GECF
Gas Exporting Countries Forum

Global Gas Outlook 2055

10th Edition

April 2026

GECF
Gas Exporting Countries Forum

Global Gas Outlook 2055

10th Edition

April 2026

Disclaimer

Report Citation: Gas Exporting Countries Forum, 10th edition of the GECF Global Gas Outlook 2055. April 2026.

Comments and questions regarding the 10th edition of the GECF Global Gas Outlook 2055 should be addressed to:

Gas Exporting Countries Forum

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

P.O. Box 23753

Tel: **+97444048400**

Email: **Outlook@gecf.org**

More information is available at **www.gecf.org**

About the GECF

The Gas Exporting Countries Forum (GECF or Forum) is an international governmental organisation established in May 2001. It became a fully fledged organisation in 2008, with headquarters in Doha, Qatar.

As of April 2026, the GECF comprises twelve Members and eight Observer Members (hereafter referred to as the GECF Countries) from four continents. The Member Countries of the Forum are Algeria, Bolivia, Egypt, Equatorial Guinea, Iran, Libya, Nigeria, Qatar, Russia, Trinidad and Tobago, the United Arab Emirates and Venezuela (hereafter referred to as Members). Angola, Azerbaijan, Iraq, Malaysia, Mauritania, Mozambique, Peru and Senegal have the status of Observer Members (hereafter referred to as Observers).

Cooperation was extended to technology with the establishment of the Gas Research Institute in 2019, headquartered in Algiers, the People's Democratic Republic of Algeria.

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

In accordance with its Long-Term Strategy, the vision of the GECF is "to make natural gas the pivotal resource for inclusive and sustainable development", and its mission is "to shape the energy future as a global advocate of natural gas and a platform for cooperation and dialogue, with the view to support the sovereign rights of member countries over their natural gas resources and to contribute to global sustainable development and energy security".

Acknowledgements

10th edition of GECF Global Gas Outlook 2055 recognises the assistance of several experts. It benefited from the comments and suggestions of the **Technical and Economic Council Members**, and the **Secretary General, Dr Philip Mshelbila.**

PROJECT LEADER

Mohammad Amin Naderian, Head, Energy Economics and Forecasting Department, EEFD

LEAD AUTHORS AND THE GECF GGM MODELLING TEAM (alphabetical order)

Abbas, Abubakar Jibrin; Senior Energy Forecast Analyst, EEFD
Adel Amer, Mustafa; Energy Technology Analyst, EEFD
Ali, Sabna; Research Assistant, EEFD
Fazeliyanova, Galia; Energy Economics Analyst, EEFD
Gordeev, Dmitrii; Energy Econometrician, EEFD
Moradzadeh, Masoumeh; Energy Environment and Policy Analyst, EEFD

ADMINISTRATIVE AND DESIGN SUPPORT

Nargiz Amirova, Secretary, EEFD

ONGOING DATA AND SERVICE SUPPORT FOR THE GECF GGM

S&P Global Commodity Insights

PEER REVIEW SUPPORT

Petroleum Economist
Petroleum Economist provided an extensive review of the report, checking for consistency and factual accuracy. The views and conclusions expressed are those of the GECF Secretariat and do not necessarily coincide with the opinions of Petroleum Economist or its staff.

COVER AND DESIGN

Strategy to Execution (S2E) Agency

GECF TECHNICAL AND ECONOMIC COUNCIL (As of March 2026)

Sofiane Dakiche | Freddy Gustavo Velasquez Robles | Yaseen Mohamed Yaseen | Antimo Asumu Obama Asangono | Ehsan Taghavinejad | Naima Suwani | Oluremi A.Komolafe | Jabor Yaser Al-Mesalam | Denis Leonov | Selwyn Lashley | Amal Al-Ali | José Agustín Ruiz

Table of Contents

Table of Figures

List of Boxes

List of Tables

List of Annexes

Foreword

The first half of the 2020s has been shaped by what may increasingly be described as a polycrisis: a succession of interconnected shocks whose combined impact on the global economy and the international order has exceeded the effect of any one event alone. The pandemic revealed the fragility of interdependence. The energy crisis of 2022 showed how quickly market balances could be disrupted by geopolitical tensions. Since the beginning of 2025, rising trade frictions, renewed instability in strategically important regions, the erosion of multilateralism, and the weakening of trust built over decades have added further complexity to the environment in which the global energy system operates. The result is a more uncertain international landscape, in which many of the assumptions that once sustained confidence in stability, cooperation, and market continuity can no longer be regarded as fully assured.

The current Middle East conflict should be understood within this broader context. At the time of writing, little more than a month has passed since its outbreak, and both the scale and duration of the resulting shock remain uncertain. As with previous major energy disruptions, its implications will depend largely on its magnitude and persistence. Even so, the significance of this shock lies not only in its immediate effects on supply, but also in the renewed exposure of critical vulnerabilities across the energy system, including infrastructure, transit routes, maritime chokepoints, and the wider frameworks of confidence that underpin cross-border energy flows. Its consequences are therefore not confined to physical balances alone; they also reach market sentiment, investment perceptions, and the strategic calculus of governments. In this respect, one shift is already becoming evident: energy security is moving further to the centre of policy thinking, and energy itself is increasingly viewed not only as a market commodity, but also as a strategic asset. In such an environment, the importance of reliable supply, resilient infrastructure, investment continuity, and system flexibility becomes more pronounced.

The modelling underpinning the 10th edition of the GECF Global Gas Outlook was completed before the outbreak of the current conflict. Accordingly, the projections presented in this report reflect the structural drivers shaping global energy markets prior to this disruption, rather than the effects of a shock whose broader consequences remain uncertain at the time of publication. Any longer-term implications of the conflict for energy markets and natural gas will be assessed more fully in the next edition, once greater clarity emerges. This edition, therefore, should be read as a long-term assessment of the fundamental forces shaping the evolution of gas demand, supply, and trade in a world undergoing profound structural change.

Those forces remain significant. Urbanisation, rising living standards, digitalisation, and accelerating electrification continue to expand the need for reliable energy services. At the same time, the foundations of economic growth are evolving: artificial intelligence and digital technologies are expected to strengthen labour productivity and reshape patterns of demand, even as geopolitical tensions, reconfigured trade relations, population decline in advanced economies, and rising debt burdens weigh on the broader outlook. Together, these forces are creating an energy landscape that is not only larger, but also more complex, more interconnected, and more exposed to strategic risk. As markets, trade flows, and investment patterns adjust, resilience, diversification, and supply security assume greater importance, reinforcing the strategic importance of natural gas.

Against this backdrop, one of the Outlook's central findings is that, in the unfolding age of electricity, the challenge is not merely to expand energy supply, but to ensure that increasingly electrified systems can deliver reliability, flexibility, and resilience. In this setting, natural gas is projected to assume a larger and more differentiated role. More than half of the net increase in natural gas demand by 2055 is expected to come from power generation, where its function is being redefined. Beyond its traditional role in baseload generation, natural gas is increasingly valued for the reliability, flexibility, and balancing services it provides in systems with growing shares of variable renewables. Its versatility is broadening further through rising use in transport and hydrogen. Natural gas, therefore, is not only growing in scale, but evolving in function, with its share in the global energy mix rising from 23% in 2024 to 26% in 2055, overtaking coal and moving closer to oil as one of the leading pillars of the global energy system.

This growing role in demand is matched by an important shift on the supply side. The Outlook points to a changing centre of gravity of supply, away from the earlier phase of shale-led expansion and increasingly toward conventional growth led by the Middle East, Eurasia, and Africa. Future production growth remains feasible, but under more demanding conditions. It depends not only on bringing new resources to market, but also on replacing natural decline, sustaining reinvestment in brownfield optimization, ensuring the timely delivery of long-cycle projects, and advancing higher-cost resources across both conventional and unconventional categories. In this respect, the challenge ahead is no longer one of resource availability alone, but of investment continuity, project execution, and the ability to translate potential into reliable supply. Reflecting this scale and complexity, cumulative upstream and midstream investment requirements are estimated to exceed USD 12.3 trillion.

As supply expands and diversifies, trade becomes an increasingly defining feature of the global gas market. The share of gas trade in global demand is projected to rise to around one-third by 2055, up from 29% in 2024, pointing to a market that is increasingly interconnected, more interdependent, and more reliant on cross-border flows. LNG is the principal driver of this shift. Its rising role expands supply flexibility, deepens market integration across distant regions, and strengthens the capacity of the global gas system to absorb and respond to disruptions. By 2055, LNG's share of international gas trade is projected to rise to 65%, with volumes doubling over the outlook period. Yet a more trade-dependent market also becomes more sensitive to disruptions in trust, infrastructure, transit, and pricing, increasing the importance of resilient infrastructure, secure routes, contractual adaptability, and robust market and risk-management frameworks.

The Outlook also examines an alternative pathway through the Sustainable Energy Scenario. This normative scenario explores the scale of transformation required for sustainable development and climate goals to be achieved by mid-century while keeping reliability and affordability within workable bounds. Its central insight is that the energy transition is not a question of contraction, but of reconfiguration. In this pathway, the energy system becomes larger in order to eradicate energy poverty and sustain development, while also becoming more efficient, less emissions-intensive, and more decisively reoriented in its fuel mix. Natural gas remains a central part of the solution, with CCUS as the key enabling technology for emissions mitigation. Even in a more accelerated decarbonization trajectory, natural gas remains essential to reliability, development, environmental protection, and system balance.

Within this evolving landscape, current GECF Member Countries are positioned to play an increasingly vital and decisive role. Their share of global natural gas production is projected to rise from 38% in 2024 to 44% by 2055, underpinned by abundant resource availability and by advancing initiatives aimed at decarbonising the natural gas supply chain. At the same time, their role in international trade is expected to strengthen further, with GECF Member Countries projected to account for nearly half of global natural gas and LNG trade by 2055. Their contribution will therefore remain central not only to supply security and market stability, but also to shaping the future role of natural gas in a transforming global energy system.

I extend my sincere appreciation to the GECF team for their dedication in producing this report. I also wish to thank the GECF Technical and Economic Council, Member Country experts, and all contributors for their invaluable insights, which have strengthened this tenth edition of the Global Gas Outlook. In addition, I express my sincere gratitude to the former Secretary General of the GECF, HE Mohamed Hamel, for his leadership and steadfast support throughout the development of this edition.

Dr Philip Mshelbila
Secretary General

Executive Summary

Executive Summary

The world is entering an era of demographic divergence and accelerated urbanisation, concentrating energy demand growth in regions where infrastructure and modern energy access remain binding constraints

The long-term outlook is anchored in a demographic transition that is global in direction but uneven in geography. Global population rises from about 8.1 billion in 2024 to nearly 9.8 billion by 2055. However, the incremental population is concentrated overwhelmingly in developing regions, led by Africa, while several developed countries face stagnation or decline alongside rapid ageing. This divergence matters for energy markets because the marginal growth in energy services is increasingly linked to development pathways rather than to the incremental consumption of already-saturated systems.

Urbanisation becomes the dominant spatial driver of energy demand. The share of the global population living in urban areas rises toward 70% by 2055, with Africa and Asia Pacific accounting for the majority of new urban residents. Urban growth raises the demand for electricity, transport, water services, cooling, and industrial supply chains. It also raises the premium on reliability: dense urban economies are more sensitive to power quality, fuel supply disruptions, and price volatility, and therefore require energy systems that combine scale, flexibility, and operational resilience.

Ageing is the parallel structural force. The share of people aged 65 and above rises from roughly 10% in 2024 to about 18% by 2055, reshaping labour markets, fiscal priorities, and consumption patterns. Working age population growth becomes increasingly concentrated in developing regions, particularly Africa. This raises a central implication for decision makers: the next phase of global energy demand is driven as much by whether emerging regions can finance, build, and operate modern infrastructure as by commodity price cycles.

Economic growth continues to expand the scale of energy services, but the composition of growth is shifting toward electricity-intensive systems and service-driven economies shaped by digitalisation and industrial upgrading

Global GDP expands from about USD 110 trillion in 2024 to USD 233 trillion by 2055 in real terms, with average annual growth moderating relative to the past three decades. The centre of gravity continues to move toward non-OECD economies, which account for the majority of incremental growth by mid-century. At the same time, the structure of value added continues to tilt toward services, which approach 70% of global GDP by 2055, while industry stabilises near one-fifth. This matters for energy markets because services and digital infrastructure are electricity-intensive and reliability-sensitive, even as some traditional heavy industries moderate in relative contribution.

Digitalisation and the diffusion of artificial intelligence are reshaping the energy–economy linkage. Electricity demand increasingly reflects non-substitutable services, computation, communication, automation, and machine intelligence, whose growth is weakly coupled to historical patterns of energy intensity. This changes the nature of system stress: the key challenge becomes the delivery of high-availability electricity, reinforced grids, and flexible supply that can accommodate both rising baseload and sharper peaks. In this setting, macroeconomic expansion remains the scale driver, but electrification and reliability become the organising principles of energy system design.

Per-capita income rises steadily, driven more by productivity and technology than by population growth. The distribution of these gains remains uneven, implying that development outcomes depend on whether investment capacity expands fast enough in regions with the largest infrastructure deficits. This is central for energy executives because it determines the pace of network build-out, demand maturation, and the bankability of long-lived energy projects.

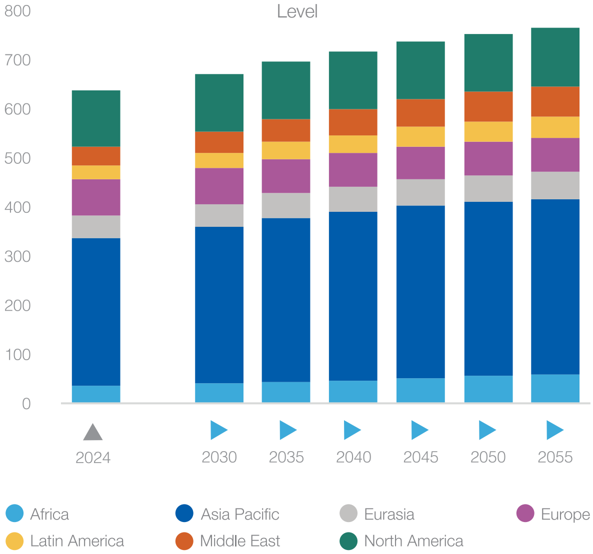
Energy policy has shifted from ambition to delivery under the energy trilemma, and this recalibration is reinforcing natural gas as a reliability instrument while tightening performance-based requirements on emissions

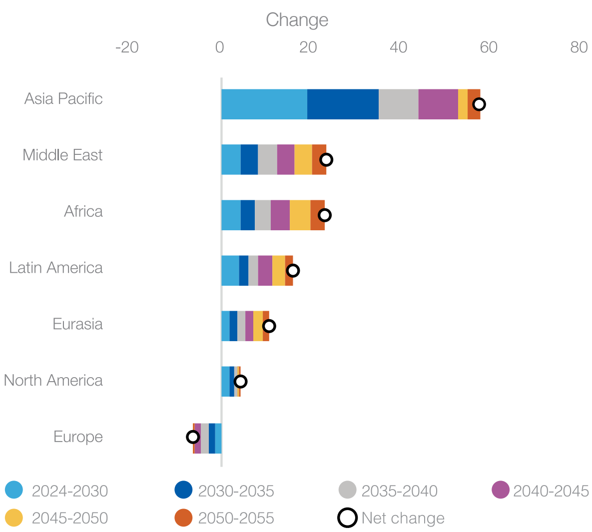
In 2024–2025, energy policy frameworks across major countries shifted decisively toward security, affordability, and competitiveness, with natural gas embedded more explicitly in long-term adequacy planning. The United States lifted its temporary pause on LNG export approvals, streamlined permitting for pipelines and terminals, and eased selected methane and power-sector compliance requirements, while maintaining support for CCUS and nuclear as reliability pillars. The European Union recalibrated elements of its Green Deal through the Omnibus Simplification Package and the Clean Industrial Deal, preserving methane, CBAM and ETS frameworks but prioritising competitiveness, storage obligations, infrastructure modernisation, and diversified LNG supply. In Asia, China advanced pipeline expansion, LNG import capacity, and peak shaving gas policies under its broader power-system upgrade and Energy Law framework, while India continued midstream gas market reforms and expanded gas-fired peaker capacity to support grid stability. Japan and South Korea reinforced long-term LNG contracting and supply diversification strategies.

Across developing regions, policy support for natural gas remained closely linked to industrialisation, energy access, and fiscal stability. Algeria, Egypt, and several Sub-Saharan producers introduced upstream incentives and LNG infrastructure measures to secure domestic supply and export revenues, while Latin American countries, including Brazil and Argentina, strengthened regulatory frameworks and infrastructure expansion to integrate domestic gas into power and industrial systems. In the Middle East and North Africa, gas-to-power and desalination strategies remained central to national energy plans.

These developments point to a differentiated yet broadly convergent policy landscape. A renewed hydrocarbons prioritisation trend in the United States is reshaping the global policy narrative, while other developed countries continue to frame natural gas within decarbonisation architectures. In parallel, developing countries emphasise affordability, access, and growth

Global primary energy demand outlook by region, 2024-2055 (EJ)





Source: GECF Secretariat based on data from the GECF GGM

through upstream expansion, domestic distribution and LNG infrastructure development. Across regions, natural gas has been reaffirmed as a structural pillar of contemporary energy strategies

The global energy system is entering the 'age of electricity': total demand continues to rise, but the fastest-growing energy services are electricity-exclusive and impose new requirements for system flexibility and dispatchable capacity

Global primary energy demand reached 641 EJ in 2024 and rises to 768 EJ by 2055, increasing at a structurally slower pace as efficiency gains strengthen and demographic growth moderates. Final energy demand increases to around 565 EJ by 2055, but its composition shifts markedly as electricity's share rises from about 22% to nearly 32%. Electricity demand approximately doubles to more than 61,000 TWh by 2055, driven by electrification of end uses and the expansion of electricity-exclusive services such as cooling, digital infrastructure, and automation.

Recent developments underscore this structural break. In 2024, electricity consumption recorded an unusually large year-on-year increase and expanded faster than GDP, reflecting rising electricity intensity. Cooling needs in a warming climate, combined with the rapid scale-up of data centres and AI-enabled services, is transforming load profiles toward higher baseload and sharper peaks. This transformation is reshaping the economics of the transition: system integration costs, network constraints, and the need for firm capacity increasingly determine the feasible pace of variable renewables deployment.

Hydrocarbons remain central to the energy system by mid-century, supplying around 62% of primary energy demand in 2055. Within the mix, coal undergoes a sustained structural decline, while renewables expand rapidly but face integration constraints at higher penetration. Natural gas strengthens its position in the primary energy mix, surpassing coal in the late 2020s and supporting both power-system adequacy and hard-to-abate industrial activity. The strategic relevance of gas increasingly reflects its system value, flexibility, dispatchability, and reliability, rather than only its volumetric contribution.

Natural gas demand grows because its flexibility and molecular value remain difficult to replicate at scale, even as direct use in buildings moderates in several mature markets

Global natural gas demand rises from 4,137 bcm in 2024 to about 5,417 bcm by 2055. This expansion is not driven by a single end use, but by a structural reallocation of gas toward applications that deliver high system value. Gas increasingly concentrates in transformation and industrial sectors, power generation, industrial process heat and feedstocks, and hydrogen generation, while direct use in buildings stabilises or declines in regions where electrification and efficiency policies are most aggressive.

Power generation is the dominant source of incremental demand. Gas demand in the power sector increases to roughly 2,100 bcm by 2055, reflecting rising electricity demand, higher peak loads, and the growing need for firm, fast-ramping capacity in systems with high shares of variable renewables. In this role, gas functions as a system-balancing asset: reserve provision, ramping, and reliability during periods of low renewable output, drought-driven hydropower deficits, and weather-driven demand spikes. This system value remains important even where gas-fired generation's share of total generation declines, because the reliability function becomes more critical as the system electrifies.

Industrial demand remains the second-largest pillar, reaching around 1,200 bcm by 2055. Gas remains competitive in hard-to-electrify industrial processes and retains a structural role as feedstock in chemicals, petrochemicals, and fertilisers. In addition, the expansion of clean-technology manufacturing and other electricity-intensive industrial value chains creates new demand for reliable process energy and heat that reinforces the role of gas in industrial competitiveness.

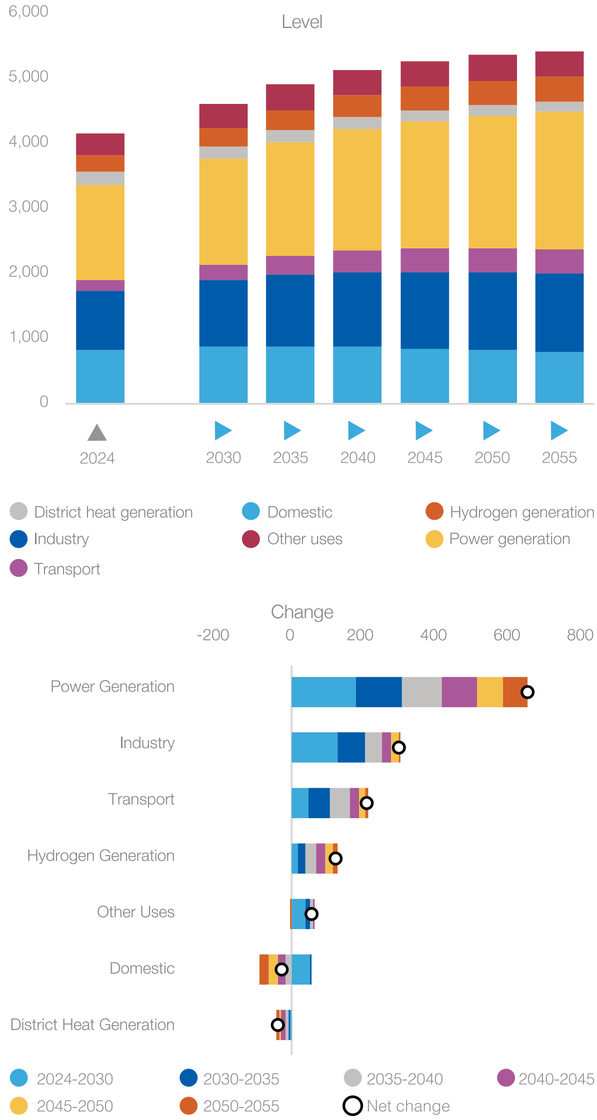
Transport records the fastest growth rate from a small base, with demand rising to roughly 380 bcm by 2055, concentrated in heavy-duty trucking and maritime segments where electrification is constrained. Hydrogen generation demand also expands, with gas consumption for hydrogen rising to just under 400 bcm by 2055, reflecting continued fertiliser and refining requirements and a gradual transition toward blue hydrogen in selected markets. Regionally, demand growth is centred in Asia Pacific, the Middle East, and Africa, while Europe is the only region with an overall decline, albeit with a non-linear path shaped by power-sector needs and market conditions.

Natural gas supply adequacy increasingly depends on decline replacement and execution discipline: the world is moving from shale-led expansion toward conventional growth led by the Middle East, Eurasia and Africa

Global natural gas production rises from 4,136 bcm in 2024 to about 5,417 bcm by 2055, but the growth profile decelerates materially after 2030 as mature provinces dominate marginal supply and decline replacement becomes the binding requirement. The outlook implies that production growth is feasible, but increasingly conditional on sustained reinvestment in brownfield optimisation, timely delivery of long-cycle projects, and the development of higher-cost resources in both conventional and unconventional categories.

A central structural shift is the reassertion of conventional gas as the dominant growth engine. The majority of net global production growth is supplied by conventional

Global natural gas demand outlook by sector, 2024-2055 (bcm)

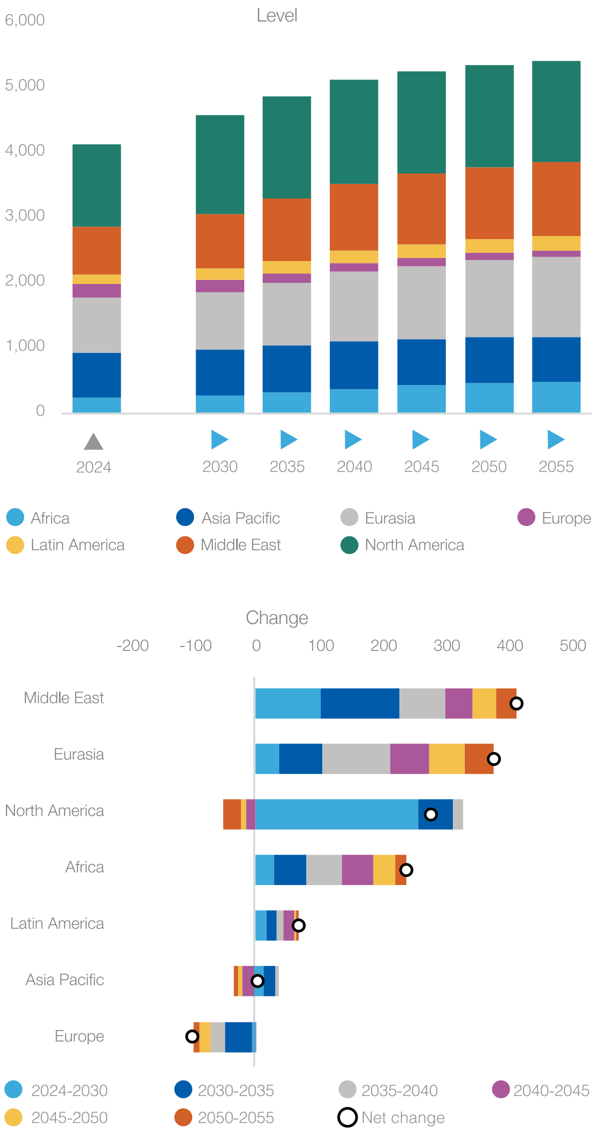


Source: GECF Secretariat based on data from the GECF GGM

Note: Industry includes natural gas used directly as fuel and as feedstock in the chemical and petrochemical sectors, as well as gas consumed for refinery utilities and processes. Transport covers natural gas used in road transport, marine bunkers, rail transport and pipeline operations (e.g., compressor fuel). Other uses comprise natural gas consumed for the energy sector's own use, together with distribution losses. Total gas demand includes primary natural gas as well as gas works gas, hydrogen blending and biomethane blending, where applicable.

resources, reflecting the scale of low-cost reserve bases in core exporting regions. North America remains the largest producing region in absolute terms and provides significant near-term growth, but unconventional basins gradually mature and the regional profile transitions toward a post-peak plateau and mild decline by mid-century. Europe declines structurally and becomes increasingly dependent on imports, reinforcing the importance of diversified LNG supply chains.

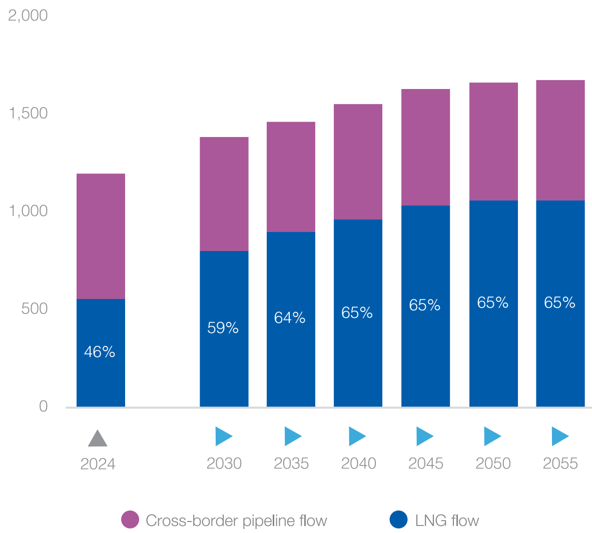
Global natural gas supply outlook by region, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

The centre of gravity of supply moves toward resource-rich exporters. The Middle East delivers the largest absolute production increase by 2055, supported by large conventional developments and parallel expansion of export capacity. Eurasia remains a key supply pillar, with growth shaped by project sequencing and the ability to route volumes through evolving export corridors. Africa records the fastest growth rate, increasingly offshore-led and highly sensitive to FID timing, execution, and the build-out of LNG and associated infrastructure. At the global level, the share of production from current GECF Member Countries rises materially, reflecting faster long-run growth in core conventional exporters.

Global natural gas trade outlook by flow type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Note: Includes all inter-regional and intra-regional trade; intraregional trade refers to trade that occurs within a particular region or geographical area

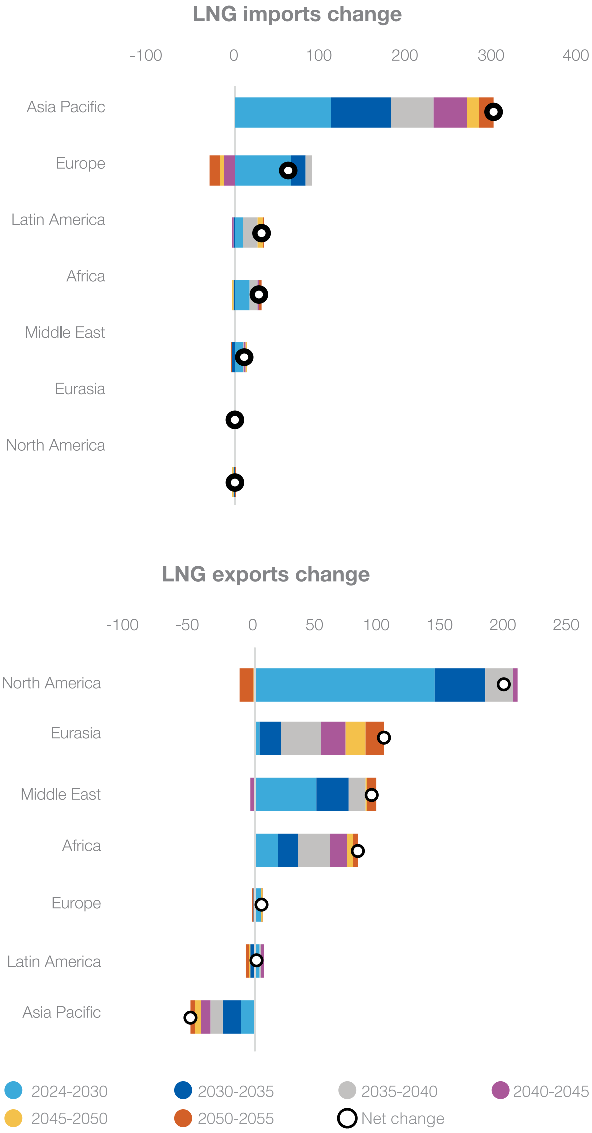
International gas trade is becoming more LNG-centred and more operationally constrained: market flexibility is expanding, but shipping, terminal bottlenecks and start-up timing increasingly shape effective deliverability

Global natural gas trade expands from about 1,211 bcm in 2024 to roughly 1,767 bcm by 2055, lifting the traded share of global gas demand from below one-third to around one-third by mid-century. LNG drives this expansion. Seaborne trade rises from about 406 Mt in 2024 to 837 Mt by 2055, implying that LNG accounts for around 65% of traded gas by mid-century. Pipeline trade remains broadly stable in aggregate volume terms and declines in relative importance, reflecting a trade system increasingly shaped by liquefaction and regasification capacity rather than by the extension of long-distance pipeline corridors.

Asia Pacific remains the dominant centre of LNG import growth and becomes more dependent on extra-regional supply as intra-regional sourcing declines with maturing production in key exporting countries. Europe remains the second-largest LNG import market and continues to rely on LNG as a structural component of supply security, with a front-loaded expansion in regasification capacity and a strong preference for floating solutions that can be deployed rapidly and flexibly. On the supply side, North America emerges as the leading LNG exporting region by mid-century, while the Middle East remains a low-cost export anchor and Africa expands materially as a supplier through new LNG projects.

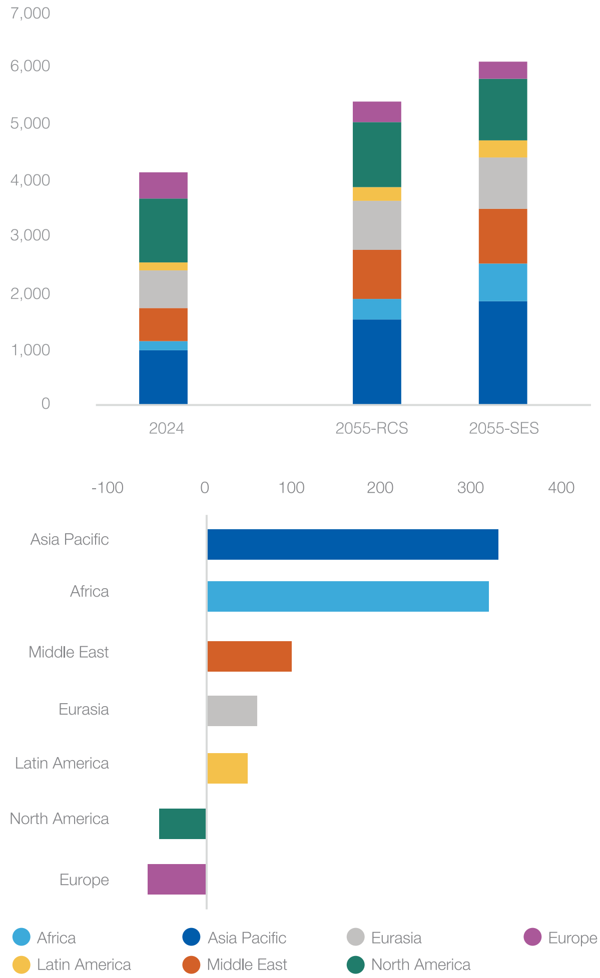
Recent market experience highlights that physical logistics can become binding even when aggregate supply appears sufficient. Shipping route disruptions

Global LNG trade outlook by region, 2024-2055 (Mt)



Source: GECF Secretariat based on data from the GECF GGM

Global natural gas demand forecast by region in RCS and SES (bcm)



Source: GECF Secretariat based on data from the GECF GGM

and chokepoint constraints increase voyage distance and round-trip times, tightening effective vessel availability through higher tonne-mile demand. Terminal operability and network constraints also matter: nominal regasification capacity does not always translate into effective send-out during peak periods, while commissioning-phase variability and upstream feedgas constraints can delay the translation of new nameplate capacity into sustained export volumes. As a result, the LNG market is simultaneously more connected and more sensitive: it can redirect supply more rapidly than pipeline-dominant configurations, yet it is more exposed to operational and logistical frictions that can tighten effective availability and transmit shocks across basins.

The Sustainable Energy Scenario shows that accelerated development and deeper decarbonisation are jointly feasible only through a portfolio that combines economic growth, electrification with firm capacity and large-scale carbon management, with natural gas increasingly embedded in carbon-managed value chains

The Sustainable Energy Scenario (SES) is designed as a development-centred pathway that reconciles accelerated energy service delivery with a Paris-aligned long-term temperature objective, while preserving reliability and affordability. Relative to the Reference Case Scenario (RCS), SES implies a larger global economy by 2055 and a higher level of delivered energy services, particularly in regions where per-capita consumption remains far below development-consistent thresholds.

In SES, global GDP rises to roughly USD 248 trillion by 2055, and global final energy demand reaches about

613 EJ, around 48 EJ higher than in the RCS. Electricity demand exceeds the RCS by about 3,060 TWh by 2055, reflecting accelerated electrification. Despite the larger energy system, emissions decline more sharply, because decarbonisation is delivered through faster intensity improvements, deeper coal displacement, and a step-change in carbon management.

Natural gas plays a pragmatic enabling role in this pathway. Global natural gas demand reaches about 6,127 bcm, around 708 bcm higher than in the RCS, driven primarily by power generation and industry in fast-growing regions. Global gas trade expands to about 2,144 bcm, and LNG's role strengthens further, reflecting the need for flexible, diversified supply chains to balance rapid growth in importing regions. The climate feasibility of this higher gas role depends on performance: CCUS deployment scales rapidly, reaching about 8.9 $GtCO_2e$ by 2055, with gas-based CCUS providing a major share of additional emissions reductions relative to the RCS.

The SES therefore clarifies an executive-level insight: the binding constraint is not the availability of low-carbon technologies in isolation, but the system capacity to finance, build and integrate them while maintaining reliability and affordability. In this setting, natural gas is not positioned as a substitute for renewables and electrification; it is positioned as a stability and scalability resource whose long-run compatibility depends on verified emissions performance and the maturation of carbon management infrastructure.

1

Economic and Demographic Assumptions

Highlights

- Global population growth remains on a decelerating trajectory, rising from 8.1 billion in 2024 to 9.8 billion by 2055, an addition of 1.7 billion people. Africa will drive nearly 70% of this increase, while Europe and OECD Asia will experience population decline and rapid ageing.
- Urbanisation accelerates to 70% by 2055, with developing Africa and Asia Pacific accounting for more than 80% of new urban residents, reshaping infrastructure and energy demand.
- The share of people aged 65 and older is projected to rise from 10% in 2024 to 18% by 2055, reaching 1.7 billion globally. The global working-age population will grow almost exclusively in developing regions, led by Africa, whose labour force will expand by 68% to 1.6 billion, compared with a sharp contraction in Europe and OECD Asia Pacific.
- Global GDP is projected to expand by USD 123 trillion (real terms) between 2024 and 2055, reaching USD 233 trillion, an average annual growth of 2.4%, down from 2.9% over the past three decades.
- Asia Pacific and Africa are projected to lead global expansion in GDP, averaging 3.3% and 4.3% of annual growth over the forecast period, while the growth of OECD countries decelerates to 1.6%. Non-OECD countries is set to supply 55% of world GDP by 2055.
- The services sector strengthens its dominance, increasing its share of global value added from 66% in 2024 to almost 70% by 2055, while industry stabilises near 20%.
- Per-capita GDP rises by 1.8% annually to reach USD 23,900 (real) in 2055, driven by technology, productivity, and efficiency gains rather than population growth.
- Brent crude oil prices are assumed to decline in real terms from USD 81/bbl in 2024 to around USD 70/bbl by 2055, reflecting moderating demand growth in transport sector and production efficiency boost, despite sustained petrochemical use.
- Hub-based natural gas prices are projected to stabilise by 2055, reaching USD 5.1/MMBtu at Henry Hub, USD 10.9/MMBtu in Europe, and USD 13.3/MMBtu in Asia, driven by balanced supply-demand dynamics, rising production costs, and expanding LNG trade.
- Carbon markets broaden to 54 countries by 2055, with the EU ETS price reaching USD 160/t CO_2, supporting decarbonisation and low-carbon investment.

1.1 Population and demographics outlook

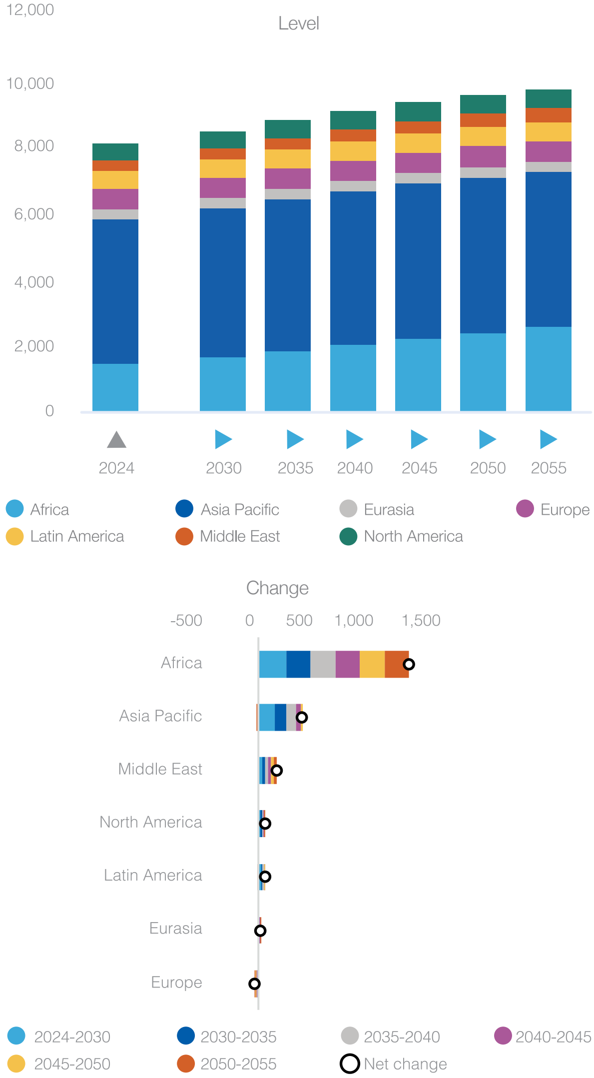
The demographic landscape of the world is entering a decisive phase of transition. Population growth, once a universal driver of economic expansion and energy demand, is now increasingly concentrated in a few regions. Fertility rates have fallen below replacement levels across much of the industrialised world, while longevity gains continue to raise the share of elderly populations. At the same time, Sub-Saharan Africa and developing Asia Pacific remain on a steep upward trajectory, accounting for nearly all net additions to the global population in the coming decades. This emerging geography of demographic momentum and demographic decline is reshaping the global labour force, altering consumption patterns, and redefining where and how future energy demand will arise (Table 1.1).

This demographic divide is reflected in the latest projections. **According to the 2024 Revision of the United Nations World Population Prospects (medium scenario), the global population is projected to increase from 8.1 billion in 2024 to nearly 9.8 billion by 2055, representing an addition of about 1.7 billion people.** This signifies a continued slowdown compared with the 2.5 billion increase recorded over the past three decades, as global population growth progressively decelerates. The gradual moderation reflects sustained declines in fertility rates and steady improvements in life expectancy, which together are reshaping the trajectory of population expansion and age structure across most regions.

However, population growth will be unevenly distributed across regions. As illustrated in Figure 1.1, Africa is projected to account for almost 70% of the total global population net increase between 2024 and 2055, driven by sustained high fertility rates and a youthful age structure. By contrast, several regions, most notably Europe and OECD Asia, are expected to experience population ageing and gradual decline, reflecting prolonged periods of sub-replacement fertility and rising

Figure 1.1

Global population outlook by region, 2024-2055 (millions)



Source: 2024 Revisions of United Nations World Population Prospects

Table 1.1

Global population outlook by region, 2024-2055 (millions)

Region	2024	2030	2035	2040	2045	2050	2055	Net Change
Africa	1,467	1,676	1,856	2,040	2,224	2,406	2,584	1,117
Asia Pacific	4,369	4,495	4,581	4,646	4,688	4,703	4,689	319
Eurasia	294	299	301	303	306	309	310	16
Europe	637	635	632	628	623	616	606	-31
Latin America	532	551	563	572	578	581	581	48
Middle East	295	326	348	370	391	411	429	134
North America	511	526	537	546	552	557	560	49
World	**8,107**	**8,507**	**8,818**	**9,105**	**9,362**	**9,582**	**9,760**	**1,653**

Source: 2024 Revisions of United Nations World Population Prospects (medium scenario) longevity. Other regions particularly South Asia will continue to expand, albeit at a moderating pace, while North America is projected to stabilise toward mid-century.

Africa, home to 1.47 billion people in 2024, representing 18% of the global population, is projected to experience the fastest population growth worldwide. By 2055, the continent's population is expected to reach 2.6 billion, an increase of about 1.12 billion or roughly 76%. This expansion is set to lift Africa's share of the world total to 26%, underscoring its central role in driving global population growth. The region's rapid demographic momentum is sustained by high fertility, averaging around 4.7 children per woman, well above the global average of 2.3, and by a youthful median age of about 19 years, ensuring that large cohorts continue to enter reproductive age. Life expectancy has also improved markedly, rising from 50 years in 1990 to 63 years in 2024, and is projected to approach 68 years by 2055. More than 90% of the continent's population increase over this period is set to occur in Sub-Saharan Africa, where the population remains predominantly young and continues to expand rapidly despite gradually declining fertility rates.

With a population of 4.37 billion in 2024, **Asia Pacific** region continues to represent the demographic centre of gravity of the world, accounting for roughly 54% of the global total. Yet, the era of rapid expansion that characterised the late twentieth century is drawing to a close. Since 1993, the region's population has expanded by nearly 1.2 billion, but growth is expected to slow to only around 320 million additional people by 2055, reaching 4.7 billion, peaking in late 2050s and easing slightly thereafter. This moderation reflects decades of structural demographic change: fertility has dropped from 4.5 children per woman in 1960 to about 2.1 in 2024, with several economies, such as China (1.2) and South Korea (0.84), well below replacement levels. At the same time, longevity continues to rise: life expectancy has improved from 57 years in 1960 to 74 years in 2024, and is projected to surpass 78 years by 2055. The combination of low fertility and longer lifespans is producing a rapid ageing process, most pronounced in OECD Asia, where the median age is expected to reach about 49 years in Japan and 45 years in South Korea by mid-century, signalling a fundamental shift in the region's demographic and economic landscape.

Demographic trajectories across **Eurasia** remain highly uneven. The region's total population is projected to rise only marginally, from 294 million in 2024 to about 310 million by 2055, a gain of less than 20 million people over three decades. Within this aggregate, diverging national patterns persist. Countries like Armenia, Russia, Ukraine, Belarus, and Moldova, face continuing demographic contraction. Russia's population, for example, is expected to decline from roughly 144 million in 2024 to around 134 million by 2055, constrained by a fertility rate averaging 1.5 children per woman and only modest gains in longevity, with life expectancy rising from 73 years in 2024 to about 76 years by 2055. In contrast, countries like Uzbekistan, Kazakhstan, and Turkmenistan are projected to expand steadily, with combined population climbing from around 78 million to more than 105 million over the same period. This growth is underpinned by fertility rates near 2.9 children per woman and a median age below 30 years, which sustain a young and expanding labour base.

Europe remains the only region projected to experience a sustained population decline over the outlook period. The total population of Europe peaked in 2024 at approximately 640 million and is projected to gradually decline thereafter. By 2055, Europe's population is expected to fall to 606 million, 31 million lower than 2024. This trend is driven by persistently low fertility rates, averaging about 1.5 children per woman, and by population ageing, with the share of people aged 65 years and above projected to exceed 30% by 2055. Europe already has the oldest population structure globally, with a median age of around 44 years in 2024, expected to rise beyond 47 years by mid-century. Among the major economies, Germany and Italy are anticipated to record the steepest declines in population, reflecting entrenched demographic stagnation and limited net migration inflows. The United Kingdom, Sweden, and Luxembourg are the only European countries not expected to reach a population peak by 2055. It should be highlighted that net migration inflows into Europe are a key factor shaping both historical developments and future trends.

In **Latin America**, population growth continues to decelerate sharply. The region, home to 532 million people in 2024, around 7% of the global total, is projected to reach roughly 581 million by 2055, an increase of only about 9%. This stands in contrast to the more than 30% expansion recorded between 1993 and 2024. The slowdown reflects a pronounced decline in fertility, which has fallen from around 2.9 children per woman in 1993 to 1.8 in 2024, now well below replacement level. At the same time, life expectancy has continued to rise, increasing from 70 years in 1990 to over 75 years in 2024, and is expected to approach 80 years by 2055. Consequently, the region's median age, currently near 32 years, is projected to exceed 41 years by mid-century, signalling a transition toward an older population structure and higher dependency ratios. Brazil will remain the region's largest country by population, although its pace of growth is expected to slow markedly in the coming decades and reach population peak by 2042.

The **Middle East** remains the second-fastest-growing region after Africa, with its population projected to increase from 295 million in 2024 to approximately 429 million by 2055, representing growth of nearly 45%. The region's share of global population is expected to remain unchanged at 4% over the same period. This expansion is supported by moderate fertility levels, averaging around 3 children per woman, which remain above the global mean of 2.4. Life expectancy has improved steadily, from 65 years in 1990 to 74 years in 2024 and is projected to approach 78 years by 2055. Meanwhile, the median age, currently around 27 years, is expected to climb to nearly 35 years by mid-century, reflecting gradual demographic maturation. Iran and Saudi Arabia are forecast to contribute the largest shares of this increase, benefiting from youthful populations, improving healthcare systems, and ongoing socio-economic transformation.

In **North America,** population growth is expected to remain moderate compared with other regions. The total population is projected to increase from 511 million in 2024 to around 560 million by 2055, representing growth of roughly 10 %. The United States will account for about half of this expansion, with its population rising from approximately 340 million to nearly 364 million. Mexico, supported by a younger demographic profile and fertility rates above those of its northern neighbours, is projected to contribute close to one-third of the regional increase, reaching about 150 million by 2055. Canada, meanwhile, is expected to experience steady population gains primarily driven by immigration, which continues to offset its persistently low fertility. Across the region, fertility rates average around 1.7 children per woman, remaining below replacement level, while life expectancy is projected to improve from 79 years in 2024 to slightly above 82 years by 2055.

The demographic trajectories outlined above mark a decisive shift in the world's population landscape, a rebalancing of growth from high-income to emerging regions. This shift signals not only a geographical redistribution of people but also a realignment of global economic potential. Rapidly expanding regions stand to benefit from a demographic dividend, provided they can create sufficient jobs and expand access to education, healthcare, and infrastructure. Yet, without accelerated development and investment, the same dynamics risk amplifying youth unemployment, migration pressures, and social disparities.

In contrast, developed countries face the opposite challenge: shrinking workforces, rising dependency ratios, and ageing-driven fiscal pressures. These trends could reduce potential GDP growth by as much as a third in mature economies by mid-century, unless offset by productivity gains, automation, or improved migration (McKinsey Global Institute, 2025).

Beyond the arithmetic of population growth, the world is also undergoing profound qualitative transformations. **Humanity is becoming older, more urban, and increasingly solitary, with over two-thirds of the population projected to live in cities by 2055. These demographic and social shifts will reshape labour markets, consumption structures, and global energy demand, redefining where and how economic activity, and energy use, will grow in the decades ahead.**

1.1.1 Rapid urbanisation

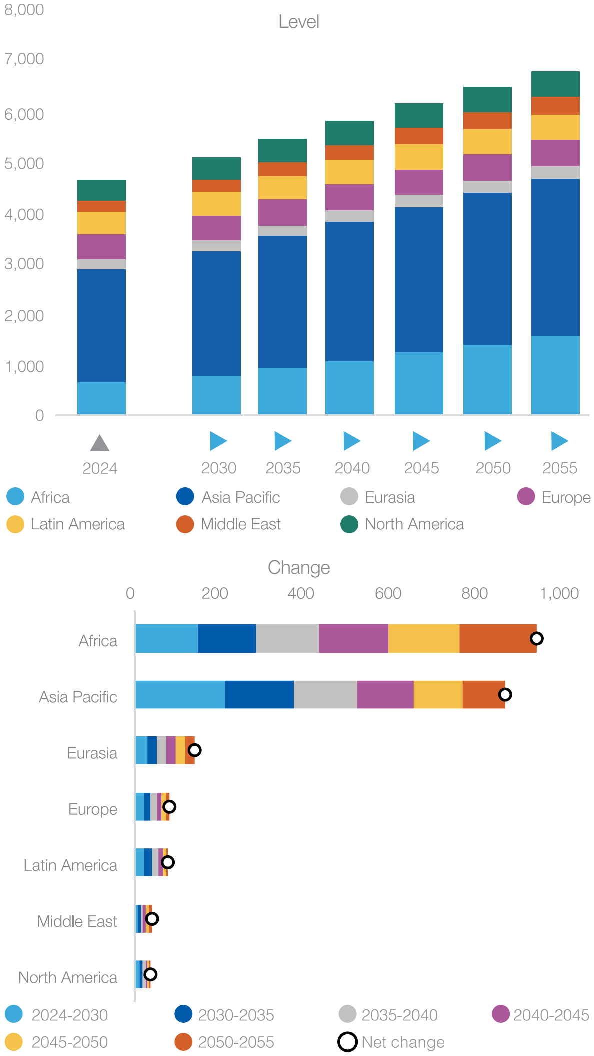
The global population's migration from countryside to city is now one of the defining dynamics of the 21st century. **According to the medium scenario of the United Nations World Population Prospects (2024 Revision), the share of people living in urban areas has risen from 46% in 2000 to nearly 58% in 2024, and is projected to approach 70% by 2055.** This transition corresponds to the addition of roughly 2.2 billion urban residents between 1993 and 2024, with another 2.1 billion expected over the next three decades. The Asia Pacific region alone has accounted for more than half of all global urban growth, reflecting rapid industrialisation, rising incomes, and large-scale internal migration. During this period, the number of megacities, urban centres exceeding 10 million inhabitants, expanded from 14 in 1993 to 33 in 2024, and could surpass 45 by 2055. These metropolitan hubs now anchor economic activity, innovation, and energy consumption, concentrating demand for energy-intensive urban services such as transport, water supply, waste management, cooling, and public infrastructure, while amplifying challenges related to congestion, housing, and sustainability.

The continuation of this urban shift will redefine the global economic and spatial landscape. Nearly all future population growth will occur in cities, with the urban population expanding by more than two billion people between 2024 and 2055 (Figure 1.2). The epicentre of this transformation will be in Africa and developing Asia Pacific, where hundreds of new medium-sized cities are emerging alongside rapidly expanding megacities. Much of this growth will occur in regions where urban infrastructure and services remain underdeveloped, creating both opportunities and acute pressures for housing, transport, water, and energy systems. By contrast, urban expansion in high-income economies will stabilise, characterised less by growth in numbers than by urban renewal, ageing populations, and increased resource efficiency.

Regionally, Africa and the Asia Pacific will account for the overwhelming share of new urban residents, together contributing more than 80% of the global increase to 2055, with 43% and 40% share in total growth, respectively. Yet, despite their rapid expansion, both regions will remain less urbanised than the global average. By 2055, the urbanisation rate is projected to reach just above 60% in Africa and 65% in Asia Pacific, compared with 70% worldwide. This reflects a profound but uneven transformation: while new cities and urban corridors continue to emerge across developing regions, infrastructure, planning capacity, and basic services often lag behind population growth, highlighting the

Figure 1.2

Global urban population outlook by region, 2024-2055 (millions)



Source: The 2024 Revision of United Nations World Population Prospects

scale of the challenge in achieving sustainable and inclusive urban development.

As indicated, the number of megacities is projected to expand sharply over the coming decades, with Africa recording the fastest growth. Driven by accelerating urbanisation and population expansion, cities (Cairo, Lagos, and Kinshasa) are growing at unprecedented rates, while new megacities are emerging across West and East Africa (Dar es Salaam, Nairobi, and Luanda). By 2055, Africa is expected to host a substantial share of the world's newly formed megacities, underscoring its rapid and transformative urban trajectory. This evolution will generate vast economic opportunities through industrial clustering, innovation, and market expansion, but will also intensify the need for massive infrastructure investment and improved energy access.

In contrast, North America, Latin America, and Europe are projected to see only marginal increases in their urban populations over the coming decades, reflecting already high levels of urbanisation. According to the projections, by 2055, the urbanisation rate is expected to stabilise around 90% in North America, 88% in Latin America, and 86% in Europe, largely in line with current levels. These figures point to the saturation of urban growth in mature economies, where population gains are modest and urban expansion has largely plateaued. The global centre of urban momentum is therefore shifting decisively toward developing regions, where urbanisation remains rapid, transformative, and closely tied to industrialisation and economic diversification.

1.1.2 Ageing population

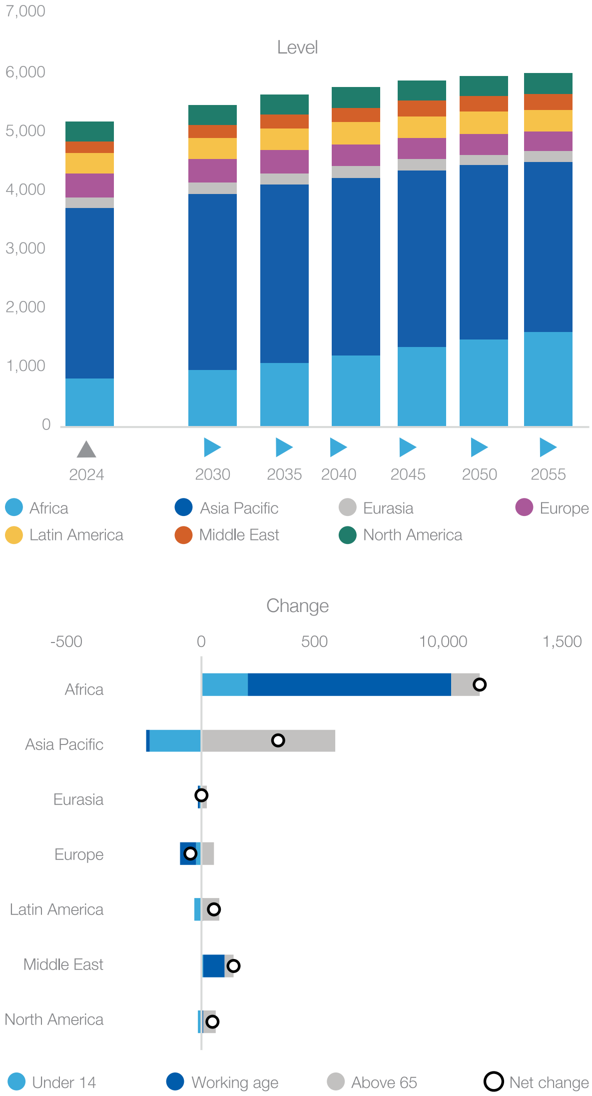
The global age structure is undergoing a profound transformation as fertility declines, and longevity improves. **The proportion of people aged 65 years and above is projected to rise from about 10% in 2024 to nearly 18% by 2055, reaching close to 1.7 billion individuals worldwide.** This reflects steady progress in healthcare, nutrition, and living conditions, which continue to extend life expectancy in most regions. As a result, the global median age, currently around 31 years, is expected to increase to nearly 38 years by mid-century, underscoring the transition toward older populations in both developed and developing countries. Concurrently, the old-age dependency ratio, the number of people aged 65 and older per 100 working-age adults (15–64), is set to climb from roughly 16% in 2024 to 28% by 2055, highlighting the growing fiscal, social, and productivity pressures associated with ageing societies.

The shift toward an ageing population is highly uneven across regions, with Africa standing out as a distinct demographic exception. While Europe, North America, and OECD Asia Pacific face shrinking workforces and rising dependency ratios, Africa's working-age population is set to expand dramatically, by nearly 68% between 2024 and 2055, equal to almost global net increase in the labour force over this period (Figure 1.3). Starting from a 16% share of the global working-age population in 2024, the continent is projected to represent 27% of the global labour force by 2055. By then, **Africa's working-age population is expected to exceed 1.6 billion, placing it on top of India and nearly 2.5 times larger than declining China, whose working-age population is projected to fall to 670 million by 2055.** This demographic shift positions Africa as a potential engine of global labour supply and economic expansion, provided that sustained investment in education, health, and employment creation enables the continent to realise its demographic dividend and turn it into an economic dividend.

In stark contrast, Europe's working-age population is projected to decline both in absolute terms and as a share of the total population. The proportion of people

Figure 1.3

Global working age population outlook by region, 2024-2055 (millions)



Source: 2024 Revisions of United Nations World Population Prospects

aged 15–64 years is expected to fall from around 64% in 2024 to 57% by 2055, reflecting a steadily shrinking labour force. At the same time, Europe's total population is set to contract, making it not only smaller but also significantly older. The share of the elderly population (65 years and above) is projected to rise from 22% in 2024 to nearly 30% by 2055, reinforcing the region's position as the world's most aged society. This demographic shift underscores mounting challenges for economic growth, fiscal stability, and labour productivity, as the balance between active workers and retirees continues to narrow.

The implications of Europe's ageing population are further accentuated by the rapid rise in its old-age dependency ratio (number of people aged 65 and over per 100 people of working age), which is projected to increase from about 31% in 2024 to an overwhelming 52% by 2055. In practical terms, this means that by around mid-century, there will be one person aged 65 or older for every two individuals of working age. Such a demographic imbalance imposes mounting economic and social pressures on a shrinking labour force, with significant repercussions for pension sustainability, healthcare systems, and social welfare programmes. The resulting fiscal burden may constrain public finances and economic growth, while simultaneously intensifying the need for productivity gains, labour market reforms, and immigration to offset the effects of an ageing society.

1.1.3 Declining household size

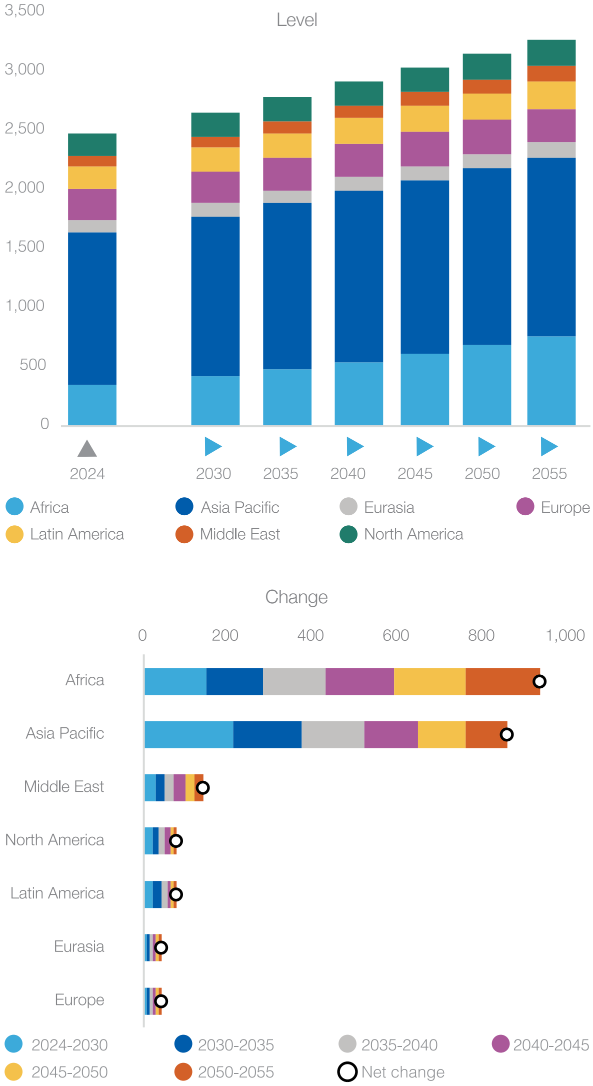
The growth in the number of households is emerging as a critical demographic driver of future energy and infrastructure demand. **According to the UN population prospects projections, the total number of households worldwide is expected to expand by about 28% between 2024 and 2055, rising from roughly 2.5 billion to 3.2 billion.** This pace far exceeds the projected 20% increase in the global population over the same period, underscoring the influence of declining household sizes, urbanisation, and ageing populations. Even as population growth slows, more people will live in smaller and often single-occupant households, an evolution that will intensify demand for housing, energy, appliances, and municipal services, particularly in emerging and urbanising regions (Figure 1.4).

A substantial share of the global rise in households will be concentrated in Africa and the Asia Pacific, which together are projected to account for nearly 80% of the total net increase by 2055. Africa alone is expected to add close to 400 million new households between 2024 and 2055, propelled by robust population growth, accelerating urbanisation, and a persistently youthful demographic profile. The Asia Pacific region will contribute an additional 219 million households, reflecting the combined impact of economic development, higher urbanisation rates, and a steady decline in average household size across rapidly industrialising economies. Latin America and the Middle East are also expected to record moderate household growth, supported by ongoing urban transition and improvements in living standards. By contrast, Europe and North America will experience only marginal increases, as household formation slows amid population ageing, saturation of urban expansion, and in some cases, absolute population decline.

The average global household size is projected to decline steadily, from about 3.3 persons per household in 2024 to around 3.0 by 2055, marking a continued shift toward smaller and more individualised living arrangements. This transition reflects profound social and demographic transformations. Rising numbers of single-person households, particularly in urbanised and high-income regions, are driven by higher incomes,

Figure 1.4

Global number of households outlook by region, 2024-2055 (millions)



Source: 2024 Revisions of United Nations World Population Prospects

shifting cultural norms, delayed marriage, and greater residential mobility. The ageing of populations in Europe, OECD Asia Pacific, and North America is also leading to more elderly people living alone or in small family units. Meanwhile, declining fertility rates in the Asia Pacific, Middle East, and parts of Africa contribute to fewer children per household. The continued increase in female labour-force participation, as more women pursue careers and financial independence, further reinforces this trend toward smaller family structures. Collectively, these forces are transforming not only social composition but also patterns of housing demand, urban infrastructure, and residential energy use, as smaller households tend to consume more energy per capita despite their efficiency gains per dwelling.

These evolving household patterns carry profound implications for energy consumption and infrastructure planning. As household sizes shrink, per-capita energy use typically rises, since fewer individuals share appliances, lighting, and space-conditioning systems. This leads to higher energy intensity per person in the residential sector, especially in densely urbanised areas where smaller dwellings dominate. Moreover, smaller and more diverse household types, single occupants, elderly households, and dual-income families, tend to rely more heavily on individual heating, cooling, and electronic devices, amplifying demand for electricity and distributed energy services. The rapid growth of households in Africa and the Asia Pacific, where urbanisation and income growth are accelerating, is expected to be a major driver of global residential energy demand, particularly for electricity and natural gas. This expansion will intensify the need for reliable power generation, grid reinforcement, and clean-cooking infrastructure, underscoring the critical intersection between demographic transformation and sustainable energy development.

The shift toward smaller and more numerous households will have far-reaching consequences for housing demand, urban planning, and utility provisioning. With more than 620 million new households expected to emerge across Africa and the Asia Pacific by mid-century, large-scale investments in residential construction, energy infrastructure, and utility networks will be essential to accommodate growth sustainably. Expanding access to electricity, clean cooking, and efficient housing will be central to improving living standards while managing the environmental footprint of urban expansion. In contrast, developed regions, where household growth is slower and populations are ageing, will increasingly focus on enhancing energy efficiency, retrofitting existing buildings, and adapting energy systems to the needs of smaller, older households. Together, these divergent regional pathways underscore how demographic and social change will reshape both the scale and structure of residential energy demand over the coming decades.

1.2 Economic growth assumptions

Energy demand is primarily shaped by the evolving interaction between economic growth and the value-added performance of individual sectors. Within the GECF Global Gas Model (GGM), projections of economic activity by region and sector are treated as exogenous drivers that underpin the model's demand outlook. This section outlines the core assumptions behind these trajectories, explaining the analytical rationale, methodological foundations, and supporting evidence that inform their integration into the modelling framework.

1.2.1 Current developments and short-term outlook

The global economy stands at a pivotal inflection point, as many of the forces that underpinned the robust expansion of the past five decades are now reversing course. After a brief period of stabilisation in late 2024, growth momentum has weakened amid a reordering of policy priorities, particularly in the United States, and broader adjustments across major economies. Trade policy uncertainty remains elevated in the absence of durable multilateral agreements, while shifts in fiscal, migration, and development aid policies are reshaping global demand and capital flows. In several advanced economies, looser fiscal stances have raised concerns over debt sustainability and cross-border spillovers, whereas low-income countries are facing rising vulnerabilities from tighter external financing and reduced development support. Meanwhile, structural reforms have stalled, leaving the world economy exposed to weaker productivity growth, intensifying fragmentation, and a more complex and uncertain policy environment.

Global annual growth moderated from 2.8% in 2024 to an estimated 2.6% in 2025 and is expected to remain at 2.6% in 2026, reflecting weaker momentum across most regions amid persistent policy and trade uncertainty. Among advanced economies, growth in the OECD area slowed to an estimated 1.5% in 2025 and is expected to edge slightly higher to 1.6% in 2026, below the 1.8% expansion recorded in 2024. In the United States, output growth is estimated to have decelerated to 1.8% in 2025 and is forecast to ease further to 1.7% in 2026, as tighter financial conditions, slower employment gains, and elevated trade barriers offset the boost from AI-driven investment and resilient household consumption. In Europe, activity is estimated to have strengthened only gradually, rising to 1.2% in 2025 and is expected to reach 1.5% in 2026, with lingering uncertainty, higher tariffs, and soft external demand weighing on exports. Gains from improving real wages and fiscal easing in Germany, alongside robust performance in Ireland, provided partial support, allowing the region to expand broadly in line with potential by 2026. In Japan, growth is estimated to have recovered modestly from 0.1% in 2024 to 0.6% in 2025 and is expected to remain at 0.6% in 2026, supported by improving real incomes and private consumption, although policy uncertainty and weaker external demand continue to constrain the pace of recovery.

Across non-OECD economies, growth strengthened moderately from 4.2% in 2024 to an estimated 4.7% in 2025, before easing to 4.3% in 2026. The temporary acceleration in 2025 reflected the impact of fiscal support, inventory rebuilding, and resilient household spending in several large emerging markets, partly offsetting the drag from weaker external demand in advanced economies. The subsequent moderation underscores the effects of rising borrowing costs, subdued export growth, and limited access to development finance, which weigh particularly heavily on low-income countries. In China, growth is estimated to have stabilised at 3.9% in 2025 and is expected to remain at 3.9% in 2026, as short-term gains from front-loaded trade and fiscal stimulus fade amid property-sector weakness, elevated tariffs, and fragile private-sector confidence. In India, output is estimated to have expanded by 6.0% in 2025 and is forecast to rise to 6.1% in 2026, supported by robust domestic demand, infrastructure investment, and strong services exports, though tempered by weaker global markets and tighter monetary policy. Collectively, these trends illustrate a world in which emerging and developing economies continue to outperform advanced peers, yet face intensifying challenges from financial tightening, trade fragmentation, and constrained policy space.

The near-term global outlook in 2025 was shaped by an interplay of cyclical and structural forces that continued to weigh on investment and confidence. As inflation receded across most regions, many central banks began transitioning toward a more accommodative monetary stance, providing partial relief to households and firms. However, the lagged effects of earlier tightening remained evident, particularly in housing, credit, and capital investment. Fiscal policy remained constrained in most economies, as elevated debt levels and higher servicing costs limited the scope for counter-cyclical stimulus. While disinflation and lower interest rates may help stabilise activity, global growth is expected to remain below its historical average through 2025–2026, reflecting a fragile equilibrium between easing inflationary pressures and slowing real demand.

Beyond these cyclical developments, the global economy is increasingly shaped by longer-term structural trends. Demographic ageing, slowing productivity, and rising inequality are constraining potential output in advanced economies, while the productivity benefits of technological innovation, particularly from AI and digitalisation, remain unevenly distributed. In emerging and developing economies, favourable demographics are offset by infrastructure gaps, limited industrial diversification, and institutional challenges that inhibit inclusive growth. Persistently high borrowing costs and limited access to external financing have further hindered capital accumulation, curbing these countries' ability to translate demographic potential into sustained productivity gains.

The balance of risks to the outlook remains tilted to the downside. Geopolitical tensions, protectionist policies, and fragmented trade relations are eroding trust, dampening investment, and disrupting supply chains. High real interest rates, mounting public debt, and expanding defence budgets are placing additional strain on fiscal positions. Meanwhile, global equity markets, fuelled by optimism over AI-related productivity gains, risk diverging from underlying fundamentals, raising the potential for abrupt corrections and renewed volatility. Slower growth in China, lingering trade disputes, and fluctuations in commodity markets further heighten uncertainty, reinforcing a fragile and uneven recovery across regions.

The evolving economic environment is also constraining progress toward sustainable development and income convergence. The slowdown in global activity, combined with limited fiscal space and declining investment flows, is reducing the resources available for infrastructure, education, and climate resilience, key enablers of long-term development. Rising trade barriers and tariff-related cost pressures are eroding real incomes, amplifying social inequality, and constraining consumption in low- and middle-income economies. Structural weaknesses, including high debt burdens, inadequate diversification, and vulnerability to climate shocks, further limit their growth potential. As a result, the convergence in per-capita income that characterised previous decades has slowed markedly, with many developing countries unable to sustain growth rates sufficient to narrow the gap with advanced economies. The outcome is an increasingly unequal and fragmented global landscape, where economic progress and technological gains are concentrated among a smaller group of countries, and the goal of shared prosperity and sustainable development remains increasingly elusive.

1.2.2 Long-term economic growth prospects

The long-term trajectory of the global economy toward 2055 will be shaped by profound structural transformations across economic, technological, demographic, and geopolitical dimensions, marking a decisive shift from the hyper-globalisation and rapid productivity expansion that defined the past half century. **Growth will increasingly depend on total factor productivity (TFP), the efficiency with which labour, capital, and technology interact, driven by digitalisation, automation, and artificial intelligence (AI).** These forces will open new frontiers of innovation while amplifying divergence between economies that effectively harness them and those constrained by structural, financial, or institutional limitations.

The first and most visible transformation is the reconfiguration of globalisation. After decades of seamless integration and creation of global supply chains, the world economy is evolving toward regionalised interdependence. Global trade is expanding more slowly than GDP as economies prioritise resilience, strategic autonomy, and national security in supply-chain design and economic development. Industrial policy has returned to prominence, with leading economies adopting large-scale initiatives to secure critical technologies, resources, and manufacturing capacity. The resulting landscape reflects a shift from global efficiency to regional resilience, an environment of "slowbalisation" in which global value chains are reorganised around geopolitical alignment. While this transformation strengthens regional partnerships, such as Regional Comprehensive Economic Partnership (RCEP) in Asia, the African Continental Free Trade Area (AfCFTA) in Africa, and Gulf Cooperation Council (GCC) integration in the Middle East, it also reduces allocative efficiency and constrains productivity gains, keeping global TFP growth below its historical average despite accelerating technological progress.

Demographic dynamics will further redefine the structure of the global economy. Population growth is slowing, but regional imbalances are widening. As illustrated in Section (1.1), advanced economies face ageing populations, shrinking labour forces, and mounting fiscal pressures from health and pension systems. Conversely, developing regions, particularly in Africa and South Asia, will account for nearly entire global labour-force expansion. These opposing trajectories will reshape savings, investment, and consumption patterns. In mature economies, productivity-enhancing technologies and automation will increasingly compensate for declining labour supply, while in younger economies, demographic potential will depend critically on investment in education, industrialisation, and digital inclusion. The traditional correlation between population growth and economic output will weaken as productivity becomes the dominant driver of long-term potential growth.

Technological innovation and digital transformation will be the principal sources of future productivity gains. Advances in AI, automation, and data-driven decision-making are redefining production processes and service delivery. Unlike earlier technological revolutions, the current wave of innovation extends into cognitive domains, enhancing efficiency and adaptability across manufacturing, logistics, healthcare, and energy systems. AI and digital infrastructure are expected to contribute substantially to global TFP growth over the next decades, partially offsetting structural headwinds from demographics and deglobalisation. Yet these benefits will accrue unevenly. Economies with strong digital ecosystems, skilled workforces, and institutional flexibility will capture the lion's share of productivity gains, while others risk technological dependency and widening development gaps. Concentration of innovation within a small group of advanced economies and global technology firms could entrench asymmetries in knowledge, investment, wealth and value creation leading to worsening global income and wealth inequality.

The geographic centre of economic activity will continue its gradual shift toward emerging and developing countries. By 2055, these countries are projected to account for roughly 60% of global GDP, up from 39% in 2024. The transformation will, however, be heterogeneous. Countries that integrate digital technology into industrial policy, foster innovation, and build resilient infrastructure will accelerate convergence, while those constrained by debt, weak institutions, or limited access to capital may experience slower progress. The ability to enhance TFP through knowledge diffusion, innovation, and human capital development will determine whether economies sustain long-term convergence or remain trapped in structural stagnation.

The global transformation toward low-carbon development adds further complexity. The transition to sustainable energy systems will reshape industrial structures, investment patterns, and trade relationships. Achieving environmental objectives while safeguarding energy security and economic development will require vast capital mobilisation and technology diffusion across all regions. Just, orderly, and equitable transitions, tailored to national circumstances, will be essential to avoid deepening inequalities between advanced and developing economies. Properly managed, these transitions can unlock long-term productivity gains through low-carbon technologies, efficiency improvements, and innovation spillovers. However, the pace and sequencing of the transition must reflect differentiated capabilities and development priorities to ensure inclusiveness and stability across regions.

Overall, these megatrends point to a global economy that grows more slowly but transforms more profoundly. Ageing populations, regionalisation, and the reordering of industrial structures will constrain growth potential, while digitalisation, innovation, and human capital development will shape new frontiers of productivity. Total factor productivity will emerge as the defining metric of long-term economic performance, reflecting each economy's capacity to innovate, adapt, and sustain progress within its own structural constraints. By mid-century, the world is likely to be more technologically advanced yet more regionally diverse, with prosperity increasingly determined by how effectively nations convert knowledge, digital capacity, and institutional resilience into sustainable and inclusive productivity growth.

Driven by the above factors, global GDP is projected to expand by about USD 123 trillion (real terms) between 2024 and 2055, reaching nearly USD 233 trillion by the end of the forecast period (Table 1.2). This corresponds to an average annual growth rate of 2.4%, signalling a gradual moderation from the 2.9% average recorded over the past three decades. The slowdown reflects the global economy's structural maturation, slower labour-force growth, stabilising investment returns, and the levelling of consumption in advanced markets. Long-term growth will rely less on factor accumulation and more on innovation, knowledge diffusion, and institutional adaptability.

Over the long term, non-OECD economies are projected to outpace OECD countries in economic expansion, signalling a continued rebalancing of global income, production, and consumption toward emerging markets. OECD economies are expected to reach about USD 109 trillion by 2055, growing at an average annual rate of 1.1%, reflecting their mature economic structures, slower capital accumulation, and subdued productivity gains. By contrast, non-OECD economies are forecast to expand by 3.4% annually, reaching nearly USD 124 trillion and accounting for around 53% of global GDP by mid-century. This shift underscores the rising economic weight of developing regions, particularly in Asia, Africa, and the Middle East, where sustained urbanisation, industrial diversification, and expanding consumer markets will underpin long-term demand growth. The increasing dominance of non-OECD economies in global output and consumption will have wide-ranging implications: trade patterns will realign toward South-South cooperations, energy and infrastructure investment will concentrate in emerging markets, and the centre of global economic influence will continue to move toward the developing world, reshaping the foundations of growth, finance, and resource demand over the coming decades.

Additionally, the service sector, in the long term, is set to consolidate its position as the main driver of

Table 1.2

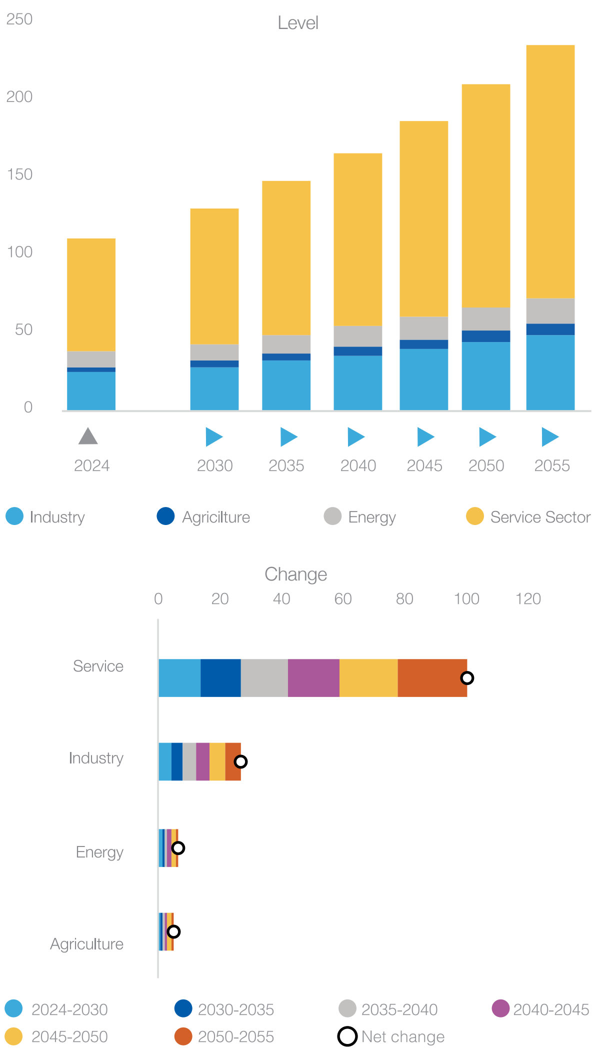
Global GDP outlook by region, 2024-2055 (real billion USD, base year=2024)

	2024	2030	2035	2040	2045	2050	2055	Net change	Growth (%, p.a.)
Africa	2,478	3,195	3,975	4,938	6,113	7,607	9,502	7,024	4.3%
Asia Pacific	36,865	45,698	54,898	65,019	76,025	88,299	101,537	64,672	3.3%
Eurasia	3,081	3,575	4,005	4,468	4,976	5,496	6,082	3,001	2.2%
Europe	25,984	28,413	30,592	32,808	35,064	37,404	39,845	13,861	1.4%
Latin America	5,104	5,974	6,913	7,973	9,159	10,458	11,929	6,825	2.7%
Middle East	3,316	4,049	4,689	5,401	6,180	7,070	8,060	4,744	2.9%
North America	33,272	37,258	40,700	44,220	47,940	52,070	56,443	23,171	1.7%
World	**110,100**	**128,163**	**145,772**	**164,827**	**185,458**	**208,405**	**233,397**	**123,297**	**2.4%**

GECF Secretariat based on data from the GECF GGM global economic growth, with its share of global GDP projected to rise from 66% in 2024 to about 70% by 2055 (Figure 1.5). In contrast, the industrial sector's contribution is expected to stabilize at nearly 20% over the same period. This gradual structural shift reflects the transition toward more knowledge- and technology-driven economies, where value creation increasingly stems from digitalisation, innovation, and high-skilled activities. The expansion of information technology, financial services, healthcare, and education continues to accelerate productivity growth, while the integration of artificial intelligence and automation reshapes the boundary between manufacturing and services, boosting efficiency and reducing resource intensity. Furthermore, rising urbanisation and income growth in emerging economies further reinforce this transformation. As the global middle class expands, particularly in Asia, Africa, and Latin America, demand is shifting toward consumer-oriented services such as retail, transport, entertainment, and professional activities.

