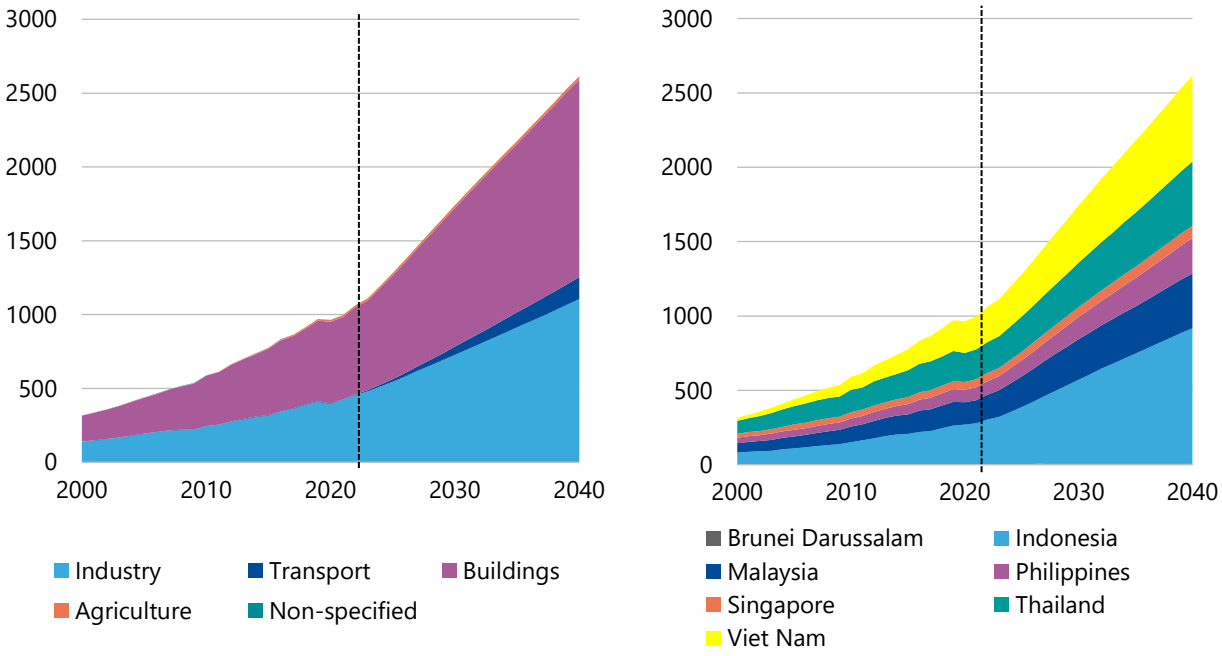
In road transport, favourable government policies and the expansion of refuelling infrastructure support demand, particularly through the use of LNG-powered trucks as a competitive and lower-emission alternative to diesel.

LNG as a bunkering fuel is expected to gain momentum amid more stringent emissions regulations for shipping. Given that several alternative marine fuels, such as hydrogen and ammonia, remain at an early stage of development and continue to face commercial and technical constraints, LNG is well-positioned to strengthen its role in the transport sector, supported by extensive LNG infrastructure and supply chains.

Special Focus: The future of natural gas in APEC Southeast Asia's power sector

Over the past two decades, electricity demand in APEC Southeast Asia has been growing at a robust average rate of 5.6% per year. According to the 9th edition of the *APEC Energy Demand and Supply Outlook*, under the Reference Scenario, this strong growth is set to continue, with demand increasing at an annual pace of 5.1% between 2022 and 2040, rising to 2,615 TWh by that date, driven mainly by Indonesia, Viet Nam, and Thailand (Figure 1.8).

Figure 1.8 Electricity demand trends in APEC Southeast Asia by sector (a) and by economy (b) (TWh)



Source: APEC Energy Demand and Supply Outlook, 2025
Note: Electricity demand is defined as total power generation less power sector own use, less transmission and distribution losses, plus net trade

The buildings sector is expected to be the largest contributor to future demand growth, propelled by higher space cooling requirements, increased household appliance ownership, and surging demand from data centres. With electricity's share in total final consumption in APEC Southeast Asia projected to rise from around 20% in 2022 to 28% by 2040, the regional power sector is slated to undergo a profound transformation to achieve sustainability goals.

Policy directions and plans to ensure reliable and sustainable electricity supply

Historically, strong increase in electricity demand has been met mainly by the expansion of coal-fired generation, followed by natural gas and hydro. In 2017, coal had already overtaken gas to become the primary source of the regional power generation. Coal dominance is likely to persist, at least over the mid-term, given that around 9 GW of coal-fired capacity is under construction and a further 21 GW is in the pre-construction phase (GEM, 2026).

Meanwhile, among the most coal-dependent economies in the region, such as Indonesia, the Philippines, Viet Nam, and Malaysia, a clear pattern has emerged in recent years: a transition away from coal. Notably, Malaysia has established a phase-out plan for coal-fired power fleet, aiming to reduce its capacity by around 50% by 2035 and fully exit coal-based power generation by 2045, as set out in its National Energy Transition Roadmap (NETR, 2023).

Indonesia has pledged not to develop new coal-fired power plants beyond those already in the pipeline. At the same time, Indonesia is pursuing a coal phase-down rather than a phase-out, citing potential impacts on economic performance and energy affordability. Thus, exceptions are allowed, specifically for captive coal, with 2024–2060 National Electricity Master Plan (RUKN) projecting new capacity to support growing mineral processing industry (Ember, 2025).

The Philippines likewise introduced a moratorium on new coal-fired power plants. This ban does not apply to projects that had already been approved. The policy also allows certain coal projects to proceed if they meet specific criteria (Department of Energy Philippines, 2024).

Viet Nam, by contrast, has articulated a more explicit long-term pathway under its revised National Power Development Plan (PDP) 8, released in April 2025, which caps coal-fired capacity at 30-31 GW by 2030 and envisages a complete phase-out by 2050 (KPMG, 2025).

In this context, economies are placing greater emphasis on expanding both natural gas and renewables. Ambitions for renewable deployment are particularly strong. Indonesia, for example, plans to add over 42 GW of renewable capacity, including solar, hydropower, wind, geothermal, and bioenergy alongside 10.3 GW of energy storage by 2034, as outlined in its 2025-2034 Electricity Supply Business Plan. Malaysia aims to increase renewable's share in installed power capacity to 70% by 2050, up from just over 25% in 2023, driven by solar PV expansion, which set to reach 59 GW by that date. Viet Nam in its revised PDP 8 considers between 78.5 GW and 128 GW of solar and wind capacity by 2030 and up to 491-526 GW by 2050, representing a substantial increase compared with the original PDP 8.

Despite ambitious plans, rapid expansion of renewable generation may be constrained by bottlenecks in electricity transmission networks, underinvestment in grid modernisation, insufficient land availability for large-scale projects, and the inherent inflexibility of power systems dominated by coal-fired generation. This is where gas-fired power plants are expected to play a critical role by facilitating the transition away from coal, complementing intermittent renewables, and enhancing system flexibility to stabilise power grids.

While natural gas accounts for around 30% of the regional power generation mix, its importance varies widely across economies. Gas' share exceeds 95% in Singapore and is also significant in Brunei Darussalam, Thailand and Malaysia. By contrast, gas contributes less than one-fifth in Indonesia and the Philippines, and around one-tenth in Viet Nam. In this context, coal-to-gas

switching potential, together with strong growth in electricity demand, suggests that natural gas could strengthen its position in the power mix over the coming decades. The momentum behind gas-fired generation in APEC Southeast Asia is reinforced by the fact that this fuel is enshrined in government energy strategies and power development plans.

At the same time, the long-term outlook for natural gas is increasingly complex. Indigenous gas production in Southeast Asian economies is expected to either decline or be unable to keep pace with rising gas demand from the power sector, industry, and other users. This will bring LNG imports to the forefront, while enhanced interconnectivity and the development of LNG-to-power projects will be pivotal factors, shaping the future of gas-fired generation in the region.

Viet Nam represents the most dynamic case in this area. The revised PDP 8 proposes 13 LNG-fired power plants with a combined capacity of 22.5 GW by 2030, followed by eight additional LNG-based plants totalling 13.8 GW by 2035 (Viet Nam Government Portal, 2025). A key milestone is the start of commercial operations at the Nhon Trach 3 and 4 power plants (1.62 GW combined) in December 2025, Viet Nam's first LNG-fired power complex (LNG Prime, 2025). In parallel, Viet Nam aims to have 14.9 GW operating on domestically produced gas by 2030, up from 8.3 GW at present.

The Philippines is also focusing on LNG-fuelled generation as part of its decarbonisation efforts. With gas production projected to decline due to the depletion of the Malampaya gas field, the Philippines aims to replace its output with LNG. Two LNG facilities in Batangas were built and the economy received its first LNG imports in April 2023. To meet electricity demand growth, the integration of seven LNG terminals has been projected, as per the Philippine Energy Plan 2023-2050. Currently, around 10 GW of gas-fired capacity is at various stages of development (Argus Media, 2025; GEM, 2026).

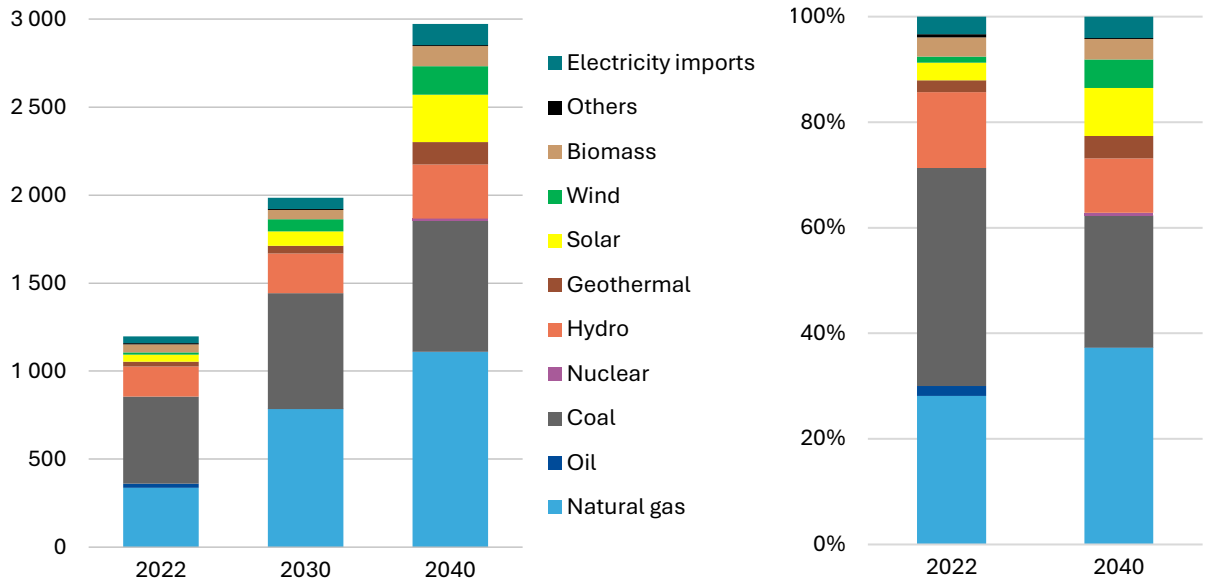
In Indonesia, the first conventional-scale LNG-to-power plant, the 1.76 GW Jawa-1, was launched in March 2024. This development aligns with the recent Electricity Supply Business Plan, which puts emphasis on supporting infrastructure for new and existing gas-fired power plants amid anticipated constraints on piped gas supply. This includes LNG receiving terminals on Java and Bali, as well as Floating Storage and Regasification Units (FSRU), in addition to a number of pipeline gas and LNG-to-power projects with a total capacity of 10.3 GW to be developed by 2034 (Ashurst, 2025).

The forecast for gas-fired generation

Under the Reference Scenario, electricity generation in the region is projected to grow 2.5-fold, from around 1,200 TWh in 2022 to 2,970 TWh by 2040. This growth drives the need for both fossil and non-fossil generation. Considering projects under construction and assessments of long-term capacity additions, gas-fired power plants are expected to serve as a key enabler, specifically beyond 2030, helping to reduce reliance on coal and accommodate higher shares of renewables.

Gas-fired generation, using both indigenous gas production and LNG imports, is projected to become the largest source of electricity generation, accounting for around 37% of the regional power generation mix by 2040 and contributing more than 40% of the total increase in electricity supply over the outlook period (Figure 1.9).

Figure 1.9 Electricity generation trends in APEC Southeast Asia by fuel (TWh) and fuel shares (%)



Source: APEC Energy Demand and Supply Outlook, 2025

Overall, electricity demand in APEC Southeast Asia is set to grow rapidly, underscoring the need for scalable and flexible generation sources. While abundant and relatively low-cost coal resources cannot be set aside – and coal-fired generation is likely to continue rising – natural gas, alongside renewable energy, is well-positioned to be at the forefront of meeting surging power needs while reducing the environmental footprint. In this context, continued investment in the development of natural gas resources and related infrastructure, including LNG import facilities, will therefore be critical to ensuring energy security and a stable electricity supply in the region.

Chapter 2 Natural gas production

2.1 Recent trends in global natural gas production

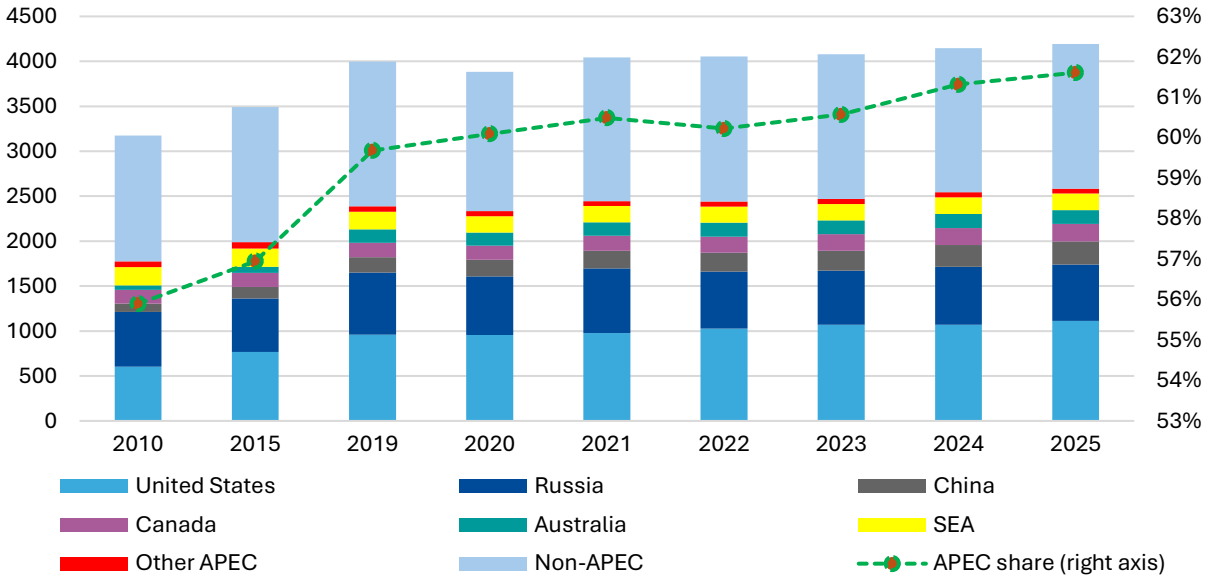
Global natural gas production accelerated in 2024, rising by 1.6% from the previous year to around 4,145 bcm, an increase of approximately 65 bcm (Figure 2.1). This growth marked a departure from the 2019-2023 stagnation period, which was shaped by a complex sequence of economic and geopolitical disruptions.