Figure 1.5

Global GDP outlook by sector, 2024-2055 (real USD trillion, base year = 2024)



Source: GECF Secretariat based on data from the GECF GGM

An examination of incremental value-added growth underscores the scale of this structural shift. **Between 2024 and 2055, the service sector is expected to generate more than 72% of the total increase in global value added, while the industrial sector will account for roughly one-fifth of the expansion.** This pattern points to a fundamental reorientation of the world economy toward a service-dominated structure, driven by rapid technological progress, the digitalisation of production and consumption, and evolving policy and consumer preferences that increasingly favour knowledge-intensive and low-carbon activities.

Meanwhile, **global per capita GDP is projected to rise steadily, growing at an average annual rate of 1.8% through 2055, reaching approximately USD 23,900 (real terms) per person.** While this rate is broadly comparable to the 1.7% annual increase observed over the past three decades, the underlying drivers of growth are undergoing a profound shift. In previous decades, expansion was propelled by both rapid population growth and rising economic output, whereas future gains will rely primarily on technological innovation, productivity improvements, and structural transformation across economies. As global population growth slows and expansion in labour force plateaus, advances in efficiency, digitalisation, and human capital development will become the principal sources of long-term prosperity, marking a transition from growth driven by quantity to one increasingly driven by quality and innovation.

1.2.3 Long-term economic growth outlook by region

In 2024, the Asia Pacific region stood at the centre of global economic activity, accounting for 33% of the world's GDP, the largest regional share worldwide. North America and Europe followed with 30% and 24%, respectively, while Africa and Eurasia each contributed about 3%, underscoring their relatively limited weight in the global economy.

Looking ahead, the Asia Pacific region's share of global GDP is projected to rise sharply to around 44% by 2055, more than double its share in 1993. This sustained expansion reflects the region's robust industrial base, dynamic services sector, rapid technological advancement, and expanding consumer markets, all of which reinforce its position as the principal engine of global growth. In contrast, North America and Europe are expected to see their shares decline to 24% and 17%, respectively, constrained by slower productivity gains, ageing populations, and mature consumption patterns. Africa's share is projected to rise modestly to about 4% by 2055, reflecting steady, though gradual, improvements in economic diversification, infrastructure investment, and demographic-driven consumption growth (Figure 1.6).

By 2055, the Asia Pacific region is expected to contribute roughly 52% of the total increase in global GDP, underscoring its central role in driving future economic expansion. This remarkable contribution will be fuelled by sustained industrial development, rapid digitalisation, expanding consumer markets, and continued integration into global value chains. In comparison, North America will remain a major, though smaller, growth engine, accounting for around 20% of global GDP gains, supported by its high-value service industries, particularly in technology, healthcare, and finance.

In contrast, Europe's contribution to global GDP is projected to decline markedly, accounting for just over 17% by 2055, down from much higher levels in previous decades. This reduction reflects persistent demographic headwinds, including ageing populations, declining labour participation, and subdued productivity growth, all of which constrain the region's long-term economic potential. Nevertheless, Europe is expected to preserve its competitive advantage in areas such as innovation, advanced manufacturing, and sustainable technologies, ensuring it remains a key player in global trade and climate-oriented industrial transformation despite slower aggregate growth.

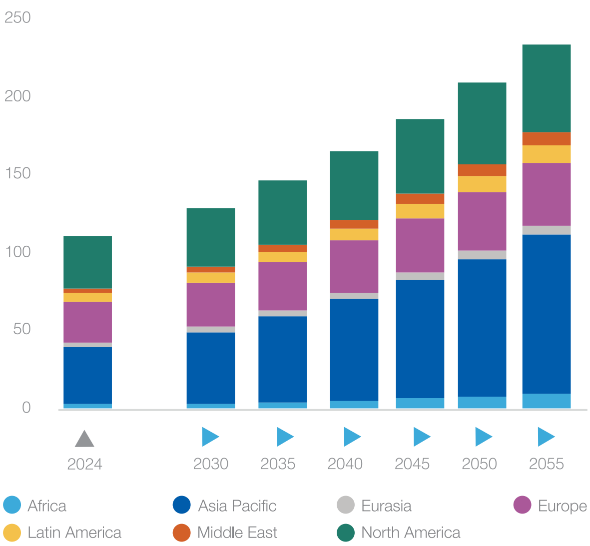
As shown in Figure 1.7, Europe is forecast to record the most modest long-term growth rate among major regions, averaging 1.4% annually through 2055, about 0.5 percentage points lower than the rate achieved between 1993 and 2024. North America is also expected to experience a gradual moderation in growth, expanding by around 1.7% per year, as mature industrial structures, slower labour-force expansion, and tighter capital productivity gains temper its long-term output trajectory relative to past performance.

Latin America is projected to record a long-term average annual growth rate of 2.7%, slightly above the global average for the forecast period. This steady expansion reflects the region's gradual integration into global trade and investment networks, supported by progress in industrial modernisation, renewable energy deployment, and regional market consolidation. Eurasia, by comparison, is expected to follow a more moderate growth path, averaging 2.2% per year, constrained by structural and demographic challenges that limit productivity gains and investment flows. In contrast, the Middle East is forecast to grow at a stronger rate of 2.9% annually, underpinned by economic diversification strategies, major energy and infrastructure investments, and deepening trade and financial linkages with Asia and other emerging markets, all of which reinforce its evolving role as a dynamic bridge between global energy and trade systems.

While the global economy is projected to expand by USD 123 trillion over the forecast period, this growth is not expected to translate into an equitable distribution of income across regions. As shown in Figure 1.8, stark disparities persist. In 2024, Africa, which accounts for around 18% of the global population, has an average per capita income of only USD 1,688 per year, roughly one-eighth of the global average. By contrast, North America, with just 6% of the world's population, enjoys an average income of about USD 65,000 per person, nearly 38 times higher than Africa's. These imbalances contribute to a global Gini index of 52% in 2024,

Figure 1.6

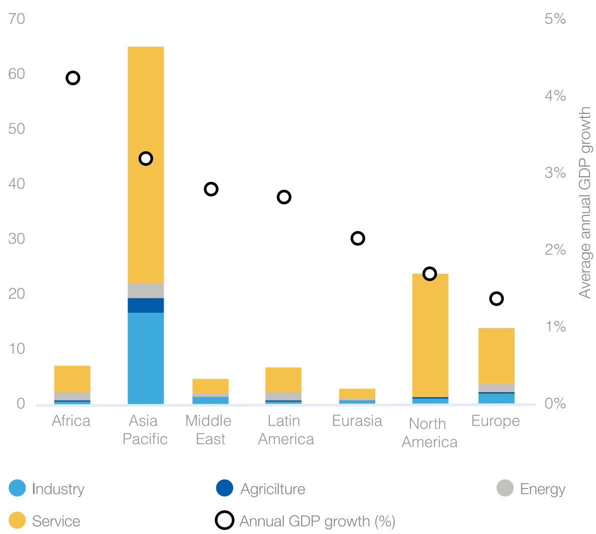
Global GDP outlook by region, 2024-2055 (real trillion USD, base year=2024)



Source: GECF Secretariat based on data from the GECF GGM

Figure 1.7

Regional GDP change outlook by sector, 2024-2055 (real trillion USD, base year=2024)



Source: GECF Secretariat based on data from the GECF GGM

underscoring the high degree of inequality in income distribution among countries.

Looking ahead, regional income convergence is expected to advance gradually but unevenly. By 2055, global per capita income is projected to reach USD 23,900, growing by an average of 1.8% per year from 2024 levels. The Asia Pacific region, propelled by sustained industrialisation, technological progress, and rising living standards, is forecast to surpass the Middle East, Latin America, and Eurasia in per capita GDP, ranking just below Europe and North America. Despite rapid population growth, Africa's per capita income is also expected to double by 2055, supported by urbanisation, infrastructure development, and stronger regional integration. As a result, global income inequality is projected to decline modestly, with the Gini index falling to around 58% by 2055, signalling gradual, though limited, progress toward a more balanced global distribution of income.

The next section of this chapter is dedicated to the economic growth prospects of each region, providing insights into their unique trajectories.

1.2.3.1 Africa

Africa, which accounts for only 2% of global GDP, is estimated to grow by around 4.1% in 2025, maintaining the recovery momentum observed in 2024 amid a complex external environment. The outlook reflects a balance between resilient domestic demand, moderating inflation, and rising investment activity on one side, and tight financing conditions, elevated debt levels, and limited fiscal space on the other. Although inflation is easing across much of the region, high borrowing costs and debt-servicing pressures continue to constrain development spending and investment capacity.

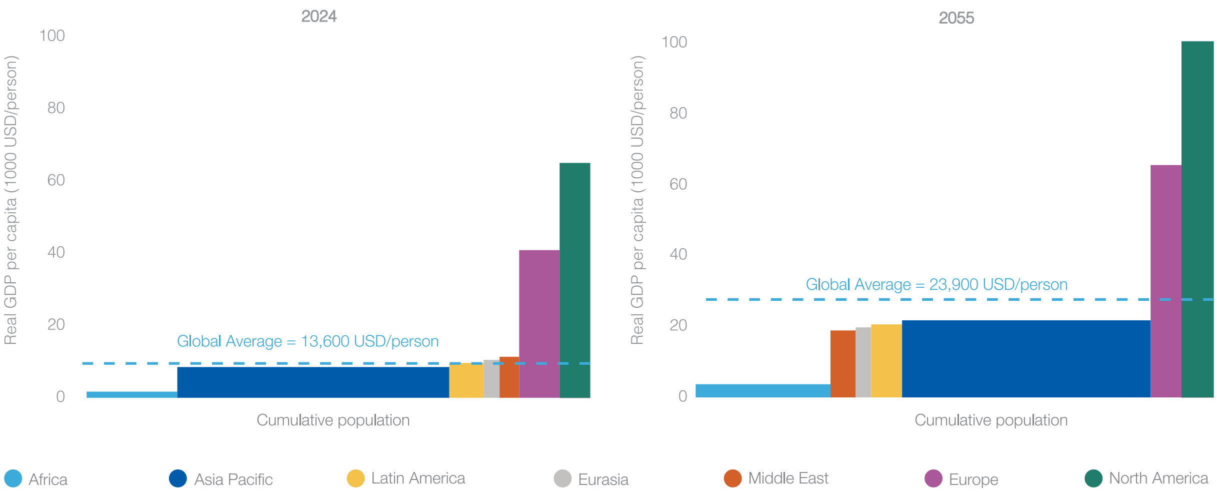
Growth will remain uneven across countries, supported by strong performances in non-resource-exporting economies and continued progress in infrastructure, trade integration, and digitalisation. Meanwhile, climate-related shocks and global economic uncertainty persist as key downside risks, weighing on agricultural productivity and long-term growth prospects.

North Africa, accounting for roughly one-third of Africa's total output in 2024, is positioned for steady long-term expansion supported by structural reform momentum, infrastructure development, and continued integration into global value chains. The region's economy is projected to grow by an average 2.8% per year through 2055, consistent with a gradual transition toward a more diversified and investment-driven growth model. In the medium term, growth is expected to average around 3.6% annually by 2030, underpinned by improvements in business environments, investment in logistics and energy systems, and rising regional trade. These gains are expected to form the basis for long-duration macroeconomic stability, even as growth moderates over the longer horizon in line with global demographic and productivity trends.

Within the region, Egypt is expected to remain the principal growth engine, with long-term output projected to expand at approximately 3.8% per year. By 2055, Egypt is expected to account for more than half of North Africa's GDP, supported by sustained population growth, strategic logistics positioning, rising industrial capacity, and continued investment in technology, energy, and services.

Sub-Saharan Africa is projected to grow at a stronger pace, averaging 4.6% annually to 2055, up from around 3.9% observed between 1993 and 2024. This sustained acceleration reflects structural drivers such as

Figure 1.8
Regional real GDP per capita outlook, 2024 and 2055 (real USD/person, base year =2024)



Source: GECF Secretariat based on data from the GECF GGM

rapid urbanisation, expanding labour forces, increased investment in digital and physical infrastructure, and deepening intra-African trade supported by the African Continental Free Trade Area. As a result, Sub-Saharan Africa's share of continental GDP is projected to approach 80% by 2055, compared with just under 70% in 2024.

Growth dynamics will remain heterogeneous across the subcontinent. East Africa is expected to demonstrate particularly strong momentum, supported by diversified economic bases, expanding technology-enabled services, and increased regional connectivity. Kenya and Mozambique are projected to grow annually at about 5.8% and 5%, respectively, while the broader East African region is expected to average above 5.7% per year by mid-century. West Africa is also poised for robust expansion, driven by demographic scale, logistical development, and rising resource and services-sector investment. Mauritania and Senegal are among the fastest growers, contributing to a regional long-term growth average of about 5.1% per year.

By contrast, the continent's two largest economies, Nigeria and South Africa, are expected to grow more moderately over the next three decades, reflecting ongoing economic rebalancing and slower productivity gains relative to peers. Their combined contribution to Sub-Saharan Africa's GDP is projected to decline from around 30% in 2024 to roughly 17% by 2055, signalling a gradual diffusion of economic weight toward a broader set of emerging regional growth centres.

1.2.3.2 Asia Pacific

The Asia Pacific region, the largest contributor to the global economy in 2024, is expected to remain the principal driver of global growth through the medium to long term, expanding at rates above the world average. The region's 4.1% growth in 2024 underscores its resilience amid tighter global financial conditions and uneven recoveries elsewhere. Although growth is projected to moderate to 3.5% per year in 2025 and 2026, the slowdown reflects a normalisation from post-pandemic rebounds rather than a loss of momentum. Strong labour-market recovery, deepening regional trade integration, and accelerating adoption of digital technologies continue to underpin activity, offsetting external headwinds. The region now contributes nearly 60% of annual global output expansion, reflecting its centrality in global production, technology, and consumption networks.

Following a strong rebound in 2023, China's economy has entered a phase of structural realignment, expanding by around 5% in 2024 and estimated to grow by about 4% per year in 2025–2026. The moderation reflects slowing property-sector investment, ageing demographics, and the ongoing transition from investment-driven to consumption-based growth. This rebalancing, though weighing on near-term activity, is fostering a more sustainable model centred on innovation, green industries, and advanced manufacturing. It should be highlighted that policy efforts to expand household income and strengthen private-sector confidence will be pivotal in sustaining domestic demand. Nonetheless, weaker import demand from China and slower trade in intermediate goods are expected to temper regional spillovers, reshaping intra-Asian trade patterns and prompting greater diversification across supply chains.

Elsewhere in the region, growth is increasingly driven by domestic consumption, services, and technology-intensive industries. India stands out as a key driver of regional dynamism, projected to expand by 6.1% in 2025–2026 on the back of infrastructure investment, rapid digitalisation, and expanding manufacturing capacity. Broader regional growth remains supported by the relocation of global supply chains, as firms diversify production from China toward emerging ASEAN economies such as Indonesia, Viet Nam, and the Philippines. These economies are benefiting from improved logistics, stable macroeconomic policies, and large domestic markets that attract new manufacturing and services investment. The continued implementation of the RCEP and deepening cross-border infrastructure links are reinforcing Asia's internal trade ecosystem, insulating it from global demand volatility.

In OECD Asia Pacific, the long-term outlook remains stable but shaped by demographic and productivity dynamics. The sub-region is expected to grow by 1.2% annually between 2024 and 2055, consistent with trend potential. Japan's growth, projected at 0.6% per year, remains constrained by an ageing population and declining labour supply, though advances in automation, AI diffusion, and robotics help to offset productivity losses. Australia, in contrast, is forecast to expand by 2.1% per year, supported by investments in renewable energy, digital services, and higher-value exports. Over the long term, technological adoption and the energy transitions are expected to be key differentiators across OECD Asia, gradually shifting output composition toward clean-technology industries and advanced services.

The non-OECD Asia sub-region, accounting for roughly one-quarter of global GDP, is projected to grow by 3.7% annually through 2055, down from the exceptional 6.6% per year recorded over the previous three decades, as economies mature and potential output converges toward advanced-economy levels. India and China together contribute nearly 80% of this output, with India maintaining stronger momentum due to favourable demographics, expanding industrial capacity, and growing integration into global technology and services trade. China's structural deceleration to around 3.2% per year long-term growth reflects productivity headwinds, high debt levels, and the diminishing gains from capital accumulation, yet it remains the single largest contributor to incremental global output over the forecast horizon.

Southeast Asia, representing about 11% of the region's GDP in 2024, continues to embody resilient and diversified growth, projected to average 3.9% annually through 2055. Economic expansion is driven by rapid urbanisation, an emerging middle class, and a vibrant private sector. The Philippines and Viet Nam are forecast to achieve the fastest growth in the sub-region, 5.2% and 4.9% per year respectively, on the back of strong manufacturing, export diversification, and digital-economy expansion. Indonesia, accounting for 35% of Southeast Asia's output in 2024, is expected to sustain growth of 4.2% annually, supported by domestic demand, energy-sector investment, and policy initiatives to enhance downstream industrialisation. These trends highlight the region's role as a hub for supply-chain diversification, energy investment, and technology transfer, strengthening its long-term competitiveness.

1.2.3.3 Eurasia

Following the contraction of previous years, Eurasia's economy extended its rebound through 2023 and 2024, recording GDP growth of 4.3% and 4.4%, respectively. This strong recovery is now estimated to lose momentum in 2025 and 2026, with growth projected to slow to around 2.8% per annum, as cyclical tailwinds fade and macroeconomic conditions tighten. The moderation reflects the combined impact of restrictive monetary policy, external trade re-routing under ongoing sanctions, and persistent structural bottlenecks, particularly in investment, labour supply, and productivity. Despite these constraints, the region's economic fundamentals remain stable, with robust domestic demand, resilient energy exports, and rising intra-regional trade offering partial offsets to weaker external demand.

In 2024, Russia, which accounts for nearly 70% of Eurasia's total GDP, outperformed expectations with growth exceeding 4%. This expansion was driven primarily by strong private consumption, high public spending, and sustained investment activity supported by an exceptionally tight labour market. Industrial production and import substitution continued to strengthen domestic supply chains, while elevated commodity prices boosted fiscal revenues. However, persistent inflation pressures led the Central Bank of Russia to maintain a tight monetary stance, raising real interest rates and restraining household consumption and private investment. Consequently, growth is projected to slow to 1% in 2025 and 1.2% in 2026, as the effects of earlier policy tightening, elevated borrowing costs, and reduced fiscal stimulus weigh on demand. The deceleration also reflects the economy's adjustment to capacity constraints and ongoing reorientation toward new trade partners in Asia, the Middle East, and Africa.

Over the long term, Eurasia's economic growth is projected to stabilise at an annual average of 2.2% by 2055, reflecting the region's gradual and uneven expansion. Russia, the dominant economy, is expected to grow at 1.6% per year, supported by its resource-based industries, strategic infrastructure investments, and diversification initiatives aimed at reducing dependence on hydrocarbon exports. While demographic pressures and productivity challenges persist, the expansion of energy trade corridors and deeper integration into Asian markets will underpin moderate but steady growth.

Among the smaller economies, Uzbekistan is anticipated to be the region's fastest-growing economy, with long-term GDP growth averaging 4.8% annually through 2055. This reflects the country's reform-driven business environment, rising energy exports, and strategic investments in logistics and power infrastructure aligned with its role in the Chinese Belt and Road Initiative. Kazakhstan is also expected to strengthen its position, with its share of Eurasia's GDP projected to reach 11% by 2055, nearly two percentage points higher than in 2024. The country's growth prospects are anchored in expanding energy capacity, agricultural productivity gains, and its strategic role as a supplier of critical minerals and a regional transport hub.

1.2.3.4 Europe

Europe's economic recovery is progressing at a cautious pace, supported by lower energy prices, improving supply chain conditions, and a gradual rebound in household purchasing power. The easing of inflationary pressures and modest wage gains are helping to restore real incomes, while resilient labour markets continue to underpin consumption. However, the region's growth remains constrained by persistent headwinds, including elevated core inflation, weak productivity growth, and heightened geopolitical uncertainty. Growth is estimated to reach 1.1% in 2024 and slightly improve to 1.2% in 2025, reflecting a fragile balance between policy normalisation and subdued external demand. Although the immediate risks of recession have receded, the recovery remains uneven, with southern and eastern European economies displaying stronger momentum than the more industrialised core.

In the near term, economic activity is shaped by the interaction between disinflation and policy recalibration. The decline in headline inflation has allowed central banks to begin cautiously easing monetary policy, but tight financial conditions and elevated interest rates continue to weigh on credit, investment, and private consumption. At the same time, fiscal policy is shifting toward consolidation as governments seek to rebuild buffers after several years of expansionary spending. This necessary adjustment is likely to restrain demand in the short run, but it also provides an opportunity to improve fiscal sustainability and redirect resources toward growth-enhancing investments in infrastructure, defence, and climate resilience. The region's services-oriented economies are expected to benefit most immediately from improving domestic demand, while manufacturing-intensive economies such as Germany and Italy are set to face a slower recovery amid weak external trade and declining industrial competitiveness.

Over the medium term, Europe's growth trajectory will depend on its ability to realign monetary and fiscal strategies while addressing deep-rooted structural weaknesses. Policy coordination will be essential to sustain disinflation and rebuild investor confidence. A gradual easing of monetary conditions should support investment recovery, particularly in technology and green industries, while fiscal reforms are needed to ensure long-term debt sustainability. Labour market flexibility, deeper capital market integration, and greater support for innovation and digitalisation will be crucial to enhancing productivity and competitiveness.

In the long term, OECD Europe, which accounts for nearly 98% of the continent's economic output in 2024, is projected to grow at an average annual rate of 1.4% through to 2055. This moderate trend mirrors structural constraints related to ageing populations, shrinking workforces, and weak productivity growth. The ongoing energy transition adds further complexity, demanding large-scale investment in renewable infrastructure and low-carbon technologies, while geopolitical fragmentation continues to weigh on investor sentiment. Deindustrialisation in major economies such as France, Germany, Italy, and the United Kingdom has raised concerns about the erosion of industrial capacity and innovation, accelerating a shift toward service-oriented activities. This transformation, while supporting higher value-added services, may reduce the region's long-term economic resilience if not balanced by strong technological and industrial renewal.

In contrast, Türkiye is expected to emerge as a key growth centre, with a long-term average annual growth rate of 3.3%. Its favourable demographics, expanding industrial base, and strategic role as a trade and energy hub linking Europe and Asia position it to play an increasingly influential role in the regional economy. Non-OECD Europe, though smaller in scale, is also projected to record stronger long-term growth, averaging 2.1% annually by 2055. Within this group, Romania stands out as a consistent performer, growing at 1.8% per year and accounting for over 43% of non-OECD Europe's GDP by mid-century, supported by structural reforms, steady investment, and productivity convergence.

1.2.3.5 Latin America

Latin America's economic outlook for 2024 and 2025 reflects a complex balance between resilience and emerging headwinds. The region has recovered more strongly than initially anticipated from the pandemic's disruptions, with GDP growth estimated to rise from 2.2% in 2024 to 2.6% in 2025. This improvement stems from robust domestic demand, firm labour markets, and credible macroeconomic frameworks, while continued caution in monetary policy and external uncertainties act as constraints on the pace of expansion.

Although elevated commodity prices in recent years have bolstered fiscal revenues and external balances, the region now faces a moderation in this momentum. The global policy environment is shifting, with trade tensions, changes in the United States import tariffs, and China's slower growth creating uncertainty for commodity exporters. These developments are particularly relevant for Latin American economies that remain reliant on exports of oil, minerals, and agricultural products. In parallel, structural changes in the United States, where growth is increasingly driven by services and non-tradable sectors, have tempered external demand for Latin American goods. Inflation is easing but remains above target in some economies, reflecting lingering pressures from exchange-rate dynamics and domestic demand. While monetary authorities have acted decisively to anchor expectations, fiscal space remains limited, as debt ratios have approached or exceeded pre-pandemic levels in several countries. Persistent structural weaknesses, such as low productivity, limited business dynamism, and concentrated market structures, continue to hinder potential growth, underscoring the urgency of reforms to foster competition, innovation, and greater trade integration.

Over the longer term, Latin America's real GDP is expected to expand at an average annual rate of 2.7%, signalling a modest acceleration relative to past performance. This growth trajectory will be underpinned by demographic advantages, investment in the energy and critical-minerals sectors, and deeper regional trade integration. A youthful and expanding labour force, combined with targeted improvements in education and skills, can lift productivity and technological absorption. Moreover, the global shift toward low-carbon and digital economies creates new opportunities: Latin America is well-positioned to supply renewable energy and key transition minerals such as lithium, copper, and nickel. Enhanced regional cooperation in infrastructure, logistics, and digital connectivity will be essential to unlock these opportunities, helping to build resilience and reduce dependence on extra-regional markets. Continued urbanisation and the expansion of the middle class will further boost domestic demand for housing, infrastructure, and consumer goods, transforming cities into dynamic growth hubs.

Within this broader picture, Brazil and Argentina, which together represent about 60% of Latin America's GDP in 2024, will remain pivotal in shaping the region's trajectory. Brazil's outlook is supported by strong agricultural exports, a diversified industrial base, and progress in structural reforms that sustain investor confidence. Over the long term, Brazil's GDP is expected to grow by 2.9% annually, aided by steady investment and domestic consumption. Argentina, despite short-term volatility, is expected to consolidate its recovery, driven by rising exports, infrastructure expansion, and the gradual implementation of macroeconomic stabilisation measures. Its long-term growth rate is projected at 2.5% per annum, reflecting progress in fiscal and institutional reforms.

1.2.3.6 Middle East

Economic activity in the Middle East in 2024 and 2025 reflects a delicate balance between resilience and uncertainty, shaped by both structural reforms and external shocks. Regional GDP growth was 1.3% in 2024, constrained by subdued oil output and heightened geopolitical tensions, yet it is projected to rise to 2.6% in 2025 as the recovery broadens. The outlook is supported by non-oil sector expansion, fiscal reform momentum, and robust domestic demand, particularly within the GCC economies, where diversification agendas continue to yield tangible results.

Across the GCC, non-oil growth remains the main driver of resilience. Construction, logistics, tourism, and technology are expanding under sustained public investment and private-sector participation, buffering the impact of moderate hydrocarbon prices. The full unwinding of OPEC+ production cuts and subsequent rebound in oil output further support short-term activity, while strong balance sheets, ample reserves, and stable financial conditions allow these economies to pursue diversification without destabilising macroeconomic frameworks.

By contrast, oil-importing and fragile economies are experiencing uneven recoveries. Improvements in agriculture, manufacturing, and tourism are helping to lift activity, yet elevated inflation, limited fiscal space, and lingering conflict risks constrain momentum.

The global decarbonisation push is reshaping regional investment priorities. The Middle East is positioning itself as a hub for renewable energy, hydrogen, and critical-mineral-based industries, capitalising on abundant solar resources and energy infrastructure. Initiatives such as Saudi Vision 2030, Qatar National Vision 2030, and the UAE Industrial Strategy are fostering new growth engines in manufacturing, logistics, and clean-energy value chains, helping to sustain non-oil revenues and attract foreign direct investment.

Over the long term, the region's average annual GDP growth is projected at 2.9% by 2055, slightly higher than the historical 2.8% average. The moderation reflects the maturation of high-income hydrocarbon economies, notably Qatar, UAE, and Saudi Arabia which together will account for over 55% of regional GDP through mid-century. Their long-term annual growth rates, 3.0%, 3.1%, and 3.3%, respectively, signal a soft landing rather than stagnation, as these economies transition toward diversified, productivity-driven models.

1.2.3.7 North America

In 2024 and 2025, North America's economic expansion remains supported by resilient consumer spending, tight labour markets, and targeted public investment in infrastructure and industrial capacity, even as new financial and trade risks emerge. In the United States, growth continues to be driven by robust household demand and strong public investment under industrial and energy transition programmes. However, the re-introduction of broad import tariffs in 2025 has added friction to global supply chains, lifted input costs, and re-ignited moderate inflationary pressures. At the same time, the extraordinary rally in technology equities, particularly AI-linked firms, has become a defining feature of the financial landscape, driving capital market gains but also heightening concerns about excessive valuations and financial vulnerability should sentiment shift. The Federal Reserve's cautious monetary easing, following a marked decline in inflation, has supported credit conditions, though high real rates and policy uncertainty continue to weigh on capital expenditure.

In Canada, growth remains moderate but stable, underpinned by steady consumption, immigration-driven labour supply, and sustained investment in clean energy and digital infrastructure. However, high household indebtedness and cooling property markets temper overall momentum. Mexico continues to benefit from strong nearshoring trends, industrial diversification, and integration into North American supply chains. Expanding manufacturing corridors, logistics hubs, and infrastructure projects are bolstering growth, although evolving United States tariff structures and trade realignment introduce new uncertainties for exporters. Across the region, large-scale investments in energy, transport, and digital infrastructure remain critical growth anchors, but rising financing costs, persistent inflation, and global trade fragmentation pose renewed headwinds. North America's GDP is estimated to have grown 2.6% in 2024, moderating to 1.7% in 2025, as the region transitions from post-pandemic resilience toward more measured, policy-dependent growth.

Over the long term, North America's structural drivers of growth are expected to evolve amid demographic and technological transitions. Slowing labour-force growth, ageing populations, and declining total factor productivity will constrain potential output, even as automation and digitalisation provide partial offsets. The ongoing AI revolution promises efficiency gains but also introduces volatility, as valuations in technology sectors increasingly decouple from underlying earnings performance. Should this exuberance unwind sharply, financial conditions could tighten abruptly, amplifying downside risks to investment and consumption. Meanwhile, widening income inequality, persistent fiscal deficits, and the need for substantial investment in energy and resilient infrastructure will define the region's macroeconomic policy agenda.

By 2055, the United States is projected to see its share of global GDP decline by 6 percentage points to 21%, reflecting faster growth in emerging markets. Nevertheless, it will remain the central pillar of regional output, contributing around 87% of North America's total GDP. Long-term United States growth is forecast at 1.7% annually, moderated by demographic constraints but supported by continued leadership in high-value services, advanced manufacturing, and clean technologies. Canada and Mexico are expected to grow by 1.7% and 2.1% annually, respectively. Canada's outlook benefits from immigration-led labour-force expansion and sustained investments in energy transitions and innovation. Mexico's momentum will be driven by nearshoring, industrial diversification, and strategic infrastructure expansion, consolidating its role as a key industrial hub in North America's re-shaped economic landscape.

1.3 Energy and carbon price assumptions

Absolute and relative energy prices influence energy consumption patterns and guide the distribution of primary and secondary energy demand across various energy options. Carbon prices also play an instrumental role in altering relative energy prices. Table 1.3. presents the assumptions for crude oil, natural gas and carbon prices.

In the Global Gas Model (GGM), prices for crude oil, natural gas, and carbon emissions are treated as exogenous variables. This section presents the reasoning behind these price assumptions. It provides a concise rationale for their inclusion and offers insights into their implications for future energy market dynamics and policy-driven transitions.

1.3.1 Crude oil prices

In 2024, the oil market reflects a delicate balance between steady demand recovery and emerging structural adjustments. Following the post-pandemic rebound and China's reopening, oil consumption remains robust, particularly in developing and emerging economies where industrialisation and urbanisation continue to fuel energy needs. However, demand growth has begun to moderate as the global economy slows and efficiency gains expand across transport and industry. Brent crude oil prices averaged around USD 81/bbl in 2024, supported by OPEC+ production discipline and limited spare capacity, yet near-term dynamics suggest a gradual softening. Easing inflation, weaker manufacturing activity, and slower Chinese demand growth are expected to temper price pressures, keeping Brent below USD 80/bbl through 2025.

Looking ahead, the long-term oil outlook is characterised by continued but slower demand growth and a gradual easing of prices in real terms. While total oil consumption is projected to expand through 2055, the composition of that growth is changing. Demand for transport fuels plateaus as electrification, efficiency improvements, and alternative energy sources gain ground, but these declines are largely offset by rising demand for non-combustion uses, including petrochemical feedstocks, lubricants, fertilisers, and medical materials. Rapid industrialisation and urban expansion in developing economies will sustain this structural demand, ensuring that oil remains an essential component of the global energy mix well beyond 205.

On the supply side, sustained investment in both conventional and unconventional resources, coupled with technological progress, is expected to enhance recovery rates and reduce production costs over time. The increasing deployment of digitalisation, automation, and advanced well technologies has lowered breakeven costs in many regions, while the growing participation of national oil companies and energy partnerships in the Middle East, Africa, and Latin America expands the supply base. Moreover, diversification of global supply sources, through frontier and offshore developments, as well as continued productivity gains in United States shale, will improve flexibility and responsiveness to market signals. These trends, together with the gradual

Table 1.3

Crude oil, hub-based natural gas and carbon prices assumptions, 2024-2055 (USD, base year=2024)

Prices	Benchmark	Unit	2024	2030	2035	2040	2045	2050	2055
Crude oil	Brent crude oil	USD 2024/bbl	81	74	74	74	72	70	70
Natural gas	Asian import gas price	USD 2024/MMBtu	11.5	8.7	9.6	10.9	12.1	12.5	13.3
	European import gas price	USD 2024/MMBtu	10.9	8.3	8.8	9.8	10.1	10.8	10.9
	United States, Henry Hub	USD 2024/MMBtu	2.3	3.1	4.4	4.5	4.6	4.8	5.1
Carbon	European ETS	USD 2024/t CO_2	72	87	89	100	129	144	160

Source: GECF Secretariat based on data from the GECF GGM

Note: 2024 is the base year and included in the table as the reference deceleration of demand growth, exert downward pressure on long-term prices.

As a result, **real Brent prices (2024 base) are projected to decline moderately over the forecast horizon, from about USD 81/bbl in 2024 to around USD 70/bbl by 2055** (Table 1.3). This long-term moderation reflects an equilibrium shaped by slower demand growth, enhanced supply efficiency, declining marginal production costs, and increased competition from alternative energy sources. However, prices are expected to remain sufficiently high to incentivise reinvestment and maintain market balance, particularly given the persistent need for new capacity to offset field decline. Overall, the outlook portrays a stable yet evolving oil market, one in which demand continues to rise but at a diminishing pace, while technological innovation, diversification, and energy transition pressures collectively anchor oil prices on a gentle downward trajectory in real terms through mid-century.

1.3.2 Natural gas prices

In 2024, global natural gas prices exhibited relative stability following two years of volatility, though regional differences persisted. In the United States, Henry Hub prices averaged USD 2.3/MMBtu, reflecting abundant supply, mild winter conditions, and record storage levels. In Europe and Asia, import prices averaged USD 10.9/MMBtu and USD 11.5/MMBtu, respectively, supported by seasonal demand, restocking needs, and competition for LNG cargoes. While supply and demand appeared more balanced than in previous years, markets remained sensitive to geopolitical tensions, extreme weather, and logistical bottlenecks that could trigger short-term volatility.

In the medium term, natural gas prices are projected to decline through 2030, driven by the unprecedented expansion of global LNG supply. The so-called third wave of LNG liquefaction projects, expected to come online between 2026 and 2030, will add substantial new capacity, mainly from Qatar, the United States, and several African producers. This surge will create an LNG overhang, increasing liquidity but marginally lowering the capacity utilisation rates of existing liquefaction plants, particularly those with higher operating costs. As a result, Asian hub-based import prices are expected to decline to around USD 8.7/MMBtu by 2030, while European spot prices fall to USD 8.3/MMBtu. In contrast, Henry Hub prices are projected to edge upward to USD 3.1/MMBtu, reflecting a gradual transition from associated to non-associated gas production and rising internal and export demand.

The decline in global gas prices during this period will have important structural and behavioural consequences. More affordable gas will accelerate coal-to-gas switching in power generation and industry, particularly in emerging Asia, resulting in meaningful emissions reductions and improving air quality. At the same time, lower gas prices are likely to slow the pace of renewable substitution in base-load generation, as natural gas remains cost-competitive for dispatchable power and system balancing. Consequently, gas will continue to play a central role in ensuring energy security, grid stability, and orderly transitions toward low-carbon systems.

Beyond 2030, as global LNG capacity expansion slows and demand rises, especially in Asia and the Middle East, gas markets are projected to tighten gradually, leading to a recovery in prices. By 2040, Asian and European spot prices are expected to return to around USD 10–11/MMBtu, supported by stronger consumption in emerging economies and higher marginal production costs. Henry Hub prices will follow a steady upward trajectory, reaching USD 4.4/MMBtu by 2040 as domestic supply becomes more capital-intensive and LNG export commitments expand.

In the long term, natural gas prices are projected to stabilise at levels reflecting the interplay between supply-side cost pressures and demand resilience. **By 2055, Asian import prices are forecast to reach USD 13.3/MMBtu, European import prices USD 10.9/MMBtu, and Henry Hub prices USD 5.1/MMBtu (in 2024 dollars).** These levels balance affordability with the investment requirements of sustaining new supply under increasingly stringent carbon and methane regulations.

Over the decades ahead, deeper market integration through flexible LNG trade and the shift toward hub-based pricing mechanisms will enhance transparency, efficiency and competition, reducing regional price gaps (see Box 1.1). Nevertheless, the need for ongoing upstream reinvestment, coupled with higher costs of capital and decarbonisation, will keep prices at levels sufficient to incentivise production.

1.3.3 Carbon prices

In 2024, global carbon markets experienced continued expansion, both in scale and sophistication. Direct carbon pricing instruments, comprising 43 carbon taxes and 37 emissions trading systems (ETSs), now cover around 28% of global greenhouse gas emissions, a sharp rise from 24% a year earlier. Revenues from these mechanisms exceeded USD 100 billion for the second consecutive year, with more than half allocated to environmental and development programmes. The expansion of China's national ETS to include cement, steel, and aluminium, alongside new systems under development in Brazil, India, and Türkiye, underscores the deepening role of carbon pricing in shaping global mitigation efforts.

Europe remains the epicentre of global carbon pricing, with the EU ETS continuing to serve as the benchmark system. Following the Fit-for-55 package and the introduction of the Carbon Border Adjustment Mechanism (CBAM), the EU ETS now exerts significant influence over carbon prices globally. In 2024, the EU ETS price averaged around USD 72/tCO_2, reflecting subdued industrial demand and increased allowance availability amid economic slowdown. Nonetheless, the long-term trajectory points upward as the EU tightens the emissions cap, expands coverage to maritime transport, and launches ETS 2 for buildings and road transport in 2028 .

Carbon prices in the EU ETS are expected to rise gradually to USD 87/tCO_2 by 2030, USD 100/tCO_2 by 2040, USD 144/tCO_2 by 2050, and USD 160/tCO_2 by 2055 (in 2024 dollars). These increases reflect the growing stringency of climate policy frameworks, rising marginal abatement costs, and the need to incentivise deployment of advanced decarbonisation technologies, including carbon capture, utilisation and storage (CCUS), low-carbon hydrogen, and negative-emission solutions. Higher carbon prices will also reinforce the economic competitiveness of natural gas, particularly in markets where coal-to-gas switching remains a major decarbonisation lever.

At the global level, the diffusion of carbon pricing continues but remains uneven across regions. While advanced economies are expanding and deepening carbon markets, emerging and developing economies are progressing more cautiously, often integrating carbon pricing within broader fiscal or industrial frameworks. Asia is emerging as a key growth region, led by China's expanding ETS and new schemes under development in India and Indonesia. In contrast, adoption in Africa and South Asia remains limited due to institutional and economic constraints, though several countries are exploring pilot mechanisms aligned with future CBAM exposure.

By 2055, carbon markets are expected to cover close to one-third of global emissions, though price fragmentation will persist. Developed countries are projected to maintain carbon prices in the range of USD 130–160/tCO_2, while developing countries will likely remain below USD 50/tCO_2 for much of the forecast horizon. Despite this heterogeneity, the global momentum for carbon pricing is expected to continue, driven by policy convergence, digital transparency, and international cooperation under Article 6 of the Paris Agreement. Importantly, higher carbon prices will indirectly support global gas demand by improving gas competitiveness relative to coal and facilitating methane-abatement investments across the gas value chain.

Box 1.1 Rolling VECM evidence of evolving oil–gas linkages and increasing gas-to-gas pricing

International gas pricing has undergone a marked transition over the past two decades. Where oil-linked indexation historically shaped price formation in many pipeline and LNG contracts, particularly in Asia, the expansion of hub trading, greater LNG liquidity and destination flexibility, and deeper inter-basin infrastructure connectivity have increasingly shifted price discovery toward gas-to-gas benchmarks. For forward-looking analysis, this evolution matters because it changes what anchors gas prices in the long run: in a hub-anchored system, the trajectory of regional gas benchmarks cannot be inferred mechanically from oil price assumptions, even if oil and gas prices occasionally move together during periods of broader energy-market stress.

To characterise this structural evolution empirically, a rolling vector error-correction model (VECM) was estimated using monthly Brent crude, Dutch TTF and Asian JKM benchmark prices over 2003–2025. The VECM framework is suited to systems in which prices may deviate in the short run but remain linked through persistent long-run equilibria (cointegration). Estimating the same model across repeated 10-year windows allows the long-run relationships and adjustment dynamics to be tracked over time, highlighting how the market's pricing architecture changes across regimes rather than imposing a single, time-invariant structure.

The results point to a long-run architecture in which the European hub benchmark (TTF) plays a pivotal bridging role between oil and Asian LNG. The system is consistent with two long-run relationships, one linking Brent and TTF and another linking JKM and TTF, while a separate direct long-run Brent–JKM anchor is not required once TTF is accounted for. The associated error-correction dynamics indicate that adjustment occurs primarily within gas markets: deviations from the Asia–Europe gas equilibrium are corrected mainly through changes in JKM, while Brent behaves as a comparatively weakly adjusting variable, consistent with oil prices being formed in a large global crude market and gas benchmarks adapting around their own regional fundamentals and cross-basin arbitrage conditions.

Figure (1) reports the rolling 10-year long-run elasticities implied by the VECM (trimmed to remove extreme tail estimates that can occur when a particular window is weakly identified). Two distinct patterns stand out. First, the JKM–TTF long-run elasticity is highly unstable in early windows, including sharp spikes in the mid-2010s, before converging toward a stable range around unity and remaining persistently positive thereafter. This convergence and subsequent stability provide a clear econometric signature of a market in which Asian LNG prices increasingly reference hub-based gas fundamentals, consistent with the growing role of flexible LNG and inter-basin arbitrage in transmitting price signals across regions.

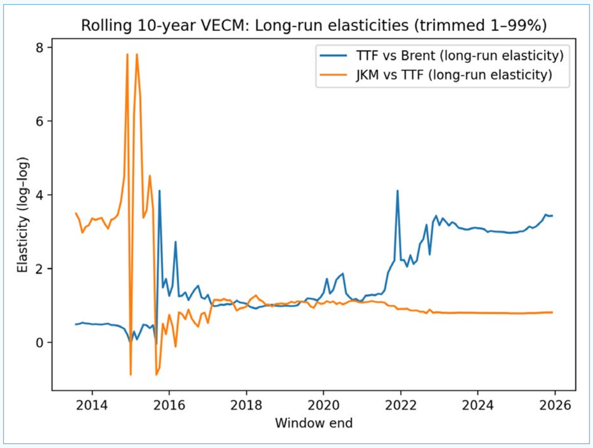
The second pattern in Figure (1) concerns the oil–gas linkage measured by the long-run TTF–Brent elasticity. In mid-2010s windows, the relationship is comparatively moderate and relatively stable, whereas from 2021 onward it rises sharply and remains elevated. This should not be read as evidence of a structural reversion to contractual oil indexation. Rather, it is consistent with a regime in which oil prices proxy broader energy scarcity, inflation and risk premia during periods of system-wide stress, while gas prices respond to contemporaneous supply–demand tightness and cross-commodity substitution incentives. In such conditions, long-run linkages can strengthen even when pricing mechanisms remain hub-based.

Figure (2) underscores why long-run elasticities should not be conflated with short-run co-movement. It contrasts the rolling 10-year VECM long-run elasticity (an equilibrium concept) with a 24-month rolling correlation between Brent and TTF (a short-horizon co-movement metric). The divergence between the two measures is informative: while the estimated long-run elasticity is high in post-2021 windows, the short-run correlation weakens substantially and can even turn negative toward the end of the sample. This indicates that contemporaneous price co-movement is regime-dependent and can decouple quickly as market conditions shift, even when the longer-horizon relationship estimated over a decade-long window remains strong. The implication is that simple correlations are an unreliable basis for inferring pricing structure; they primarily capture shared shocks over a short horizon rather than the long-run anchoring mechanism.

Taken together, the rolling VECM results support three conclusions relevant for price assumptions in Chapter 1. First, the long-run relationship between JKM and TTF strengthens and stabilises over time, consistent with gas-to-gas pricing gaining traction and with increasing integration between Asian LNG and European hub markets. Second, oil remains relevant for gas pricing mainly through indirect and time-varying channels, especially during stress, rather than through a persistent direct anchor on LNG benchmarks once hub prices are accounted for. Third, scenario design benefits from separating structure from stress: baseline price assumptions should be grounded in hub and LNG fundamentals, while stress cases can allow for temporary episodes of stronger oil–gas co-movement without implying a structural return to oil indexation.

Figure 1

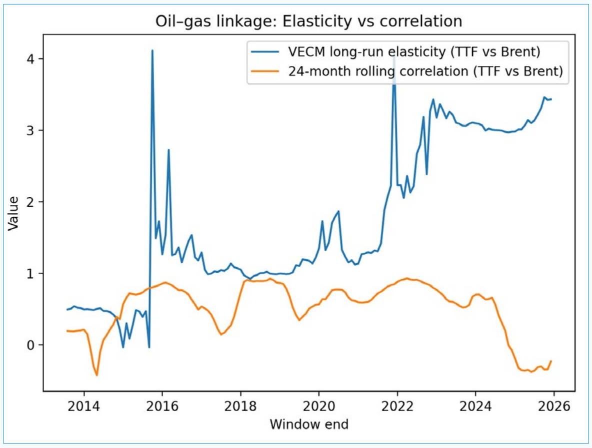
Rolling 10-year VECM long-run elasticities (trimmed 1–99%)



Note: Elasticities are estimated from rolling 10-year windows of monthly log prices; trimming removes extreme tail estimates to enhance interpretability

Figure 2

Oil–gas linkage: long-run elasticity versus short-run correlation (TTF vs Brent)



Note: The blue line reports the rolling 10-year VECM long-run elasticity; the orange line reports the 24-month rolling correlation, illustrating that short-run co-movement can diverge from long-run equilibrium linkages

Energy Policy Developments and Technology Advancements

2

Highlights

- Energy policy has shifted toward pragmatism, with governments recalibrating climate ambition to accommodate security, affordability, and competitiveness. This rebalancing acknowledges the persistent structural role of natural gas in power and industrial sectors.
- The energy transitions have slowed, as high financing costs, supply-chain pressures, and policy reversals delayed renewable deployment and grid upgrades. This rollback has strengthened the immediate policy reliance on natural gas to manage energy system adequacy.
- A widening arc of geopolitical hotspots has reshaped energy production, transport routes, and fuel choices. For natural gas, the impact is especially pronounced, given pipeline exposure across multiple jurisdictions and LNG shipping routes that traverse increasingly vulnerable maritime corridors.
- Several major jurisdictions have adjusted or streamlined climate and sustainability regulations to address competitiveness pressures and administrative complexity. This recalibration marks a shift from the stringent expansion of earlier years, creating a more stable and predictable environment for energy investment, including natural gas within long-term decarbonisation frameworks.
- The latest NDC update shows only marginal improvement in global ambition, with Parties collectively pledging around a 12% emissions reduction relative to 2019 levels, an incremental step beyond previous submissions. COP30 did not deliver a significant uplift in mitigation commitments, underscoring the widening gap between long-term climate goals and near-term political realities.
- Gas-fired power has expanded as a global reliability tool, compensating for renewable intermittency, hydro variability, and surging electricity demand. Its emissions performance is now directly influencing procurement decisions and power-market design.
- Policy support for natural gas strengthened visibly in 2024–2025, with many governments lifting exploration constraints, accelerating LNG infrastructure, and embedding gas into long-term adequacy planning.
- Support for natural gas has become broader and more differentiated: developed countries focus on low-carbon certification, methane performance, and CCUS-ready gas, while developing countries emphasise affordability, access clean cooking, and rapid electrification.
- Transparent emissions accounting and verified low-carbon credentials are emerging as new competitive determinants in gas and LNG trade. Certification schemes, methane intensity benchmarks, and product-level carbon attributes are beginning to reshape market access and pricing. The need for common standards across schemes is also more evident.
- The innovation frontier in the gas the industry is characterised less by any single “silver bullet” technology and more by cumulative, engineering-led performance gains enabled by standardisation, modularisation, electrification, digitalisation, advanced materials, and progressively stricter expectations for methane and CO_2 performance.

Energy policy remains a primary force shaping global energy markets, but its impact is increasingly mediated by technological change, especially in the natural gas industry. As geopolitical realignments, supply-chain reconfiguration, and intensifying climate constraints reshape decision-making, governments are recalibrating the balance between energy security, affordability, and sustainability. At the same time, innovation across the gas value chain is altering what is technically feasible and economically competitive, lowering costs in some segments, reducing emissions intensity through methane abatement and electrification, and expanding flexibility via LNG, storage, and digital optimisation.

In this environment, market outcomes are determined by the interaction between policy frameworks and technology deployment. Fiscal regimes, permitting and infrastructure planning, carbon and methane regulation, and international partnerships influence where gas is produced and traded; meanwhile, advances in upstream productivity, gas processing, modular and electrified LNG, carbon capture and storage, hydrogen-ready combustion systems, and data-driven operations increasingly define the emissions profile, resilience, and commercial viability of gas supply chains. For natural gas, this policy–technology coupling directly affects demand formation, investment appetite and timing, contract structures, and the geography of trade.

This chapter therefore examines how policy evolution and technological advancement together shape the outlook for energy and natural gas. It first reviews global energy policy trends emerging from current economic and geopolitical conditions, then assesses policy support for natural gas within energy security and transition strategies. It next considers trade dynamics over the coming decade, before analysing policy drivers and developments across key regions. Finally, it evaluates technology pathways across the gas supply chain that can raise productivity, reduce costs, and improve efficiency and emissions performance over the longer term.

2.1 Global developments and trends

Global energy policy in recent years has been shaped by fragile economic recovery, shifting political priorities, and intensifying climate pressures. Inflation and high interest rates have weighed on households and industries, while trade disruptions and geopolitical rivalries have deepened uncertainty. Debates over energy affordability and competitiveness have intensified, with climate measures increasingly portrayed as economic burdens even as extreme weather and record temperatures underscore the urgency of action. At the same time, new sources of demand have emerged: the rapid expansion of digital technologies, rising cooling needs during prolonged heatwaves, recurrent droughts reducing hydropower output, and the growing energy intensity of water supply. These pressures have placed intensified strain on electricity systems and have pushed governments to reinforce energy security through stockpiling, diversification, infrastructure expansion, and new policy frameworks to safeguard reliability.

Within this environment, natural gas has been reinforced as a cornerstone of resilience. Flexible generation, integration with low-carbon technologies, and expanded infrastructure have made it a central tool for securing supply and stabilising grids, while its role has extended beyond power to development priorities such as clean cooking access, lower-emission transport, and industrial competitiveness.

These dynamics have set the stage for the policy evolution of the past three years: from the economic fragility of 2023, through the recalibration of 2024, to the renewed fragmentation of 2025. In this section, we review the main global energy policy trends of recent years, which have been incorporated into our model to provide realistic projections for the future natural gas markets.

The year 2023 revealed the limits of climate ambition in an uncertain global economy. Inflation proved difficult to contain, growth remained uneven, and geopolitical instability, including conflicts and trade disruptions, added to uncertainty. At the same time, a new reality of higher-for-longer interest rates began to loom large over the energy transitions. Elevated borrowing costs made capital-intensive clean energy projects, such as renewables, nuclear, and emerging low-carbon technologies, more expensive to finance, slowing the pace of deployment despite strong policy ambitions. By contrast, oil and gas companies, having reduced debt in earlier years, proved less exposed to this financial squeeze, leaving natural gas and LNG projects relatively more competitive even as their financing costs also edged higher.

Policymakers therefore faced the delicate task of managing immediate economic needs while keeping longer-term climate targets in sight. In the political arena, climate measures were increasingly framed as potential threats to competitiveness, particularly amid rising household energy costs. This shift translated into recalibrated commitments: many governments delayed or scaled back environmental goals, even as climate science warned of record-breaking temperatures and global warming topped the key limit of 1.5°C above pre-industrial levels.

Within this context, natural gas emerged as a pragmatic response to the “energy trilemma”, balancing security, affordability, and sustainability. Its role was highlighted in international forums where policymakers sought flexible solutions that could maintain energy access while sustaining progress toward emissions reduction.

In 2024, energy security returned to the centre of policymaking. Energy security re-emerged as the dominant policy theme. After several years of market volatility, governments emphasised resilience through strategic fuel stockpiling, diversification of supply routes, and approval of new infrastructure. These measures were often framed as insurance against external shocks.

Yet momentum in the energy transitions slowed. The political cost of high energy prices eroded public support for ambitious climate measures, leading several countries to ease their targets. International oil companies followed suit, adjusting strategies and softening their climate commitments. Even so, the legacy of strong earlier policy support remained visible: record levels of investment in solar, wind, and batteries were deployed, while initiatives in CCUS and hydrogen gained traction. However, high interest rates and financial constraints weighed heavily on the pace of delivery.

These tensions were most evident at COP29 in Baku, where the principal task was to agree on a new climate finance goal. While countries ultimately established a new framework, the level of ambition fell far short of the expectations of many developing countries, leaving negotiations strained and unresolved on other issues such as mitigation pathways, adaptation strategies, and the role of fossil fuels.

By 2025, political change deepened fragmentation in global energy policy. What began in 2024 as a careful balancing act between inflation control, affordability, and decarbonisation evolved in 2025 into a more fragmented policy order. Geopolitics and energy security once again rivalled climate ambitions as the central drivers of government action.

The most visible shift came with political change in the United States. The new administration pulled back from earlier climate commitments, rolled back elements of clean energy support, and placed strong emphasis on domestic energy expansion. Fossil fuel exports, particularly LNG, were reasserted as instruments of foreign policy. The reorientation of United States policy reverberated across international energy markets. Washington encouraged allies to source more from American producers, while sanctions and tariffs re-emerged as tools of trade diplomacy. These moves reshaped investment flows, heightened competition in gas markets, and added further uncertainty to multilateral climate engagement.

For natural gas, the developments of 2025 underscored its dual role: on one hand, expanded supply potential and reinforced security in consuming markets; on the other, a more complex environment of trade competition, financing scrutiny, and political conditionality.

The spread of live geopolitical hotspots in recent years has profoundly affected major energy production, transportation, and consumption. Conflicts, sanctions, and political instability have disrupted production and delayed investment, with effects spreading far beyond local markets. Transportation routes through pipelines and maritime chokepoints have become tools of leverage, with rerouting and security risks adding costs and volatility. Consumption has also been shaped by these dynamics, as governments prioritise diversification, storage, and long-term contracts to shield their economies from shocks. For natural gas, the exposure is particularly acute, given its reliance on pipelines crossing multiple jurisdictions and LNG trade dependent on vulnerable shipping corridors. The experience of recent years shows that energy and geopolitics cannot be separated, and the role of natural gas will continue to be defined not only by its technical and environmental attributes but also by its ability to withstand geopolitical pressures.

High interest rates are reshaping the trajectory of the energy transition pathways, with lasting implications for the role of natural gas. The persistence of elevated borrowing costs into 2025 has made it clear that financing conditions will remain a decisive factor for future investment patterns. Clean energy technologies that depend heavily on upfront capital, such as wind, solar, hydrogen, and nuclear, are the most exposed, as higher financing costs directly increase their levelised cost of electricity (LCOE) and extend project timelines. This has the potential to slow deployment rates and delay some of the ambitious targets set in recent years, particularly in countries with weaker fiscal capacity.

For natural gas, the picture is more nuanced. While LNG projects also face higher development costs, producers in this sector benefit from comparatively stronger balance sheets and lower leverage after years of debt reduction. This resilience cushions them from the impact of high interest rates, reinforcing natural gas's position as a competitive option in a strained financial environment. In particular, flexible LNG supply and gas-fired power are likely to gain traction as cost-effective complements to renewables, capable of delivering reliability without the same financing hurdles.

Looking ahead, the financing landscape suggests that the energy transitions may evolve more gradually than previously anticipated, with natural gas playing an extended role. Higher interest rates tilt the balance toward fuels and technologies that combine moderate capital requirements with proven reliability, positioning gas as both a stabiliser of power systems and a pragmatic bridge for economies navigating the dual challenge of climate ambition and financial constraint.

Although climate change has not been at the forefront of policy steering, it remains a key theme shaping energy markets. The global trajectory of climate policy in 2024 and 2025 can best be described as a pivot from ambition to accountability. A new wave of regulatory tightening emerged, focusing on emissions performance, carbon markets, and product standards. Several jurisdictions reduced free allocations under carbon pricing schemes, broadened coverage to new sectors, and advanced product-based carbon footprint rules. Border measures and trade adjustments transformed climate policy into a commercial factor, directly influencing contract design, financing, and project timelines. The European Union remained the main driver, pressing ahead with its Carbon Border Adjustment Mechanism (CBAM), Corporate Sustainability Due Diligence Directive (CSDDD), and Methane Emissions Regulation to reinforce its climate neutrality pathway. Other actors also played a role in sustaining momentum. China continued to prioritise renewable deployment and dual climate goals, while small island states, treating climate change as an existential threat, succeeded in pushing the International Court of Justice to clarify states' legal responsibilities on climate protection. These strands of action, though varied, kept climate policy firmly embedded in the global agenda.

At the same time, the multilateral process showed growing signs of strain. Several years of limited progress on climate finance, mitigation, and adaptation raised doubts about the UNFCCC's ability to deliver. The United States' withdrawal from international commitments further eroded confidence in the COP process, where the sheer size of the conference and the diversity of national interests make reaching consensus elusive. Increasingly, unilateral measures and alternative forms of climate leadership are shaping the agenda, raising questions over whether COP can remain the central platform for collective climate action. Against this backdrop, preserving the UNFCCC process became a central political priority for the COP30 Presidency. The negotiations were deliberately steered toward maintaining cohesion, avoiding procedural crises, and demonstrating that consensus-based diplomacy remains viable. The final outcome reflected this balancing act: while COP30 delivered progress in selected areas, it fell short of providing the decisive breakthroughs on finance and mitigation needed to restore full confidence in the multilateral system (see Box 2.1).

Box 2.1 Outcomes of COP30

COP30 convened in Belém (Brazil) at a moment when confidence in multilateral climate diplomacy was increasingly strained. Entering 2025, several structural concerns shadowed the process, notably the slow submission of 3rd cycle of Nationally Determined Contributions (NDCs), persistent uncertainty around climate finance, widening geopolitical divides, and questions over the viability of consensus-based negotiations. These pressures were intensified by the absence of the United States following its withdrawal from the Paris Agreement and by the growing influence of unilateral trade-related climate measures. Against this backdrop, COP30 became an important test of whether the multilateral process could still deliver meaningful outcomes.

Ultimately, COP30 produced incremental but uneven progress. The continued shortfall in NDC submissions, lack of clarity on finance and increased reliance on parallel initiatives outside the UNFCCC framework underscored the pressures facing the process. Nevertheless, COP30 reaffirmed the enduring importance of multilateral negotiations as a forum for establishing norms, addressing cross-border impacts and advancing the interests of countries whose development pathways depend on energy security and economic stability.

New NDCs and mitigation ambition

The central expectation for COP30 was the submission and assessment of new NDCs informed by the Global Stocktake. However, progress remained uneven. Despite an extended deadline, only 113 Parties had submitted their new NDCs by the time COP30 opened, leaving major economies absent. Analysis based on available submissions indicates global emissions in 2035 will be only around 12% below 2019 levels, far from pathways compatible with limiting warming to 1.5°C, and insufficient even for a credible 2°C trajectory. This underscores a persistent and significant emissions gap, despite successive rounds of NDCs.

Mitigation discussions were further shaped by renewed divisions over the future of fossil fuels. Some Parties pushed for a fossil-fuel roadmap building on COP28's call to "transition away from fossil fuels," while an equally large group opposed singling out specific energy sources, emphasising national circumstances and development needs. With no consensus possible, the Presidency kept the issue outside the formal agenda and announced that discussions on a potential roadmap would continue beyond the COP, with Colombia and the Netherlands set to host a ministerial meeting in 2026. As a result, only limited references to the UAE Consensus appeared in the final text, and no roadmap was agreed.

The final text also acknowledged that the 1.5°C goal now faces a "likely overshoot," the first explicit recognition of this in a COP decision. Two voluntary initiatives, the Global Implementation Accelerator and the Belém Mission to 1.5°C, were launched to support implementation, though their impact will depend on future design and participation.

Finance and adaptation

Finance remained the most contested issue for developing countries. The final decision reaffirmed the COP29 finance architecture, including the developed-country commitment to mobilise USD 300 billion annually by 2035, and the broader call to scale up total finance to USD 1.3 trillion per year. However, COP30 did not clarify how these amounts will be shared among contributors, how much will come from public versus private sources, or when individual pledges will be delivered. As a result, the overall finance package remains uncertain for developing countries that depend on predictable support.

Adaptation, framed by Brazil as the core theme of COP30, saw the most substantive movement. Parties agreed to "efforts to at least triple adaptation finance by 2035," though no baseline was specified, weakening accountability and delivery prospects. On the Global Goal on Adaptation (GGA), Parties adopted 59 indicators and launched a two-year program to operationalise them. While this advances the technical framework, the absence of predictable finance remains a barrier for many developing countries.

Unilateral trade measures

Concerns over unilateral trade-related climate measures (UTMs) featured prominently at COP30. While the principle that climate measures should not result in arbitrary or unjustifiable trade discrimination has been part of the UNFCCC since Article 3.5 of the Convention, and reiterated in the UAE Consensus, the issue gained heightened political visibility in Belém due to the expanding global use of instruments such as carbon border adjustments. Many developing countries and energy exporters warned that UTMs risk imposing additional burdens on their economies and could affect sectors central to energy security and industrial development. In response, Parties agreed to hold annual dialogues from 2026 to 2028 under the Subsidiary Bodies to examine the trade and cross-border effects of climate policies, marking the first time that UTMs have been given a dedicated, structured process within the UNFCCC.

Just transition

COP30 negotiations under the Just Transition Work Program resulted in agreement to establish a Just Transition Mechanism, creating a formal structure to support countries in managing the social and economic dimensions of transition. The mechanism aims to facilitate cooperation and exchange of national approaches and was broadly welcomed as a step forward.

However, the scope of the final text was significantly narrowed. References in earlier drafts to critical minerals, transitional fuels, trade measures and transitioning away from fossil fuels were removed to secure consensus. As adopted, the text focuses on high-level principles such as universal access to affordable and reliable energy, protection of livelihoods and recognition of diverse national pathways. While the mechanism provides a foundation for future work, many energy-related elements will need further discussion in subsequent sessions.

Climate science

Scientific guidance remained a sensitive issue at COP30. The final text on research and systematic observation did not endorse the IPCC as the "best available science," nor did it reference the latest findings presented by the Intergovernmental Panel on climate Change (IPCC) and World Meteorological Organisation (WMO) on the state of the climate. Earlier language on the need to "counter misinformation on climate change" was also removed during negotiations. These changes reflected objections from several Parties who opposed explicit references to IPCC assessments and preferred a broader framing, with some calling instead for increased finance to support climate research.

As a result, COP30 was unable to agree on a request for the IPCC to align its next assessment cycle (AR7) with the second Global Stocktake in 2028. A separate decision ultimately "encouraged" the scientific community to provide the best available inputs and "invited" organisations such as the IPCC to consider how they could contribute to future stocktakes, falling short of a formal mandate.

Other Outcomes: Loss and damage, forests and carbon markets

The Loss and Damage Fund issued its first call for funding requests, but COP30 saw few new pledges, and broader questions about sustainable financing for loss and damage remain unresolved.

Forest protection gained visibility through the launch of the Tropical Forests Forever Facility (TFFF), a financing mechanism aiming to mobilise USD 125 billion to reward countries that curb tropical forest loss.

On implementation of Article 6 of the Paris Agreement, which governs international carbon markets and cooperative approaches, COP30 focused on operational issues rather than new rules. Parties noted inconsistencies in early reporting under Article 6.2, which covers bilateral and multilateral carbon-crediting arrangements, and agreed on steps to improve transparency. For Article 6.4, the centralised UN crediting mechanism, Parties adopted a six-month extension for transitioning eligible Clean Development Mechanism (CDM) projects into the new system, acknowledging delays and technical challenges. While these decisions advance implementation, many design and accounting issues will require continued work in the coming year.

2.2 Policy support for natural gas

The years 2024 and 2025 marked a decisive realignment in global natural gas policy, as governments shifted from managing crisis-driven uncertainty to reinforcing long-term supply security and affordability. After a subdued 2024, when LNG trade slowed due to project delays, high storage, and moderate prices, the market entered 2025 with renewed momentum. A new wave of liquefaction projects began to emerge, setting the stage for supply expansion in the second half of the decade. At the same time, the halt of Russian gas transit through Ukraine, rebounding European industrial demand, and sustained Asian consumption created tighter balances and elevated the strategic importance of LNG as a global stabiliser.

This period has witnessed a decisive turn away from the regulatory tightening of previous years. In major producing economies, such as the United States and Australia, restrictions on exploration and export approvals have been lifted, while fiscal and permitting frameworks have been streamlined to accelerate upstream investment. Across Europe, the new European Commission's focus on competitiveness and affordability has softened parts of the Green Deal architecture, with measures like the Omnibus Simplification Package easing compliance burdens under the Corporate

Sustainability Due Diligence Directive (CSDDD) and Carbon Border Adjustment Mechanism (CBAM). Developing regions, meanwhile, have reinforced their commitment to gas as a pillar of industrialisation, energy access, and fiscal security, a position strengthened by limited climate finance and the need for self-funded growth.

Policy support for natural gas strengthened visibly across both developed and developing countries. The United States set the pace by lifting its temporary pause on LNG export approvals under an Energy Emergency Declaration, reactivating a significant backlog of projects. Australia's Future Gas Strategy confirmed continued exploration and development to meet domestic and export needs, while Indonesia, Suriname, and several African producers introduced fiscal incentives to attract upstream investment. Countries that had previously restricted exploration, such as the Netherlands and New Zealand, reversed earlier constraints, citing the need to maintain indigenous supply. These coordinated policy signals revived investment confidence, with upstream capital expenditure rising through 2025 as gas regained recognition as a compatible element of energy transitions when paired with CCUS and methane mitigation.

Policy support for natural gas has become both broader and more differentiated. Developed economies are embedding gas within decarbonisation pathways through CCUS integration, certified low-carbon LNG, and methane performance standards, while developing and least-developed countries are prioritising access, affordability, and reliability. The expansion of LNG capacity in the United States, Qatar, and Africa is reshaping trade balances, moderating prices, and encouraging coal-to-gas switching in price-sensitive markets. Meanwhile, new carbon pricing systems in Asia and Europe, coupled with the operationalisation of Article 6 carbon markets, are gradually translating emissions performance into a determinant of trade competitiveness.

The demand side also shaped policy direction. Rapidly growing electricity consumption, driven by data centres, AI applications, and climate-related extremes, has reinforced the necessity of gas as a flexible and dispatchable power source. Delays to and cancellations of offshore wind projects, declining renewable subsidies, and persistent grid constraints slowed the pace of renewable expansion, further anchoring natural gas in national power strategies. Governments in Asia, particularly Japan, South Korea, and Indonesia, extended the operational life of LNG power plants or launched small-scale LNG projects to displace diesel. India expanded gas-fired peaker capacity under its National Electricity Plan, and China accelerated the construction of pipelines and LNG import terminals to support its industrial and power sectors. Across Latin America and the Middle East, gas-to-power and gas-for-desalination initiatives have become central to energy and water security policies amid harsher climate conditions.

Climate policy shifts in major economies further improved the policy environment for gas. In the United States, the suspension of methane and greenhouse gas reporting obligations, along with the easing of emissions caps for power plants, reduced compliance costs and revitalised upstream and midstream activity. In Europe, the Omnibus Simplification Package streamlined CSDDD and CBAM reporting, signalling a pragmatic recalibration toward competitiveness and regulatory simplicity. The new European Commission, in office since December 2024, embedded this shift through the Clean Industrial Deal and Affordable Energy Action Plan, prioritising affordability and investment stability over further tightening. These reforms collectively marked a pause in the regulatory escalation cycle and created a more permissive climate for natural gas across OECD markets.

The liberalisation of LNG contracting and trade frameworks advanced further in 2024–2025 as policies increasingly encouraged diversified and resilient supply structures. Governments and buyers gravitated toward long-term strategic partnerships to safeguard energy security amid heightened geopolitical fragmentation. This was reflected in the EU–United States energy cooperation framework and Japan's new supply arrangements with major Middle Eastern producers, both signalling a clear shift toward durable, security-oriented contracting. At the same time, the integration of renewables and growing variability in power demand strengthened the case for more flexible LNG procurement. Markets such as Japan and China sought contracts with greater adaptability to accommodate fluctuations, whether driven by nuclear restarts, renewable expansion, climate-related demand shocks, or the need to balance their broader energy mix. Across Asia, investments in LNG import terminals and expanded procurement portfolios by China, India, and Southeast Asian countries underscored this dual preference: combining the reliability of long-term deals with the operational agility provided by flexible terms. While producers increasingly recognise the need for such flexibility, long-term commitments remain indispensable for the financing and development of new LNG supply projects, reinforcing the evolving yet interdependent nature of the global LNG contracting landscape.

Geopolitics remain a defining factor. Russia's eastward gas reorientation has been slow but persistent, centred on negotiations over the Power of Siberia 2 pipeline. The EU–United States coordination on LNG trade, combined with the emergence of new export corridors from Africa and North America, is reshaping global energy geography. Meanwhile, Ukraine and Eastern European states are repositioning themselves as alternative transit and storage hubs within Europe's new gas security architecture.

Finally, **financing and certification have emerged as new policy frontiers.** Access to capital increasingly depends on transparent emissions accounting and verified low-carbon credentials. High interest rates and tightening ESG taxonomies have not curtailed gas investment but have reshaped its character, rewarding certified low-emission LNG and CCUS-linked projects. Advanced economies are focusing on decarbonising gas value chains, while developing ones pursue access and affordability through public–private partnerships supported by multilateral financing.

Taken together, 2025 represents a decisive turn toward pragmatic energy governance. Policy frameworks worldwide now treat natural gas not as a temporary bridge, but as an adaptive and essential component of the transition—anchoring reliability, moderating costs, and enabling an orderly move toward decarbonisation. The convergence of production incentives, regulatory easing, and infrastructure expansion ensures that natural gas remains a cornerstone of global energy resilience and trade in the decade ahead.

2.3 Policy drivers and developments in the key markets

Natural gas remains a defining force in the global energy system, linking producing regions, major consumers, and expanding trade routes within an evolving policy and geopolitical landscape. Global production continues to be driven by a relatively small number of key exporters, while new supply hubs are emerging in Africa, the Eastern Mediterranean, and parts of the Americas. On the demand side, growth is increasingly concentrated in Asia, where China, India, and Southeast Asian countries are shaping long-term consumption patterns. Europe, once the anchor of pipeline gas trade, is now structurally reliant on LNG after the end of Russian transit, while new supply corridors are emerging from Africa, the Eastern Mediterranean, and the Americas.

Trade dynamics are being reshaped by two concurrent trends: the expansion of LNG capacity in the United States, Qatar, and Africa, and the reconfiguration of demand across Asia and Europe. These shifts are redefining traditional supplier–buyer relationships, giving rise to new forms of interdependence grounded in energy security, price stability, and emissions performance. At the same time, the interplay of climate policy, industrial strategy, and energy affordability continues to drive national approaches to gas, ranging from production incentives in resource-rich economies to diversification and carbon market integration in import-dependent ones.

This section explores how these global forces manifest across the major regional markets, Africa, Asia Pacific, Europe, Latin America, and North America, highlighting the policy drivers, institutional shifts, and strategic trends that together are reshaping natural gas supply, demand, and trade in the decade ahead. Table 2.1 offers a concise summary of primary government objectives across these regions, highlighting the diverse strategies employed by different governments to tackle energy challenges.

2.3.1 Africa

Africa's natural gas policy in 2024–2025 reflects a phase of consolidation and repositioning. Governments are shaping gas around three strategic priorities, securing domestic stability, monetising exports, and anchoring regional integration, while navigating the growing constraints of international finance and shifting global energy politics.

North African producers such as Algeria and Egypt have reinforced their upstream and midstream systems to guarantee supply both for domestic power generation and for export. Algeria continues to expand partnerships sustaining flows to Europe, while Egypt has become both an importer and an exporter, importing East Mediterranean gas to stabilise its own market and re-exporting LNG when capacity allows, leveraging its location and liquefaction assets as a regional balancing hub.

In West Africa, Nigeria remains a cornerstone LNG supplier and regional hub, pursuing new gas infrastructure and domestic utilisation to diversify its economy. Mauritania and Senegal joined the exporter group through the GTA project, while Ghana and Côte d'Ivoire advance regasification and power-sector gas use. In East Africa, Mozambique continues its gradual return to production with renewed confidence in its offshore LNG developments, and Tanzania is a significant prospect to watch.

In Southern Africa, South Africa's Integrated Resource Plan has formally embedded gas-to-power as a core element for grid stability and industrial supply, marking gas as a complement, not competitor, to renewables, while Namibia is moving from discovery to early commercial planning.

Meanwhile, the tightening of global climate finance is reshaping how these ambitions are funded. With the United States rolling back international climate commitments and the EU redirecting budgets toward domestic competitiveness, concessional funding for African clean energy has contracted sharply, by up to 40% in some donor countries. African policymakers now face reduced access to low-cost capital, prompting a recalibration toward self-financed, resource-based growth strategies where natural gas revenues are treated as the foundation for economic resilience and diversification.

Table 2.1

Policy developments in the key markets

	Global	India
Main policies	• Achieving universal access to affordable, reliable, and modern energy services by 2030 • Increasing the proportion of renewable energy sources by 2030 • Promoting access to clean energy research and technology by 2030 • Utilizing zero- and low-carbon fuels, well before by around mid-century	• Aiming at energy security, affordability and decarbonization by ◦ Boosting energy efficiency ◦ Increasing domestic production ◦ Reducing dependence on imports ◦ Transitioning towards cleaner energy alternatives • The strategy relies on diversification—coal for reliability, renewables for scale, and natural gas for system stability and cleaner growth
Natural gas	• Transitioning away from fossil fuels in energy systems, in a just, orderly and equitable manner, with recognising the role of transitional fuels in facillitating energy transitions and maintaining energy security	• A 15% share of gas in the primary energy mix by 2030 • Natural gas consumption of 500 Million cubic meters per day by 2030 • Infrastructure development for natural gas to enhance natural gas availability, boost imports (regasification capacity to 70 MMTPA by 2030 and 100 MMTPA by 2040), expand domestic production and to build the necessary infrastructure, including pipelines and city gas distribution (CGD) networks • Transition a third of long-haul trucking fleet to LNG within five to seven years
Other fossil fuels	• Transitioning away from fossil fuels in energy systems, in a just, orderly and equitable manner • Phasing down unabated coal power (G7 to phase out by 2035) • Phasing out inefficient fossil fuel subsidies	• Coal remains a significant part of the energy mix with an additional 25.5 GW of coal capacity for the second half of the decade • 50% of installed energy capacity from non-fossil fuels by 2030
Renewables	Tripling capacity globally by 2030	500 GW capacity by 2030
Nuclear	Accelerating nuclear	A three-fold rise in nuclear-installed capacity by 2032
Hydrogen	Accelerating low-carbon hydrogen production	Achieving a yearly production capacity of 5 MtH_2 of green hydrogen by 2030
Emissions reduction	• GHGs: 43% by 2030, 60% by 2035 compared to 2019 • CO_2: net zero by 2050 • Reducing non-CO_2 emissions globally in particular methane emissions by 2030, G7 to reduce methane emissions from fossil fuels by 75% by 2030	• Reducing emissions intensity 45% below 2005 levels by 2030 • Achieving carbon neutrality by 2070 • Tighter emission controls under the Perform, Achieve and Trade (PAT) framework • Introducing low-carbon tools: Carbon Market Framework and Sustainable Finance Taxonomy (2025)
Energy efficiency	Doubling the global average annual rate of energy efficiency improvements by 2030	Setting new regulations for the energy consumption of equipment, appliances, buildings, and industries (2024)

China	Europe	United States
• Pursuing an all-of-the-above energy strategy • Prioritising renewables and coal, using trading mechanisms to cut energy use and CO_2 emissions • Providing tax credits to support low-carbon development • Aiming to derive 30% of energy from non-fossil sources by 2035	• Enhancing energy transition efforts to achieve dual goals: Diversifying its energy sources and advancing emissions reduction initiatives • While energy security remains a top priority, climate ambitions are being adjusted in favour of affordability to enhance industrial competitiveness	• Strategic pivot away from decarbonisation and clean-energy leadership, toward a framework focused on energy abundance, fossil-fuel dominance, and industrial competitiveness • Prioritising expanded oil, gas, and coal production, cutting regulatory constraints, and accelerating energy export growth • Clean energy goals remain nominally in place (e.g. carbon-free power by 2035), but have lost political traction and no longer guide policy implementation
• Encourage new gas-fired peak-shaving facilities • Prioritise gas for peak-shaving and grid-balancing • Reinforce coal-to-gas switching where feasible • Recognise gas as a reliability resource under the 2025 Energy Law • Support LNG-fuelled heavy-duty trucks and related infrastructure • Expand natural gas imports and upgrade domestic pipeline networks	• Expanding LNG imports from multiple sources • LNG to provide +50 bcma of added gas supply by 2030 • Pipeline gas demand of at least +10 bcma by 2030 • EUR 10 billion investment in LNG infrastructure by 2030 to diversify suppliers • Repurpose gas grids for hydrogen and reneable gas • Tariff relief for critical storage and LNG • Ban new long-term contracts for unabated natural gas beyond 2049	• Gas reaffirmed as the core fuel for both domestic use and export strategy • LNG exports actively promoted, reversing prior pauses • Permitting accelerated for pipelines and terminals
• Maximise coal's role as the primary energy source by boosting domestic supply and investing in coal power • Shift to controlled, lower-carbon coal use under the 2024 Coal Action Plan through efficiency upgrades, flexible retrofits, biomass/ammonia co-firing, and CCUS • Increase domestic oil and gas production while limiting energy imports	• Strengthened environmental restrictions on coal-based activities • Phasing out coal by 2040	• Coal restored as a backup power source; leasing bans lifted • Oil production incentivised as part of energy security drive • Regulatory easing supports rapid infrastructure expansion
• Set renewable energy target of 5 billion tonnes of standard coal equivalent by 2030 • Expand wind and solar capacity to 3,600 GW by 2035 • Double new-energy storage capacity to 180 GW by 2027 • Shift focus from capacity expansion to systemic demand creation and stronger integration mechanisms	• 42.5% renewables in final energy consumption by 2030 • Over 90% of power generated from renewables and nuclear energy by 2040 • Modernise infrastructure and integrate variable renewables • Reduce subsidies for renewables in major markets	• Clean energy tax credits remain in law but lack active federal backing • 30 GW offshore wind target by 2030 remains on paper amid weakened support and permitting delays
10% of power generation by 2035 and 18% by 2060, with 400 GW capacity	• Include nuclear power plants as eligible investments for green labeling • Over 90% of power generated from renewables and nuclear energy by 2040	• Lifetime extensions and small modular reactors actively pursued • 20% of electricity from nuclear by 2040 • Financial assistance up to USD 15/MWh
100-200 KtH_2 annually from renewable sources by 2025	Aim for 20 million tonnes of renewable hydrogen production and imports by 2030	• 10 MtH_2 annually by 2030, 20 mt by 2040, and 50 Mt by 2050 • USD 7 billion hydrogen hub programme frozen, slowing rollout
• Set dual carbon goals: peak emissions by 2030 and carbon neutrality by 2060 • GHG emissions 7–10% below peak by 2035 • Expand the emissions trading scheme and tighten penalties for non-compliance in energy-intensive sectors • Enforce strict MRV requirements under the 2024 Methane Plan for coal, oil, and gas facilities	• Aming for reducing emissions to 55% of 1990 levels by 2030 • Reducing net greenhouse gas emissions by 90% by 2040 • Achieving carbon neutrality by 2050 • Implement an integrated climate framework (MR, CSDDD, CBAM, ETS) linking emissions, trade, and supply chains • Capturing 280 million tons of CO2 annually by 2040 and around 450 million tons by 2050 • New heavy-duty vehicles to reduce emissions by 90% by 2040 • Banning new CO_2-emitting cars by 2035	• Paris Agreement withdrawal reasserted • Federal targets (e.g. 100% carbon-free electricity by 2035) remain on paper but are now largely symbolic • Waste Emissions Charge suspended until 2034 • EPA's 2024 mandate for CCUS or hydrogen in new fossil plants by 2032 put on hold • 45Q tax credit remains a main incentive for CCUS at $85/tCO_2$
13.5% energy intensity reduction by 2025	• Targeting an 11.7% reduction in final energy consumption by 2030 • Capping final consumption at 763 Mtoe and primary consumption at 993 Mtoe in the EU	• Tax incentives • Adoption of Energy Efficiency Resource Standards

Overall, Africa's 2024–2025 gas policy landscape is one of strategic pragmatism. Gas underpins fiscal stability, powers electrification, and provides geopolitical leverage, even as renewables and hydrogen projects advance selectively. The continent's exporters, from Algeria and Nigeria to Mauritania, Senegal and Mozambique, illustrate a shared approach: using gas to fund development, sustain reliability, and engage global markets on African terms.

However, the development of the domestic gas market in producing countries remains a common challenge, often competing with export. Addressing this requires a value-chain approach that ensures the viability of investments along every part of the chain. How domestic gas fiscal and pricing policies, including subsidy regimes, are balanced to increase investment, provide access and affordability to growing demand and cater for vulnerable populations is not always easily achievable.

2.3.2 Asia Pacific

The Asia Pacific region represents the core of global natural gas demand, reflecting both rapid economic growth and structural transitions in power, industry, and transport. The region's diversity, ranging from mature economies like Japan and South Korea to rapidly industrialising nations such as India, Indonesia, and Viet Nam, creates a complex policy landscape. Most countries are advancing multi-fuel transition strategies anchored in natural gas, renewables, and emerging low-carbon technologies, while maintaining affordability as a political imperative.

Natural gas occupies a central but differentiated role: as a baseload stabiliser in developed countries, a bridge to renewables in developing ones, and a key pillar of industrial decarbonisation through CCUS and low-carbon LNG. Rising urbanisation, electrification, and manufacturing growth continue to drive gas demand, while governments view gas as the "backbone fuel" that complements renewables and enables an orderly coal phase-out. Japan's revised energy and climate strategy through 2040 envisions renewables and nuclear jointly providing 70% of power but still reserves space for LNG to ensure grid stability and industrial competitiveness. Similarly, South Korea's 2025 energy mix plan targets replacing 40 coal units with LNG and low-carbon fuels, raising carbon-free power to 70% by 2038. In Southeast Asia, countries are expanding LNG infrastructure and small-scale regasification to displace diesel and support electrification, Indonesia alone is investing USD 1.5 billion in small-scale LNG projects to fuel 41 diesel-to-gas plants.

However, structural coal reliance persists. The global momentum to phase down unabated coal has depressed coal prices, with domestic coal remaining particularly cheap, making gas less competitive in price-sensitive power markets such as India, Indonesia, and Viet Nam. Despite its clear emissions advantage, coal-to-gas switching remains constrained by electricity tariffs and infrastructure limitations. Yet two emerging trends are gradually rebalancing the economics in favour of gas. First, the expansion of carbon pricing and emissions trading systems (ETS) is improving the relative cost competitiveness of gas vis-à-vis coal. China's ETS extended beyond power generation in 2025, Japan's GX League entered an operational trading phase, and South Korea's ETS remains the region's most mature compliance market. Meanwhile, Indonesia, Thailand, and Viet Nam are advancing pilot carbon markets under Article 6 cooperation frameworks, and Singapore and Malaysia are developing regional carbon trading hubs.

Second, the upcoming wave of global LNG supply additions, notably from the United States, Qatar, and Africa, is expected to ease market tightness and moderate prices through the late 2020s. This improved supply outlook will strengthen the economic case for coal-to-gas switching across Asia, making natural gas a more accessible and cost-effective option for power generation and industry. Together, these market and policy shifts are expected to support a more sustainable and economically viable transition toward cleaner fuels, reinforcing the region's long-term role as the centre of global LNG demand.

The following sections examine national pathways within this broader regional framework, focusing on the distinct approaches and policies shaping gas and energy transitions in China, India, Japan, South Korea, Indonesia, and Australia.

China

China's natural gas policy reflects both ambition and restraint, shaped by post-pandemic recovery and new economic headwinds. Following the rebound from COVID-19 disruptions, 2023 marked a period of solid industrial recovery and strong energy demand growth. Falling international gas prices and expanding manufacturing output supported a rapid rise in gas consumption, particularly for power generation to balance renewable intermittency. However, this momentum proved short-lived. In 2024, weak domestic demand, structural challenges in real estate, and mounting trade protectionism tempered growth. An interim assessment of the 14th Five-Year Plan showed that China was not on track to meet its 2025 energy- and carbon-intensity targets, prompting new measures to curb emissions and improve air quality while safeguarding energy security. These included tighter controls on coal use and guidance on the "orderly" consumption of natural gas, recognising it as a cleaner option but to be used under conditions of supply stability and cost efficiency.

By 2025, China entered a phase of economic consolidation and policy recalibration. Growth remained near the government's "around 5%" target, supported by targeted stimulus and a moderately loose monetary stance. Yet deflationary pressures persisted, and the external environment grew more complex. The re-escalation of tariff measures by the new United States administration, alongside broader protectionist responses in Europe and Asia, constrained export-oriented sectors such as solar, batteries, and electric vehicles. These headwinds reinforced Beijing's "security-first" stance, prioritising self-reliance, technological innovation, and domestic market resilience. For the energy sector, this has translated into greater focus on supply diversification, grid stability, and a pragmatic, phased low-carbon transition.

Policy dynamics in 2024–2025 underscored the complexity of China's transition. Renewables expanded at an unprecedented pace, allowing China to meet its 2030 target of 1,200 GW of wind and solar capacity six years ahead of schedule. Yet the construction of new coal power generation also accelerated, reflecting Beijing's determination to preserve supply security. This dual track reinforces coal as the baseline for stability while renewables meet most incremental demand growth. Facing shortfalls on energy- and carbon-intensity goals, policymakers introduced the "dual carbon control" framework, shifting from energy-consumption caps to emissions accountability. In March 2025, China expanded its national Emissions Trading Scheme (ETS) to cover steel, cement, and aluminium, raising coverage to about 60% of national emissions and signalling a deeper reliance on market-based decarbonisation tools. However, the main direction for energy and natural-gas policy will be set by the forthcoming 15th Five-Year Plan (2026–2030), expected to consolidate new NDC commitments, including 2035 climate targets, into a unified strategy balancing security, affordability, and sustainability.

China's renewable policy shift embeds systemic demand creation and strengthens integration mechanisms. By 2024, renewables expanded at record speed, allowing China to meet its 2030 goal six years ahead of schedule. This rapid buildout, however, revealed new challenges, particularly the electricity system's limited ability to absorb and dispatch the growing renewable output. To address these constraints, the government released the Guiding Opinions on Vigorously Implementing the Renewable Energy Substitution Initiative in October 2024, marking a shift from capacity expansion to systemic integration. The plan sets targets for renewable-energy consumption equivalent to 1 billion tonnes of standard coal by 2025 and 5 billion tons by 2030, focusing on electrifying industry, upgrading infrastructure, and accelerating the deployment of green technologies to better integrate renewable supply.

In 2025, renewed United States-China trade tensions further complicated this agenda. Tariffs on clean-technology exports weakened external demand and prompted China to "front-load" renewable installations at home, even as grid and storage capacity lagged behind. These pressures reinforced the urgency of policies that ensure renewables can be effectively absorbed into the power system. China's newly submitted NDC reflected this direction, pairing new 2035 climate targets, with greenhouse gas emissions 7–10% below their peak and the non-fossil share of primary energy above 30%, with a commitment to expand wind and solar capacity to 3,600 GW. Together, these objectives emphasise not only emissions reduction but also the practical challenge of integrating unprecedented levels of renewable generation into the energy system.

To support this transition, China aims to double its new-energy storage capacity to 180 GW by 2027, mainly through lithium-ion systems, and expand its national Emissions Trading Scheme to heavy industry, embedding carbon pricing as a core policy tool for incentivising lower-emission fuels and flexible generation. For natural gas, this evolving framework narrows its baseload role but reinforces its importance as a flexible stabiliser, essential for peak-shaving, seasonal balancing, and maintaining reliability in a renewable-dominated power system.

Climate and environmental regulations continue to redefine China's energy policy space. The 2024 Coal Action Plan shifted from capacity expansion toward controlled, lower-carbon operation. It requires efficiency upgrades, flexible retrofits, and co-firing with biomass or ammonia, while promoting CCUS deployment. These measures raise coal compliance costs and reduce its short-term competitiveness, indirectly supporting gas in balancing and industrial-heat applications. Simultaneously, the Methane Emissions Control Action Plan (2024) introduced comprehensive MRV requirements for coal mines, oil and gas facilities, and wider energy systems, with supplementary standards rolling out in 2025. Embedding methane control into investment and procurement frameworks gives advantage to gas supply chains with lower verified emissions.

Recent policy initiatives have embedded natural gas more firmly into China's regulatory and strategic framework. The 2024 revision of the Natural Gas Utilization Policy prioritised gas for peak-shaving and grid-balancing applications, while the Air Quality Action Plan reinforced substitution of coal with gas where feasible. The 2025 Energy Law established a legal foundation for energy governance, balancing the rapid expansion of renewables with recognition of gas as a reliability resource. Complementing these efforts, the State Council's transition from "dual energy control" to "dual carbon control" elevated the value of lower-carbon dispatch options such as gas, while new Basic Rules for Power Market Operation (2024) and Ancillary Services (2025) expanded flexibility markets that reward fast-response generation.

At the same time, transport and supply security policies are broadening the foundations of gas demand. LNG-fuelled heavy-duty trucks are receiving policy incentives and infrastructure investment as part of a national strategy to reduce oil imports and decarbonise freight, with the forthcoming 15th Five-Year Plan expected to accelerate this shift. On the supply side, agreements surrounding Russia's Power of Siberia pipelines and Far-East deliveries, together with sustained LNG imports despite sanctions-related frictions, reflect a deliberate portfolio approach, combining pipeline stability with LNG flexibility. This diversification reduces price volatility, strengthens energy security, and underpins the continuing role of natural gas as a stabilising force within China's evolving energy mix.

China's evolving climate policy links gas more closely to carbon pricing and performance standards. The expanded ETS now covers heavy industry, driving demand for lower-emission fuels in energy-intensive value chains. Product-carbon-footprint (PCF) and lifecycle-assessment standards embed emissions accountability at the product level. Where gas enables verifiable carbon-intensity reductions, such as in chemicals, glass, or materials, it retains policy traction; where electrification or hydrogen deliver deeper decarbonisation, its role narrows. China's new NDC integrates these domestic policies into an international framework, reaffirming the dual-carbon goals of peaking emissions before 2030 and achieving net zero by 2060, while adding 2035 targets to reduce greenhouse-gas emissions by 7–10% below peak levels and lift the non-fossil share above 30%. These ambitions constrain large-scale gas expansion but confirm its value as an enabling and stabilising fuel.

Nuclear policy has gained strong momentum as Beijing seeks to reduce volatility and import dependence. In late 2024, the State Council approved 10 new nuclear units, continuing the pace of 10–11 annual approvals since 2022. China is on track to become the world's largest nuclear power producer by 2030, with nuclear expected to reach 10% of generation by 2040. The sector's expansion, driven by domestic technologies and self-reliance, underscores nuclear's role as a reliable, low-carbon baseload complement to renewables. For natural gas, this growth introduces competition in reliability services but does not diminish its importance for fast-response and peak-shaving needs.

Overall, China's evolving policy framework underscores a selective but durable role for natural gas. Rather than mandating large-scale substitution, policies enable gas where it aligns with emissions control, system flexibility, cleaner transport, and security of supply. Tightening domestic regulations on carbon and methane, combined with trade frictions and uneven renewable absorption, have further reinforced its stabilising role within the energy system. As China integrates record levels of wind and solar capacity while imposing stricter limits on coal use to curb emissions and improve air quality, natural gas continues to serve as a pragmatic partner fuel, supporting reliability, sustaining industrial output, and facilitating renewable integration, yet it remains a measured component rather than a dominant force in China's long-term energy strategy.

India

India's 2025 energy strategy is driven by the need to sustain rapid growth while ensuring energy security, affordability, and lower emissions. With rising electricity demand, expanding industrial output, and record summer heatwaves, reliability has become a core policy objective. The government's approach builds on diversification, coal for assurance, renewables for scale, and natural gas for system stability and cleaner growth.

Natural gas has become a structural pillar of this balance. The government continues to pursue its target of 15% of the primary energy mix by 2030, supported by an investment plan of about USD 67 billion through 2030 to expand LNG terminals, pipelines, and city-gas networks. Policy reforms, such as unified pipeline tariffs, rationalised pricing, and new HELP bidding rounds, aim to strengthen affordability and attract private investment. Projects like Dhamra LNG and the Jagdishpur–Haldia–Bokaro–Dhamra pipeline extend access to new regions, embedding gas more deeply into the national energy infrastructure.

Coal continues to anchor supply security, yet tighter emission controls under the Perform, Achieve and Trade (PAT) framework and grid pressures from extreme weather have enhanced gas's value as a reliable and lower-emission complement. Gas-fired plants are increasingly used to meet short-term surges and smooth renewable fluctuations, roles that are expanding as power demand becomes more variable.

The rapid build-up of renewables, anchored in the 500 GW non-fossil capacity target by 2030, and emerging low-carbon instruments such as the National Framework for Carbon Markets (2024) and the draft Sustainable Finance Taxonomy (2025) are shaping a more integrated system where gas supports industrial competitiveness, grid flexibility, and cleaner transport. Complementary efforts under the National Green Hydrogen Mission (2024) and plans to triple nuclear capacity by 2032 further diversify the low-carbon mix, while gas continues to underpin reliability and industrial output.

Internationally, India's status as one of the top five LNG importers gives it growing influence over global trade dynamics. Even marginal shifts in Indian demand now affect global market balances, underscoring the country's rising weight in shaping LNG flows, contracting terms, and price trends.

By and large, India's expanding infrastructure, sustained policy support, and cross-sectoral demand drivers point to a steady rise in natural gas consumption. As policy reforms mature and supply diversification advances, natural gas is set to play a decisive role in underpinning India's energy reliability, supporting industrial growth, and enhancing its global significance in the evolving LNG landscape.

Indonesia

Indonesia's 2025 energy strategy emphasises stability and domestic resilience while maintaining coal and gas as the backbone of supply. The new Ten-Year Power Plan (RUPTL 2025–2034) prioritises near-term expansion of fossil-based capacity, mainly gas, while renewable growth is pushed to the latter part of the decade. This reflects a pragmatic approach to securing reliable power amid rising demand, high costs, and slow infrastructure development.

Natural gas has been reaffirmed as the key pillar of Indonesia's energy transition. The government is promoting investment in gas networks, encouraging domestic use over exports, and supporting new LNG infrastructure to bridge gaps in supply. While new coal plants are restricted, existing units continue to operate, with gas increasingly used for peaking and grid stability as renewables scale up.

At the same time, Indonesia is reopening to international carbon trading and advancing complementary clean projects, such as geothermal, hydro, and floating solar, to diversify its energy mix. Yet challenges persist, including declining domestic gas production, slow grid upgrades, and the financial hurdles facing renewable investment. For now, natural gas remains the country's most viable tool to balance affordability, security, and gradual decarbonisation.

Japan

Japan's 2025 energy strategy balances ambition with pragmatism. Rising electricity demand from data centres and semiconductor industries, coupled with renewed trade frictions with the United States, has led Tokyo to reaffirm its guiding "S+3E" principles, safety, energy security, economic efficiency, and environmental sustainability. The Seventh Strategic Energy Plan (2025) and GX 2040 Vision together outline a pragmatic path toward net zero, aiming for a 60% reduction in emissions by 2035 and 73% by 2040, while maintaining supply stability and industrial competitiveness.

Renewables are positioned as mainstream, targeting a 40–50% share of power generation by 2040, supported by 45 GW of offshore wind and incentives for perovskite solar cells. Nuclear power is now slated for "maximum use," with lifetime extensions and next-generation reactors expected to deliver 20% of electricity by 2040, a decisive shift from the post-Fukushima phase-down policy. The GX Promotion Act underpins this trajectory through USD 128 billion (¥20 trillion) in transition bonds and phased carbon pricing, starting with a voluntary ETS in 2026, carbon levies in 2028, and emission allowance auctions by 2033.

However, **cost inflation, rising material prices, and regulatory uncertainty have weakened investor confidence and slowed renewable deployment.** Leading energy companies such as Japex and Eneos have redirected capital toward oil, gas, and LNG, citing profitability concerns. Offshore wind, once Japan's flagship renewable sector, has also lost momentum, with only a fraction of the planned capacity auctioned and several developers withdrawing amid high costs and permitting hurdles.

Within this recalibrated landscape, **natural gas remains indispensable for flexibility and energy security.** The Strategic Energy Plan projects 53–74 million tonnes of LNG use by FY2040–41, while the Japan Gas Association's 2025 revision envisions up to 50% of 2050 gas supply from natural gas integrated with CCUS. Gas's role is further reinforced by its ability to balance intermittent renewables and meet industrial demand during transitional bottlenecks.

Japan's path to net zero by 2050 remains demanding. Emissions-reduction targets face delays amid public resistance to nuclear restarts and slow renewable expansion constrained by land scarcity, costs, and lengthy approval processes. Solar continues moderate growth, while offshore wind, essential for deeper decarbonisation, requires stronger policy and permitting reform. Pilot projects in hydrogen, ammonia, and CCS signal technological progress but remain far from scale. Consequently, natural gas and LNG will continue to act as stabilising pillars of Japan's energy system, ensuring grid reliability when renewables fall short. Over time, LNG demand is expected to gradually decline, yet its role in power generation will become more strategic and variable. Japan thus remains a pivotal LNG market, whose evolving decarbonisation pathway will continue to shape regional gas dynamics and global energy trade.

South Korea

South Korea's 2025 energy strategy centres on reliability and competitiveness, with natural gas anchoring the transition between rising nuclear and slower renewable expansion. As power demand surges from industrial and digital growth, policy prioritises grid stability and fuel security over rapid decarbonisation.

Coal is being phased down through stricter seasonal air-quality controls, while LNG remains essential for peak coverage and balancing renewables. Nuclear restarts and lifetime extensions are restoring baseload capacity, but gas-fired generation continues to provide flexibility during outages and low-renewables periods.

Renewable growth, particularly offshore wind, faces high costs and slow permitting, making gas a critical stabiliser. Meanwhile, hydrogen and ammonia co-firing pilots, alongside expanding CCUS projects, mark the first steps toward low-carbon gas integration.

Reforms to the national emissions trading scheme and exposure to carbon border measures are driving cleaner industrial fuel choices, with utilities adopting certified, lower-emission LNG. In policy terms, gas is treated not as transitional but as a structural reliability pillar, ensuring system adequacy and industrial competitiveness while longer-term technologies scale.

Australia

Australia's 2025 energy policy balances rapid renewable expansion with pragmatic support for gas to ensure reliability and export competitiveness. The federal government's Future Made in Australia Act (2025) consolidates incentives for clean manufacturing, critical minerals, and hydrogen while retaining natural gas as a reliability and export pillar during the transition.

Domestically, gas continues to underpin system adequacy as coal plants retire faster than new firm capacity comes online. The Capacity Investment Scheme targets 32 GW of new renewables and storage by 2030, yet grid congestion, permitting delays, and community opposition have slowed project delivery. In this environment, policy frames gas generation as an essential stabiliser and a bridge toward an expanded hydrogen and storage ecosystem.

Australia remains a global LNG leader, with exports central to fiscal revenue and regional energy security. Policy emphasis has shifted toward maintaining investment confidence in new supply projects and certifying lower-emission LNG to preserving market access, particularly in Japan, South Korea, and Southeast Asia, under tightening methane and lifecycle-carbon standards.

At the same time, Canberra is scaling hydrogen hubs, CCUS projects, and critical minerals processing as growth engines for a decarbonised export portfolio. However, high project costs, infrastructure bottlenecks, and policy inconsistency across states continue to temper the pace of transition. For now, natural gas retains a dual role: a stabiliser in the domestic power mix and a cornerstone of Australia's export-driven energy diplomacy.

2.3.3 Europe

The EU is recalibrating climate ambition to political and security realities while keeping gas in a managed, time-bound role. The new European Commission, in office since December 2024, has shifted its focus toward competitiveness and affordability, launching the Clean Industrial Deal and the Affordable Energy Action Plan to support industry while safeguarding supply stability. The expiration of the temporary gas price cap on 31 January 2025 signalled a return to market pricing as crisis conditions eased, even as security of supply remains a core priority. Political pressures from farmers and energy-intensive sectors have prompted the Commission to adjust or slow certain environmental and climate-related legislative initiatives, particularly those affecting agriculture, land use, and industrial compliance, while the Omnibus Simplification Package (2025) eased reporting and due-diligence requirements under the CSDDD and related ESG laws to reduce compliance costs. Yet, despite this recalibration, Brussels remains anchored by the 2040 Climate Target (net GHG –90% by 2040), the Net-Zero Industry Act (NZIA), and the Industrial Carbon Management Strategy, together steering power toward near-zero CO_2 by 2040, phasing down coal, and reserving a narrow, declining role for natural gas where it supports system adequacy and industrial competitiveness. Debate continues over the binding nature of the 2040 target, with some EU Member States advocating flexibility to shield competitiveness, while others push for legal certainty to preserve long-term direction.

Within this evolving framework, **renewables remain the backbone of the decarbonisation agenda**, but 2025 has revealed the economic and structural strains of the transition. The share of renewables in EU power generation rose to 47% in 2024, yet the expansion of solar and wind is slowing for the first time in a decade as subsidies are reduced and financing costs rise. According to the European Commission, the bloc will require about Euro 1.2 trillion (roughly USD 1.3 trillion) in grid investments by 2040 to modernise ageing infrastructure and integrate variable renewables. Recent system failures, such as the Iberian blackout in April 2025 have exposed the fragility of outdated grids, while offshore wind cancellations and postponed tenders highlight the mounting cost pressures. Rooftop solar installations have also declined sharply amid subsidy cuts in major markets. Against this backdrop, natural gas continues to provide the stabilising backbone of the power mix, bridging gaps in renewable output and supporting the orderly phase-out of coal while maintaining grid reliability.

To support this balance, **gas market rules have been rebuilt to hard-wire the transition and preserve resilience.** The Renewable & Natural Gases and Hydrogen (RNGH) Directive and Regulation translate crisis-era lessons into lasting law: enabling repurposing of gas grids for hydrogen, providing targeted tariff relief for storage and LNG where essential for security, and prohibiting new long-term contracts for unabated fossil gas beyond 2049. The package is deliberately technology-neutral, accommodating demand response, storage, and low-carbon gases, yet it retains conventional gas as a reliability option while the energy system decarbonises.

The EU's hydrogen infrastructure is moving from vision to implementation, reinforcing the RNGH framework for integrated networks. In early 2025, Italy, Germany, Austria, Algeria, and Tunisia advanced the SouthH2 Corridor, linking North Africa's renewable hydrogen to Europe. In parallel, the H2Med project, backed by France, Spain, Portugal, and Germany, will connect Barcelona and Marseille through a Euro 2.5 billion subsea line expected to deliver around 2 million tonnes of hydrogen annually by 2030. Supported by EU co-funding, these projects illustrate the transition of Europe's gas backbone toward a low-carbon, hydrogen-ready system.

Supply chains are being aligned with climate accountability, both within the EU and at its borders. The EU Methane Regulation (MR) extends from domestic operations to imports, with detailed monitoring, reporting, and verification (MRV) ramping up ahead of import standards set to apply from 2030, pressuring foreign suppliers to curb leakage or risk restricted access (see Box 2.2). In parallel, the Corporate Sustainability Due Diligence Directive (CSDDD), streamlined in 2025 under the Omnibus Simplification Package, continues to tighten company-level responsibilities across value chains, while the Carbon Border Adjustment Mechanism (CBAM) was likewise refined in 2025 to simplify procedures and ease administrative burdens without weakening its core function of levelling the carbon cost of imports. Together, these adjustments reflect Brussels' effort to preserve regulatory credibility and climate ambition while reducing compliance costs and addressing competitiveness concerns. At the same time, the EU Emissions Trading System (ETS), expanded in 2024 to include maritime transport and extended through the new ETS II for buildings and road transport from 2028, remains the cornerstone of internal carbon pricing. Together, MR, CSDDD, CBAM, and ETS now operate as an integrated framework linking industrial emissions, trade, and supply chains under a unified climate accountability regime, one that rewards lower-carbon gas and penalises high-emission imports while keeping industry viable under tightening climate discipline.

Box 2.2 The EU Methane Regulation

The EU Methane Regulation (MR) introduces a comprehensive framework to monitor, report, and reduce methane emissions across the oil, gas, and coal supply chains. It imposes robust Monitoring, Reporting, and Verification (MRV) obligations on both EU and non-EU operators, including detailed reporting protocols, third-party verification, and public disclosure. These obligations aim to enhance transparency and data comparability but may also pose compliance challenges, particularly for exporters with limited access to advanced MRV infrastructure and harmonised quantification methodologies.

Beyond MRV, the Regulation sets a clear distinction in mitigation obligations. EU-based operators are subject to prescriptive operational rules, such as Leak Detection and Repair (LDAR) programs, flaring and venting limits, and requirements for inactive wells. In contrast, non-EU exporters are not required to adopt specific operational practices but are expected to meet future methane intensity (MI) thresholds as a condition for market access. While these thresholds are yet to be finalised, they function as de facto performance standards and may necessitate equivalent mitigation actions in practice.

This dual structure may result in uneven compliance costs and added complexity for third-country exporters. It creates legal and governance frictions by departing from multilateral climate norms. Critics argue that the MR's extraterritorial effects risk violating principles of the UNFCCC and the Paris Agreement, including nationally determined contributions (NDCs) and common but differentiated responsibilities and respective capabilities (CBDR-RC). Several developing exporters also view it as incompatible with WTO principles of non-discrimination by indirectly disadvantaging imports and the technical barriers to trade (TBT Agreement).

From a technical perspective, implementation bottlenecks include limited access to accurate measurement technologies, gaps in site-level data, and a lack of globally harmonised methodologies. These challenges are more pronounced in low-capacity countries, raising the risk of exclusion from the EU market or disproportionate economic burdens on compliant exporters.

In response to the MR, countries are likely to adopt divergent approaches depending on their political alignment, technical readiness, and strategic priorities. Some high-capacity exporters may proactively align with EU requirements to preserve market share and signal leadership on methane mitigation. Others may resist the MR's provisions, raising objections through WTO or UNFCCC forums, or pushing for equivalence mechanisms through bilateral channels. Still others, especially those with constrained resources, may seek technical and financial support or opt to redirect their exports toward less regulated markets. This divergence in responses could reshape global gas trade dynamics and widen the gap between high- and low-mitigation supply chains.

If fully implemented and enforced, the EU MR could exert a transformative effect on methane governance in global gas markets, elevating methane intensity as a key trade metric, restructuring investment priorities, and amplifying calls for standardised international frameworks. Yet its long-term impact will depend on how legal uncertainties are resolved, how stringently benchmarks are enforced, and whether external suppliers can overcome compliance and capacity constraints in time.

Geopolitics is reshaping EU gas sourcing, with Russia contained and Türkiye's corridor relevant but constrained. Russian pipeline flows remain structurally limited, with any residual LNG trade being gradually phased down. Türkiye's transit role (via existing corridors) still matters for Southeast Europe's diversification, but EU strategy prioritises diversified LNG plus intraregional interconnectors over new long-lived exposure to single routes. Green-power interconnectors with MENA and the East Med proceed selectively, tempered by cost inflation and permitting risk.

Transatlantic trade politics add volume, but not certainty, to LNG flows. The EU–United States 2025 framework signals higher EU purchases of United States energy (with United States tariff relief in play), yet it is non-binding and ultimately constrained by EU demand trends, regasification and interconnection bottlenecks, and corporate contracting economics. Crucially, any incremental United States LNG must meet the EU's methane import standards, so exporters are leaning into certified gas and third-party verification even as United States federal methane rules loosen, putting market access, not Washington, in the regulatory driver's seat.

EU policy now recognises that natural gas will remain part of the energy system well into the 2040s, and, as DG ENER (The European Commission's Energy Directorate) recently underscored, at least until 2050, while its role becomes progressively more flexible, emissions-conditioned, and system-supportive. The RNGH package provides the framework for this managed evolution, enabling a gradual shift toward hydrogen and renewable gases while preserving security of supply during the transition. The Methane Regulation, CBAM, and CSDDD together raise the bar on emissions accountability across the value chain, embedding climate performance into market access and corporate governance. At the same time, the Clean Industrial Deal, the Affordable Energy Action Plan, and the Omnibus simplification reforms reflect a pivot toward competitiveness and cost realism without retreating from long-term climate objectives. Gas demand and contracting tenors continue to shorten, yet flexible LNG, storage, and peak-shaving capacity remain indispensable for adequacy through the 2030s and beyond, particularly during cold spells, low-renewables periods, and industrial stress points, until electrification, grids, storage, and low-carbon gases mature to fully assume these functions.

2.3.4 Latin America

Latin America's natural gas policy in 2024–2025 is characterised by consolidation and strategic adaptation. Governments are aligning gas policy around three priorities: ensuring reliable supply, expanding export revenues, and protecting power systems from the volatility of hydropower and global fuel markets. Across the region, natural gas is being positioned as a foundation of fiscal stability, energy reliability, and regional cooperation, while cautiously creating space for renewables where financing conditions and policy frameworks permit.

First, policy is centred on defending gas supply and turning it into macro stability. Argentina has moved aggressively to elevate domestic shale gas (Vaca Muerta) from a national fuel into a regional export platform. Recent deregulation and pro-investment measures aim to attract large-scale upstream capital, accelerate pipeline buildout to the north and across borders, and normalise seasonal exports to Chile, Brazil, and potentially Bolivia. The strategic message from Buenos Aires is clear: gas is not just for winter heating at home; it is an external revenue instrument and a way to reduce expensive LNG imports. Trinidad & Tobago is following the same logic from the opposite direction. Faced with falling domestic output and underutilised LNG and petrochemical capacity, Port of Spain has prioritised long-term cross-border gas agreements and new upstream development to refill its industrial complex and protect export earnings. Brazil, for its part, is pursuing a dual track: it is trying to bring more of its own offshore associated gas to shore (rather than flaring or reinjecting it in oil fields), while also lining up additional LNG offtake and pipeline access to guarantee flexibility in dry years. These policy choices all point toward the same regional shift: governments view gas supply as too strategic to be left to depletion cycles and spot cargoes, and they are intervening (through fiscal incentives, deregulation, and contract frameworks) to lock in secure molecules for the next decade.

Second, **natural gas policy is increasingly about keeping the lights on and the economy running in the face of structural fragility.** Brazil's power system still relies heavily on hydropower, and recurrent droughts have exposed how quickly the country must pivot to gas-fired generation to avoid blackouts and industrial curtailments. Brasília's response has been to ensure access to flexible gas, via LNG regasification, negotiated pipeline volumes, and domestic processing reforms to bring offshore gas to market at a lower delivered cost. Chile, with almost no domestic gas and an accelerating coal exit, is pursuing guaranteed supply through two channels: long-term LNG import capacity and renewed pipeline flows from Argentina. Santiago's policy stance reflects a hard lesson of the past decade: intermittent renewables alone cannot protect industrial load and grid stability during stress periods. Argentina itself, historically a winter LNG importer, is trying to break that vulnerability by expanding internal transport capacity and positioning seasonal surpluses for export instead of emergency import. In all three cases, gas is treated as reliability infrastructure, not just another commodity fuel.

Third, **governments are using regulation and ownership models to defend strategic control of gas value chains.** The policy instruments differ by country, but the intent is similar. Argentina has liberalised pricing, eased export restrictions, and introduced preferential regimes to attract private investment into shale gas, guided by the argument that export-led gas monetisation will stabilise its external accounts. Brazil is pushing domestic market reforms to lower delivered gas prices to industry, linking energy affordability directly to competitiveness in manufacturing. Trinidad & Tobago is leveraging long-term supply arrangements and regional resource pooling to extend the life of its LNG and petrochemical platforms, which are central to jobs, fiscal revenue, and foreign exchange. In each case, policymakers see gas not only as fuel but as an industrial policy lever. This mirrors a broader Latin American trend: gas is being woven into national economic positioning, not left as a passive by-product of oil.

Fourth, **hydropower stress is quietly reinforcing gas's political legitimacy.** Severe drought episodes across Brazil and the Southern Cone have repeatedly forced governments to lean on gas-fired generation to prevent supply crises. That experience has hardened a policy view that gas is indispensable "insurance" against water scarcity and climate variability. This is especially relevant because, in many countries, hydropower is still marketed as the clean, sovereign, affordable backbone of the power mix. When reservoir levels fall, the only scalable, dispatchable alternative available at short notice is gas. As a result, natural gas is now being explicitly integrated into long-term resource adequacy planning, not only as baseload for industry and petrochemicals, but as a contingency fuel for the grid when hydro underperforms.

Fifth, **regional integration is being reshaped through evolving gas flows.** For years, Bolivia served as the cornerstone supplier for its neighbours, anchoring the Southern Cone's pipeline network. That model is now transitioning as production patterns shift and new supply centres emerge. Argentina is increasingly taking on the role of swing supplier, using its expanding shale output to sustain Chilean industries and support Brazil during hydropower shortfalls. Chilean policy, in turn, is deliberately diversifying between LNG imports and Argentine pipeline gas to avoid being stranded during winter peaks. Brazil is keeping every door open, domestic offshore gas, Argentine inflows, regasified LNG, to avoid having to choose between industrial curtailment and politically unacceptable power rationing. At the same time, Caribbean and Central American markets remain structurally dependent on imported LNG to replace diesel in power generation, locking in long-term demand for flexible supply and floating regasification capacity. This web of bilateral arrangements and seasonal swaps is shaping a more interconnected gas market in Latin America, one in which natural gas policy is as much about cross-border reliability deals as about national production targets.

Finally, **renewables and hydrogen strategies are emerging, but they sit behind gas in the policy hierarchy, not in front of it.** Chile continues to position itself as the region's flagship for green hydrogen and has maintained ambitious electrolyser build-out targets. Brazil has advanced early frameworks for offshore wind, battery storage auctions, and large-scale biofuels blending. Some solar, hydrogen, and industrial decarbonisation plans are also appearing in Mexico and the Southern Cone. But the regional reality is that these initiatives are being layered on top of, not in place of, a gas-centred system. In many cases, nascent clean projects are explicitly underwritten by gas-backed grid stability or gas-funded fiscal space. The message from policymakers is pragmatic: hydrocarbons, and especially natural gas, will continue to finance and stabilise the transition.

Taken together, Latin America's current natural gas policy is focused on consolidation, coordination, and strategic interdependence. Governments are refining investment frameworks to accelerate upstream development and convert resource potential into export revenues. Power systems continue to codify gas as the anchor of energy reliability when hydropower underperforms or renewable deployment lags. Importing countries are securing long-term and bilateral supply contracts to shield themselves from market volatility. Across the region, gas diplomacy, spanning Southern Cone pipeline cooperation, Caribbean LNG partnerships, and long-term linkages to United States supply, has become a defining feature of regional integration. Overall, these dynamics show how natural gas policy functions as both a stabilising force and a catalyst for broader economic diversification, defining a critical dimension of the region's energy future.

2.3.5 North America

North America in 2024–2025 is shaping the global gas system at every level: production, pricing, trade routes, and deregulation. The region supplies a growing share of the world's LNG, anchors long-term contracts with Europe and Asia, and is using natural gas policy as an economic, industrial, and geopolitical instrument. Across the United States, Canada, and Mexico, governments are treating gas as strategic infrastructure: essential for grid stability under rising electricity demand, fiscal stability through export revenues, and industrial stability as heavy industry faces higher capital costs and tighter trade conditions. At the same time, approaches diverge. The United States is maximising production and export capacity through deregulation and emergency powers. Canada is positioning gas as an export growth engine tied to lower-carbon standards and indigenous partnerships. Mexico is prioritising reliability and sovereignty: locking in state control of power while still depending on cross-border gas flows and new storage and processing capacity. Together, these policies are determining not just how much gas is produced and burned in North America, but where it flows, on what terms, and under whose rules.

The United States

The United States in 2025 stands at the centre of global natural gas dynamics, both as the world's largest producer and as a defining force in LNG trade. Its energy policy has taken a decisive turn away from the transition-driven framework that defined the previous administration. The withdrawal from the Paris Agreement, the declaration of a national energy emergency, and a comprehensive review of climate regulations have collectively redirected priorities toward fossil-fuel expansion, industrial competitiveness, and supply security. The new strategy is grounded in an energy-dominance narrative, restoring coal and oil, reinforcing natural gas, and maintaining nuclear power as the clean component of a secure baseload, while tempering or suspending the ambitious decarbonisation targets once central to United States energy planning.

At the macro level, the new administration's trade and fiscal policies have profoundly shaped the energy outlook. A sweeping tariff regime, including a 10% baseline import duty and higher country-specific rates for countries with persistent trade surpluses, has been designed to rebalance external accounts and stimulate domestic production. Although energy commodities such as LNG remain exempt, the tariffs have sharply increased costs for clean-technology components including solar modules, batteries, and wind turbines. This protectionist turn has slowed renewable deployment and complicated efforts to reach earlier milestones such as 30 GW of offshore wind capacity by 2030, 100% carbon-free electricity by 2035, and a 61–66% reduction in GHG emissions by 2035 compared with 2005 levels. These targets technically remain on record but have lost federal traction, with progress now reliant on state mandates and private investment rather than federal acceleration.

Natural gas lies at the core of this recalibrated strategy. In particular, LNG has become a defining feature of the United States' contemporary energy diplomacy. Beyond its economic importance, natural gas, especially in its liquefied form, now functions as a strategic instrument of foreign policy, binding allies through energy interdependence while reinforcing United States industrial and geopolitical influence. The administration's active promotion of LNG exports has turned the sector into a central pillar of its trade strategy, combining economic leverage with strategic reassurance to partners seeking diversification away from Russian and Middle Eastern supplies.

Policy support for LNG expansion has been decisive. The 2025 Energy Emergency Order, combined with the reversal of previous export permit pauses, has created a permissive regulatory environment for hydrocarbon growth. Streamlined approvals, simplified permitting for pipelines and terminals, and direct executive backing for new projects have positioned LNG as both an economic growth engine and a tool of geopolitical alignment. In this framework, export growth is not merely a market outcome but an extension of statecraft, a tangible means of strengthening alliances and reasserting United States leadership in global energy governance.

To secure long-term outlets for this expanding supply, Washington has pursued a series of bilateral and regional energy arrangements. Frameworks with partners across Europe, Asia, and the Mediterranean link trade concessions to energy commitments, ensuring both political reciprocity and stable export markets. In Asia, initiatives such as the revival of the Alaska LNG project are presented as strategic corridors connecting North American gas to Japan, South Korea, and Southeast Asia, offering a substitute for Middle Eastern routes and enhancing maritime security. Meanwhile, transatlantic cooperation under the 2025 United States–EU trade framework places LNG at the heart of a wider commercial reset, framed as a mutually beneficial effort to bolster European energy security and rebalance trade.

Yet the feasibility of these ambitions remains uncertain. The unprecedented pace of global LNG expansion has raised warnings of a potential structural oversupply later in the decade. With export capacity growing faster than consumption, particularly in Asia and Europe, prices are likely to come under downward pressure. This scenario threatens to squeeze margins for higher-cost United States producers, especially as financing conditions tighten and investor sentiment becomes more cautious. Even with United States government support, questions persist about the commercial viability of many planned projects in the Gulf Coast and Alaska, where escalating costs and market saturation have already slowed investment decisions.

For partner countries, the gap between political pledges and practical absorption capacity adds another layer of uncertainty. In Europe, gas demand remains in structural decline due to energy efficiency measures, rapid renewable deployment, and methane emission regulations that could constrain imports from non-compliant suppliers. Infrastructure bottlenecks also persist, with limited interconnections preventing efficient distribution of LNG within the region. In Asia, while governments welcome access to United States gas, logistical challenges and high capital requirements limit the scale of new commitments. As a result, many of the recently announced import frameworks appear more symbolic than binding, politically valuable but commercially constrained.

Domestically, the picture is equally complex. Surging baseload electricity demand from AI, industrial electrification, and manufacturing expansion has tightened the natural gas balance. Gas-fired power generation remains the most reliable and flexible means of meeting these loads, particularly amid slower renewable deployment and ageing coal capacity. This rising demand places LNG exporters in competition with domestic consumers for available supply, potentially lifting prices and challenging affordability for industries and households. The government's policy of prioritising production growth, by easing drilling restrictions and expediting permitting, seeks to mitigate this tension. However, if global markets enter a sustained period of oversupply, export margins could contract sharply, making the economics of large-scale United States LNG ventures less attractive.

Ultimately, the United States finds itself navigating a paradox of abundance. Its vast natural gas reserves and infrastructure make it indispensable to global energy security, yet the very scale of expansion risks undermining profitability and balance. The ambition to rewire global energy dependencies through LNG exports is strategically potent but commercially fragile. In the years ahead, the sustainability of this strategy will depend on maintaining equilibrium between foreign commitments and domestic needs, ensuring that natural gas remains both the cornerstone of United States energy strength and a stable pillar of global supply.

While gas assumes this central role, **coal and nuclear have been repositioned as complementary supports within the domestic mix.** Coal has re-emerged as a reliability reserve: restrictions on leasing and plant operation have been lifted, and some units reopened under energy security exemptions. Nevertheless, high costs and emissions keep its contribution limited to ensuring baseload stability during peak demand. Nuclear energy, by contrast, has retained broad political backing. Lifetime extensions for existing reactors and pathways for small modular reactors (SMRs) form a crucial part of the administration's supply-stability agenda. The sector's long-term objective of securing around 20% of generation by 2040 remains feasible, offering a low-carbon counterweight in a fossil-fuel-heavy environment.

Other technology pillars from the previous decade continue under altered terms. Hydrogen development remains guided by the 45V production tax credit, finalised before the change in administration. The framework is technology-neutral, rewarding projects based on lifecycle emissions regardless of whether they use renewable, nuclear, or gas-based feedstocks. However, the freeze on USD 7 billion in hydrogen-hub funding has delayed implementation. Investment momentum has shifted toward blue hydrogen, produced from natural gas with carbon capture, in line with the administration's preference for hydrocarbon-linked innovation. The earlier goal of cutting hydrogen production costs to USD 1 per kilogram by 2031 is now unlikely to be met.

CCUS continues to benefit from the 45Q tax credit, offering USD 85 per tonne of stored CO_2. Yet oversight has become increasingly decentralised as the Environmental Protection Agency transfers well-permitting authority to states such as North Dakota, Louisiana, Wyoming, and West Virginia to speed up approvals. The federal narrative now treats CCUS less as a decarbonisation tool and more as a means of sustaining industrial output and fossil production under nominally cleaner conditions. This decentralised approach accelerates infrastructure rollout but dilutes national coordination, leaving climate effectiveness dependent on voluntary verification and corporate disclosure standards.

The most visible reversal has occurred in methane governance. The Waste Emissions Charge, established under the Inflation Reduction Act, has been suspended until 2034, the Greenhouse Gas Reporting Program (Subpart W) delayed, and compliance deadlines under the NSPS OOOOb and OOOOC rules extended. These steps collectively roll back the stricter methane control regime of 2024, reducing costs for producers but widening the policy gap between the United States and the European Union. Given the EU's new Methane Regulation, which mandates verified emissions data for imported gas, United States exporters face increasing pressure to self-certify through voluntary schemes such as MiQ and OGMP 2.0 to retain market access. This divergence underscores a growing asymmetry between domestic deregulation and international environmental expectations.

Power sector rules have followed a similar path. The EPA's 2024 standard requiring new coal and gas plants to install CCUS or hydrogen co-firing by 2032 has been suspended. The emphasis has shifted to permitting reform and rapid capacity expansion. With electricity demand expected to grow, gas-fired generation remains the most reliable source of incremental supply, while nuclear and coal provide baseload stability. This prioritisation of reliability ensures short-term security but locks in a higher-emission generation profile that will complicate future efforts to return to carbon-neutral trajectories.

The combined effect of these policy reversals has re-anchored the United States energy system around fossil fuel abundance, though the clean-energy transition has not been entirely derailed. Former transition goals, such as those for offshore wind, carbon-free electricity, deep emission reductions, and hydrogen cost benchmarks, remain referenced in federal roadmaps and planning documents, but under current policy they are largely aspirational and lack enforceability. Nevertheless, a substantial portion of earlier clean-energy funds and incentives continues to sustain investment in solar, storage, and grid-modernisation projects. After two years of weak sentiment, renewables are regaining investor confidence as rising electricity demand and greater fiscal clarity improve the market outlook. The sector's recovery now reflects a gradual shift from policy dependence to market fundamentals, with rapid power demand growth from AI, data centres, and electrification making renewables an increasingly indispensable part of the generation mix.

By and large, the 2025 United States energy policy marks a full-scale reorientation from transition leadership to energy dominance. The system that once aimed for 100% clean power by 2035 is now defined by production maximisation, deregulation, and export ambition. Yet the duality persists: natural gas continues to underpin reliability at home and leadership abroad, serving both as the guarantor of short-term stability and the vehicle through which the United States projects economic strength. The outcome is a more self-reliant and geopolitically influential energy system, but one increasingly detached from its former climate trajectory, anchored firmly in natural gas, and guided by pragmatism over pledges.

Canada

Canada's approach is more explicitly framed around "orderly competitiveness": expand natural gas supply and LNG exports but keep those exports compatible with climate positioning and social licence. Ottawa and key producing provinces continue to back LNG projects on the Pacific coast, aimed primarily at Asian markets, as a way to monetise western Canadian gas, diversify away from the United States pipeline market, and strengthen long-term energy ties with Northeast Asia. Canadian policy debates in 2024–2025 have therefore focused less on whether to export LNG and more on how to export it: methane performance, indigenous partnership in infrastructure, and the promise of "lower-carbon" cargoes compared with other LNG competitors and coal in Asian power systems. (This framing matters commercially: Asian buyers increasingly want predictable, contract-backed LNG but face domestic pressure to show emissions credibility, not just price competitiveness.)

At the same time, Canada is managing an internal balancing act. Gas remains critical for winter heat, industrial feedstock, and backup generation during periods of hydro and wind constraint, especially in provinces where electrification targets are tightening and demand from electrified transport and industry is rising. But unlike the United States, Canada is not presenting deregulation as the tool; the policy narrative is that gas can continue to expand, particularly via LNG, if it is paired with emissions controls, carbon pricing, and carbon capture. That positioning is designed to keep capital flowing into Canadian LNG as a "credible transition fuel" for export markets, while maintaining alignment with national climate targets.

Mexico

Mexico's natural gas strategy is centred on security of supply and maintaining state leadership in the power sector. Federal policy keeps the state utility, Comisión Federal de Electricidad (CFE), at the core of the system, with an obligation that CFE control a majority share of national electricity generation and dispatch priority on the grid. Natural gas is central to that model: Mexico sources most of its gas through pipeline imports from the United States, and policy in 2024–2025 has focused on making that dependence less risky rather than reducing it outright. That means expanding strategic storage, upgrading domestic processing and compression capacity, and exploring additional regasification and coastal LNG handling so the country is less exposed to single route feedgas shocks at the border.

At the same time, Mexico has begun to reopen controlled spaces to private capital, but on terms defined by the state. Recent measures allow mixed participation in selected gas fields and midstream assets, provided the state retains strategic control, and invite private co-investment in new generation and industrial clusters where reliable, reasonably priced gas-fired power is a precondition for nearshoring and manufacturing expansion. This is not liberalisation in the classic sense. It is targeted partnership: using private balance sheets to reinforce national gas security, not to replace public ownership.

Parallel to its domestic strategy, Mexico is positioning itself as an emerging LNG platform for global markets. Several new Pacific-coast liquefaction projects are designed to process United States pipeline gas for export to Asian buyers, allowing Mexico to use its geography, existing cross-border midstream system, and shorter shipping distances to Asia as competitive advantages. This outward-facing LNG role complements Mexico's internal priorities, enabling it to participate more actively in global gas trade while maintaining secure and affordable domestic supply.

Taken together, North America's gas policy in 2024–2025 is defined by alignment on fundamentals and divergence in method. All three countries treat natural gas as indispensable to grid stability, industrial output, and export positioning in a tighter, more politicised global energy market. But they operationalise that view differently:

- The United States is maximising throughput, fast-track permitting, revived LNG licensing, and explicit use of gas as leverage in trade and strategic alliances.
- Canada is monetising resource strength through LNG aimed at Asia, but tying that expansion to emissions credibility and long-term partnership narratives rather than deregulation.
- Mexico is hardening state-led control of power and using gas as the reliability backbone of that system, while cautiously allowing private capital to co-finance infrastructure the state deems strategic.

In practical terms, this means North America will remain the anchor of global LNG supply and contract stability through the second half of the decade, and that regional gas policy, not just geology, will continue to shape global pricing, security of supply planning in Europe and Asia, and the pace at which coal-to-gas switching can proceed in the rest of the world.

2.4 Technology and innovation advancements

Technological progress across the natural gas value chain is increasingly central to reconciling energy security, affordability, system flexibility, and environmental performance over the long term. In contrast to earlier phases of gas-market development, where innovation was dominated by scale-up and unit-cost reduction, current and emerging technologies increasingly target system-level optimisation and emissions-intensity management across upstream resource appraisal and production, surface facilities and gas processing, long-distance transport and storage, LNG liquefaction and shipping, distribution networks, and final end-use applications. **The innovation frontier is therefore characterised less by any single "silver bullet" technology and more by cumulative, engineering-led performance gains enabled by standardisation, modularisation, electrification, digitalisation, advanced materials, and progressively stricter expectations for methane and CO_2 performance.** These developments collectively aim to improve energy efficiency, reduce capital and operating expenditure, mitigate methane and CO_2 emissions, and materially reduce local air pollutants, including NO_x, SO_2, and particulate matter, without compromising the deliverability and reliability that distinguish gas in many power, industrial, and heating systems.

Within the RCS, technologies currently at pilot, demonstration, or early commercial stages can be expected to mature and diffuse through a sequence that has historically been observed in the gas industry: initial deployment in high-value niches, progressive learning-by-doing, standardisation of designs and work practices, followed by broader commercial adoption as costs decline and performance uncertainty narrows. Over a multi-decade horizon, the dominant mechanism is not assumed to be discontinuous breakthroughs beyond observable trajectories, but rather incremental yet compounding progress driven by turbomachinery and process optimisation, improved heat integration and reduced parasitic energy loads, equipment electrification, better materials and sealing technologies, and the increasingly pervasive use of high-frequency sensing and advanced analytics to reduce downtime and emissions while improving asset utilisation.

At the upstream end of the chain, innovation begins with subsurface characterisation and exploration. The long-term trend is toward higher-resolution, more information-dense geophysical acquisition and interpretation, supported by high-performance computing and cloud-based workflows that compress cycle times and improve uncertainty quantification. Broadband seismic, ocean-bottom sensing in offshore settings, and advanced imaging and inversion methods improve delineation of complex structures (e.g., salt-affected provinces) and help reduce the probability of non-commercial discoveries. Increasingly, machine-learning methods are used not as a substitute for geoscience, but as an accelerator for pattern recognition, automated horizon and fault interpretation, and probabilistic prospect ranking, particularly when integrated with physics-based constraints and historical analogue databases. The practical impact is a reduction in exploration and appraisal risk, better-informed well placement, and earlier identification of development concepts that minimise surface footprint and infrastructure intensity.

From appraisal to development drilling, the dominant long-term innovation themes are drilling efficiency, extended reservoir reach, and automation of well construction and well placement. Extended Reach Drilling (ERD) and sophisticated multilateral architectures enable access to larger reservoir volumes from fewer surface locations, especially valuable in offshore developments, environmentally constrained onshore settings, and mature basins where incremental access and reduced pad count translate into both lower unit costs and lower lifecycle emissions intensity. Advanced well designs, including U-shaped and complex multilateral trajectories, can reduce the number of well pads and surface facilities per unit of production, thereby lowering fugitive emissions and simplifying logistics. These mechanical and geometric advances are complemented by a steady evolution in rotary-steerable systems, downhole telemetry, drilling fluids, bit design, and managed-pressure drilling, which together improve rate of penetration, reduce non-productive time, and enhance wellbore stability in challenging formations. In parallel, real-time drilling optimisation, increasingly supported by automated control systems and reinforcement-learning-style optimisation under human supervision, improves consistency and reduces operational variability, an important driver of cost and safety performance over large multi-well programs.

As production moves from the wellbore to field-level operations, a key long-term shift is toward more electrically driven and digitally integrated upstream facilities. Electrification of compressors and pumps, where reliable low-carbon electricity is available, reduces direct combustion emissions and can improve part-load efficiency and operational controllability compared with gas-turbine drives. In offshore contexts, electrification may be enabled by dedicated power-from-shore links, hybrid power systems, or integration with nearby low-carbon generation. Subsea processing, separation, and compression, as well as all-electric subsea systems, can reduce topside equipment requirements and improve recovery by managing reservoir pressure and flow assurance closer to the source. These approaches tend to reduce the number of rotating equipment trains exposed to harsh surface environments and can lower maintenance-related venting events. Over long time horizons, upstream innovation also increasingly includes enhanced gas recovery concepts, including CO_2-assisted processes where suitable, aligning reservoir management with broader carbon-management infrastructure; such integration can improve ultimate recovery in some settings while providing an additional sink for captured CO_2, subject to robust storage integrity and monitoring.

Methane measurement, monitoring, reporting, verification, and quantification (MRV/Q) is now a foundational technical layer across upstream and midstream operations, because credible quantification is a prerequisite for high-impact abatement and for any credible emissions-intensity certification. The long-term direction is toward multi-scale sensing architectures that fuse equipment-level continuous monitoring with periodic aerial surveys and increasingly capable satellite observations. High-frequency sensors deployed at valves, tanks, compressors, and processing units enable rapid detection of abnormal emission events, while aerial and satellite systems provide facility-, corridor-, and basin-scale mapping that improves completeness and helps identify "super-emitters" that disproportionately drive total emissions. A critical technical evolution is the shift from simple leak identification toward quantitative estimation of emission rates by combining concentration measurements with meteorological data, dispersion modelling, and operational context. As these MRV systems mature, they increasingly become integrated into routine operations, feeding maintenance planning and reliability engineering rather than being treated as episodic compliance exercises.

Abatement technologies themselves are largely commercial, yet their long-term impact depends on systematic deployment, integration with operations, and continued incremental performance improvement. Key measures include replacing high-bleed pneumatic devices with low- or zero-bleed alternatives, improving seals and packing on rotating equipment, deploying vapour recovery units for tanks and low-pressure sources, capturing and recompressing vent streams, implementing flare-gas recovery, and transitioning to electric-drive compressors where feasible. The elimination of routine flaring is increasingly approached as a system-design problem rather than a narrow operational target, combining gathering network optimisation, modular field compression, small-scale gas conditioning, and, where pipeline access is limited, decentralised utilisation options such as micro-LNG, modular CNG, on-site power generation with high-efficiency units, or in selected contexts small-scale gas-to-liquids (GTL). Over time, these measures shift associated gas from being a disposal challenge to becoming a managed resource stream, improving both environmental performance and field economics.

Once produced, the viability of supply increasingly depends on gas processing and treatment technologies, particularly as marginal resources in many regions exhibit higher CO_2, H_2S, nitrogen, or trace contaminants. Acid gas removal technologies, based on advanced amine formulations, physical solvents, and hybrid solvent–membrane configurations, continue to evolve through better solvent chemistry, improved mass-transfer equipment, and more effective heat integration that reduces reboiler duty and solvent circulation rates. The engineering objective is to lower the energy penalty per unit of CO_2 removed while delivering a high-purity CO_2 stream compatible with compression, transport, and storage. In this way, gas processing is not only a quality-conditioning step but increasingly an enabling interface with carbon-management systems. For high-nitrogen resources, nitrogen rejection units (NRUs), typically cryogenic, sometimes combined with adsorption or membrane stages, remain inherently energy intensive, but steady advances in turbomachinery efficiency, process integration, and advanced controls improve their economics and availability. Complementary treatment steps such as dehydration, mercury removal, sulphur recovery, and waste-heat utilisation reduce corrosion and fouling, improve plant uptime, and lower safety risks. Over a multi-decade horizon, the convergence of "hard" process engineering with advanced monitoring and model-predictive control yields plants that operate closer to their thermodynamic and reliability limits with fewer unplanned upsets, directly improving both cost and emissions intensity.

LNG technologies, situated between processing and international transport, are also shifting from a singular focus on scale toward a more multidimensional optimisation that includes energy intensity, modular execution, and emissions performance. Large-train liquefaction continues to benefit from incremental improvements in heat exchanger design, compressor aerodynamics, refrigerant management, and advanced control strategies that reduce fuel-gas consumption at scale. In parallel, modular LNG and floating LNG (FLNG) concepts expand the set of resources that can be monetised by shortening delivery schedules, improving fabrication quality through controlled-module construction, and reducing the need for long subsea pipelines to shore in some offshore settings. Over the long term, electrified LNG designs, where large compressor trains are driven by electric motors rather than gas turbines, represent a critical pathway for reducing direct CO_2 and NO_x emissions, contingent on access to reliable, low-carbon power. The same design philosophy is increasingly applied to “CCS-ready” LNG facilities, where layout, plot space, and integration points are reserved to reduce retrofit complexity for CO_2 capture. Additional innovation is occurring in boil-off gas management and reliquefaction, cold-energy utilisation at regasification terminals, and improved ship-to-shore logistics and metering that reduce losses and enhance operational flexibility across the LNG chain.

Between supply and demand, midstream transport and storage infrastructure is undergoing both incremental modernisation and strategic adaptation to new operating requirements. For pipeline systems, a major long-term opportunity lies in reducing methane emissions and improving integrity management through better sealing technologies, lower-leak valves and fittings, compressor electrification with variable-speed drives, and pervasive sensing. Distributed fibre-optic monitoring, advanced inline inspection tools, and AI-assisted anomaly detection improve the early identification of corrosion, cracking, ground movement, and third-party interference risks. Digital pipeline twins that assimilate real-time SCADA data with physical flow models enable more efficient linepack management, compressor dispatch optimisation, and faster isolation and response to abnormal events, improving both safety and deliverability. Underground gas storage also benefits from improved subsurface characterisation, high-frequency monitoring of pressure and geomechanics, and better well integrity practices; salt cavern storage, depleted reservoirs, and aquifer storage are increasingly managed with a level of instrumentation and modelling that supports both seasonal balancing and short-cycle flexibility. Over time, as gas systems are increasingly required to provide balancing for variable renewable generation, flexibility and cycling capability become as important as peak throughput, reinforcing the value of advanced controls, low-minimum-load compression, and digitally optimised dispatch across the midstream system.

Carbon management becomes an increasingly structural element of the value chain as the outlook extends toward mid-century. Capture from high-concentration process streams, such as CO_2 separated during gas sweetening or hydrogen production, remains comparatively mature and cost-effective, and therefore is likely to scale first where storage and transport are available. For dilute flue gas streams, including those from gas-fired power plants and large combustion sources, continued innovation is required to reduce energy penalties through improved solvents, structured packings, heat integration, membrane systems, and emerging solid-sorbent and cryogenic capture approaches. Critically, capture technology alone is insufficient without the parallel development of CO_2 transport and storage systems. **The long-term direction is toward networked CO_2 infrastructure, pipelines where scale and geography permit, complemented by CO_2 shipping in regions where early-stage flexibility is valuable or where dispersed emitters must be aggregated.** Robust monitoring, measurement, and verification for storage, using pressure monitoring, seismic methods, tracer approaches, and well integrity surveillance, underpins public and regulatory confidence and reduces long-term liability uncertainty, thereby lowering the cost of capital for projects that rely on CO_2 storage performance.

A further long-term development influencing the gas value chain is the growing interface between natural gas, hydrogen, and synthetic or renewable methane. Natural gas is likely to remain a primary feedstock for hydrogen production in many regions, with “blue hydrogen” configurations relying on high-capture-rate reforming (e.g., ATR/SMR with integrated capture) and reliable CO_2 transport and storage. Methane pyrolysis, where it can be scaled economically and managed safely, offers an alternative route producing hydrogen and solid carbon, potentially reducing the need for CO_2 storage but introducing new requirements for solid carbon handling and markets. In parallel, power-to-gas pathways, producing hydrogen via electrolysis and converting it with captured CO_2 into synthetic methane, create a technical bridge between electricity systems and gas infrastructure, enabling long-duration energy storage and leveraging existing gas transport and storage assets. Biomethane upgrading and injection into gas grids also expands the portfolio of lower-carbon gaseous fuels, though it requires consistent gas-quality management and robust certification systems. These developments do not displace the conventional gas value chain so much as diversify the molecules moving through parts of it, increasing the importance of gas quality monitoring, materials compatibility, metering accuracy, and digital traceability.

At the downstream end, end-use technologies continue to evolve along two main axes: higher efficiency and greater operational flexibility under tighter emissions constraints. **In power generation, combined-cycle gas turbines remain among the most efficient large-scale thermal technologies, and further progress is expected through continued advances in high-temperature materials, cooling designs, combustion systems, and control strategies that maintain efficiency under part-load and cycling conditions.** Hydrogen-ready combustion systems and turbines enable gradual blending and future fuel switching where hydrogen supply becomes available, preserving asset optionality. Over the long term, the integration of carbon capture with gas power generation may become more prominent in regions where deep decarbonisation is pursued while retaining dispatchable capacity; here, system-level optimization, capturing not only at the plant boundary but also considering CO_2 transport, storage, and flexible operation, will determine cost and feasibility. Complementary innovations such as advanced bottoming cycles, improved heat-recovery steam generator designs, and digital optimisation of dispatch and maintenance enhance both the economic and environmental performance of gas-fired generation, particularly in power systems with high shares of variable renewable energy.

In buildings and industry, technology evolution increasingly reflects "hybridisation" rather than a single-path transition. High-efficiency condensing boilers and ultra-low-NO_x burners continue to reduce local air pollutants, while gas heat pumps, hybrid heat pump–boiler configurations, and district energy systems combine electrification benefits with gas reliability during peak-demand or cold-weather events. In industrial applications, where high-temperature heat and continuous processes impose constraints on full electrification, efficiency improvements, advanced burner designs, process integration, and in selected cases on-site carbon capture may play a larger role. Distributed generation technologies, including microturbines and fuel-cell-based combined heat and power, can increase overall energy utilisation by converting fuel to electricity and useful heat with high total efficiency, while providing resilience benefits for critical facilities. As gas distribution systems evolve, smart metering, pressure optimisation, and network digitalisation improve demand forecasting, reduce losses, and enable more granular management of gas quality and blending, capabilities that become increasingly important if hydrogen, biomethane, or synthetic methane shares rise.

In transport, LNG and CNG technologies continue to mature where they provide clear advantages in emissions and logistics, particularly in maritime shipping and heavy-duty road transport. The long-term innovation agenda includes improved engine designs and after-treatment systems that reduce methane slip, more efficient onboard fuel systems, enhanced bunkering infrastructure and safety systems, and digital optimisation of logistics to reduce boil-off and handling losses. These developments strengthen the environmental case for gaseous fuels in segments where alternatives face practical barriers, while also tightening performance expectations regarding unburned methane emissions.

Across the entire chain, digitalisation and automation increasingly function as a unifying technological layer that amplifies the impact of physical innovations. Digital twins, ranging from equipment-level replicas to integrated models of entire facilities, pipelines, and storage systems, support model-predictive control, predictive maintenance, and scenario testing, enabling operators to anticipate bottlenecks, manage cycling, and reduce unplanned downtime. The most consequential digital advances are likely to arise from the integration of high-frequency sensor data with hybrid modelling approaches that combine physics-based constraints with machine learning, improving generalisability and robustness under changing operating conditions. In upstream contexts, AI-assisted interpretation and drilling optimisation compress decision cycles; in processing and LNG, advanced controls reduce energy intensity and stabilise operations; in pipelines and distribution networks, anomaly detection and digital integrity management reduce both safety risks and emissions. As digital dependence grows, cybersecurity and data governance become critical enablers rather than ancillary concerns, and the standardisation of data architectures becomes a determinant of how effectively innovations diffuse across regions and operators. Finally, digital MRV and traceability systems, potentially including auditable emissions-intensity certification mechanisms, can reinforce market and regulatory incentives by enabling differentiation of gas supply based on methane and carbon performance, thereby translating technical improvements into durable commercial value.

Overall, the long-term trajectory of technological advancement in the natural gas value chain is best understood as a cumulative transformation: fewer emissions per unit of gas delivered, higher efficiency at each conversion and transport step, improved flexibility and reliability under more variable system conditions, and deeper integration with carbon-management and low-carbon molecule pathways. Over the outlook horizon to 2055, these technology trends do not eliminate the sector's structural constraints, such as the thermodynamic costs of separation and compression, or the need for large-scale infrastructure, but they can materially expand the set of economically viable resources, improve the competitiveness of gas under evolving policy and market conditions, and enable a progressively lower-emissions gas system compatible with tighter environmental performance expectations.

Energy Demand Outlook

3

Highlights

- Global primary energy demand continues to grow, but at a structurally slower pace, increasing by 20% (18% CAGR) to 768 EJ by 2055, reflecting stronger efficiency gains and moderating economic and population growth.

- Final energy demand rises by 32% (28% CAGR) to 565 EJ by 2055, with the share of electricity in final energy consumption increasing from around 22% in 2024 to nearly 32% by 2055, reflecting deepening electrification across end-use sectors.

- Electrification is the dominant structural trend, with global electricity demand doubling from around 30,800 TWh in 2024 to over 61,400 TWh by 2055, requiring a substantial expansion in generation capacity to support digitalisation, cooling, electric mobility, desalination and industrial electrification.

- Asia Pacific remains the main engine of global primary energy demand growth, contributing 45% of the net increase, led by India and Southeast Asia, while Africa records the fastest growth rates from a low per-capita base.

- Hydrocarbons remain central to the global energy system, supplying around 62% of primary energy demand by 2055, up from 80% in 2024, underscoring their continued role in energy security, affordability, and system reliability.

- Natural gas demand grows strongly, rising by 31% (27% CAGR) to nearly 196 EJ by 2055, overtaking coal by 2027 and reinforcing its role in power generation, industry, transport, and as a platform for low-carbon hydrogen.

- Coal demand enters a sustained structural decline, falling from 171 EJ in 2024 to 79 EJ by 2055, driven by fuel switching, lower utilisation rates, and tightening environmental constraints, particularly in the power sector.

- Renewables expand rapidly but face rising system integration challenges, with primary renewable demand increasing to around 146 EJ by 2055, nearly seven-folds larger than 2024, yet constrained by grid readiness, flexibility requirements, and financing conditions.

- Energy efficiency improves significantly, with global primary energy intensity declining at 2.3% per year, yet remains insufficient to compensate growth in global energy demand, driven largely by economic activity.

- Total global hydrogen demand rises to around 229 MtH_2 by 2055, with blue hydrogen reaching about 81 MtH_2, roughly one-third of total output. Natural gas underpins this scale-up, supplying around 70 MtH_2 of overall blue-hydrogen production.

- Global energy-related emissions decline structurally, falling by nearly 11 $GtCO_2e$ between 2024 and 2055, with over 60% of reductions delivered by the power sector.

3.1 Energy demand overview

Global primary energy demand reached 641 EJ in 2024, setting a new historical high and expanding by 1.6% year-on-year, a pace faster than the average rate of the past decade. Importantly, all major fuels and technologies recorded growth, including hydrocarbons, underscoring the continued resilience and diversification of global energy systems. Non- hydro renewables and hydropower, together contributed the largest share of the increase in global energy supply (35%), followed by natural gas (33%), oil (14%), coal (11%), and nuclear power (3%). Final energy demand also grew robustly, rising by 2.1% annually to 428 EJ, highlighting the broad expansion of energy services in all end-use sectors, especially those depending on electricity.

Electricity remained the primary engine of global energy growth. Global power demand rose by 3.7% in 2024, significantly outpacing GDP growth, reflecting rising electricity intensity as economies electrify and digitise. This widening divergence reflects a fundamental transformation in useful energy. Alongside traditional drivers, useful energy demand is increasingly shaped by new non-substitutable electricity services. Record heatwaves and extreme temperatures sharply increased cooling requirements, while the rapid expansion of digital services, cloud computing, artificial intelligence (AI), and automation added substantial and continuous loads to power systems. These developments point to an ongoing shift: useful energy growth is now driven not only by heat, mobility, and lighting, but also by information processing, communication, digitalisation, machine intelligence and space cooling, all exclusively powered by electricity. With the expected acceleration of these trends, the global energy system is increasingly entering the age of electricity.

Global electricity consumption increased by 1,102 TWh in 2024, nearly 75% above the average annual increase of the past decade and the largest rise recorded outside major post-crisis recoveries. Asia Pacific, particularly China and India, accounted for more than three-quarters of global growth, while electricity demand in Eurasia declined slightly. Critically, developed countries returned to growth after several years of stagnation or decline. The United States recorded the third-largest absolute increase worldwide, after China and India. Electricity consumption in the European Union grew by 3.9%, its first meaningful increase since 2017 (excluding the temporary rebound in 2021).

A sectoral decomposition shows that residential and commercial sectors accounted for nearly half of the global growth in electricity consumption, driven by intensifying cooling needs and increased appliance ownership. Digital infrastructure expanded rapidly, with global data centre capacity rising by an estimated 20% in 2024, led by developments in the United States and China. Transport electrification continued to accelerate, with global Electric Vehicle (EV) sales increasing by more than 25% to over 17 million units, representing one-fifth of global car sales. These trends collectively underscore the emergence of new, non-substitutable electricity end uses, cooling, digital services, and electric mobility, as defining features of contemporary energy demand.

Contributing almost one-third of the increase in total final energy consumption in 2024, industrial energy demand remained a key driver of global energy growth, particularly in developing countries where construction, manufacturing, and heavy industries continue to expand. The hard to electrify-industrial processes remain heavily dependent on hydrocarbons for medium-and high-temperature heat and for feedstock use in chemicals, petrochemicals, and fertilisers. Amid low electrification rate of approximately 30% in 2024 and prioritisation of energy security, coal consumption increased in several developing Asia Pacific countries due to rising cement and steel output, while natural gas demand strengthened in refining, fertilisers, petrochemicals, food processing, and other energy intensive segments. Furthermore, in many regions, natural gas continued to replace coal where reliability, process stability, emissions requirements, and cost competitiveness increasingly prioritise cleaner thermal options. These dynamics highlight that, despite the rapid rise of electricity-exclusive services, industrial hydrocarbon use, particularly natural gas, remains central to global energy demand and will continue to shape long-term consumption trends.

Amid strong growth in electricity and industry, global primary energy efficiency improvements remained moderate. Primary energy intensity (measured in PPP, base year = 2024) improved by 1.7% in 2024, broadly in line with the trend observed since 2019 but below the 2010–2019 average of around 2% per year. Several factors contributed to this performance namely, post-pandemic growth remained concentrated in energy-intensive industrial sectors in China and India; extreme temperatures lifted cooling loads; and hydropower underperformance increased reliance on thermal generation in several regions. As a result, the gap between expanding useful energy services and limited efficiency gains widened further.

Regional dynamics were dominated by the Asia Pacific, which accounted for just under 80% of global primary energy demand growth in 2024. China's energy demand increased by less than 3%, roughly half the pace of 2023 and below its long-term historical average of 4.3%, reflecting structural adjustments in its industrial base and real-estate sector. Nonetheless, China continued to be the world's largest contributor to incremental demand in absolute terms. India recorded the second-largest increase globally, exceeding the combined growth of all developed countries, reinforcing its position as one of the principal engines of global energy consumption.

Overall, the developments of 2024 signal an emerging transition in global energy demand. Growth is increasingly driven by electricity-exclusive useful energy services, from cooling in a warming climate to computation, communication, and digital intelligence, services that were negligible only a decade ago but are now deeply embedded in modern economic activity. At the same time, efficiency gains and electrification ensure that rising useful energy demand does not translate proportionally into higher final or primary energy consumption.

The events of 2024 also highlighted the evolving role of natural gas in the global energy landscape. Beyond its traditional applications, natural gas increasingly serves as a flexibility and reliability backbone across regions. In Europe and North America, cold spells during the 2023/24 and 2024/25 winter seasons demonstrated the necessity of gas-fired capacity to stabilise power systems when heating loads surged and renewable output weakened. In South Asia, particularly India, the extreme heatwaves of 2024 drove record cooling demand, with natural gas plants providing critical peak-hour support. In Latin America, persistent droughts exposed the vulnerability of hydro-dependent systems, reinforcing the role of natural gas in offsetting volatile hydropower and maintaining grid security. At the same time, natural gas continued expanding into new demand segments, including LNG-fuelled trucks, buses, and vessels, as well as supplying North America's fast-growing, power-intensive data-centre clusters where reliable, uninterrupted electricity is vital. These developments illustrate not only natural gas's evolving function in today's energy system but also a trend expected to intensify in the future. As electrification advances, weather extremes become more frequent, renewable penetration deepens, and system-reliability requirements grow, natural gas is poised to play an even more prominent role as a flexible, dispatchable, lower-carbon pillar supporting the stability, adequacy, and resilience of increasingly complex energy systems worldwide.

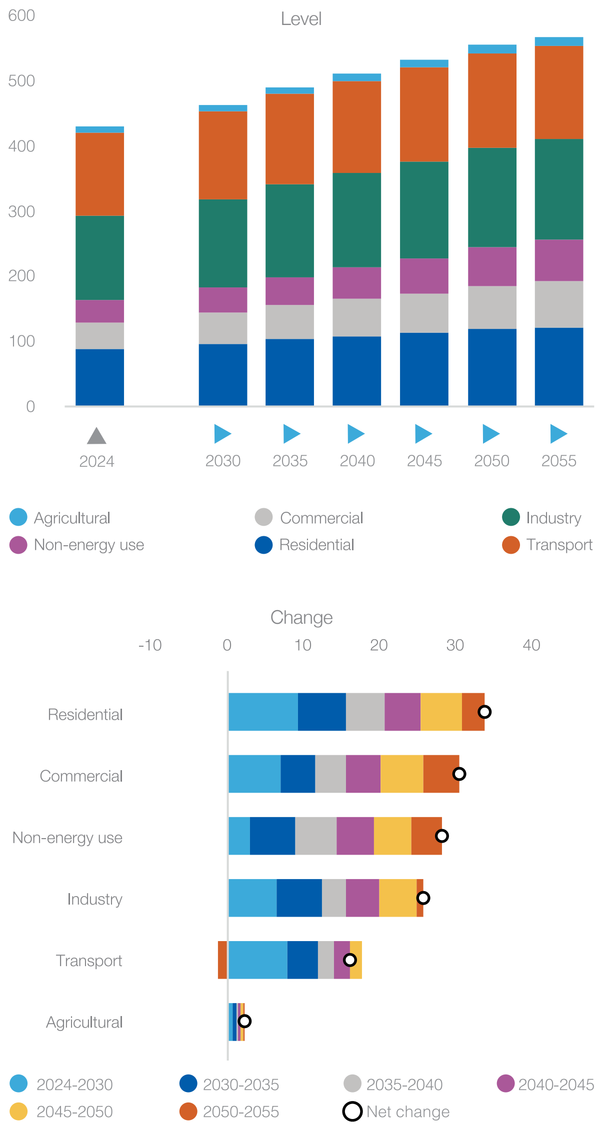
3.2 Global final energy demand outlook

Global final energy demand is projected to rise by 32% (28% CAGR) by 2055, reaching 565 EJ (Figure 3.1). **Nearly 45% of this increase is expected to occur before 2035, reflecting a front-loaded expansion driven by structural economic shifts, rising household incomes in developing countries, and the rapid penetration of electricity-exclusive energy services.** The evolution of final energy demand over the outlook period signals a gradual transition away from traditional demographic and industrial drivers toward a more complex interplay of technology diffusion, electrification, climate-related requirements, and shifting patterns of economic activity.

Demographic factors, once among the most powerful determinants of energy demand, are gradually diminishing in influence. While the global population will continue to expand, growth is slowing: annual increments decline from roughly 80 million people since 2000 to 65 million through 2035, and further to 47 million through 2055. Several major regions, including East Asia and Europe, are projected to experience absolute population decline. As a result, demographics shift from being an accelerator of energy demand to a moderating force. As a consequence, energy consumption becomes increasingly shaped by income growth, urbanisation, digitalisation, and climate-driven needs rather than by population alone.

Figure 3.1

Global final energy demand outlook by sector, 2024-2055 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

The industrial sector undergoes a notable transformation. Although industrial activity continues to grow in absolute terms, its share of global final energy demand is expected to decline from 30% in 2024 to 27% in 2055. This reflects structural economic adjustments, rising efficiency, gradual electrification, and technological improvements. Growth in several hard-to-electrify, energy-intensive subsectors, particularly steel, iron, and cement, slows as construction demand plateaus in China and moderates elsewhere. Consequently, their contribution to incremental final energy demand diminishes. In contrast, non-energy uses of fuels, especially petrochemicals and plastics, expand rapidly, reaching 11% of final energy demand by 2055, up from 8% in 2024. This highlights the growing importance of oil, natural gas, and natural gas liquids (NGLs) as feedstock fuels within global industrial value chains.

Structural adjustments in the transport sector reinforce the broader trajectory of efficiency improvements. As car ownership peaks in China, growth in the global vehicle fleet increasingly shifts to other developing regions. At the same time, rising fuel efficiency of internal combustion engines (ICEs) and accelerating global penetration of electric vehicles reduce sectoral energy intensity. Although total transport final energy demand increases by 13% over the outlook period, its share in global final energy demand falls by 5 percentage points to 25% by 2055. Electrification emerges as a central influence, moderating oil demand growth, particularly after 2035, even as mobility services in aviation and maritime continue to expand across all regions, particularly in developing countries.

Conversely, the residential and commercial sectors become the dominant contributors to the rise in final energy demand. Their combined share reaches 34% by 2055 and accounts for approximately 47% of total demand growth. Within these sectors, the drivers of consumption shift significantly. Space cooling becomes one of the most dynamic sources of growth as rising temperatures and more frequent extreme heat events drive widespread adoption of air-conditioning, especially in rapidly urbanising and increasingly affluent developing economies. While appliance ownership continues to rise, the centre of gravity for energy use in buildings moves decisively toward developing regions and climate-driven end uses.

A further structural trend is the exponential growth of energy-intensive digital infrastructure. Data centres supporting AI, cloud computing, and high-performance computing are emerging as a major load category, operating at high utilisation rates and requiring an uninterrupted power supply. This creates a new class of electricity-exclusive final energy demand that was negligible only a few years ago, reinforcing the centrality of electricity in the modern energy system and increasing the requirement for system flexibility, reliability, and supportive dispatchable capacity.

Rapid electrification across all major end-use sectors solidifies electricity's dominant role in future final energy demand. Electricity's share is projected to rise to 32% by 2055; an increase of 10 percentage points compared to 2024. Nearly 63% of the total increase in final energy demand over the forecast period is met by electricity, underscoring its expanding role in delivering both traditional and emerging energy services. Despite this shift, natural gas continues to maintain a stable contribution of around 17% to global final energy consumption due to its role in industry, power, and new applications, while oil experiences a moderate decline in its share over the longer term reaching 34%, down by 6 percentage points compared to 2024.

Regionally, **Asia Pacific** remains the dominant centre of global final energy consumption throughout the outlook period. Its share of global final energy demand rises from 44% in 2024 to 46% by 2055, accounting for 52% of the total global increase. The region's expanding role is underpinned by sustained economic growth, rapid urbanisation, rising incomes, and more importantly accelerating electrification of residential, commercial, and industrial activities.