Following the collapse in gas demand during the COVID-19 pandemic in 2020, upstream investment and drilling activity were reduced significantly. As global gas demand rebounded in 2021, gas supply growth struggled to keep pace, contributing to tighter market conditions and higher energy prices. Broader inflationary pressures subsequently increased the costs of labour, steel, equipment, and other inputs required for upstream development. These already fragile market conditions were further compounded in 2022 and 2023 by geopolitical disruptions, which forced a reorganisation of international gas trade flows and created exceptional price volatility.

By 2024, however, stronger company revenues and heightened energy security concerns encouraged a recovery in upstream investment, including the reactivation of delayed drilling projects. Government measures also created a more favourable investment environment through higher minimum storage requirements, accelerated infrastructure permitting, and support for long-term supply contracts.

Against this backdrop, global natural gas production increased by a further 1.1% in 2025 to around 4,190 bcm, with major producing economies demonstrating high operational resilience as market conditions began to stabilise. North America was the leading contributor to global natural gas production growth in 2025, with the increase driven primarily by the United States.

Figure 2.1 Natural gas production in APEC and the world (bcm)



Source: APERC based on Cedigaz (2026) and EGEDA (2026)

As shown in Figure 2.1, growth in global natural gas production during 2024–2025 was concentrated in the APEC region. APEC gas output increased by over 70 bcm in 2024, exceeding the net global increase as total non-APEC production declined slightly. In 2025, APEC added a

further 40 bcm, accounting for almost 90% of global production growth and bringing regional output to 2,585 bcm. As a result, APEC raised its share of global production to almost 62%. Gas production developments across APEC economies are discussed in more detail in the following section.

Outside APEC, natural gas production exhibited regional variations during 2024–2025, with considerable differences also observed among individual economies.

The Middle East recorded the strongest natural gas production growth among non-APEC regions in both 2024 and 2025, driven by the development of multiple regional gas projects. Specifically, in 2025, regional gas production rose by 2%, an increase of roughly 15 bcm, approaching 745 bcm. This growth was led by higher production in Qatar and Saudi Arabia, alongside significant contributions from Iran and the UAE.

Saudi Arabia's gas production grew by 4.9%, or around 5 bcm, reaching 107 bcm in 2025. This additional supply supported continued oil-to-gas switching in economy's power sector. Saudi Arabia also began gas production from the Jafurah unconventional gas field, the largest liquids-rich shale gas play in the Middle East. Similarly, Qatar recorded a 2.8% increase, or around 5 bcm, reaching 172 bcm in 2025. Most of this additional production boosted Qatar's LNG exports.

Conversely, natural gas production in Africa declined slightly by around 1% in 2024 and contracted marginally in 2025, staying at around 250 bcm (Cedigaz, 2026). This decline was driven largely by Egypt, where production fell by around 17% in 2024 and 14% in 2025. This represents a cumulative reduction of approximately 17 bcm over the two years, which offset production gains by other producers on the continent. The lower output reflected technical challenges at the Zohr field, combined with high depletion rates at mature fields.

In 2025, the regional decline was mostly offset by higher gas production in several sub-Saharan African economies, led by Nigeria and Angola, alongside new production in West Africa following the commissioning of the Greater Tortue Ahmeyim project on the maritime border between Mauritania and Senegal. Nigeria recorded particularly strong growth, with gas production increasing by 9%, or around 4 bcm, supported by improved feedgas availability and easing operational constraints that had limited output in 2024 (Cedigaz, 2026; IEA, 2026).

In Europe, following a 2% increase in natural gas production in 2024, regional output declined by 1.6% in 2025, or around 3 bcm, to about 188 bcm. The reduction was driven mainly by Norway, where production fell by 3.2% to just under 122 bcm, reflecting higher-than-expected planned and unplanned maintenance at key offshore facilities (Cedigaz, 2026). Lower output from Troll, Norway's largest natural gas field, following record production in 2024, contributed significantly to the decline (IGU, 2026).

Production in the United Kingdom also decreased by 3.7%, or around 1 bcm, to 27 bcm in 2025, where a drop in upstream investment accelerated natural field depletion. However, the overall regional decline was partially mitigated by production growths in Denmark and Türkiye, supported by the redeveloped Tyra field and the ramp-up of the Sakarya field, respectively (Cedigaz, 2026; GECF, 2026).

Central and South America maintained a steady output that mirrored 2024 levels. Among non-APEC economies in the region, record-high annual gas production in both Brazil and Argentina

effectively counterbalanced declines in other regional producers. Brazil's gas production increased by 18%, or around 3 bcm, to 22 bcm in 2025, supported by the development of offshore resources in the Santos Basin and lower volumes of gas flaring. In Argentina, gas production rose by 4.5%, or around 2 bcm, to nearly 47 bcm, driven by continued development of the Vaca Muerta Basin (Cedigaz, 2026; GECF, 2026).

Among non-APEC gas producers in Eurasia, Kazakhstan and Turkmenistan recorded declines of an estimated 1.5 bcm and 1.2 bcm, respectively, in 2025. By contrast, production increased in Uzbekistan and Azerbaijan, adding more than 1 bcm combined.

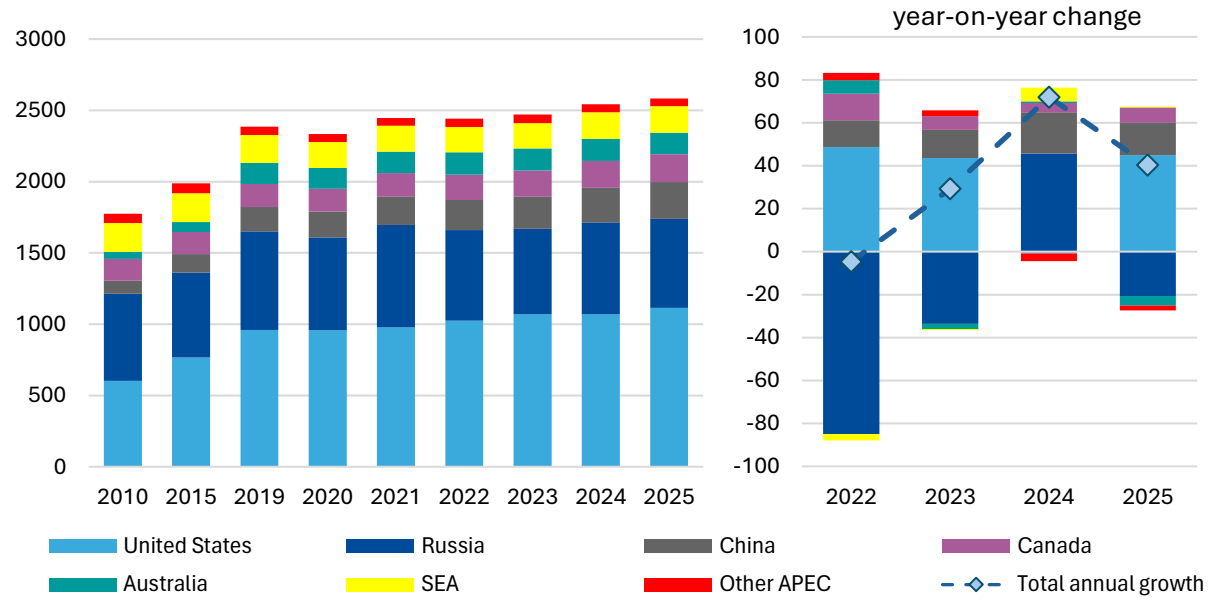
In South Asia, natural gas production declined in 2025. India's production fell by 3.1%, or by around 1 bcm, to 34.5 bcm, as natural declines from mature fields were not fully offset by additional output from new projects, mainly in offshore blocks. Bangladesh and Pakistan recorded larger declines, with production falling by 8%, or 1.7 bcm, and 6%, or 2 bcm, respectively (Cedigaz, 2026).

Looking ahead, global natural gas production is forecast to decline by around 1.4% in 2026 (IEA, 2026). This projected contraction is largely attributable to the conflict in the Middle East, with regional gas production set for its first decline since the early 1990s. Security threats to critical maritime chokepoints such as the Strait of Hormuz have increased logistical uncertainty and contributed to price spikes. Geopolitical headwinds have also constrained upstream investment in conflict-affected areas, while tightening the short-term global gas supply-demand balance.

2.1.1 Natural gas production in APEC

In 2024, natural gas production across APEC economies increased by around 3% to approximately 2,545 bcm, adding more than 70 bcm of supply. Regional growth was driven primarily by a strong supply recovery in Russia, alongside continued production growth in China. This expansion occurred during a period of relatively high energy prices, which encouraged increased drilling activity across both conventional and unconventional resources.

Figure 2.2 Natural gas production trends in APEC (bcm)



Source: APERC based on Cedigaz (2026) and EGEDA (2026)

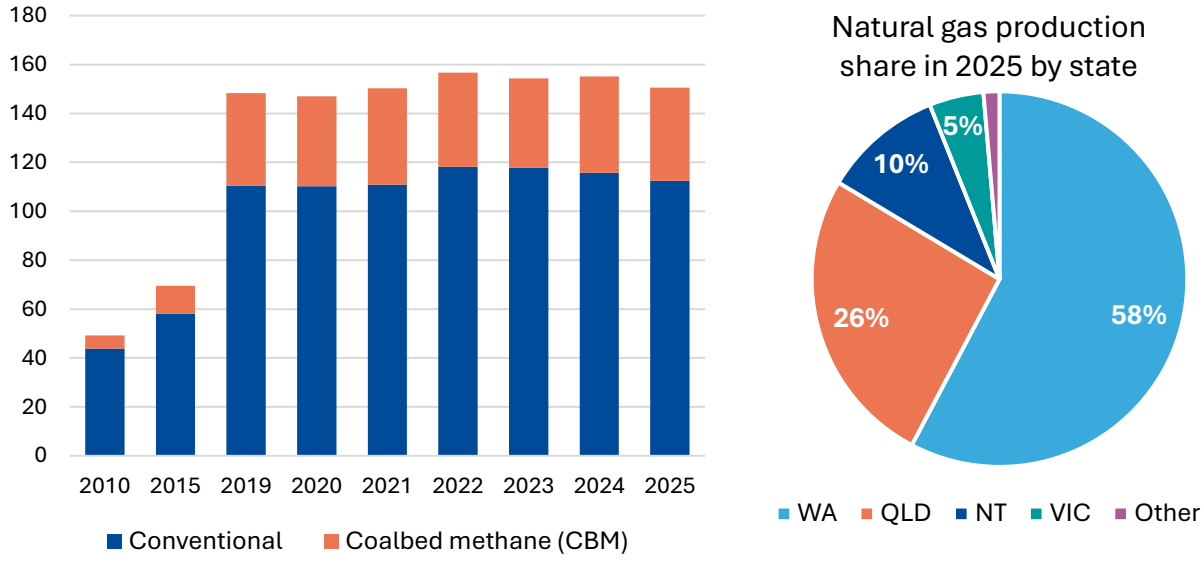
In 2025, regional output growth moderated to 1.5%, bringing total production to nearly 2,585 bcm (Figure 2.2). APEC economies recorded a net increase of about 40 bcm, with North America, led by the United States, emerging as the main driver of regional gas demand growth.. Higher output from unconventional gas resources, supported by expanding pipeline capacity, contributed significantly to this increase. Continued production growth in China also added to regional supply.

These gains were partly offset by lower gas production in Australia, associated with maintenance-related disruptions at LNG facilities, and in Russia, where output declined amid lower domestic demand and reduced exports to Europe. The following subsections outline gas production developments and upstream characteristics across the main producing economies in the region.

Australia

Australia's upstream performance highlighted the impact of maintenance and unexpected operational disruptions. Following broadly stable production in 2023-2024, the economy's total output contracted by 3.2% in 2025 (Figure 2.3), declining by roughly 5 bcm to around 150 bcm. This adjustment was highly localised, driven primarily by scheduled technical maintenance campaigns at major liquefaction complexes in Northern and Western Australia (INPEX, 2025). These planned outages were further extended by unexpected operational issues, which coincided with a moderate decline in domestic industrial gas use.

Figure 2.3 Natural gas production trends in Australia (bcm)



Source: APERC based on Cedigaz (2026), EGEDA (2026) and Australia's Department of Climate Change, Energy, the Environment and Water (2026).

Australia remains the global leader in coalbed methane (CBM) production, maintaining this position despite the temporary decline in its overall upstream output in 2025. This reflects a production profile divided by resource type and distinct regional gas systems. Conventional offshore basins continue to anchor Australia's extraction mix, holding a stable 75% share of total output over recent years to support large-scale export facilities. In contrast, unconventional CBM projects generate the remaining 25% of production. These onshore assets primarily feed the

liquefaction trains on Curtis Island in eastern Australia, while also supplying the interconnected domestic gas network of the eastern states (Geoscience Australia, 2024).

Geographically, this production structure results in a significant concentration of supply, with Western Australia (WA) accounting for 58% of total production, followed by Queensland (QLD) at 26%, the Northern Territory (NT) at 10%, and Victoria (VIC) at 5%. As major production centres are located far from key demand hubs, mature fields in southern states like Victoria, where most of the gas is produced at the Bass Strait, are experiencing localised supply tightness. To address this regional imbalance, evolving policy frameworks are focusing on the implementation of a Domestic Gas Reservation Scheme. This scheme aims to secure gas availability for domestic industrial and residential consumers from 2028 onwards, following an administrative rollout in 2027. The challenges of balancing domestic gas security with international export commitments are further examined in Box 2.1.

Box 2.1 Balancing LNG exports, domestic gas security, and upstream investment: Insights from Australia

Australia remains one of the world's largest LNG exporters, supported by LNG export facilities in Western Australia, the Northern Territory, and Queensland. LNG exports play an important role in Australia's economy and are expected to remain a key component of the global LNG market over the coming decades. At the same time, recent policy discussions have increasingly focused on domestic gas security, particularly in Australia's east coast gas market, where declining production from mature gas fields has increased the importance of continued upstream investment. Australia's experience provides an example of the policy challenges that mature LNG-exporting economies may face in balancing export growth with reliable domestic gas supply.

Australia's domestic gas market is not homogeneous. Policy discussions are centred on the East Coast gas market, which differs from Western Australia in both market structure and policy framework (Table 2.1).

Table 2.1 Comparison of Australia's principal gas markets

	East Coast	Western Australia
Main sources of gas supply	Queensland, Bass Strait and Cooper Basin	Offshore gas fields
Principal demand centres	New South Wales and Victoria	Perth metropolitan area and industrial users
LNG export facilities	Gladstone, Queensland	North West Shelf, Gorgon, Wheatstone, Pluto and other LNG projects
Policy context	Proposed Domestic Gas Reservation Scheme in response to projected supply risks	Long-standing Domestic Gas Reservation Policy

Source: Australian Energy Market Operator (2025); Australian Government (2024).

The development of LNG export facilities at Gladstone linked the east coast gas market more closely to international LNG markets by creating an alternative outlet for gas produced in Queensland. At the same time, the East Coast gas market is characterised by a geographic

mismatch between supply and demand: a substantial share of production is concentrated in Queensland, while major demand centres are located further south, particularly in New South Wales and Victoria. This challenge is compounded by expected decline of gas production from mature fields, particularly in the Bass Strait, which supply the Longford processing facilities in Victoria.

Against this backdrop, AEMO's 2026 Gas Statement of Opportunities indicates that near-term gas adequacy has improved compared with previous projections, reflecting increased supply capability, new infrastructure investment, and lower demand forecasts. However, risks to gas adequacy increase over the longer term, with additional supply required from around 2030 under most scenarios. Timely investment in new production, storage, and transportation infrastructure therefore remains important to maintaining long-term gas adequacy (AEMO, 2026)

In response to these challenges, the Australian Government is progressing a Domestic Gas Reservation Scheme following the 2025 Gas Market Review. Under exposure-draft legislation released in September 2026, LNG exporters would be required to meet an annual domestic supply obligation equivalent to 20% of their export volumes, with the obligation able to be calibrated downwards according to domestic energy-security requirements. The scheme is intended to commence on 1 July 2027, with domestic supply obligations expected to take effect from 1 January 2028. The proposed framework seeks to strengthen domestic gas availability while maintaining Australia's international trade commitments (Australian Government, 2026).

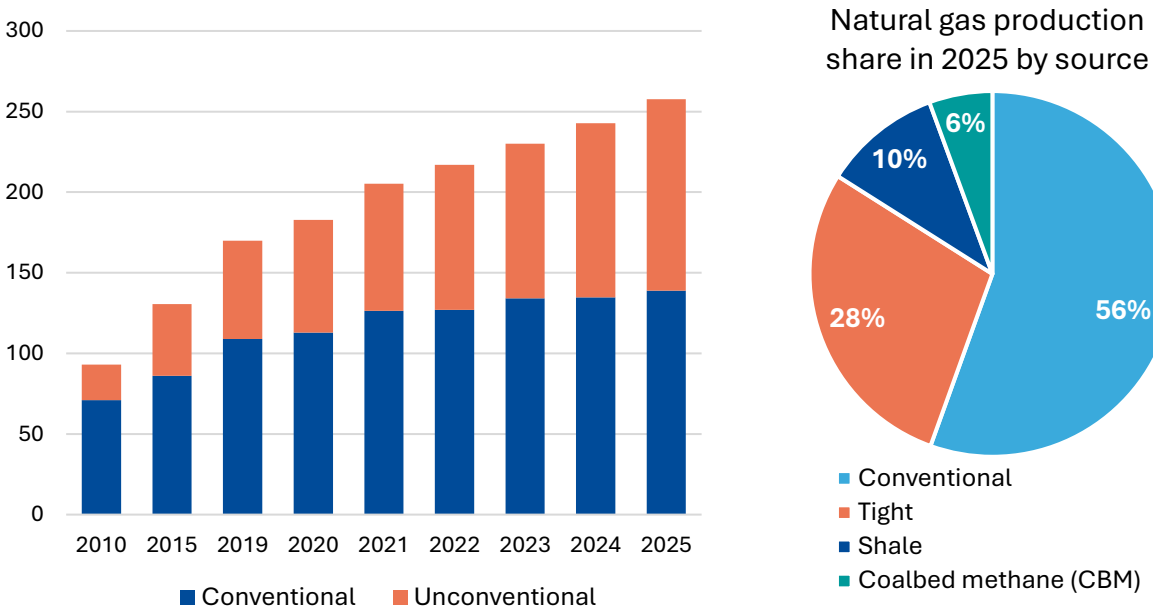
The proposed framework has generated considerable discussion among industry participants. Australian Energy Producers supports the principle of a well-designed, prospective domestic gas reservation scheme linked to new supply, but has argued that its design should preserve competition, avoid crowding out domestic-focused producers and maintain incentives for investment in future gas supply. More broadly, the industry has emphasised that maintaining adequate gas supply for both domestic consumers and LNG exports over the longer term requires continued investment in new gas resources and supporting infrastructure, rather than relying solely on the reallocation of existing production (Australian Energy Producers, 2026)

Australia's experience illustrates that domestic gas security and LNG exports are not necessarily competing objectives. Rather, both depend on maintaining sufficient investment in upstream gas production to replace declining output from mature fields while providing reliable supply to domestic consumers and international markets. As APEC economies continue to develop their natural gas sectors under different market conditions and policy frameworks, Australia's experience highlights the importance of considering how investment incentives, domestic energy security, and export objectives interact over the long term.

China

Following a strong 6.5% increase in 2024, which brought total output to roughly 245 bcm, China's domestic natural gas production rose by a further 6.1% in 2025 to reach 260 bcm (Figure 2.4). This multi-year expansion reflects the continued prioritisation of domestic gas supply to strengthen energy security and reduce exposure to international price volatility. The addition of approximately 15 bcm in 2025 was underpinned by continued deployment of advanced drilling and fracturing technologies across deep tight and shale formations (IEA, 2026).

Figure 2.4 Natural gas production trends in China (bcm)



Source: APERC based on Cedigaz (2026), EGEDA (2026) and China's National Energy Administration (2026)

As part of China's continuing efforts to expand domestic production and reinforce energy security, nine new gas fields were brought online in 2025, contributing an initial combined volume of 4.5 bcm. These developments illustrate the ongoing shift in the economy's gas production mix. Conventional reservoirs remained the primary source at 56% of total production, although their share moderated even as projects such as the Dukouhe-Qilibei Phase 1 in the Sichuan Basin, with a target of 1.3 bcm per year, came online. At the same time, unconventional gas production expanded by 9.8% year-on-year to account for 44% of the total, led by tight gas at 28% of output. Within the tight gas segment, the Tongnanba project was the most significant development launched in 2025, with anticipated plateau production of 2.0 bcm per year. Shale gas comprised 11% of the mix, supported by the commissioning of the Qianfoya shale field, which contributed around 0.8 bcm per year at its plateau. CBM accounted for the remaining 6% of total gas production (NEA, 2026; GECF, 2026).

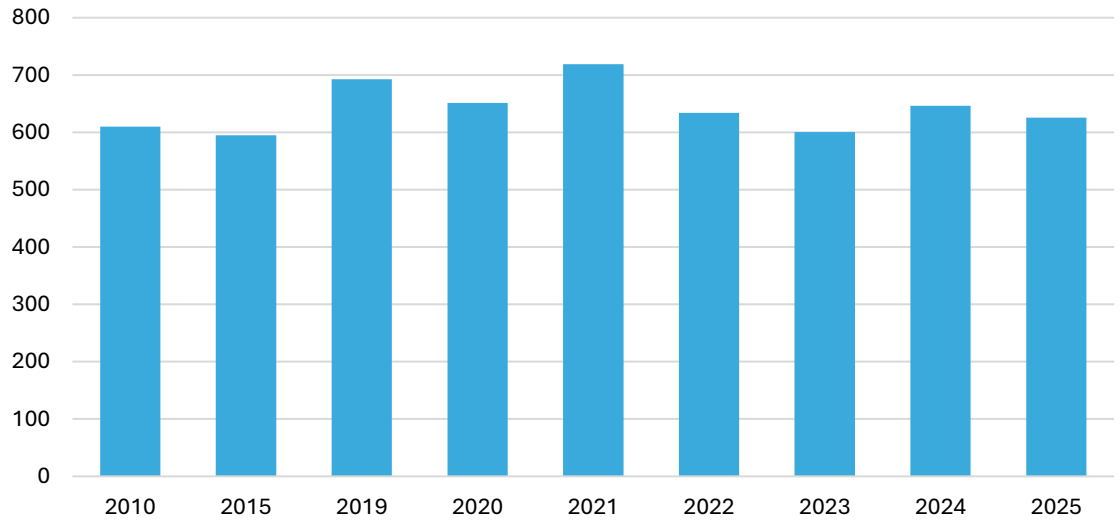
Complementing this unconventional growth in southwest China, developments during 2024–2025 also targeted ultra-deep conventional reservoirs in other key regions, alongside improvements in midstream infrastructure. In the northwestern Tarim Basin, the deployment of advanced deep-drilling technologies enabled China's operators to access conventional reserves at depths previously considered commercially challenging. These developments were accompanied by expansions in underground gas storage working capacity and the completion of the China-Russia East pipeline corridor, strengthening gas supply to demand centres along the eastern seaboard (IGU, 2025).

Russia

Following a 7.5% rebound in 2024 that brought total output to roughly 645 bcm, Russian natural gas production declined by 3.1% in 2025 to around 625 bcm (Figure 2.5). The 2024 recovery was supported by stronger domestic gas demand, particularly from gas-intensive industries and fertiliser production. In 2025, this trend reversed, with lower domestic gas demand and reduced

pipeline exports contributing to the decline in gas production. The expiry of the Ukraine gas transit agreement at the beginning of 2025 reduced pipeline exports to Europe. At the same time, expanding deliveries to China via the Power of Siberia 1 pipeline continued to support the strategic pivot of Russian gas exports towards Asian markets.

Figure 2.5 Natural gas production trends in Russia (bcm)



Source: APERC based on Cedigaz (2026) and EGEDA (2026)

The underlying resource base remains heavily concentrated in the Yamal-Nenets Autonomous Area of Western Siberia, which accounts for approximately 80% of total production (Novatek, 2026). Large-scale conventional fields, including Bovanenkovo and Zapolyarnoye, continue to play a central role in meeting domestic demand and export commitments. To sustain these operational volumes, infrastructure developments focus on connecting newer assets, such as the Kharasaveyskoye field on the Yamal Peninsula, to the main transmission network to offset natural output declines across mature reservoirs (Interfax, 2026).

Midstream capacity adjustments have been a key factor in balancing changing gas flows, particularly through the ramp-up of gas deliveries via the Power of Siberia 1 pipeline. Deliveries to China increased by nearly 25% from 31 bcm in 2024 to 38.8 bcm in 2025 (exceeding its contractual design capacity of 38 bcm), reinforcing its role as a reliable alternative route for transcontinental volumes (Interfax, 2026). Additionally, regional pipeline trade expanded within Central Asia, with gas transit from Russia to Uzbekistan via Kazakhstan increasing compared to the previous year to optimize regional grid integration (Interfax, 2025).

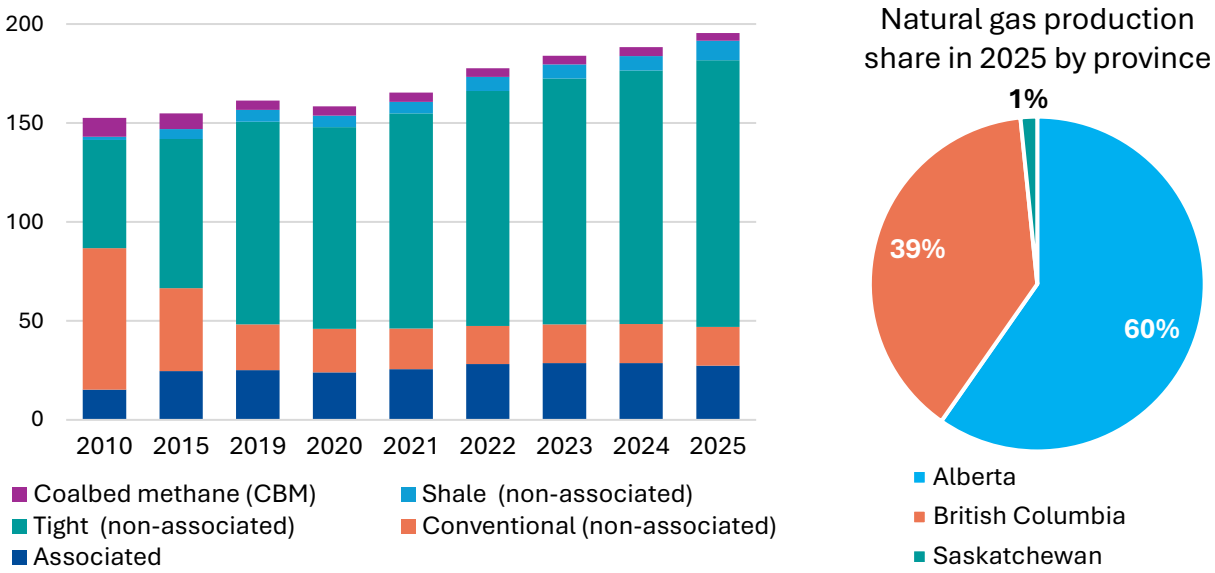
Looking ahead, the expansion of pipeline export infrastructure to China will further support growth in Russia's natural gas production. In September 2025, a legally binding memorandum was signed for the Power of Siberia 2 pipeline project, which could enable gas exports of up to 50 bcm per year from Russia via Mongolia. In addition, Gazprom and CNPC reached agreements to increase gas supplies through the Power of Siberia 1 pipeline from 38 to 44 bcm per year and to expand the planned capacity of the Far Eastern route from 10 to 12 bcm per year. Deliveries through the latter are expected to commence in 2027 (Interfax, 2026; Enerdata, 2025). Together, these developments point toward the establishment of a 106 bcm per year supply corridor.

APEC North America

North America was the leading contributor to APEC natural gas production growth in 2025, with regional output increasing by 3.9% to around 1,330 bcm, an addition of about 50 bcm, led by the United States. Rebounding from a slight decline in 2024, U.S. gas production returned to its long-term growth trajectory, rising by 4.2% to almost 1,115 bcm in 2025.

Canada followed the broader North American upward trend, building on growth in 2024, when production increased by 2.7% to a new high of roughly 190 bcm. This momentum continued in 2025, with a further 2.6% increase, bringing total production to 195 bcm (Figure 2.6). This steady growth reflected high drilling activity in liquids-rich formations. The start-up of LNG Canada, the first major LNG export facility on Canada's west coast, also created a new outlet for western Canadian gas, laying the structural foundation to feed liquefaction operations in the coming years (CER, 2026).