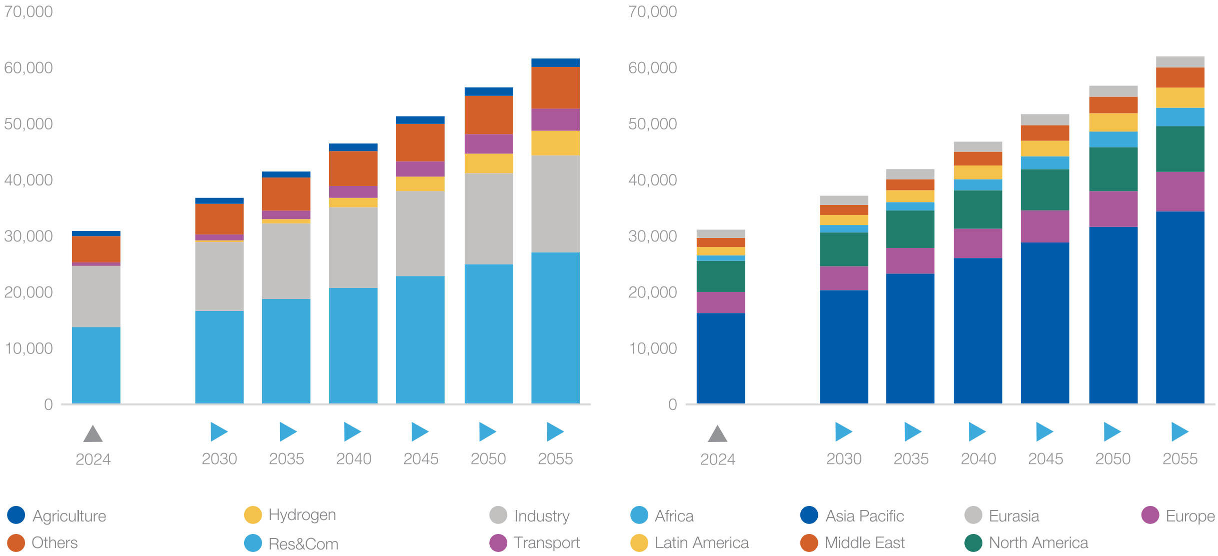
Africa is projected to experience the fastest annual growth in final energy demand, averaging around 2% per year and resulting in nearly a doubling of consumption by 2055. Strong population growth, accelerated urbanisation, expanding industrial activity, and rising access to modern energy services support this trajectory. However, even with this robust increase, per-capita final energy demand in Africa remains below the global average and minimum human development requirement by 2055, reflecting persistent structural development gaps and the region's relatively low starting point.

Europe, by contrast, is the only region expected to register an overall decline in final energy demand over the forecast period, with a modest reduction of around 0.2%. This decline occurs despite already high levels of per-capita energy consumption and is mainly driven by diminishing population, structural shifts in industrial output, widespread improvements in energy efficiency, and continued progress in electrification and building refurbishment.

3.3 Outlook for electricity demand and generation

Driven by expanding industrial output, escalating cooling needs amid rising global temperatures, accelerating electrification across end-use sectors, and the rapid scale-up of power-intensive data centres, global electricity demand surged to historic levels in 2024. **Electricity consumption grew by 3.7%, an increase of approximately 1,100 TWh in a single year, reaching 30,805 TWh**. China accounted for more than

Figure 3.2
Global electricity demand outlook by sector and region, 2024-2055 (TWh)



Source: GECF Secretariat based on data from the GECF GGM
Note: Others include district heat, refineries, energy sector own use, transmission and distribution losses

half of this rise, with electricity demand growing by 7% in 2024, broadly in line with the previous year. Electrification is advancing rapidly in China, where electricity already represents 28% of final energy consumption, significantly higher than in the United States (22%) or the European Union (21%). Over the three-year period from 2022 to 2024, industry was the principal driver of global electricity growth, contributing to nearly half of the increase, while the commercial and residential sectors together accounted for around 40%. The industrial sector has become distinctly more electricity-intensive, with roughly one-third of global demand growth over this period attributed to the manufacturing of solar PV modules, batteries, and electric vehicles, reflecting both structural economic realignment and the energy demands of the clean-technology supply chain.

As illustrated in Figure 3.2, global electricity demand is projected to double by 2055, reaching approximately 61,430 TWh. This substantial expansion is driven primarily by rapid growth in non-substitutable electricity demand associated with emerging energy services that rely exclusively on electrons, most notably space cooling, information technology, digitalisation, and machine intelligence. At the same time, demand for substitutable electricity is also rising across end-use sectors, though at a more moderate pace, as hydrocarbons are progressively replaced by electricity at the final energy consumption level in applications such as space heating, water heating, and cooking to improve efficiency and support decarbonisation efforts. Importantly, results from the Reference Case Scenario (RCS) indicate that this shift does not lessen the role of hydrocarbons within the broader energy system; instead, the expansion of electricity consumption heightens the need for reliable, dispatchable and flexible power generation. This, in turn, reinforces the continued importance of natural gas and other dispatchable fuels in ensuring system adequacy, stability, and resilience.

This surge in electricity demand is projected to manifest across all regions, though not uniformly. Differences in the penetration of electric technologies, such as heat pumps, EVs, industrial electrification, and digital infrastructure, along with disparities in supply-chain readiness, affordability, and policy frameworks will shape uneven electrification trajectories across the globe. Asia Pacific will account for roughly 60% of the global increase in electricity demand, led by rapid economic expansion, urbanisation, and accelerating adoption of electricity-exclusive services. Notably, electrification is set to rise strongly even in developed countries, marking a clear break from the past decade in which electricity consumption in some regions such as Europe and developed Asia Pacific either stagnated or declined due to efficiency gains, depopulation, economic restructuring toward services, and mild winters. Looking forward, these regions are entering a new phase of electricity demand growth, supported by widespread uptake of heat pumps, EVs, data centres, and electrified industrial processes. Europe and North America are projected to contribute around 11% and 8% of global incremental demand, respectively, underscoring the broadening scope of electrification beyond emerging markets.

By 2055, the Asia Pacific is projected to be the most electrified region, with electricity accounting for around 40% of final energy consumption, almost 14 percentage points higher than in 2024. Europe, however, is expected to exhibit the strongest electrification momentum, with the electricity share in final energy consumption rising to 36% by 2055, a remarkable 16-percentage-point increase from 2024. These divergent regional dynamics highlight that future electrification will be shaped not only by the pace of economic growth, but also by technological diffusion, readiness of low-carbon technology supply chains, policy support, and the evolving demand for electricity services.

With global electricity demand projected to double by 2055, the residential and commercial sectors are expected to account for around 44% of total electricity consumption, broadly in line with their 2024 share, and yet representing the largest absolute and incremental contributor to global power demand growth. This reflects profound structural changes in energy-service needs, particularly in developing countries where rising household formation, urbanisation, and higher per-capita incomes significantly increase demand for electricity-intensive end uses. The most prominent drivers include rapidly expanding space-cooling requirements in response to higher ambient temperatures, and the accelerated build-out of digital infrastructure, especially data centres that operate at high load factors and require uninterrupted power supply. Electrification of space and water heating, as well as cooking, in developed countries and China, primarily through the uptake of heat pumps, further contributes to rising electricity demand in buildings. However, the growth trajectory is tempered by persistent barriers: high upfront capital costs, building-stock retrofit constraints, and grid-integration requirements, including the reinforcement of local distribution networks to manage winter and summer peak loads associated with electrified heating and cooling. Importantly, the expansion of electricity demand in these sectors is expected to lead to a substantial increase in peak load, given the intrinsically time-sensitive nature of cooling, heating, and digital-service operations. This amplifies system-flexibility needs and reinforces reliance on dispatchable, fast-ramping power generation, including natural gas, to ensure grid stability, maintain real-time supply–demand balance, and support the secure integration of variable renewable energy sources.

Electricity demand from data centres is emerging as one of the fastest-growing loads in the commercial sector. **In the RCS, data centre electricity consumption rises from 415 TWh in 2024 to around 1,543 TWh by 2030, increasing its share of final electricity demand from 1.6% to 4.2%.** This growth is concentrated primarily in the United States, followed by China and Europe, reflecting the rapid uptake of generative and agentic AI, cloud computing, and high-performance digital infrastructure. Deployment, however, is increasingly constrained by grid-connection bottlenecks, equipment supply-chain shortages (transformers, cables, gas turbines) and rising system-adequacy concerns. Given the 24/7 operational profile and stringent reliability requirements of AI-driven data centres, natural gas-fired generation is projected to remain an important source of firm and flexible capacity in many markets, alongside storage, demand response, interconnections and other low-emissions firm options. **Under the RCS, the projected expansion of data centre power generation increases natural gas demand by 54 bcm by 2030.**

The industrial sector is poised to become the second-largest driver of global electricity demand growth, with consumption projected to rise by nearly 46% over the forecast period and to contribute 21% of total demand growth by 2055, ultimately accounting for 28% of global electricity use. This long-term expansion is underpinned by several structural shifts. First, the electrification of low- and medium-temperature process heat, notably in food processing, textiles, pulp and paper, and light manufacturing, continues to advance as electric boilers, industrial heat pumps, and induction systems improve gradually in efficiency and cost. Second, the rapid growth of electricity-intensive clean-technology manufacturing, including solar PV modules, lithium-ion batteries, and semiconductor and EV-component production, significantly increases industrial electricity intensity. Third, ongoing digitalisation, automation, and AI-enabled process optimisation raise continuous power requirements across multiple subsectors. The increasing adoption of Electric Arc Furnaces (EAF) in steelmaking and rising industrial cooling loads, partly driven by climate change and expanded use of digital equipment, further reinforce this structural shift toward higher electricity use. However, this transformation is neither uniform nor unconstrained. The pace of industrial electrification faces significant barriers, including high capital costs for electric heat technologies, limited availability of low-carbon electricity, and grid-capacity constraints, particularly in regions with rapidly growing industrial output. Many high-temperature industrial processes remain technically difficult or prohibitively expensive to electrify, necessitating continued reliance on hydrocarbons or alternative decarbonisation pathways such as natural gas with CCUS.

Driven primarily by the accelerating electrification of road transport, supported by the increasing uptake of EVs, the transport sector, currently a marginal consumer of electricity, is poised for a transformative shift. Electricity demand in transport is projected to increase by more than seven-fold by 2055, albeit from a low base, contributing approximately 11% of the total global increase in electricity consumption over the forecast period. As a result, the sector's share of global electricity demand rises from 1.7% in 2024 to 6.5% by 2055. However, the pace of electrification remains constrained by several structural barriers. High upfront vehicle costs, even as battery prices decline, still limit affordability in many developing countries. The rollout of public and private charging infrastructure lags behind vehicle adoption in several major markets, while grid-capacity constraints, especially at the distribution level, pose risks of local congestion and require substantial investment to accommodate fast-charging loads. In addition, concerns about battery durability, mineral supply-chain constraints, and the carbon footprint of battery manufacturing continue to affect consumer confidence and policy design.

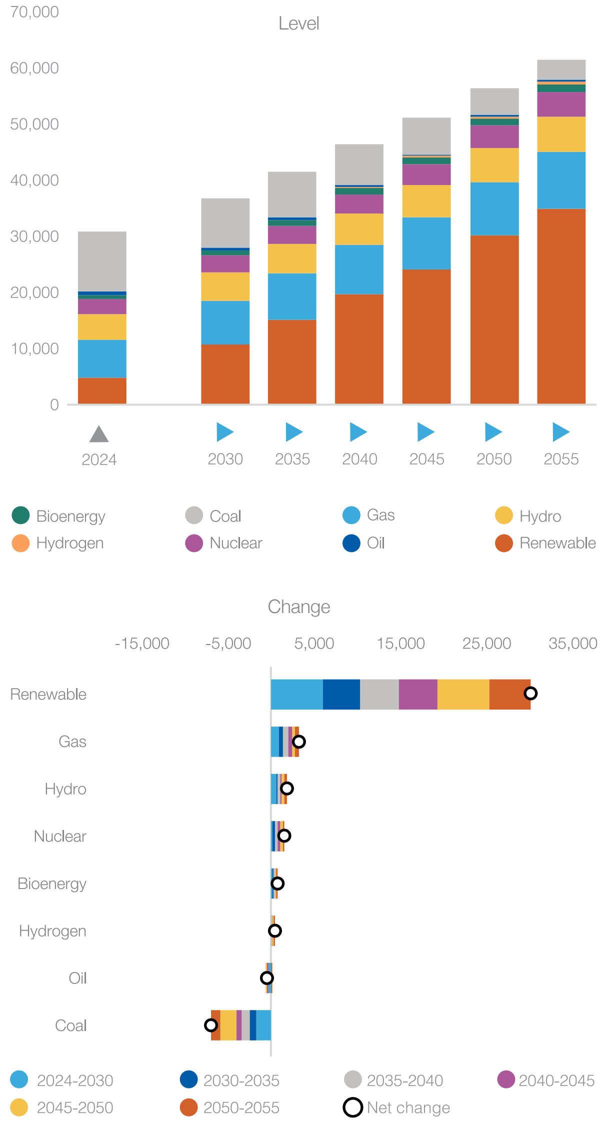
One of the most significant emerging sources of electricity demand over the long term is the production of green hydrogen, which rises from a negligible level in 2024 to become the third-largest contributor to global electricity demand growth by 2055. Over the outlook period, electricity use for hydrogen production via electrolysers, drawing on both dedicated renewable capacity and grid-connected supply, is projected to increase by nearly 4,000 TWh, corresponding to an average annual growth rate of around 13%, with hydrogen production ultimately accounting for 7% of global electricity demand. This rapid expansion reflects hydrogen's growing role in decarbonising hard-to-abate sectors, yet it also underscores the inherent energy intensity and relatively low conversion efficiency of green hydrogen. Moreover, large-scale deployment faces several structural barriers, including high electrolyser capital costs, competition for renewable electricity needed for direct electrification, grid-integration and flexibility constraints associated with large variable loads, water-resource limitations in key producing regions, and persistent uncertainties around certification standards, carbon-intensity methodologies, and long-term offtake agreements.

To meet the projected surge in electricity demand, global power generation is expected to double by 2055, with domestic electricity output rising to 61,426 TWh, up from 30,795 TWh in 2024, supplemented by only a modest contribution from cross-border electricity trade (Figure 3.3). In the RCS, this expansion is accompanied by a structural transformation of the global power mix, which becomes progressively less energy-intensive and lower in carbon intensity, reflecting sustained growth in renewable generation capacity. At the same time, the system becomes increasingly diversified, characterised by increased penetration of variable renewable energy sources, particularly solar and wind, supported by flexible, dispatchable technologies required to ensure reliability, grid stability, and real-time balancing in an increasingly complex emerging power system.

As the global power system transitions toward a Variable Renewable Energy (VRE)-heavy configuration marked by greater variability, higher integration needs, and structurally lower thermal load factors, natural gas stands out as the primary source of system flexibility. Although gas-fired power generation increases in

Figure 3.3

Global power generation outlook by fuel type, 2024-2055 (TWh)



Source: GECF Secretariat based on data from the GECF GGM

absolute terms, its share of global electricity supply declines from 22% in 2024 to 17% by 2055, meeting around 12% of incremental demand. This moderated growth reflects rising renewable penetration, efficiency gains in modern Combined Cycle Gas Turbines (CCGT), and strategic shifts in several gas-exporting countries, to substitute domestic gas with renewables to maximise exportable volumes.

The key driver of natural gas demand in power generation is its unparalleled ability to stabilise VRE-heavy systems. Gas turbines provide fast-ramping, firm capacity, inertia, and voltage support, capabilities that solar and wind cannot offer, making natural gas the backbone of reliability as variable renewables scale. This role strengthens further with surging peak-load requirements from intensifying cooling needs in a warming climate and rapidly growing demand for uninterrupted, high-availability power for digital infrastructure, particularly data centres. In Asia, coal-to-gas switching continues to deliver large and immediate reductions in Green House Gases (GHG) and local air pollutants, especially where ageing coal fleets dominate. Meanwhile, in hydropower-dependent regions across Latin America, Sub-Saharan Africa, and parts of the Asia Pacific, recurrent droughts and growing hydrological volatility increase dependence on natural gas to backfill dry-year deficits. In emerging economies, particularly in Africa and the developing Asia Pacific, with limited access to low-cost capital for large-scale VRE deployment, natural gas remains the most feasible and economic source of reliable, dispatchable capacity.

Decarbonisation pathways further reinforce the long-term role of natural gas. CCUS deployment at gas-fired units is expected to accelerate in the 2030s, enabling low-carbon, high-availability generation aligned with emissions-reduction goals. Hydrogen and ammonia co-firing, already demonstrated in Japan, South Korea, China, the United Kingdom, and the United States, provides additional decarbonisation potential, though widespread adoption remains constrained by fuel availability, infrastructure readiness, and cost. These dynamics confirm that natural gas will remain a foundational pillar of global power-system adequacy, flexibility, and resilience, supporting VRE integration, enabling coal displacement, meeting rising peak and firming requirements, and ensuring orderly and reliable energy transitions even as its proportional share in generation gradually declines.

Coal, the largest source of global electricity generation today, is projected to experience the steepest long-term decline, driven by structural system dynamics that outweigh continued coal capacity additions in China and India. Even where new units are commissioned for energy security and affordability reasons, coal-fired generation is increasingly constrained by falling utilisation rates as the rapid expansion of VREs with near-zero marginal cost pushes coal down the merit order and erodes baseload operating hours. Rising VRE penetration simultaneously elevates system flexibility requirements, demanding fast-ramping, cycling capability, and reliable mid-merit balancing, technical and economic functions for which coal plants are poorly suited compared with natural gas and other dispatchable technologies. Tightening emissions and air-quality regulations, escalating carbon-pricing pressures, and growing financial restrictions on unabated coal further undermine its competitiveness worldwide. As a result, the RCS projects coal's share in global power generation to decline sharply from 34% in 2023 to just 6% by 2055. While mitigation options such as retrofitting coal plants with CCUS, co-firing with hydrogen or ammonia, or deploying more efficient ultra-supercritical technologies may extend the operational viability of selected assets in parts of Asia Pacific, their large-scale deployment faces significant barriers, including high fuel and retrofit costs, infrastructure and storage-readiness constraints, and limited availability of low-carbon hydrogen, hindering their ability to materially offset the overarching structural decline in coal's role within the global power system.

Global renewable energy penetration, particularly solar and wind, in the global power generation mix continues to rise, with the RCS projecting its share to increase from 15% in 2024 to 57% by 2055, marking a significant structural shift in the global electricity system. However, the pace of renewable penetration is expected to slow over time as systems mature and multiple structural, economic, and operational constraints emerge. In China, now accounting for over 40% of global renewable capacity additions, the geographical concentration of solar and wind in resource-rich but load-distant regions and growing curtailment pressures increasingly limit incremental growth. Globally, supply-chain fragmentation, rising trade barriers, friend-shoring and reshoring efforts, and cost inflation for critical components add friction to deployment, reducing the rapid cost declines seen in earlier phases. In developing countries, renewable expansion is further impeded by high upfront capital requirements, elevated financing costs, weak institutional capacity, and constrained public budgets, which collectively slow project execution and limit grid investment. At the system level, higher VRE penetration brings substantial integration challenges: increased needs for grid reinforcement, storage, firm dispatchable capacity, and advanced flexibility mechanisms. Many regions, particularly in Africa, South and Southeast Asia, and parts of Latin America, lack sufficient firm generation to balance intermittent resources, requiring a careful equilibrium between VRE deployment and reliable thermal or hydro capacity. These factors collectively explain why the RCS projects a gradual deceleration in renewable penetration rates over the long term, especially as major markets in Asia Pacific and Europe approach structural saturation and face rising marginal integration costs.

Hydropower will remain a key component of global electricity systems, valued for its low-carbon baseload and flexibility services, but its future growth is increasingly constrained by climate-related pressures. Recurrent droughts, shifting precipitation patterns, rising evaporation rates, and heightened hydrological variability are already reducing reservoir inflows, capacity factors, and output stability in major producing countries such as China, Brazil, the United States, and parts of Africa. At the same time, environmental constraints, water-use competition, and the limited availability of new viable sites, combined with long lead times and frequent cost overruns, are curbing prospects for large-scale hydropower expansion. As a result, hydropower's role is expected to shift from system expansion to system support, with growing reliance on complementary technologies, particularly natural gas and storage, to manage increasingly volatile dry-year deficits and ensure grid stability as climate risks intensify. In the RCS, despite absolute increase in output, hydropower's share of the global power mix declines from 14% in 2024 to 10% by 2055.

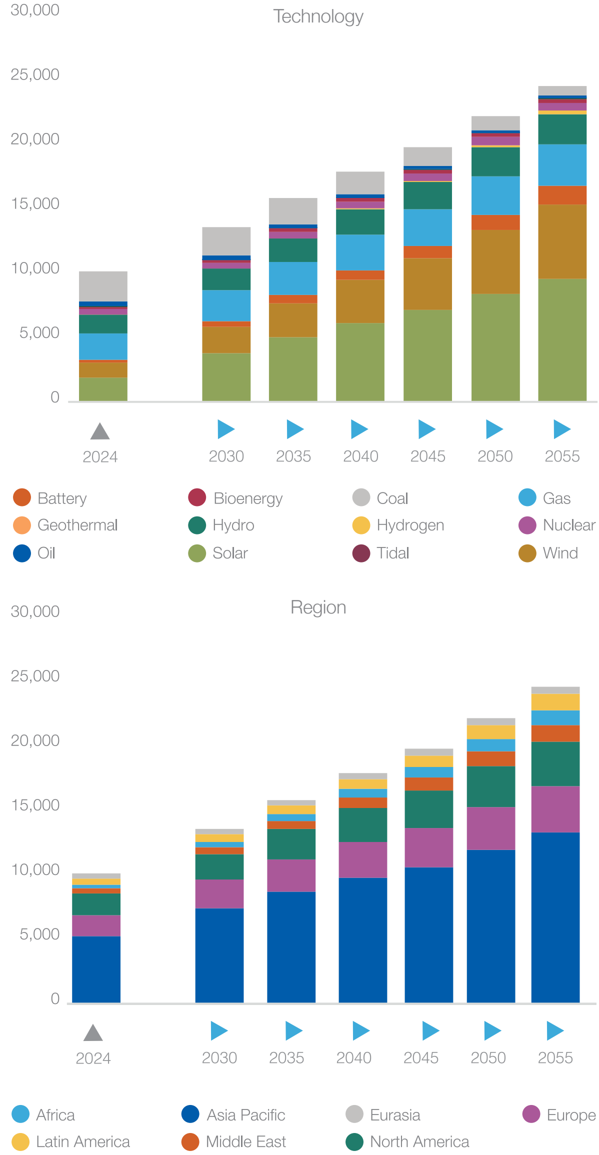
Nuclear power is expected to play a steadily expanding, though regionally uneven, role in the global power mix over the coming decades. Its future trajectory is shaped by the interplay of energy security priorities, decarbonisation objectives, technological innovation, and structural constraints on deployment. Nuclear energy is increasingly viewed as a critical firm, low-carbon generation source capable of providing baseload output and essential system stability in power systems with rising shares of fluctuating renewable energy. The combination of dispatchability, high-capacity factors, and minimal land-use footprint reinforces nuclear's strategic value in countries seeking to decarbonise while maintaining reliability. In the RCS, these dynamics translate into moderate but steady growth. Nuclear power generation is projected to increase in absolute terms over the outlook period; however, its share in the global electricity mix declines from around 9% today to 7% by 2055, constrained by long construction lead times, high capital intensity, regulatory complexity, and uneven deployment across region.

As global power generation systems transition toward higher shares of VREs, installed capacity expands far more rapidly than electricity generation, rising nearly 2.5-fold to 24,136 GW by 2055, while global average utilisation rates fall from 35% to 29%. This reflects the inherently low-capacity factors of solar and wind, as well as the increasing assignment of thermal units to flexibility and reserve services rather than continuous baseload operation (Figure 3.4). The feasible pace of VRE deployment is determined less by continued declines in plant-level Levelised Cost Of Electricity (LCOE) and more by the system-wide LCOE, which incorporates transmission expansion, grid reinforcement, balancing reserves, seasonal storage, curtailment, and congestion management. As VRE penetration rises, these integration costs escalate non-linearly and often become the binding constraint on further renewable expansion.

A structural asymmetry across regions intensifies these dynamics. Developed countries and China already possess extensive firm and renewable capacity and mature grids capable of absorbing higher VRE volumes. In contrast, developing regions, especially Africa and parts of Asia Pacific, start from very low installed capacity levels, despite contributing a large share of global electricity demand growth to 2055. These regions must simultaneously build new firm capacity,

Figure 3.4

Global power generation capacity outlook by technology and region, 2024-2055 (GW)



Source: GECF Secretariat based on data from the GECF GGM

new intermittent capacity, and new transmission infrastructure, while also managing rapid demand growth driven by urbanisation, population expansion, electrification, and rising cooling needs. Limited fiscal space, high sovereign borrowing costs, and elevated risk premiums restrict access to the low-cost capital required for VRE deployment, slowing the transition relative to developed countries.

These constraints are further compounded by fragmentation of clean-technology supply chains, reshoring and friend-shoring policies, export controls, and rising trade barriers that increase price volatility and delivery uncertainty for renewable components.

At the same time, accelerating uptake of electricity-exclusive energy services, such as data centres, digital infrastructure, AI computation, and cooling, raises system adequacy requirements and heightens the need for firm, dispatchable capacity to maintain real-time reliability. Accordingly, the evolution of global installed capacity is shaped not only by renewable technology cost declines but by the interplay of system-wide LCOE, financing conditions, supply-chain resilience, grid maturity, and structural demand characteristics, which collectively define the feasible trajectory of the global power mix to 2055.

Within this evolving landscape, natural gas–fired power capacity is projected to expand from 2,042 GW in 2024 to 3,153 GW by 2055, accounting for around 8% of global installed capacity increase over the forecast period. Growth is concentrated in Asia Pacific, the Middle East, and North America, where natural gas remains indispensable for system adequacy, fast-ramping flexibility, seasonal balancing, and reliability during periods of low renewable output. At the same time, the shift toward modern, higher-efficiency CCGTs, which generate substantially more electricity per unit of installed capacity and offer enhanced operational flexibility compared with older gas units, moderates the scale of additional gas capacity required despite rising system needs. In developing countries with rapidly increasing electricity demand and limited access to low-cost capital for VRE projects, gas-fired plants continue to provide a technically robust and cost-effective means of expanding supply while maintaining grid stability. In developed countries and China, gas capacity increasingly shifts from baseload operation toward mid-merit and peaking roles as VRE penetration deepens.

In parallel, solar and wind are poised to reshape the global capacity mix, together accounting for around 85% of net additions over the outlook period. Solar PV becomes the largest source of installed capacity in the second half of this decade and extends its lead through 2055, supported by steep learning curves, modular deployment, and scalable manufacturing. Wind power, onshore and to a lesser extent offshore, also expands as supply chains mature and plant-level LCOE declines. However, the inherently low-capacity factors of solar and wind mean that considerably more installed capacity is required to deliver each unit of electricity, driving rapid capacity expansion even where demand growth is moderate. This stands in sharp contrast to high-efficiency CCGTs, where each MW of installed capacity yields far higher energy output, thereby moderating capacity additions and required upfront capital expenditure. Most VRE additions are concentrated in Asia Pacific, Europe, and North America, where policy frameworks and system capabilities facilitate large-scale deployment, though expansion rates vary widely across regions.

Complementing the rise of VREs, battery storage capacity is projected to increase nearly tenfold, from 166 GW in 2024 to 1,443 GW in 2055, raising its share of global capacity from below 2% to about 6%. This considerable expansion reflects mounting requirements for short-duration flexibility, intraday balancing, and fast-response grid-stabilisation services as solar and wind become dominant sources of incremental capacity. Nonetheless, the majority of deployed storage remains suited to short-duration applications (typically 2–4 hours), meaning that even with rapid growth, batteries primarily address diurnal variability rather than seasonal balancing or prolonged renewable shortfalls. As such, the acceleration of storage deployment enhances system flexibility but does not eliminate the need for firm, dispatchable generation and long-duration flexibility resources in VRE-heavy systems.

Looking ahead, global electricity demand is set to rise sharply as the world enters an era in which electricity becomes the primary energy carrier for both traditional and emerging services. Beyond its essential role in lighting, mobility, heating, and industry, electricity is increasingly the foundation of high value-added activities such as information technology, digitalisation, cloud computing, quantum computing, robotics, and machine learning. These services, not substitutable by other energy forms, elevate the strategic importance of electricity within modern economies. As a result, access to affordable, reliable, sustainable, and secure electricity will be a defining determinant of future economic competitiveness, industrial capability, and geopolitical influence. In this context, the value of electricity is rising rapidly, and the cost at which it can be produced, shaped by the evolution of the global power generation mix, fuel choices, technological advancements, and system integration requirements, will increasingly define the winners and losers of the next phase of global order.

3.4 Outlook for hydrogen demand and generation

Hydrogen demand in recent years has been shaped overwhelmingly by its traditional industrial uses, particularly as feedstock in refining, ammonia, and methanol production, which continue to account for virtually all global consumption. Its role as an energy vector remains nascent, highly policy-dependent, and far from commercially mature. Despite significant political momentum, the deployment of low-emissions hydrogen has been constrained by high production costs, capital-intensive infrastructure requirements, limited offtake agreements, and uncertain regulatory environments, making most projects economically unviable without substantial public support. As a result, global hydrogen demand increased only modestly, reaching nearly 100 MtH_2 in 2024, an annual rise of about 2%, broadly aligned with overall industrial energy demand trends rather than reflecting any structural shift toward new energy uses. Supply remains dominated by hydrocarbons, in particular natural gas followed by coal, in 2024. Although low-emissions hydrogen output expanded by around 10% in 2024, albeit from a low base, and reached an estimated 1 MtH_2 in 2025, its contribution remains below 1% of global hydrogen production, underscoring that the uptake of low-emissions hydrogen is not yet meeting the ambitions set in recent years in developed countries.

Market momentum weakened further as a growing wave of project delays, downscaling, and cancellations prompted downward revisions in global deployment expectations for this decade. Cost dynamics also became less favourable: the post-crisis decline in natural gas prices broadened the cost gap between green hydrogen (affected by rising electrolyser prices due to inflation and slower-than-expected learning rates) and natural gas-based hydrogen, thereby reducing the competitiveness of low-emissions pathways. Absent significant carbon pricing or subsidies, the economic case for switching remains weak, and this cost gap is projected to widen toward 2030 under the RCS assumptions of lower natural gas prices, further constraining adoption.

Against this backdrop, **the RCS projects global hydrogen demand to rise from just under 100 MtH_2 in 2024 to around 229 MtH_2 by 2055, a downward revision from earlier GGO outlooks in light of evolving market and policy realities** (Figure 3.5). Two structural drivers underpin this long-term expansion: first, continued growth in hydrogen's conventional feedstock applications, especially in chemicals and refining; and second, the gradual emergence of hydrogen as an energy carrier in hard-to-abate sectors such as steel, shipping, high-temperature industrial heat, and, to a limited extent, power generation. These new applications shift hydrogen's function within the energy system, from a specialised industrial input toward a supporting enabler of decarbonisation, but the trajectory remains highly dependent on technology costs, policy incentives, carbon pricing frameworks, and the pace of infrastructure development.

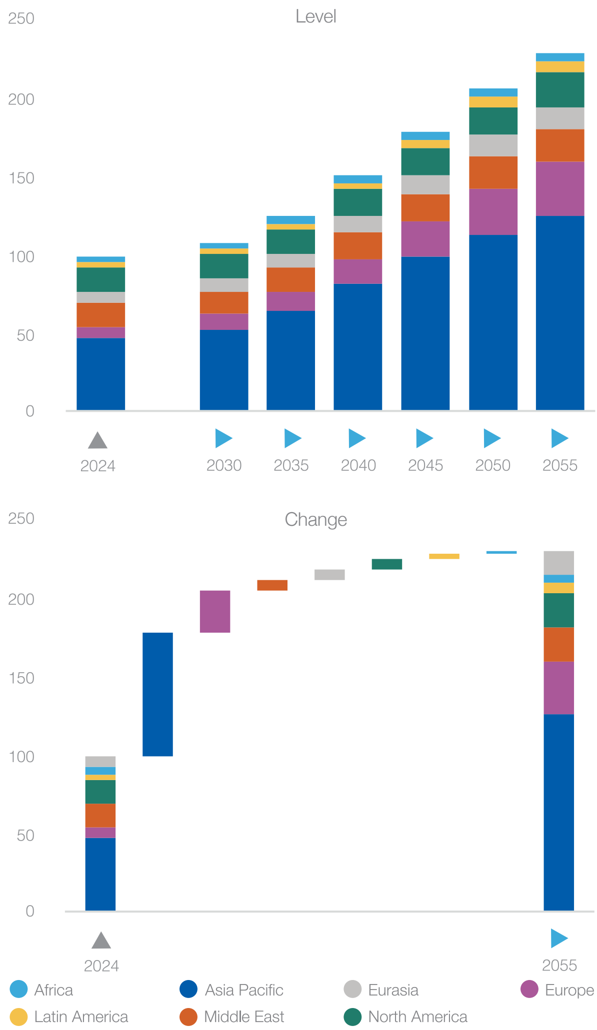
Regional patterns of hydrogen consumption in 2024 reveal a system still dominated by industrial users in Asia Pacific, North America, and Middle East, which together accounted for nearly 80% of global demand. Asia Pacific alone represented almost half of worldwide consumption, reflecting the scale of its chemical, refining, and materials industries and the prominent role of hydrogen as a feedstock. China, with 31% of global demand, remains by far the largest consumer, underpinned by its vast industrial base and continued production of coal-based fertiliser, synthetic fuels and chemicals.

Over the coming decades, the geography of hydrogen use is set to shift in response to policy, industrial restructuring, and the pace of low-carbon technology deployment. While Asia Pacific remains the central hub of hydrogen demand through 2055, rising by 77 MtH_2 and maintaining its position as the world's largest consumer, Europe emerges as the fastest-expanding market. Strong policy mandates for industrial decarbonisation, dedicated support frameworks for low-carbon hydrogen, and sector-specific transition pathways drive a structural increase in hydrogen use across European industry, transport, and power applications. By 2055, Europe's hydrogen consumption is projected to reach 15% of the global total, a more than 25 MtH_2 increase compared with 2024.

Looking forward, hydrogen demand is expected to grow both within established industrial uses and across emerging energy applications. By 2055, hydrogen's role as a feedstock for fertiliser production and refining operations remains the largest single component, reaching 123 Mt and accounting for 53% of total consumption, equivalent to a 1.3% average annual increase over 2024–2055. Emerging energy-carrier

Figure 3.5

Global hydrogen demand outlook by region, 2024-2055 (MtH_2)



Source: GECF Secretariat based on data from the GECF GGM

Chapter 3

applications expand steadily, converging with feedstock demand by 2055 as deployment in transportation, power generation, and heavy industry accelerates (Figure 3.6).

Transport-sector demand for hydrogen, primarily in the form of ammonia, methanol, and synthetic fuels, is forecast to reach 33 MtH_2 by 2055 (14% of global demand). However, progress remains shaped by significant technical and economic barriers: ammonia's toxicity, the wide flammability range of hydrogen, high storage costs, and a lack of compatible port and bunkering infrastructure. Hydrogen uptake in road transport remains concentrated in heavy-duty and long-haul segments, where its high gravimetric energy density and fast refuelling offer advantages over battery-electric alternatives. Yet scaling beyond these niches is limited by uncertainties in fuel-cell cost trajectories, regulatory pathways, and competing technology options, contributing to the downward revision of transport-related demand relative to earlier projections.

Hydrogen use in power generation remains limited today, but is set for substantial growth over the long term. Consumption is projected to rise from just 0.6 MtH_2 in 2024 to nearly 29 MtH_2 by 2055, around 13% of global hydrogen demand. Initial adoption emerges in the early 2030s through hydrogen blending into existing natural gas turbines. Over time, dedicated hydrogen-capable combustion turbines, combined-cycle configurations, and fuel cells begin to play a more meaningful role, especially in systems with very high VRE penetration where long-duration flexibility is essential. Hydrogen's potential as a seasonal storage medium, converting surplus renewable electricity into hydrogen for later dispatch, reinforces its strategic value, although high conversion losses and cost constraints moderate its expansion.

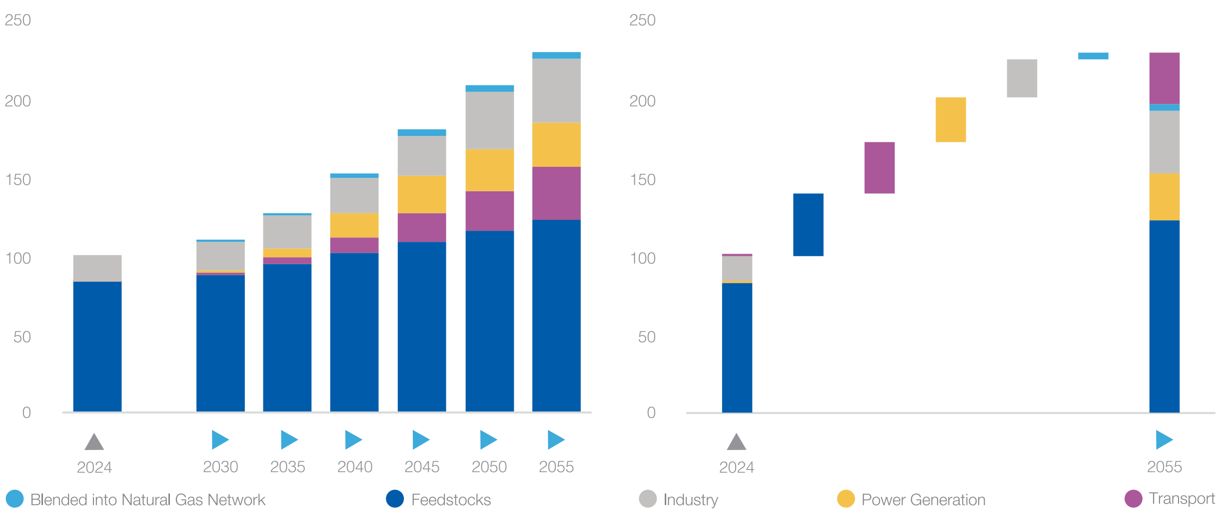
Industrial applications, including blending into natural gas networks and beyond feedstock use, also expand, with demand rising to 45 Mt by 2055 (20% of global consumption). The steel sector becomes a major driver as hydrogen-based direct reduction (H_2-DRI) and hydrogen-natural gas blends gain traction in China, Europe, and selected emerging economies. These pathways offer substantial emissions reductions compared with coal-based methods, though their deployment remains highly sensitive to hydrogen pricing, carbon policies, and infrastructure readiness.

By contrast, hydrogen plays a negligible role in the residential and commercial sectors. Safety risks in dense urban areas, low system efficiency relative to electric alternatives, high upfront appliance and infrastructure costs, and the emergence of cost-competitive district heating and advanced gas systems all limit its adoption through 2055.

Looking ahead, the RCS anticipates a structural transformation in global hydrogen production, though the shift is more gradual than earlier expectations suggested. Green hydrogen, produced via water electrolysis powered by renewable electricity, is projected to expand significantly, reaching 92 MtH_2 by 2055 and accounting for roughly 40% of total hydrogen output (Figure 3.7). Its growth is underpinned by declining renewable electricity costs, improvements in electrolyser efficiency and manufacturing scale, and increasingly supportive policy frameworks across major economies. However, despite its rapid expansion, green hydrogen remains highly energy-intensive and exhibits lower system-wide efficiency relative to other energy carriers, making its long-term competitiveness contingent on continued cost declines in both electricity supply and electrolyser technologies along with continued policy support.

Figure 3.6

Global hydrogen demand outlook by sector, 2024-2055 (MtH_2)



Source: GECF Secretariat based on data from the GECF GGM

Blue hydrogen, generated from hydrocarbon-based processes equipped with CCUS, is also expected to become a cornerstone of the emerging hydrogen economy. **By 2055, blue hydrogen output is projected to reach 81 MtH_2, representing around 35% of global production.** Natural gas–based blue hydrogen dominates this category, reflecting the significant cost and performance advantages of reforming natural gas relative to coal pathways, the higher capture efficiency achievable in natural gas-based systems, and the extensive availability of existing Steam Methane Reforming (SMR) and Autothermal Reforming (ATR) infrastructure. The combination of abundant natural gas reserves, mature supply chains, and favourable CCUS economics positions blue hydrogen as a key decarbonisation pathway for industrial and transport applications.

Conversely, grey hydrogen production, derived from hydrocarbons without CCUS, is set to decline sharply over the outlook period, falling in total by roughly 42 MtH_2 to reach 56 MtH_2 by 2055 and accounting for just 24% of the global supply mix. This decline is driven by tightening environmental regulations, escalating carbon pricing mechanisms, and shifting investment priorities that make unabated hydrogen production progressively less competitive. Nonetheless, the persistence of grey hydrogen at substantial absolute levels reflects structural affordability constraints, the inertia of existing assets, and uneven progress in infrastructure deployment across regions.

Overall, hydrogen production from natural gas, including both grey and blue, remains central to the global supply landscape, reaching 112 MtH_2 by 2055, which represents an increase of nearly 28 MtH_2 from 2024 levels. Despite the rapid rise of green hydrogen, natural gas–based hydrogen continues to represent around one-third of global output in 2055, highlighting its enduring importance as a scalable, cost-effective, and reliable production pathway.

The fuel mix underpinning global hydrogen production in 2024 remained heavily dominated by hydrocarbons. Natural gas accounted for 9.5 EJ, around 57% of the total 16.7 EJ fuel input, reflecting its widespread use in SMR and ATR. Coal remained the second-largest contributor at 25% (4.3 EJ), primarily concentrated in China's coal-gasification sector, while oil supplied 16% (2.7 EJ). Electricity played only a marginal role, consistent with the still-limited scale of electrolytic hydrogen production.

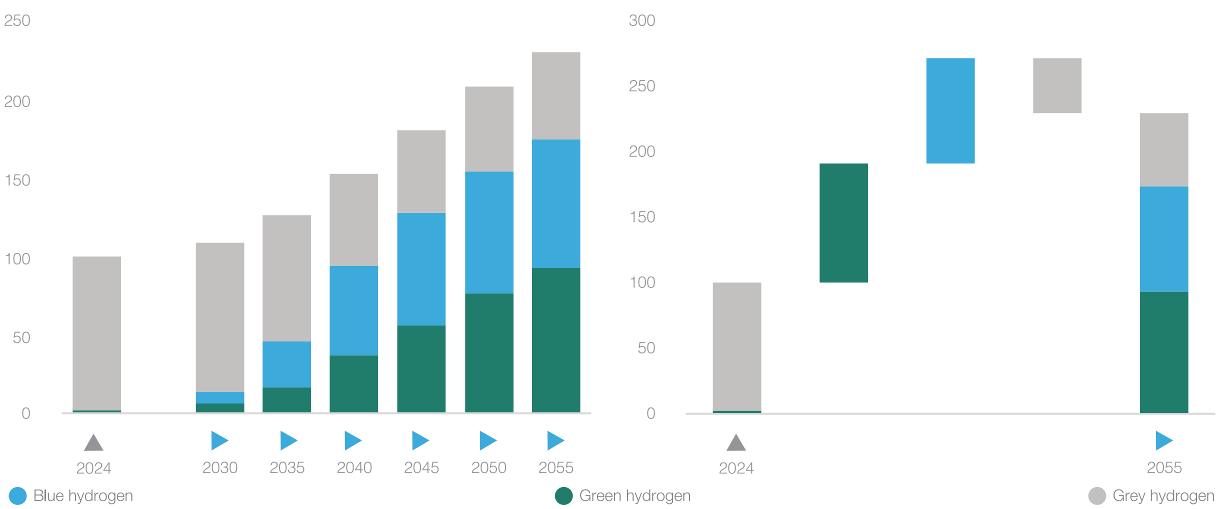
Looking ahead, as illustrated in (Figure 3.8), the RCS projects a profound restructuring of fuel inputs for hydrogen production by 2055, shaped by both the expansion of low-emissions hydrogen and the rising energy intensity of electrolysis-based pathways. Total fuel input is expected to reach 38 EJ, an increase of 21.3 EJ relative to 2024, driven by projected hydrogen output surge. Electricity becomes the single largest source of energy input for hydrogen production, surging to 15.5 EJ by 2055 in line with green hydrogen's rise to 41% of total supply. This reflects both the scale-up of electrolyser deployment and the inherently high energy requirement of water electrolysis.

Natural gas remains a structural pillar of hydrogen supply through 2055, although its share falls from 57% to 35%, driven by the decline of unabated grey hydrogen and the gradual transition toward blue hydrogen with CCUS. In absolute terms, however, natural gas consumption for hydrogen production increases to 13.3 EJ, up 39% from 2024, underscoring its continued relevance as a cost-effective and scalable feedstock, particularly in

Chapter 3

Figure 3.7

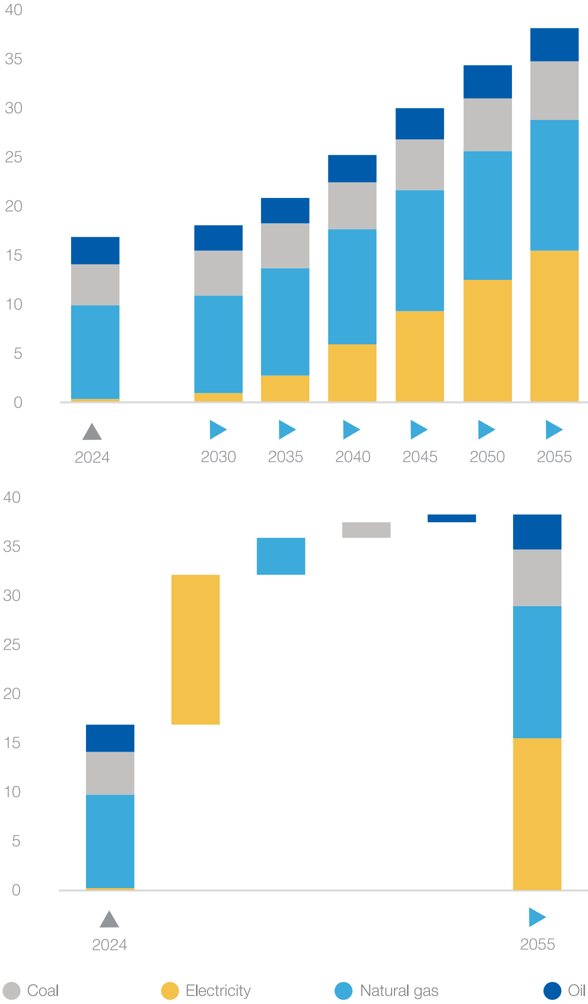
Global hydrogen generation outlook by technology, 2024-2055 (MtH_2)



Source: GECF Secretariat based on data from the GECF GGM

Figure 3.8

Global hydrogen fuel input outlook by source, 2024-2055 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

regions with extensive gas infrastructure. Blue hydrogen dominates the natural gas-based segment by 2055, while grey hydrogen persists at reduced but still material volumes due to affordability and infrastructure inertia.

Coal follows a similar trajectory of shrinking share but rising absolute consumption, reaching 5.7 EJ by 2055 as coal-gasification remains prevalent in selected markets where coal retains a competitive advantage. The persistence of coal and natural gas in the hydrogen fuel mix highlights the slow turnover of industrial production assets and the challenges of rapidly scaling renewable-powered electrolysis, even as the energy transition accelerates.

A clear understanding of hydrogen's energy losses across the value chain is essential for assessing the feasibility and cost-competitiveness of different production pathways, particularly green hydrogen, whose economics are dominated by electricity inputs. Because electrolysis is inherently inefficient, requiring large quantities of zero-carbon electricity, up to 70% of green hydrogen's production cost is attributable to electricity consumption alone, with additional energy consumed during compression, liquefaction, conversion to derivatives (e.g., ammonia or methanol), storage, and transport. These losses accumulate at each stage, often resulting in end-use energy efficiencies below 30–35%, which materially constrains the scalability of green hydrogen in applications where alternative decarbonisation options exist.

These system-wide inefficiencies have profound implications for future energy system design. Meeting projected levels of green hydrogen production will require dedicated electricity generation capacity far beyond existing levels, heightening competition for renewable electricity between hydrogen production and direct electrification of end-use sectors. By 2055, according to the RCS projections, green hydrogen alone could consume close to 7% of global electricity demand, equivalent to over 4,300 TWh. This creates a structural tension: large-scale green hydrogen adoption demands massive renewable deployment, yet the energy system must also decarbonise other sectors simultaneously, all under increasing integration and flexibility constraints.

In this context, blue hydrogen emerges as a practical, scalable, and lower-cost complementary pathway for hydrogen expansion during the transition. Because blue hydrogen utilises natural gas reforming paired with CCUS, it does not rely on vast quantities of renewable electricity. As a result, it imposes significantly lower pressure on power systems and can be deployed more rapidly using existing gas infrastructure, mature reforming technologies, and increasingly cost-competitive CO_2 capture solutions. Moreover, blue hydrogen provides a reliable avenue for early emissions abatement and supply security while green hydrogen scales gradually in line with renewable capacity growth and cost declines.

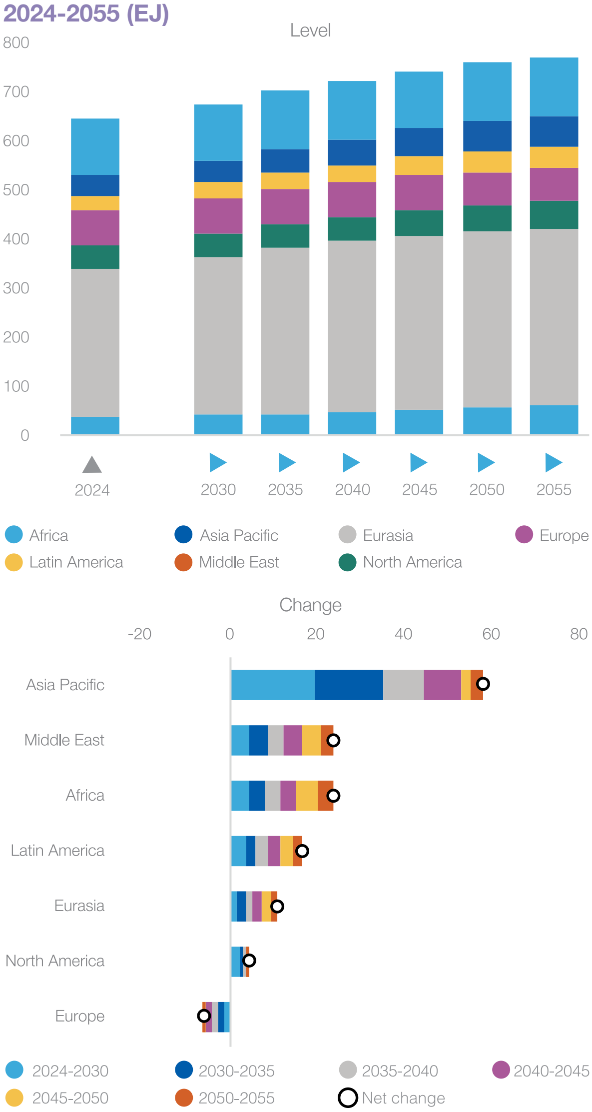
Taken together, these dynamics highlight that the future hydrogen economy will not be driven by a single pathway but by a diversified portfolio, where green and blue hydrogen evolve in parallel, each serving different sectors, timelines, and system constraints, ensuring both climate ambition and energy system feasibility.

3.5 Outlook for primary energy demand

Driven by continued global population growth, accelerating urbanisation, and the expansion of economic output, global primary energy demand is projected to rise by 20% (18% CAGR) over the period 2024–2055, increasing from 641 EJ in 2024 to 768 EJ by 2055 (Figure 3.9). This corresponds to an average annual growth rate of nearly 0.6%. Despite this increase, the projected trajectory represents a pronounced deceleration relative to historical trends, as global primary energy demand expanded by approximately 1.8% per

Figure 3.9

Global primary energy demand outlook by region, 2024-2055 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

annum over the past three decades. The moderation in demand growth reflects a confluence of structural and cyclical factors, most notably sustained improvements in energy efficiency, a gradual slowdown in global population growth, and a moderation in economic expansion as major economies mature (See Box 3.1).

Energy efficiency gains are expected to be a defining feature of the evolving global energy system and a central determinant of the slower growth in primary energy demand. Global primary energy intensity, measured on a purchasing power parity basis (base year 2024), is projected to decline at an average rate of 2.3% per year between 2024 and 2055, significantly faster than the historical average reduction of 1.6% per year recorded over the past decade. This accelerated decline is underpinned by rapid technological progress, particularly digitalisation, automation, and the deployment of advanced energy-efficient technologies across industry, transport, buildings, and power systems. These developments are reinforced by increasingly stringent policy frameworks, price signals, and regulatory standards, as well as by ongoing structural shifts in the global economy towards services and other less energy-intensive activities.

The overall slowdown in global primary energy demand growth masks pronounced regional divergences, reflecting differences in demographic trends, economic development stages, and energy transition pathways. A regional breakdown shows that Asia Pacific is projected to account for around 57 EJ, approximately 45% of the global net increase in primary energy demand between 2024 and 2055, driven primarily by developing countries such as India and Southeast Asia, where rapid population growth, urbanisation, and rising per-capita incomes underpin expanding energy needs. The Middle East and Africa are projected to be the second- and third-largest contributors to global demand growth by 2055, each adding nearly 22 EJ, equivalent to about 18% of the total net increase worldwide, reflecting continued economic expansion, population growth, industrial development, and rising energy access requirements.

Box 3.1 Drivers of primary energy demand growth (2024–2055): what changes, and why

Understanding why primary energy demand increases in the GGO is as important as knowing by how much. A decomposition of the 2024–2055 change in total primary energy supply (TPES) helps distinguish between growth driven by expanding economic activity, growth avoided through efficiency improvements, shifts in the sectoral composition of activity (e.g., deeper electrification increasing the role of power generation), and changes in the fuel mix within sectors. This distinction is policy-relevant because each driver implies a different set of investment needs and constraints: activity-driven growth translates into broad supply expansion, intensity reductions reflect the scale of efficiency and technological progress required to moderate demand, structural shifts reveal where energy services are increasingly delivered (notably via electricity), and fuel switching determines which fuels expand or contract as the system transitions.

To quantify these channels, an additive Logarithmic Mean Divisia Index (LMDI) decomposition is applied to TPES between 2024 and 2055. In intuitive terms, the method attributes the observed change in primary energy demand to four components that together add up exactly to the total change: an activity effect capturing the impact of higher overall economic output (GDP) on energy demand if all other relationships were unchanged; an intensity (technical efficiency) effect capturing changes in primary energy used per unit of GDP; a structural effect capturing shifts in the sectoral shares of activity, which matter because sectors differ in energy intensity and in the degree to which services are delivered through electricity; and a fuel-mix (fuel switching) effect capturing changes in within-sector fuel shares, i.e., the extent to which the same sectoral activity is supported by different fuels over time.

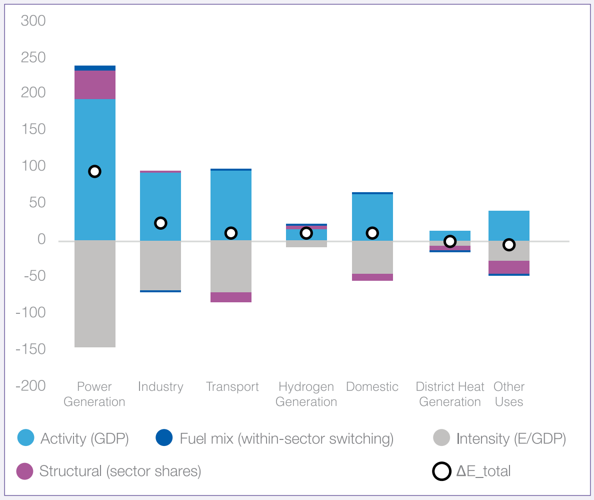
Using an additive LMDI decomposition over 2024–2055, the net increase in primary energy demand (excluding "additives and blending") is +127 EJ, rising from 641 EJ (2024) to 768 EJ (2055). The aggregate result is dominated by two large and opposing forces. Economic expansion contributes a very large activity effect of +507 EJ, while improvements in energy intensity subtract –385 EJ, offsetting roughly 76% of the activity-driven increase. By comparison, the global structural effect is small (–2.3 EJ) and the net fuel-mix effect is modest (+7.6 EJ). The headline implication is that the outlook's moderate net growth in primary energy demand is not the result of weak underlying demand drivers; rather, it reflects substantial intensity improvement that absorbs most of the growth pressure from rising activity.

As illustrated in Figure 1, the sectoral decomposition shows that the long-run increase in primary energy demand is increasingly channelled through transformation sectors rather than direct end-use combustion, consistent with a system that converts more molecules into electrons to supply electricity-based services. Net primary energy growth is highly concentrated in power generation, which increases by +92 EJ, accounting for about 72% of total net growth. In power generation, the activity effect (+193 EJ) is partially offset by intensity improvements (–147 EJ), but the structural contribution is strongly positive (+38 EJ), a signature of rising electrification, whereby a larger share of energy services is delivered through the power sector, supplemented by a positive fuel-mix contribution (+7.7 EJ). The remaining net growth is comparatively modest in direct end-use categories: transport rises by +9 EJ, and domestic uses rise by +7 EJ, each reflecting large activity effects that are largely offset by intensity improvements and (for transport and domestic uses) negative structural shifts. Importantly, hydrogen generation rises by +7 EJ, signalling that a growing portion of primary energy is also allocated to producing hydrogen as an energy carrier, i.e., another transformation pathway in the broader decarbonisation portfolio. Taken together, power generation and hydrogen generation alone add 100 EJ, close to four-fifths of net global growth, illustrating that the system's incremental primary energy requirements are increasingly mediated through conversion processes rather than being used directly in end-use sectors.

As depicted in Figure 2, the fuel decomposition reinforces that the outlook embodies a visible decarbonisation dynamic, while also clarifying the role of natural gas as part of the transition mix. Over 2024–2055, renewables record the largest net increase

Figure 1

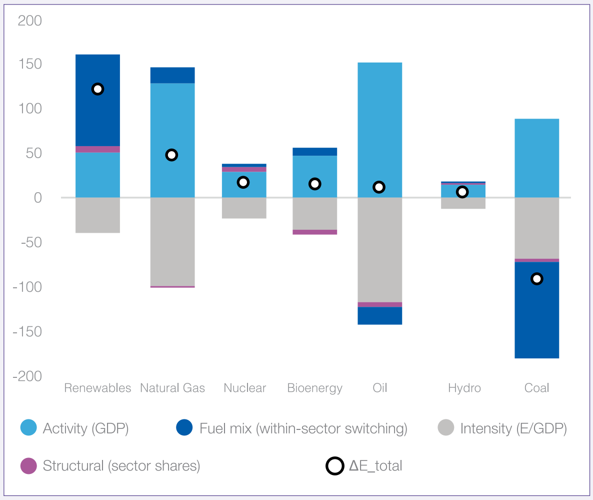
Primary energy demand growth decomposition by sector (EJ)



Source: GECF Secretariat based on data from the GECF GGM

Figure 2

Primary energy demand growth decomposition by fuel (EJ)



Source: GECF Secretariat based on data from the GECF GGM

(+122 EJ), while coal declines sharply (–92 EJ). Natural gas increases by +46 EJ, alongside smaller increases in nuclear (+18 EJ), bioenergy (+14 EJ), oil (+12 EJ), and hydro (+7 EJ). The LMDI breakdown shows that fuel switching is not a single bilateral substitution, but a system-wide reallocation of within-sector fuel shares across all fuels. This is particularly clear for coal and renewables: the fuel-mix component is –108 EJ for coal and +102 EJ for renewables, indicating that within-sector switching is the dominant mechanism behind coal's contraction and renewables' expansion. However, the results also show material coal-to-gas (and oil-to-gas) switching, with the fuel-mix effect contributing +18 EJ to natural gas, a non-trivial share gain, alongside smaller positive switching effects for bioenergy (+9 EJ) and nuclear (+5 EJ), and a negative switching effect for oil (–18 EJ). The overall fuel-mix effect is only +7.6 EJ because large positive switching into renewables and gas is partly offset by switching away from oil and the arithmetic of reallocating shares across fuels; nonetheless, the internal composition of switching reveals a broad decarbonisation pattern in which coal's declining share is absorbed predominantly by renewables, but also materially by gas and other low-carbon sources.

Natural gas warrants a specific emphasis because it expands in both absolute and strategic terms within this transition. Gas increases by +46 EJ, around 39% of total net primary energy growth, and about 38% of this increase is attributable to fuel switching (+18 EJ) rather than activity alone, confirming that gas gains share within sectors as the system reconfigures. The sectoral allocation of gas growth underscores its dual role. Roughly half of the gas increase occurs in power generation (+24 EJ), consistent with its contribution to firm capacity and flexibility as electrification rises. Additional gas growth is observed in industry (+8 EJ) and transport (+8 EJ), and gas input to the hydrogen sector increases by +5 EJ, indicating a growing linkage between gas and hydrogen production in the outlook (with the climate relevance of this channel depending on the emissions intensity of hydrogen supply). Smaller increases occur in feedstocks and non-energy uses. Overall, the decomposition suggests that gas growth is shaped by both macro drivers (activity) and transition dynamics (fuel switching and the re-centring of energy conversion in the power sector), occurring alongside a large renewables expansion and a structural decline in coal.

Overall, three insights emerge. First, the outlook's net growth in primary energy demand is the residual of very large activity growth and very large intensity improvements, with efficiency/intensity dynamics offsetting most of the demand pressure. Second, the additional primary energy required to 2055 is increasingly routed through transformation sectors, consistent with a system that converts fuels into electricity, and, increasingly, into hydrogen, to supply non-substitutable energy services. Third, decarbonisation is visible in the fuel mix: switching away from coal is absorbed mainly by renewables but also by natural gas and other low-carbon sources, while gas plays a quantitatively meaningful role through both switching and its concentration in the power sector's expansion.

Beyond the major growth centres in Asia Pacific, the Middle East, and Africa, more moderate increases in primary energy demand are projected in other developing countries. Latin America is expected to record an increase of 16 EJ by 2055, supported by steady economic expansion, favourable demographic dynamics, and rising energy consumption linked to industrial development. By contrast, Eurasia is projected to experience the smallest increase in global primary energy demand, adding around 9 EJ over the outlook period. This limited growth reflects subdued population trends and gains in energy efficiency, as ongoing structural economic shifts and technological modernisation continue to restrain energy demand growth across the region (Table 3.1).

Table 3.1

Global primary energy demand outlook by region, 2024-2055

	Level (EJ)					Change (EJ)	Growth (% p.a.)	Share (%)	
	2024	2030	2040	2050	2055	2024-2055	2024-2055	2024	2055
Africa	35	39	46	55	58	22	1.6%	6%	8%
Asia Pacific	302	321	346	356	359	57	0.6%	47%	47%
Eurasia	47	48	51	54	56	9	0.6%	7%	7%
Europe	74	74	72	70	70	-4	-0.2%	12%	9%
Latin America	28	32	37	42	44	16	1.4%	4%	6%
Middle East	40	44	52	59	62	22	1.4%	6%	8%
North America	115	117	119	119	119	4	0.1%	18%	16%
World	**641**	**675**	**722**	**755**	**768**	**127**	**0.6%**	**100%**	**100%**

Source: GECF Secretariat based on data from the GECF GGM

Europe stands out as the only region where primary energy demand is projected to remain on a sustained declining trajectory, a trend that began in 2017. By 2055, Europe's primary energy demand is expected to decrease by 4 EJ, reaching 70 EJ. This contraction reflects a combination of moderate economic growth, ongoing de-industrialisation, and a declining population, alongside the widespread deployment of energy-efficient technologies. These structural factors are further reinforced by stringent energy and climate policies aimed at achieving carbon neutrality and enhancing energy efficiency across all sectors. In contrast, primary energy demand in North America is projected to continue rising through the 2040s before entering a prolonged plateau. This trajectory is underpinned by gains in total factor productivity that support economic expansion, offset by substantial improvements in energy efficiency, particularly through digitalisation, efficiency gains in road transport, and the increasing penetration of renewable energy technologies.

Under the RCS, hydrocarbons are projected to retain a dominant role in the global primary energy mix over the next three decades, accounting for around 62% of total demand by 2055, although this represents a marked decline from nearly 80% in 2024. Oil is expected to remain the single largest source of primary energy throughout the outlook period, despite its share in the global energy mix declining from 30% in 2024 to around 26% by 2055. The most pronounced structural shift is anticipated for coal, whose share is projected to fall sharply from 27% to just 10% over the same period, reflecting accelerated retirements, fuel switching, and tightening environmental regulations. In contrast, natural gas is projected to strengthen its position in the global energy system, with its share rising from 23% of global primary energy demand in 2024 to nearly 26% by 2055, supported by its role in power generation, industry, and as a complement to variable renewable energy (Table 3.2).

As the global energy system continues to expand, the imperative to strike an effective balance between reliability, affordability, and sustainability in meeting rapidly rising energy demand is expected to drive a more diversified global primary energy mix by 2055. Within this transition, renewable energy sources are at the forefront, with their share projected to increase from 4% in 2024 to over 19% by the end of the outlook period, supported primarily by continued cost reductions and technological advancements in solar and wind power. Nuclear energy and hydropower are expected to remain important pillars of the global energy mix, accounting for around 6% and 3% by 2055, respectively, reflecting sustained investment in low-carbon and dispatchable sources that enhance system reliability. In parallel, global bioenergy demand is forecast to expand, reaching a 9% share of the energy mix by 2055, driven by the growing deployment of modern biomass technologies, including biofuels and biogas, which progressively substitute the declining use of traditional biomass share over the forecast period (Figure 3.10).

Against the backdrop of a rapidly diversifying global primary energy mix and accelerating electrification over the next three decades, natural gas and renewable energy emerge as central pillars in meeting future final energy demand, particularly in the provision of low-carbon, reliable, and affordable power generation (Figure 3.11). **As a key partner to renewables, natural gas is expected to progressively displace more carbon-intensive fuels, notably coal, while providing the flexibility and system balancing required to integrate rising shares of VREs.** Beyond the power sector, the role of natural gas is set to broaden further across hard-to-electrify segments of the economy, including energy-intensive manufacturing, petrochemicals, and chemical production. In addition, natural gas continues to play a critical role in the domestic sector, most notably through the expansion of clean cooking solutions in Africa, and

Table 3.2

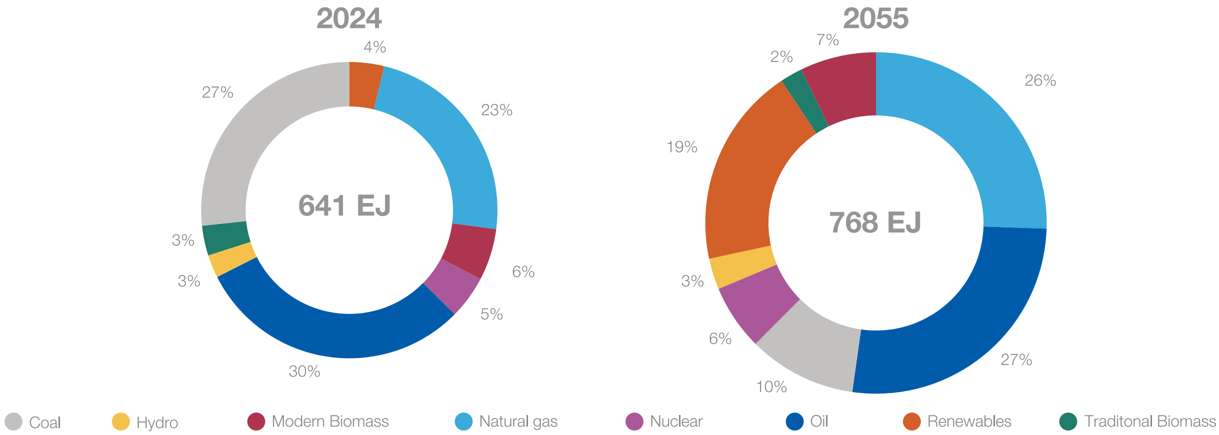
Global primary energy demand outlook by fuel type, 2024-2055

	Levels (EJ)					Change (EJ)	Growth (% p.a.)	Share (%)	
	2024	2030	2040	2050	2055	2024-2055	2024-2055	2024	2055
Natural Gas	150	166	185	194	196	46	0.9%	23%	26%
Oil	193	200	203	204	205	12	0.2%	30%	27%
Coal	171	147	120	90	79	-92	-2.5%	27%	10%
Nuclear	30	33	39	45	48	18	1.5%	5%	6%
Hydro	16	18	20	21	23	7	1.1%	3%	3%
Renewables	24	50	87	130	146	122	5.8%	4%	19%
Traditional Biomass	21	20	19	17	16	-5	-0.8%	3%	2%
Modern Biomass	36	41	50	55	55	19	1.4%	6%	7%
Total	**641**	**675**	**722**	**755**	**768**	**127**	**0.6%**	**100%**	**100%**

Source: GECF Secretariat based on data from the GECF GGM

Figure 3.10

Global primary energy mix outlook, 2024 and 2055 (%)



Source: GECF Secretariat based on data from the GECF GGM

Note: Renewables include solar, wind, tidal and geothermal energy

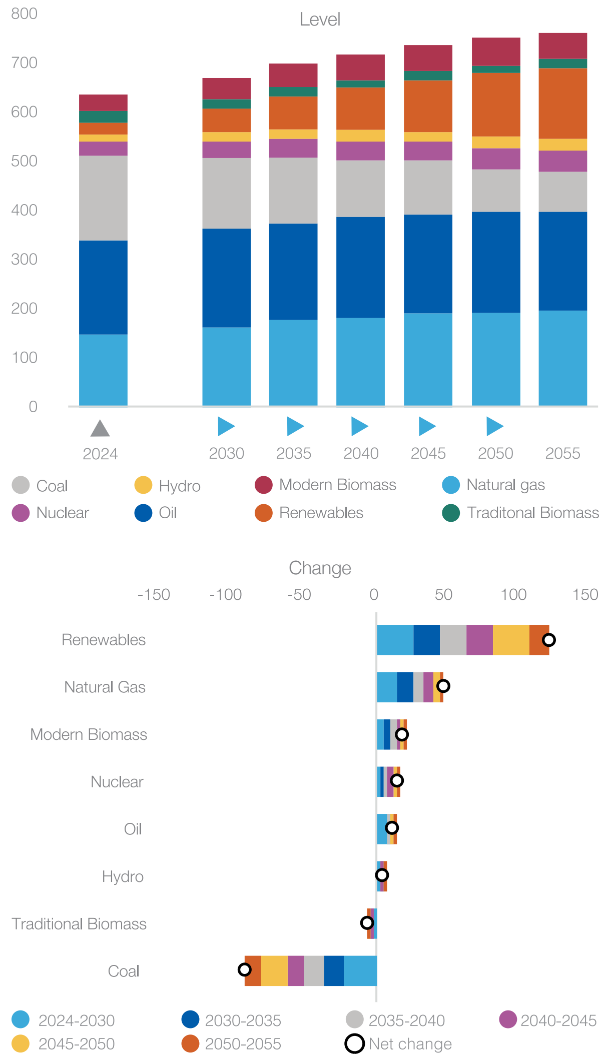
in transport, where LNG-fuelled heavy-duty vehicles and maritime vessels contribute to emissions reductions and improved air quality.

Driven by an increasing risk of overshooting global temperature goals and the need for pragmatic, just, and inclusive energy transition pathways, the role of emissions-mitigation technologies within the natural gas value chain is gaining renewed importance. CCUS is becoming progressively more cost-competitive and technically mature, enabling substantial reductions in emissions across upstream, midstream, and downstream segments of natural gas production and use. At the same time, the accelerated deployment of advanced methane measurement, monitoring, and abatement technologies is materially lowering fugitive emissions, directly addressing one of the most critical environmental challenges associated with natural gas. Collectively, these measures significantly enhance the climate performance of natural gas, reinforcing its position as a key enabler of orderly, equitable, and achievable pathways towards global climate objectives while safeguarding energy security and affordability.

Reflecting the combined impact of the structural, technological, and policy drivers discussed above, the **RCS projects global natural gas demand to expand at an average annual rate of around 0.9% through 2055, increasing from 150 EJ in 2024 to approximately 196 EJ by 2055, equivalent to a cumulative growth of about 31% (28% CAGR).** The projections further indicate that natural gas is set to surpass coal as the world's second-largest source of primary energy as early as 2027, ranking behind oil. This transition marks a pivotal shift in the global energy system, highlighting the strengthening role of natural gas as a cornerstone of energy systems that seek to reconcile affordability, reliability, and decarbonisation objectives, while allowing countries the flexibility to pursue transition pathways aligned with their national capabilities, development needs, and policy priorities.

Figure 3.11

Global primary energy demand outlook by fuel type, 2024-2055 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

3.5.1 Oil

Current oil demand trends are being shaped by a combination of energy security and affordability priorities, post-pandemic normalisation of mobility, and uneven progress in energy transitions across regions. In developed countries, policy recalibration and uncertainty, particularly in the United States and Europe, are slowing fuel substitution by moderating EV deployment, easing efficiency requirements, and sustaining domestic oil supply, thereby extending oil use. In developing regions, especially in Asia Pacific and Africa, structural factors such as population growth, urbanisation, rising incomes, and expanding transport and industrial activity remain the primary drivers of oil demand growth. In China, efficiency gains and EV uptake temper growth in traditional fuel use, but continued expansion in petrochemicals and aviation offsets these effects, while technological progress simultaneously improves efficiency and enables new oil-intensive applications, sustaining demand in hard-to-abate sectors.

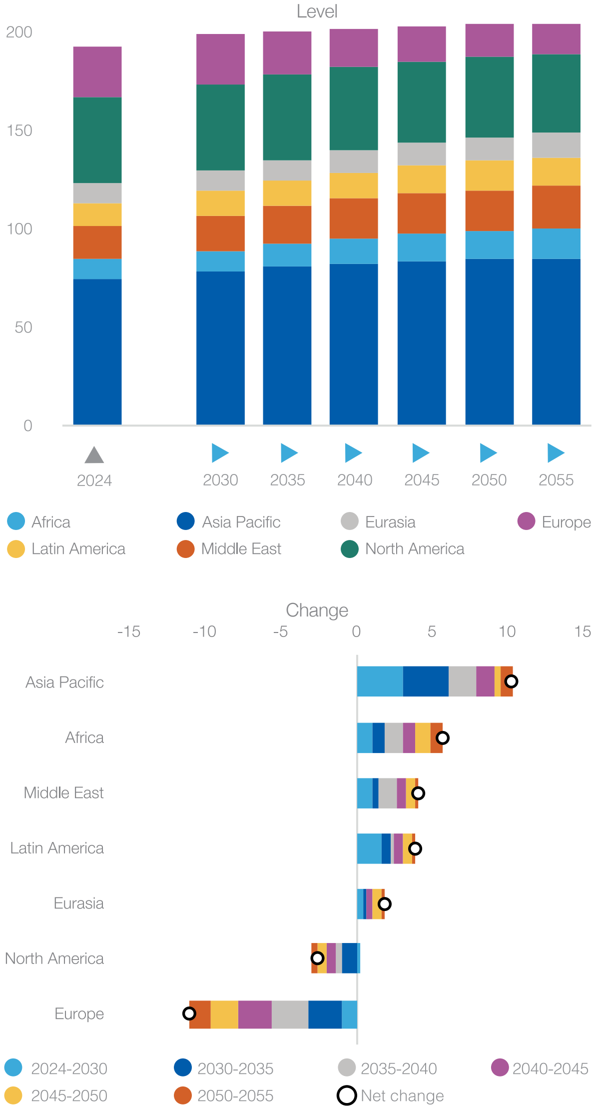
Driven by these factors, **global oil demand is projected to continue expanding over the outlook period, rising from 193 EJ in 2024 to nearly 205 EJ by 2055** (Figure 3.12). This increase is underpinned by demographic and income growth in developing countries, which continue to support demand for mobility, freight transport, and petrochemical feedstocks. Robust growth in aviation, road freight, and maritime transport, alongside the continued expansion of petrochemicals driven by plastics, synthetic materials, and industrial products, underpins long-term oil demand. Although efficiency improvements, electrification, and alternative fuels moderate oil use in light-duty transport, these effects are more than offset by demand growth in hard-to-abate sectors and developing countries. As a result, oil remains the dominant source of primary energy over the next three decades, even as its growth trajectory gradually slows over time.

Transport sector remains a key pillar underpinning long-term oil consumption, even as EV penetration accelerates over time. While the increasing adoption of EVs and efficiency improvements progressively reduce oil use in light-duty passenger transport, particularly in developed countries, the impact on aggregate transport oil demand is moderated by slow fleet turnover, affordability constraints, and uneven charging infrastructure deployment across regions. Moreover, rising transport activity and continued reliance on oil in aviation, long-haul freight, maritime shipping, and off-road transport, where electrification faces technical and economic limitations, more than offset demand reductions from passenger vehicles.

Alongside transport, petrochemicals emerge as a central and increasingly influential pillar of long-term oil demand, driven by structural growth in non-combustion uses rather than mobility. Rising global population, urbanisation, and income growth, particularly in developing countries, continue to underpin expanding

Figure 3.12

Global oil demand outlook by region, 2024-2055 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

demand for plastics, synthetic materials, fertilisers, and a wide range of consumer and industrial products, translating into sustained growth in oil-based feedstock demand. Technological innovation and efficiency gain moderate energy intensity in some processes, but they do not fundamentally displace oil's role as a primary feedstock due to its cost competitiveness, chemical properties, and integration within existing industrial value chains. As a result, petrochemicals and other non-energy uses increasingly account for a larger share of incremental oil demand over the long term, partially offsetting the moderating growth in transport fuels and reinforcing oil's continued relevance in the global energy and industrial system.

The long-term outlook for oil demand reveals pronounced regional divergence, shaped by differences in demographics, economic structure, policy orientation, and the pace of energy transitions. Structural declines are concentrated in Europe, North America, and selected OECD Asia Pacific economies, notably Japan and South Korea, driven mainly by the gradual contraction of gasoline- and diesel-powered passenger vehicle fleets as electrification, efficiency improvements, and fuel substitution advancement. Europe is expected to lead this decline, with oil demand falling by around 11 EJ to approximately 15 EJ by 2055, reflecting ambitious climate policies alongside de-industrialisation and adverse demographic trends. In North America, oil demand is projected to decline more moderately, decreasing by nearly 3 EJ to around 41 EJ by the end of the outlook period, as efficiency gains in ICE vehicles and electrification in passenger transport offset continued demand in freight, aviation, and petrochemicals.

Meanwhile, the developing world has become the primary engine of global oil demand. Growth is concentrated in India, China, Southeast Asia, and Sub-Saharan Africa, where fundamental shifts, such as rapid urbanisation, rising incomes, and expanding industrial and transport sectors, continue to drive oil demand higher. This shift is most evident in the Asia Pacific region, which is projected to account for nearly 87% of global net oil demand growth through 2055. India, in particular, will become the world's fastest-growing source of oil demand, fueled by rapid economic expansion, a surge in vehicle ownership and accelerating demand for aviation and mobility and refining and petrochemical feedstocks. Unlike in more mature markets, efficiency gains and electrification in road transport moderate but do not offset demand growth, as expanding freight activity, infrastructure development, and rising consumption of oil-based products continue to underpin a sustained increase in India's oil demand well into the long term. Africa follows as the second-largest contributor, with growth underpinned by rising mobility and industrialisation, as well as the substitution of traditional biomass with Liquefied Petroleum Gas (LPG) to address persistent clean-cooking deficits.

3.5.2 Coal

Global coal demand remained elevated in 2024, reflecting the continued prioritisation of energy security following the 2022 energy crisis, with China and India accounting for the bulk of consumption. While global coal use reached record levels in 2023 and stayed high in 2024, growth moderated as renewable generation expanded and demand conditions softened in some regions. In China, coal demand increased modestly in 2024, supported by strong electricity demand growth and the need to maintain system reliability amid rising shares of variable renewables. Although approvals of new coal-fired power plants slowed compared with the 2022–2023 surge, construction activity remained substantial in 2024, reflecting the lagged impact of earlier approvals. At the same time, coal's role increasingly shifted towards system support rather than baseload expansion, highlighting a dual-track approach in which short-term energy security considerations coexist with longer-term decarbonisation and renewable deployment objectives.