Figure 2.6 Natural gas production trends in Canada (bcm)



Source: APERC based on Cedigaz (2026), EGEDA (2026), and Canada Energy Regulator (2026)

The expansion of Canadian gas production has focused on underground rock formations containing valuable natural gas liquids, which were a major source of growth in 2025. In 2024, tight gas extraction remained the main source of domestic production, accounting for 68%, followed by associated gas from oil drilling at 15%, and conventional at 11%. Shale gas and coalbed methane (CBM) reservoirs contributed the remaining 4% and 2%, respectively. This production mix shifted slightly in 2025, with tight gas rising to 69%, followed by associated gas at 14%, conventional fields at 10%, shale gas at 5%, and CBM holdings at 2% (CER, 2025). This shift was led by efficient drilling activities in the Montney Formation across British Columbia and Alberta, allowing operators to increase output despite low North American benchmark prices.

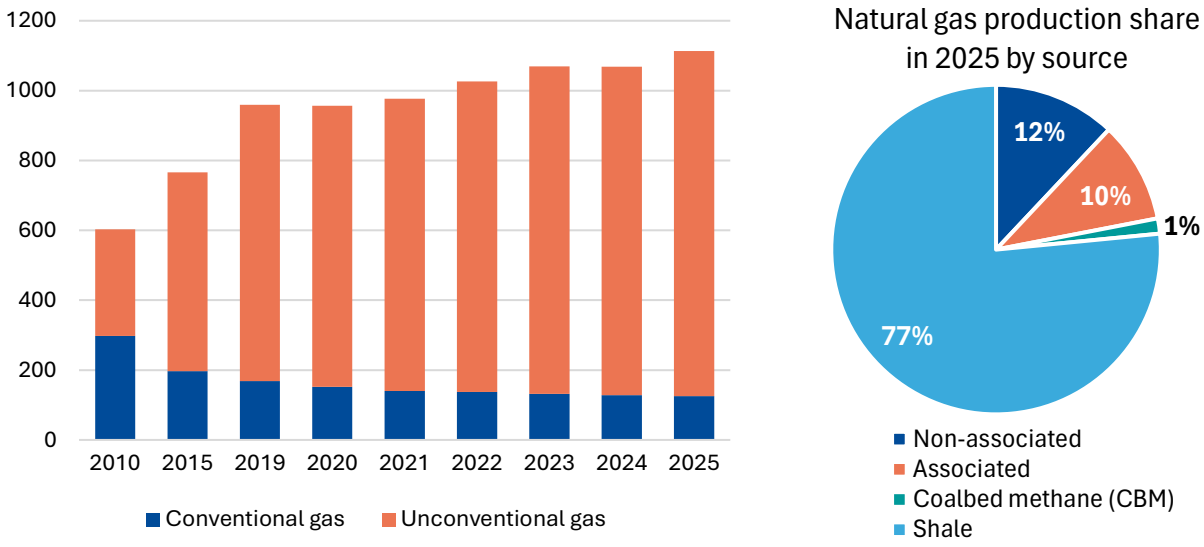
Pipeline infrastructure projects facilitated the delivery of these rising volumes to market. The start-up of LNG Canada provided a direct route for Canadian gas to Asian markets, diversifying the historical dependence on selling gas exclusively to the United States. Regional pipeline expansions also enabled producers to transport gas to both domestic industrial centres and coastal export facilities. On environmental performance, Canada finalised enhanced regulations

to tighten leak inspections and reduce facility venting across upstream operations, aiming to cut oil and gas methane emissions by 72% by 2030 (ECCC, 2026).

The **United States** remained the leading natural gas producer in both North America and APEC. Following a marginal, price-driven decline of 0.8 bcm in 2024, which left total output at roughly 1,070 bcm, gas production increased by 4.2% in 2025 to a new record of almost 1,115 bcm (Figure 2.7), an increase of approximately 45 bcm from the previous year.

Lower Henry Hub benchmark prices prompted drilling operators to decrease production in response to compressed margins, which, combined with pipeline capacity constraints, caused a temporary output plateau in 2024. However, market conditions changed sharply in 2025, leading to a rebound. This was primarily driven by the expansion of liquefaction capacity and the commissioning of key cross-basin pipelines which resolved prior midstream bottlenecks by connecting producing basins to coastal export hubs. Additionally, rising domestic gas demand further supported this production growth (EIA, 2026; IEA, 2026).

Figure 2.7 Natural gas production trends in the United States (bcm)



Source: APERC based on Cedigaz (2026), EGEDA (2026), and EIA (2026)

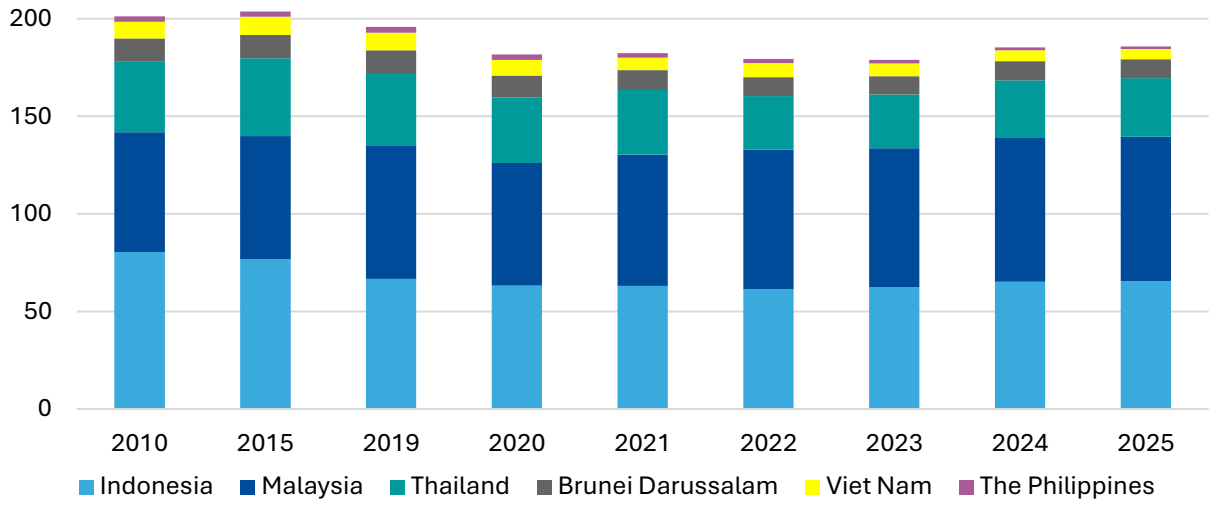
The U.S. gas production profile continues to be dominated by unconventional resources. In 2024, conventional gas production fell by 2.9%, while unconventional production rose by 0.3%, accounting for 88% of total domestic output. This trend continued in 2025, with conventional gas declining by a further 2.4%, while unconventional production expanded by 5.1% to account for 89% of total U.S. gas production. Growth in unconventional production was supported by associated gas from active tight oil plays, which helped offset declining output from mature conventional fields (EIA, 2026).

Geographically, gas production remains concentrated in the Appalachian Basin, the Permian Basin, and the Haynesville play. The Marcellus Formation within the Appalachian Basin remains the leading producing region, contributing 31% of total production (EIA, 2026). Growth was highly sustained across the Permian Basin, where upstream operations were supported by associated gas from active oil drilling. Meanwhile, the Haynesville play maintained its strategic importance due to its immediate proximity to expanding LNG export infrastructure along the Gulf Coast.

APEC Southeast Asia

Natural gas production across Southeast Asian economies shifted from strong subregional growth of 3.6% in 2024 to broadly stable output in 2025, when aggregate production increased by just 0.2% to approximately 185 bcm (Figure 2.8). This regional plateau masked diverse trends, with production recoveries and higher processing efficiency in major exporting economies being offset by natural reservoir depletion and technical extraction challenges in legacy offshore blocks. Overall, APEC Southeast Asia appears to be entering a transition phase, as incremental production from newly commissioned gas facilities is balanced by accelerating depletion profiles within mature regional fields (ACE, 2026; Cedigaz, 2025).

Figure 2.8 Natural gas production trends in APEC Southeast Asia (bcm)



Source: APERC based on Cedigaz (2026) and EGEDA (2026)

Within the subregion, gas production trends varied considerably across economies. Following a 4.3% increase in 2024, **Indonesia's** gas production rose by a further 0.6% in 2025 to 65.5 bcm, supported by improved field management across offshore blocks and growing domestic industrial gas demand (IEA, 2026; Cedigaz, 2026). **Malaysia's** production increased by 3.5% in 2024 and by a further 0.4% in 2025, supported by high processing efficiency across its coastal liquefaction infrastructure. Malaysia's production reached 74 bcm, maintaining its position as the largest gas producer in the subregion.

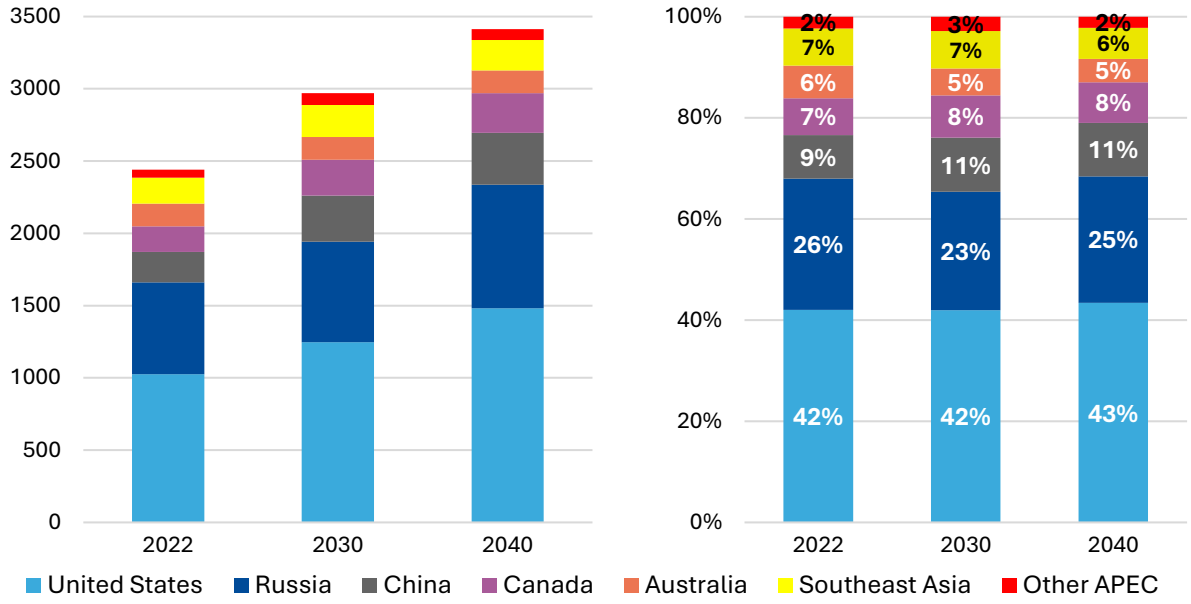
Similarly, **Thailand's** gas production rose by 7.5% in 2024 and by a further 1.7% in 2025 to 30 bcm, supported by a recovery in production from domestic fields, thereby reducing reliance on international spot LNG shipments (IEA, 2026; Cedigaz, 2026).

Other producers faced operational constraints and declining output from mature fields. **Brunei Darussalam's** gas production grew by 6.6% in 2024 but declined by 2.7% in 2025 to 9.5 bcm, reflecting maintenance-related constraints at mature offshore facilities. In **Viet Nam**, following a 15% decline in 2024, gas production fell by a further 5.6% in 2025 to 5.2 bcm due to natural declines from mature fields and technical production complexities (ACE, 2026; Cedigaz, 2026). Gas production in **the Philippines** also declined in both years, falling by 21% in 2024 and by a further 10% in 2025 to 1.3 bcm, largely due to continued reservoir depletion at its primary legacy offshore field (EMA, 2025).

2.2 APEC natural gas production outlook

According to the *APEC Energy Demand and Supply Outlook, 9th Edition*, regional natural gas production is projected to expand by approximately 40% between 2022 and 2040, as shown in Figure 2.9. This growth highlights the continued importance of regional gas producers in meeting demand both within and outside APEC, though production growth is increasingly concentrated among a few key suppliers. While absolute production is projected to increase across several economies in the region, the shifting shares of total APEC output reveal a consolidation of supply among the largest producers.

Figure 2.9 APEC natural gas production outlook (bcm) and shares in regional gas production (%)



Source: APEC Energy Demand and Supply Outlook, 2025

In **Australia**, natural gas production is projected to increase moderately over the outlook horizon. Future output will depend on balancing international supply commitments with domestic infrastructure requirements and field life-extension strategies, while maintaining commercial conditions that can attract the capital needed to manage mature-field declines.

China is projected to record the fastest production growth among major producers, with output projected to increase by roughly 70% through 2040. Consequently, China's share of regional production is expected to rise from 9% to 11%. This growth reflects continued efforts to strengthen energy security through the development of unconventional resources, specifically shale gas and coalbed methane. China has accelerated the deployment of domestic hydraulic fracturing and horizontal drilling technologies to tap complex reservoirs in basins such as the Sichuan and Ordos basins. These efforts aim to overcome challenging geological conditions, including greater burial depths and tectonic complexity, and reduce import dependency. The government has supported these efforts through fiscal incentives and by encouraging state-owned enterprises to prioritise domestic exploration over external acquisitions.

Russia's production is expected to grow broadly in line with the regional average, allowing it to maintain a share of roughly one-quarter of total APEC output. This growth is expected to be accompanied by the continued reorientation of Russian gas flows towards Asian markets,

supported by the development of major transmission corridors like the Power of Siberia 2 pipeline and the scaling of Arctic LNG projects to connect Siberian reserves with high-growth gas demand centres.

In **APEC North America**, the **United States** is expected to maintain its leading position, with production projected to grow by approximately 44%. This expansion allows the United States to increase its relative share of total APEC production from 42% to 43% by 2040. Growth is supported by continued investment in unconventional resources and the expansion of infrastructure needed to meet both domestic demand and export requirements. Midstream capacity expansion in the Gulf Coast and Permian Basin will remain essential to move gas from wellheads to domestic industrial hubs and export facilities.

Canada also shows a robust path, with production projected to increase in line with the APEC average, maintaining a consistent 8% share of total regional output over the forecast period. This outlook reflects continued gas demand from power generation, oil sands extraction and processing, and petrochemical production, alongside the gradual expansion of LNG export capacity supported by coastal pipeline infrastructure.

Meanwhile, **APEC Southeast Asia** is projected to moderately increase production levels, though the realisation of these volumes will depend on deploying advanced technology and the availability of capital. Projected growth in economies such as Indonesia, Malaysia, the Philippines, Thailand, and Viet Nam is increasingly associated with the development of more technically challenging and costly resources. As subregional production shifts away from more accessible shallow-water fields, a greater share of future development is expected to come from deepwater and high-CO_2 reservoirs.

This transition introduces higher capital intensity and significant technical complexity, requiring advanced extraction methods and carbon management strategies to keep projects viable. Specifically, the integration of CCS has become a technical necessity for new developments in the region. Without the ability to mitigate the high carbon content found in many remaining offshore clusters, these resources risk becoming stranded in an increasingly carbon-conscious global market.

Beyond the technical challenges of extraction, maintaining production will also require supportive regulatory and commercial conditions to attract investment. For many Southeast Asian economies, attention is increasingly shifting towards life-extension of mature fields and exploration of frontier blocks. This requires stable fiscal terms and streamlined permitting processes that can compete with other global supply regions for investment. In economies such as the Philippines and Viet Nam, the development of new supply is also contingent on the expansion of domestic midstream infrastructure to connect remote offshore gas resources with industrial centres. Consequently, future production in Southeast Asia will depend not only on the availability of gas resources, but also on the capital, technology, and infrastructure required to bring increasingly challenging resources to market.

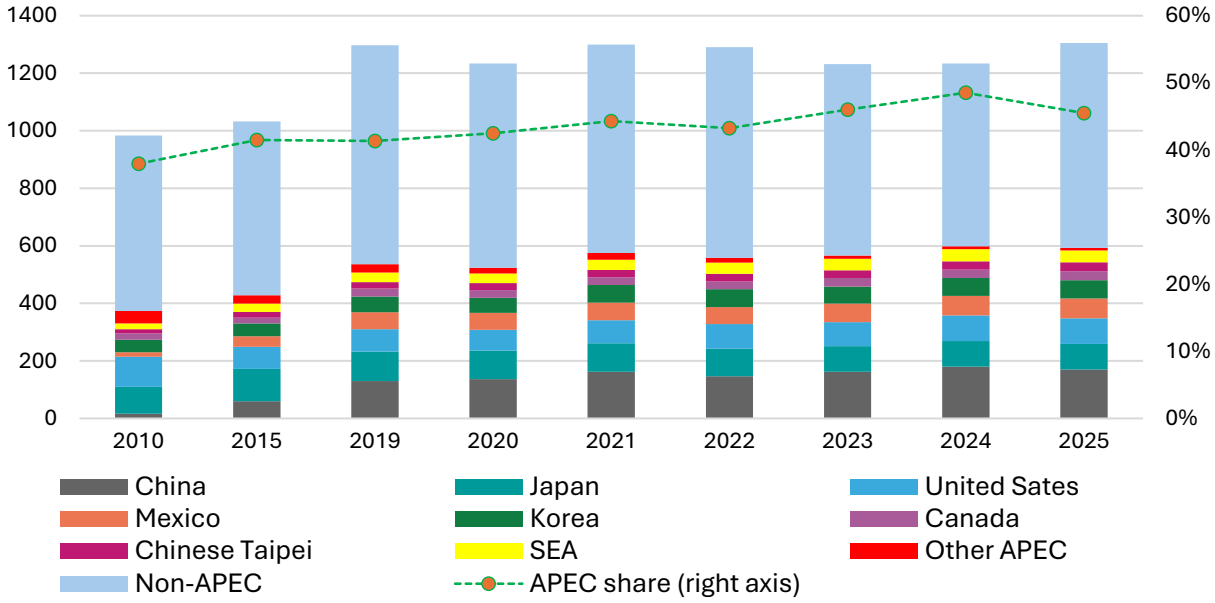
Chapter 3 Natural gas trade

3.1 Recent trends in global and APEC natural gas imports

Global natural gas imports expanded in 2024, driven by a recovery in industrial procurement, the commissioning of new import terminals, and expanded pipeline interconnections. Total international gas imports reached 1,235 bcm in 2024, representing an increase of 5 bcm compared to 2023. This upward trajectory was concentrated in the APEC region, which accounted for 48% of global gas imports, totaling around 600 bcm. This regional concentration of gas imports reflected trade integration among APEC member economies alongside rising gas use across industries and power utilities.

Moving into 2025, international gas imports rose by 5.7% to reach 1,305 bcm, supported by higher gas intake across several large importing markets outside APEC. Within this context, the APEC region maintained its strong position in global trade, although its share declined to 45% of total global gas imports. This occurred as total APEC imports adjusted down from 600 bcm in 2024 to 595 bcm in 2025, driven mainly by a decrease in gas imports by China. This decline in APEC imports coincided with strong growth in European LNG imports, which contributed to higher total import volumes outside the APEC region.

Figure 3.1 Natural gas imports trends in APEC and non-APEC (bcm)



Source: APERC based on Cedigaz (2026) and EGEDA (2026)

Outside APEC, natural gas imports displayed varying regional patterns during 2024–2025, driven by changes in pipeline and LNG supply arrangements, differing sensitivities to spot market prices, and evolving domestic gas balances.

Europe saw the most significant changes in gas procurement, with regional imports falling by 8% in 2024 to 460 bcm, before expanding by 14% to reach 525 bcm in 2025. The initial 2024 contraction reflected high underground storage inventories carried over from an unseasonably mild winter, which temporarily reduced procurement needs.

The 2025 European rebound was driven by lower winter temperatures and higher gas demand in the power sector. Economies in Europe increased pipeline imports from Norway, Algeria, and Azerbaijan to offset the expiry of legacy pipeline transit contracts. This upward trajectory was supported by a 28% increase in LNG imports to roughly 170 bcm. This growth reflected elevated European spot prices, which attracted flexible Atlantic Basin LNG cargoes, particularly during the late-winter price peak in 2025.

In South Asia, non-APEC markets displayed high sensitivity to gas prices, with import volumes responding to global spot price movements. India's gas imports grew by 21% to reach 35.4 bcm in 2024, as lower international spot prices supported fuel switching towards gas in the industrial sector and helped offset stagnant domestic gas production.

A tighter global LNG market during the first half of 2025 drove international spot prices above 2024 averages, prompting a 3% decrease in India's gas imports to 34 bcm and leading to gas allocation changes and fuel-switching to alternative sources. Pakistan mirrored this price-elastic behaviour, recording a procurement increase to 10.5 bcm in 2024 before a 14% decrease to 9 bcm in 2025, responding to higher spot prices during the first half of the year.

In contrast to these developments, Bangladesh continued to increase its gas imports, reaching almost 10 bcm by 2025 to meet growing demand in the manufacturing and fertiliser sectors, as domestic gas production continued to decline sharply (Cedigaz, 2026; IEA, 2026).

In Africa, gas procurement trends were largely shaped by developments in Egypt, with total regional imports rising from roughly 24 bcm in 2024 to 32 bcm in 2025. Egypt's gas import rose to 13.5 bcm in 2024 and increased further to 21 bcm in 2025. This increase in imports was driven by natural depletion and technical constraints at mature offshore fields. Meeting this shortfall required deploying floating storage and regasification units (FSRUs) to support gas supply during periods of high summer electricity demand.

In the Middle East, total imports hovered steadily at nearly 42 bcm over 2024 and 2025, with Kuwait and the UAE being the key importers. In Kuwait, where LNG comprises the bulk of gas imports, inflows stabilized at 9.1 bcm by 2025. This steady procurement pattern was driven by a long-term domestic policy to displace oil products and crude oil burning in local power stations with gas infrastructure. UAE imports remained stable at roughly 20 bcm, supported by pipeline gas deliveries from Qatar (Cedigaz, 2026).

Non-APEC Central and South America registered a marginal decrease in gas imports to 20 bcm in 2024, before contracting by 15% to roughly 17 bcm in 2025. This regional decline was led by Argentina, where gas imports dropped to 2.4 bcm in 2024 and fell further to 1.4 bcm in 2025. This reduction marked an important shift, as the ramp-up of domestic shale production from the Vaca Muerta basin reduced Argentina's long-standing reliance on pipeline gas imports from Bolivia.

Brazil's gas imports decreased from 8 bcm in 2024 to 7 bcm in 2025. This level of imports reflected the fluctuation of domestic hydro power availability, which necessitated gas-fired backup generation to stabilise the electricity grid.

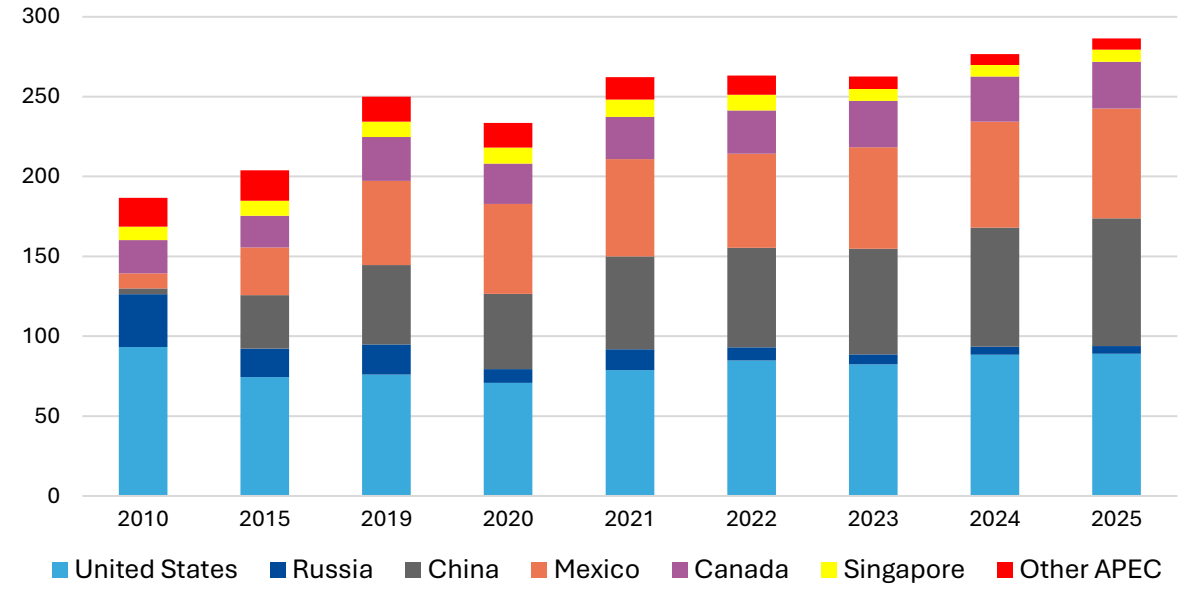
3.1.1 Pipeline gas imports in APEC

Pipeline natural gas imports into APEC economies grew by 3.8% in 2024 to reach roughly 275 bcm, reflecting a ramp-up in cross-economy pipeline gas deliveries. In 2025, total APEC pipeline imports grew by a further 3.6%, adding 10 bcm of pipeline trade, as shown in Figure 3.2.

China led regional pipeline gas import growth, driven by an expansion in pipeline deliveries from Russia. Pipeline imports grew by 14% in 2024 to reach 75 bcm, and expanded by a further 6.7% in 2025 to reach 80 bcm. This growth was supported by the ramp-up of supplies via the Power of Siberia 1 pipeline toward its full contractual capacity of 38 bcm per year, alongside stable gas deliveries via the Central Asia-China network. These flows helped to meet rising gas demand in buildings and industry and supported gas-fired generation, which is increasingly utilised to provide grid flexibility as renewable generation continued to expand.

Looking ahead, pipeline imports are expected to increase in the coming years with the commissioning of the Far Eastern route, which is scheduled to begin operations in 2027 and reach 12 bcm per year. Further growth is expected from the planned expansion of Power of Siberia 1 capacity from 38 bcm to 44 bcm per year.

Figure 3.2 Pipeline gas imports in APEC (bcm)



Source: APERC based on Cedigaz (2026) and EGEDA (2026)

Cross-economy pipeline flows within the integrated **APEC North American** market shifted dynamically between 2024 and 2025. In 2024, U.S. inbound flows from Canada increased by 8.4% to reach 90 bcm, while Mexican imports from the United States grew by 4.7% to 66 bcm. Conversely, Canadian imports from the United States contracted by 3.4%, dropping to 28 bcm in 2024.

These individual trends changed course in 2025. The United States maintained its pipeline imports from Canada at 90 bcm due to stable seasonal heating and power-sector demand. Mexico expanded its gas imports from the United States by another 4.5% to reach almost 70 bcm in order to feed its industrial and power sectors. Canada reversed its previous decline, recording

a 3.6% increase in inbound U.S. gas deliveries, settling at roughly 30 bcm. This uptick was driven by higher industrial and heating demand in eastern Canadian provinces.

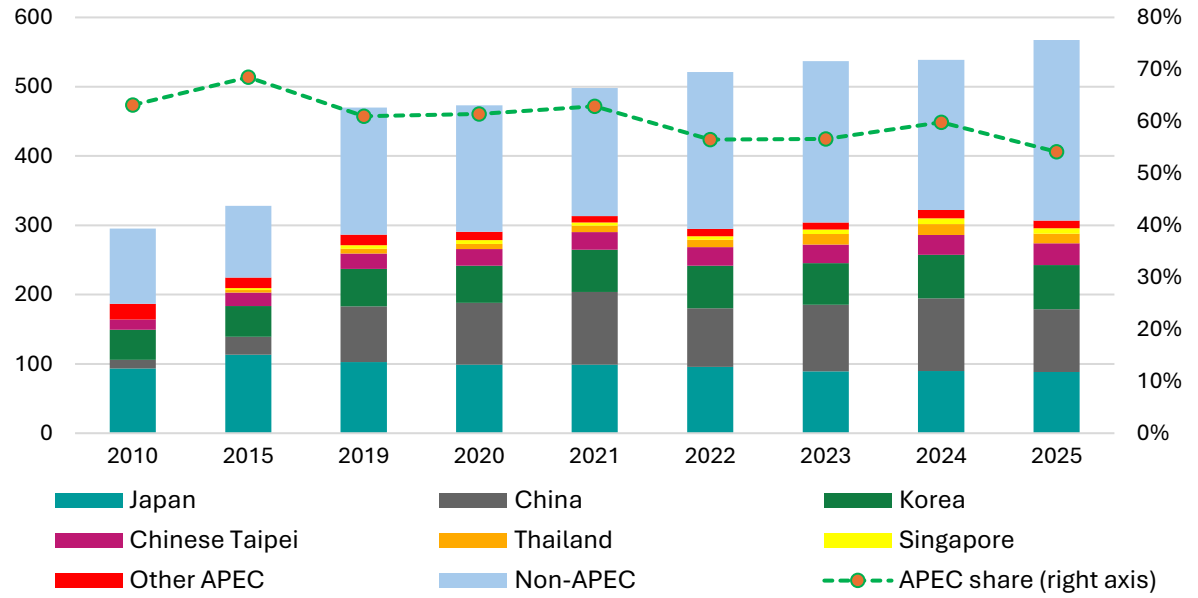
In **APEC Southeast Asia**, aggregate regional pipeline imports decreased in 2024 before partially recovering in 2025. Within this subregion, Singapore's pipeline imports fell to 7.2 bcm in 2024, but subsequently expanded by 6.9% in 2025 to reach 7.6 bcm. This recovery occurred despite a downward trend since 2022, as production optimisation and contractual delivery priorities in Indonesia enabled higher gas supplies to Singapore (ACE, 2026).

Thailand experienced a continued decline, as its pipeline gas imports fell by 21% in 2024 to 4.5 bcm and declined further to 4.4 bcm in 2025. This contraction was driven by natural reservoir depletion at supply fields in Myanmar, which reduced pipeline deliveries to Thailand's power and industrial sectors.