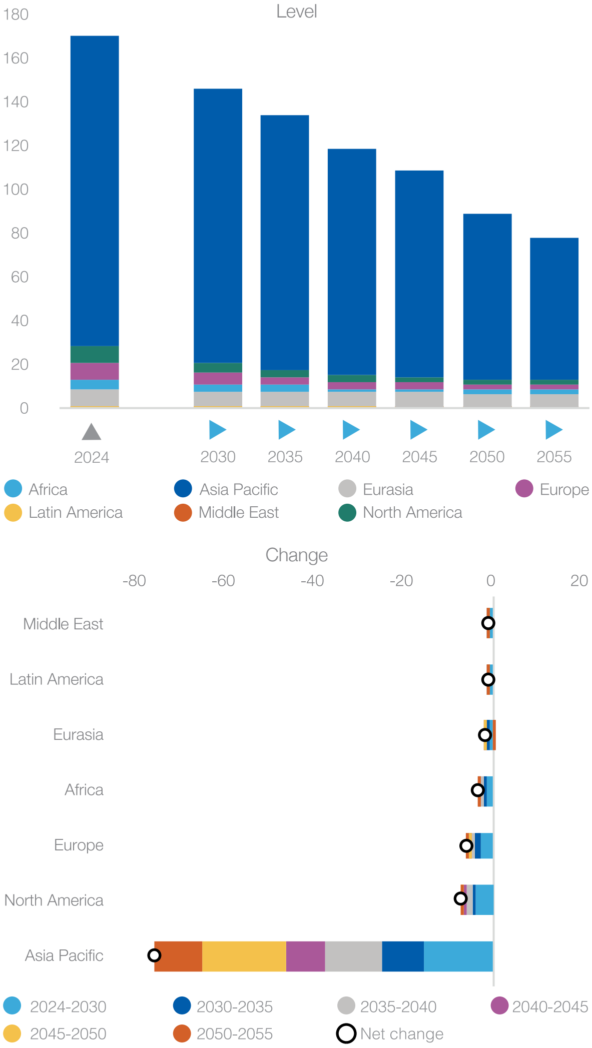
Despite the recent uptick in coal use driven by short-term energy security concerns, the longer-term outlook points to a renewed and sustained structural decline in global coal demand. This trajectory is underpinned by tightening climate and air-quality regulations, growing policy commitments to reduce unabated coal use, and accelerating fuel switching across power systems. The rapid scale-up of cleaner and more flexible alternatives, particularly natural gas, renewables, and nuclear power, progressively displaces coal from baseload generation, confining its role increasingly to peak-load and system-balancing functions and reducing plant utilisation rates. **Under the RCS, global coal demand is projected to fall sharply from 171 EJ in 2024 to 79 EJ by 2055, implying an average annual decline of 2.5%, in stark contrast to the 2.1% annual growth observed over the past three decades** (Figure 3.13). Nearly 80% of this reduction is expected to occur in the power generation sector, reflecting retirements and declining load factors, while coal use in residential and industrial sectors also contracts steadily as cleaner energy sources, efficiency gains, and alternative technologies increasingly take hold.

Coal demand is projected to decline across all regions over the outlook period, although the scale and pace of this contraction vary markedly by region, reflecting differences in energy systems, policy ambition, and development priorities. In absolute terms, the Asia Pacific is expected to account for around 82% of the total global reduction in coal demand between 2024 and 2055. As a result, coal's share in the region's primary energy mix is projected to fall sharply from 47% in 2024 to around 18% by 2055. Despite this substantial decline, Asia Pacific will remain the world's largest coal-consuming region over the period, owing to the sheer scale of its energy demand and the continued reliance on coal in key economies such as India, where coal remains central to energy security and the provision of affordable electricity to support rapid economic and population growth. Within the region, the bulk of the decline is driven by China, Japan, South Korea, and Australia, reflecting tightening environmental regulations, accelerated renewable deployment, and long-term commitments to reduce reliance on unabated coal.

This transition is even more aggressive in North America and Europe which are projected to experience the most rapid pace of coal demand reduction, with average annual declines of around 5.1% and 3.7%, respectively. In these regions, coal consumption is expected to fall to minimal levels by 2055 as unabated coal is progressively phased down in line with ambitious climate and air-quality objectives. The majority of the reductions are projected to occur before 2040, underpinned by increasingly stringent policy frameworks, particularly in

Figure 3.13

Global coal demand outlook by region, 2024-2055 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

the United States, and reinforced by the rapid expansion of renewable generation and sustained access to competitively priced natural gas. Together, these factors significantly accelerate coal-to-gas switching and the displacement of coal in power generation, cementing coal's long-term structural decline in developed countries.

3.5.3 Nuclear

Nuclear power is entering a phase of renewed momentum after more than a decade of subdued growth, reflecting its reassessment as a low-carbon, dispatchable, and system-stabilising source of energy. This renewed interest is being driven by rising global electricity demand, heightened concerns over energy security, and the growing need for firm generation capacity to complement the rapid expansion of variable renewable energy. Recent developments include the acceleration of new reactor construction in selected regions, widespread lifetime extensions of existing plants, and increasing policy and commercial focus on next-generation technologies, particularly Small Modular Reactors (SMRs). Together, these trends signal a shift from nuclear power's earlier stagnation towards a more prominent role in long-term energy system planning.

Over the outlook period, global nuclear energy demand is projected to increase by more than 60%, rising from around 30 EJ in 2024 to nearly 48 EJ by 2055 (Figure 3.14). This growth is underpinned by three interrelated drivers. New build programs in fast-growing electricity markets support rising baseload demand while limiting emissions growth, while lifetime extensions of existing reactors preserve large volumes of low-carbon generation capacity at comparatively low cost. At the same time, the gradual deployment of SMRs enhances nuclear power's flexibility, reduces upfront capital requirements, and expands its potential applications beyond large, interconnected grids to include industrial sites, remote locations, and non-power uses such as heat and desalination. Collectively, these developments reflect renewed confidence in nuclear energy as a scalable and reliable pillar of low-carbon power systems.

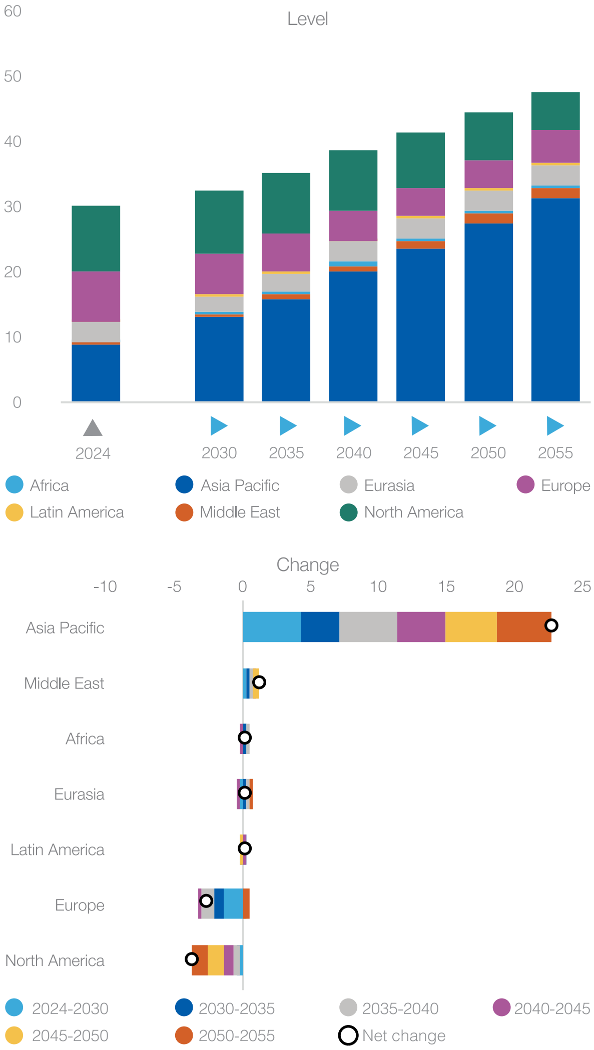
Growth in nuclear energy demand is highly concentrated in Asia Pacific, which remains the primary engine of global expansion. The region's share of global nuclear energy demand is projected to increase from 29% in 2024 to nearly 66% by 2055, driven by strong policy support, domestic technology development, and rapidly rising electricity demand. China, India, and South Korea are leading reactor construction efforts, with China on track to operate the world's largest nuclear reactor fleet by the mid-2030s and India continuing to scale up capacity as part of its long-term decarbonisation and energy security strategy. Japan's revised nuclear policy, including the restart of idled reactors, further reinforces regional growth as nuclear re-emerges as an important component of its energy mix.

Beyond Asia Pacific, the Middle East is emerging as an increasingly important contributor to global nuclear development, with countries such as the United Arab Emirates and Saudi Arabia investing in large-scale nuclear capacity to diversify power generation, strengthen energy security, and preserve hydrocarbons for export. In parallel, several countries in the region are actively exploring SMR technologies, recognising their potential to support low-carbon electricity generation and energy-intensive applications such as large-scale water desalination, both of which are critical for long-term regional sustainability. Eurasia, led by Russia, maintains a strong presence through continued domestic reactor construction and export-oriented nuclear technology partnerships, with Russian-designed reactors, fuel supply, and associated services remaining central to nuclear deployment in several developing markets.

In contrast, nuclear energy demand in North America and Europe is expected to gradually decline over the

Figure 3.14

Global nuclear demand outlook by region, 2024-2055 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

outlook period as ageing reactors retire, and new large-scale projects face regulatory, financial, and social constraints. While countries such as the United States, Canada, France, and the United Kingdom are increasingly focusing on selective lifetime extensions and the development of SMRs, traditional large-scale nuclear plants continue to lose share within increasingly diversified power systems. In these mature markets, nuclear power faces growing competition from renewables, energy storage, and flexible gas-fired generation, reshaping its long-term role.

3.5.4 Hydro

Hydropower continues to play a foundational role in the global renewable energy mix, providing reliable, dispatchable electricity alongside critical grid-balancing, flexibility, and storage services. Unlike variable renewables, hydropower offers inherent system stability and remains an important source of peak-load capacity and ancillary services. However, its growth trajectory is increasingly constrained by geographical limitations, environmental and social considerations, long permitting timelines, and growing competition for water resources. As a result, while hydropower remains strategically important, its expansion is more moderate compared with the rapid scale-up observed in solar and wind technologies. By the end of 2024, the global hydropower development pipeline exceeded 1,000 GW, with the majority of projects already under construction expected to be commissioned by around 2030, reinforcing the view that most economically viable large-scale opportunities are already identified.

Over the long-term, global hydropower generation is projected to continue growing, albeit at a measured pace. **By 2055, demand for hydropower generation is expected to increase by nearly 44%, reaching around 23 EJ** (Figure 3.15). This growth is driven primarily by the completion of projects currently under development, incremental capacity additions in emerging economies, and efficiency upgrades, refurbishment, and digital optimisation of existing facilities. Hydropower's contribution increasingly shifts from pure capacity expansion towards system optimisation, reservoir management, and enhanced flexibility to support power systems with rising shares of variable renewable energy. At the same time, climate variability and increasing hydrological uncertainty underscore the importance of adaptive operation and investment in resilience, further shaping hydropower's evolving role.

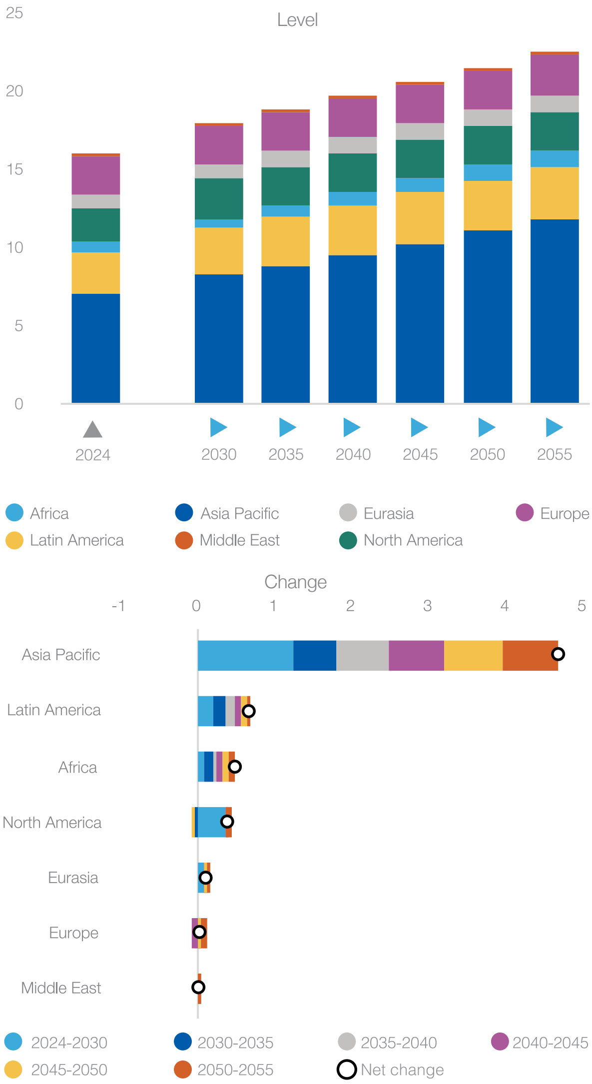
Regionally, the Asia Pacific region remains the dominant centre of hydropower generation and growth, accounting for more than half of global output throughout the outlook period and around 67% of the projected increase in global hydropower demand. Continued expansion in China, India, and Southeast Asia underpins this trend, supported by new capacity additions, upgrades of existing dams, and the strategic use of hydropower to complement rapidly expanding solar and wind fleets. While the pace of new large-scale developments slows over time, efficiency improvements and pumped storage expansion sustain moderate growth and reinforce hydropower's system value in the region.

Africa also records gradual growth in hydropower generation, reflecting the development of major regional projects and untapped technical potential in several river basins. Large-scale developments, including the Grand Ethiopian Renaissance Dam, alongside ongoing projects in Central and West Africa, contribute to improved electricity access, regional interconnection, and system reliability.

In Latin America, hydropower remains the backbone of electricity generation in countries such as Brazil, Colombia, and Chile, but future growth is increasingly constrained. Limited availability of new suitable sites, heightened environmental scrutiny, and growing

Chapter 3

Figure 3.15
Global hydro demand outlook, 2024-2055 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

exposure to droughts and climate-related water stress restrict further large-scale expansion. As a result, capacity growth is modest, with a greater emphasis on modernisation, operational optimisation, and integration with other renewable technologies to enhance system resilience.

In North America and Europe, hydropower growth is marginal over the outlook period, driven primarily by refurbishment, digital optimisation, and life-extension of ageing assets rather than new construction. Environmental constraints, competing land and water uses, and lengthy permitting processes limit large-scale project development. In these mature markets, hydropower's role increasingly centres on flexibility provision, seasonal storage, and balancing services rather than capacity expansion. Eurasia maintains relatively stable but limited hydropower contributions, with generation focused on regional balancing and the utilisation of existing infrastructure rather than large new developments.

3.5.5 Renewables

Renewable energy continues to expand rapidly and plays an increasingly important role in the global energy system, supported by declining technology costs, policy support, and accelerating electrification, particularly in the power sector. Solar and wind power dominate new capacity additions worldwide, reflecting their improving competitiveness and scalability. However, despite this strong momentum, renewable growth remains constrained by intermittency, grid integration challenges, infrastructure bottlenecks, and the need for complementary dispatchable capacity. As a result, under prevailing policies, renewables emerge as the fastest-growing source of energy demand, but do not displace oil and natural gas in absolute terms by mid-century, instead evolving as a critical component of a more diversified and balanced energy mix.

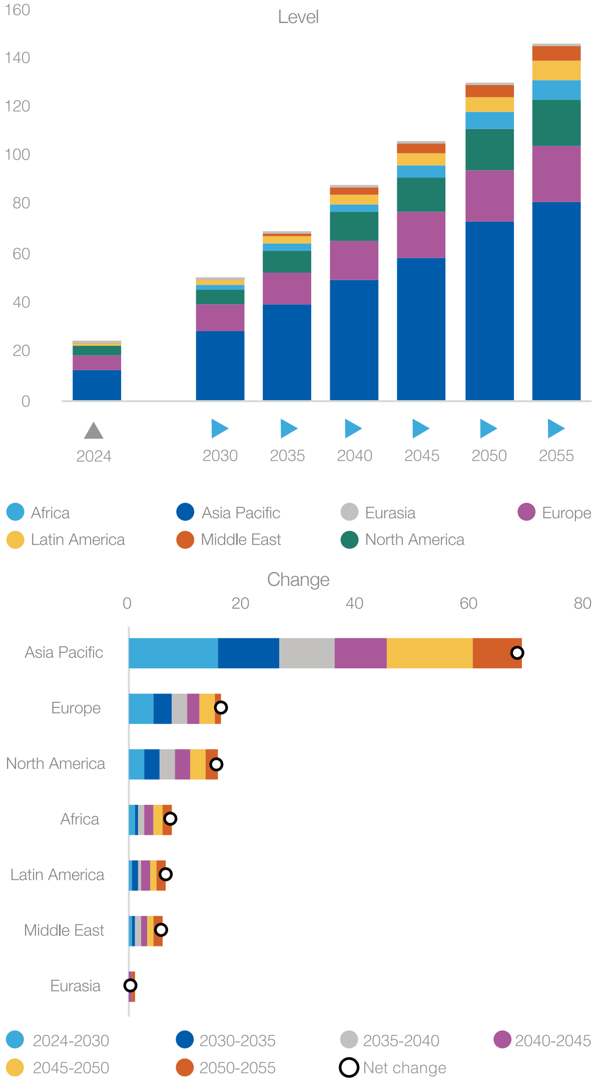
Over the outlook period, global renewable primary energy demand is projected to rise sharply, increasing from around 24 EJ in 2024 to nearly 146 EJ by 2055 (Figure 3.16). This expansion is driven primarily by the electricity sector, where renewables capture a growing share of incremental demand, supported by electrification of transport, buildings, and selected industrial processes. Solar and wind account for the bulk of this growth, while geothermal and other renewables expand more gradually, providing firm low-emissions power in specific geographies. Nevertheless, renewable penetration into hard-to-abate sectors remains limited, reinforcing the continued importance of hydrocarbons, nuclear power, and other firm energy sources in meeting global energy demand reliably and affordably.

Regionally, the Asia Pacific region emerges as the principal engine of renewable energy expansion, accounting for nearly 57% of global renewable demand growth between 2024 and 2055. Rapid industrialisation, urbanisation, and rising electricity demand, combined with national decarbonisation objectives and strong domestic manufacturing capacity, underpin renewable deployment across China, India, and Southeast Asia. China remains at the forefront of global solar and wind installations, supported by advances in grid integration and large-scale storage, with renewables increasingly meeting incremental electricity demand rather than fully displacing conventional generation. India continues to accelerate renewable deployment alongside complementary investments in hybrid systems and green hydrogen, while emerging Southeast Asian economies scale up solar and wind as cost competitiveness improves relative to coal-based power generation.

In Europe and North America, accounting each to 13% of global increase, renewable growth continues from

Figure 3.16

Global renewables demand outlook by region, 2024-2055 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

a more mature base, driven by policy frameworks that support offshore wind, utility-scale solar, and distributed generation increasingly integrated with energy storage. Electrification of transport and heating reinforces renewable demand in these regions; however, grid congestion, permitting delays, land-use constraints, and rising system integration costs increasingly temper the pace of new project development. As VRE penetration rises, the need for dispatchable capacity and balancing services becomes more pronounced, reinforcing the continued role of natural gas, nuclear power, and cross-border interconnections in maintaining system reliability.

Africa emerges as a frontier market for renewable deployment, albeit from a low base. Growth is driven by solar mini-grids, hybrid systems, and selected grid-scale wind and solar projects aimed at expanding electricity access, improving affordability, and supporting economic development. While renewable growth is strong in relative terms, its absolute contribution remains constrained by financing challenges, grid limitations, and rapid population growth, reinforcing the need for a diversified energy approach that includes natural gas and other modern fuels.

Latin America continues to leverage its abundant renewable resource base, particularly in solar and wind, with countries such as Brazil, Chile, and Colombia expanding capacity through competitive auctions, foreign investment, and growing regional interconnections. Renewables strengthen power system diversification and resilience, while also supporting emerging low-carbon hydrogen export strategies. Nevertheless, growth is moderated by hydrological variability, investment risks, and infrastructure limitations in some markets, constraining the pace at which renewables can transform the broader energy mix.

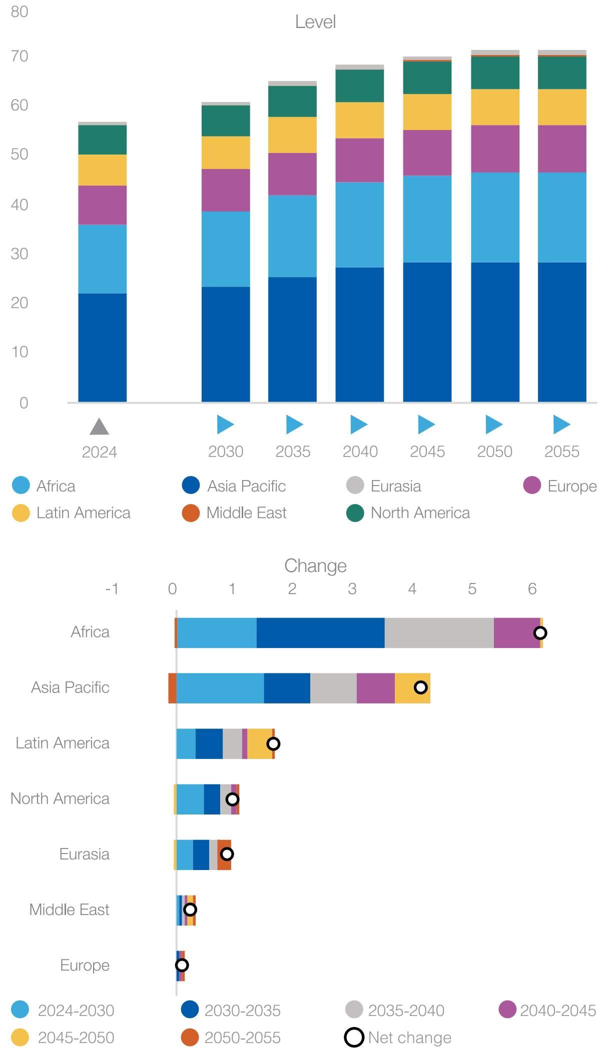
In the Middle East, renewables, especially solar, gain strategic importance as countries seek to diversify power generation, reduce domestic oil and gas consumption, and preserve hydrocarbons for export. Large-scale solar projects in Saudi Arabia, the United Arab Emirates, and Oman reshape power generation portfolios, increasingly linked to low carbon hydrogen and ammonia initiatives. However, renewables remain complementary to hydrocarbons, with natural gas continuing to underpin power system reliability and flexibility across the region.

3.5.6 Bioenergy

Bioenergy continues to play a strategically important and highly differentiated role in the global energy system, sitting at the nexus of energy access, rural development, emissions mitigation, and energy security. In 2024, global bioenergy demand, covering both traditional and modern biomass, amounted to approximately 57 EJ, underscoring its continued relevance across both developing and developed countries. Traditional biomass, including fuelwood, agricultural residues, and animal waste, accounted for around 37% of total bioenergy use, reflecting its persistent role in providing basic energy services for cooking and heating in off-grid and low-income households. While essential for meeting immediate energy needs, reliance on traditional biomass is associated with severe negative externalities, including indoor air pollution, adverse health outcomes, ecosystem degradation, and low energy efficiency. As a result, bioenergy policies are increasingly framed not only through a climate lens, but also in terms of public health, social equity, and sustainable development. **Over the outlook period, total bioenergy demand is projected to grow at an average rate of around 1% per year, reaching approximately 72 EJ by 2055** (Figure 3.17). Beneath this moderate aggregate growth lies a profound structural transformation, marked by a steady decline in traditional biomass use and a corresponding expansion of modern bioenergy applications.

Figure 3.17

Global bioenergy demand outlook, 2024-2055 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

Traditional biomass demand is projected to decline by around 25% over the forecast period, falling to approximately 16 EJ by 2055. This decline is driven by expanding access to modern energy services, rising urbanisation, and targeted policy interventions aimed at improving air quality and public health. The reduction is most pronounced in the Asia Pacific, where large-scale clean cooking programmes, fuel switching, and electrification efforts are actively reducing reliance on polluting fuels. India's clean cooking initiatives, including the Ujjwala Scheme, illustrate how coordinated policy support, infrastructure rollout, and affordability measures can rapidly displace traditional biomass with cleaner alternatives such as LPG and electricity. By contrast, Sub-Saharan Africa follows a more gradual transition pathway. Despite growing efforts to expand clean cooking access, rapid population growth, persistent income constraints, and limited infrastructure are expected to sustain high levels of traditional biomass consumption through much of the 2040s. As a result, traditional biomass use in the region is projected to remain broadly stable before declining modestly to around 8.2 EJ by 2055, only about 0.5 EJ below 2024 levels. This divergence highlights the critical need to accelerate investment in scalable and affordable clean cooking solutions, including LPG, electricity, and modern bioenergy, to close the energy access gap and advance progress towards Sustainable Development Goal 7.

In parallel, **modern bioenergy is set to expand steadily, with demand projected to increase by around 42% to reach approximately 55 EJ by 2055.** This growth is supported by multiple structural drivers, including decarbonisation policies, energy security considerations, and the growing recognition of bioenergy's role in sectors where electrification is challenging. In the power sector, modern biomass is increasingly deployed through co-firing and dedicated biomass plants, enabling emissions reductions while leveraging existing thermal infrastructure. In the residential and commercial sectors, modern biomass contributes to cleaner heating solutions, particularly in colder climates. In transport, liquid biofuels, such as bioethanol and biodiesel, remain an important abatement option for road transport, supported by blending mandates, fiscal incentives, and established supply chains. Moreover, Sustainable Aviation Fuels (SAF) are gaining strategic importance as one of the few viable pathways to reduce emissions from long-haul aviation, given their compatibility with existing aircraft fleets and refuelling infrastructure.

Biogas and biomethane, while currently accounting for a relatively small share of global bioenergy demand, are expected to experience rapid growth over the outlook period. Their appeal lies in their ability to provide low-emissions, dispatchable gaseous energy while utilising waste streams from agriculture, municipalities, and industry. Biomethane, in particular, is increasingly viewed as a strategic complement to natural gas, benefiting from falling production costs, technological improvements, and supportive policy frameworks. Several regions are prioritising biomethane to strengthen energy security and reduce emissions from gas supply chains. The European Union has set ambitious production targets as part of its broader decarbonisation and energy security strategy, while the United States, China, and India are also scaling up biomethane deployment through regulatory incentives, infrastructure investments, and integration with existing gas networks.

Despite its significant potential, the expansion of bioenergy is not without challenges. Infrastructure gaps, financing constraints, and uneven technology diffusion across regions could limit the pace of deployment, particularly in developing countries. Ensuring the sustainability of bioenergy remains paramount, requiring careful management of land-use impacts, feedstock sourcing, and lifecycle emissions to avoid conflicts with food security and biodiversity objectives.

3.6 Energy intensity and consumption per capita prospects

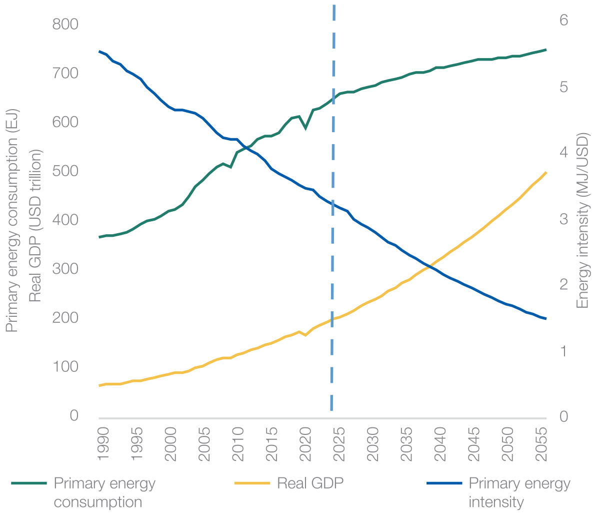
Energy intensity remains the most immediate and cost-effective lever for improving energy security, affordability, and emissions performance under current policy settings, yet recent progress continues to fall short of what is required to fundamentally alter global energy demand trends. In 2024, global primary energy intensity improved by around 1.7%, alongside economic growth of approximately 3.2% (PPP terms) and a 1.5% increase in primary energy consumption. While this represents a recovery from earlier slowdowns, it remains broadly in line with the long-term historical average of about 1.6% per year, highlighting that efficiency gains are stabilising rather than accelerating. Recent improvements have been driven mainly by incremental technological advances, structural economic shifts towards less energy-intensive activities, and the retirement of inefficient assets, while deeper efficiency gains, particularly in buildings, transport, and emerging economies, remain constrained by investment gaps, slow retrofitting rates, and uneven policy implementation.

Looking ahead, as illustrated in Figure 3.18, **the RCS projects a faster decline in global primary energy intensity of around 2.3% per year between 2024 and 2055, reducing energy intensity to approximately 1.5 MJ per USD (PPP, base year 2024).** This reflects stronger efficiency standards, wider electrification, and greater use of digital optimisation across sectors. Nevertheless, these improvements are insufficient to deliver absolute reductions in global primary energy demand, which is projected to continue rising through 2055. Population growth, rising incomes, urbanisation, and expanding industrial and service activity, particularly in developing countries, continue to outweigh efficiency gains. As a result, energy efficiency plays a critical role in moderating demand growth, but under current policies, it cannot, on its own, decouple economic expansion from rising global energy consumption.

Energy efficiency trajectories vary markedly across regions and are unlikely to converge toward a uniform global pathway, reflecting differences in economic structure, stages of development, demographic trends, climatic conditions, and patterns of urbanisation. Recent energy efficiency assessments underline that progress is shaped as much by institutional capacity, investment availability, and policy enforcement as by technology alone. Developed countries, where basic efficiency measures are largely exhausted, increasingly rely on incremental gains through digitalisation, system optimisation, and electrification, while developing regions face the dual challenge of expanding energy access and reducing energy intensity simultaneously. These structural disparities underscore the uneven nature of global efficiency progress, with each region following a distinct pathway aligned with its economic priorities and energy system constraints.

Figure 3.18

Global energy intensity outlook, 2024-2055



Source: GECF Secretariat based on data from the GECF GGM
Note: GDP in PPP term (base year=2024)

In 2024, Europe emerged as the most energy-efficient region globally, followed by Latin America. Europe's leadership reflects decades of stringent efficiency policies, comprehensive building codes, appliance and vehicle standards, and a mature shift toward service-oriented, low-energy-intensity economic activity. As shown in Figure 3.19, Europe is projected to retain its position as the most energy-efficient region through 2055, with energy intensity improving at an average annual rate of around 1.9%. This comparatively moderate pace reflects diminishing marginal gains from efficiency improvements at high baseline levels, where further reductions increasingly depend on deep retrofits, digital optimisation, and behavioural change rather than large technological leaps.

Asia Pacific, by contrast, is expected to undergo the most pronounced transformation in energy efficiency over the outlook period, with average annual improvements of around 3.1%, well above the global average. This acceleration is driven by industrial upgrading, tighter efficiency standards, and large-scale investment in modern infrastructure, particularly in China and India. The replacement of outdated industrial assets, electrification of end-use sectors, and deployment of best-available technologies contribute significantly to these gains. As a result, by 2055 Asia Pacific is projected to become the second most energy-efficient region globally, overtaking Latin America and substantially narrowing the gap with Europe, illustrating the strong catch-up potential highlighted in recent energy efficiency assessments.

North America is also projected to achieve a sustained decoupling of economic growth from energy consumption, with annual energy efficiency improvements averaging around 1.9%. Progress in the region is underpinned by stringent efficiency standards for buildings and vehicles, expanding electrification of transport and heating, and continued structural shifts toward less energy-intensive industries and services. However, the pace of improvement is moderated by slow turnover of existing building stock and transport fleets, as well as rising demand for cooling, data centres, and digital services.

Africa stands out as a region with strong relative efficiency gains, with energy intensity projected to improve by around 2.4% annually over the outlook period. These gains are driven by the gradual modernisation of energy systems, the phasing-out of inefficient traditional biomass use, and the expansion of access to cleaner and more efficient energy sources, including natural gas, electricity, and modern renewables. Although starting from a low base, efficiency improvements in Africa are closely linked to energy access expansion and structural transformation. By the end of the forecast period, Africa's energy intensity is expected to converge with that of Latin America, surpassing both the Middle East and Eurasia.

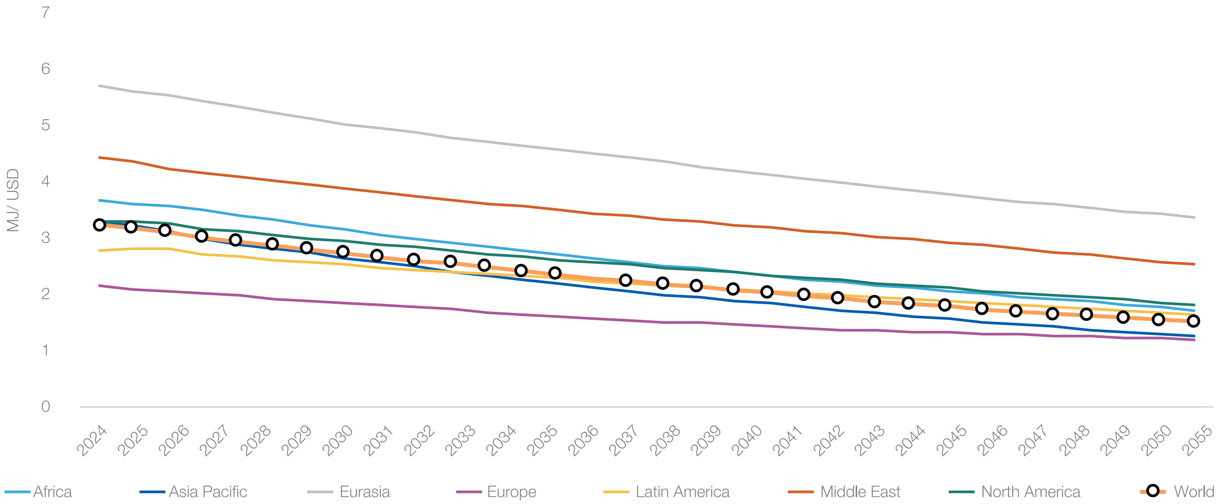
Despite being the second most energy-efficient region globally in 2024, Latin America is projected to experience the slowest rate of efficiency improvement, averaging around 1.7% per year through 2055. This reflects the region's already favourable energy mix, including high shares of hydropower, as well as more limited policy tightening and slower diffusion of next-generation efficiency technologies relative to other regions. As a result, while Latin America maintains a relatively low energy intensity, further efficiency gains are more incremental in nature.

It is important to recognise that energy efficiency improvements exhibit two structural characteristics that shape their effectiveness as a long-term demand-moderation strategy. First, efficiency gains are inherently subject to diminishing returns. As technologies, equipment, and processes mature, the scope for further efficiency improvements narrows, particularly once the most cost-effective measures, the so-called "low-hanging fruit", have been exhausted. At higher levels of efficiency, additional gains increasingly depend on complex system optimisation, advanced digital solutions, and capital-intensive retrofits, which raise costs and slow deployment. This dynamic constrains the pace of sustained efficiency improvements, especially in developed countries and sectors where energy performance is already relatively high, and helps explain why efficiency progress tends to decelerate over time without stronger policy intervention and investment support.

Second, energy efficiency improvements are often accompanied by rebound effects, whereby lower effective energy costs lead to increased energy consumption or expanded energy services, partially offsetting the initial savings. As energy services become more affordable, households and firms may respond by increasing usage, upgrading comfort levels, or expanding productive activity. This effect is particularly pronounced in regions with low per-capita energy consumption and significant unmet demand, such as Sub-Saharan Africa and parts of developing Asia, where efficiency gains enable higher levels of heating, cooling, lighting, and mobility. In these contexts, improved efficiency supports economic development and welfare gains but also translates into higher absolute energy demand rather than net reductions. Together, these characteristics underscore why energy efficiency, while essential for improving energy productivity and moderating demand growth, cannot on its own deliver sustained absolute reductions in global energy consumption under current policy conditions.

Figure 3.19

Projection of regional energy intensity, MJ/USD (PPP, base year =2024) (2024-2055)



Source: GECF Secretariat based on data from the GECF GGM

Despite continued improvements in global energy efficiency, per-capita primary energy consumption is projected to remain broadly unchanged between 2024 and 2055. Over this period, global primary energy demand is expected to grow at an average annual rate of around 0.6%, broadly in line with projected global population growth. As a result, gains in energy productivity are largely absorbed by demographic expansion, leaving global average per-capita primary energy use effectively flat. This outcome highlights a central structural challenge of the global energy system: while efficiency improvements moderate aggregate demand growth, they are insufficient to raise per -capita energy availability at the global level in the absence of faster progress on energy access and infrastructure development.

The persistence of stagnant global per-capita energy consumption also reflects deep, enduring inequalities in energy access and use. As of 2024, approximately 770 million people worldwide still lack access to electricity, with more than 600 million of them residing in Sub-Saharan Africa. These access deficits are most acute in regions experiencing rapid population growth, notably Sub-Saharan Africa, where demographic expansion continues to outpace the deployment of modern energy infrastructure. While global energy efficiency gains help contain overall demand growth, they do not address the structural deficit in modern energy access. Closing this gap requires sustained investment in power generation, grids, clean cooking solutions, and affordable fuels, alongside targeted policies that prioritise inclusivity and affordability (See Box 3.2).

Box 3.2 Electricity per Capita Inequality: The Catch-Up Slows

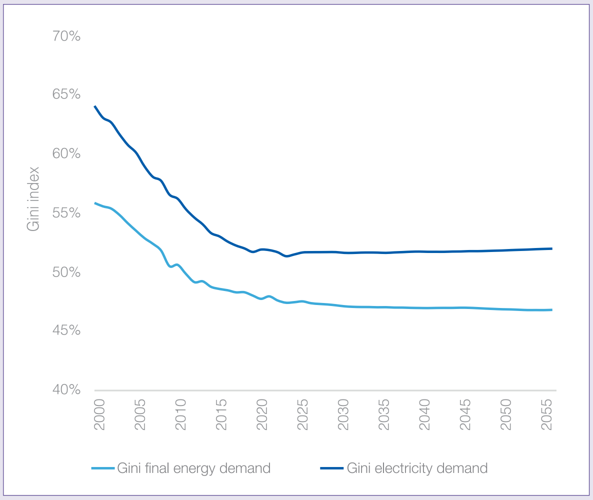
Electricity consumption per capita is becoming an increasingly decisive marker of inclusion in the energy transitions because a growing set of welfare-critical and productivity-critical services is effectively electricity-dependent and weakly substitutable by other fuels. Digital connectivity and information technology, data processing and communications, modern cooling and climate resilience, parts of health and education services, and an expanding share of mobility and urban energy services all rely on reliable electricity at scale. As electrification deepens, disparities in per-capita electricity use therefore signal more than differences in "energy comfort"; they increasingly reflect unequal access to the enabling infrastructure of modern economic activity and to the non-substitutable services that underpin future growth. This makes the evolution of electricity demand per capita inequality a forward-looking issue for both development and energy-system planning, particularly as the distribution of incremental electricity demand will shape investment needs, fuel requirements for firm capacity, and the geography of power-sector expansion through mid-century.

Against this background, the results of analyzing Gini index illustrated in Figure (1) show a persistent and quantifiable "electricity inequality premium" relative to final energy consumption. Since 2000, the population-weighted Gini index for electricity demand per capita has been systematically higher than the corresponding index for final energy consumption per capita, even as both improved over time. In 2000, the electricity Gini stood at 64%, compared with 56% for final energy, a gap of 8 percentage points. Convergence proceeded over the following two decades: by 2010 the gap had narrowed (electricity 56% vs final energy 51%), and by 2024 it narrowed further (electricity 51% vs final energy 47%), implying a reduction in the electricity–final energy gap to about 4 percentage points. The historical improvement is substantial in absolute terms: electricity inequality declines by 13 percentage points between 2000 and 2024, compared with a 8 percentage points decline for final energy. However, the outlook to 2055 under the GGO forecasts indicates that this historical catch-up in electricity consumption per capita stalls and modestly reverses. Final energy inequality continues to drift downward to 47% by 2055, whereas electricity inequality increases to 52%, widening the electricity–final energy gap again to around 5 percentage points. The reversal is small in magnitude, but it is analytically important because it suggests that the earlier drivers of convergence in electricity use no longer dominate the distributional dynamics of the power system in the long run.

A coherent explanation for these patterns follows from the structural economics of electricity. Electricity consumption at meaningful per-capita levels remains constrained by the breadth and quality of power-system infrastructure, grid coverage, reliability, affordability, and the institutional capacity to finance and operate the system. In contrast, final energy aggregates a wider set of carriers and uses that can be met through more heterogeneous supply chains. This naturally produces greater dispersion in electricity consumption than in total final energy. Historically, the diffusion of basic electrification and mass-market appliances helped compress electricity inequality faster than final-energy inequality, which is consistent with the sharper decline observed in the electricity Gini between 2000 and 2024. In the future, however, the composition of incremental electricity demand shifts toward forms of deep electrification and electricity-intensive services whose adoption is more uneven across countries. Electrified transport and heating, higher-quality cooling, and electricity-intensive industrial and service activities expand fastest where grids are already robust, and investment capacity is high. In addition, new digital loads, including those associated with data infrastructure, tend to cluster where firm capacity, network quality, and enabling regulation are in place. At the same time, rapid population growth in many low-consumption regions can mechanically dampen per-capita gains even when total electricity supply increases,

Figure 1

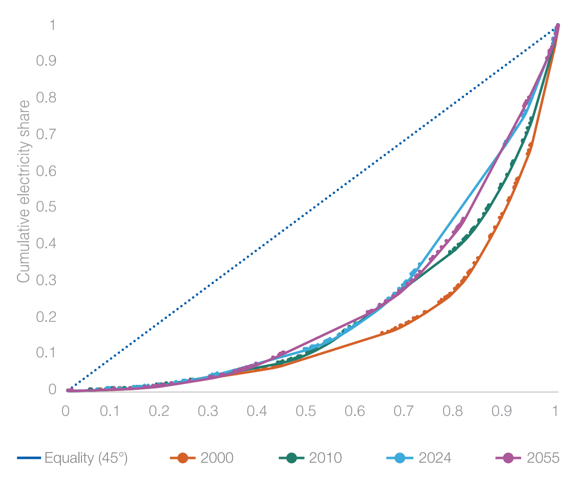
Gini index for per capita electricity demand and final energy consumption (2000-2055)



Source: GECF Secretariat based on data from the GECF GGM

Figure 2

Per capita electricity demand Lorentz curves



Source: GECF Secretariat based on data from the GECF GGM

reinforcing a "two-speed" electrification outcome in per-capita terms. The net effect is that continued progress in basic electrification is not sufficient to offset the concentration of incremental, high-load electricity demand, resulting in the observed plateauing and mild re-divergence in electricity inequality by 2055.

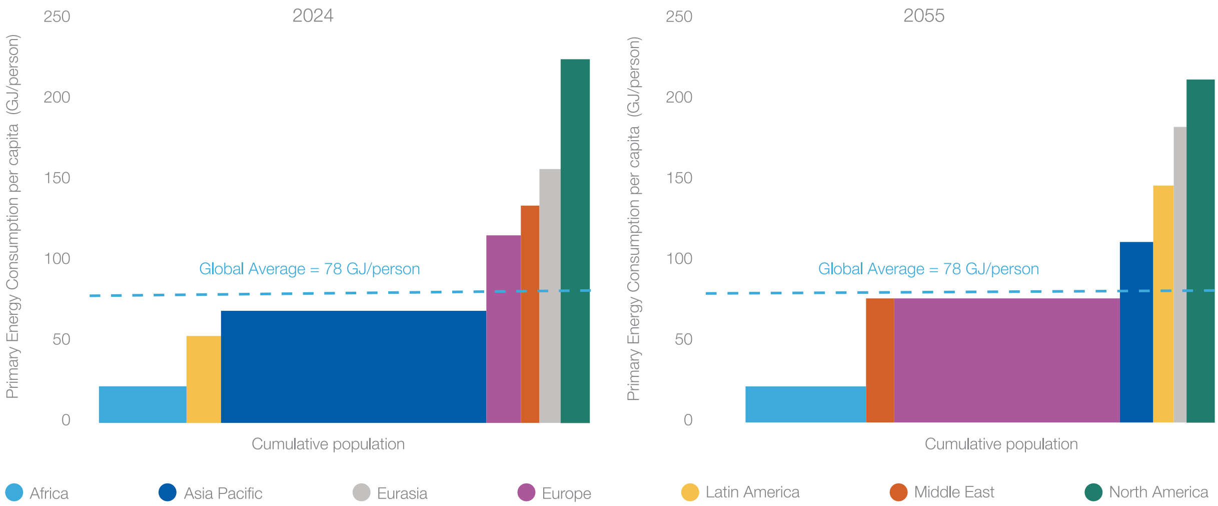
The Lorenz curves for electricity demand per capita, depicted in Figure (2), deepen this interpretation by showing where in the distribution the future re-divergence emerges. In 2000, the Lorenz curve was strongly bowed: the bottom 80% of the global population accounted for only 29% of electricity demand, while the top 20% accounted for 71%; the top 10% held 48%, and the top 1% about 7%. By 2024, the curve shifts markedly toward equality, with the bottom 80% reaching 50% of electricity demand (and the top 20% correspondingly 50%), consistent with the historical decline in the Gini index. The outlook to 2055, however, shows a partial "re-bowing" in the upper part of the distribution: the bottom-80% share falls back to 45% and the top-20% share rises to 55%, while the top-1% share increases from 4% in 2024 to 5% in 2055. Importantly, the Lorenz curves indicate that this does not arise from a simple surge of the very top alone, but from a redistribution within the upper half of the global population. Between 2024 and 2055, the consumption share of the 50–80th percentile drops from 38% to 31% (a decline of roughly 7 percentage points), while the 80–90th percentile share rises from 19% to 25% (an increase of about 6 percentage points), alongside the rise in the top-1% share. Meanwhile, the bottom 50% improves from 12% (2024) to 14% (2055), suggesting that basic electricity consumption continues to expand among lower-consumption populations, even as a broader group of higher-consumption economies captures a growing share of incremental demand. This combination, continued gains at the lower tail, coupled with a strengthening of the upper quintile, provides a distributional rationale for why the electricity Gini can increase slightly even when parts of the distribution continue to improve.

The central implication is that electrification of increasingly non-substitutable energy services is likely to remain uneven: gains in basic access and low-level consumption do not automatically translate into convergence in the electricity-intensive services that are becoming integral to modern living standards and competitiveness. Consequently, incremental electricity demand, and thus investment requirements and the need for firm capacity, geographically concentrated through 2055.

Policy responses should therefore evolve from expanding access alone toward enabling affordable, reliable, and scalable electricity consumption in lower-consuming regions, as future inequality is increasingly shaped by gaps in grid quality, system adequacy, and the capability to support electricity-dependent services such as digitalisation and cooling. This calls for prioritising transmission and distribution investment, reducing losses, strengthening utility performance and regulatory frameworks to improve bankability, and mobilising targeted finance to de-risk capacity and network upgrades, while protecting vulnerable consumers through well-designed tariffs and social support. In parallel, governments should proactively manage fast-growing large loads, including data infrastructure, via connection standards, locational incentives, and flexibility requirements to ensure they do not crowd out broader electrification. Finally, scaling energy-efficiency standards (notably for cooling, buildings, appliances, and data centres) and strengthening regional interconnections and power trade can reduce system stress and costs, supporting a more even distribution of electrification gains through 2055.

Figure 3.20

Regional primary energy consumption per capita forecast (2024 vs. 2055) (GJ/person)



Source: GECF Secretariat based on data from the GECF GGM

Against this backdrop, **global average primary energy consumption per -capita, a commonly used proxy for energy access, is projected to remain broadly constant at around 78 GJ per person over the outlook period** (Figure 3.20). While this apparent stability reflects improvements in energy efficiency at the global level, it masks pronounced regional disparities driven by divergent population growth rates, economic structures, and patterns of energy use. Aggregate averages therefore obscure the fact that rising energy consumption in high-income regions coexists with persistent energy deprivation elsewhere.

Regional contrasts in per-capita energy consumption remain stark. In 2024, Africa recorded the lowest level of primary energy consumption, at just 23 GJ per person, underscoring the scale of unmet energy needs across the continent. Despite accounting for around 18% of the global population, Africa's per -capita energy use was approximately nine times lower than that of North America, which registered the highest level globally at around 224 GJ per person. North America, home to only about 6% of the world's population, consumed a disproportionately large share of global energy, reflecting its advanced industrial base, widespread electrification, high levels of mobility, and energy-intensive lifestyles. Europe, Eurasia, and the Middle East also recorded above-average per-capita energy consumption, driven by a combination of industrial activity, climatic requirements, and established patterns of energy use.

By contrast, Africa, Latin America, and the Asia Pacific region, together accounting for around 80% of the global population in 2024, remain below the global average in per-capita energy consumption. In many of these regions, limited infrastructure, continued reliance on traditional biomass, and lower levels of economic development constrain access to modern energy services. These disparities underline that the challenge facing the global energy system is not one of excessive energy use alone, but of unequal access and uneven distribution. Addressing this imbalance will be critical to achieving inclusive growth and meeting sustainable development objectives, requiring a shift from focusing solely on efficiency improvements toward a broader agenda centred on energy addition, access expansion, and affordability alongside efficiency gains.

Under the RCS, global primary energy consumption per- capita is projected to stabilise through coming three decades, reflecting a growing divergence between efficiency-driven demand moderation in developed countries and rising energy needs in developing regions. At the global level, continued improvements in energy productivity largely offset population growth, resulting in a broadly flat average per-capita energy footprint. However, this apparent stability conceals persistent regional imbalances, with convergence occurring only gradually and unevenly across regions.

In developed countries, notably Europe and North America, per-capita energy consumption is projected to trend downward over the outlook period. This decline is driven predominantly by structural reductions in primary energy demand rather than demographic change, reflecting efficiency gains, electrification, and a shift toward less energy-intensive economic activity. Nonetheless, these regions are expected to remain among the most energy-intensive globally, given their high levels of mobility, extensive infrastructure, advanced industrial bases, and energy-intensive consumption patterns associated with elevated living standards.

In contrast, several developing regions, including Eurasia, the Middle East, Asia Pacific, and Latin America, are projected to experience rising per-capita energy consumption. This increase reflects ongoing economic expansion, urbanisation, and industrial development, alongside the gradual extension of modern energy services. Growth in per-capita demand is particularly influenced by expanding energy-intensive activities, including heavy manufacturing, resource extraction, refining, and petrochemicals, as well as rising electricity demand linked to higher incomes and improved access. The scale and pace of these increases vary widely across regions, shaped by domestic policy choices, resource endowments, and the speed of technology adoption.

Africa follows a distinctly different trajectory. Despite rapid population growth and steadily rising total energy demand, increases in per -capita energy consumption remain limited over the forecast period. This outcome reflects persistent structural constraints, including insufficient energy infrastructure, limited access to electricity and clean fuels, and continued reliance on traditional and inefficient energy sources. As a result, even by 2055, per-capita energy consumption in Africa, alongside that of Latin America and parts of the Asia Pacific, remains below the global average, despite these regions collectively accounting for nearly 80% of the world's population.

Taken together, these trends indicate that while regional disparities in per-capita energy consumption narrow modestly over time, significant inequalities persist. The stabilisation of global average pe -capita energy use therefore does not signal convergence in energy welfare but rather highlights the coexistence of declining energy intensity in developed countries and constrained energy access in developing regions. Addressing this imbalance, particularly in Africa, will require a sustained focus on energy access, infrastructure investment, and affordability, alongside efficiency improvements, to ensure that rising energy demand translates into meaningful socio-economic development over the long term.

3.7 Outlook for energy-related emissions

Global energy-related emissions rose by about 0.85% in 2024, reaching 41.2 $GtCO_2e$. This uptick underscores the continuing tension between the rapid expansion of renewables and the persistence of high-carbon infrastructure. While the world's coal-fired power capacity increased only marginally, marking its smallest annual rise in two decades, new projects in the Asia Pacific, particularly in China and India, offset retirements elsewhere and pushed global capacity to a higher level.

This outcome illustrates the mixed character of the current energy transition pathways. Renewable power capacity expanded by around 15% in 2024, the fastest pace on record, yet much of this growth was absorbed by rising electricity demand rather than displacing existing generation. Delays in coal-fired power plant retirements in several developed countries, combined with high financing costs and policy uncertainty in developing countries, further constrained near-term progress and slowed the pace of substitution.

Despite these short-term headwinds, structural improvements continued. Looking ahead, **the RCS projects a sustained decline in emissions, around 23% by 2050 and 26% by 2055 relative to 2024 levels, as total energy-related emissions fall from 41.2 $GtCO_2e$ in 2024 to 31.5 $GtCO_2e$ in 2050 and 30.3 $GtCO_2e$ in 2055.** This reduction is expected to be driven by progressive structural and technological shifts already under way, including the continued expansion of low-carbon power sources, efficiency gains across end-use sectors, and the broader uptake of digital solutions and carbon-management technologies. Natural gas is set to play a stabilising role, complementing renewables and replacing higher-carbon fuels across power generation, transport, and industry.

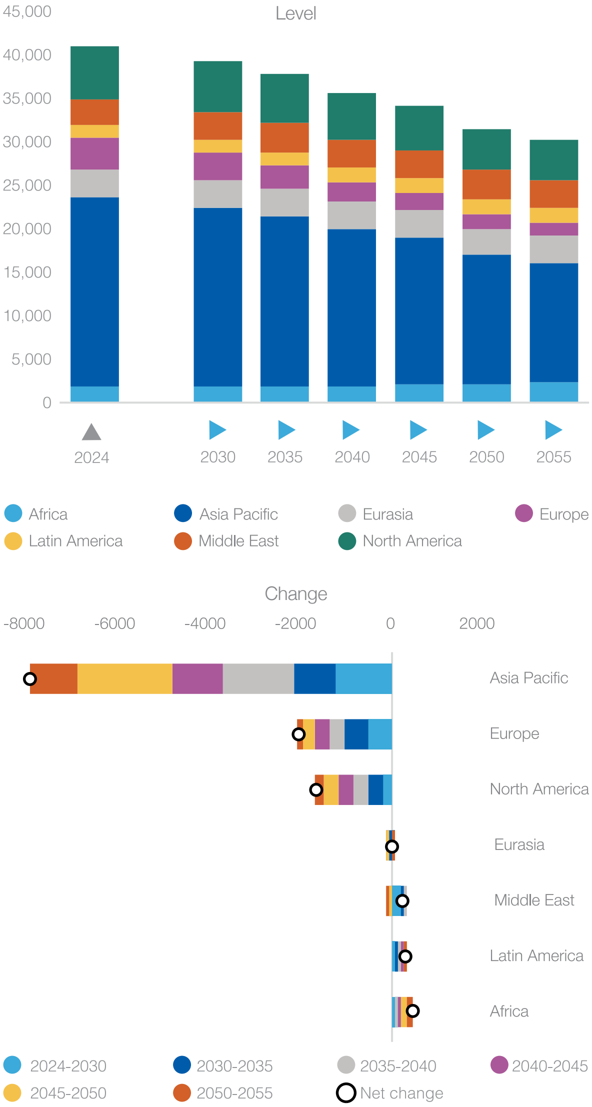
However, these updated projections also indicate a slightly slower pace of decarbonisation than last edition of the GGO, which had estimated emissions of 31.2 $GtCO_2e$ in 2050. This moderation largely reflects persistent policy uncertainty and elevated capital costs that continue to constrain clean-energy investment, particularly in developing countries. Throughout 2024, several countries revised, postponed, or scaled back elements of their transition agendas in response to economic headwinds, geopolitical tensions, and supply security concerns. As a result, near- and medium-term emissions pathways have been reassessed to reflect slower policy implementation and a more prolonged reliance on high-carbon infrastructure.

As illustrated in Figure 3.21, the projected decline is shaped by substantial contributions from key regions, each playing a distinct role in steering global emissions downward. Of the global reduction of around 10.9 $GtCO_2e$ in energy-related emissions between 2024 and 2055, the Asia Pacific accounts for the largest share, with emissions declining by nearly 8 $GtCO_2e$ over the outlook period. This trajectory is underpinned by a structural shift away from coal, large-scale renewable deployment, and an increasing reliance on natural gas to provide a flexible, lower-carbon supply. The region's decarbonisation remains progressive but uneven, with China and India balancing energy security priorities against the growing requirements of renewable integration.

Europe follows with a cumulative reduction of about 2.1 $GtCO_2e$, supported by binding policy frameworks, high carbon prices, and accelerated electrification of end-use sectors. The pace moderates in later decades as the region approaches saturation in efficiency improvements and in the most readily deployable renewable potential.

Figure 3.21

Global energy-related emissions outlook by region, 2024-2055 ($MtCO_2e$)



Source: GECF Secretariat based on data from the GECF GGM

Note: Energy-related emissions include both combustion-related emissions and fugitive emissions of CO_2 and methane from energy sector

North America records total reductions of around 1.7 GtCO2e, reflecting continued technological progress but a comparatively slower policy-driven transition. In the United States, regulatory uncertainty, changes to some climate measures, and delays in energy-efficiency improvements and methane-abatement regulations weaken long-term momentum. Nevertheless, natural gas and renewables together continue to displace higher-carbon fuels, while industry-led innovation, including CCUS and digital energy management, helps keep overall emissions on a downward trajectory.

In contrast, Africa, Latin America, and the Middle East register modest emissions increases as energy demand rises alongside population growth and economic expansion. Africa's increase of about 0.46 GtCO2e reflects stronger population growth, expanding energy access, electrification, and industrialisation, albeit from a low starting base. Latin America adds around 0.27 GtCO2e, driven mainly by transport and industry, while the Middle East increases by about 0.21 GtCO2e, as new industrial and petrochemical capacity expands faster than low-carbon deployment. Across all three regions, natural gas development and renewable expansion play pivotal roles in meeting growing demand more efficiently and in limiting the rate of emissions growth. Eurasia remains broadly stable, with only minor net variations linked to shifts in production and export patterns, consistent with a more static underlying energy structure. Overall, the regional results point to a dual global dynamic: developed countries continue to decarbonise steadily under mature policy frameworks, while developing regions experience rising energy demand that is moderated by gradual efficiency gains and diversification.

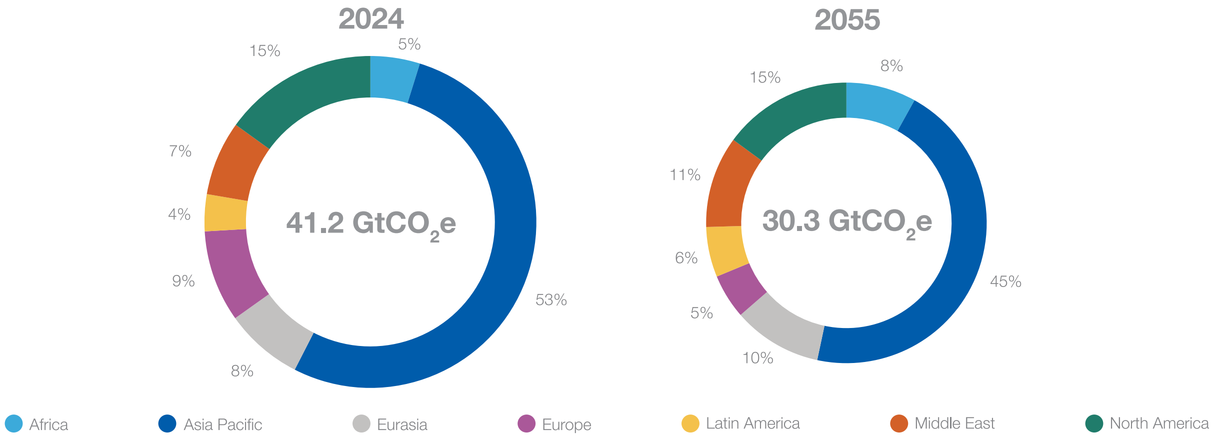
Figure 3.22 depicts projected regional contributions to global energy-related emissions in 2024 and 2055. The regional composition of global energy-related emissions in 2024 remains highly uneven, with Asia Pacific accounting for approximately 53% of the total. This reflects both the scale of energy demand and the concentration of high-emitting economies within the region. While China continues to account for the largest single share globally, other major Asian countries, particularly India, Indonesia, Viet Nam, Malaysia, and the Philippines, have also contributed to sustained emissions growth in recent years. Collectively, these countries have pushed regional emissions to record levels, with the Asia Pacific accounting for more than half of the world's total energy-related emissions in 2024. This indicates that global emissions dynamics are increasingly shaped by a broader set of fast-growing Asian countries rather than by China alone. By 2055, the Asia Pacific is projected to retain the largest share, but at a lower level of around 45%, as relative contributions shift across regions.

Europe and North America together represent roughly 24% of global emissions in 2024, declining to about 20% by 2055, reflecting sustained decarbonisation and slower demand growth. Over the same period, the combined share of Africa, Latin America, the Middle East, and Eurasia rises from around 24% to about 35%, driven by rising energy demand in developing countries as population, urbanisation, and economic activity expand. These contrasts underscore differences in stages of economic development, the pace of energy-transition progress, and the capacity to implement and finance policy measures across regions.

Overall, the comparison between 2024 and 2055 points to a gradual geographic rebalancing of emissions. Asia Pacific remains the central contributor, but its relative dominance narrows as emissions decline in developed

Figure 3.22

Projected regional contribution to global energy-related emissions, 2024 and 2055 (%)



Source: GECF Secretariat based on data from the GECF GGM

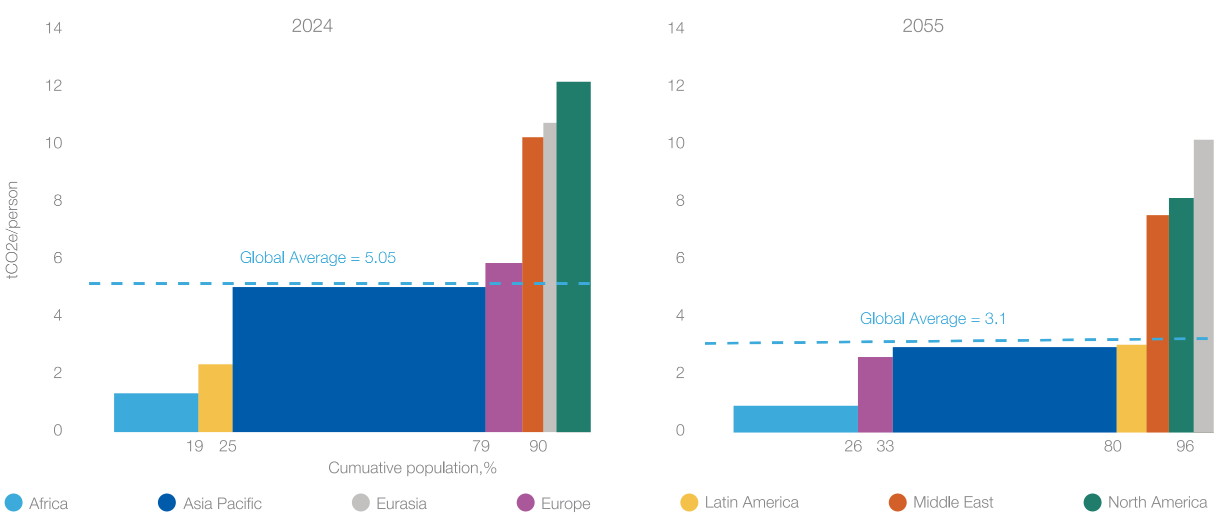
countries and increase in several developing regions in line with stronger growth in economic output and population.

When viewed on a per-capita basis, disparities in energy-related emissions across regions remain pronounced. In 2024, as illustrated in Figure 3.23, global per-capita emissions stood at approximately 5.05 tonnes of CO_2 per person, with wide variation across regions. The majority of the global population, concentrated in Africa, Latin America, and parts of the Asia Pacific, continued to emit well below this level. Africa, for instance, representing around 18% of the global population in 2024, recorded emissions of roughly 1 tonne of CO_2 per person per year, compared with levels roughly ten times higher in North America. These contrasts underscore the highly uneven distribution of per-capita emissions and reflect differing stages of economic development, industrialisation, and energy access.

Looking ahead, **global per-capita emissions are projected to decline to around 3.1 tonnes of CO_2 per person by 2055, even as population and energy demand continue to expand.** This reduction is mainly underpinned by substantial declines in Asia Pacific, North America, and Europe, which currently account for the bulk of global emissions. Europe's per-capita emissions are expected to fall well below the global average by 2055, while Asia Pacific is anticipated to converge toward it, driven primarily by the rapid expansion of low-carbon power generation and broad-based efficiency gains across the region.

Figure 3.23

Projected energy-related emissions per capita in 2024 and 2055 (tCO_2e/person)



Source: GECF Secretariat based on data from the GECF GGM

In contrast, Africa and Latin America are projected to experience moderate increases in per-capita emissions as energy access, electrification, and industrial activity expand from low starting points. By 2055, around 87% of the global population is expected to live in regions emitting below the world average, up from roughly 80% in 2024, signalling a measurable narrowing of disparities. Overall, these shifts point to a gradual convergence in per-capita emissions worldwide. However, differences in development trajectories, investment capacity, and the speed of decarbonisation will continue to shape regional pathways and the prospects for a more balanced and equitable transition.

Over the outlook period, despite continued growth in population, economic activity, and energy consumption, CO_2 emissions are projected to decline by around 1% per year, signalling a sustained decoupling of energy use from CO_2 emissions. At the global level, the upward pressure on emissions from population and economic growth is expected to be offset by improvements in energy efficiency (higher economic output per unit of energy consumed) and declines in carbon intensity (lower emissions per unit of energy consumed), reflecting both structural change and technological progress.

However, these global trends mask significant regional differences linked to varying stages of development. The decoupling pattern is most consistent with trajectories in Europe, North America, and parts of the Asia Pacific, where populations are ageing or declining and economic growth is expected to moderate, reinforcing the impact of efficiency and decarbonisation policies. By contrast, Africa, the Middle East, and Latin America are projected to face stronger population growth and more robust economic expansion, which raises the scale of energy-system buildout required and makes emissions reductions through efficiency gains and decarbonisation strategies more challenging at their current stages of development. Many of these regions remain in earlier phases of industrialisation and still contribute a smaller share of global CO_2 emissions than more developed countries, but their pathways will increasingly shape the global distribution of emissions, and the equity dimensions of the transition, over the coming decades.

To contextualise this disparity, historical emissions provide critical insight into global responsibility for addressing climate change. Between 1850 and 2024, North America and Europe accounted for 57% of cumulative global CO_2 emissions, reflecting their early industrialisation and prolonged reliance on hydrocarbons. By contrast, Africa and Latin America contributed just 3% and 5%, respectively, highlighting their limited historical responsibility. This imbalance underscores the unequal contributions to global emissions, with Africa's minimal per capita emissions reflecting limited energy access and economic development. At the same time, North America and Europe bear a heavier cumulative and per capita emissions burden.

Looking forward, Figure 3.24 illustrates the sectoral contributions to global CO_2 emissions and their projected trends through 2055. **Global CO_2 emissions decline steadily across the projection period, falling from around 37.7 $GtCO_2$ in 2024 to below 27.9 $GtCO_2$ by 2055, driven primarily by structural changes in the power generation sector.** However, sectoral dynamics reveal contrasting trajectories: some areas decarbonise rapidly, while others remain relatively emissions-intensive due to structural and technological constraints.

Power generation remains the dominant source of global energy-related CO_2 emissions, while also delivering the largest absolute decline over the outlook. Cumulative reductions are estimated at around 6.4 $GtCO_2$ between 2024 and 2055. The sector remains the largest emitter throughout, but its share drops sharply, from 34% in 2024 to 23% in 2055, as absolute emissions fall by more than 6.3 $GtCO_2$. This steep decline reflects the continuing shift away from coal toward renewables and natural gas, alongside efficiency improvements in thermal generation. Decarbonisation accelerates after 2045, as ageing high-carbon capacity is retired and renewable deployment intensifies.

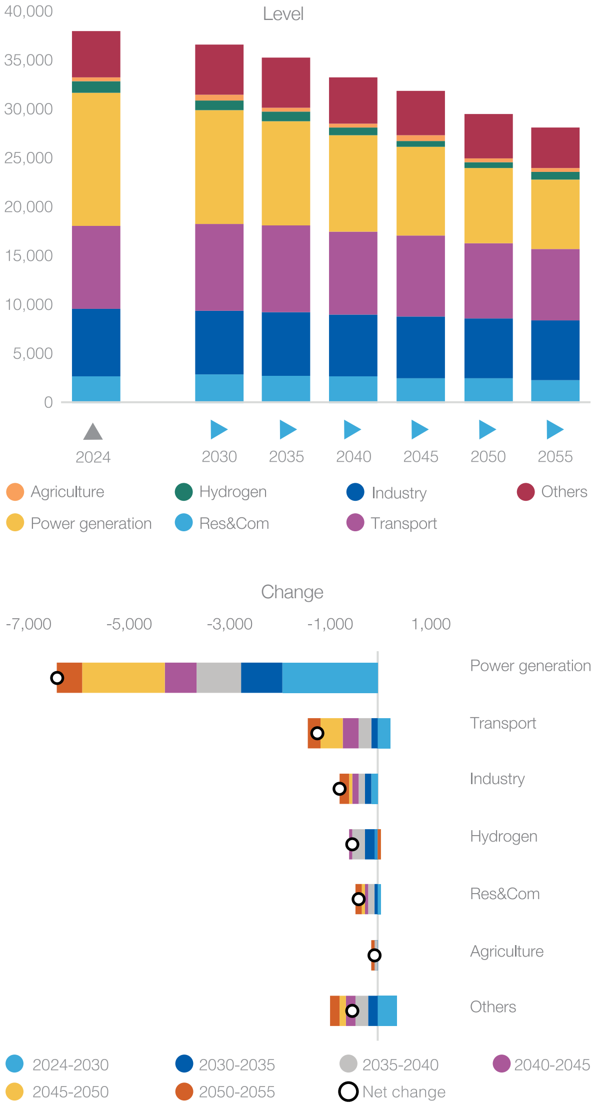
Transport is expected to become the largest emitting sector from 2050, rising in relative importance from 23% to 26% of global energy-related CO_2. Emissions decline more slowly than in the power sector, with total reductions projected at around 1.2 $GtCO_2$. Early progress is constrained by continued reliance on oil-based fuels in aviation, shipping, and heavy freight, but electrification and efficiency gains in light-duty vehicles drive stronger reductions after 2035. The sector's mitigation potential expands in later decades as EV penetration deepens and low-carbon fuels scale up.

Industrial CO_2 emissions are projected to decline by around 0.8 $GtCO_2$ over the outlook period, reflecting incremental but still meaningful progress through efficiency improvements, fuel substitution, and the gradual diffusion of cleaner production technologies. These reductions are primarily driven by improved process efficiency, partial electrification, and the selective deployment of carbon capture technologies in energy-intensive sectors such as cement and steel. Nevertheless, a substantial volume of residual emissions persists, as many industrial processes remain technologically or economically constrained from full electrification or fuel switching. This persistence highlights the structural challenges faced by heavy industry and sets the context for the growing role of complementary mitigation options, including hydrogen and broader carbon management.

Against this backdrop, hydrogen is expected to evolve from a small but growing source of emissions into a net contributor to mitigation over time, delivering cumulative emissions reductions of around 0.5 $GtCO_2$ by 2055. This shift is underpinned by the progressive replacement of

Figure 3.24

Global CO_2 emissions outlook by sector, 2024-2055 ($MtCO_2$)



Source: GECF Secretariat based on data from the GECF GGM
Note: Others include district heating, refineries, coke ovens, energy sector own use and losses and fugitive CO_2 emissions

grey hydrogen with low-carbon alternatives, including renewable-based electrolysis and natural-gas-based hydrogen equipped with carbon capture technologies. While deployment is set to remain gradual, hydrogen increasingly supports emissions reductions in industrial processes, refining, and selected transport applications, particularly in segments where direct electrification remains limited and where substitution options are narrower.

A similar pattern of delayed but accelerating mitigation is observed in the residential and commercial sectors. Emissions from buildings are projected to decline by nearly 0.4 $GtCO_2$ by 2055, with most reductions occurring after 2035 as electrification of heating, improved building envelopes, and higher appliance efficiency become more widespread. In the near term, emissions continue to grow due to expanding floor space and rising energy demand in developing countries, before efficiency gains and electrification effects begin to dominate. This lagged response reflects the long lifetimes of buildings and heating systems, which slow the pace of structural change and delay the turnover of capital stock.

By contrast, agricultural energy-related emissions show limited scope for deep reductions over the outlook period. Emissions in this sector are expected to remain broadly stable, with only modest reductions of around 0.08 $GtCO_2$ by 2055. Improvements in energy efficiency in mechanisation, irrigation, and fertiliser production are largely offset by rising demand for agricultural energy services in developing countries, underscoring the limited mitigation potential of efficiency measures alone in this sector and the importance of wider structural and technology shifts beyond efficiency.

Taken together, these sectoral dynamics explain why the bulk of emissions reductions remain concentrated in a small number of areas. Across all sectors, total energy-related CO_2 emissions are projected to decline by nearly 11 $GtCO_2$ between 2024 and 2055, with more than 60% of these reductions occurring in the power generation sector. Power systems decarbonise more rapidly due to the scale-up of renewables, coal-to-gas switching, and the deployment of carbon capture technologies, while emissions reductions in industry, transport, and buildings are expected to accelerate in the later periods of the outlook—yet at a slower pace and from a more structurally constrained starting point.

These differentiated pathways illustrate that the global energy transition is not a single, uniform process but a set of interconnected transformations unfolding at different speeds across sectors and regions. Power generation leads the decarbonisation process, while industry progressively adopts cleaner production methods, transport transitions gradually toward electrification and alternative fuels, and the residential sector improves efficiency over time, particularly through electrification. Emerging technologies—especially hydrogen and carbon management—begin to scale more visibly toward mid-century, even if their near-term impact remains limited and uneven across regions.

Within this evolving system, natural gas plays a unifying and enabling role across multiple sectors. Its historical contribution to emissions reduction demonstrates its effectiveness in replacing higher-carbon fuels, improving power system efficiency, and enhancing air quality. These benefits are most visible in electricity systems, where the flexibility and dispatchability of gas-fired generation support the rapid expansion of variable renewables without compromising grid stability, adequacy, or operational reliability.

The importance of this flexibility intensifies as global electricity demand accelerates, driven by digitalisation, data centres, electric mobility, and urban expansion. While renewable capacity continues to scale rapidly, its variable output necessitates reliable and responsive generation sources. In many markets, natural gas fulfils this balancing role, helping prevent a reversion to coal and supporting system reliability. At the same time, in industry, natural gas remains essential for processes requiring high-temperature heat or specific chemical feedstocks, enabling emissions reductions to proceed without undermining industrial competitiveness, affordability, or broader economic development objectives.

This enabling role is further strengthened when natural gas is combined with CCUS. Carbon capture, utilisation and storage unlocks deeper emissions reductions in both power generation and hard-to-abate industrial activities, while also underpinning large-scale production of low-carbon hydrogen. Blue hydrogen, in particular, can offer a cost-effective pathway for decarbonising heavy industry, long-haul transport, and chemical production during the transition period in which renewable-based hydrogen remains constrained by cost, infrastructure, and availability. **Under the RCS, global CCUS capacity could reach around 1.4 GtCO_2 per year by 2055, with natural-gas-based applications accounting for approximately 30%,** supported by supportive policy incentives, innovative business models, and maturing project pipelines across both developed and developing countries.

Finally, maximising the climate benefits of natural gas requires sustained progress in reducing methane emissions across the supply chain. In 2024, methane emissions are estimated at around 3.44 GtCO_2e, equivalent to roughly 8% of global energy-related emissions. Under the RCS, methane emissions are projected to decline to around 2.39 GtCO_2e by 2055, reflecting improvements in leak detection and repair, operational practices, infrastructure upgrades, and the wider adoption of certified low-emission gas. These reductions represent some of the most cost-effective mitigation opportunities available and are critical to reinforcing the credibility of natural gas as part of environmentally responsible, just, and orderly energy transition pathways.

4 Natural Gas Demand Outlook

Highlights

- Global natural gas demand increases by around 31% (27% CAGR), rising from 4,134 bcm in 2024 to nearly 5,417 bcm by 2055, corresponding to an average annual growth rate of about 0.9%. Growth is driven by structural shifts toward applications where gas delivers high efficiency, flexibility, and system value.

- Power generation is the main source of incremental demand, with gas consumption rising by around 641 bcm to reach approximately 2,100 bcm by 2055, accounting for just over half of global demand growth. Gas-fired generation is expanding at around 1.2% per year, supported by electrification, renewable integration needs, rising peak loads, and climate-related system risks.

- Industrial demand increases by around 296 bcm, reaching about 1,200 bcm by 2055, and remains the second-largest consuming sector. Growth is underpinned by infrastructure expansion in developing countries, continued fuel switching, clean-energy technology manufacturing, and the progressive deployment of CCUS in hard-to-abate industries.

- Transport records the fastest growth rate, with demand rising by 208 bcm to approximately 380 bcm by 2055, increasing its share from 4% to about 7%. Growth is concentrated in heavy-duty road transport and maritime shipping, where LNG and CNG offer cost-effective and lower-emissions alternatives to oil-based fuels.

- Natural gas demand for hydrogen generation increases by 127 bcm, reaching just over 390 bcm by 2055, and accounting for around 10% of incremental demand. Growth is driven mainly by fertiliser production and refining, alongside a gradual shift from grey to blue hydrogen with CCUS.

- Asia Pacific absorbs around 43% of global demand growth, with consumption rising to about 1,516 bcm by 2055, driven by electrification, coal-to-gas switching, air-quality policies, fertiliser demand, and emerging loads from cooling, digital infrastructure, and transport.

- Europe is the only region with a net decline, falling from around 460 bcm in 2024 to roughly 370 bcm by 2055, although demand rebounds in the medium term due to power-sector needs, easing gas prices, rising carbon prices, coal phase-outs, and slower renewable deployment.

- North America's demand is front-loaded, increasing through the late 2020s before stabilising and declining modestly, remaining slightly above 2024 levels by 2055, supported by power demand, LNG exports, and system-balancing needs.

- The Middle East accounts for about 23% of global growth, with demand rising to nearly 887 bcm by 2055, driven by oil-to-gas switching in power, petrochemicals and fertilisers, and LNG liquefaction own-use.

- Africa shows the fastest growth, at around 2.4% per year, with demand more than doubling to nearly 364 bcm by 2055, driven by electrification, power-sector expansion, industrialisation, and the transition from traditional biomass to LPG.

4.1 Natural gas demand outlook

Global natural gas demand increased by nearly 90 bcm in 2024, reaching a new all-time high of 4,134 bcm, despite a turbulent geopolitical and macroeconomic environment (Figure 4.1). With growth of around 2.2% year on year, natural gas demand returned to its long-term structural growth trajectory, signaling a broad-based rebalancing across the global energy system. As a result, natural gas accounted for around one-third of the total increase in primary energy demand in 2024, second to renewables and reaffirming its central role in meeting incremental global energy needs.

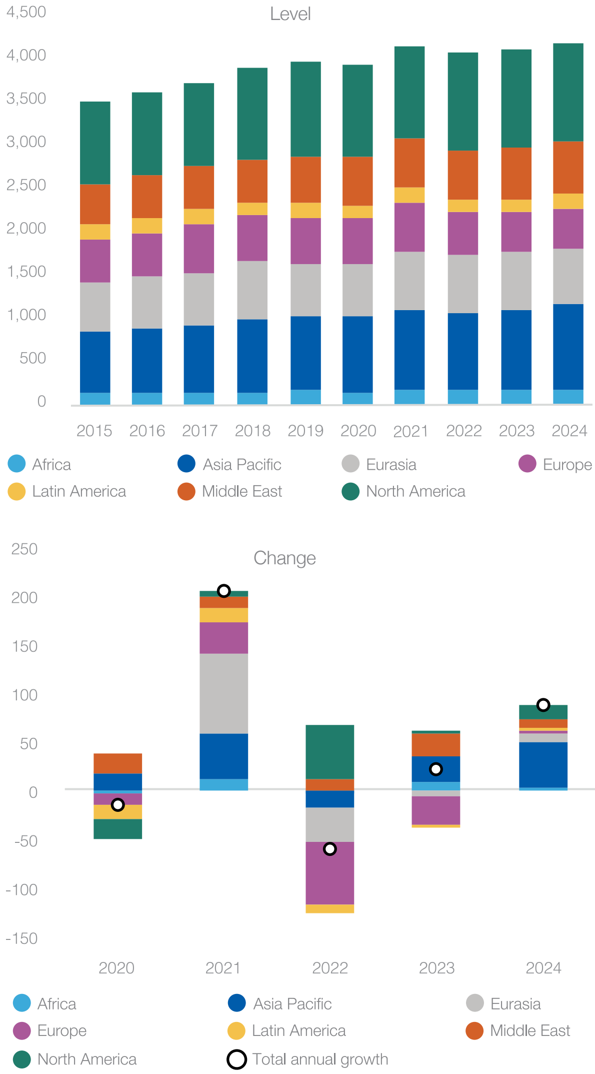
This expansion was driven by a combination of traditional demand centres and emerging sources of consumption. In the Middle East, continued oil-to-gas switching in power generation supported demand growth, while in China, rising LNG consumption in the transport sector, reflecting the rapid expansion of LNG-fuelled trucks and buses, as well as growing LNG bunkering for shipping, provided an important new source of demand. These structural drivers coincided with short-term pressures from extreme weather events, which further reinforced gas consumption. Natural gas played a pivotal role in ensuring affordable and reliable heat and electricity supply during winter cold spells and summer heatwaves, while also serving as a critical backup fuel to mitigate hydropower variability in regions exposed to hydrological risks. Together, these factors underscored the resilience and flexibility of natural gas in responding to both cyclical shocks and longer-term structural shifts in global energy demand.