3.1.2 LNG imports in APEC

In 2024, LNG imports into APEC economies grew by 5% to reach 320 bcm. This trend reversed the following year as regional LNG procurement contracted by 3.1% in 2025 to about 310 bcm, as shown in Figure 3.3. This regional decline contrasted with the global LNG market, which expanded by 5.5% in 2025 to reach 570 bcm, driven by a 45 bcm increase across non-APEC economies, bringing their total LNG imports to 260 bcm. Consequently, the APEC share of global LNG imports fell from around 60% in 2024 to 54% in 2025. This change was driven primarily by a reduction in LNG imports by China.

Figure 3.3 LNG imports in APEC and non-APEC (bcm)



Source: compiled by authors based on Cedigaz (2026).

Following a 10% increase in 2024 to 105 bcm, **China's** LNG imports decreased by 14% in 2025 to reach 90 bcm. This reduction did not reflect a drop in total gas consumption, but a shift towards lower-cost supply sources, as rising domestic gas production and cheaper pipeline imports increased overall supply availability. These alternatives enabled China to reduce its procurement

of higher-priced spot LNG cargoes to meet gas demand in industry, buildings, and power generation.

In **APEC Northeast Asia**, Japan, Korea, and Chinese Taipei remained key LNG markets, collectively accounting for 60% of total APEC LNG imports in 2025. **Japan's** LNG imports remained stable at 89 bcm across both 2024 and 2025, as continued nuclear reactor restarts and rising solar power generation helped stabilise gas demand. **Korea's** LNG imports rose by 3.3% in 2024 to reach 62 bcm and increased further in 2025 to 64 bcm, driven by nuclear power curtailments and higher gas-fired power generation. **Chinese Taipei** recorded continued growth in LNG imports, rising from 29 bcm in 2024 by 10% to 32 bcm in 2025, supporting its transition away from nuclear power generation.

In **APEC Southeast Asia**, LNG import dynamics reflected the emergence of new importing economies alongside an ongoing rebalancing between LNG, pipeline supplies, and domestic gas production. **Singapore's** LNG imports increased by 24% in 2024 to reach 8.3 bcm, before contracting by 3.6% in 2025 to 8 bcm, as a partial recovery in cheaper pipeline deliveries from Indonesia reduced the need for higher-priced spot LNG cargoes. **Thailand** experienced a similar trajectory as its LNG imports reached a record high of 15.7 bcm in 2024, before falling by 11% in 2025 to 14 bcm, as a partial recovery in domestic production reduced spot LNG purchases. In **the Philippines** and **Viet Nam**, LNG imports increased in both years amid declining domestic gas production. Both economies are emerging LNG buyers, having initiated their first commercial LNG imports in 2023.

LNG remains an important source of gas supply across many Asian APEC economies, leaving import-dependent markets exposed to disruptions along major supply routes. This vulnerability became particularly evident in early 2026, when the blockade of the Strait of Hormuz significantly tightened global LNG supply, with major implications for Asian importers (Box 3.1).

Box 3.1 Strait of Hormuz blockade: The impact on gas supply in Asia

The blockade of the Strait of Hormuz, together with the March closure of LNG capacities in Qatar and the UAE, represents the largest supply shock ever to hit the global gas industry. The disruption removed around 20% of global LNG exports, equivalent to over 7 Mt per month. In 2025, nearly 90% of LNG volumes exiting the Persian Gulf were destined for Asia, making the region particularly exposed. However, the effects of this shock are felt across all LNG import markets, reflecting the increasingly globalised nature of regional gas markets.

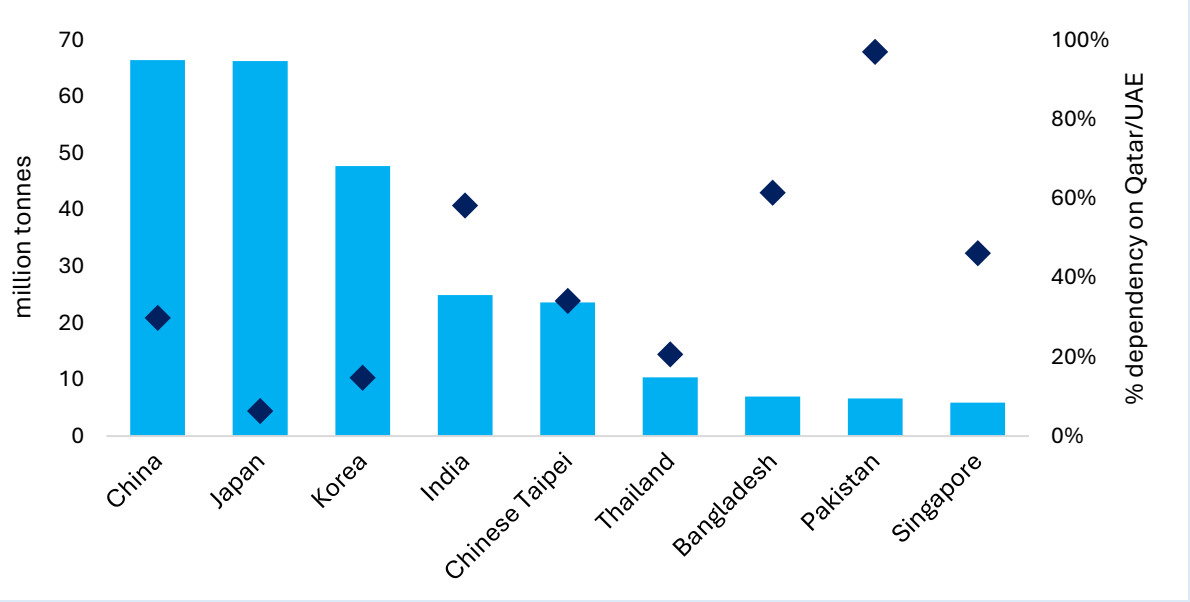
Amid escalating conflict in the Middle East, on 2 March 2026, QatarEnergy announced that it had ceased production of LNG and associated products at its Ras Laffan liquefaction facility (QatarEnergy, 2026). Two days later, on 4 March 2026, the company declared force majeure to its affected buyers (QatarEnergy, 2026). The situation deteriorated on 18-19 March 2026 when Iranian missile attacks on Qatar's Ras Laffan complex damaged two LNG liquefaction trains, removing 12.8 mtpa, around 17% of Qatar's capacity. According to QatarEnergy, it could take three to five years to repair the damaged LNG facilities (Reuters, 2026). The conflict has also delayed Qatar's 48 Mtpa expansion projects, putting significant stress on medium-term global LNG supply capacity growth.

The price response was rapid and pronounced. The European TTF and Platts JKM month-ahead contracts rose from around USD 11/MBtu in February to USD 18/MBtu and USD 21/MBtu in March, respectively, reflecting a marked tightening of supply fundamentals (IEA, 2026).

As noted above, around 90% of LNG exports from Qatar and the UAE were directed to Asian markets in 2025. The ongoing crisis therefore poses an unprecedented test of gas supply security in the region. Figure 3.4. indicates that, in absolute terms, the largest impact has been on China, India, Chinese Taipei, and Korea. In relative terms, however, the most severe impacts have fallen on India, Bangladesh, and Pakistan, which collectively imported 65% of their LNG from Qatar and the UAE in 2025, compared to 30% for China, and 15% for Japan, Korea, Chinese Taipei, and Singapore combined.

Following the sharp supply shock and given the high dependence of certain importing economies on LNG from the Gulf, a range of measures has been progressively implemented across the region's key LNG import economies, including revisions to domestic gas allocations, additional spot purchases, the use of LNG in storage tanks and underground gas inventories, as well as fuel-switching policies.

Figure 3.4 LNG demand in selected Asian economies and share of Qatari and UAE supply, 2025



Source: APERC based on data from Kpler (2026) and OIES (2026)

In particular, **India** is among the Asian economies most exposed to the disruption, as LNG supplied via the Strait of Hormuz accounted for nearly 30% of its primary gas supply and almost 60% of total LNG imports in 2025. In response, India invoked the Essential Commodities Act, 1955, and introduced the Natural Gas (Supply Regulation) Order 2026 to prioritise and ration gas allocation. Piped gas supplies to households and CNG for transport have been fully maintained, while fertiliser plants received around 95% of average volumes and other industrial users around 80%. As a result, some sectors have already faced cuts of 10–30%, prompting fuel switching to alternative fuels (IEA, 2026; S&P Global, 2026).

China has remained relatively insulated from LNG supply disruptions in early 2026, despite around 30% of its LNG imports passing through the Strait of Hormuz in 2025. High domestic

inventories, strong gas production, and pipeline imports have allowed China to navigate and cushion the immediate impact on supply while dampening spot LNG purchases. Underground gas storage stood at around 16.8 bcm at the end of February, about 20% higher year-on-year, while LNG terminal inventories remain elevated, with some sources estimating levels of more than 40% above the same period last year (ICIS, 2026). As a result, since the start of the Middle Eastern conflict, Chinese firms were able to resell bigger volumes of LNG to other Asian economies as its own need for LNG plateaued (Reuters, 2026). Specifically, in March, China re-exported eight cargoes to Japan, the Philippines, Korea, and Thailand (GECF, 2026).

In **Korea**, LNG sourced from the strait accounted for around 15% of primary gas supply in 2025. Korea has taken several emergency measures to minimise LNG imports, including increasing coal-fired and nuclear generation to reduce reliance on gas-fired power (Reuters, 2026). On the nuclear side, efforts have focused on accelerating maintenance schedules, with six reactors targeted for early return to service. Two units, including Kori-2 and Shin-Wolseong Unit 1, have already resumed operations (Asia Today, 2026). In addition, the newly built Unit 3 of the Saeul nuclear plant is expected to begin operations around mid-2026, which could further reduce gas-on-power demand (World Nuclear News, 2026).

Chinese Taipei is heavily dependent on imported LNG, which has become the backbone of its power system following the phase-out of nuclear power in 2025. Although Qatar accounted for around one-third of LNG imports, diversified procurement has helped mitigate immediate risks (ICIS, 2026). On 10 March 2026, the Ministry of Economic Affairs (MOEA) noted that all 22 LNG cargoes scheduled for March-April delivery have been secured, easing short-term supply concerns (MOEA, 2026). Beyond this, Chinese Taipei has outlined a three-stage plan, including the increase of cargoes from non-Middle Eastern suppliers such as the United States and Australia, coordination of mutual supply support with regional buyers including Japan and Korea, and additional spot purchases (MOEA, 2026).

Although demand-side and fuel-switching measures reduced the immediate impact of the Strait of Hormuz blockade on some Asian economies, these measures were not able to fully compensate for the loss of LNG from Qatar and the UAE. In this context, higher LNG exports from the United States, Canada, and other suppliers helped to offset the decline, supporting a gradual rebalancing of the global LNG market over the following months.

Nevertheless, the crisis highlighted the structural exposure of Asian gas markets to major supply disruptions. More fundamentally, the crisis underscored how heavily global gas supply stability had come to depend on the Strait of Hormuz, with the risks of its closure significantly underestimated. It therefore serves as a reminder that gas security in Asia depends not only on access to LNG, but also on the resilience, flexibility, and diversification of the broader energy system.

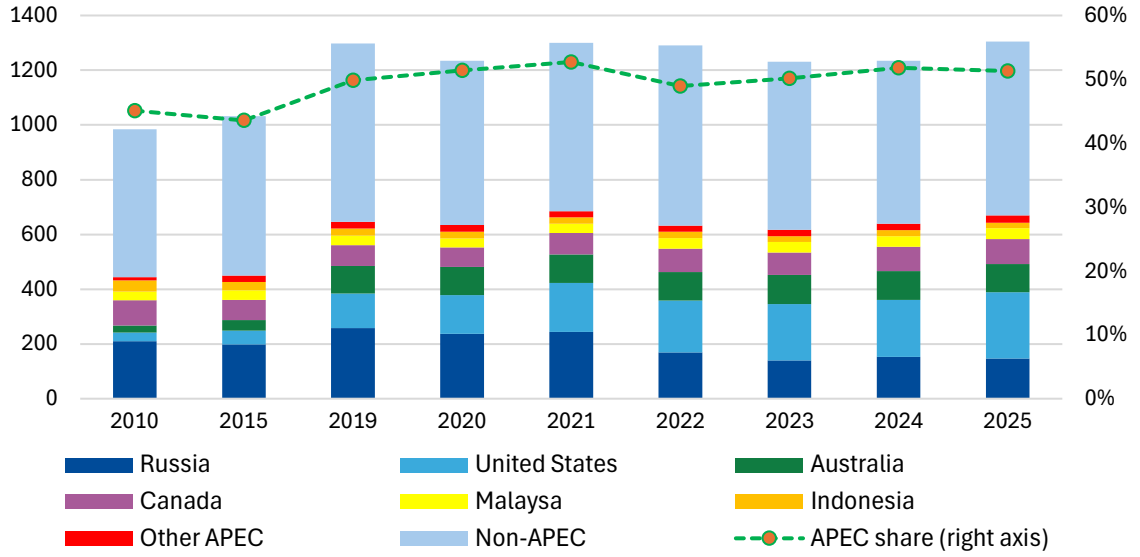
3.2 Recent trends in global and APEC natural gas exports

Global natural gas exports expanded moderately in 2024, before increasing by 5.7% in 2025 to 1,305 bcm. This growth trajectory was supported by APEC economies, which increased their aggregate gas exports from 640 bcm in 2024 to 670 bcm in 2025. APEC economies therefore maintained a collective share of 51% of total gas exports over the two-year period. This upward

trend reflected a continuous build-out of export-oriented infrastructure linking gas fields to international markets.

Moving into 2025, natural gas exports within APEC became increasingly concentrated in North America, where expansions in liquefaction capacity in the United States became the main driver of gas export growth in the region and globally.

Figure 3.5 Natural gas exports in APEC and non-APEC (bcm)



Source: APERC analysis based on CEDIGAZ (2026).

Outside the APEC region, natural gas exports during 2024 and 2025 were characterized by varying operational profiles and planned maintenance cycles across the primary exporting economies.

In Europe, non-APEC natural gas exports were led by Norway, where natural gas exports increased by 8% in 2024 to reach 124 bcm, before declining to 120 bcm in 2025. This decline in gas exports reflected production disruptions due to planned maintenance at producing fields and processing and receiving facilities upgrades, which constrained production despite high gas import demand from neighbouring continental markets.

The United Kingdom also recorded a reduction in its gas exports during 2024, followed by a partial recovery. Natural gas exports fell by 33% in 2024 to 10.5 bcm, before rebounding by 13% to reach 11.9 bcm in 2025 as upstream optimisation partially balanced ongoing mature field depletion.

In the Middle East, total regional gas exports rose by 2.9% in 2024 to 177 bcm and maintained a similar level of exports in 2025. Qatar remained the primary source of exports in the region, with its natural gas exports registering roughly 125 bcm in 2024 and increasing by 3.2% in 2025 to reach 129 bcm. This consistent export volume was supported by high utilisation rates at its liquefaction facilities.