The Asia Pacific region was the primary driver of global natural gas demand growth in 2024, accounting for more than half of the net increase. China and India led this expansion, supported by continued economic growth, widespread heatwaves, and relatively lower spot LNG prices, which strengthened gas demand across power generation, industry, and transport. In China, higher gas-fired power generation during summer peak demand and the rapid expansion of LNG-fuelled heavy-duty vehicles were key contributors, while in India strong growth in industrial, refining, transport, and power-sector demand drove higher LNG imports.

The Middle East also recorded solid demand growth, underpinned by ongoing oil-to-gas switching in power generation, expanding LNG liquefaction capacity, and rising petrochemical feedstock use. North America saw moderate growth, driven mainly by higher gas burn in the power sector during peak cooling periods. Africa and Latin America contributed more modestly, reflecting incremental demand from new industrial projects and gas-fired power generation, often linked to hydropower shortfalls. In contrast, Europe's natural gas demand remained subdued, constrained by higher prices, continued efficiency improvements, and fuel switching toward renewables and nuclear, highlighting increasingly divergent regional demand dynamics.

Figure 4.1

Natural gas demand by region, 2015-2024 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

4.2 Global natural gas demand outlook

Global natural gas demand is projected to increase steadily from 4,134 bcm in 2024 to nearly 5,417 bcm by 2055, representing around 31% cumulative growth (27% CAGR) over the outlook period (Figure 4.2). This expansion is not driven by a single factor, but by the interaction of macroeconomic growth, energy-system transformation, decarbonisation imperatives, and structural changes in how energy is produced and consumed. Together, these forces shape both the scale of global energy demand and the functional role natural gas plays within increasingly complex and constrained energy systems (See box 4.1).

At the macro level, economic growth, population expansion, urbanisation, and deep electrification

Table 4.1

Global primary natural gas demand outlook by region, 2024-2055

	Levels (bcm)					Change (bcm)	Growth (% p.a.)	Share (%)	
	2024	2030	2040	2050	2055	2024-2055	2024-2025	2024	2055
Africa	175	206	281	351	364	188	2.4%	4%	7%
Asia Pacific	959	1,172	1,446	1,515	1,516	558	1.5%	23%	28%
Eurasia	665	698	768	827	863	198	0.8%	16%	16%
Europe	459	473	431	387	371	-88	-0.7%	11%	7%
Latin America	147	176	226	252	261	114	1.8%	4%	5%
Middle East	590	650	779	864	887	297	1.3%	14%	16%
North America	1,139	1,212	1,196	1,167	1,155	17	0.0%	28%	21%
World	**4,134**	**4,589**	**5,127**	**5,363**	**5,417**	**1,283**	**0.9%**	**100%**	**100%**

Source: GECF Secretariat based on data from the GECF GGM

continue to raise aggregate energy demand, particularly in developing economies where per-capita energy use remains well below developed countries' levels. Electrification of end-use sectors, transport, domestic, and industry, does not reduce energy demand in absolute terms; rather, it raises electricity consumption, increasing the need for reliable, dispatchable generation. This trend is reinforced by digitalisation and artificial intelligence, which simultaneously improve efficiency across the gas value chain through automation, monitoring, and optimisation, while also creating new, highly load-sensitive electricity demand via data centres, cloud computing, and digital infrastructure. The result is structurally higher and more volatile power demand, strengthening the system value of natural gas as a flexible and reliable energy source.

Within this expanding demand envelope, energy efficiency improvements alter the quality and allocation of gas use rather than eliminating it. The deployment of high-efficiency CCGT plants, modern industrial furnaces, advanced boilers, and upgraded district heating systems increases the productivity of gas consumption and improves its competitiveness relative to alternative fuels. Rather than driving demand contraction, efficiency gains enable gas to retain and expand its role in sectors where electrification is technically constrained or economically inefficient, particularly in energy-intensive industries such as cement, iron and steel, chemicals, and refining.

A critical structural shift underpinning long-term demand growth is the reallocation of natural gas across sectors. As direct use in residential and commercial sectors gradually declines in some regions, gas is increasingly concentrated in transformation and industrial sectors, notably power generation, where its flexibility, high utilisation rates, and system-balancing capability are most valuable. In power systems characterised by rising shares of variable renewables and tighter carbon constraints, natural gas provides essential services, ramping, reserve capacity, and reliability, that are not yet substitutable at scale by storage or other low-carbon alternatives.

Decarbonisation objectives further reinforce this trajectory. Relative to coal and oil products, natural gas delivers immediate and substantial reductions in CO_2 emissions and near-elimination of local air pollutants such as SO_2, NO_x, and particulate matter. This makes gas a preferred option for rapid emissions abatement and air-quality improvement, particularly in urban and industrial centres. Consequently, coal-to-gas switching in power generation and industry remains a central decarbonisation and flexibility pathway, while the growing complementarity between natural gas and variable renewables, including hydropower, enhances system resilience and reduces the overall cost of integration.

A further pillar supporting long-term natural gas demand is the combination of expanding system versatility and the persistence of structurally embedded uses across value chains. While natural gas increasingly demonstrates versatility through its growing role in power-system flexibility, transport, and clean cooking, its demand base is simultaneously reinforced by long-standing applications that remain technically and economically difficult to substitute. In particular, natural gas continues to underpin hydrogen production for ammonia and urea manufacturing, sustaining fertiliser supply and food security, especially in major agricultural economies. It also remains indispensable in refining operations, notably hydrotreating and desulphurisation, where it is required to meet tightening fuel-quality and environmental standards. These uses do not represent an expansion of versatility, but rather a durable structural foundation of demand that persists even as energy systems transform.

Asia Pacific is projected to account for the largest share of global natural gas demand growth over the outlook period, absorbing around 43% of the total net increase, with regional consumption expanding at an average rate of approximately 1.5% per year (Table 4.1). This growth is underpinned by a combination of structural and emerging drivers. On the structural side, rapid electrification, sustained coal-to-gas switching in power generation and industry, efforts to reduce air pollution, and expanding fertiliser production, to support food security, remain the primary sources of demand. At the same time, emerging drivers are gaining prominence, including rising air-conditioning ownership driven by urbanisation and warming climates, the expansion of digital infrastructure and data centres, and the growing use of LNG and CNG in road transport and maritime shipping.

The Middle East is projected to be the second-largest contributor to global natural gas demand growth, accounting for around 23% of the net increase over the outlook period, with regional demand expanding at an average rate of approximately 1.3% per year. This growth is driven primarily by rapid electrification and industrialisation, which are reshaping the region's energy mix. A key structural driver is the substitution of oil and other liquid fuels with natural gas in power generation, reflecting both cost-efficiency considerations and efforts to reduce emissions and free up oil for export. In parallel, expanding petrochemical and fertiliser production strengthens gas demand through its role as both a feedstock and a source of process energy. Additional growth is supported by rising own-use consumption in upstream and liquefaction facilities, as several countries continue to expand LNG export capacity.

Natural gas demand in **Eurasia** is projected to increase at an average rate of around 0.8% per year, reaching approximately 863 bcm by 2055 and accounting for nearly 15% of global net demand growth over the outlook period. This expansion is underpinned by the role of natural gas in supporting industrial development, system modernisation, and energy-efficiency improvements, particularly across economies seeking to upgrade legacy energy infrastructure. Wider gasification of end-use sectors, combined with the decarbonisation of coal-based heat and power generation, drives sustained demand while delivering significant air-quality benefits through the reduction of local pollutants. Natural gas also enhances power-system flexibility and reliability, especially as electricity demand grows and generation portfolios evolve. In addition, the continued deployment of natural gas vehicles, particularly in urban transport and commercial fleets, contributes to incremental demand growth, reinforcing gas's role in improving environmental performance and supporting economic activity across the region.

With an average annual growth rate of around 2.4%, **Africa** is projected to be the fastest-growing natural gas consuming region over the outlook period, despite starting from a relatively small base in global demand. This rapid expansion is primarily driven by accelerating electricity demand, underpinned by strong population growth, rapid urbanisation, and rising income levels, which necessitate significant additions to reliable and dispatchable power generation capacity. In this context, natural gas is increasingly utilised as a scalable and cost-effective fuel for power generation expansion, supporting grid stability while complementing variable renewable energy deployment. In parallel, efforts to address the region's clean cooking deficit are driving a structural shift away from traditional biomass toward LPG, which is widely regarded as the most immediately deployable and affordable clean cooking solution across much of the continent.

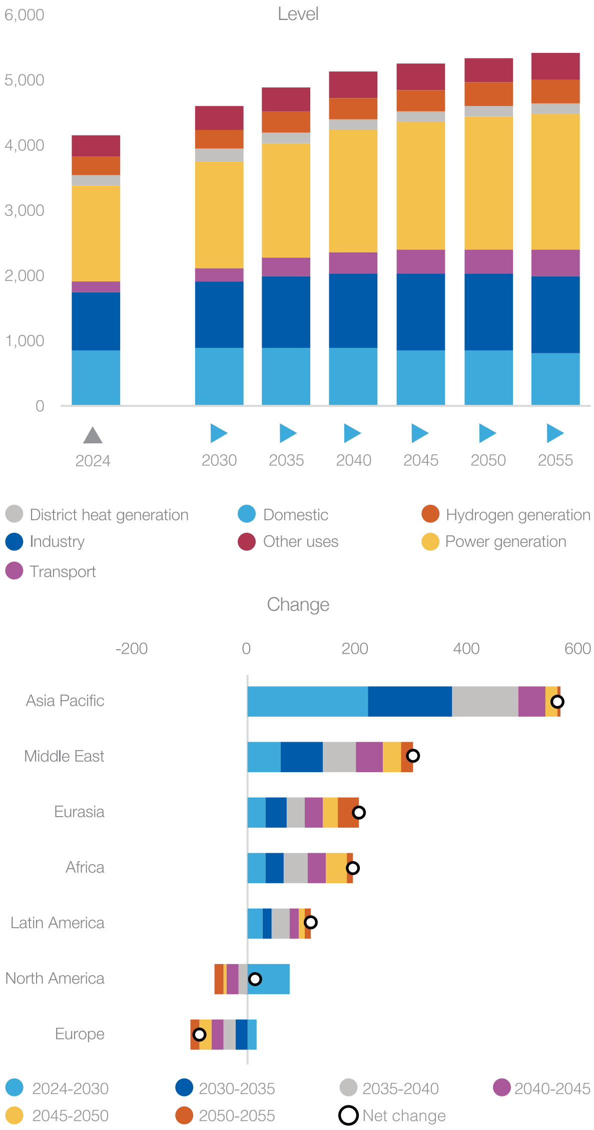
In **Latin America**, natural gas demand is projected to grow at an average rate of around 1.8% per year, accounting for approximately 9% of the net global increase over the outlook period. This expansion is driven by a combination of structural power-sector requirements, ongoing industrial fuel substitution, and the gradual expansion of gas-based value chains. In the power sector, natural gas plays an increasingly important role in providing flexibility and reliability in systems with high hydropower dependence and growing shares of variable renewables, particularly in markets exposed to hydrological volatility. In the industry, the competitive advantage of gas relative to fuel oil and coal supports higher utilisation of existing assets and underpins incremental investment in gas-intensive activities, including chemicals and fertilisers. At the same time, the pace and distribution of demand growth remain uneven, as infrastructure constraints, particularly in transmission, distribution, and LNG import capacity, continue to limit gas penetration in several markets, shaping a regionally differentiated demand trajectory.

North America's natural gas demand is strongly front-loaded, rising sharply through the late 2020s before entering a gradual decline toward the end of the outlook period. By 2055, demand is expected to remain slightly above 2024 levels, contributing modestly to net global growth. Near-term expansion is driven by rapidly rising electricity demand, particularly from data centres, AI-related digital infrastructure, and broader electrification, which sustain gas-fired generation as a critical source of reliability and flexibility. In parallel, strong LNG export growth, led by the United States, continues to support upstream production and midstream investment. Recent policy and regulatory shifts emphasising energy security and affordability, alongside a more measured pace of renewable deployment, further reinforce the structurally resilient role of natural gas in the regional energy mix.

Europe is the only region projected to record an overall decline in natural gas demand over the outlook period;

Figure 4.2

Primary natural gas demand outlook by region, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

however, this trajectory is distinctly non-linear. Rather than a continuous contraction, demand is expected to reverse in the medium term, following years of decline, before entering a gradual and moderate downward trend thereafter. Over the longer term, accelerated electrification, expanding renewable capacity, and sustained energy-efficiency gains exert downward pressure on direct gas use, while structural deindustrialisation in parts of the region further limits demand growth. In the medium term, however, a rebound in electricity demand, combined with easing global gas market conditions and lower hub-based prices, supports higher gas consumption, particularly in power generation. This effect is further reinforced by rising carbon prices, coal phase-out policies, and slower-than-expected renewable capacity deployment, particularly in offshore wind, which collectively enhance the relative competitiveness of natural gas as a dispatchable, lower-emissions generation option.

4.3 Sectoral trends

Over the coming decades, the pattern of natural gas consumption is expected to evolve structurally in line with the broader transformation of global energy systems toward higher efficiency, reinforced flexibility, expanded versatility, and lower emissions intensity. In this context, natural gas demand is shaped less by uniform volume growth and more by qualitative changes in how the fuel is deployed across sectors. Consumption increasingly concentrates in applications that maximise conversion efficiency, system responsiveness, and emissions performance per unit of useful energy delivered, reflecting the rising premium placed on flexibility and reliability in carbon-constrained and increasingly complex energy systems.

This transformation is driven by the interaction of market dynamics, policy frameworks, and technological progress. Together, these forces favour the use of natural gas that delivers high operational efficiency while providing system-level services that alternative fuels cannot yet supply at scale. Advanced CCGT power generation, modern industrial heat systems, and integrated energy hubs exemplify this shift, combining high thermal efficiency with fast-ramping, dispatchable capability. As a result, natural gas consumption becomes structurally cleaner and more efficient, not only through higher conversion efficiencies and the selective deployment of CCUS, but also through its reallocation toward roles where flexibility, scalability, and emissions mitigation are jointly optimised.

A key manifestation of this shift is the reallocation of gas demand away from rigid, price-inelastic, and politically sensitive end uses, particularly residential and commercial heating, toward system-critical applications. In many regions, electrification strategies explicitly prioritise these non-flexible sectors to reduce seasonal demand volatility and exposure to energy security risks. However, electrification does not eliminate natural gas demand; instead, it reshapes it. Rising electricity consumption, driven by digitalisation, air conditioning, desalination, and other load-sensitive services, intensifies the need for firm, dispatchable generation that intermittent renewables cannot yet provide reliably. In this setting, natural gas increasingly functions as a system-balancing asset within the power sector, deployed through high-efficiency technologies and, where applicable, CCUS, resulting in higher system efficiency and a lower carbon footprint.

Within this evolving structure, natural gas's role extends beyond direct combustion into transformation pathways that reinforce its system value. Blue hydrogen represents a key example: by converting natural gas into hydrogen with carbon capture, gas demand is embedded within lower-carbon value chains that support fertiliser production, refining, and selected hard-to-abate industrial processes. This pathway enables the decarbonisation of molecular energy use, complementing electricity-based solutions and enhancing the flexibility, storability, and transportability of energy supply across sectors.

A similar logic underpins the expanding role of natural gas in transport, particularly in heavy-duty road transport and maritime shipping. In segments where electrification faces persistent technical, economic, or operational constraints, LNG and CNG provide immediate emissions reductions, significant improvements in local air quality, and competitive operating costs relative to oil-based fuels. The growing deployment of gas-fuelled vehicles, vessels, and refuelling and bunkering infrastructure reinforces natural gas as a multi-sector fuel capable of serving power, industry, hydrogen, and transport within an increasingly integrated energy system.

These dynamics indicate that future natural gas demand is becoming more concentrated, more efficient, more flexible, and cleaner. Rather than expanding uniformly, demand is increasingly allocated to sectors and applications where natural gas delivers the highest system value under tightening emissions constraints. This structural transformation enhances the competitiveness and resilience of natural gas within the global energy mix and provides a coherent analytical foundation for its sustained role in energy transition pathways that reward efficiency, flexibility, and emissions performance over volume growth alone.

Consistent with these structural transformations in global energy systems, the **RCS projects that natural gas demand in the power sector increases by around 641 bcm over the outlook period, reaching approximately 2,097 bcm by 2055** (Figure 4.3). This accounts for just over half of total incremental global natural gas demand and corresponds to an average annual growth rate of around 1.2%, raising the share of power generation in total gas demand to 39% by 2055, up from 35% in 2024 (Table 4.2). This shift reflects not merely higher electricity consumption, but a deeper reconfiguration of power systems toward greater flexibility, reliability, and resilience under rising electrification and decarbonisation pressures.

As renewable penetration expands across both mature and emerging electricity systems, the role of natural gas is fundamentally changing. While gas continues to displace coal and oil in absolute terms, its primary function shifts away from baseload generation toward system balancing and flexibility provision. Gas-fired power plants increasingly operate as fast-ramping, dispatchable assets that stabilise grids characterised by high shares of variable wind and solar generation, providing essential services such as reserve capacity, frequency control, and real-time balancing. This functional transition underpins sustained gas demand even as the share of renewables rises.

Crucially, this reallocation of gas toward power generation is accompanied by structural efficiency gains. The growing dominance of high-efficiency CCGT technology significantly reduces fuel consumption per unit of electricity generated compared with legacy coal- and oil-fired capacity. At the same time, the progressive

Table 4.2

Global total gas demand outlook by sector, 2024-2055

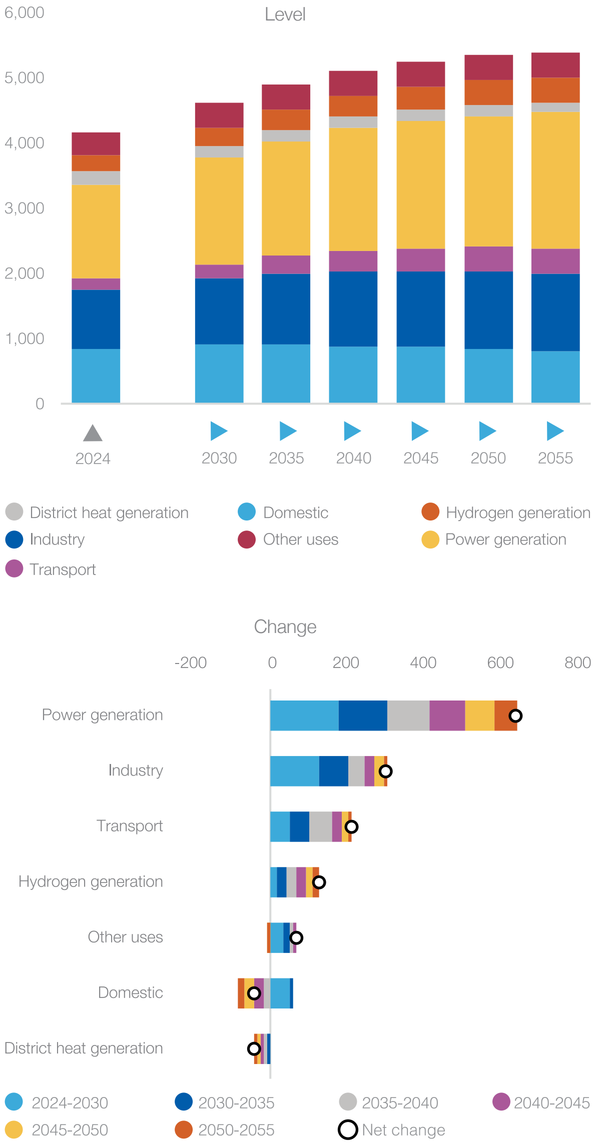
	Levels (bcm)					Change (bcm)	Growth (% p.a.)	Share (%)	
	2024	2030	2040	2050	2055	2024-2055	2024-	2024	2055
Domestic	2055	2024	2055	827	802	-31	-0.1%	20%	15%
Industry	904	1,030	1,152	1,198	1,200	296	0.9%	22%	22%
Transport	172	219	332	371	380	208	2.6%	4%	7%
Power generation	1,457	1,629	1,868	2,035	2,097	641	1.2%	35%	39%
Direct heat generation	195	191	178	160	153	-42	-0.8%	5%	3%
Hydrogen generation	265	281	333	376	391	127	1.3%	6%	7%
Other uses	339	377	396	397	393	54	0.5%	8%	7%
Total	**4,165**	**4,609**	**5,129**	**5,364**	**5,417**	**1,252**	**0.8%**	**100%**	**100%**

Source: GECF Secretariat based on data from the GECF GGM

Note: Industry includes natural gas used directly as fuel and as feedstock in the chemical and petrochemical sectors, as well as gas consumed for refinery utilities and processes. Transport covers natural gas used in road transport, marine bunkers, rail transport and pipeline operations (e.g., compressor fuel). Other uses comprise natural gas consumed for the energy sector's own use, together with distribution losses. Total gas demand includes primary natural gas as well as gas works gas, hydrogen blending and biomethane blending, where applicable.

Figure 4.3

Global natural gas demand outlook by sector, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

deployment of CCUS further lowers the emissions intensity of gas-fired generation, enabling substantial CO_2 abatement while preserving the system value of dispatchable thermal capacity in increasingly constrained power systems.

The system-critical role of natural gas is further reinforced by climate-driven variability. More frequent extreme weather events, including heatwaves, cold spells, and droughts, amplify peak electricity demand and expose power systems to hydrological risk, particularly in hydro-dependent regions. In this context, gas-fired generation provides a uniquely reliable and scalable hedge against climate volatility. In hydropower-dominated systems, notably in Latin America, natural gas functions as a complementary backup source during periods of low reservoir availability, enhancing climate resilience and safeguarding security of supply.

Amid rising natural gas demand in the power sector and continued renewable expansion, its contribution to the overall surge in electricity generation is projected to decline from 22% in 2024 to 17% by 2055. Nonetheless, higher utilisation in flexibility roles, increasing system value, efficiency gains through CCGT deployment, and progressively lower emissions enabled by CCUS support a durable and internally consistent role for natural gas in the power sector through 2055, aligned with the imperatives of secure, efficient, and orderly energy transitions.

The industrial sector, including process energy use in manufacturing operations, remains the second-largest contributor to global natural gas demand growth over the outlook period. **Under the RCS, industrial gas demand is projected to increase by around 296 bcm, reaching approximately 1,200 bcm by 2055, accounting for about 24% of total net global demand growth.** As a result of these combined forces, the share of natural gas in the industrial sector's overall energy demand is expected to remain stable around 22% over the outlook period, amid structural reallocation of industrial energy use toward fuels that balance cost, reliability, and emissions performance.

At the core of this trajectory are scale-driven demand fundamentals, notably population growth, urbanisation, and infrastructure expansion, particularly in Asia Pacific and Africa, which sustain rising output of iron and steel, cement, chemicals, and plastics. These industries are characterised by continuous operations and medium- to high-temperature heat requirements, making deep electrification technically complex and capital-intensive. While some industrial processes are technically capable of electrification, the rapid surge in electricity demand, driven by electrification of end uses, digitalisation, AI, and data-centre expansion, is expected to exert upward pressure on power prices, widening the relative cost gap between electricity and natural gas. This deterioration in relative price competitiveness is likely to slow electrification in marginal industrial applications, reinforcing natural gas as the preferred source of process heat and steam.

Beyond scale effects, structural reconfiguration of industrial value chains further supports gas demand. The expansion of clean-energy technology manufacturing, semiconductors, and critical minerals processing introduces new sources of structurally resilient demand, as these activities rely on reliable medium- to high-temperature heat for refining, smelting, and advanced materials processing, where alternatives remain limited. In parallel, continued coal- and oil-to-gas switching, driven by air-quality regulations, emissions constraints, and operating-cost considerations, supports incremental gas uptake across industrial boilers, kilns, and furnaces. Importantly, the progressive deployment and upscaling of CCUS technology in hard-to-abate, energy-intensive industries further strengthens the resilience of natural gas demand by enabling substantial emissions reductions while preserving the operational and economic advantages of gas-based processes.

Finally, geopolitical and policy-driven shifts in global manufacturing patterns reinforce these trends. Industrial reshoring, supply-chain diversification, and strategic trade and industrial policies, particularly in North America and Europe, are encouraging the expansion of domestic manufacturing capacity, increasing demand for secure, affordable, and dispatchable energy inputs.

The transport sector, encompassing road, maritime, and pipeline transport, emerges as the fastest-growing source of natural gas demand over the outlook period, albeit from a relatively small base. **Under the RCS, natural gas demand in transport is projected to increase by around 208 bcm, reaching approximately 380 bcm by 2055.** While this accounts for around 17% of total incremental global natural gas demand, the sector's share of overall gas consumption rises markedly to about 7% by 2055, up from around 4% in 2024, reflecting its increasing structural relevance within the energy system. Overall, the share of natural gas in the global transport energy mix is projected to double to 10% by 2055.

The bulk of transport-sector growth is driven by the expansion of natural gas use in hard-to-electrify segments, notably heavy-duty road transport and maritime shipping, where technical, economic, and operational constraints limit large-scale electrification. In road transport, LNG-fuelled trucks and buses are gaining traction as a cost-competitive and lower-emissions alternative to diesel in long-haul and high-utilisation applications. This shift is reinforced by tightening vehicle emission standards, air-quality regulations targeting NO_x and particulate matter, and progressive restrictions on new diesel vehicle sales in several regions. In addition, for oil-importing countries, adopting natural gas vehicles enhances energy security by reducing exposure to oil price volatility and import dependence, while oil-exporting countries benefit from freeing up liquid fuels for export markets.

In maritime transport, natural gas demand is supported by stricter environmental regulations, including sulphur and nitrogen oxide limits, alongside the rapid adoption of LNG-fuelled and dual-fuel vessels, initially concentrated in short-sea shipping and ferries but increasingly extending to deep-sea segments. The parallel expansion of LNG bunkering infrastructure, often leveraging existing LNG import terminals, is creating a reinforcing loop between vessel deployment and fuel availability. Amid rising global maritime freight demand, the share of natural gas in international marine bunkering is projected to increase to around 30% by 2055, up from about 4% in 2024. Reflecting this momentum, DNV estimates that the LNG-fuelled fleet will more than double by the end of the decade, with well over 1,200 LNG-powered vessels in operation by 2030 based on the current orderbook. Across both road and maritime transport, Asia Pacific remains the leading growth region, underpinned by supportive policies, expanding freight activity, and accelerated investment in CNG and LNG refuelling networks along major logistics corridors.

Natural gas demand for hydrogen generation is projected to increase by around 127 bcm, reaching just over 391 bcm by 2055, accounting for approximately 10% of total incremental global natural gas demand over the outlook period. As a result, the share of hydrogen-related uses in global natural gas demand rises modestly to around 7% by 2055, up from about 6% in 2024, underscoring the continued relevance of natural gas as a cost-effective and scalable feedstock, particularly in regions with extensive gas infrastructure. Within this segment, blue hydrogen progressively dominates gas-based hydrogen production by 2055, while grey hydrogen declines but remains material, reflecting affordability considerations, existing asset lock-in, and infrastructure inertia. Consequently, although natural gas remains a structural pillar of hydrogen generation through 2055, its share in total hydrogen fuel input declines from around 57% today to approximately 35%, driven by the phase-down of unabated grey hydrogen and the gradual transition toward green hydrogen.

The primary driver of natural gas demand for hydrogen generation is a scale effect linked to rising fertiliser demand, driven by population growth, agricultural intensification, and food security priorities. Natural gas–derived hydrogen continues to be used predominantly as a feedstock for ammonia and urea production, often supported by targeted subsidies to stabilise domestic fertiliser supply and limit exposure to volatile international markets, particularly in major consuming countries such as India, Brazil and China. In addition, natural gas–based hydrogen remains essential in refining operations, notably for hydrogenation and desulphurisation processes, to meet tightening fuel-quality and environmental standards.

Beyond traditional uses, blue hydrogen is projected to gain momentum as an energy vector, providing a lower-carbon and dispatchable source of hydrogen for hard-to-abate industrial applications, where alternatives remain limited. This reinforces the role of natural gas not only as a feedstock, but as an enabler of emissions reduction within industrial value chains. The Middle East, Eurasia, and Asia Pacific emerge as the primary regions driving natural gas demand for hydrogen generation, reflecting a combination of large fertiliser and refining sectors, competitive gas supply, and early deployment of CCUS infrastructure.

Natural gas demand in the domestic sector, including residential and commercial sectors, is projected to decline by around 31 bcm over the outlook period, reaching approximately 802 bcm by 2055. As a result, the sector's share in global natural gas demand falls to around 15% by 2055, down from about 20% in 2024, reflecting a structural reorientation of household energy use. This global decline is highly regionalised: it is concentrated primarily in Europe, where accelerated electrification, stringent efficiency standards, building retrofits, and policy-driven substitution of fossil fuels in heating significantly reduce direct gas use in residential and commercial buildings.

In contrast, declining demand in Europe is partially offset by continued growth in Eurasia and the Asia Pacific, where gasification programs aimed at expanding access to modern energy services in rural and remote areas, together with coal-to-gas switching in household heating, continue to support domestic gas demand. In addition, the transition from traditional biomass to LPG, a by-product of natural gas processing, remains a key driver in Sub-Saharan Africa, contributing to higher gas demand while delivering substantial public health, environmental, and clean-cooking benefits over the long term.

Despite these offsetting effects, global domestic gas demand remains constrained by structural efficiency improvements and the growing deployment of alternative heating solutions, including heat pumps, district heating upgrades, and low-carbon gases. Moreover, the low price elasticity and pronounced seasonality of residential gas demand, often associated with winter peak loads, pose challenges for energy security and system management. As a result, many countries are increasingly prioritising the electrification of heating and the substitution of natural gas with biomethane and other low-carbon alternatives in the domestic sector. Consequently, the share of natural gas in total final energy demand in the domestic sector is projected to decline to around 14% by 2055, compared with approximately 21% in 2024, reinforcing the longer-term trend toward reduced direct gas use in buildings.

Box 4.1 Peak-timing archetypes and the three waves of natural gas demand

Country-level natural gas demand pathways are heterogeneous, reflecting differences in macroeconomic and demographic trajectories, infrastructure maturity, end-use composition, and the pace of technology and policy change. A compact, transparent clustering helps summarise this heterogeneity, reveal systematic patterns that are obscured in country-by-country reporting, and provide an interpretable bridge between national pathways and global aggregates. The peak-timing lens used here is deliberately parsimonious: rather than clustering on multiple correlated indicators, it groups countries by the timing of the maximum in their full demand trajectory, thereby highlighting the sequential re-weighting of global demand across development and transition stages.

The clustering uses annual natural gas demand trajectories for each country/entity over 1990-2055. For each trajectory, the peak year is identified as the year of maximum demand (with a small tolerance to treat near-equal values as a plateau). Countries are then classified into three peak-timing archetypes: "Peaked before 2024" (peak year prior to 2024), "Peaks during 2024-2055" (peak year between 2024 and 2054), and "No peak by 2055" (peak at 2055, or a plateau extending to 2055). Aggregating demand across countries within each archetype produces the three archetype trajectories that underpin the wave interpretation.

The resulting archetypes represent a declining wave that peaked in the historical period, a transition wave that peaks within the outlook horizon, and a growth wave that continues rising through 2055. The growth wave becomes the single largest component of global demand from 2036, and it exceeds half of global demand from 2045. In parallel, the already-peaked wave falls below a 10% share of global demand from 2042. These timing markers indicate that the global centre of gravity shifts from the transition wave to the growth wave within the mid-2030s and that the decline wave becomes progressively less influential in global totals despite remaining material in specific regions (Figure 1). Table. 1 summarizes the size and global contribution of each archetype over the forecast period.

Regional patterns and implications

The archetypes exhibit distinct regional footprints, implying a progressive shift in the geography of demand growth. In the "Decline Wave" archetype, the contraction

Table 1

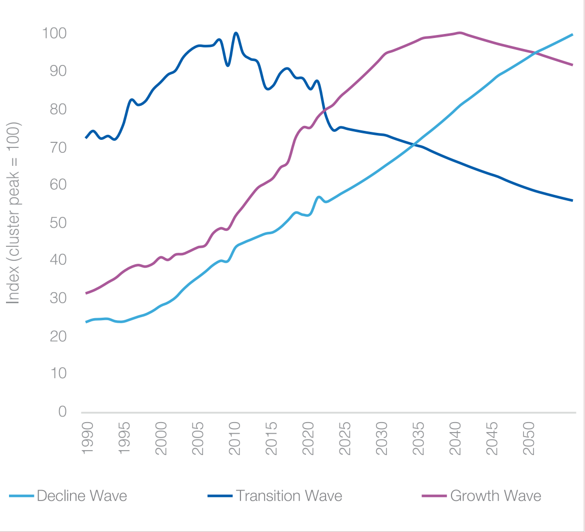
Peak-timing archetypes and contribution to global natural gas demand

Archetype	Entities	Peak year	Peak value (bcm)	Demand 2024 (bcm)	Demand 2055 (bcm)	Change 2024-2055 (bcm)	Share 2024 (%)	Share 2055 (%)
Decline Wave	37	2010	798	600	446	-154	15	8
Transition Wave	29	2040	2.197	1,827	2,010	182	44	37
Growth Wave	52	2055	2,961	1,707	2,961	1,255	41	55

Note: Totals may not sum due to rounding over 2024-2055 is dominated by Europe (approximately -144 bcm) and, to a lesser extent, OECD Asia Pacific (approximately -44 bcm), partially offset by modest gains in Eurasia and Latin America. The "Transition Wave" archetype reflects a handover dynamic: developing Asia Pacific contributes strongly to net growth (around +139 bcm) alongside Latin America and Africa, while North America shows a net decline (around -36 bcm) within this group, shaping the mid-horizon peak. The "Growth Wave" archetype drives the bulk of global growth, with the largest increments concentrated in non-OECD Asia Pacific and Southeast Asia (around +463 bcm), the Middle East (+270 bcm), Eurasia (+182 bcm) and Africa

Figure 1

Wave profiles by peak-timing archetype (index, each archetype peak = 100),1990-2055



Source: GECF Secretariat based on data from the GECF GGM

(+163 bcm). These patterns imply that the geography of incremental demand becomes increasingly concentrated in regions where the growth archetype is dominant, while regions dominated by the already-peaked archetype make a progressively smaller contribution to global net growth despite retaining significant absolute demand.

Sectoral drivers and implications

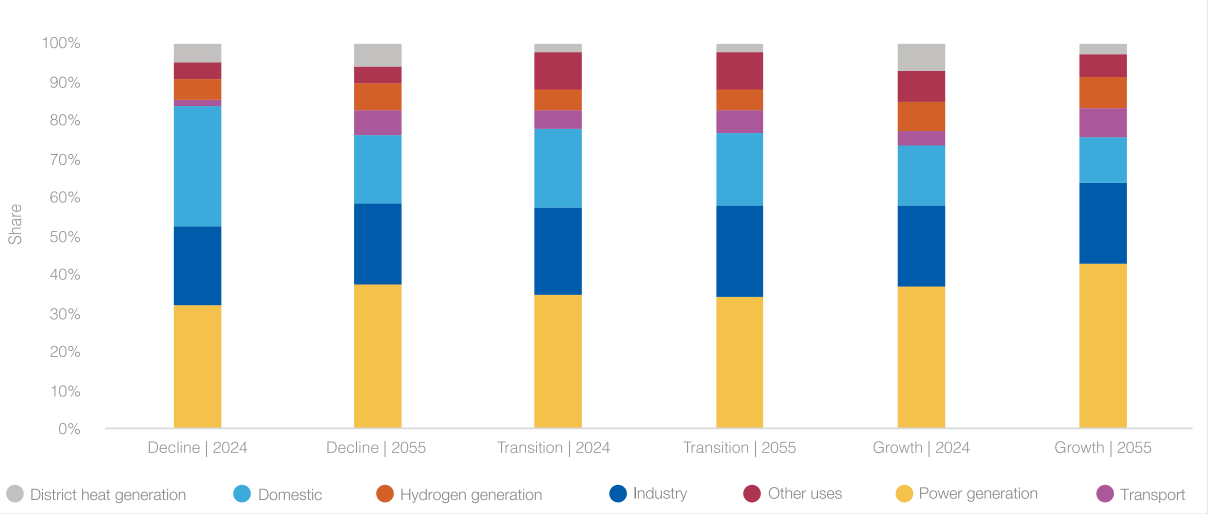
Sectoral decomposition over 2024-2055 indicates that the archetypes differ not only in timing but also in the end-uses that drive growth or decline (Figures 2). In the "Decline Wave" archetype, net decline is led by domestic demand (approximately -107 bcm), with additional reductions in Industry (-28 bcm) and power generation (-21 bcm), while transport increases from a small base (+21 bcm). In the transition archetype, net change is modest and broadly distributed across industry (+57 bcm), power generation (+49 bcm), transport (+29 bcm) and hydrogen (+15 bcm), while domestic demand declines slightly (-11 bcm), indicating that the peak is driven more by the slowing and eventual reversal of aggregate growth than by a wholesale change in end-use composition. In the "Growth Wave" archetype, growth is power-led (+624 bcm) and complemented by industry (+266 bcm), transport (+159 bcm) and hydrogen (+105 bcm), while district heat generation declines (-43 bcm) and domestic demand rise in absolute terms but falls in share. The combined picture is a gradual shift in the sectoral engine of global gas demand toward power-system requirements and industrial use, with an emerging contribution from new molecule pathways such as hydrogen.

Key drivers of gas demand within archetypes

The evolution of demand within each archetype can be interpreted through interacting activity, intensity, structural, and fuel-mix effects. In the already-peaked archetype, aggregate demand reaches its maximum in the historical period and then declines through

Figure 2

Sector mix by archetype (shares of demand, 2024 vs 2055)



Source: GECF Secretariat based on data from the GECF GGM

2055. The dominance of domestic demand in the contraction, alongside declines in industrial and power-sector consumption, is more consistent with combined efficiency improvements, electrification of end-use services, and fuel switching within power and district heat generation than with activity effects alone, although demographic and mature-growth headwinds reinforce the downward trajectory. In the transition archetype, demand continues to rise into the 2030s and peaks around 2040 in the aggregate; the relatively stable sector mix implies that the peak emerges when incremental demand growth in power and industry is progressively offset by intensification of efficiency and an acceleration of non-gas supply options in electricity and district heat generation, rather than a single dominant structural break. In the growth archetype, strong activity growth and rising electricity needs dominate, with gas demand expanding primarily via power generation and industrial use even as building-related shares decline; this pattern is consistent with a system in which electrification increases the scale of electricity demand and gas retains a role in providing scalable generation and flexibility, while industrial expansion and new molecule pathways (including hydrogen-related use in a subset of markets) contribute additional demand. Across archetypes, the results indicate that peaks are more likely where efficiency and electrification are sufficiently strong to outpace activity-driven demand growth and where fuel switching in power and heat supply erodes incremental gas use.

Overall, the peak-timing clustering shows that global gas demand evolution is best understood as the superposition of three concurrent waves that differ in timing, geography, and end-use consumption structure. Over the forecast period, the global aggregate becomes increasingly shaped by the growth archetype, which becomes the largest component of global demand from the mid-2030s and exceeds half of global demand by the mid-2040s. The already-peaked archetype remains regionally important but loses global weight, reflecting the concentration of contraction in mature markets. Sectorally, incremental demand becomes progressively more power- and industry-led, with a rising contribution from transport and hydrogen-related demand in some markets and a declining role for building-related uses. Taken together, these patterns imply a long-run transformation in both the geography and the sectoral drivers of gas demand through 2055.

4.4 Regional trends in natural gas demand

4.4.1 Africa

With a natural gas demand of around 175 bcm in 2024, Africa remains a relatively small contributor to global gas consumption, accounting for just under 4% of the global total, marginally above Latin America. Over the outlook period, however, Africa is projected to record the fastest growth in natural gas demand among all regions, expanding at an average rate of 2.4% per year through 2055. As a result, **regional gas demand more than doubles, reaching just below 364 bcm by 2055, equivalent to around 7% of global consumption. By the end of the forecast period, Africa is expected to** account for nearly 15% of net global natural gas demand growth (Figure 4.4).

This rapid expansion reflects a structural rebalancing of global gas demand toward emerging regions, driven less by saturation effects elsewhere and more by Africa's low starting point and substantial unmet energy needs. By the end of the outlook period, Africa is projected to converge with Europe in absolute natural gas demand, underscoring the continent's rising importance in shaping long-term global gas consumption patterns.

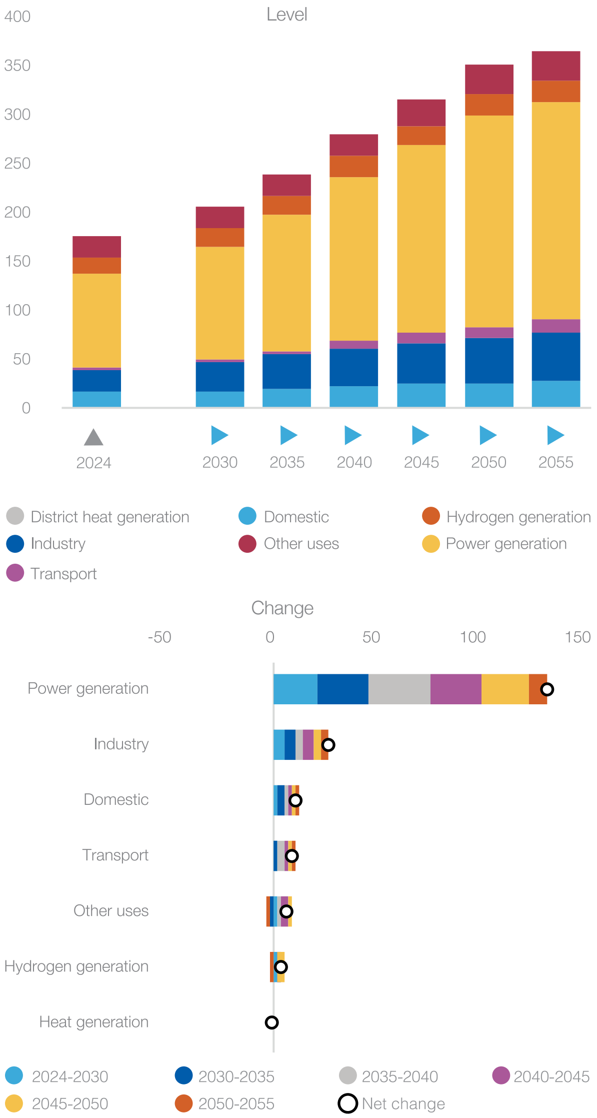
The acceleration in demand is mirrored by a strengthening role for natural gas within Africa's energy mix, with its share increasing from around 18% in 2024 to about 23% by 2055. This shift is overwhelmingly power-sector driven. Amid accelerated demand for electricity in Africa, exceeding 3.8% per year to reach 3,210 TWh by 2055, natural gas is expected to supply nearly one-third of the projected increase in electricity generation across Africa over the outlook period. By 2055, gas-fired generation is projected to account for around 50% of the regional power mix, up from 40% in 2024, reinforcing its role as a backbone fuel for power system expansion, grid stability, and the effective integration of variable renewable energy across the continent. As a result, electricity generation accounted for around 53% of Africa's natural gas demand in 2024 and is projected to contribute nearly 61% by 2055, consolidating natural gas as the primary outlet for demand growth.

This growing prominence of natural gas in power generation reflects a convergence of structural and system-level drivers. Rapid population growth and accelerating urbanisation are intensifying the need to expand electricity access and meet rising demand reliably, particularly in fast-growing urban centres. At the same time, the accelerated deployment of variable renewable energy, notably solar and wind in countries such as Algeria, Egypt and Tunisia, is increasing the requirement for flexible and dispatchable generation capacity to manage intermittency and maintain grid stability.

In parallel, decarbonisation objectives are reinforcing coal-to-gas switching in baseload power generation, particularly in countries such as South Africa and Morocco, where natural gas offers a lower-emissions alternative to coal while improving operational flexibility and reducing local air pollutants. Beyond baseload applications, fuel substitution away from heavy fuel oil and diesel in peak-load and backup generation is emerging as an increasingly important driver. Countries including Egypt, Senegal, Ghana, Côte d'Ivoire, Kenya,

Figure 4.4

Natural gas demand outlook in Africa by sector, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

and Tanzania are progressively replacing liquid fuels with natural gas to lower generation costs and reduce emissions, especially in urban and industrial load centres.

At the same time, climate-related stresses, including recurrent droughts and increasingly frequent dry seasons, are intensifying generation variability in hydropower-dependent systems. In countries such as Angola, Tanzania, and Zambia, this strengthens the case for natural gas as a complementary source of firm and flexible capacity, enhancing power system resilience, mitigating hydrological risks, and supporting a reliable electricity supply.

Consistent with these trends, Africa's installed gas-fired power generation capacity is projected to more than double under the RCS, rising from around 115 GW in 2024 to approximately 282 GW by 2055. This expansion is already materialising on the ground, with around 6.6 GW of gas-to-power capacity currently under construction and a further 33 GW at advanced stages of development. Large-scale projects are progressing across a range of gas-rich and high-growth electricity markets, including Mauritania, Mozambique, Senegal, South Africa, and Côte d'Ivoire, reflecting both rapidly rising power demand and the strategic need for reliable baseload and balancing capacity to support increasingly complex power systems.

Beyond power generation, natural gas is increasingly required as a strategic enabler of Africa's next phase of economic transformation, supporting industrialisation, urbanisation, job creation, and the expansion of value-added activities with strong multiplier effects. Natural gas plays a critical role as a source of high-temperature industrial heat and steam, as well as a feedstock for essential materials, including iron and steel, cement, plastics, glass, ceramics, bricks, and fertilisers. However, despite this potential, industrial gas use remains relatively modest, concentrated in a limited number of countries with established gas infrastructure and industrial ecosystems.

Countries such as Algeria, Egypt, and Nigeria represent early forerunners, having developed integrated gas-based industrial value chains in which natural gas underpins manufacturing, fertiliser production, petrochemicals, and export-oriented industries. In parallel, a growing group of countries with newly developed or recently discovered gas resources, including Mauritania and Senegal, Angola, Namibia, and Ethiopia, are beginning to invest in pilot-scale industrial applications. These initiatives are expected to scale up progressively as constraints related to midstream infrastructure, market access, and predictable policy and regulatory frameworks are gradually addressed.

Reflecting these developments, RCS projects that natural gas use in Africa's industrial sector, including feedstock demand, will reach 50 bcm by 2055, an increase of around 26 bcm compared with 2024. Industry is therefore expected to emerge as the second-largest driver of natural gas demand growth in the region, accounting for around 14% of total gas consumption by 2055, broadly in line with its current share. This trajectory is underpinned by a growing pipeline of industrial and infrastructure projects across the continent, reinforcing the role of natural gas as a cornerstone of Africa's long-term energy and development strategy.

Several countries are advancing concrete initiatives to expand gas supply to industrial hubs. Senegal is investing in a national pipeline network to supply natural gas to power plants and energy-intensive industries such as fertilisers, ceramics, and steel, while Ghana is developing gas distribution infrastructure to serve the Tema industrial zone. Côte d'Ivoire plans to extend gas supply to its PK24 industrial zone, further strengthening its manufacturing base. In parallel, multiple countries are pursuing fertiliser production strategies to monetise domestic gas resources and improve food security. Angola is developing the AMUFERT urea project in Soyo, adjacent to the Angola LNG complex; Tanzania has signed agreements with an Indonesian firm to establish a urea plant; and Mozambique, Senegal, and Ghana are exploring similar projects. Most recently, Ethiopia has signed an agreement with a Nigerian conglomerate to monetise its discovered gas resources at Calub and Hilala, marking a significant step toward gas-based industrial development in East Africa.

Africa's energy system remains heavily reliant on the residential and commercial sectors, where energy demand is still dominated by traditional biomass use, particularly for cooking and space heating. This reliance imposes significant public health, economic, and environmental costs, including indoor air pollution, reduced labour productivity, deforestation, and persistent energy poverty across large parts of the continent. Addressing these challenges requires scalable and affordable solutions that can be deployed rapidly and at scale. In this context, the transition from traditional biomass to LPG and pipeline natural gas represents one of the most practical and immediately deployable pathways for improving energy access, particularly for clean cooking. LPG's portability, ease of storage, and compatibility with existing household practices make it especially well suited to African markets, while pipeline gas offers a complementary solution in urban and peri-urban areas where infrastructure development is feasible.

Several countries, including Nigeria, Senegal, Kenya, Tanzania and Ghana, have emerged as regional frontrunners in integrating LPG into national energy planning and clean cooking strategies. Their experience demonstrates that a combination of public–private partnerships, regulatory clarity, targeted subsidies, and consumer engagement can accelerate LPG adoption and expand access to modern energy services at scale.

Reflecting these developments, RCS projects that natural gas demand in the residential and commercial sectors will rise to 28 bcm by 2055, effectively doubling from 2024 levels and accounting for around 8% of total regional gas demand. The imperative to address the clean cooking challenge, particularly in Sub-Saharan Africa, together with the unique attributes of LPG and pipeline natural gas, underpins this growth.

Natural gas also presents a compelling opportunity to decarbonise rapidly expanding Africa's transport sector, particularly in freight transport, public transport, and maritime shipping, where electrification remains challenging in the near to medium term. The transition toward CNG and LNG for road transport, together with the development of LNG bunkering for shipping, is emerging as a practical pathway to reduce emissions and improve air quality. Several countries, including Nigeria and Tanzania, have already embarked on pilot and early-stage programs to introduce CNG and LNG vehicles and supporting infrastructure, reflecting growing interest in gas-based transport solutions.

The deployment of CNG and LNG fleets offers multiple benefits beyond emissions reduction. These include lower local air pollution, reduced fuel costs, and enhanced energy security by limiting reliance on imported oil products and exposure to price volatility. Such advantages are particularly relevant for densely populated urban areas and major freight corridors, where transport emissions and fuel import bills are rising rapidly.

Building on these developments, RCS identifies the transport sector as an emerging source of natural gas demand in Africa, with consumption projected to quadruple by 2055 to reach around 13 bcm, albeit from a low base. As a result, the share of transport in total regional gas demand increases from around 1% in 2024 to about 4% by 2055, driven by continued urbanisation, expanding logistics and freight activity, and the gradual scaling-up of gas-based transport infrastructure across the continent.

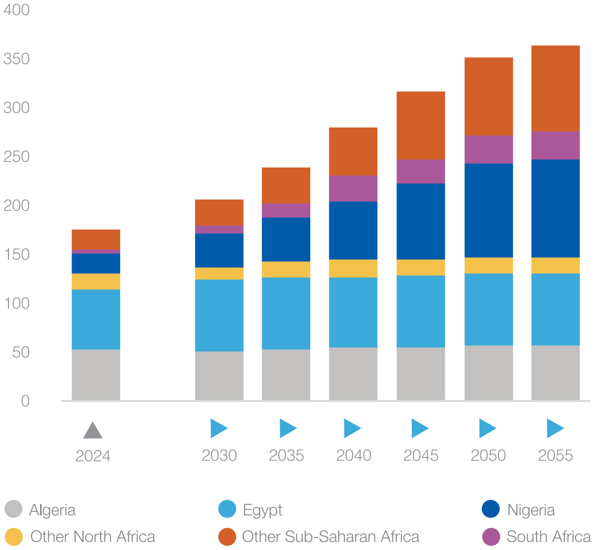
A comprehensive assessment of Africa's natural gas demand prospects requires a sub-regional perspective, as current consumption patterns are highly uneven. In 2024, North Africa, home to around 15% of the continent's population, accounted for approximately 36% of Africa's primary energy demand excluding traditional biomass. Reflecting its more developed gas infrastructure and power systems, natural gas demand in North Africa was around three times higher than in Sub-Saharan Africa, with gas representing about 48% of the sub-region's energy mix, compared with only around 6% in Sub-Saharan Africa. While power generation is the dominant source of energy demand in both sub-regions, accounting for more than half of total consumption, around 75% of Africa's natural gas demand in the power sector was concentrated in North Africa in 2024 (Figure 4.5).

This highly concentrated pattern, however, is expected to shift fundamentally over the coming decades. **Under the RCS, Sub-Saharan Africa is projected to account for around 90% of the total increase in Africa's natural gas demand by 2055, driven by rapid population growth, accelerating urbanisation, and gradual progress in expanding gas infrastructure, strengthening policy and regulatory frameworks, and developing more efficient and liquid domestic gas markets.** These developments are also expected to unlock demand associated with newly explored and developed gas resources across the sub-region.

As a result, the share of natural gas in Sub-Saharan Africa's energy mix is projected to triple to around 18% by 2055, amid rapidly expanding energy demand. In contrast, the share of gas in North Africa's energy mix is projected to decline to around 40% by 2055, down

Figure 4.5

Natural gas demand outlook in Africa by country, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

from 48% in 2024, as countries such as Algeria and Egypt accelerate renewable energy deployment to meet domestic power demand while preserving natural gas availability for export markets.

A key manifestation of this structural rebalancing is observed in the power sector. Collective natural gas consumption for power generation in Sub-Saharan Africa is projected to exceed that of North Africa by the late 2030s, reflecting the faster expansion of electricity demand and gas-fired capacity south of the Sahara. By 2055, Sub-Saharan Africa is expected to account for around 60% of Africa's total natural gas demand, marking a decisive shift in the regional distribution of gas consumption across the continent.

Algeria and Egypt, the first- and second-largest natural gas consumers in Africa, respectively, benefit from well-developed gas infrastructure, mature domestic markets, and long-standing integration with international gas trade. These structural advantages position both countries to pursue strategic energy transition pathways that increasingly complement natural gas with renewable energy in power generation and broader electrification plans. As renewable capacity expands, particularly in utility-scale solar and wind, natural gas is expected to play a more balancing and system-support role rather than serving as the primary source of incremental electricity supply.

As a result, domestic natural gas demand growth in Algeria and Egypt is projected to slow markedly over the outlook period, with consumption in both countries entering a prolonged plateau. This trajectory reflects a deliberate export optimization strategy to preserve export capacity and foreign revenue streams, while still meeting rising domestic electricity demand across residential, industrial, and service sectors through energy efficiency improvement. **Under the RCS, natural gas demand in Algeria and Egypt is projected to reach around 58 bcm and 71 bcm by 2055, respectively, an increase of only about 5 bcm for Algeria and 10 bcm for Egypt compared with 2024 levels.** This subdued growth underscores improvement in energy efficiency and the role of renewables in moderating domestic gas demand, even as natural gas remains a critical component of system reliability and energy security in North Africa.

In contrast to North Africa's optimisation-driven trajectory, natural gas strategies in Sub-Saharan Africa are predominantly development-driven, reflecting the region's need to expand energy access, industrial capacity, and economic diversification. Nigeria is projected to assume a leading role in this transition, recording the largest incremental natural gas demand increase across the continent. **Under the RCS, Nigeria's gas demand is expected to grow fivefold, reaching around 100 bcm by 2055, underpinned by the government's "Decade of Gas" strategy and the introduction of a range of policy instruments aimed at accelerating gas monetisation and expanding domestic consumption across the power, industrial, residential, and transport sectors.**

The expansion of gas infrastructure is central to this outlook. The Ajaokuta–Kaduna–Kano (AKK) pipeline is expected to play a transformative role by extending gas access to northern states and urban centres, while continued network expansion into key industrial corridors, supported by robust public–private partnership frameworks, is set to deepen gas penetration across the country. Together, these developments are expected to unlock latent demand and support sustained growth in domestic gas consumption over the coming decades.

Beyond Nigeria, Western Africa is emerging as an increasingly important source of incremental natural gas demand. Under the RCS, gas demand in the sub-region, led by Senegal and Ghana, is projected to rise by around 21 bcm, reaching approximately 25 bcm by 2055 from a very low base. In Senegal, the Réseau Gazier du Sénégal (RGS) is laying the groundwork to connect offshore gas developments to domestic power generation and industrial consumers through an extensive pipeline network. In parallel, Ghana has made significant progress in developing gas distribution infrastructure to supply the Tema industrial zone and other energy-intensive industries. These infrastructure-led initiatives are expected to materially expand the scale and geographical spread of natural gas demand across Sub-Saharan Africa, reinforcing the region's development-driven gas consumption trajectory.

In South Africa, natural gas demand growth follows a distinct transition-driven pathway, rather than a development-led trajectory. The expansion of gas use is primarily associated with the gradual decarbonisation of the power generation sector and the strategic need to reduce reliance on coal. **Under the RCS, natural gas demand in South Africa is projected to increase by around 24 bcm, reaching approximately 28 bcm by 2055. Nearly 90% of this incremental demand is expected to be absorbed by the power sector, where natural gas increasingly serves as a substitute for coal-fired generation. The deployment of high-efficiency CCGT plants enables** substantial emissions reductions, improved system flexibility, and lower local air pollutants compared with coal. As a result, natural gas is projected to account for around 22% of South Africa's total power generation by 2055, reflecting its role as a key fuel in the country's evolving electricity system.

It should be noted, however, that the contribution of natural gas to power generation is moderated over time by the accelerating deployment of renewable energy, particularly solar and wind, after 2040. As renewables gain a larger share of the generation mix, natural gas increasingly shifts toward a balancing and flexibility role, supporting grid stability and system reliability rather than acting as the primary source of baseload electricity.

4.4.2 Asia Pacific

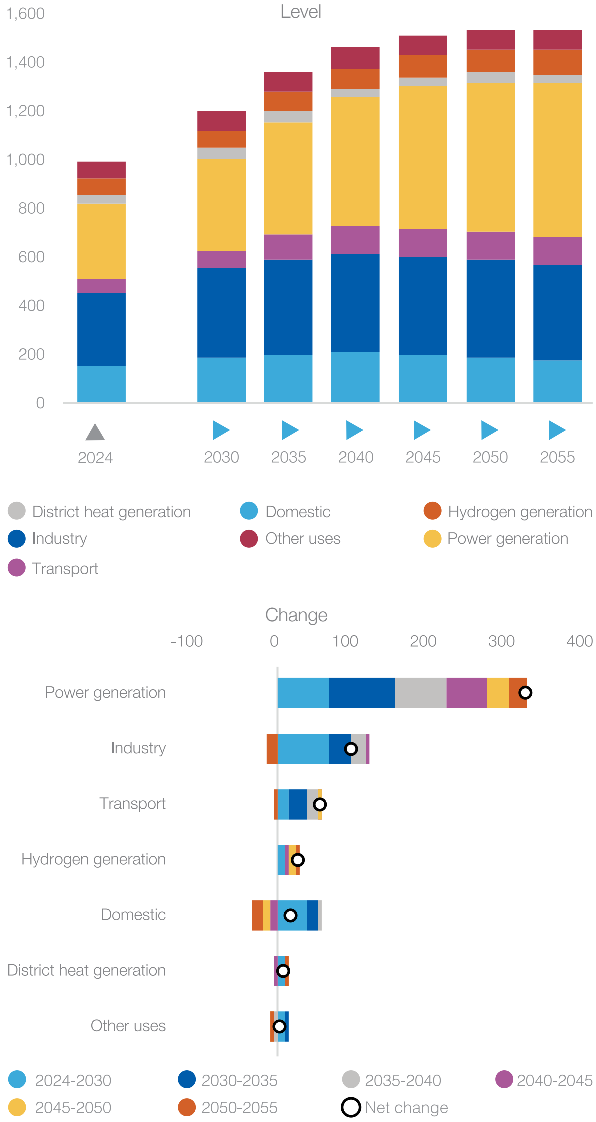
In 2024, Asia Pacific was the world's second-largest natural gas consuming region, following North America, and accounts for around 23% of global gas demand. Supported by sustained economic expansion, rapid urbanisation, and rising energy needs across countries, natural gas demand in Asia Pacific is projected to surpass that of North America in the early 2030s, positioning the region as the largest gas consumer globally thereafter. By 2055, Asia Pacific is expected to account for around 28% of global natural gas demand, underscoring a significant shift in the regional distribution of gas consumption. **With an average annual growth rate of around 1.5% over the outlook period reaching 1,516 bcm by 2055, Asia Pacific is projected to contribute approximately 43% of net global primary natural gas demand growth, the largest share among all regions. This highlights Asia Pacific's central role in shaping the** long-term trajectory of global natural gas markets over the upcoming three decades (Figure 4.6).

A comprehensive assessment of gas demand in Asia Pacific requires attention not only to primary natural gas, but also to secondary gaseous fuels that remain relevant in specific national contexts. In particular, gas works gas (manufactured gas) and hydrogen–natural gas blending represent small but non-negligible components of the region's overall gas supply, supplementing primary natural gas in selected sectors and markets.

Gas works gas, produced mainly through coal- and oil-based gasification processes, remains concentrated in China and Japan, where legacy industrial systems and coal-based value chains are still present. In 2024, gas works gas consumption in Asia Pacific is

Figure 4.6

Natural gas demand outlook in Asia Pacific by sector, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

estimated at around 26 bcm, but it is projected to decline steeply over the outlook period, falling to zero by the early 2040s. This contraction reflects structural shifts away from coal-based gas production, tightening environmental regulations, and increasing substitution by primary natural gas and low-carbon alternatives.

At the same time, hydrogen blending into natural gas networks is emerging as a modest but growing source of gaseous fuel supply, particularly in Japan and South Korea, where hydrogen strategies are being integrated into broader decarbonisation and energy security plans. From negligible levels in 2024, hydrogen–natural gas blends are projected to reach around 14 bcm by 2055, supporting gas demand in power generation, industry, and residential–commercial applications while reducing the carbon intensity of delivered gas.

At the sectoral level, natural gas demand in Asia Pacific is currently concentrated in power generation and industry, including feedstock use for petrochemicals, which together accounted for around 32% and 30% of total regional gas demand in 2024, respectively. Looking ahead, natural gas demand is projected to increase across all Asia Pacific sub-regions, with the power sector emerging as the dominant source of incremental demand. By 2055, power generation is expected to account for nearly 61% of the total increase in natural gas demand, equivalent to around 320 bcm, lifting the sector's share in total gas consumption by approximately 10 percentage points to about 42%.

This structural shift is closely linked to the accelerating electrification of Asia Pacific's energy system. As the leading region in global electrification, nearly 40% of final energy demand in Asia Pacific is projected to be electrified by 2055, driven by rapid urbanisation, industrial expansion, electric mobility, and digitalisation. In this context, natural gas is set to play a critical dual role in the power sector: first, as a reliable and cost-effective fuel to meet rising electricity demand, particularly in systems where coal, hydropower variability, or limited interconnections constrain supply; and second, as a lower-emissions alternative to coal, supporting decarbonisation and improvements in local air quality through targeted coal-to-gas switching.

As the penetration of VREs, notably solar and wind, continues to accelerate across the region, the role of natural gas in electricity systems is also evolving. Gas-fired generation is increasingly deployed to provide flexibility, ramping capability, and reserve capacity, ensuring real-time load balancing and system stability. Consequently, natural gas is transitioning from a predominantly baseload fuel in some markets to a system-balancing and integration resource in power systems with high VRE shares, reinforcing its strategic importance in Asia Pacific's evolving electricity landscape.

Consistent with the above structural trends, the RCS projects a substantial expansion of gas-fired power generation capacity in Asia Pacific, with installed capacity more than doubling over the outlook period to reach around 980 GW by 2055. This expansion raises Asia Pacific's share of the global gas-to-power fleet to approximately 30%, up from around 24% in 2024, reinforcing the region's central role in shaping global gas demand for power generation. As capacity expands, electricity generation from natural gas-fired plants is projected to rise by around 2.5-fold, reaching approximately 3,700 TWh by 2055. Despite this significant increase in absolute terms, the share of gas in Asia Pacific's power generation mix remains broadly stable at around 11%, reflecting the parallel and rapid scale-up of other generation sources, particularly renewables and, in selected markets, nuclear power.

In Asia Pacific, the industrial sector remains a structurally important pillar of natural gas demand, second only to power generation. In 2024, industry, including refining utility and feedstock for chemicals, accounts for around 30% of total regional gas demand, with consumption projected to rise by nearly 99 bcm to around 393 bcm by 2055, equivalent to 26% of regional demand. Natural gas continues to play a critical role in hard-to-abate manufacturing sectors such as iron and steel, cement, petrochemicals and plastics, where it is required both as a source of high-temperature process heat and as a chemical feedstock, supported by coal-to-gas switching and the gradual deployment of CCUS in selected applications. However, despite continued absolute growth, the share of industry in total gas demand declines over the outlook period, reflecting faster expansion of gas demand in the power sector as electrification accelerates. In addition, structural economic rebalancing in China, including a prolonged adjustment in the real estate sector, a shift toward services and high-value manufacturing, and increasing electrification and efficiency of industrial processes, moderates growth in energy-intensive output such as steel and cement.

Although the transport sector currently represents a small share of natural gas demand in Asia Pacific, it is emerging as a notable source of incremental growth over the coming decades. Decarbonisation efforts in heavy-duty road transport, public transit, and maritime shipping are driving increased adoption of CNG- and LNG-fuelled vehicles, particularly where electrification remains challenging. In road transport, policy tightening on emissions and air quality, most notably through China's China VI emission standards and the 14th Five-Year Plan (2021–2025), has accelerated the shift toward LNG in heavy-duty trucks. As a result, China's LNG truck fleet has nearly tripled since 2019, reaching around one million vehicles by 2025, creating a material new outlet for gas demand and a template that could be replicated in other Asia Pacific markets such as India over the medium to long term.

In parallel, maritime transport is emerging as a measurable and fast-growing source of LNG demand in the region. In 2024, LNG bunkering volumes in Asia Pacific are estimated at around 0.6–0.8 million tonnes, led by Singapore, which supplied close to 0.5 million tonnes of LNG as marine fuel, alongside rapidly expanding bunkering activity in major Chinese ports such as Shanghai and Ningbo-Zhoushan. Additional ports across Northeast and Southeast Asia, including in Japan, South Korea, Malaysia, and Viet Nam, have commissioned or announced LNG bunkering facilities, further lowering infrastructure barriers. Looking ahead, the combination of growing LNG-fuelled vessel orderbooks, tightening maritime emissions regulations, and continued expansion of bunkering infrastructure is expected to support sustained growth in LNG demand from shipping. While maritime LNG demand remains modest relative to total regional gas consumption, its upward trajectory positions transport as an increasingly relevant niche driver of natural gas demand in Asia Pacific over the long term.

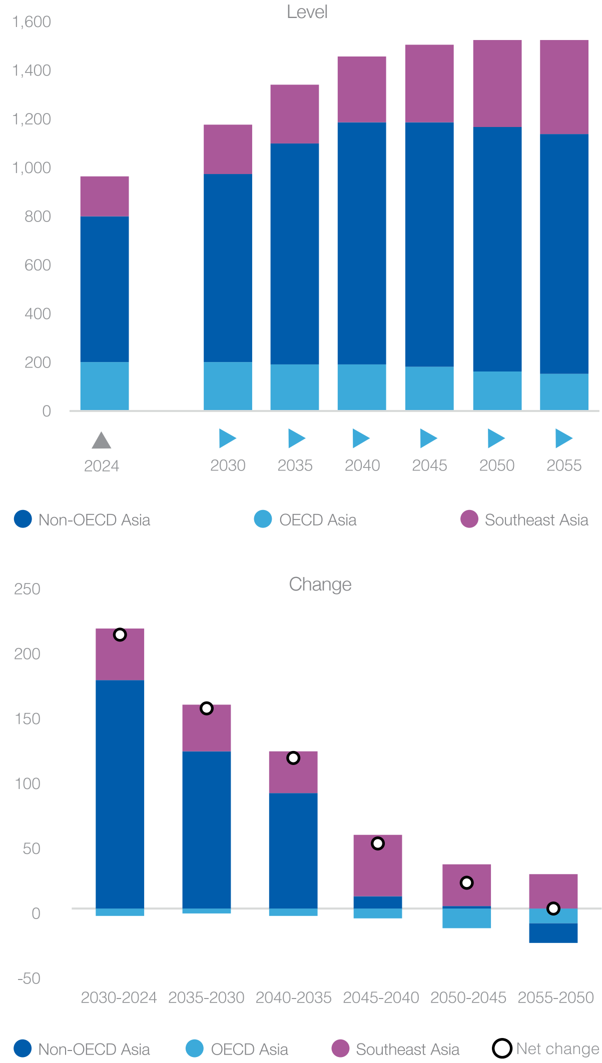
Against this backdrop, the RCS indicates a sustained expansion of natural gas use in the transport sector, with demand doubling to around 112 bcm by 2055. Transport is projected to contribute around 10% of total incremental natural gas demand in Asia Pacific over the outlook period, lifting its share in overall gas consumption from about 6% in 2024 to roughly 7% by 2055. Although smaller than power and industrial uses, this increase reflects the growing scale of gas penetration in transport and underscores the sector's emerging role as a structurally durable source of demand, particularly in hard-to-electrify transport segments.

Asia Pacific countries are expected to follow distinct natural gas demand pathways, shaped by differing energy-security imperatives, stages of development, policy choices, and end-use structures. In non-OECD Asia, particularly China and India as well as parts of Southeast Asia, gas demand is projected to grow, underpinned by rising industrial and urban energy needs and by decarbonisation strategies that prioritise coal-to-gas switching in selected sectors to curb local air pollutants and lower emissions intensity. By contrast, in OECD Asia Pacific countries such as Japan and South Korea, gas demand is projected to continue its structural decline in the long-term as mature energy systems face slower demand growth and ageing demographics, while policy and investment increasingly favour efficiency improvements, electrification, and a larger role for nuclear and renewables in the power mix (Figure 4.7). Crucially, gas plays different functional roles across the region: in China and India, it is anchored in industrial process heat and feedstock use, whereas in Southeast Asia, gas demand is primarily power-sector driven, providing dispatchability, system balancing, and flexibility to integrate variable renewables. A further differentiating factor is transport, where natural gas, especially LNG in heavy-duty trucking and shipping, is emerging as a niche growth market in specific countries, adding another layer of divergence in regional demand profiles.

China, the largest gas consumer in Asia Pacific, closely competing with India, is projected to add around 146 bcm of primary natural gas demand by 2055, lifting total consumption to about 565 bcm. This would make China one of the largest contributors to global natural gas demand growth, alongside India, even though national demand is expected to peak in the early 2040s and then enter a moderate, structurally driven decline (Figure 4.8). Given the high policy sensitivity of natural gas demand in China, the 2024 update of the Natural Gas Utilisation Policy, with its explicit emphasis on emissions reduction, efficiency improvements, and prioritisation of high-value and hard-to-abate end uses, is expected to play a decisive role in shaping the sectoral allocation and trajectory of gas demand over the outlook period, reinforcing gas use in abatement-enabling and strategic applications while constraining its expansion in lower-efficiency uses.

Figure 4.7

Natural gas demand outlook in Asia Pacific by sub-region, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

The industrial sector, including refinery feedstock and fuel use, remains the principal driver of natural gas demand in China, accounting for nearly 40% of total consumption in 2024. The largest industrial gas consumers comprise oil and gas extraction, chemical products manufacturing, and petroleum and nuclear fuel processing, reflecting the critical role of natural gas in process heat provision, hydrogen production, and feedstock applications.

Looking ahead, industrial gas demand is shaped by structural shifts in China's growth model. The gradual transition away from real estate-led expansion and traditional energy-intensive industries toward electricity-intensive, higher value-added manufacturing, particularly clean energy technologies, is expected to moderate the pace of industrial gas demand growth. These trends are reinforced by persistent industrial overcapacity, weakening profit margins, and external pressures stemming from the United States–China trade dispute and rising global protectionism, which collectively constrain manufacturing output and limit new capacity additions.

At the same time, several countervailing forces are expected to support industrial natural gas demand. Rising carbon prices, together with a reduction in imported natural gas prices, improve the relative competitiveness of gas in manufacturing and incentivise fuel switching in favour of gas-based heat and steam. In parallel, the progressive scale-up of CCUS in hard-to-abate industries and strategic responses to cross-border decarbonisation measures, most notably the EU Carbon Border Adjustment Mechanism (CBAM), reinforce the role of natural gas as a compliance and risk-mitigation option within export-oriented industrial sectors. Under the RCS, industrial natural gas consumption for heat and steam is therefore projected to reach around 217 bcm by 2055, representing an increase of approximately 40 bcm compared with 2024 levels.

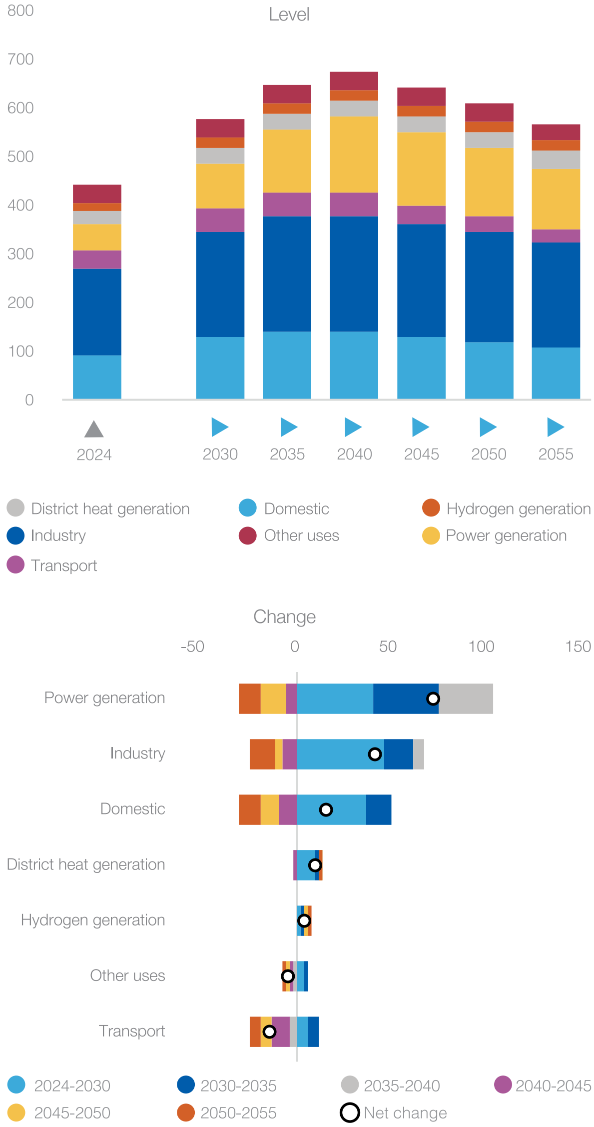
In contrast, gas use in ammonia and methanol production is increasingly constrained by policy. Under the 2024 update of the Natural Gas Utilisation Policy, these applications are largely classified as restricted, with supply predominantly met through coal gasification (gas works gas) rather than primary natural gas. Although the coal-derived share is expected to decline over the outlook period due to tightening environmental constraints and efficiency requirements, the linkage between fertiliser output and primary natural gas demand remains structurally weak, despite China's emphasis on fertiliser self-sufficiency.

Overall, these offsetting dynamics imply a gradual flattening of industrial gas demand over the longer term. Industrial natural gas consumption is projected to peak in the early 2040s at around 242 bcm, before entering a gradual decline, reflecting the combined effects of energy security imperatives, economic rebalancing toward a more consumption-oriented growth model, industrial upgrading toward electrified manufacturing processes, and increasingly stringent decarbonisation policies shaping China's long-term energy demand trajectory.

Power generation is projected to become the primary driver of incremental natural gas demand over the outlook period, accounting for around 57% of total net demand growth by 2055. Although natural gas currently plays a limited role in China's power sector, contributing only around 4% of total electricity generation in 2024 and absorbing about 12% of total gas demand, its use in power generation is expected to expand steadily. Under RCS, gas demand in the power sector is projected to grow at an average rate of around 2.7% per year, reaching approximately 125 bcm by 2055, an increase of nearly 70 bcm compared with 2024 levels. As a result, the share of gas-fired generation in the total power mix is projected to increase modestly to around 5% by 2055, reaching approximately 850 TWh, which is more than 2.6 times the level recorded in 2024.

Figure 4.8

Natural gas demand outlook in China by sector, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

This growth is underpinned by both capacity expansion and system-level requirements. In 2024, installed gas-fired power capacity accounted for around 6% of China's total generation fleet, equivalent to approximately 153 GW. Recent years have seen accelerated investment in gas-fired power plants, reflecting the need for dispatchable capacity to meet rising peak electricity demand, particularly from residential cooling loads during summer months, and to provide flexibility and balancing services in a power system increasingly dominated by VREs. Gas-fired generation also plays a growing role as backup for hydropower, whose availability is becoming more volatile due to climate-related variability.

Structural and technological factors further reinforce this outlook. The development of domestic gas-turbine manufacturing capabilities, including the production of F-class and higher-efficiency turbines with capacities in the 300–400 MW range, has reduced reliance on foreign technology and lowered investment risks. Combined with declining natural gas import prices, rising carbon prices and upscaling CCUS technologies, these developments enhance the competitiveness of gas-fired generation relative to coal. Consequently, while the role of natural gas in China's power sector increasingly shifts toward flexibility provision rather than baseload generation, these economic and system-integration drivers are expected to accelerate gas penetration and sustain upward demand in the power sector over the medium to long term.

The domestic sector is poised to remain an important contributor to natural gas demand growth in China, with consumption projected to increase from around 91 bcm in 2024 to approximately 107 bcm by 2055, before peaking in the late-2030s at about 138 bcm and subsequently declining. Despite this front-loaded demand profile, the domestic sector is expected to account for around 13% of total incremental gas demand over the outlook period, reflecting both infrastructure maturity and longer-term efficiency gains. Supported by an extensive transmission and distribution network, nearly 1 million kilometres of pipelines connecting more than 470 million households, China operates the largest gas distribution system globally, with particularly high penetration in major urban centres.

Policy support remains a key underpinning factor. The 2024 update of the Natural Gas Utilisation Policy continues to classify rural clean-heating projects as a priority application, signalling sustained institutional backing for gas-based heating solutions in underserved and colder regions. In this context, lower wholesale and import gas prices, partially passed through to end users, are expected to support further grid expansion and utilisation in the near to medium term. Over the longer term, however, residential gas demand faces increasing competitive pressure from alternative heating technologies, including electric heat pumps, geothermal systems, biomass-based district heating, and solar thermal solutions, which are expected to gain traction after the 2040s as electrification deepens and efficiency standards tighten. China is the world's largest manufacturer of heat pumps, and the new Action Plan for promoting the high quality development of the heat pump industry (April 2025) places a strong emphasis on further expanding domestic manufacturing capacity, accelerating technological deployment, and reducing production costs, thereby reinforcing China's leadership in this segment and strengthening the competitiveness of heat pumps in both domestic and international markets.

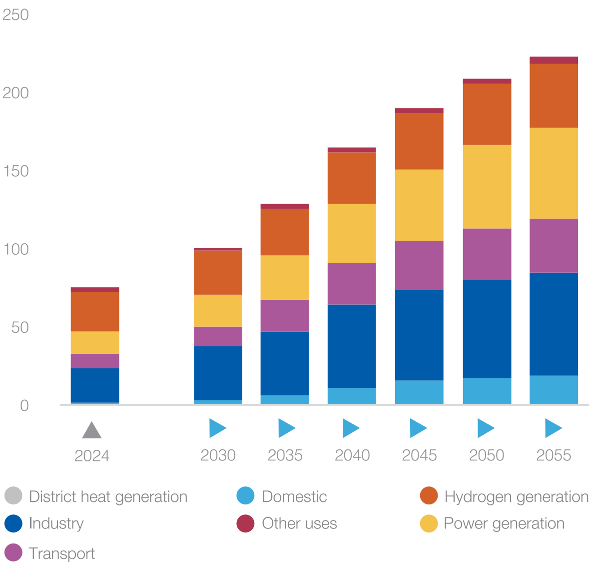
The transport sector is emerging as a niche but increasingly relevant source of natural gas demand growth in China, albeit from a low base. Policy support has been central to this expansion. Under the 14th Five-Year Plan (2021–2025), China has prioritised the phasing out of diesel trucks in favour of cleaner alternatives, supported by subsidies for scrapping older vehicles and incentives for fleet renewal. In parallel, the updated Natural Gas Utilisation Policy classifies heavy-duty road transport as a priority application for LNG, facilitating access to financing for LNG-powered trucks and accelerating the rollout of LNG refuelling infrastructure. As a result, China's LNG truck fleet has nearly tripled since 2019, surpassing 1 million vehicles by 2025, making it the largest such fleet globally.