Oman also contributed to the regional supply baseline. Exports increased by 3.3% in 2024 to reach 15.5 bcm, before settling at roughly 15 bcm in 2025 as production stabilised following the completion of infrastructure projects that helped offset declines at mature fields.

In Africa, total gas exports contracted by 3.9% in 2024 to 92 bcm, and grew marginally in 2025 to maintain a similar level of exports. While this flat regional performance was heavily influenced by Algeria, whose gas exports rose initially to 50 bcm in 2024 but subsequently contracted by 8% to reach 46 bcm in 2025 due to mature field declines and rising gas demand for power generation, the reduction was counterbalanced by sub-Saharan production gains.

Improved feed gas availability at Nigeria LNG, steady optimisation of liquefaction operations at Angola LNG, and the commercial ramp-up of the Coral Sul floating facility in Mozambique provided additional gas exports that offset the contraction observed in Algeria.

In Eurasia, gas exports were supported by Azerbaijan, where exports grew by 8% in 2024 to 27 bcm. Moving into 2025, exports declined by 3.7% to 26 bcm. This downward movement was driven by planned upstream maintenance shutdowns at major offshore production assets, which temporarily reduced gas deliveries into the Southern Gas Corridor.

In Turkmenistan, gas exports rose by 2.2% in 2024 to 46 bcm, before declining by 8.7% in 2025 to 42 bcm. This latter contraction was driven by production variations at mature gas fields and scheduled infrastructure maintenance along international pipeline networks, which restricted Turkmenistan's ability to maintain its full delivery commitments to international markets (Cedigaz, 2026).

Non-APEC Central and South America gas exports contracted by 5% in 2024 to settle at 19 bcm, before further declining by 5.3% in 2025 to roughly 18 bcm. Trinidad and Tobago remained the leading regional gas exporter due to its LNG shipments, with exports remaining stable at 10 bcm in both years.

These stable LNG volume trends stood in contrast to the region's pipeline trade, which was defined by a divergence between expanding production in Argentina and accelerating field depletion in Bolivia. Argentina's pipeline exports reached 2.4 bcm in 2024 and rose by a further 8.3% in 2025 to 2.6 bcm, driven by the ongoing development of unconventional shale resources in the Vaca Muerta basin. In contrast to this growth, Bolivia recorded a continued decline in pipeline exports, as its pipeline deliveries fell by 24% in 2024 to 6 bcm and contracted further by 22% in 2025 to below 5 bcm due to depletion at mature fields.

Looking ahead, global gas trade growth is expected to remain constrained in 2026. In particular, LNG trade is projected to remain broadly flat in 2026 compared with 2025. Supply losses in the Middle East amid regional conflict and facility disruptions are expected to be largely offset by an increase of nearly 50 bcm from non-Gulf exporters, led primarily by the ramp-up of new liquefaction capacity in North America (IEA, 2026).

3.2.1 Pipeline gas exports in APEC

Pipeline natural gas exports from APEC economies expanded by 7.1% in 2024 to reach 300 bcm, driven by an expansion in Russian pipeline gas exports. The regional total declined marginally the following year to 298 bcm in 2025. This downward adjustment was driven by a further reduction in Russian pipeline gas deliveries to Europe, which more than offset continued growth in pipeline gas trade across North America.

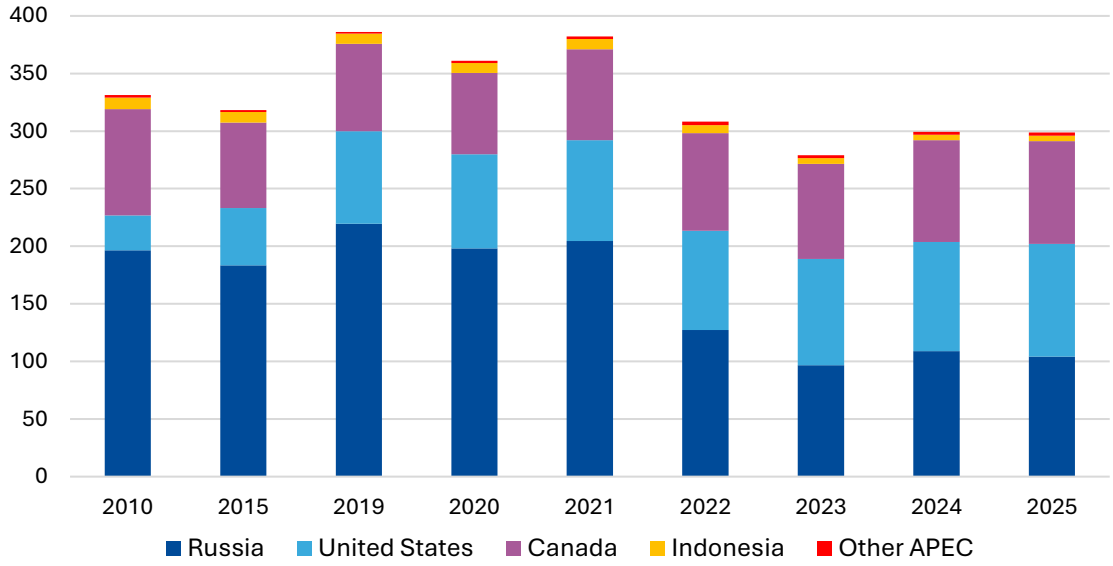
Russia led regional pipeline export adjustments, as its extensive pipeline network experienced a reallocation of trade destinations across 2024 and 2025. Russian pipeline exports expanded by

13% in 2024 to reach 110 bcm. The contractual ramp-up of the Power of Siberia I pipeline to China served as the primary physical driver for this volume expansion.

Central European buyers further supported this 2024 upward trend by maximizing contract nominations to secure pipeline gas deliveries ahead of the expiry of the Russian gas transit agreement via Ukraine.

This trend reversed in 2025, as Russian pipeline exports contracted by 4.6% to 105 bcm. This decline reflected further reductions in pipeline gas deliveries to Europe, which more than offset higher contractual volumes to China.

Figure 3.6 Pipeline gas exports in APEC (bcm)



Source: APERC analysis based on CEDIGAZ (2026).

Cross-economy pipeline exports within the integrated North American market expanded across both years. The United States led this growth, increasing its total outbound pipeline shipments by 2.7% in 2024 and by 5.2% in 2025 to reach nearly 100 bcm. This total included roughly 70 bcm sent southward to meet expanding industrial and power-sector demand in Mexico, alongside approximately 30 bcm delivered to eastern Canada.

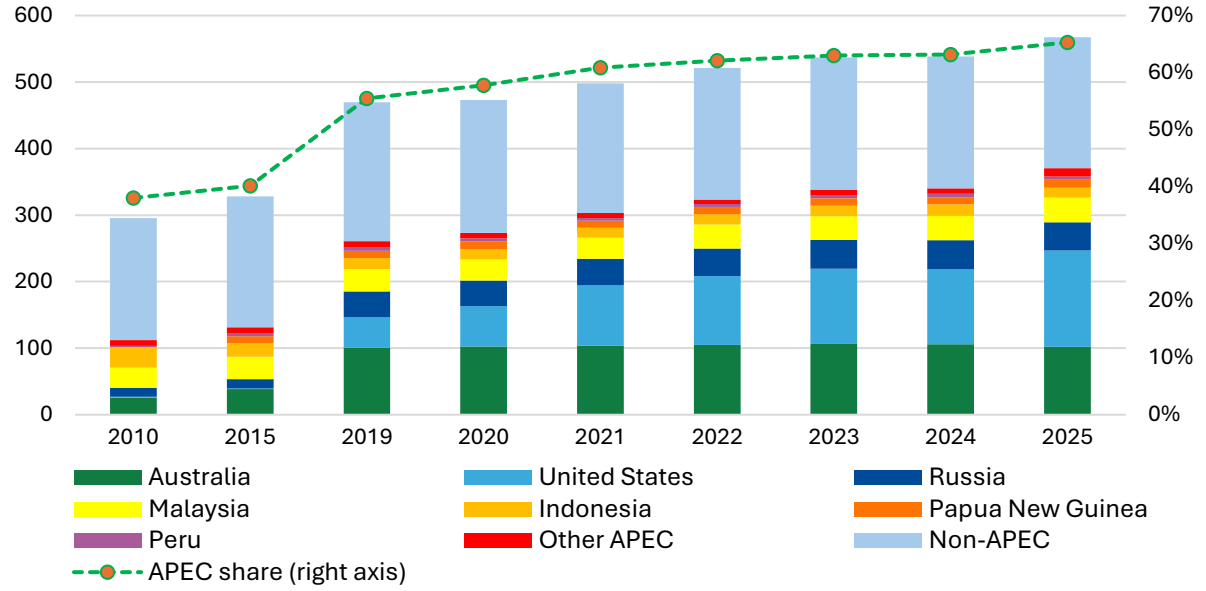
Canada's pipeline exports to the United States increased by 6.6% in 2024, followed by marginal growth in 2025 to settle at roughly 90 bcm. This volume was sustained by record natural gas production in western Canadian basins and low domestic regional prices. These factors enhanced the competitiveness of Canadian gas entering U.S. pipeline networks to fulfill utility sector storage injections.

In Southeast Asia, pipeline exports remained near historical lows across 2024 and 2025. Indonesian pipeline exports fell 7.8% in 2024 to 4.7 bcm, driven by maintenance shutdowns and production declines at mature offshore assets. These pipeline shipments partially recovered in 2025, increasing by 6.4% to reach almost 5 bcm, as optimisation of drilling schedules and improved processing efficiency supported higher gas deliveries to Singapore (ACE, 2026). Malaysia's pipeline gas exports remained stable at 2.5 bcm in 2024, before expanding by 8% in 2025 to 2.7 bcm, due to minor upstream improvements.

3.2.2 LNG exports in APEC

APEC LNG exports expanded marginally in 2024 to reach roughly 340 bcm before accelerating by 8.8% in 2025 to reach approximately 370 bcm (Figure 3.7). This regional growth outpaced non-APEC LNG exporters, allowing the APEC share of global LNG trade to increase from 63% in 2024 to 65% in 2025. This upward trajectory was driven by new liquefaction capacity in North America, which offset maintenance outages and domestic gas supply prioritisation in other LNG exporters.

Figure 3.7 LNG exports in APEC and non-APEC (bcm)



Source: APERC analysis based on CEDIGAZ (2026).

The United States led this regional expansion. Following stable performance in 2024, its LNG exports grew by 25% in 2025 to reach more than 140 bcm as newly commissioned liquefaction capacity and coastal export terminals came fully online (EIA, 2026).

Conversely, Australia recorded a 4% decrease in 2025 to roughly 102 bcm, due to facility maintenance at major liquefaction complexes and measures prioritising domestic gas supply in the East Coast market (AEMO, 2026).

Russia recorded a 3% decline in LNG exports in 2025 to approximately 43 bcm, a volume change driven by logistical adjustments.

Peru also registered a decline, with its LNG exports decreasing by 3.7% in 2025 to roughly 5 bcm, reversing the 8.5% increase recorded in 2024, amid upstream pipeline adjustments and field maintenance.

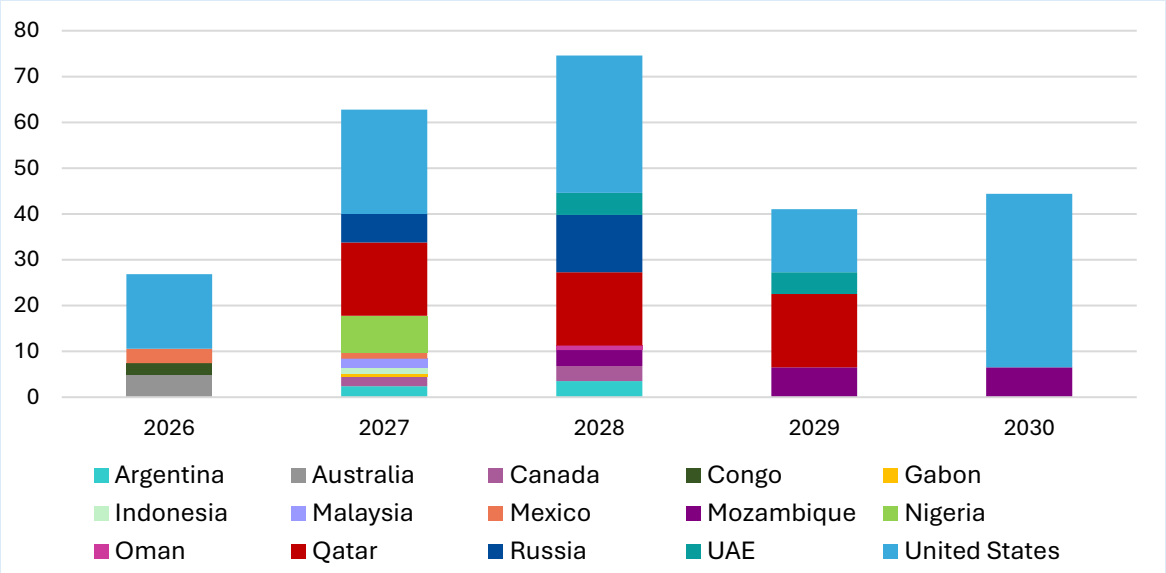
In Southeast Asia, LNG export trends diverged based on domestic supply priorities and regional supply conditions. Malaysia maintained steady growth across both years, posting a 1.3% increase in 2025 to approximately 37 bcm, due to high processing efficiency across its liquefaction assets. Conversely, Indonesia recorded a 12% contraction in 2025 to almost 15 bcm, as domestic operators prioritised domestic industrial gas supply over LNG exports (ACE, 2026).

In Oceania, Papua New Guinea recorded a 10% increase in 2025 to reach roughly 12 bcm, recovering from a previous drop in LNG exports, supported by upstream drilling efficiency gains and improved processing at its liquefaction plant (Cedigaz, 2026).

Box 3.2 Snapshot of global LNG liquefaction capacity expansion, 2026–2030

Global LNG liquefaction capacity reached approximately 548 million tonnes per annum (Mtpa) at the end of 2025 (GECF, 2026). Building on this expansion, more than 240 Mtpa of additional liquefaction capacity is expected to commence operations between 2026 and 2030 (Figure 3.8). The project pipeline indicates that the current expansion cycle will be the largest ever recorded, with an exceptionally large number of LNG projects having reached final investment decision (FID) in recent years.

Figure 3.8 Expected start-up of new global LNG liquefaction capacity, 2026–2030 (Mtpa)



Source: APERC based on GECF (2026) and updates by the U.S. EIA

The expansion is highly concentrated in a small number of exporting economies. The United States is expected to account for approximately half of the scheduled liquefaction capacity additions between 2026 and 2030, supported by a large portfolio of projects that reached FID between 2022 and 2026. Qatar represents the second-largest source of new capacity through the phased expansion of the North Field, while additional capacity is expected from Canada, Russia, Mozambique, Nigeria, the UAE, Mexico, and several emerging LNG exporters. In contrast, Australia's additions are limited to Pluto LNG Train 2, reflecting the relatively small number of additional liquefaction projects currently under construction (GECF, 2026; IEA, 2026).