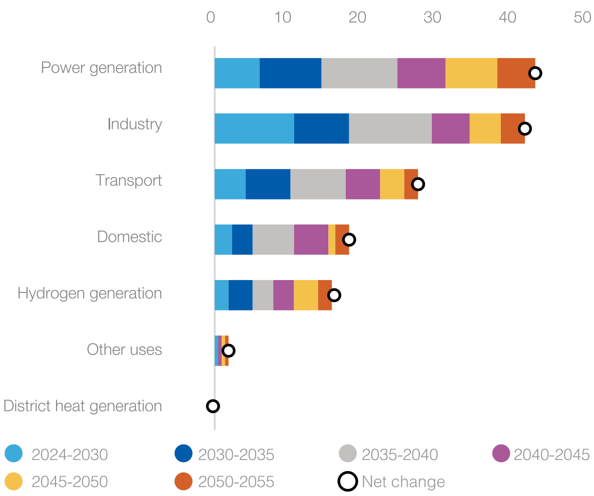
Looking ahead, natural gas demand in the transport sector is projected to increase over the coming decade, driven primarily by LNG use in long-haul trucking and logistics, where electrification remains technically and economically challenging in the near term. However, beyond the 2030s, transport gas demand is expected to enter a gradual decline as electric heavy-duty vehicles gain market share and CNG passenger vehicles are progressively replaced by battery electric alternatives. Additional support for gas demand is expected from the marine and shipping segment, where LNG is increasingly adopted as a marine fuel, leveraging China's extensive LNG bunkering infrastructure across coastal ports and inland river networks. Overall, while the transport sector contributes to medium-term growth in natural gas demand, its long-term outlook points to a declining role, reflecting rapid advances in vehicle electrification and broader decarbonisation of the transport system.

Following China, India is projected to record one of the largest absolute increases in natural gas demand over the next three decades, with consumption rising to around 222 bcm by 2055, nearly 147 bcm above 2024 levels (Figure 4.9). At present, demand is anchored primarily in hydrogen generation, including gas-based hydrogen for nitrogen fertiliser production and refinery hydrogen used in hydrotreating and hydrocracking, alongside the industrial sector and a steadily expanding city gas distribution (CGD) segment. These pillars account for approximately 25 bcm, 21

Figure 4.9

Natural gas demand outlook in India by sector, 2024-2055 (bcm)





Source: GECF Secretariat based on data from the GECF GGM

bcm, and 14 bcm, respectively, reflecting the structural role of gas in feedstock applications, process heat, and urban fuel switching. This demand configuration is largely underpinned by priority allocation of lower-cost, subsidised natural gas, sourced predominantly from domestic production, to sectors with high socio-economic sensitivity. The policy framework supporting these allocations is expected to remain broadly intact over the long term, consistent with the government's objectives of shielding end-users, particularly farmers, from global LNG price volatility, preserving fertiliser affordability, and safeguarding food security. By contrast, power generation continues to play a marginal role in India's gas demand profile: gas-fired output accounted for around 2% of total electricity generation in 2024, reflecting the availability and cost competitiveness of domestic coal, alongside policy prioritisation of renewables and other non-gas sources in the evolving power mix.

Building on this structure, the hydrogen generation sector is projected to expand at a moderate but sustained pace over the outlook period, contributing around 11% of India's incremental natural gas demand growth under the RCS. Demand in this segment is expected to rise to just above 40 bcm by 2055, corresponding to around 18% of total primary natural gas demand by the end of the outlook. Growth is driven primarily by the scaling of fertiliser output to meet rising food demand and by increasing refinery hydrogen requirements associated with tighter fuel-quality standards and higher refinery complexity, rather than by broad-based fuel switching. As a result, natural gas demand for hydrogen generation remains structurally resilient, even as other uses face stronger price sensitivity and competition from electrification over the longer term.

Closely following hydrogen generation, the industrial sector remains a major pillar of natural gas demand in India, where gas is used predominantly as a source of process heat rather than as a feedstock. While iron and steel and cement manufacturing remain structurally reliant on coal and petcoke, reflecting existing process designs and fuel economics, natural gas plays a supplementary and location-specific role, particularly in gas-based DRI units, downstream steel processing, auxiliary heating, and clinker grinding, alongside a broader set of light and medium industries such as glass, ceramics, textiles, and food processing. In practice, industrial gas demand is highly spatially concentrated, shaped by pipeline availability and proximity to industrial clusters, notably in Gujarat, Maharashtra, and parts of Uttar Pradesh.

Under the RCS, natural gas demand in the industrial sector is projected to rise to around 64 bcm by 2055, an increase of nearly 41 bcm compared with 2024 levels. However, with an average annual growth rate of around 3.3%, slightly below the average overall gas demand growth rate of 3.5% per annum, the sector's share of total natural gas consumption is expected to decline modestly to about 29% by 2055, from 31% in 2024. This reflects faster relative expansion in other demand segments, rather than a weakening of industrial gas use. The outlook is underpinned by easing conditions in international gas markets and lower projected import prices, which improve gas competitiveness against coal and liquid fuels and support selective coal-to-gas switching in industrial applications where air-quality constraints, operational flexibility, and infrastructure access are binding. At the same time, continued infrastructure expansion sustains demand for steel, cement, and plastics, anchoring steady growth in industrial gas use, even as efficiency improvements and gradual electrification temper its longer-term share in the overall demand mix.

Since 2016, CGD has emerged as the primary driver of natural gas demand growth in India, at a time when traditional demand centres, most notably power generation and segments of heavy industry, have exhibited stagnation or limited growth. The expansion of CGD has been fundamentally policy-driven, underpinned by successive rounds of Geographical Area (GA) auctions conducted by the Petroleum and Natural Gas Regulatory Board (PNGRB), which have rapidly extended pipeline coverage into urban, peri-urban, and semi-rural regions.

The CGD rollout encompasses both pipeline natural gas connections for the residential and commercial sectors and CNG for the transport sector. Continued priority allocation of subsidised natural gas, together with improved competitiveness of PNG and CNG relative to LPG, diesel, and petrol, has strengthened end-user adoption and underpinned demand growth. As network density increases, economies of scale further improve utilisation rates, reinforcing the expansion trajectory of both household connections and vehicle refuelling infrastructure.

Looking ahead, CGD expansion remains a central pillar of India's gas strategy. The government has articulated ambitious targets of around 120 million PNG connections and approximately 17,500 CNG stations nationwide. Current penetration levels remain well below these objectives, highlighting a substantial gap between policy ambition and on-the-ground deployment. This gap underscores the significant upside potential for natural gas demand growth from the CGD sector over the coming decade, particularly as urbanisation accelerates, vehicle fleets expand, and air-quality considerations continue to favour gas over more polluting alternatives. According to the latest PNGRB projections, CGD is expected to remain a central driver of natural gas demand growth over the coming decades, with consumption rising from around 13.5 bcm in 2024 to approximately 32 bcm by 2030 and nearly 79 bcm by 2040.

With sustained policy support, the transport sector is set to become an increasingly important source of natural gas demand growth in India, accounting for around 18% of total incremental demand over the outlook period. Under the RCS trajectory, natural gas consumption in transport is projected to quadruple by 2055 to around 36 bcm, lifting the sector's share of total gas demand to approximately 16%, from around 12% in 2024. This expansion is driven primarily by the continued penetration of CNG in urban and peri-urban mobility, where CNG demand is rising rapidly across four-wheelers, light goods vehicles, and three-wheelers, supported by favourable fuel economics, lower local air pollution, and expanding refuelling infrastructure. As network coverage improves, further uptake is anticipated in private passenger vehicles and light motor vehicles, reinforcing demand growth.

Infrastructure expansion remains a central enabler. India currently has around 6,900 operational CNG stations, with government targets envisaging a rise to approximately 17,500 stations nationwide, significantly improving accessibility and utilisation rates. Beyond urban transport, India is increasingly emulating China's experience by promoting LNG as a long-haul fuel for heavy-duty vehicles, targeting decarbonisation of hard-to-abate freight segments. According to projections by PNGRB, the LNG truck fleet is expected to reach around 30,000 vehicles by 2030 and approximately 200,000 by 2040, consistent with the government's ambition to transition roughly one-third of long-haul heavy-duty trucking to LNG over time. The emergence of a conducive ecosystem, combining aggregated demand signals to encourage investment in dedicated manufacturing lines, toll exemptions and fiscal incentives, and preferential allocation of domestic gas for LNG vehicles, is expected to underpin this transition and anchor sustained growth in transport-sector gas demand over the coming decades.

With around 24 GW of installed gas-fired capacity in 2024, representing about 6% of India's total power generation fleet, gas-based power plants operated at an average load factor of only around 15%, resulting in gas-fired generation accounting for less than 3% of total electricity output. In practice, gas-based generation in India has been confined largely to meeting peak demand, providing grid reliability, and offering operational flexibility in a power system increasingly dominated by VRE. The sharp surge in LNG prices during 2021–2022 further constrained utilisation, pushing gas-fired plants to historically low operating levels as dispatch shifted decisively toward coal and renewables.

At prevailing tariff structures, gas-based power generation remains structurally uncompetitive against coal- and renewables-based generation, even when supplied with subsidised domestic gas, reflecting both fuel cost differentials and the priority dispatch afforded to renewables. As a result, gas-fired plants have increasingly functioned as capacity assets rather than energy suppliers, valued for their fast ramping capability, peaking support, and system balancing services rather than baseload generation.

Looking ahead, however, the role of gas in the power sector is expected to evolve. Easing conditions in international LNG markets, together with lower projected import prices, improved access to LNG infrastructure, and policy support for power-sector decarbonisation and grid stability, are anticipated to gradually improve the utilisation of gas-fired capacity. In particular, gas is well positioned to address seasonal and intraday demand peaks, notably those associated with rapidly rising cooling loads during summer months, and to complement hydropower variability and VRE integration.

Reflecting these dynamics, the RCS projects that natural gas demand in the power sector grows by 4 folds by

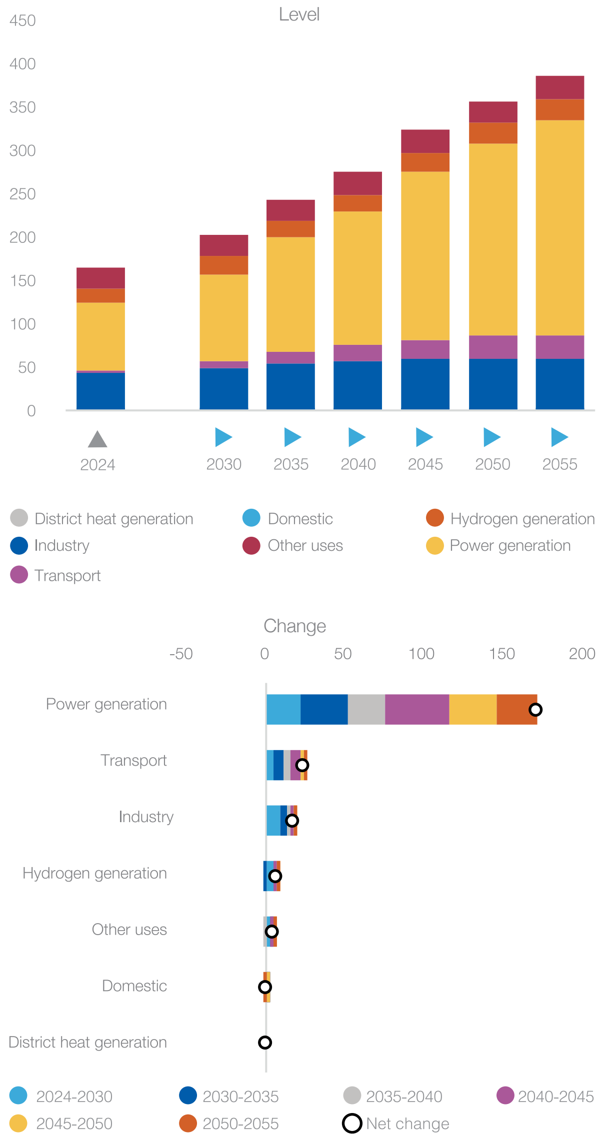
2055, reaching around 57 bcm, as gas-fired generation plays a more prominent role in flexibility provision rather than baseload supply. This expansion would raise the contribution of gas-fired generation to around 27% of the total gas demand, up from around 19% in 2024, while still remaining modest in terms of overall electricity generation share. Installed gas-to-power capacity is projected to increase to around 76 GW by 2055, with near-term growth driven primarily by improved utilisation of existing underutilised plants, followed over the longer term by selective capacity additions to support system flexibility, peak demand, and reliability in an increasingly renewables-heavy power system.

Southeast Asian countries accounted for around 17% of Asia Pacific natural gas demand in 2024, positioning the sub-region as an increasingly important contributor to regional gas demand growth over the long term. **Under the RCS, natural gas demand in Southeast Asia is projected to more than double, rising from 163 bcm in 2024 to around 380 bcm by 2055** (Figure 4.10). As a result, the sub-region contributes approximately 40% of the net increase in natural gas demand in Asia Pacific over the outlook period, with its share of total regional gas consumption rising to about 25% by 2055. Reflecting this structural shift, the share of natural gas in Southeast Asia's primary energy mix is projected to increase to 25% by 2055, up from 17% in 2024, underscoring gas's expanding role in power generation, industry, and system balancing amid rapid electrification and economic growth.

Importantly, this demand growth is highly uneven across the sub-region. A small group of countries, Malaysia, Indonesia, Viet Nam, Singapore, and the Philippines, collectively account for around 92% of incremental natural gas demand growth in Southeast Asia. This concentration reflects differing stages of economic development, power sector structures, domestic resource endowments, and policy choices regarding energy security, fuel diversification, LNG imports, and the role of natural gas as an enabling fuel in nationally determined energy transition pathways.

Against the backdrop of rapid population growth, sustained economic expansion, and Southeast Asia's role as a major global manufacturing and industrial hub, energy security and affordability remain central policy priorities across the sub-region, particularly amid heightened geopolitical tensions and increasing fragmentation of global trade and supply chains. At the same time, reducing local air pollution and lowering the carbon intensity of manufactured products have become increasingly critical to safeguarding industrial competitiveness and maintaining access to international markets subject to stricter environmental standards. In this context, natural gas is positioned to emerge as a durable pillar of Southeast Asia's energy mix, offering a scalable and dispatchable source of energy that balances affordability, reliability, and emissions performance.

Figure 4.10
Natural gas demand outlook in Southeast Asia by sector, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Reflecting these considerations, across Southeast Asia, recent policy developments reaffirm natural gas as an enabling fuel with an evolving but durable role in national energy systems. In Indonesia, the 2025 energy planning framework, spanning Government Regulation No. 40/2025, the RUKN 2025–2060, and PLN's RUPTL 2025–2034, confirms gas as a key enabler of system reliability, with around 10 GW of new gas-fired capacity planned by 2034 to provide flexibility and peaking support as renewables scale up. In Malaysia, post-2024 implementation of existing policies has shifted gas use onto a more market-oriented footing: natural gas continues to underpin power generation and industry, while expanded application of Malaysian

Reference Prices (MRP) has reduced subsidies, improved price transparency, and disciplined demand, alongside rising LNG imports and investment in high-efficiency gas generation. In Viet Nam, the adjusted Power Development Plan VIII positions gas and LNG as strategic balancing fuels, with 28–37 GW of capacity targeted by 2030 (around 20–25% of installed capacity) and power-sector gas demand of roughly 18–22 bcm per year, increasingly met by LNG as domestic supply declines.

Sectorally, power generation is projected to be the dominant driver of natural gas demand growth in Southeast Asia, accounting for more than three-quarters of the total increase in gas consumption over the outlook period. As a result, the share of natural gas in total energy demand is forecast to rise markedly, from around 48% in 2024 to about 65% by 2055. This expansion is reflected in the evolving power mix, with gas-fired generation increasing its share to around 35% by 2055, up from 29% in 2024. Supported by national energy strategies, power development plans, and the growing importance of dispatchable capacity for grid stability and system reliability in increasingly VRE-heavy power systems, installed gas-fired generation capacity is projected to triple to nearly 320 GW by 2055, accounting for around 28% of total installed capacity, broadly in line with current levels in relative terms.

This outlook is underpinned by robust electricity demand growth, particularly in Indonesia and Viet Nam, where power demand is projected to increase by around 3.5% per annum through 2055. Growth is driven primarily by the residential and commercial sectors, reflecting surging air-conditioning penetration and ownership, rising living standards, and rapid digitalisation and data-centre expansion, followed by transport electrification and industrial demand.

Under the RCS, coal-to-gas switching in the power sector emerges as a key structural driver of rising natural gas demand, despite Southeast Asia's relatively young coal-fired fleet, with an average age of less than 15 years. Over the outlook period, the share of coal in power generation is projected to decline sharply, from around 45% in 2024 to about 11% by 2055, as new capacity additions increasingly favour gas and renewables, and as accelerated retirement of existing coal-fired plants is facilitated by innovative policy and financing mechanisms aimed at meeting climate commitments and reducing local air pollution. As a result, natural gas is expected to overtake coal as the leading thermal fuel in the regional power mix by the early 2030s, reinforcing its role as the preferred dispatchable and balancing fuel in Southeast Asia's evolving electricity systems.

The industrial sector represents the second-largest source of natural gas demand in Southeast Asia, with consumption concentrated in Malaysia, Indonesia, and Thailand. Under the RCS, industrial gas demand is projected to increase to around 59 bcm by 2055, up by nearly 17 bcm from 2024 levels. Despite this absolute growth, the sector's share of total natural gas demand is expected to decline markedly, from about 26% in 2024 to around 15% by 2055, reflecting faster expansion in power-sector gas use rather than a weakening of industrial demand fundamentals.

Natural gas in the industrial sector is used predominantly as a source of high-quality process heat, supporting energy-intensive activities such as metal processing, including nickel, aluminium, and copper; cement manufacturing; chemicals and petrochemicals; and a range of light manufacturing industries, including textiles and components for clean energy technologies. As Southeast Asian economies seek to enhance competitiveness in global markets increasingly sensitive to embedded carbon content, coal-to-gas switching in industry has emerged as a priority decarbonisation strategy, enabling reductions in emissions intensity and local air pollution while maintaining cost efficiency. In addition, methanol production within the petrochemical sector, particularly in Malaysia, constitutes a structurally important source of industrial gas demand, reinforcing the role of natural gas as both a fuel and feedstock in the region's industrial value chains.

The hydrogen generation sector, encompassing the production of grey and, to a more limited extent, blue hydrogen from natural gas, constitutes another important source of natural gas demand in Southeast Asia. Gas-derived hydrogen is used primarily in nitrogen-based fertiliser production, notably ammonia and urea, and in refining processes, where hydrogen is required for hydrotreating and hydrocracking to improve fuel quality and meet increasingly stringent product specifications. This demand is structurally supported by national strategies aimed at food self-sufficiency and fertiliser export capacity, particularly in leading producer countries. Under the RCS, natural gas demand for hydrogen generation, still dominated by grey hydrogen pathways, is projected to increase to around 23 bcm by 2055, representing an increase of approximately 6 bcm from 2024 levels. Demand in this segment is highly concentrated in Indonesia, where natural gas is preferentially allocated to fertiliser production for both domestic consumption and export markets, underpinned by administered pricing and subsidy mechanisms that sustain the competitiveness of gas-based hydrogen and fertilizer output.

Starting from a relatively low base, the transport sector is set to emerge as an increasingly important source of natural gas demand in Southeast Asia, driven predominantly by the maritime segment. Over the outlook period, the sector is projected to account for around 11% of total incremental natural gas demand, ranking second only to power generation as a growth driver. Under the RCS, natural gas demand in transport is forecast to rise to around 27 bcm by 2055, representing an increase of nearly 24 bcm from 2024 levels and implying an average annual growth rate of about 7.6%, the fastest among all demand sectors.

This expansion is highly concentrated in Singapore, reflecting its role as a global maritime and bunkering hub and the rapid uptake of LNG as a marine fuel in response to tightening international shipping emissions standards. Formal government policies and regulatory frameworks supporting LNG bunkering, combined with investments in ship-to-ship bunkering infrastructure and parallel initiatives to explore future low-carbon marine fuels, underpin sustained growth in gas demand from the transport sector, reinforcing LNG's role as an optimal solution in Southeast Asia's decarbonisation of maritime transport.

OECD Asia, comprising Japan, South Korea, Australia, and New Zealand, accounted for around 21% of Asia Pacific's natural gas demand in 2024. Amid structurally declining gas consumption across this sub-region, its share is projected to fall to around 10% of total Asia Pacific natural gas demand over the outlook period, reflecting accelerated efficiency gains, fuel switching, and deeper electrification in mature energy systems (Figure 4.11).

While Japan remains one of the largest sources of natural gas demand in the Asia Pacific region, its overall gas consumption has been on a structural downward trend since 2014. This decline reflects a combination of population contraction, subdued long-term economic growth, and government strategies to meet climate commitments, including the objective of achieving net-zero emissions by 2050, through the accelerated deployment of renewables, enhanced energy efficiency, and the gradual restart of nuclear capacity.

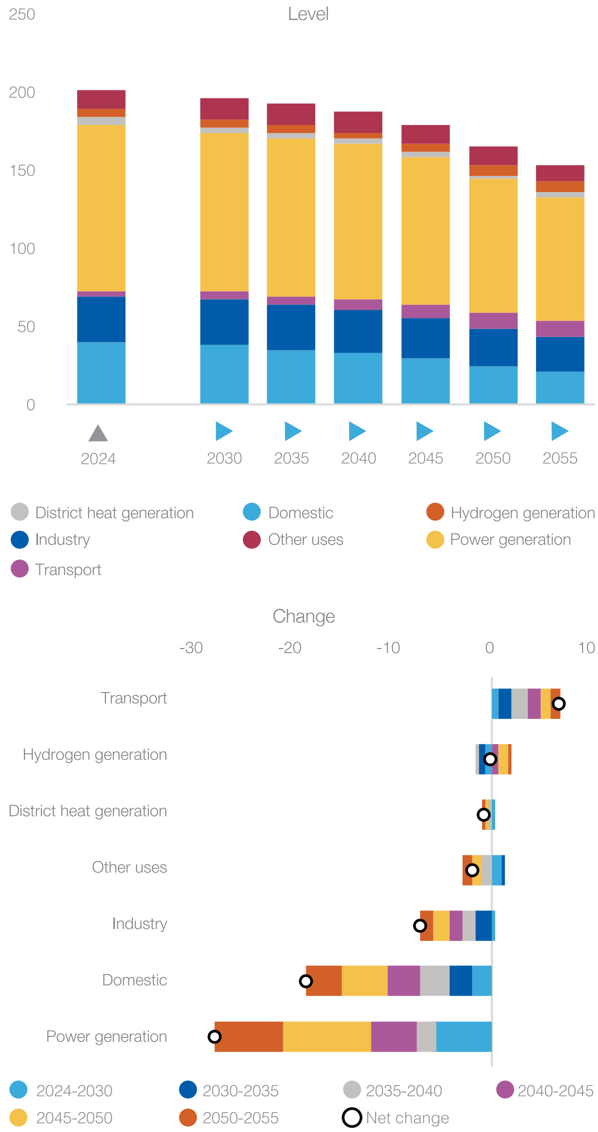
At the same time, Japan faces a potential reversal in electricity demand trends, driven by the expansion of digital infrastructure, semiconductor fabrication, electrification, and AI-related loads. Given the constraints on the pace of renewable deployment, particularly offshore wind, and uncertainties surrounding the speed and scale of nuclear restarts, hydrocarbons, notably LNG, are expected to retain an important role in ensuring energy security and affordability. In this context, LNG, potentially combined with CCUS, is positioned as a pragmatic long-term option within Japan's energy strategy. Reflecting these considerations, the 7th Strategic Energy Plan published in 2025 projects natural gas demand in the range of 68–72 bcm by 2040 under a 73% GHG-reduction pathway, rising to around 99 bcm under a less stringent 61% GHG-reduction scenario.

Consistent with these policy signals, the RCS projects that total natural gas demand in Japan, including a minor contribution from gas works gas (around 2.3 bcm), declines by approximately 35 bcm over the outlook period, reaching close to 60 bcm by 2055. Power generation remains the dominant source of gas demand, accounting for around two-thirds of total consumption throughout the forecast, both in absolute terms and in incremental changes. The overall downward trajectory is driven by demographic decline, modest economic growth, and policies prioritising renewables, nuclear energy, and efficiency improvements. However, easing global LNG market conditions and lower wholesale prices are expected to encourage coal-to-gas switching in the power sector, helping to moderate the pace of decline and reinforcing gas's role as a balancing and transition fuel in Japan's evolving energy system.

In South Korea, natural gas accounts for close to 18% of the primary energy mix, with demand predominantly

Figure 4.11

Natural gas demand outlook in OECD Asia by sector, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

driven by power generation, which represented around half of total gas consumption in 2024. Looking ahead, gas demand is supported by industrial expansion, accelerated electrification, and structural changes in the power sector, including ambitious coal phase-out targets, constraints on the pace of offshore wind deployment, and delays and rising costs associated with planned nuclear capacity additions. These factors reinforce the role of natural gas as a reliable and flexible source of generation over the coming decades.

This policy direction is reflected in the 11th Basic Plan for Electricity Supply and Demand (2024–2038), finalised in February 2025, which projects peak electricity demand to reach around 129 GW by 2038 and requires approximately 158 GW of installed capacity to ensure adequate reserve margins. While the plan prioritises a rapid expansion of carbon-free generation, with the combined share of renewables and nuclear rising to over 70% by 2038, it also underscores the need for dispatchable capacity, including around 10 GW of additional gas-fired generation, to support system reliability as variable renewables scale up. Importantly, the plan also provides for the retirement of around 40 coal-fired power units by 2038, accelerating the structural shift away from coal.

In parallel, substantial ongoing and planned investments in LNG import terminals, regasification, and storage infrastructure strengthen supply security and enhance the ability of gas demand, particularly in the power sector, to respond flexibly to price signals. Against this backdrop, easing global LNG market conditions and lower projected spot LNG prices, combined with accelerated coal retirements and continued uncertainty surrounding nuclear project timelines, create material upside potential for LNG utilisation, even as longer-term decarbonisation efforts advance. Reflecting these dynamics, under the RCS, total natural gas demand in South Korea declines modestly by around 7 bcm, reaching approximately 57 bcm by 2055. Within this total, power-sector gas demand increases by about 3 bcm to around 35 bcm, raising its share of overall gas consumption to roughly 61%, up from 49% in 2024. Despite higher absolute gas use in electricity generation, the share of natural gas in the power mix edges down slightly to around 25% by 2055, from 28% in 2024, as renewable and nuclear generation expand more rapidly. Over the same period, coal-fired generation contracts sharply, from around 190 TWh (31% of power generation mix) in 2024 to about 19 TWh (2.5%) by 2055, underscoring South Korea's rapid coal phase-out and the progressive reconfiguration of the power system toward natural gas and low-carbon sources to meet emission targets.

Natural gas has emerged as the fuel of choice in Chinese Taipei, driven by the formal phase-out of nuclear power by 2025, structural constraints on scaling up renewables, and policies aimed at progressively reducing coal-fired generation. Renewable deployment is constrained by limited land availability for large-scale solar projects and the higher costs and longer development timelines associated with offshore wind, while electricity demand is set to rise further due to the expansion of energy-intensive semiconductor manufacturing, data centres, and rapid AI adoption. These structural factors have been explicitly recognised in recent government policy. Under the Second Energy Transition Policy reaffirmed in 2024–2025, the authorities prioritise replacing coal with natural gas, strengthening grid resilience, and expanding energy storage, positioning gas as an enabling fuel to maintain system reliability and manage emissions. Consistent with this approach, official power-mix targets envisage around 50% gas-fired generation by 2025, following the shutdown of the last nuclear unit, while renewable expansion continues under binding deployment plans.

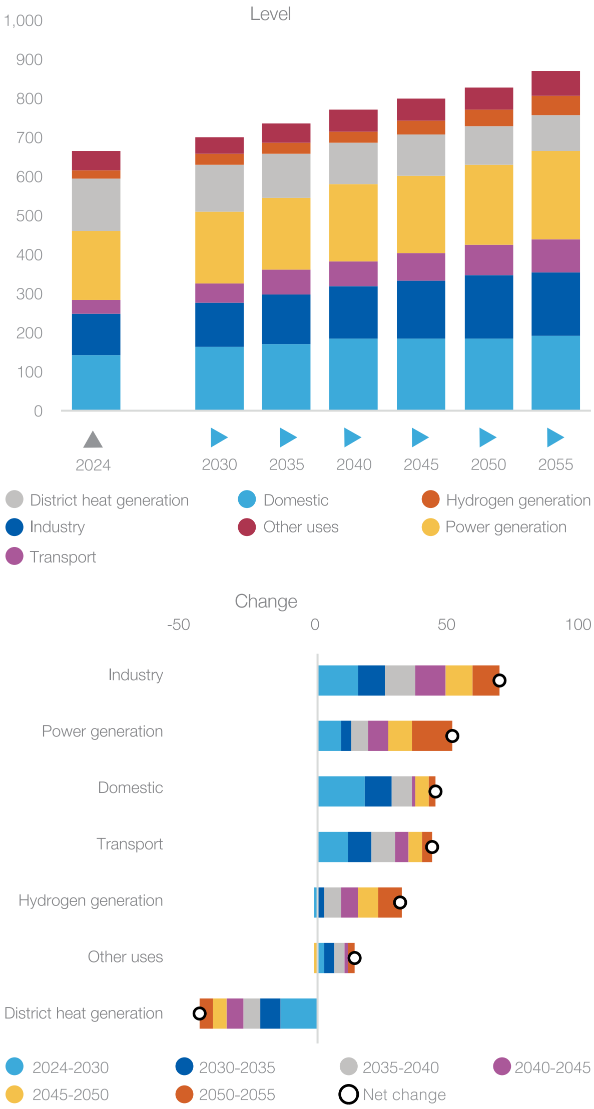
Reflecting these policy signals, the share of natural gas in primary energy demand is projected to rise to around 35% by 2055, up from 26% in 2024. Under the RCS, natural gas demand in Chinese Taipei increases by around 5 bcm to reach approximately 40 bcm by 2055, with virtually all incremental demand absorbed by the power generation sector. As a result, the share of power generation in total gas consumption rises to around 82% by 2055, from 78% in 2024, while gas-fired generation accounts for roughly 60% of the electricity mix, compared with around 42% in 2024. Rising electricity demand, the retirement of nuclear and coal capacity, and the more modest pace of renewable penetration underpin this trajectory, even as population growth slows and eventually turns negative. Meeting this outlook will require continued investment in LNG import terminals, regasification capacity, and gas-fired power plants, reinforcing the central role of LNG and natural gas in Chinese Taipei's long-term power system transition.

4.4.3 Eurasia

Natural gas constitutes the core structural fuel of Eurasia's energy system and is projected to account for 58% of the region's primary energy mix by 2055, up from around 50% in 2024. **This increasing dominance is underpinned by a substantial rise in regional gas demand, which is forecast to reach approximately 863 bcm by 2055, compared with 659 bcm in 2024** (Figure 4.12). As economic output expands and income levels rise, the role of natural gas is expected to strengthen further, supporting industrial development, modernization and efficiency upgrade, wider gasification and access to modern and cleaner energy, and the evolution of power systems with growing penetration of VREs. In parallel, natural gas plays a critical role in decarbonising coal-based heat and power generation, improving local air quality, and enhancing system flexibility. Its contribution also extends to the transport sector, particularly through the continued deployment of natural gas vehicles, notably CNG, as a cost-effective and lower-emissions alternative to oil-based fuels.

Figure 4.12

Natural gas demand outlook in Eurasia by sector, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Natural gas demand in Eurasia is projected to increase across all major end-use sectors, with the exception of district heat generation, where consumption is expected to decline gradually as efficiency improves and systems are modernised. Power generation remains the single largest source of natural gas demand in the region, accounting for approximately 26% of total consumption in 2024. Under the RCS, gas demand in the power sector is projected to increase by around 50 bcm, reaching 223 bcm by 2055. As a result, the sector's share in total regional gas demand remains broadly stable over the outlook period, highlighting the enduring role of natural gas in supporting Eurasia's electrification trajectory.

This trend reflects sustained growth in electricity demand driven by urbanisation, industrial modernisation, digitalisation, and rising living standards, with total power generation projected to grow at just over 1% per year, reaching approximately 2,027 TWh by 2055. Gas-fired generation accounted for around 45% of total electricity output in 2024 and is expected to maintain a similar share through 2055, underscoring natural gas's central role as a reliable, dispatchable, and flexible source of power in the region's evolving electricity systems.

With long, cold winters and extended heating seasons, space heating represents the dominant component of domestic energy demand across Eurasia. Against this backdrop, the presence of extensive gas transmission and distribution networks, largely inherited as sunk infrastructure, together with regulated and subsidised residential gas prices, has made natural gas the most efficient, affordable, and scalable solution for household heating and small commercial premises. As a result, the domestic sector constitutes a major pillar of natural gas demand in the region, accounting for around 22% of total consumption.

Under the RCS, while the sector's share in overall gas demand remains broadly stable, absolute consumption is projected to increase by around 43 bcm, reaching approximately 186 bcm by 2055, reflecting population dynamics, rising living standards, and continued expansion of gas access. This outlook is strongly underpinned by policy support, notably the Social Gasification (Dogazifikatsiya) program in Russia, which aims to connect millions of additional households by 2030, particularly in rural areas and small towns, through free or subsidised pipeline connections. In parallel, Kazakhstan's gasification strategy, as set out in the National Development Plan to 2029, prioritises the expansion of gas access to northern and eastern regions, replacing coal-based household heating, improving air quality, and supporting socio-economic development. Collectively, these structural and policy factors reinforce the durable role of natural gas in the domestic sector across Eurasia over the outlook period.

A distinctive legacy feature of natural gas consumption in Eurasia is the widespread use of large-scale, centralised district heating systems, historically supplied by coal- and gas-fired combined heat and power (CHP) plants serving dense urban areas. In 2024, district heat generation accounted for around 20% of total natural gas demand (about 135 bcm). However, much of the existing CHP fleet is technologically outdated, with low efficiency, high operating and maintenance costs, continued reliance on coal, and significant contributions to urban air pollution, undermining its long-term viability.

In response, governments across Eurasia are pursuing a structural transformation of district heating, prioritising electrification of heat, decentralised heating solutions, and fuel switching away from coal. This transition accelerates the early retirement of inefficient coal-based CHP plants and the gradual phase-down of older gas-fired steam CHP units, while new investment increasingly favours high-efficiency CCGTs deployed mainly for power generation and system flexibility. As a result, natural gas demand in district heating declines structurally, even as gas use continues to grow in other sectors such as power generation, industry, and direct residential consumption.

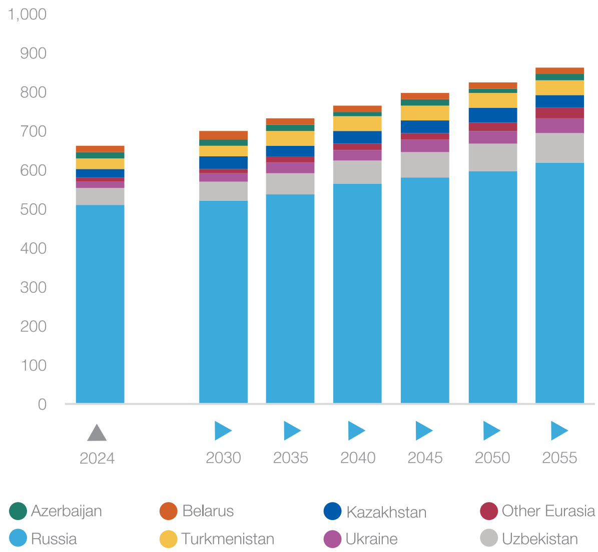
Consistent with these trends, the RCS projects that gas demand for district heat generation falls by nearly 44 bcm to around 91 bcm by 2055, reducing its share in total regional gas demand to about 11%, down roughly 9 percentage points from 2024. This development reflects a sectoral reallocation and efficiency-driven upgrading of gas use, rather than a general phase-down of natural gas in Eurasia.

Against the backdrop of continued industrialisation, the industrial sector emerges as the strongest driver of natural gas demand growth in Eurasia over the coming decades. Under the RCS, industrial gas demand is projected to increase by nearly 68 bcm, reaching around 168 bcm by 2055, raising the sector's share of total natural gas consumption from 15% in 2024 to 19%. This growth is underpinned by the region's process-heat-intensive industrial structure, particularly in metals, non-metallic minerals, and heavy manufacturing, where natural gas remains difficult to substitute. Additional support comes from coal-to-gas switching in industrial boilers and furnaces driven by tightening air-quality standards, as well as the modernisation of legacy assets favouring higher-efficiency gas-fired systems. In parallel, infrastructure-led gasification is expanding access to gas in industrial clusters, enabling the displacement of oil products. These upward pressures are partially offset by electrification and efficiency improvements, especially in low- and medium-temperature processes, which moderate long-term growth while leaving industrial gas demand structurally resilient in absolute terms.

The role of natural gas in the transport sector across Eurasia is expected to expand steadily over the outlook period, with demand nearly doubling to around 82 bcm by 2055. As a result, the sector's contribution to total natural gas consumption rises to about 10% by 2055, up from 6% in 2024. This growth is driven primarily by the continued expansion of natural gas vehicles (NGVs), dominated by CNG in road transport, particularly in buses, taxis, and light-duty commercial vehicles. The underlying drivers combine economic incentives, including fuel-cost advantages and enhanced energy security; environmental considerations, notably improvements in urban air quality; and industrial policy objectives, such as the development of domestic vehicle supply chains and refuelling infrastructure. In Russia, Kazakhstan, and Uzbekistan, governments have actively supported this transition through policies focused on public transport conversion, municipal fleet renewal, and the scaling up of CNG refuelling networks, positioning

Figure 4.13

Natural gas demand outlook in Eurasia by country, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

natural gas as a pragmatic and cost-effective pathway to decarbonise high-mileage urban transport segments.

Natural gas consumption patterns vary significantly across Eurasia and remain highly concentrated, with Russia, Turkmenistan, Uzbekistan, Ukraine, and Kazakhstan collectively accounting for over 90% of total regional gas demand in 2024, as well as the bulk of projected demand growth over the outlook period. Among these countries, Russia represents the centre of gravity, accounting for more than three-quarters of Eurasia's natural gas consumption and over half of the region's incremental demand growth by 2055 (Figure 4.13).

Driven by rising electrification, continued gasification policies, and energy efficiency improvement strategy in heat generation, transmission and distribution, natural gas demand in Russia is projected to increase to around 620 bcm by 2055, nearly 110 bcm higher than in 2024. Power generation, which accounts for roughly one-quarter of total gas demand, is expected to record an incremental increase of about 21 bcm, reaching 149 bcm by 2055, corresponding to an average annual growth rate of around 1.7%. Reflecting this trend, Russia announced plans in 2024 to add around 14 GW of new gas-fired power capacity, with the 2025–2030 Electric Power Industry Development Program identifying priority regions for new capacity, including southern Russia, the Far East, southeastern Siberia, and the Moscow region.

Natural gas is also expected to retain its central role in the industrial sector, which emerges as the strongest driver of demand growth over the coming three decades. Under the RCS, industrial gas demand is projected to rise by 59 bcm to reach around 140 bcm by 2055, increasing its share of total gas consumption to 23%, up from 16% in 2024. In parallel, continued household gasification programs support rising demand in the domestic sector, where consumption is projected to exceed 113 bcm by 2055, an increase of about 26 bcm relative to 2024. These trends are reinforced by the Energy Strategy of the Russian Federation adopted in 2025, which underscores the strategic role of natural gas in supporting economic development, energy security, and system modernisation over the long term.

Uzbekistan is the second-largest natural gas consumer in Eurasia, with natural gas accounting for around 73% of the primary energy mix in 2024, a share projected to rise to approximately 81% by 2055. Natural gas forms the backbone of Uzbekistan's energy system, underpinning electricity generation, transport, and residential energy use. Supported by a long-standing and extensive gas transmission and distribution network, the domestic sector remains the largest source of gas demand, reflecting widespread use of gas for space heating, cooking, and water heating, and is expected to retain its importance over the outlook period. Seasonal demand peaks during winter months have, however, highlighted the importance of demand management and system optimisation, reinforcing ongoing policy efforts to enhance efficiency and reliability rather than signalling a structural shortfall.

Power generation is the second-largest consumer of natural gas, with gas-fired plants accounting for around 80% of the power mix in 2024, underscoring gas's central role in ensuring system stability and affordability. In parallel, Uzbekistan hosts one of the largest CNG vehicle fleets globally, positioning the transport sector as another structurally important outlet for natural gas, particularly in urban mobility. Reflecting these entrenched sectoral dynamics and continued policy support, the RCS projects that total natural gas demand in Uzbekistan increases by around 32 bcm to reach approximately 79 bcm by 2055, reinforcing the country's status as one of the most gas-intensive energy systems in Eurasia.

With near-total reliance on natural gas for power generation and a share of around 77% in the primary energy mix in 2024, **Turkmenistan** stands out as another major natural gas consumer in Eurasia. Natural gas underpins the country's energy system, with the domestic sector and power generation together accounting for more than 70% of total gas demand, reflecting widespread use of gas for electricity production, space heating, and household energy needs, supported by extensive gas infrastructure and regulated domestic pricing.

Looking ahead, Turkmenistan is expected to gradually diversify the sources of gas demand, with policy emphasis shifting toward downstream monetisation through the expansion of petrochemical and fertiliser industries, including gas-based chemical production aimed at value addition and export revenue. In parallel, gas-fired power generation is expected to remain central to ensuring reliable and affordable electricity supply. Reflecting these dynamics, the RCS projects that natural gas demand in Turkmenistan continues to rise to around 38 bcm by 2055, nearly 8 bcm higher than in 2024, reinforcing the country's position as a highly gas-intensive energy system while gradually broadening the economic role of natural gas beyond power and household use.

4.4.4 Europe

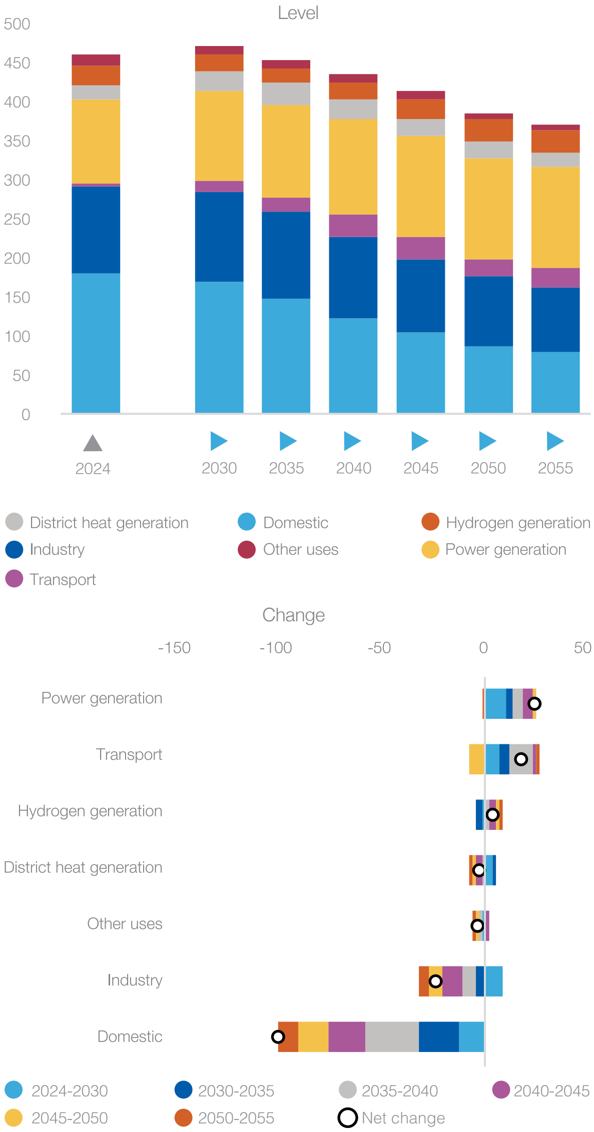
Natural gas has long constituted a structural pillar of Europe's energy system, and its role remains deeply embedded despite accelerating decarbonisation ambitions. For more than two decades, natural gas has consistently accounted for over 20% of total primary energy consumption, remaining resilient at around 23% in 2024. This persistence reflects not merely its scale, but the depth of functional integration across Europe's energy architecture. In 2024, natural gas supplied approximately one-third of residential energy use, 27% of commercial demand, 32% of industrial energy consumption, and around 15% of power generation, while also accounting for one-third of district heat production and nearly 63% of hydrogen generation.

Europe enters the outlook period with natural gas demand of around 460 bcm in 2024, representing close to 11% of global consumption. Unlike most other regions, however, Europe's demand trajectory reflects a mature energy system operating under binding climate targets, high electrification ambition, and heightened energy-security concerns. **Over the period to 2055, regional gas demand is projected to decline gradually at around 0.7% per year, falling to just above 370 bcm, while Europe's share of global demand declines to approximately 7%. Crucially, this trajectory is non-linear. Rather than an immediate** or monotonic decline, natural gas demand is expected to stabilise and rise modestly through the late 2020s, before entering a shallower, managed decline thereafter as structural decarbonisation pathways mature and alternative technologies scale (Figure 4.14).

At the aggregate level, Europe's gas outlook broadly mirrors the flattening of primary energy demand, yet this headline trend masks important sectoral and national divergences. Accelerated electrification, expanding renewable capacity, and efficiency gains exert sustained downward pressure on direct gas use, while structural deindustrialisation in parts of the region further dampens long-term demand. At the same time, natural gas retains a critical system function: maintaining stability, managing affordability risks, and ensuring security of supply during periods of rapid structural change. The result is not the

Figure 4.14

Natural gas demand outlook in Europe by sector, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

displacement of natural gas, but a reconfiguration of its role, from a volume-driven fuel toward a strategic enabler of system reliability and flexibility, particularly during the most challenging phases of the transition.

This reconfiguration is most clearly expressed in the power sector, which increasingly anchors Europe's medium-term gas demand. After a prolonged period of stagnation, electricity demand is projected to re-accelerate, growing at an average rate of around 2% per year over the outlook period to reach approximately 7,020 TWh by 2055. This growth is driven by the electrification of end-use sectors, rising cooling demand, data centres, digitalisation, and emerging AI-related loads. Importantly, this demand expansion coincides with a period in which carbon prices continue to rise and global natural gas markets are expected to ease, improving the relative economics of gas-fired generation. Under these conditions, coal-to-gas switching accelerates in countries such as Germany, Poland, and Türkiye (of roughly 126 GW of coal-fired capacity in 2025, about 37 GW is expected to be decommissioned by 2030, and a further 26 GW by 2035), while the pace of renewable scale-up, particularly offshore wind, is constrained by cost inflation, financing conditions, and delivery bottlenecks. At the same time, heat-pump deployment has lost momentum, partly reflecting subsidy phase-downs and affordability constraints, indirectly reinforcing gas demand in both the power and heating systems.

These interacting trends materially reinforce the need for dispatchable, fast-ramping capacity, a role that gas-fired power plants are positioned to fulfil at scale. As a result, natural gas demand in power generation is projected to increase by around 24 bcm, reaching approximately 119 bcm by 2035, even as gas's share of the power generation mix declines to around 10%, down from 15% in 2024. This apparent paradox reflects the growing absolute scale of electricity demand and the rising value of flexibility. Importantly, this increase is front-loaded: gas demand in power generation strengthens over the coming decades before entering a prolonged plateau after 2045 as low-carbon capacity, storage, and grid reinforcements progressively reduce reliance on thermal balancing.

In the industrial sector, natural gas demand is projected to decline by around 25 bcm over the outlook period, reaching approximately 84 bcm by 2055, while its share of industrial energy consumption remains broadly stable at around 24%. This reflects the interaction of structural headwinds rather than accelerated fuel switching. Europe's energy-intensive industries face a dual constraint: subdued end-product demand amid weak economic growth, and continued exposure to geopolitical tensions, trade fragmentation, and supply-chain disruptions. The loss of low-cost pipeline gas has exposed long-standing competitiveness challenges, leading to industrial contraction in some segments rather than widespread substitution away from natural gas.

At the same time, progress in electrifying industrial process heat remains slow, particularly for high-temperature applications, while many industrial clusters are deeply integrated into existing gas transmission and distribution networks, reinforcing path dependency. Episodes of extremely high electricity prices have further underlined natural gas's role as a cost-stabilising and reliable energy source, limiting the pace of displacement by electricity. As a result, while a strong rebound in industrial gas demand is unlikely, moderating gas prices in the medium term are expected to support demand stabilisation, delaying a sharper decline and anchoring

Chapter 4

natural gas as a core industrial fuel through much of the outlook period.

The residential and commercial sectors represent Europe's most politically sensitive and structurally complex decarbonisation challenge. Together accounting for close to 40% of regional gas demand in 2024, consumption in these sectors is projected to decline by roughly half by 2055, yet still amount to a notable 78 bcm level. Heat-pump deployment has persistently fallen short of targets due to affordability constraints, housing stock limitations, behavioural inertia, and political resistance. Fiscal pressures, linked to rising healthcare, social, and defense spending, limit the scope for sustained subsidy support, while large-scale electrification of heating would impose additional strain on power systems increasingly dependent on intermittent renewables. Consequently, Europe's extensive gas distribution networks and large installed base of gas appliances continue to confer a durable structural advantage to natural gas in heating, particularly through the medium term.

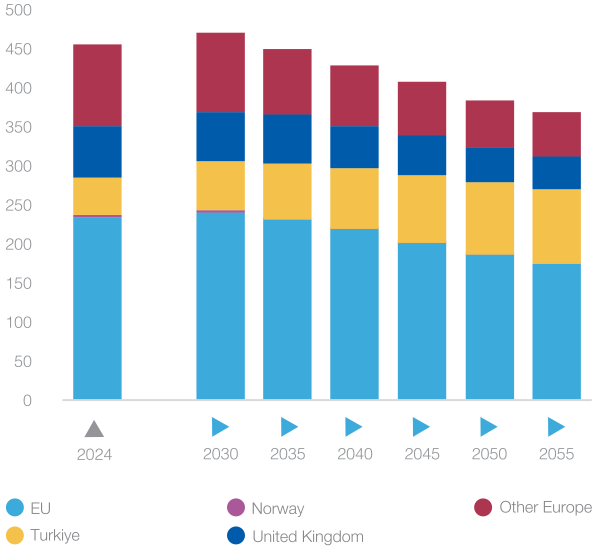
At the country level, Europe's gas outlook is shaped by a limited number of large markets that together account for over 80% of regional demand. Germany, the United Kingdom, Italy, Poland, and Türkiye dominate both in absolute consumption and in shaping regional trends through 2055. While aggregate demand in several of these markets declines or stabilises over time, sectoral composition, policy choices, and transition pathways diverge markedly, producing heterogeneous national trajectories (Figure 4.15).

Natural gas demand in **Germany** is projected to decline by around 20 bcm over the outlook period, reaching just below 60 bcm by 2055, reflecting a gradual rebalancing across end-use sectors rather than a uniform contraction. While gas consumption in the residential sector and parts of industry is expected to erode over time due to electrification and efficiency improvements, power generation increasingly emerges as the central pillar of long-term gas demand. This reflects the evolving function of natural gas within Germany's electricity system, where it is valued less as a baseload fuel and more as a source of dispatchable capacity, system flexibility, and reliability.

Following the contraction in electricity demand during the recent energy crisis, power consumption is expected to recover and expand over the long term, driven by electrification of end-use sectors, digitalisation, data centres, and broader structural changes in the economy. This recovery coincides with easing natural gas prices, rising carbon prices under the EU ETS, and a slower-than-anticipated rollout of offshore wind, where higher capital costs, grid constraints, and permitting delays have weakened near-term investment momentum. Together, these factors strengthen the economic and system case for gas-fired generation through the late

Figure 4.15

Natural gas demand outlook in Europe by country, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

2020s and early 2030s.

Coal-to-gas switching remains a key driver under Germany's Coal Exit Law, which mandates the phase-out of coal-fired power generation by 2038 at the latest, with implementation increasingly conditioned on system adequacy and security-of-supply considerations. In practice, the pace of coal retirements has become closely linked to the availability of sufficient gas-fired backup capacity to manage renewable intermittency and preserve grid stability. As a result, natural gas's share in power generation is projected to increase from around 19% in 2024 to over 40% by 2055, with gas consumption in the power sector rising from approximately 15 bcm to 24 bcm. This increase is front-loaded, peaking over the coming decades before gradually easing as renewable capacity, storage solutions, and grid reinforcements scale up.

The **United Kingdom** remains Europe's second-largest natural gas market, with demand of nearly 65 bcm in 2024 projected to decline only gradually to 43 bcm by 2055, reflecting strong structural resilience across key end-use sectors. The domestic sector continues to underpin demand, supported by a highly integrated high- and low-pressure gas grid serving more than 20 million homes. Domestic consumption, at around 30 bcm in 2024 (nearly 46% of total demand), is expected to plateau before declining to 18 bcm by 2055, as electrification progresses slowly amid affordability constraints, housing stock limitations, and the policy exclusion of hydrogen from mass residential heating.

In the power sector, gas retains a critical role following the completion of coal phase-out in 2024. Supported by capacity mechanisms and the UK Energy Security Strategy, gas-fired generation remains central to system adequacy and flexibility, with demand staying above 10 bcm by 2055 despite growing renewable penetration. Ongoing reliance on LNG imports, and interconnectors further anchors gas demand by reinforcing security of supply rather than driving volumetric growth.

Natural gas demand is also supported by hydrogen production with CCUS, endorsed under the UK's hydrogen strategy and cluster sequencing, particularly through projects such as HyNet and the East Coast Cluster. While the scale and timing remain subject to cost and execution risks, gas demand for hydrogen could rise toward 6 bcm by 2055 in higher-uptake cases. Taken together, these dynamics underpin a gradual and managed decline in UK gas demand, with natural gas retaining a system-critical role in heating, power generation, and transition pathways well into the long term.

With natural gas accounting for around 25% of primary energy supply, **Türkiye** stands out as the only major European market with sustained long-term growth in gas demand. Consumption is projected to rise from approximately 49 bcm in 2024 to nearly 95 bcm by 2055, driven by rapid electrification, urbanisation, and supportive policy frameworks. The power sector is the main engine of this growth, as electricity demand is forecast to increase by 3.1% per year, reaching just under 880 TWh by 2050. To meet rising demand while balancing expanding renewable capacity, installed gas-fired power capacity is expected to grow from around 29 GW in 2024 to approximately 65 GW by 2055, lifting gas use in power generation by around 29 bcm to 40 bcm.

This expansion is reinforced by coal-to-gas switching in urban air-quality zones and the absence of a formal coal phase-out, while Türkiye's National Energy Plan to 2035 positions gas as a core balancing fuel alongside renewables. Beyond power generation, continued expansion of the national gas distribution network increases household access, raising domestic demand to nearly 27 bcm by 2055, up from around 22 bcm in 2024. Additional support comes from growing gas use in hydrogen production and transport, ongoing market liberalisation, and Türkiye's ambition to operate as a regional gas trading hub, underpinned by long-term LNG import and storage expansion that strengthens supply flexibility and system resilience.

4.4.5 Latin America

Latin America accounted for around 4% of global natural gas demand in 2024, equivalent to approximately 150 bcm, making it the smallest gas-consuming region among major global aggregates. Natural gas use is concentrated primarily in the power generation and industrial sectors, which together account for the bulk of regional demand, while gas represents around 18% of total primary energy demand. Notable exceptions exist in Argentina and Colombia, where long-standing gas massification programs have resulted in relatively high levels of residential consumption, particularly during winter season. Beyond these more mature markets, however, the limited availability of transmission and distribution infrastructure continues to constrain wider gas penetration, particularly in countries with incipient industrialisation, fragmented energy systems, and limited access to pipeline or LNG infrastructure. **Under the RCS, natural gas demand in Latin America is projected to increase by around 111 bcm over the outlook period, reaching approximately 261 bcm by 2055.** As a result, Latin America's share in global natural gas demand remains broadly stable at around 5% throughout the forecast period (Figure 4.16).

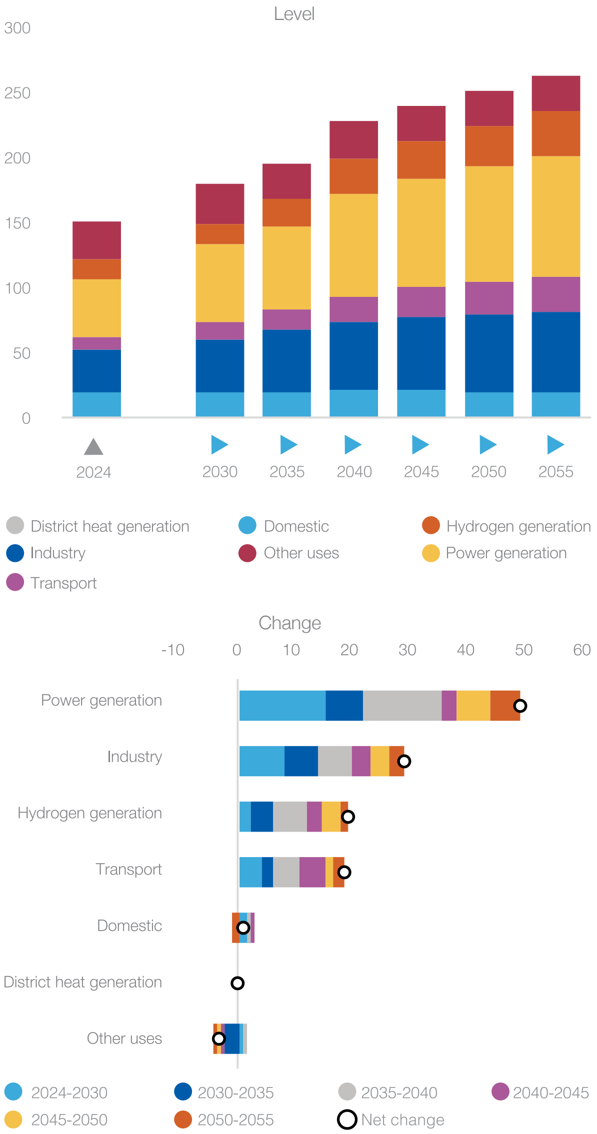
Looking ahead, long-term natural gas demand growth in Latin America is underpinned by a combination of structural power-sector requirements, industrial fuel substitution, and the progressive deepening of gas-based value chains. While infrastructure constraints remain a limiting factor in some markets, gas demand growth is increasingly shaped by system-level needs and strategic industrial priorities rather than short-term price effects alone. In this context, the power and industrial sectors emerge as the dominant sources of incremental demand over the outlook period.

In the power sector, natural gas demand growth is increasingly driven by the need to ensure system flexibility, reliability, and real-time balancing as electricity systems undergo rapid structural transformation. Regional electricity demand is projected to nearly double over the forecast period, reaching around 3,660 TWh by 2055, supported by sustained economic growth, rapid increases in cooling demand, urbanisation, progressive electrification of end-use sectors, and the emergence of data centres, particularly in large markets such as Brazil. These demand-side pressures are unfolding alongside a growing exposure of power systems to hydropower variability, which has historically underpinned regional electricity supply, as well as an expanding share of variable renewable energy, increasing intermittency and short-term volatility in generation profiles.

Within this evolving system context, natural gas-fired power plants offer a unique combination of dispatchability, fast ramping capability, and high availability, positioning gas as the most effective complement to both hydropower and variable renewables. Gas-fired generation plays a critical role in mitigating hydrological risks, smoothing renewable output, and maintaining frequency and voltage stability, thereby safeguarding overall system adequacy and security of supply. In addition, in selected countries with existing thermal fleets, most notably Chile, there remains scope for coal-to-gas switching, which is expected to accelerate as global gas markets ease and hub-based spot gas prices decline, improving the variable-cost

Figure 4.16

Natural gas demand outlook in Latin America by sector, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

competitiveness of gas-fired generation relative to coal. Taken together, these dynamics underpin a structurally resilient and system-critical role for natural gas in the regional power mix, increasingly anchored in flexibility provision and balancing services rather than baseload expansion. Under the RCS, natural gas demand in power generation is projected to increase by around 49 bcm, reaching approximately 93 bcm by 2055, accounting for 44% of incremental natural gas demand growth over the outlook period and around 36% of total regional gas demand, up from 29% in 2024. As a result, share of natural gas in the regional power mix is projected to rise to 21% by 2055, up from 18% in 2024.

In the industrial sector, natural gas demand growth in Latin America is underpinned by a combination of fuel switching, industrial competitiveness considerations, and targeted policy-driven investment in gas-based industries. Lower global gas prices and continued market liberalization, most notably under Brazil's New Gas Law and associated regulatory reforms, are improving the cost competitiveness of natural gas relative to fuel oil and coal. This facilitates broader uptake of gas in industrial boilers and process heat applications, particularly in chemicals, refining, metals, and other energy-intensive industries, where fuel costs and operational efficiency are critical determinants of competitiveness.

These demand-side dynamics are reinforced by structural supply-side developments that strengthen the regional gas ecosystem. Regional gas integration, most prominently through expanded pipeline flows from Argentina's Vaca Muerta to neighbouring markets, together with sustained upstream investment in countries such as Colombia, enhances supply availability and reliability. Collectively, these infrastructure and policy developments reinforce natural gas as a core industrial feedstock and energy source, particularly where it displaces residual liquid fuels and supports the development of higher-value manufacturing activities. Under the RCS, natural gas demand in the industrial sector is projected to increase by around 29 bcm, reaching approximately 63 bcm by 2055, accounting for 26% of total incremental demand growth over the outlook period and around 24% of total regional gas demand, broadly in line with its share in 2024.

Within this broader industrial expansion, hydrogen and ammonia production emerges as a key and increasingly structural source of natural gas demand. The revival and expansion of domestic fertiliser production, particularly in Brazil, is being prioritized to reduce import dependence, strengthen food security, and mitigate exposure to volatility in global fertiliser markets. In this context, Petrobras has restarted operations at its nitrogen fertiliser plants in Sergipe and Bahia, resuming production of ammonia, urea, and ARLA-32, with individual plant capacities in the range of 1,300–1,800 tonnes per day. In parallel, state-led plans envisage further capacity additions across Paraná, Espírito Santo, and Mato Grosso do Sul, with the objective of supplying up to 35% of Brazil's nitrogen fertiliser demand by the late 2020s, supported by targeted investment and federal industrial policy.

As a result, natural gas demand for hydrogen and ammonia production is projected to grow structurally over the outlook period. Under the RCS, gas demand for hydrogen production is forecast to increase by around 19 bcm, reaching approximately 34 bcm by 2055, accounting for 17% of total incremental gas demand growth and around 13% of regional natural gas demand, up from around 10% in 2024. This evolution underscores the role of natural gas not only as an industrial fuel, but also as a strategic feedstock supporting regional industrial resilience and value-chain deepening.

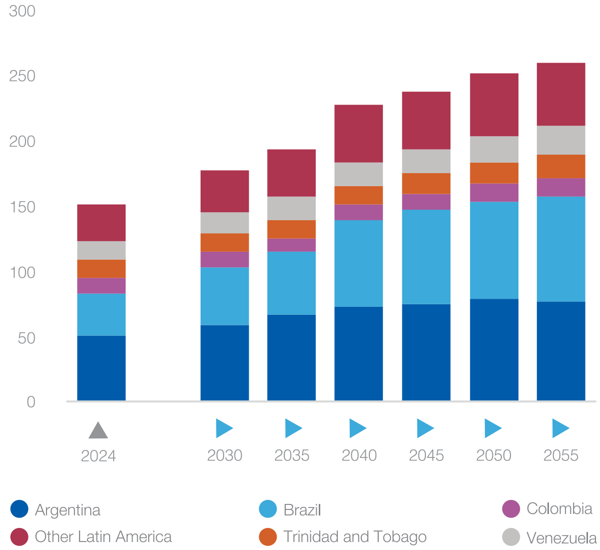
Over the outlook period, natural gas is expected to maintain a modest yet structurally resilient role in Latin America's transport sector, supported by existing market depth, targeted policy support, and infrastructure lock-in in segments where electrification remains constrained. The region already hosts around 5.5–6 million natural gas vehicles (NGVs), nearly 25% of the global fleet, supported by more than 7,000 CNG refuelling stations, providing a durable foundation for continued gas use in urban and commercial road transport, particularly in Argentina, Brazil, Colombia, Peru, and Bolivia. While penetration in light-duty vehicles is approaching saturation, future growth is increasingly concentrated in heavy-duty road transport, where LNG-fuelled trucks are being deployed along major freight corridors in countries such as Brazil and Chile, benefiting from lower fuel costs, high utilisation rates, and the absence of scalable zero-emission alternatives for long-haul applications. In parallel, maritime demand for natural gas is expected to expand gradually from a low base, driven by tightening environmental regulations, port decarbonisation strategies, and the rollout of LNG bunkering infrastructure in key hubs, including Panama, Brazil, and Chile, often leveraging existing LNG import terminals. Under RCS, natural gas demand in the transport sector is projected to increase by around 18 bcm, reaching approximately 27 bcm by 2055, accounting for 16% of total incremental demand growth while rising to around 10% of regional gas demand, up from 6% in 2024.

Natural gas demand growth over the forecast period in Latin America is concentrated in **Argentina** and Brazil, accounting for just below 70% of overall increase. These two countries consuming around 55% of natural gas demand in 2024, are expected to account for just above 60% of the regional natural gas demand by 2055 (Figure 4.17).

Natural gas accounted for around 50% of Argentina's primary energy supply in 2024 and is expected to maintain a broadly stable share over the outlook period, reflecting its central role in the national energy system. Demand is concentrated in power generation, the domestic sector, and industry, which represented approximately 28%, 25%, and 18% of total gas consumption in 2024. While domestic demand is largely mature and projected to remain stable, future growth is driven by the power and industrial sectors, where consumption is expected to increase by around 11 bcm and 13 bcm, reaching approximately 25 bcm and 22 bcm by 2055, respectively. This growth is supported by rising electricity demand and continued oil-to-gas substitution, although much of the latter occurs during winter peak periods, limiting its impact on annual demand growth.

Figure 4.17

Natural gas demand outlook in Latin America by country, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

These demand trends are reinforced by supply-side developments. The completion of Phase 1 of the Néstor Kirchner Gas Pipeline, linking Vaca Muerta to Buenos Aires Province with a capacity of around 21 million cubic metres per day, has strengthened internal gas transmission and improved access to low-cost domestic supply. Combined with rising production, this has reduced winter LNG imports and enabled the cessation of pipeline gas imports from Bolivia in late 2024, marking a structural shift in Argentina's gas balance. The planned, but yet-to-be-tendered, Phase 2 expansion, which would add around 20 million cubic metres per day, would further enhance system flexibility if implemented, supporting deeper fuel oil substitution in power and industry, increased gas use in petrochemicals, and potential new urea production, while further reducing reliance on LNG for seasonal balancing.

Gas pricing policy further shapes these dynamics: while residential consumption remains largely insulated from market price signals through targeted subsidies, ongoing reforms and greater reliance on market-based pricing for LNG offtakers and large consumers are strengthening the responsiveness of power and industrial demand to improved domestic supply and relative fuel price competitiveness.

Reflecting these factors, the RCS projects that natural gas demand in Argentina will increase by around 28 bcm to reach approximately 77 bcm by 2055, corresponding to an average annual growth rate of about 1% over the forecast period.

Natural gas currently accounts for around 9% of **Brazil**'s primary energy demand, reflecting its historically limited role in a power system dominated by hydropower. Over the outlook period, this share is projected to increase to around 13% by 2055, driven by structural changes in both the power and industrial sectors. These two sectors emerge as the dominant sources of natural gas demand growth, together accounting for around 46% of total gas consumption by 2055, with industry and power generation representing approximately 25% and 21%, respectively. In absolute terms, natural gas demand in industry and power generation is projected to increase by around 23 bcm and 11 bcm, reaching approximately 30 bcm and 19 bcm by 2055, respectively.

The expansion of natural gas demand is closely linked to developments in Brazil's electricity system. Electricity demand is projected to grow by around 2.5 times over the forecast period, exceeding 2,000 TWh by 2055, driven by economic growth, electrification, rising air-conditioning penetration, and the emergence of data centres. At the same time, Brazil's power system is becoming increasingly exposed to hydropower variability, as recurrent droughts reduce reservoir reliability, while the share of variable renewable energy continues to rise. In this context, natural gas-fired power generation plays a critical system role as a flexible and dispatchable source, providing real-time balancing, capacity adequacy, and insurance against renewable intermittency and hydrological risk. As a result, the share of gas in the power generation mix is projected to increase to around 13% by 2055, up from 8% in 2024, supported by an expansion of installed gas-fired capacity from around 20 GW in 2024 to approximately 90 GW by 2055.

Beyond the power sector, industrial demand represents a second major pillar of natural gas growth. Easing conditions in global gas markets and lower international gas prices, combined with Brazil's policy objective of reducing fertiliser import dependency, are supporting a renewed expansion of gas-based industrial capacity. In this context, three ammonia and urea plants mothballed since 2022 are expected to restart, while two additional fertiliser plants are under development and expected to be commissioned over the coming years. These developments reinforce natural gas demand through both feedstock use and process energy consumption. In parallel, improved gas price competitiveness is expected to encourage new investment in gas-intensive industrial activities and non-energy uses, further embedding natural gas into Brazil's industrial value chains.

Reflecting these combined power-sector and industrial drivers, natural gas demand in Brazil is projected to increase by around 48 bcm over the outlook period, reaching approximately 80 bcm by 2055, corresponding to an average annual growth rate of about 3%. This trajectory marks a structural deepening of natural gas use in Brazil's energy system, anchored in system flexibility needs, industrial policy priorities, and improved gas market fundamentals.

4.4.6 Middle East

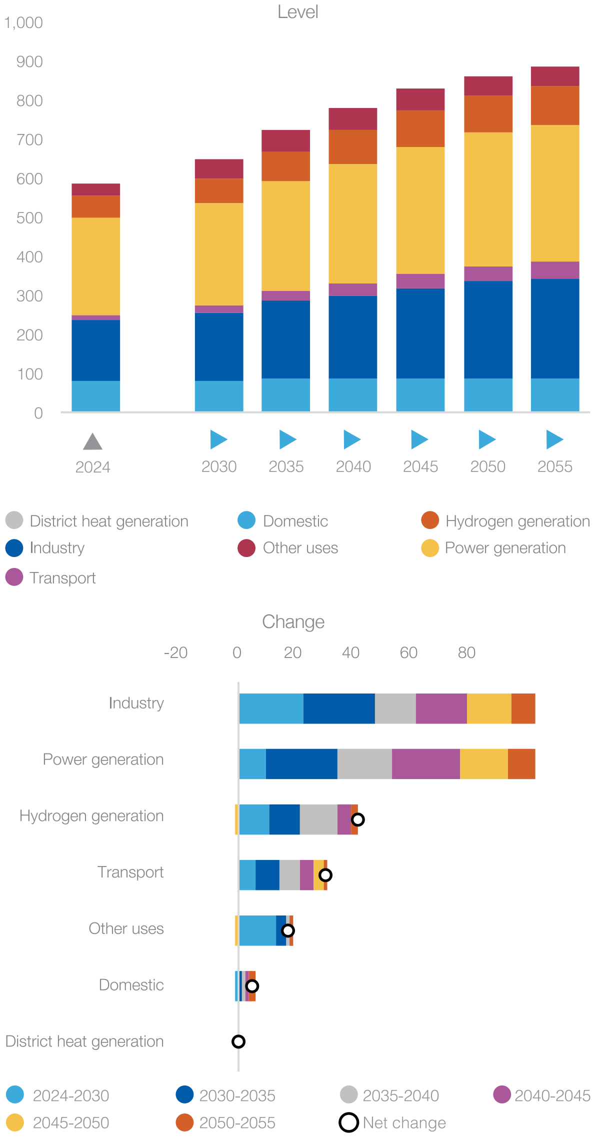
Middle East is the second largest contributor to natural gas demand growth over the upcoming three decades after Asia Pacific. Natural gas accounts for 52% of primary energy demand in 2024 and is projected to rise to 54% by 2055. This growth is underpinned by rapid urbanization, rising income, robust economic expansion, industrial expansion and economic diversification strategies, fuel switching away from oil and liquids in power generation and energy security and domestic resource monetization. Moreover, the integration of renewables and emerging clean technologies paradoxically support gas demand. As solar and wind capacity scale rapidly across the region, natural gas increasingly provides flexibility, balancing and firm capacity, ensuring system reliability during peak demand and periods of renewable output. Consistent with this trend, **the RCS predicts that natural gas demand in the Middle East will increase from 591 bcm in 2024 to 887 bcm in 2055, reflecting 1.3% annual growth over the outlook period** (Figure 4.18).

As electricity demand in the Middle East rises rapidly, growing at an average rate of 2.6% per year to reach around 3,430 TWh by 2055, natural gas demand in the power sector increases substantially. This trend is reinforced by accelerating electrification, with the share of electricity in final energy demand projected to rise from 16% in 2024 to 23% by 2055, reflecting expanding cooling needs, desalination, urbanisation, and economic growth. Natural gas remains the dominant fuel for power generation, accounting for around 70% of the power mix in 2024, equivalent to approximately 1,064 TWh. Under the RCS, gas-fired electricity generation is expected to rise to about 1,577 TWh by 2055; however, its share in the power mix declines modestly to 46%, as renewables and, in some countries, nuclear expand more rapidly.

Consistent with these dynamics, natural gas demand for power generation is projected to increase by around 102 bcm by 2055, reaching approximately 353 bcm and accounting for about 40% of total regional gas demand. Despite this absolute growth, the power sector's share in overall gas consumption declines from 42% in 2024 to around 40% by 2055, reflecting faster growth in other demand segments. A key structural driver underpinning these trends is the continued shift away from oil and liquid fuels in power generation toward natural gas, particularly in Iran and Saudi Arabia. This policy-driven transition enhances export availability of liquid fuels, reduces local air pollution and CO_2 emissions, lowers system costs, and improves overall power sector efficiency, reinforcing natural gas's central role in the region's evolving electricity systems.

Figure 4.18

Natural gas demand outlook in the Middle East by sector, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

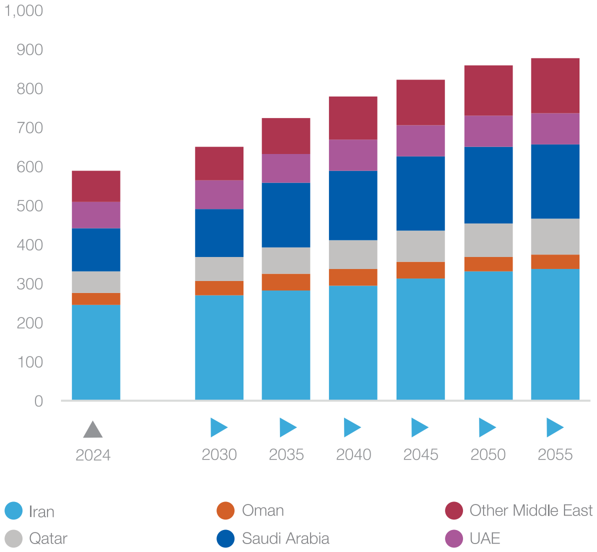
Natural gas serves as a strategic fuel for the industrial sector in the Middle East, underpinning international competitiveness through the provision of process heat, steam, and captive power. Its role is particularly pronounced in energy-intensive industries, including petrochemicals and refining, which dominate industrial activity in the region, as well as in selected basic materials and light manufacturing segments such as cement, food processing, textiles, and paper, primarily serving domestic and regional markets. Under the RCS, the industrial sector emerges as the largest contributor to natural gas demand growth, accounting for around 34% of the total increase in regional gas demand over the outlook period. Industrial gas demand is projected to rise from 153 bcm in 2024 to around 255 bcm by 2055, driven mainly by Iran's broad-based industrial and manufacturing base and Saudi Arabia's expansion of petrochemicals and integrated downstream industries. As a result, the industrial sector's share in total natural gas demand increases to about 29% by 2055, up from 26% in 2024, reinforcing natural gas's central role in supporting industrial growth, value addition, and economic diversification across the region.

Natural gas is expected to remain the dominant feedstock for hydrogen production in the Middle East, reflecting its long-standing role in supplying grey hydrogen for refining, petrochemicals, and fertiliser manufacturing. Looking ahead, the region is positioning itself as one of the world's leading hydrogen producers, with a growing strategic emphasis on low-carbon hydrogen, particularly blue hydrogen, leveraging abundant gas resources, low upstream costs, and extensive CO_2 storage potential in depleted oil and gas reservoirs. This shift is increasingly underpinned by recent national strategies and large-scale project announcements, notably in Saudi Arabia, the United Arab Emirates, and Qatar, where hydrogen development is closely integrated with CCUS deployment, industrial decarbonisation, and export-oriented energy transition pathways. Saudi Arabia's Vision 2030 and hydrogen roadmap, the UAE's National Hydrogen Strategy, and Qatar's expanding CCUS-linked gas monetisation plans collectively signal a durable policy commitment to scaling hydrogen value chains anchored in natural gas. Consistent with these trends, under the RCS, natural gas demand for hydrogen generation in the Middle East is projected to rise to around 94 bcm by 2055, nearly 40 bcm above 2024 levels, accounting for approximately 13% of total natural gas demand growth over the outlook period and reinforcing gas's central role in the region's transition-oriented industrial strategy.

Natural gas demand in the domestic and transport sectors of the Middle East remains highly concentrated in Iran, reflecting the country's extensive gas transmission and distribution network and its long-standing reliance on gas as the primary domestic sector fuel (Figure 4.19). Iran has one of the world's most comprehensive domestic gas grids, with near-universal urban coverage and continued expansion into rural and remote areas, underpinning its dominant contribution to residential gas consumption in the region. In parallel, Iran operates one of the largest CNG vehicle fleets globally, supported by a dense refuelling infrastructure and longstanding fuel-pricing policies aimed at reducing oil product consumption, improving urban air quality, and strengthening energy security. Under the RCS, natural gas demand in the domestic sector is projected to continue rising, driven by population growth, ongoing gasification efforts, and rising living standards, even as efficiency improvements gradually moderate per-capita consumption.

Figure 4.19

Natural gas demand outlook in the Middle East by country, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Beyond Iran, the transport sector is set to become an increasingly important source of gas demand growth at the regional level. Saudi Arabia is emerging as a new driver through policy-backed initiatives to promote natural gas and LNG use in heavy goods vehicles (HGVs), logistics fleets, and industrial transport corridors, aligned with broader goals to reduce oil use domestically and lower transport-sector emissions. At the same time, the Middle East's strategic location along major Europe–Asia shipping routes, combined with expanding LNG bunkering infrastructure, positions the region to benefit from rising demand for LNG as a marine fuel. Reflecting these developments, natural gas demand in the transport sector across the Middle East is projected to surge to around 42 bcm by 2055, up from approximately 12 bcm in 2024, corresponding to a robust average annual growth rate of about 4.1% over the outlook period. This expansion underscores the growing role of natural gas in both road and maritime transport as countries seek cost-effective, lower-emission alternatives to oil-based fuels while leveraging existing gas resource advantages.

Natural gas demand in the Middle East is highly concentrated, with **Iran**, Qatar, the UAE, and Saudi Arabia together accounting for around 80% of regional consumption in 2024 and projected to contribute approximately 76% of total demand growth over the outlook period. Iran is by far the largest consumer, with natural gas representing roughly 65% of its primary energy mix in 2024 and underpinning energy use across the domestic, industrial, and power sectors, both as fuel and feedstock. Under the RCS, Iran's natural gas demand is projected to increase by around 90 bcm to reach approximately 340 bcm by 2055, corresponding to an average annual growth rate of about 1%. Industrial activity and power generation together account for nearly two-thirds of this incremental growth, reflecting Iran's continued reliance on gas to support economic activity and rising electricity demand.

The domestic sector, while remaining structurally important, is expected to exhibit moderating growth over time. With nearly 95% of the population already connected to the gas grid, future demand expansion is increasingly constrained by saturation effects and reinforced by government policies aimed at improving building energy performance, upgrading household equipment, and reducing energy intensity. In contrast, electricity demand is projected to rise by nearly 40% by 2055, driven primarily by urbanisation, rising living standards, and growing cooling requirements. Power generation in Iran remains heavily gas-based, with gas-fired plants accounting for around 70% of installed capacity and close to 80% of electricity generation in 2024, anchoring continued growth in gas demand from this sector.

At the same time, the government is pursuing a multi-pronged strategy to manage the pace of gas demand growth in power generation. This includes improving system efficiency through demand-side management, upgrading the generation fleet by replacing older steam units with higher-efficiency CCGTs, and accelerating the deployment of renewable energy to enhance grid stability and reduce peak gas burn. Renewable capacity, predominantly solar and wind, has expanded rapidly to about 3.16 GW in 2024, with official targets to reach 10 GW by 2026. Against this backdrop, the RCS projects that natural gas demand in Iran's power sector rises more moderately, increasing by around 18 bcm to reach approximately 91 bcm by 2055, reflecting a balance between rising electricity needs and efficiency- and diversification-driven policy interventions.