The commissioning profile is also uneven. Almost 60% of the liquefaction capacity scheduled between 2026 and 2030 is expected to commence operations in 2027 and 2028, making these the peak years of the current expansion cycle. This concentration is largely due to the large number of projects that reached FID during the recent investment cycle and are expected to complete construction within a relatively narrow timeframe. Consequently, annual liquefaction capacity additions are set to vary considerably across the period rather than increase steadily.

The project schedule shown in Figure 3.8 reflects information available at the time of analysis and remains subject to change. As with previous LNG investment cycles, commissioning dates may evolve as projects progress through construction, commissioning, and regulatory processes. Additionally, ongoing geopolitical challenges may also affect the timing of some projects.

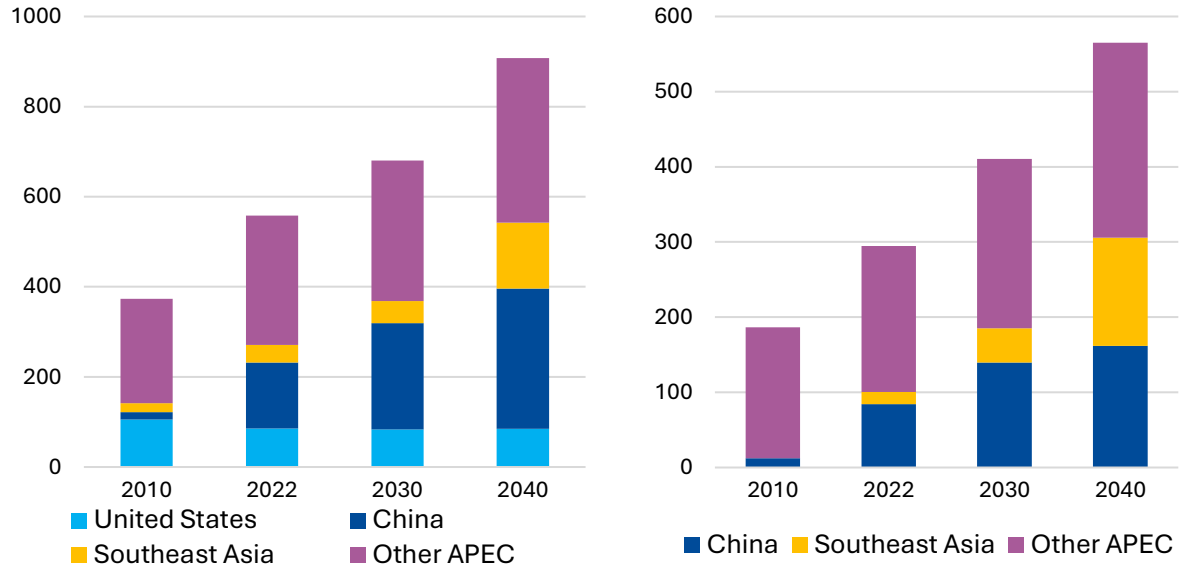
3.3 APEC natural gas imports outlook

Natural gas trade remains an important component of the APEC energy system, allowing economies with limited domestic production to meet demand while enabling resource-rich economies to supply regional markets. According to the Reference Scenario of the *APEC Energy Demand and Supply Outlook, 9th Edition,* natural gas trade continues to expand through 2040, with LNG accounting for an increasing share of cross-economy trade.

Regional natural gas imports are projected to increase by almost 65% between 2022 and 2040 (Figure 3.9), reflecting continued growth in natural gas demand across APEC economies, particularly in Asia. While domestic production is expected to expand in some economies, it is generally insufficient to keep pace with rising consumption, resulting in greater reliance on imported gas.

China accounts for a substantial share of the projected increase in regional imports, with total natural gas imports exceeding 300 bcm by 2040, supported by continued growth in natural gas demand across the industrial, power, and residential sectors.

Figure 3.9 Outlook of total gas imports (left) and LNG imports (right) in APEC economies (bcm)



Source: APEC Energy Demand and Supply Outlook, 2025.

LNG imports in APEC are projected to increase by around 92% between 2022 and 2040, outpacing the growth rate in total natural gas imports. The expansion of LNG receiving infrastructure, together with the flexibility of LNG supply, enables importing economies to diversify supply sources and meet growing demand where pipeline imports or domestic production are insufficient.

Southeast Asia emerges as the primary growth engine for regional LNG imports, as declining domestic gas production and rising electricity demand drive a major expansion in LNG import infrastructure. China continues to account for a large share of regional LNG imports throughout the outlook period, with its LNG imports increasing by around 90% between 2022 and 2040.

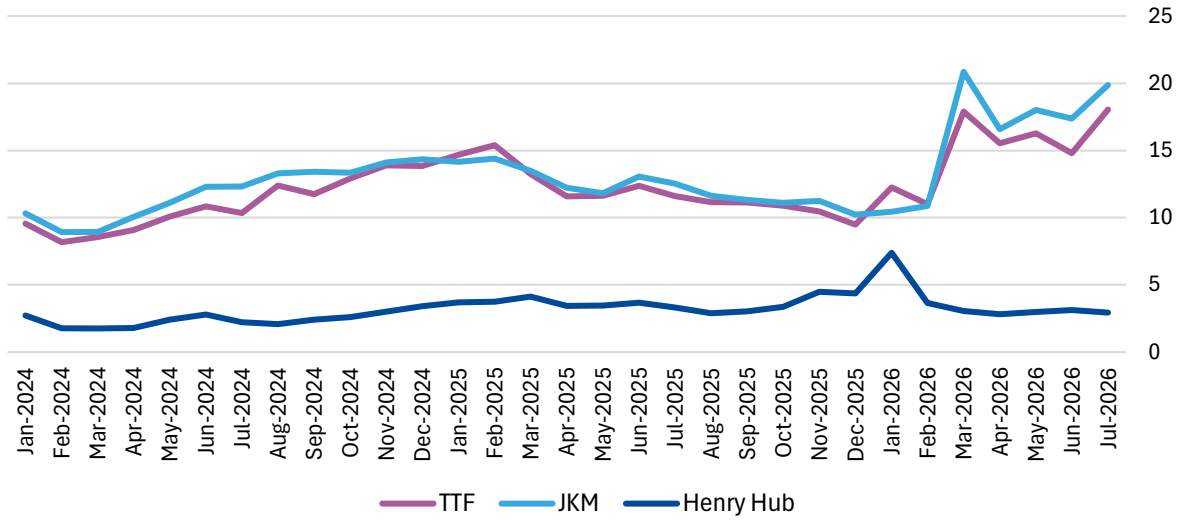
Overall, the projections indicate that LNG will play an increasingly important role in supporting the security and flexibility of natural gas supply across APEC economies.

Chapter 4 Gas Prices

Between early 2024 and mid-2026, international natural gas benchmark prices progressed through four distinct phases: market normalisation throughout 2024, renewed tightening during the winter of 2024–2025, fundamental easing during mid-to-late 2025, and resurgent volatility due to supply shocks in early-to-mid 2026. Figure 4.1 presents the monthly average front-month futures prices for Henry Hub in North America, Title Transfer Facility (TTF) in Europe, and Japan Korea Marker (JKM) in Northeast Asia over this period. Unless otherwise specified, all benchmark price figures discussed in this chapter represent monthly averages, which serve to illustrate prevailing market conditions while smoothing out short-term daily price volatility.

While each benchmark reflects distinct regional supply and demand dynamics, their similar trends, especially for TTF and JKM, demonstrate the expanding integration of global gas markets through flexible LNG trade, with direct implications for energy security across APEC member economies.

Figure 4.1 Monthly average prices of the primary global gas benchmark ($/MMBtu)



Source: APERC based on Investing.com, Argus Media, LSEG

2024: post-crisis normalization and widening North American price spread

Following the extreme volatility of the 2022–2023 energy crisis, natural gas markets continued to rebalance throughout 2024. Global natural gas demand returned to structural growth, though market fundamentals remained fragile due to narrow global supply margins, even as high European storage levels provided a temporary buffer (IEA, 2025). European TTF monthly average prices dipped from $9.56/MMBtu in January to a low of $8.18/MMBtu in February before trending upward over the remainder of the year. JKM followed a matching seasonal trajectory, with monthly averages ranging between $8.93/MMBtu and $14.34/MMBtu, maintaining a persistent premium over TTF due to strong Northeast Asian demand and intense competition for flexible LNG cargoes.

The elevated JKM premium during peak demand months had distinct operational consequences across Asian APEC economies. While major Northeast Asian importers such as Japan and Korea

cushioned the impact of spot spikes through long-term oil-indexed contracts and ongoing nuclear reactor restarts, price-sensitive developing economies in South and Southeast Asia faced severe procurement challenges. Spot prices in the $12–14/MMBtu range frequently led utility operators in these markets to curtail spot LNG purchases and temporarily shift power generation toward domestic coal and fuel oil (IEA, 2024; IEEFA, 2024).

In contrast, North American Henry Hub prices demonstrated relative stability, remaining below $3.00/MMBtu for most of 2024. Henry Hub touched a monthly low of $1.76/MMBtu in March and hovered predictably between $1.76/MMBtu and $2.81/MMBtu through October before rising slightly toward year-end. Supported by abundant domestic shale production in key basins, such as the Permian and Haynesville, Henry Hub remained largely insulated from international market swings, showing considerably less volatility than TTF or JKM. This stability provided a predictable, low-cost supply foundation that supported the competitiveness of North American LNG export.

Winter 2024–2025: regional bidding competition driven by storage and gas transit changes in Europe

International gas markets tightened again heading into the winter of 2024–2025. In January and February 2025, TTF monthly averages increased to $14.67/MMBtu and $15.38/MMBtu, while JKM reached $14.16/MMBtu and $14.40/MMBtu, respectively. This tightening reflected several converging factors, including the expiry of the Russia–Ukraine gas transit agreement on 31 December 2024, relatively limited global LNG supply growth in late 2024, and lower European storage inventories compared to early 2024 (IEA, 2025). Colder winter weather further tightened market conditions by boosting seasonal space-heating demand, forcing European buyers to compete with Asian utilities for spot LNG cargoes to meet immediate consumption needs and slow the depletion of underground storage.

The winter tightness highlighted the structural reliance of European markets on flexible LNG to replace reduced Russian pipeline supplies. European buyers maintained high spot bids to attract uncommitted cargoes away from Asia, contributing to elevated global gas prices. This cross-regional bidding competition illustrated how European regulatory requirements, such as binding gas storage filling targets, can transmit price pressure to APEC markets during periods of global supply constraint.

Mid-to-Late 2025: price easing via new North American LNG capacity expansion

Spot prices began to ease during the spring shoulder season in 2025 as seasonal space-heating demand subsided. TTF monthly averages fell to $13.24/MMBtu in March and $11.58/MMBtu in April, while JKM declined to $13.50/MMBtu and $12.22/MMBtu over the same period. High spot prices in late winter and broader economic uncertainty slowed gas demand growth in price-sensitive Asian import markets, particularly China and India, reducing competition for spot LNG cargoes and allowing regional balances to loosen (IEA, 2025).

By the second half of 2025, fundamental market conditions improved further as a new wave of global liquefaction capacity, primarily located in North America, accelerated global LNG supply growth (IEA, 2026). Between July and December 2025, TTF monthly averages stabilised between $9.48/MMBtu and $11.20/MMBtu, while JKM traded within a similar range of $10.10/MMBtu to $11.62/MMBtu.

The price spread between the two regional benchmarks remained relatively narrow, frequently ranging from $0.20 to $0.90/MMBtu. This spread compression reflected closer alignment between Atlantic and Pacific market conditions, as muted spot demand growth in Northeast Asia reduced the need for inter-basin competition for LNG cargoes. Within this environment, destination-flexible U.S. LNG played an important role in market integration. Because U.S. LNG export contracts generally lack destination restrictions, portfolio players continually redirected uncommitted spot cargoes between the Atlantic and Pacific basins to optimise netback margins, helping to align European and Asian price formation more closely.

Meanwhile, North American Henry Hub prices strengthened toward year-end, averaging $4.48/MMBtu in November and $4.36/MMBtu in December 2025. This upward movement occurred as expanding LNG export feedgas demand coincided with tighter domestic winter balances across Lower 48 production basins (EIA, 2026).

Early-to-Mid 2026: Hormuz transit disruption and summer demand surge

A major supply shock renewed international market volatility in early 2026. Following a tight winter setup where freezing weather reduced gas production and drove the U.S. benchmark Henry Hub to a monthly average of $7.39/MMBtu in January, global supply dynamics changed by the spring. While North American heating demand subsided, allowing Henry Hub to ease back toward normalized levels, international benchmarks spiked sharply by March, with TTF climbing to $17.89/MMBtu and JKM reaching $20.85/MMBtu. This sudden surge was primarily driven by physical supply disruptions following transit curtailments through the Strait of Hormuz, which affected nearly 20% of global LNG trade flows (IEA, 2026). The disruption highlighted the energy security vulnerabilities of APEC economies dependent on Middle Eastern LNG, demonstrating how maritime transit bottlenecks can trigger global price spikes regardless of underlying long-term contract coverage.

Prices moderated slightly during the April–May shoulder period. TTF dropped to $15.53/MMBtu in April before rising to $16.27/MMBtu in May, while JKM remained elevated above $16.50/MMBtu throughout the spring. However, market tightness resumed aggressively as the summer cooling season got underway. By July 2026, TTF monthly averages climbed to $18.04/MMBtu while JKM reached $19.87/MMBtu. In contrast, Henry Hub remained structurally insulated from these overseas spikes, easing to $2.93/MMBtu in July after a brief uptick to $3.14/MMBtu in June.

This mid-summer price surge aligns with traditional seasonal tightening patterns driven by peak air-conditioning loads in Northeast Asia and intense European competition for LNG cargoes for storage injection. The persistent divergence between Henry Hub and international benchmarks highlights how North American prices remain insulated by massive domestic supply and physical liquefaction export capacity limits. Meanwhile, the synchronised movements of TTF and JKM demonstrate the central role of destination-flexible LNG in transmitting both seasonal demand surges and geopolitical supply shocks across gas markets.

APEC regional grouping

Australia	
China	
North America	Canada; Mexico; United States
Northeast Asia	Hong Kong, China; Japan; Korea; Chinese Taipei
Oceania	New Zealand; Papua New Guinea
Other Americas	Chile; Peru
Russia	
Southeast Asia	Brunei Darussalam; Indonesia; Malaysia; the Philippines; Singapore; Thailand; Viet Nam
United States	

Abbreviations and acronyms

Abbreviations

bcm	Billion cubic meters
MW	Megawatt
GW	Gigawatt
TWh	Terawatt-hour
MMBtu	Million British thermal units
Mtpa	Million tonnes per annum
CBM	Coalbed methane
LNG	Liquefied natural gas
PV	Photovoltaic

Acronyms

APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
EGEDA	Expert Group on Energy Data and Analysis
GECF	Gas Exporting Countries Forum
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
IGU	International Gas Union
JKM	Japan Korea Marker
TTF	Title Transfer Facility

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