The drivers of natural gas demand in **Qatar** are structurally distinct from those of most consuming countries, reflecting its role as a resource-rich exporter with a gas-centred economic model. Natural gas accounts for around 90% of the primary energy mix and underpins virtually all power generation and water desalination, as well as industrial activity and downstream gas monetisation. Under the RCS, Qatar's domestic natural gas demand is projected to increase by around 37 bcm to reach approximately 88 bcm by 2055, with growth overwhelmingly driven by export-linked activities rather than end-use consumption.

The largest source of incremental demand is own use within the gas value chain, particularly for gas processing, compression, and liquefaction. The North Field East and North Field South expansion projects, which raise LNG capacity to 126 Mtpa by the early 2027, significantly increase fuel and utility gas requirements. Under the RCS, own-use gas demand rises by around 12 bcm by 2030 before plateauing through mid-century, accounting for roughly one-third of total demand growth. Industrial demand, notably from petrochemicals and gas-to-liquids (GTL) operations, also strengthens in line with Qatar's strategy to maximise value added per unit of gas. In parallel, Qatar is advancing low-carbon hydrogen and ammonia initiatives anchored in natural gas and supported by large-scale CCUS associated with the North Field. These projects reinforce gas demand while aligning with decarbonisation and export diversification objectives.

Natural gas demand in the **UAE** is fundamentally system- and investment-driven, anchored in power–water security, industrial competitiveness, upstream self-consumption, and emerging hydrogen value chains. Under the RCS, total natural gas demand is projected to increase by around 14 bcm to reach approximately 80 bcm by 2055. In 2024, power generation and industry together account for over 90% of gas consumption, reflecting the central role of natural gas in electricity and desalination, as well as in refining, petrochemicals, and other energy-intensive industries.

Looking ahead, hydrogen production emerges as the principal source of incremental gas demand. Natural gas use in hydrogen generation, predominantly blue hydrogen, is projected to rise by around 11 bcm to reach approximately 15 bcm by 2055, accounting for nearly three-quarters of total demand growth over the outlook period. This trajectory is underpinned by the UAE's National Hydrogen Strategy, which targets hydrogen production of up to 15 Mt per year by 2050 and positions blue hydrogen as a key transitional fuel, leveraging abundant gas resources and expanding carbon capture and storage capacity.

At the same time, rising gas demand from hydrogen is expected to be partially offset by a structural decline in gas use for power generation as nuclear and renewable capacities expand. By the end of 2024, the UAE's installed renewable capacity reached around 6.8 GW, with plans to scale clean energy capacity to over 22 GW by the early 2030s. As a result, solar generation is projected to increase from around 5% of the power mix in 2025 to nearly 38% by 2055, while the share of natural gas in electricity generation declines from approximately 76% to around 36%. Consequently, the UAE's gas demand outlook reflects a reallocation across sectors rather than a broad-based contraction, with natural gas remaining a strategic pillar of the energy system through mid-century.

4.4.7 North America

Natural gas demand in North America is projected to continue rising through 2030 before entering a gradual and shallow decline toward 2055. **Under the Reference Case Scenario (RCS), regional demand increases by around 73 bcm by 2030, driven primarily by structural load growth, before easing to approximately 1,155 bcm by the end of the outlook period, still about 16 bcm above 2024 levels** (Figure 4.20). In line with these dynamics, the share of natural gas in primary energy demand remains broadly stable at around 35–36% throughout the forecast period, reflecting largely stagnant growth in overall primary energy demand and the absence of large-scale fuel substitution away from gas.

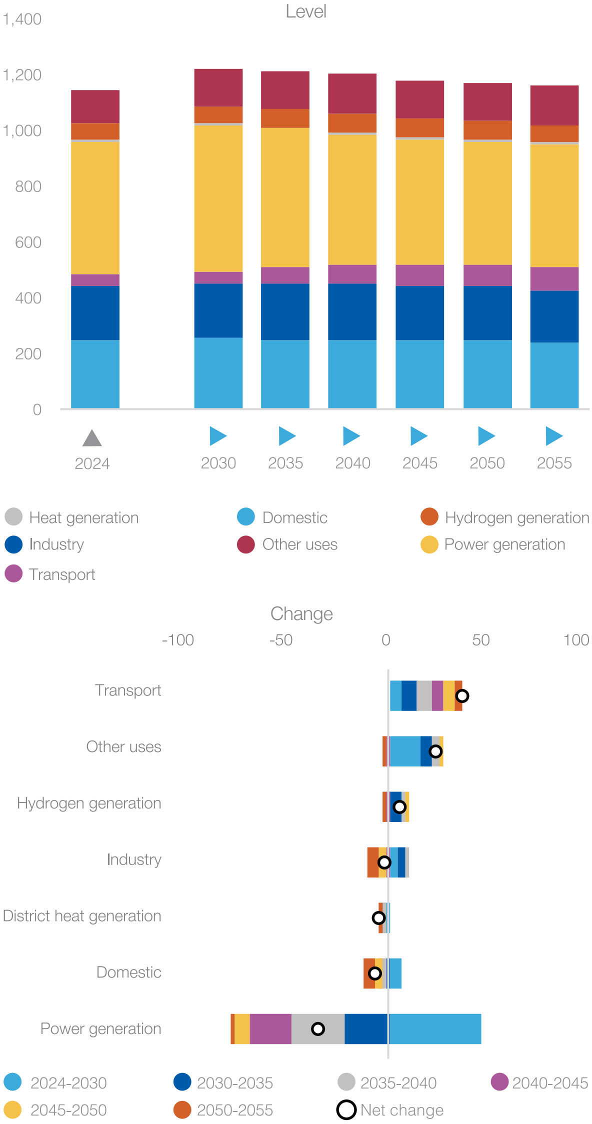
This trajectory is underpinned by several reinforcing drivers. In the power sector, rapidly expanding electricity demand, particularly from data centres, AI-related digital infrastructure, and broader electrification of end uses, sustains gas-fired generation as a key source of reliability and flexibility. In parallel, strong LNG export growth, especially from the United States, continues to exert a significant pull on upstream gas production and midstream infrastructure. Industrial demand is further supported by the competitiveness of North American gas prices, the reshoring of manufacturing activity, and the expansion of energy-intensive industries. Finally, recent policy and regulatory shifts favouring fossil fuels and nuclear energy, alongside a more measured pace of renewable deployment, reinforce the role of natural gas as a strategic transition fuel, underpinning its resilience in the regional energy mix even as longer-term decarbonisation pressures gradually intensify.

Despite relatively modest electricity demand growth of around 0.4% per year since 2000, North America is entering a markedly different phase. Under the RCS, electricity demand accelerates to 1.3% per annum, reaching over 8,180 TWh by 2055. As a result, electricity's share in final energy demand rises structurally to 31% by 2055, up from 22% in 2024, reflecting deepening electrification across the economy. This shift is reinforced by rapid growth in digital infrastructure. According to the Energy Information Administration (EIA), commercial computing loads, including data centres and AI-related applications, expand sharply, with their share of commercial electricity consumption increasing from around 8% in 2024 to about 20% by 2050, fundamentally reshaping load profiles and peak demand dynamics.

Against this backdrop, the role of natural gas in the power system strengthens in absolute terms over the near-term. Slower and more volatile clean energy buildout, combined with rising system stress from variable renewable energy (VRE), elevates the importance of gas-fired generation as a source of firm capacity and operational flexibility. Natural gas underpins reliability during periods of low and intermittent renewable output, supports capacity additions required to meet planning reserve margins, and provides essential ancillary services, including fast ramping, inertia substitution, frequency control, and voltage support, particularly in regions constrained by transmission

Figure 4.20

Natural gas demand outlook in North America by sector, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

bottlenecks. This is reflected in a growing pipeline of gas-fired capacity additions across North America, consistent with a power system prioritising firmness and flexibility alongside decarbonisation.

As a result, natural gas demand in power generation increases by around 46 bcm by 2030 to reach 520 bcm, before entering a gradual and shallow decline thereafter. Over the longer term, strong growth in total electricity generation sustains absolute gas burn even as renewable penetration rises, while the evolving role of gas shifts progressively toward balancing and system support. Consequently, the share of power generation in total natural gas demand declines structurally to around 38% by 2055, down from 42% in 2024, reflecting diversification of gas use across LNG exports, industry, and other sectors rather than a weakening of gas's role in the power system.

LNG exports and natural gas demand for own use constitute a major structural driver of long-term gas demand growth in North America. This is particularly evident in Canada, where natural gas consumption associated with upstream oil production, used for steam generation, processing, compression, and electrification substitutes in oil sands and tight oil operations, adds a structurally firm layer of demand. In parallel, large-scale additions to LNG export capacity in both the United States and Canada materially strengthen this trend. As new liquefaction trains come online, natural gas demand rises not only for feed gas but also for self-consumption within the LNG value chain, including gas used to power liquefaction, compression, and auxiliary systems. Under RCS, natural gas demand for own use is projected to rise by 23 bcm to reach just under 140 bcm by 2055.

Rising electricity demand in North America, combined with a widening relative price differential between electricity and natural gas, is slowing the electrification of low- and medium-temperature industrial heat, particularly in the United States. As electricity prices rise faster than gas prices, the economic incentive for electrifying industrial boilers, furnaces, and CHP systems weakens, sustaining natural gas demand in energy-intensive industries where reliability, continuous heat supply, and cost efficiency remain critical.

This trend is reinforced by United States manufacturing reshoring strategies, which support new investments in chemicals, metals, fertilisers, food processing, and advanced manufacturing, sectors that are structurally reliant on natural gas for process heat and captive power. At the same time, the scale-up of CCUS, supported by federal incentives, enables emissions reductions while preserving gas-based industrial systems, strengthening the long-term resilience of industrial gas demand.

Under the RCS, natural gas demand in North America's industrial sector rises to around 200 bcm by 2040, before easing marginally to approximately 188 bcm by 2055, only 2 bcm below 2024 levels, reflecting sustained price competitiveness, industrial policy support, and the growing role of CCUS in decarbonising industrial gas use.

Road and marine transport also contribute materially to natural gas demand growth in North America, adding an incremental 37 bcm by 2055. This expansion is driven primarily by the United States, where the development of the natural gas vehicle (NGV) market is increasingly concentrated in heavy-duty road transport and selected marine applications. The momentum reflects a combination of tighter emissions standards, fuel-cost competitiveness relative to diesel, and continued expansion of refuelling and bunkering infrastructure, largely led by private-sector investment.

In road transport, the heavy goods vehicle (HGV) segment remains the principal focus for gas-based solutions, as electrification faces persistent challenges related to vehicle weight, range, charging times, and grid capacity. Natural gas, mainly in compressed (CNG) and liquefied (LNG) forms, offers an immediately deployable pathway to reduce local air pollutants and CO_2 emissions while maintaining operational flexibility. In parallel, LNG adoption in marine transport, particularly along major coastal and inland waterways, supports compliance with tightening fuel and emissions regulations and enhances fuel diversification. As a result, transport-sector gas demand growth partially offsets declines in other segments, reinforcing the role of natural gas as a transition fuel in hard-to-electrify transport applications over the outlook period.

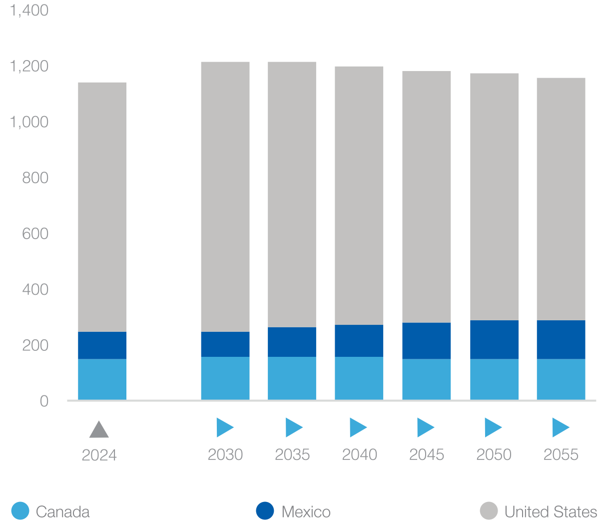
Natural gas demand in North America is heavily concentrated in the United States, which accounted for nearly 80% of regional gas consumption in 2024 and is projected to represent around 75% by 2055. While overall regional demand remains broadly stable, Mexico emerges as the sole source of net demand growth. In contrast, natural gas demand in both the United States and Canada is projected to decline gradually over the outlook period (Figure 4.21).

Mexico's natural gas demand is projected to rise by around 53 bcm to reach approximately 145 bcm by 2055, underpinned by structurally strong growth in power generation and industry, with the power sector accounting for about 54% of the total increase. Electricity demand is forecast to expand rapidly, by around 2.8% per year to reach roughly 865 TWh by 2055, driven by population growth, urbanisation, cooling demand, and industrial activity. In this context, natural gas remains the marginal fuel for power generation, supported by its cost competitiveness relative to fuel oil and diesel and its critical role in ensuring system reliability alongside rising variable renewables. As a result, gas demand in power generation increases by around 29 bcm over the outlook period to reach about 85 bcm by 2055. However, despite higher absolute gas use, the share of gas-fired generation in the power mix declines to around 64% by 2055, from 68% in 2024, reflecting faster growth in renewables rather than a displacement of gas in absolute terms.

Beyond power, industrial demand for natural gas is reinforced by its role as a competitive source of process heat, steam, and captive power in cement, metals, food processing, refining, and petrochemicals, particularly as higher electricity prices moderate the electrification of low- and medium-temperature heat. Infrastructure-led expansion remains a central pillar of Mexico's gas outlook: ongoing pipeline expansions and system reinforcements led by Comisión Federal de Electricidad

Figure 4.21

Natural gas demand outlook in North America by country, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

and Centro Nacional de Control del Gas Natural are progressively easing regional bottlenecks, extending access to the southeast and other underserved regions, and enabling further substitution away from fuel oil and diesel. Anchored by abundant and competitively priced United States pipeline gas, Mexico's long-term natural gas demand trajectory is therefore driven less by cyclical factors and more by electrification-driven load growth, fuel switching in power generation, and the continued pace of grid and pipeline buildout across the country.

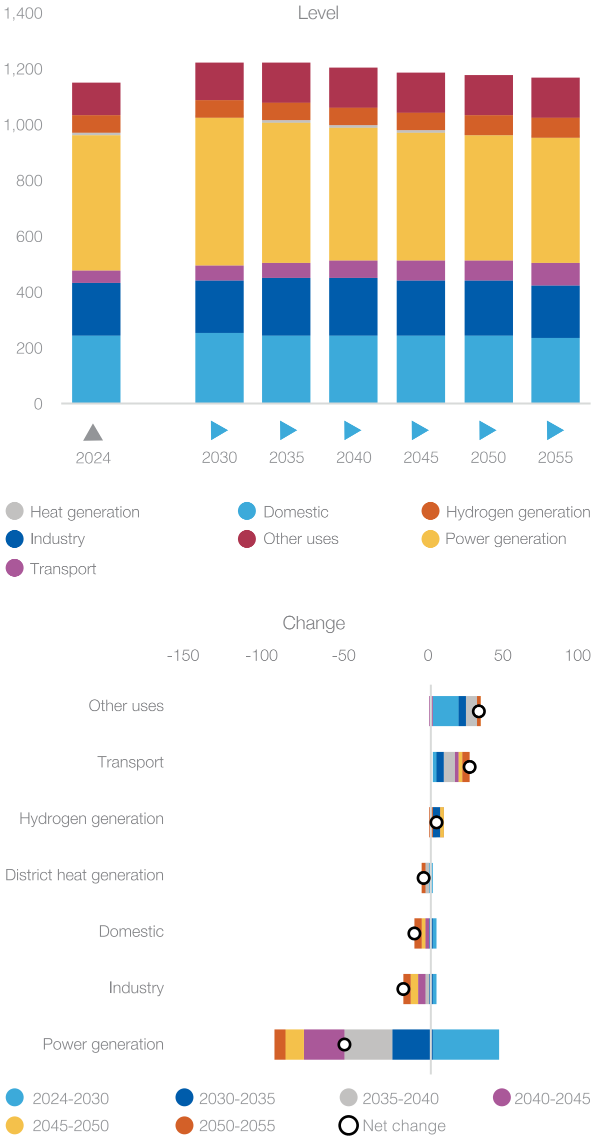
Natural gas demand in the **United States** is shaped by a combination of structural, economic, and policy-driven factors that underpin its medium-term expansion and long-term resilience. Under the RCS, total natural gas demand is projected to increase by around 67 bcm by 2030, reaching approximately 966 bcm, before entering a gradual and shallow decline toward mid-century to about 870 bcm by 2055, only around 31 bcm below 2024 levels (Figure 4.22). As a result, the share of natural gas in the United States primary energy mix remains broadly stable over the outlook period, hovering in the range of 33–34%, underscoring gas's enduring role in the energy system.

A central driver of this trajectory is the acceleration of electricity demand. Under the RCS, United States electricity consumption grows at an average rate of about 1.1% per year, reaching more than 6,480 TWh by 2055, significantly higher than growth rates observed over the past two decades. This shift reflects rapid expansion of data centres and AI-related computing, continued electrification of end uses, and rising industrial electricity loads. These demand sources require large volumes of firm, dispatchable power, reinforcing the

Chapter 4

Figure 4.22

Natural gas demand outlook in the United States by sector, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

role of natural gas as a system-balancing fuel. Gas-fired generation provides critical support during periods of low variable renewable output, contributes to planning reserve margins, and delivers essential ancillary services such as ramping capability, voltage support, and inertia substitutes, particularly where transmission expansion lags demand growth.

Recent policy developments reinforce this outlook. While the Inflation Reduction Act (IRA) initially provided strong incentives for renewable energy deployment, clean hydrogen, and electrification, subsequent legislative and regulatory changes, culminating in the passage of the "One Big Beautiful Bill" act and associated executive orders, have significantly weakened or neutralised several core IRA provisions. These changes include the rollback or early sunset of tax credits for electric vehicles and selected renewable technologies, reduced federal support for clean power investment, relaxed environmental permitting constraints for fossil fuel projects, and expanded access to federal lands for oil and gas development. In parallel, fiscal and regulatory support for firm generation sources, notably natural gas and nuclear power, has strengthened under a renewed emphasis on energy security, affordability, and domestic industrial competitiveness.

As a result, the pace of renewable deployment has become more uncertain, particularly in regions facing grid congestion, permitting delays, and local opposition to large-scale infrastructure. This slower and more volatile clean-energy build-out increases reliance on existing and new gas-fired capacity to meet rising electricity demand in the medium term. Consequently, even as the share of natural gas in the power generation mix faces longer-term pressure from renewables and nuclear additions, absolute gas burn remains firm through the early 2030s as total electricity generation expands.

Relative long-term price dynamics further reinforce this trend. As electrification accelerates, electricity prices increasingly reflect system-level costs associated with capacity adequacy, grid reinforcement, and intermittency management. At the same time, abundant domestic gas supply, supported by favourable fiscal treatment and relaxed upstream regulation, continues to anchor natural gas prices at comparatively lower levels. This widening electricity–gas price differential slows the electrification of low- and medium-temperature industrial heat and reinforces continued reliance on natural gas for process heat, boilers, furnaces, and combined heat and power systems. Supported by federal and state-level reshoring strategies aimed at strengthening domestic manufacturing, industrial gas demand remains structurally resilient. Under the RCS, natural gas demand in the industrial sector declines only modestly, by about 17 bcm over the outlook period, to reach around 130 bcm by 2055.

Finally, the scaling up of CCUS, particularly in the United States, further strengthens the long-term outlook for natural gas. Enhanced tax incentives for CCUS under revised federal policy frameworks improve the carbon performance of gas-based power and industrial applications without undermining their cost competitiveness. This extends the economic life of gas assets, supports continued investment in gas-intensive value chains, and reinforces demand resilience. Together with LNG export growth and rising upstream and midstream own-use, these factors contribute to a broad-based natural gas demand profile that remains robust in the medium term and only gradually moderates toward mid-century.

5

Natural Gas Supply Outlook

Highlights

- Global natural gas production is projected to expand, but at a moderating pace. Output rises from 4,136 bcm in 2024 to 5,417 bcm in 2055, representing growth of 31% (27%, CAGR), with supply additions front-loaded and expected to slow after 2030 as mature producing areas increasingly dominate marginal output.
- Incremental supply is projected to remain regionally concentrated. The Middle East, Eurasia, and Africa are expected to account for nearly 80% of net production additions through 2055, while several mature producing regions contribute only limited growth or enter structural decline.
- GECF Member Countries are projected to strengthen their role in global gas supply. The GECF share of world production increases from around 38% in 2024 to 44% in 2055, reflecting stronger long-term growth among major conventional gas exporters relative to non-GECF producers.
- Conventional gas is expected to remain the main source of incremental supply growth. Around 87% of net global production growth through 2055 is projected to come from conventional resources, pointing to a gradual shift away from shale-led growth as the dominant source of additional supply.
- The Middle East is projected to be the largest absolute contributor to global supply growth. Regional production is expected to increase by around 414 bcm by 2055, supported by large, low-cost conventional developments and parallel expansion of export infrastructure, including LNG.
- Africa is projected to be the fastest-growing gas-producing region. Production rises from 244 bcm in 2024 to around 482 bcm in 2055, almost doubling over the outlook period, with growth increasingly led by offshore developments and large LNG-oriented projects.
- Eurasia is expected to remain a key pillar of global gas supply growth. Regional production increases from 856 bcm in 2024 to 1,253 bcm in 2055, equivalent to an addition of nearly 400 bcm, supported by major project developments and evolving export routes.
- Europe is projected to undergo a structural decline in natural gas production. Output falls from 199 bcm in 2024 to about 100 bcm in 2055, a reduction of 99 bcm, lowering Europe's share of global production to around 2% by the end of the outlook period and reinforcing its import dependence.
- North America is projected to remain a major producer, but with a maturing growth profile. Production increases from 1,266 bcm in 2024 to 1,398 bcm in 2055, a net gain of 132 bcm, with strong near- to medium-term output increasingly giving way to a post-peak plateau as major shale plays mature.
- Upstream investment requirements are projected to remain substantial through 2055. Global cumulative upstream natural gas capex requirements over 2025–2055 are estimated at USD 11.6 trillion in real terms, averaging around USD 350 billion per year, highlighting the scale of investment needed both to offset decline and to deliver new supply.

5.1 Global natural gas production overview

Natural gas production reached 4,136 bcm in 2024, rising by 1.8%, marking an acceleration from the 0.7% growth recorded in 2023.The acceleration was driven mainly by Eurasia and the Middle East, followed by Asia Pacific. Approximately 130 projects commenced production during the year, unlocking roughly 1.2 tcm of reserves over their lifecycles. A further 170 projects reached FID in 2024.

In 2024, the global gas production landscape was characterised by a distinct geographic shift in supply momentum. While North American gas production stabilised following previous surges, the focal point of expansion pivoted toward the Eastern Hemisphere. The following regional breakdown details these production dynamics.

Eurasia experienced the largest growth among regions in 2024 with production increased by 31 bcm. This was primarily led by Russia, which added approximately 33 bcm, driven by strategic infrastructure development and the ramp-up of key projects including the Yamal Megaproject, Urengoyskoye, Dobycha Yamburg, and the Eastern Gas Program; conversely, production declines were observed in Turkmenistan and Uzbekistan.

The Middle East followed closely, expanding gas production by 30 bcm to 731 bcm in 2024. Growth was led by Saudi Arabia, with additional contributions from Iran, Iraq, Oman and the UAE. The region's trajectory reinforces its position as a key pillar of global supply, underpinned by vast reserves and sustained upstream investment.

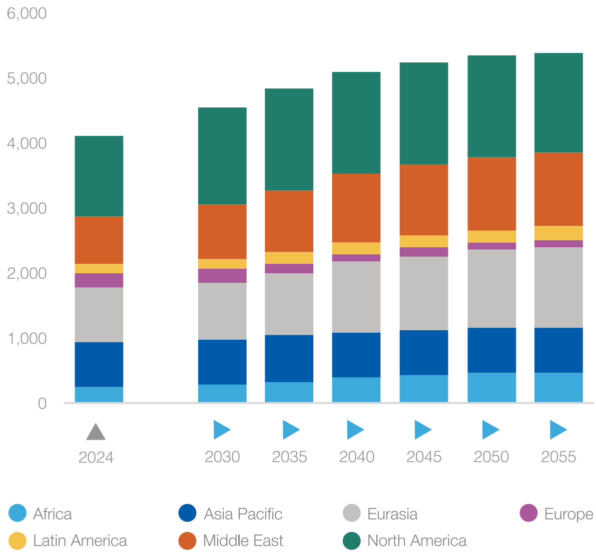
Gas production in Asia Pacific increased by 16 bcm to 692 bcm, driven overwhelmingly by China, which accounted for roughly 80% of the regional increase. China's marketed production reached 230 bcm, surpassing its five-year plan targets. Malaysia, Thailand, Indonesia, and Australia also posted gains, while Bangladesh, Pakistan, and Papua New Guinea saw small declines.

North America experienced a slight growth of 5 bcm in 2024 and reached 1,266 bcm, this comes after a growth of around 50 bcm in 2023.The growth was dominated by Canada while the United States remained the dominant contributor with 1,066 bcm, maintaining stable production levels.

Europe and Latin America recorded marginal increases. European production rose by 3 bcm to 199 bcm, supported by record growth from Norway and the ramp-up of Türkiye's Sakarya field, offsetting steep declines in the Netherlands and the United Kingdom. Latin America edged up by 1 bcm to 153 bcm as growth in Argentina outweighed reductions in Bolivia, Brazil and Trinidad and Tobago.

Figure 5.1

Natural gas production outlook by region, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

By contrast, Africa's natural gas production fell by 13 bcm to 244 bcm in 2024. The decline stemmed from higher re-injection volumes in Algeria and lower production from Egypt's major offshore field. Regional supply, however, is expected to rebound in 2025 driven by the emerging gas producers and the expected growth in Nigeria.

5.2 Global natural gas production outlook

Global natural gas production is projected to reach 5,417 bcm by 2055. This year's outlook extends the forecast horizon by five years compared with last year's edition, projecting 5,363 bcm for 2050 (Figure 5.1). This 2050 forecast represents an upward revision from last year's 5,300 bcm projection, reflecting updated assessments of development timelines, resource economics and demand trends outlined in Chapter 4.

Global natural gas production is projected to grow at an average annual rate of 0.9% through to 2055. However, this expansion follows distinct phases over the outlook period. By 2030, gas production is expected to expand by around 1.6% annually, supported by the commissioning and ramp-up of new projects across multiple regions to support the accelerated demand. Growth moderates to 1% per year during the 2030s as major developments reach plateau levels and unconventional supply in North America peaks, before slowing further to 0.6% in the 2040s and easing to 0.25% thereafter. The gas production outlook by region is detailed in Table 5.1.

North America is expected to remain the world's largest producing region, reaching 1,572 bcm by 2050 before easing to 1,543 bcm by 2055, representing a growth rate of 0.6% annually. The 2050 outlook for the region is revised up by 110 bcm compared to the previous edition. North American production is set to peak around 2035 at approximately 1,580 bcm before entering a gradual decline to 2055. The upward revision reflects stronger anticipated domestic gas demand growth, faster LNG project sanctioning and continued technical gains in unconventional production.

Eurasian production is forecast to reach 1,188 bcm by 2050 and 1,233 bcm by 2055, growing at 1.2% annually. The region adds 377 bcm of incremental supply along the outlook, representing about 30% of global growth. Russia's strategic pivot toward Asian markets underpins this trajectory, with Power of Siberia now at full capacity and additional export routes to Asia planned. Russia continues to develop new production hubs in the Yamal Peninsula, East Siberia and the Far East to offset declines in legacy Western Siberian fields.

The **Middle East** is projected to reach 1,112 bcm by 2050 and 1,145 bcm by 2055, growing at an average of 1.5% annually. Expansion is driven by the simultaneous scaling of conventional and unconventional reserves. The region's extensive reserves, strategic position between Asian and European markets, and increasing domestic demand for power and petrochemicals reinforce its expanding role in global supply. Its share of world production is set to rise from 18% in 2024 to 21% by 2055, marking a notable shift in the geography of global supply.

Africa emerges as the fastest-growing region, with production projected to reach 482 bcm by 2055, representing average growth of 2.2% per year. The continent adds 239 bcm, around 19% of total incremental gas production. The 2050 forecast of 466 bcm is revised down from last year's 502 bcm, reflecting updated timelines for FIDs on large projects and more conservative assumptions regarding near-term exploration outcomes.

Latin American production is forecast to reach 217 bcm by 2055, growing at 1.1% per year and contributing 68 bcm to global growth. The region's growth is driven primarily by Argentina's unconventional resource development. Most of the increase is concentrated in the 2020s and 2030s as Vaca Muerta production scales up and export infrastructure is completed.

Asia Pacific production is expected to remain broadly flat, reaching 696 bcm by 2055. This apparent stability conceals diverging national trajectories as strong growth in China is offset by declines in mature producers. China continues expanding domestic production from both conventional and unconventional resources, with the latter now accounting for around 40% of regional supply. However, mature producers such as Australia and Malaysia experience ongoing declines through the outlook period, reflecting challenging project economics, ageing basins and policy frameworks that have not consistently incentivised upstream investment.

Europe faces the steepest production decline, falling to 110 bcm by 2050 and 100 bcm by 2055, an average contraction of 2.2% per year. The region's gas production is projected to decline by 99 bcm over the forecast horizon, with declines accelerating in the 2030s as major fields mature and few new developments advance.

Time-phased growth contributions highlight shifting dynamics across the outlook (Figure 5.2). Between 2024 and 2030, global production rises by 453 bcm, led primarily by North America. Growth continues to 538

Table 5.1

Global natural gas production by region, 2024-2055

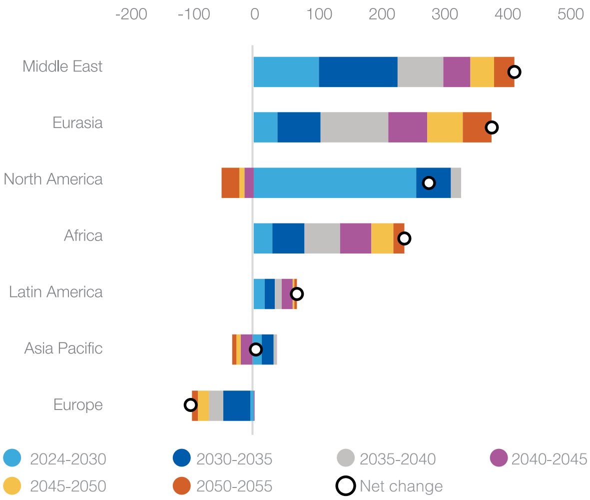
	Levels (bcm)					Change (bcm)	Growth (% p.a.)	Share (%)	
	2024	2030	2040	2050	2055	2024-2055	2024-2055	2024	2055
Africa	244	273	380	466	482	239	2.2%	6%	9%
Asia Pacific	692	706	729	704	696	5	0.0%	17%	13%
Eurasia	856	893	1,070	1,188	1,233	377	1.2%	21%	23%
Europe	199	193	128	110	100	-99	-2.2%	5%	2%
Latin America	149	166	193	213	217	68	1.1%	4%	4%
Middle East	731	834	1,032	1,112	1,145	414	1.5%	18%	21%
North America	1,266	1,524	1,595	1,572	1,543	277	0.6%	31%	28%
Total	**4,136**	**4,589**	**5,127**	**5,363**	**5,417**	**1,281**	**0.9%**	**100%**	**100%**

Source: GECF Secretariat based on data from the GECF GGM

Chapter 5

Figure 5.2

Natural gas supply change outlook by region, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

bcm during the 2030–2040 period, dominated by the Middle East, Eurasia and Africa, while North American supply growth decelerates significantly. From 2040 to 2055, Eurasia becomes the largest contributor to global growth, adding 163 bcm, followed by the Middle East and Africa; during this period Asia Pacific, Europe and North America all experience declines as resource maturity outweighs limited new project additions.

The geographic distribution of natural gas production is poised for a marked shift by 2055, driven by evolving regional disparities in resources, market demand and policy. The primary shift moves the centre of gravity toward resource-rich regions in the developing world. The Middle East is forecast to have the largest gain, expanding its global share to 21% by 2055. It is followed by Eurasia (rising to 23%) and Africa (rising to 9%). Meanwhile, Latin America maintains a stable 4% share (Figure 5.3).

Conversely, while North America remains the world's largest producer, its market share is projected to decline to 28% by 2055 as expansion is outpaced by faster-growing regions. Asia Pacific's share falls to 13%, as continued growth in China is insufficient to offset structural maturity in other regional basins. Europe faces the steepest contraction, with its share of global supply shrinking to just 2% by 2055.

5.2.1 Non-associated and associated gas production outlook

Over the outlook period, non-associated gas remains the cornerstone of global supply while associated gas gradually declines. **Nearly all projected production growth comes from non-associated sources, which increase from 3,243 bcm in 2024 to 4,670 bcm by 2055 at a growth rate of 1.2% annually.** By contrast, associated gas production is expected to fall by 150 bcm.

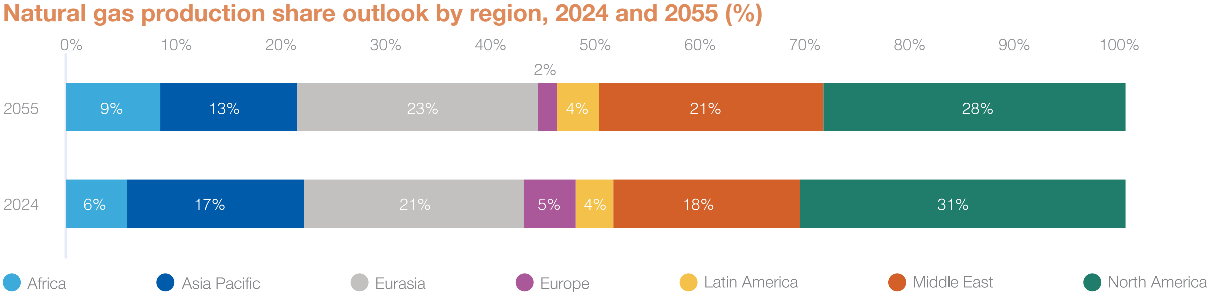
Non-associated gas from conventional fields is expected to remain the dominant source of global supply throughout the projection period, supported by substantial proven reserves and ongoing development in established producing regions. Conventional non-associated gas production is expected to rise from 2,377 bcm in 2024 to 3,534 bcm by 2055 at annual growth rate of 1.3% (Figure 5.4). Growth is led by major projects in the Middle East, particularly Qatar's North Field expansion, Iran's continued development of the South Pars field, as well as Eurasia's vast Arctic and Siberian reserves. These developments benefit from well-understood reservoir characteristics, existing infrastructure, and favourable project economics that sustain long-term production growth.

The decline in associated gas production reflects broader shifts in global oil market dynamics rather than resource constraints. Conventional associated gas production falls from 414 bcm in 2024 to 322 bcm by 2055, while associated gas from tight oil declines from 483 bcm to 425 bcm by 2055.

Coalbed methane (CBM) remains broadly stable, easing from 59 bcm in 2024 to 50 bcm by 2055, as production centers in Australia and China mature and limited new developments proceed. CBM remains geographically concentrated and continues to function as a supplementary source within the broader supply mix.

Figure 5.3

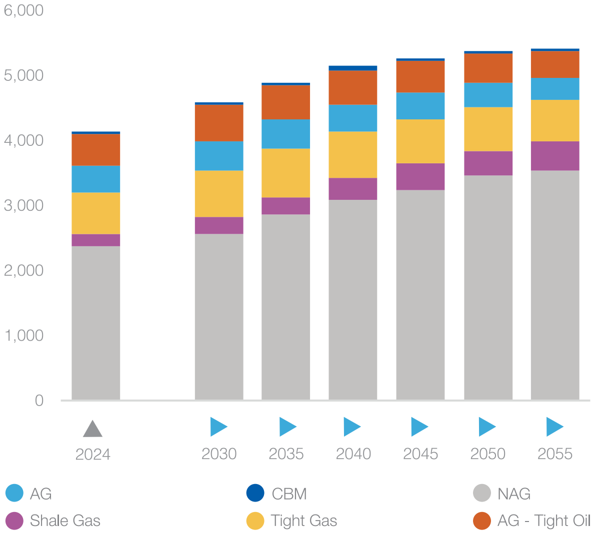
Natural gas production share outlook by region, 2024 and 2055 (%)



Source: GECF Secretariat based on data from the GECF GGM

Figure 5.4

Natural gas production outlook by hydrocarbon type, 2024-2055 (bcm)

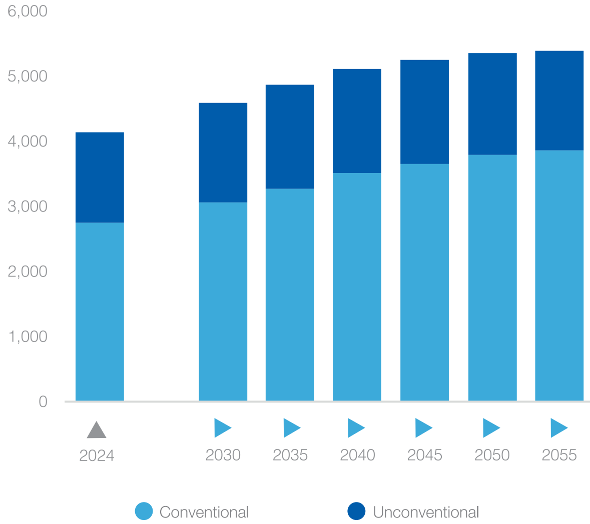


Source: GECF Secretariat based on data from the GECF GGM

Note: NAG: Non-associated gas, AG: Associated gas, CBM: Coalbed methane

Figure 5.5

Global natural gas production outlook by field type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

5.2.2 Conventional and unconventional gas production outlook

Global natural gas growth signals a distinct shift in supply dynamics, with conventional gas contributing 1,117 bcm of incremental production along the outlook to 2055 compared with 164 bcm from unconventional sources. This represents a structural departure from the 2010s, when unconventional resources dominated global expansion.

Conventional gas production is projected to increase from 2,764 bcm in 2024 to 3,880 bcm by 2055, reflecting compound annual growth rate of 1.1%. Conventional resources account for 87% of total supply expansion over the period, driven primarily by the Middle East, Eurasia and Africa, where substantial reserve bases and major developments underpin sustained output increases. The Middle East alone is expected to add 343 bcm of conventional supply by 2055, with growth concentrated in Qatar, Iran, Iraq, and Saudi Arabia (Figure 5.5).

The expansion of conventional gas is underpinned by a critical rotation in the project pipeline, necessitated as legacy fields decline and new capacity enters operation. Existing conventional assets, having contributed 2,764 bcm in 2024, face steady natural decline due to reservoir maturation. These fields are projected to contract to approximately 700 bcm by 2055, thereby mandating substantial replacement volumes. Regional decline profiles diverge significantly; the Middle East benefits from favourable reservoir characteristics, low base decline rates, and substantial remaining reserves, whereas mature basins in Asia Pacific and Europe contend with accelerating decline rates compounded by ageing infrastructure. Consequently, supply from new conventional projects ramps up progressively, reaching 2,267 bcm by 2055.

Unconventional gas supply, having expanded rapidly from 155 bcm in 2004 to 1,376 bcm in 2024, is projected to moderate, reaching 1,540 bcm by 2055 implying a compound annual growth rate of 0.4%. This deceleration stems from the steep decline rates characteristic of unconventional reservoirs, which average approximately 10% per annum for developed assets. Consequently, supply from existing conventional assets, dominated by North American shale and tight gas plays, is forecast to fall sharply. Offsetting this steep natural decline necessitates the continuous development of new unconventional acreage. While new projects drive supply growth throughout the outlook, this momentum is projected to moderate post-2030s. This deceleration reflects a strategic migration from core acreage to secondary and tertiary tiers, signalling the anticipated maturity and subsequent plateau of major unconventional basins in the United States.

Regional unconventional development profiles diverge markedly, contingent upon local geology, infrastructure maturity, and policy frameworks. North America is set to remain the dominant unconventional producer along the outlook, however, its unconventional production is set to peak in 2030s. Conversely, the Middle East registers the strongest relative growth; unconventional supply is forecast to increase by 4 times from current level driven by Saudi Arabia's Jafurah Basin, while the

Chapter 5

number of regional producers is expected to widen from two to five countries over the outlook. In the Asia Pacific region, unconventional contributions grow despite distinct challenges. Chinese unconventional production is projected to reach 160 bcm by 2055, up from 105 bcm in 2024, propelled by strategic policy mandates and subsidies designed to bolster energy security. In contrast, Australia faces regulatory headwinds that have stifled investment and constrained gas developments.

As existing producing fields decline, the industry focus shifts toward bringing substantial new capacity online to counterbalance natural depletion rates of 4.4% per annum for conventional reservoirs and 10.7% for unconventional assets. Consequently, new conventional projects are projected to scale up progressively, contributing 2,267 bcm by 2055. Parallel to this conventional expansion, new unconventional developments are forecast to add a further 1,220 bcm over the outlook (Figure 5.6).

Yet-to-Find (YTF) resources emerge as critical contributors to long-term supply stability, particularly post-2040 as the depletion of existing fields accelerates. Conventional YTF resources are projected to contribute approximately 930 bcm by 2055, with unconventional YTF adding a further 280 bcm. The necessity for sustained development and exploration success is clear; by 2055, new projects and YTF resources combine to account for 86% of global natural gas supply, leaving legacy assets to contribute just 14%.

Regional reliance on YTF resources varies significantly. The Asia Pacific region exhibits the highest exposure; YTF volumes are projected to constitute over 50% of regional supply by 2055. Indonesia's recent deepwater discoveries, together with China's licensing campaigns, reflect recognition of this exploration urgency. Australia, by contrast, faces regulatory stringency and environmental opposition that constrain its long-term resource replacement outlook. Latin America shows similarly high dependence, with YTF resources accounting for 61% of 2055 production. Conversely, Eurasia, the Middle East, and North America rely far less on YTF resources due to their substantial undeveloped discovered reserves and ongoing field expansions.

5.2.3 Onshore and offshore gas production outlook

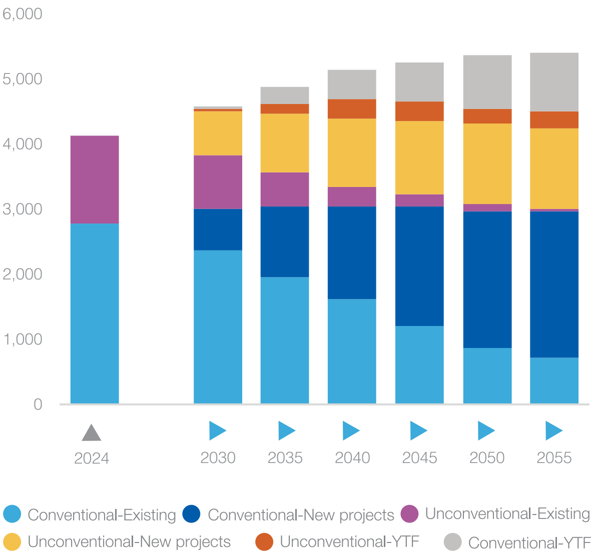
Onshore production remains the backbone of global supply, contributing 71% of the total in 2024, while offshore production accounts for 29%. Over the outlook period, offshore supply expands more rapidly than onshore production and accounts for 31% by 2055. **Offshore volumes are projected to rise at 0.9% per annum, growing from 1,252 bcm in 2024 to 1,679 bcm by 2055. Concurrently, onshore production increases at 0.6% per annum, rising from 3,064 bcm to 3,738 bcm** (Figure 5.7).

In terms of regions, Eurasia provides the largest increment of onshore growth, adding about 230 bcm between 2024 and 2055, driven by Russia's vast conventional reserves and continued development across Central Asia. This is followed by North America and the Middle East.

Two regions leading global offshore gas production expansion over the outlook. The Middle East is set to be the world's premier offshore producer, with supply

Figure 5.6

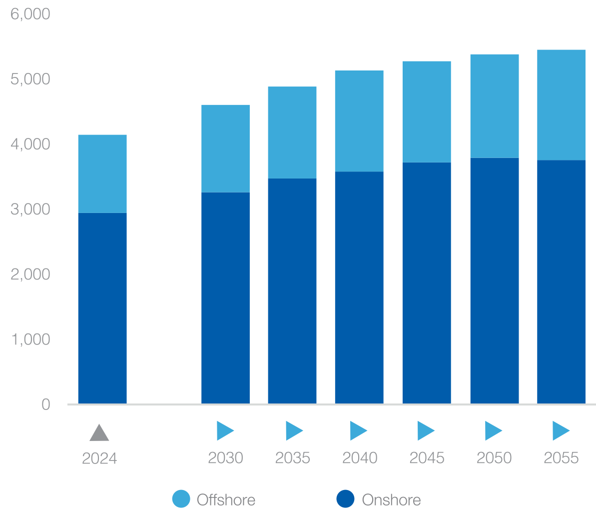
Global natural gas production outlook by project type, 2024 - 2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 5.7

Natural gas production outlook by field location, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

forecast to reach 765 bcm by 2055. This represents a net addition of 285 bcm, underpinned by compound annual growth of 1.5%. Meanwhile, Africa plays a transformative role in the global landscape; the continent's supply mix is projected to invert from 34% offshore in 2024 to 63% by 2055, a near-quadrupling of offshore gas production from 82 bcm to 302 bcm.

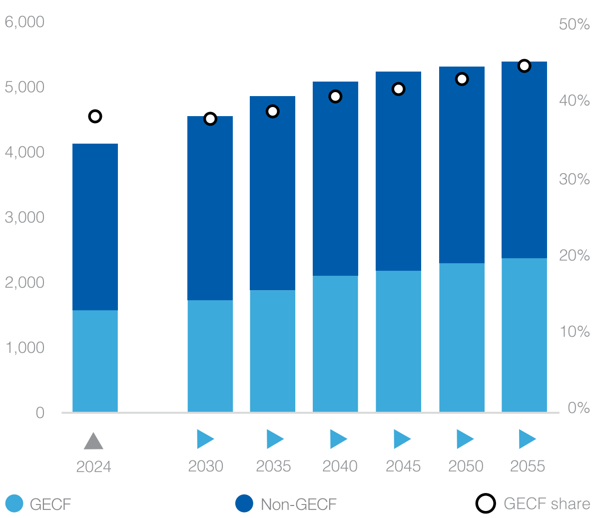
The number of gas-producing countries is expected to increase over the outlook period. In 2024, Mauritania and Senegal entered the market with first gas production, followed in 2025 by their initial LNG exports. Additional new entrants include Cyprus and Namibia, which are leveraging recent discoveries to position themselves as emerging natural gas producers during 2030s. Several smaller producers today, notably Tanzania and Türkiye, are also poised for sizeable expansions, enabling them to evolve into meaningful contributors to global supply.

5.3 GECF share of global natural gas production

The share of the current GECF Member Countries in global natural gas production is projected to expand significantly through 2055. In 2024, volumes from GECF Member Countries stood at 1,568 bcm, accounting for 38% of the global total. **By 2055, GECF production is forecast to reach 2,389 bcm, representing 44% of world supply.** This marks an increase of approximately 820 bcm over the forecast period. In contrast, non-GECF supply is expected to rise at a slower pace, adding 460 bcm to reach 3,028 bcm by 2055 (Figure 5.8).

Figure 5.8

GECF and non-GECF natural gas production outlook, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

The growth rates differ considerably over the outlook. The average annual growth rate of natural gas production from GECF Member Countries is projected at 1.4%, substantially outpacing the 0.5% growth rate anticipated for non-GECF producers. This robust production expansion will be driven primarily by GECF Member Countries in three strategically positioned regions: the Middle East, Eurasia, and Africa. These regions are poised to be the fastest-growing natural gas producers globally.

Production from GECF member countries follows a steady growth trajectory through 2055, while non-GECF output peaks in the first half of 2040s at 3,070 bcm. This reflects the maturing production outlook for major non-GECF producers, including the United States and China.

5.4. Regional natural gas production outlook

The regional outlook for natural gas production through 2055 reflects a fundamental rebalancing of global supply dynamics, as conventional resources reassert their dominance after two decades of unconventional-led growth. The projected 1,281 bcm increase in global production masks substantial regional divergence. The Middle East, Eurasia, and Africa are poised to drive most of the expansion in conventional supply, while North America's unconventional growth moderates as major shale basins mature. Some regions will face accelerating declines due to ageing assets and insufficient reserve replacement, while others leverage substantial resource bases to capture more market share. The following analysis examines each region's prospects through 2055 and the key factors shaping their contribution to global supply.

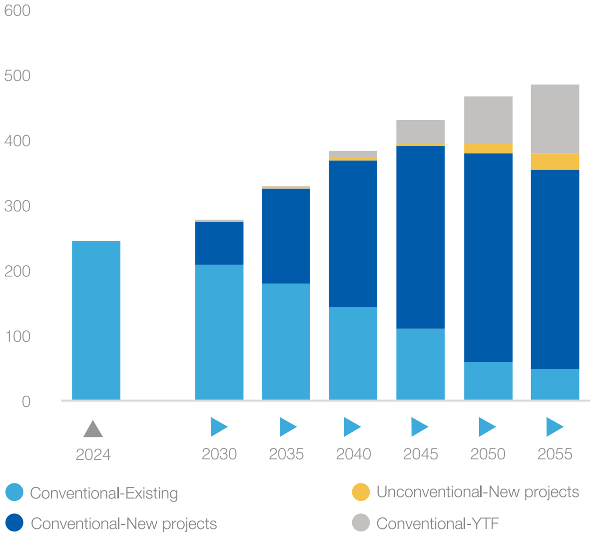
5.4.1 Africa

Africa's natural gas production declined by 13 bcm to 244 bcm in 2024. This decrease was driven by increased gas re-injection in Algeria and lower supply from Egypt's major offshore field. The region is expected to return to growth in 2025 as emerging gas producers ramp up volumes and Nigeria expands supply. **Regional supply is projected to rise from 244 bcm in 2024 to 482 bcm by 2055.** This effectively doubles the 2024 level, mirroring the growth recorded between 2000 and 2024. This upward trend is underpinned by offshore resource development, large-scale LNG projects, and increased exploration across multiple producing states. Consequently, Africa's share of global supply rises from 6% in 2024 to 9% by 2055 (Figure 5.9).

Nigeria is expected to become Africa's largest producer, reaching 118 bcm by 2055. Expansion is driven by the NLNG Train 7 project and new FLNG developments, supported by the 2021 Petroleum Industry Act and the 2022 renewal of major deepwater production sharing contracts. Mozambique is forecast to reach

Figure 5.9

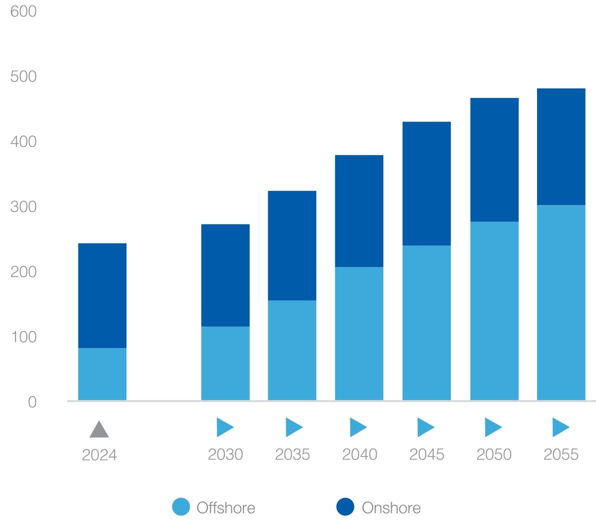
Africa's natural gas production outlook by project type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 5.10

Africa's natural gas production outlook by field location, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

98 bcm by 2055, supported by development of the offshore Rovuma Basin through LNG projects such as Rovuma LNG, Coral North FLNG, and the resumption of Mozambique LNG. Algeria is projected to reach 75 bcm by 2055, benefiting from substantial unconventional gas resources that have not yet been developed.

Emerging producers in the region include Mauritania and Senegal, which achieved first gas from the shared Greater Tortue Ahmeyim project in 2024, and first LNG exports in 2025. The two countries are projected to reach 24 bcm and 22 bcm respectively by 2055. Tanzania could reach 25 bcm by 2055, dependent on the USD 42 billion Tanzania LNG project proceeding. Libya's production could grow to 22 bcm by 2055, supported by offshore developments including Structures A and E scheduled for 2026 startup, and exploration activity following the launch of the 5th Libya Lease Round in 2025 blocks.

The composition of Africa's production changes significantly over the period. Existing fields, entirely conventional reservoirs, decline from 244 bcm in 2024 to 47 bcm in 2055. New projects contribute 304 bcm, nearly two-thirds of total gas production, while unconventional production, primarily from Algeria's shale, begins in the mid-2030s. YTF resources supply around 105 bcm, 21% of production, concentrated in Algeria, Egypt, Nigeria, and frontier basins.

Offshore production grows from 82 bcm, 33% of total, in 2024 to 302 bcm, 61% of total, by 2055, while onshore production expands from 162 bcm to 180 bcm over the same period. Growth in offshore output will be underpinned by deepwater and ultra-deepwater developments in Mozambique's Rovuma Basin, the Senegal–Mauritania Basin, Nigeria's deepwater plays, Tanzania's Indian Ocean blocks, and the Mediterranean. Development resources in water depths often exceeding 2,000 meters requires collaboration with international oil companies with deepwater technical capabilities and access to project financing.

The outlook faces several technical, commercial, and political considerations. Technical challenges include deepwater engineering requirements. Commercial factors include exposure to global LNG pricing dynamics. Additionally, infrastructure requirements include multiple large-scale LNG facilities across the continent, along with upstream gathering systems, processing facilities, and pipeline infrastructure for both export and domestic markets. Licensing activity has increased across Africa, with recent rounds in Algeria, Libya, Nigeria, and Tanzania indicating continued exploration interest. The next decade will be critical for FIDs, determining Africa's production trajectory through 2055 (Figure 5.10).

Algeria's gas production declined by 7% to 98 bcm in 2024. This contraction occurred despite stable gross production, primarily due to increased gas re-injection at oil fields. A recovery is projected over 2025 and 2026, supported by higher volumes from the Hassi Ba Hamou and Hassi Mounia fields and the startup of the Ain Tsila development.

Algeria's upstream development pipeline includes several projects through the late 2020s and early 2030s. The Southwest Phase 2, Gassi Touil, and Ain Tsila gas projects represent the primary near-term growth drivers, with these developments expected to support export capacity into the late 2020s.

The government launched its Algeria Bid Round 2024, the country's first oil and gas licensing round since 2014, offering six onshore exploration blocks, primarily in Algeria's southwest. Five of these blocks secured winning bidders (Ahara, Reggane II, Zerafa II, Toual II, and Guern El Guessa II). This renewed licensing activity, with the government committing to annual rounds through 2028, signals a strategic pivot toward accelerating exploration and reversing the decade-long hiatus in attracting foreign investment.

Over the long-term, the outlook expects Algeria to reach 75 bcm by 2055. Notably, Algeria possesses huge unconventional gas resources. This untapped potential, combined with the ongoing developments, an attractive regulatory regime, and international partnerships, suggests that Algeria's natural gas sector has significant room for growth, dependent on the trajectory of unconventional development.

Libya's gas production remained steady in 2024 at 13.6 bcm. Production growth from the West Libya Gas Project and Attahadi was offset by decline at the Nasser project. The near-term development pipeline offers is strong: Structures A and E are expected to start production in 2026 and reach a combined plateau of 8 bcm/y. The Bouri Gas Utilisation project, also due online in 2026, aims to capture flared gas and increase supply while supporting emissions reductions. A milestone came with the award of Block NC-07 to a consortium, and discussions continue between international oil companies and Libya's National Oil Corporation on developments in the Ghadames Basin.

Exploration activity has resumed after decades of inactivity. In 2025, Libya launched the 5th Libya Lease Round offering 22 blocks, its first such contest since 2007. The onshore basins include Ghadames, Murzuq, Sirte, Cyrenaica, and Kufra, while the offshore basins comprise Sirte Offshore, Cyrenaica Offshore, and Sabratha Offshore. This renewed exploration push is critical given Libya's substantial yet underexplored hydrocarbon potential, particularly in frontier basins and offshore areas.

Existing field optimization, major offshore developments like Structures A and E, and potential discoveries from the new licensing round could support growth through the 2030s, and lift production to 15 bcm by 2055.

Mauritania and **Senegal** are emerging as significant players in West Africa's natural gas sector, underpinned by deepwater resources in the prolific Senegal-Mauritania Basin. Both countries achieved a milestone in December 2024 when the shared Greater Tortue Ahmeyim (GTA) project began production, with the first phase flowing gas from subsea wells to the FPSO vessel for delivery to the 2.7 Mtpa FLNG facility. First LNG exports were announced in April 2025. The GTA field, alongside Mauritania's Orca and Bir Allah discoveries and Senegal's Yakaar-Teranga fields, anchors the region's resource base. Mauritania is projected to reach 24 bcm by 2055, and Senegal 22 bcm.

Future growth centres on phased GTA expansion and the development of discovered resources. GTA Phase 2 could potentially double liquefaction capacity to approximately 5.4 Mtpa by the early 2030s, with Senegal targeting 5 bcm by 2030 as production ramps up. Mauritania's Bir Allah project and Senegal's Yakaar-Teranga fields offer further potential but face medium-term uncertainties. Key risks include deepwater technical challenges at depths exceeding 2,500 metres, commercial exposure to volatile LNG prices amid more than 200 Mtpa of new global capacity coming online before 2030, and the need to secure financing for post-GTA developments.

Mozambique's natural gas sector is poised for substantial growth towards 2055, driven by Rovuma Basin resources and ongoing exploration efforts. The nation's current production baseline is reliant on two distinct sources. In the north, the sole operating LNG project is Eni's Coral South FLNG (Area 4), which commenced production in 2022 with a nameplate capacity of 3.4 Mtpa. In the south, the 20-year-old Pande-Temane fields.

Exploration activity continues, albeit eclipsed by the focus on developing the known Rovuma resources. Rystad Energy reported that in the first half of 2024, new acreage awards were concentrated in Mozambique's deepwater Angoche basin, indicating continued interest in new frontiers despite Eni's unsuccessful Raia-1 wildcat well in the basin in 2023.

Mozambique is forecast to reach 98 bcm by 2055, contingent on the successful execution of large-scale LNG projects in the Rovuma Basin. The largest, the 18 Mtpa Rovuma LNG project (Area 4), is progressing through its FEED phase after shifting to a more cost-efficient modular design and is expected to reach FID in 2027, with start-up in the first half of 2030s. Coral North FLNG is advancing steadily with FID achieved in October 2025, and startup expected by 2030. As at the end of 2025, the 13 Mtpa Mozambique LNG project remained stalled under a force majeure declared in 2021 but is expected to start production by 2030.

Nigeria's natural gas production maintained its gas production level at 46 bcm, with an increase to 52 bcm expected in 2025, driven by increased LNG capacity.

The development pipeline is centred on increasing LNG exports. The development pipeline is anchored by NLNG Train 7, expected to start up in 2027 and raise liquefaction capacity from 22 to 30 Mtpa. Additional growth is expected from rising FLNG activity: the UTM Offshore FLNG project is nearing FID and targeting a 2028–2029 launch, while Ace FLNG and Transoceanic FLNG are in the pre-FEED stage. These projects are supported by associated gas from new deepwater oil developments such as Bonga North Phase 1, which reached FID in 2024.

Mozambique is forecast to reach 98 bcm by 2055, contingent on the successful execution of large-scale LNG projects in the Rovuma Basin. The largest, the 18 Mtpa Rovuma LNG project (Area 4), is progressing

through its FEED phase after shifting to a more cost-efficient modular design and is expected to reach FID in 2027, with start-up in the first half of 2030s. Coral North FLNG is advancing steadily with FID achieved in October 2025, and startup expected by 2030. As at the end of 2025, the 13 Mtpa Mozambique LNG project remained stalled under a force majeure declared in 2021 but is expected to start production by 2030.

The fiscal framework is anchored by the 2021 Petroleum Industry Act (PIA), which was introduced to create regulatory certainty and attract new investment for new projects. For deepwater gas projects, the PIA replaces the previous 50% Petroleum Profits Tax with a 30% Corporate Income Tax and variable, price-and-production-based royalties (5%-17.5%). The 2022 renewal of six major deepwater Production Sharing Contract (PSC), including Egina, Bonga, and Erha, has provided long-term clarity for the IOCs essential to developing Nigeria's deepwater gas reserves.

Nigeria is expected to reach 118 bcm by 2055. This projection is dependent on the successful and timely commissioning of NLNG Train 7, the sanctioning of the UTM FLNG project, and the industry's ability to develop stalled deepwater gas projects under the PIA framework.

Tanzania's current production is modest, supplied by shallow-water and onshore fields such as Songo Songo and Mnazi Bay for domestic power and industry. Future growth hinges entirely on developing Tanzania's vast offshore reserves, estimated at 1.6 tcm (57 tcf). The main project is the long-delayed, USD 42 billion Tanzania LNG project, by a consortium of IOCs. Finalizing the Host Government Agreement remains essential for an FID on the project's first phase.

Tanzania is simultaneously revitalizing exploration to drive further growth. Rystad Energy reports that Tanzania launched its Fifth Licensing Round in May 2025, offering 26 blocks, including 23 offshore in the Indian Ocean and three onshore in Lake Tanganyika. Concurrently, Zanzibar opened its inaugural licensing round in 2024 with eight offshore blocks, later expanded to include two onshore blocks. The success of these new licensing rounds will be critical for achieving 22 bcm of annual production by 2055 envisaged in the outlook.

5.4.2 Asia Pacific

Natural gas production across the Asia Pacific region experienced strong growth of 16 bcm in 2024, reaching 692 bcm. China remains the primary driver, underpinned by a national strategy that prioritises energy security. The country accounted for almost 80% of the region's growth last year, with marketed volumes rising to 230 bcm, surpassing targets set in the five-year plan. Two decades ago, China was producing only 20 bcm annually, similar to India and Thailand and approximately half the level recorded in Australia. Additional growth came from Malaysia, Thailand, Indonesia, and Australia, while Bangladesh, Pakistan, and Papua New Guinea recorded modest declines.

Regional natural gas production is forecast to rise moderately, reaching 706 bcm by 2030, led by China's continued focus on unconventional resources, targeting 270 bcm. Asia Pacific supply is expected to peak at around 729 bcm by 2040, before entering a gradual decline to 696 bcm by 2055. This long-term trajectory reflects China's anticipated production plateau and subsequent decline in the 2040s, reaching 315 bcm by 2055, as major basins mature. and there is a significant forecasted reduction in Australian production to 115 bcm by 2055 due to legacy declines and exploration constraints. Indonesia and Malaysia also face maturation challenges, with their long-term outlook heavily dependent on YTF resources (Figure 5.11).

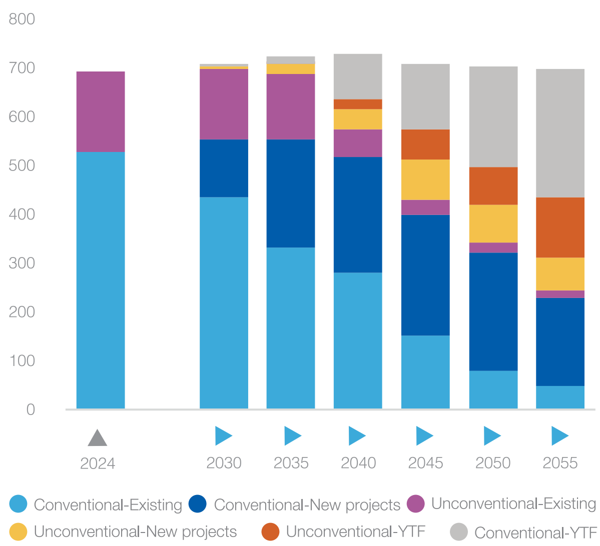
Asia Pacific's share of global production is projected to fall from 17% in 2024 to 13% by 2055. The region is set to remain the world's largest gas importer over the long term, with implications for regional balances discussed in Chapter 6.

Exploration activity diverged sharply across the region in 2024. China experienced a surge in licensing, while Indonesia regained significant momentum following major deepwater discoveries in Kutei Basin and large finds in the Andaman Basin. By contrast, Australia saw exploration collapse to historic lows due to increasingly stringent regulation, environmental opposition, and restrictions on activities like seismic surveys, significantly undermining its long-term ability to replace reserves.

Regulatory frameworks are exerting significant influence on investment and development trajectories. Australia's

Figure 5.11

Asia Pacific's natural gas production outlook by project type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

policy environment has created investment paralysis and hindered unconventional gas growth. By contrast, Indonesia is seeking to attract upstream investment through mechanisms such as Joint Studies, while China employs direct subsidies and policy mandates to achieve its targeted growth in unconventional gas production and meet national energy security goals.

Exploration will be decisive for the region's long-term supply. YTF resources are expected to account for over 50% of the region's production by 2055. Existing conventional and unconventional production will contribute only a small share by 2055 with most supply dependent on the new projects. Countries in the region may therefore need to reassess policies that impede exploration and development to avoid increasing reliance on imports.

A notable shift in the geographical source of Asia Pacific's gas production is expected through 2055. Onshore production becomes the primary driver of regional supply, rising from 360 bcm in 2024 to 520 bcm by 2055, and accounting for 75% of total production This growth is led by China's extensive development of onshore unconventional resources. By contrast, offshore production, currently 332 bcm, is projected to decline sharply to 175 bcm by 2055, as legacy offshore fields in Australia and Southeast Asia mature and deplete (Figure 5.12). The long-term outlook is increasingly defined by China's dominant role in unconventional gas, and the region's critical dependence on exploration success and the development of yet-to-find resources.

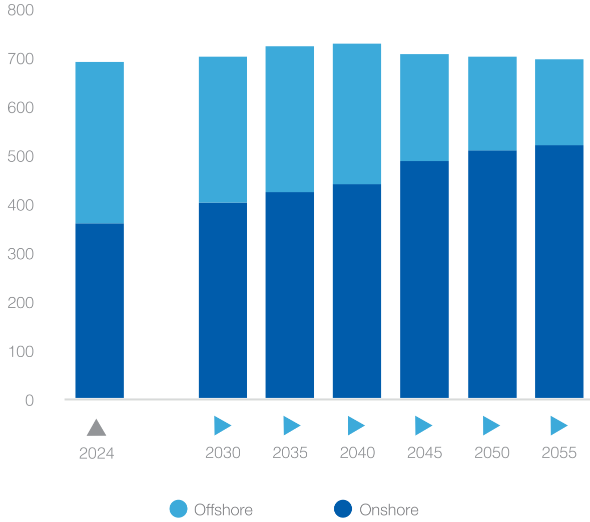
Australia's gas production rose slightly in 2024, increasing by 0.7% to 145 bcm. Growth was supported by output from the unconventional Bowen-Surat basin followed by the conventional Browse basin.

The development pipeline to 2030 is centred on large-scale projects already sanctioned. Scarborough, supplying Pluto Train 2, is targeting start-up in 2026, with production reaching 7 bcm by 2030. Santos' Barossa project will backfill Darwin LNG from 2026, although legal challenges from Traditional Owners have caused delays. Browse, which depends on an extension of NWS infrastructure, faces environmental challenges despite updated development plans, with an FID pending regulatory clarity. Emerging unconventional plays, such as Queensland's Taroom Trough and the Northern Territory's Beetaloo Basin, could support growth post-2030, contingent on infrastructure development and acceptance of hydraulic fracturing.

Australia's unconventional sector continues to face significant environmental, political, and regulatory headwinds. The expansion of the national "water trigger" in December 2023 brought all unconventional gas developments under federal scrutiny, extending approval timelines and increasing project costs. Furthermore, the strengthened Safeguard Mechanism requires new gas fields supplying LNG facilities to achieve net-zero Scope 1 emissions at entry, dramatically raising development

Figure 5.12

Asia Pacific's natural gas production outlook by field location, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

costs. Although the May 2024 Future Gas Strategy acknowledged the long-term necessity of natural gas to support renewables and hard-to-decarbonise sectors, limited supportive policy measures have left the industry in prolonged uncertainty.

Consequently, exploration activity collapsed to historic lows in 2024. According to Rystad Energy, the July 2024 acreage awards came with unprecedented restrictions prohibiting new seismic surveys, while Australia's largest-ever planned seismic survey in the Otway Basin was cancelled. Amid such developments, exploration expenditure has fallen by more than 70% from its 2013 peak, posing a structural challenge to long-term resource replacement.

In this constrained environment, CCUS has become essential for project viability, though operational results have been mixed. While the Gorgon facility has faced persistent technical challenges and high abatement costs, the Moomba project has demonstrated greater operational success and economic efficiency.

Australia's long-term gas production is forecast to decline, with this outlook revising the projection downward to 115 bcm by 2055. This reflects a confluence of factors, including declining supply from major legacy fields, slow progress in commissioning new projects, and a reduction in exploration activity.

In 2024, **China** exceeded its 14th Five-Year Plan (2021–2025) annual target of 230 bcm ahead of schedule. Momentum is expected to continue in 2025, with Rystad Energy projecting production to reach 236 bcm.

The project pipeline remains focused on unlocking unconventional and ultra-deep conventional resources.

For example, 21 projects reached FID in 2024, with combined plateau capacity of 15 bcm annually, concentrated on shale gas expansions in the Sichuan Basin's Longmaxi Formation, tight gas in the Ordos Basin's Sulige and surrounding blocks, and CBM development in Shanxi Province's Qinshui Basin, where CNOOC's Shenfu reserves approach 100 bcm. Major pre-FID projects include the expansion of the Jafurah-analogous tight formations in northwest China, additional phases of offshore development in the South China Sea's deepwater frontier at water depths exceeding 1,500 meters, and ambitious plans to commercialise over 30 tcm of technically recoverable shale gas, despite challenging geology, water scarcity, and mountainous terrain.

The government has extended subsidies for unconventional drilling through 2029, allocating CNY 3.2 billion (USD 440 million) for 2025 to incentivize CBM, shale, and tight gas development. Policy directives under the 14th Five-Year Plan (2021-2025) mandate national oil companies prioritize gas over oil to reinforce domestic supply security and reduce import dependence.

Exploration and licensing activity has surged in recent years, with China awarding 23 blocks in the first half of 2025 alone across the Tarim, Songliao, and Pearl River Mouth basins. According to Rystad Energy, exploration success rates remain modest at 25-30% for frontier plays but improves to 60-70% in established basins, with notable 2024 discoveries including offshore gas accumulations in the Bohai Bay's buried hill reservoirs and onshore breakthroughs in ultra-deep Cambrian formations exceeding 8,000 meters depth in the Tarim Basin.

China's natural gas production is projected to maintain its upward trajectory over the next two decades. This trend is underpinned by a national mandate to bolster energy security through the development of complex unconventional resources. Supply is forecast to rise from 230 bcm in 2025 to 270 bcm in 2030. Growth is strongest through the remainder of the 2020s, expanding at 2.7% annually between 2025 and 2030. The pace is expected to moderate to approximately 2% per year in the 2030s, with supply reaching 335 bcm by 2040. Subsequently, gas production enters a gradual decline to reach 315 bcm by 2055 as the key Ordos, Sichuan, and Tarim basins mature.

Indonesia produced 57 bcm of gas in 2024, growing by 1.7%, supported by the Tangguh LNG project. The existing production base is facing significant maturity challenges. Gas production is sustained by key legacy assets like Tangguh LNG, the Mahakam block, the Muara Bakau block, and the Corridor block. Pertamina plays a critical role in managing decline, having taken over numerous mature blocks, such as Mahakam and Offshore Northwest Java. These require significant brownfield spending to slow decline, and many ageing fields face high production costs, according to Rystad Energy.

Indonesia benefits from a robust pipeline of new projects that could raise to 81 bcm by 2030. Rystad Energy estimates that USD 55 billion in planned FIDs between 2025 and 2030 are expected. The anchor project is Abadi LNG project in the Masela Block. Following the start of FEED work in August 2025, the project is targeting first gas in 2030, with 13 bcm of LNG production. Other critical developments include the Eni-operated Indonesia Deepwater Development (IDD), BP's Tangguh Ubadari, CCUS, Compression (UCC) project, and new hubs emerging from recent discoveries in the Andaman Basin and Kutei Basin.

Recent exploration has delivered major successes, confirming strong remaining prospectivity in both frontier and mature basins. Multi-tcf finds in the deepwater Andaman Basin, including Timpan, Layaran, Tangkulo, and Gayo, and the giant Geng North discovery in the Kutei Basin, have attracted a diverse range of players, including international majors, national oil companies, and specialized independents. The Joint Study (JS) mechanism has emerged as the principal entry route for new investors, allowing collaboration with the Ministry of Energy and Mineral Resources (MEMR) to de-risk prospects in open areas and gain preferential bidding rights in subsequent licensing rounds. As of August 2025, 37 such joint studies were ongoing or completed, marking the largest coordinated exploration effort in the country's history. This momentum is translating into tangible investment, with Rystad Energy estimating USD 138 million in new exploration commitments during 2025 alone. This activity is supported by active licensing, including the 2024 the Indonesia Petroleum Bid Round (PBR2) and the 2025 1st Bid Round, as the Upstream Oil and Gas Regulatory Task Force (SKK Migas) plans to release over 60 new blocks in the next three years.

Indonesia's production is projected to reach 81 bcm by 2035 then decline to 70 bcm by 2040. It could then rise to 85 bcm by 2055 depending on exploration success and timely conversion of YTF resources.

In **Malaysia**, building on the post-pandemic recovery, gas production grew by 2% year-on-year and reached 81 bcm in 2024. This performance was supported by the ramp-up of newly commissioned projects, primarily SK408, Kasawari, and the Rosmari–Marjoram development. Although the Bindu field is scheduled to start up in 2025, total supply is expected to decline as key legacy assets mature.

Since 2020, Malaysia has significantly intensified its upstream exploration strategy, demonstrating the government's recognition of the reserve replacement challenge. This is evident in annual licensing rounds which offered 14 blocks in 2022, 10 in 2023, and 5 in 2024. The latest round included both frontier areas and mature basins with discovered resources. While the country has recorded multiple discoveries in Sarawak over the past five years, exploration blocks in Peninsular Malaysia and Sabah are being actively offered in 2025.

According to Wood Mackenzie data, the country's remaining gas resources are estimated at 1.4 tcm.

Natural gas production is projected to decline to 55 bcm by 2055. YTF resources account for around 40% of this total, highlighting the dual challenge of field maturation and the necessity of developing new finds.

5.4.3 Eurasia

Eurasia recorded the strongest production growth of any region in 2024, reaching 856 bcm, an increase of 31 bcm. This expansion was primarily driven by Russia, where gas supply grew by 5.2% to 670 bcm, on the back of rising domestic demand and increased pipeline and LNG exports. Russian growth was led by the Yamal Megaproject, Urengoyskoye, Dobycha Yamburg, and the Eastern Gas Program.

Eurasia is set to maintain its role as the world's second-largest gas-producing region, with production projected to reach 1,233 bcm by 2055 (Figure 5.13). This represents a robust 44% increase from the 856 bcm produced in 2024, equivalent to an average annual growth rate of 1.3%. The region's share of global supply is expected to expand from 21% in 2024 to 23% by 2055, reflecting the scale of its conventional resource base and sustained investment in strategic export infrastructure.

Russia remains the central driver of Eurasia's long-term outlook. The country accounted for 76% of regional supply in 2024 at 670 bcm and is projected to reach 977 bcm by 2055. The country's growth strategy rests on three pillars: the Eastern Gas Program, which expands pipeline capacity to China; Yamal Peninsula developments, which aim to restore volumes to historical highs and support Asian exports; and Arctic offshore projects, which mark the pursuit of frontier resources. Turkmenistan also shows considerable potential, with production forecast to nearly double from 74 bcm in 2024 to 139 bcm by 2055. This growth is contingent on the phased development of the Galkynysh field and export pipeline infrastructure. In contrast, Uzbekistan presents the region's only declining trajectory. Supply is expected to fall from 42 bcm in 2024 to 16 bcm by 2055 due to the depletion of aging fields and underinvestment in exploration.

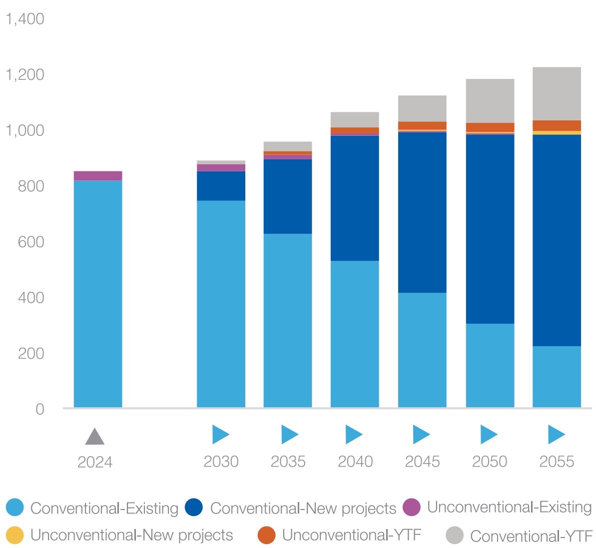
Eurasia's existing conventional production, which totalled 822 bcm in 2024, is projected to decline sharply to 222 bcm by 2055. New conventional projects will serve as the primary growth engine, adding 767 bcm by 2055. This expansion is driven by major developments across Russia and Turkmenistan. While unconventional resources remain at an early stage of development, they are expected to contribute 51 bcm by 2055. Additionally, YTF resources are projected to add a further 195 bcm.

Onshore production accounted for 91% of the region's total in 2024, stood at 783 bcm. This sector will remain dominant, with supply projected to rise to 1,011 bcm by 2055. Meanwhile, offshore supply is set for significant expansion. Its share is expected to more than double to 20%, driven by developments in the Caspian and Russia's Arctic offshore (Figure 5.14).

Infrastructure development emerges as both a critical enabler and potential constraint. Existing pipelines to Asia provide proven export corridors, but proposed expansions face uncertain timelines due to pricing disagreements. Despite geopolitical pressures, Eurasia's long-term outlook remains robust, supported by vast

Figure 5.13

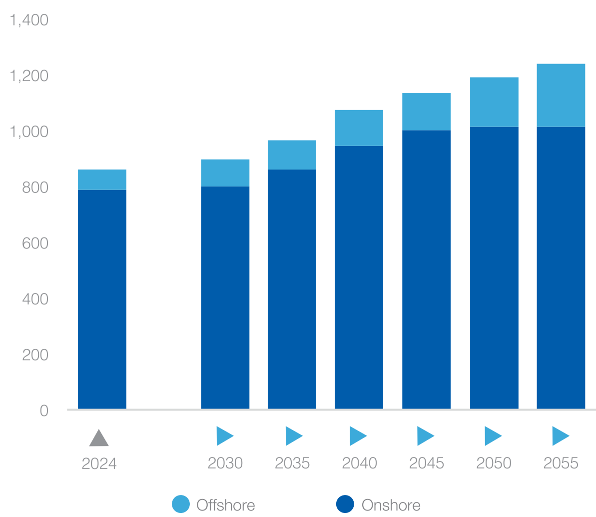
Eurasia's natural gas production outlook by project type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 5.14

Eurasia's natural gas production outlook by field location, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

reserves, a sizeable project pipeline, and the central role of natural gas in regional and Asian energy systems.

Azerbaijan continued its strong performance in 2024, with production reaching 39 bcm a 7.8% increase from the 36 bcm produced in 2023. Growth is largely driven by increased volumes from the Shah Deniz field in the South Caspian Basin, supplemented by a ramp-up at the Absheron field.

Shah Deniz remains the backbone of Azerbaijan's gas sector, accounting for over 70% of Azerbaijan's marketed production and operating at its Phase 1 and 2 plateau output of 26 bcm. A robust pipeline of new projects will be essential to managing the long-term production decline. The USD 2.9 billion Shah Deniz Compression project, recently approved, is critical to maintaining the field's plateau output and is expected to be online by 2030. Absheron represents the next major growth driver, with its 4 bcm Phase 1 scheduled for start-up before 2030 and the 7 bcm Phase 2 expected in the early 2030s.

Exploration momentum has strengthened. A follow-up discovery well is underway at the Shafag-Asiman block, with production anticipated in the early 2030s. Interest in plays has also grown, with ExxonMobil signing a Production Sharing Agreement (PSA) with SOCAR to evaluate unconventional resources in the Ganja-Yevlakh concession and MOL securing the Shamakhi-Gobustan block.

Azerbaijan's natural gas production is forecast to reach 40 bcm by 2055. However, realising these potential hinges on the timely expansion of the Southern Gas Corridor (SGC) to commercialise additional supply. The country's exports will increasingly compete in a dynamic market against global LNG volumes and other pipeline suppliers.

Russia,the world's second-largest natural gas producer, is poised for significant production growth along the outlook, supported by a diversification of export infrastructure. Natural gas production grew by 7% in 2024, reaching 670 bcm. Growth reflected higher domestic gas demand and increased pipeline and LNG exports. Production rose by 17 bcm at the Yamal Megaproject, 10 bcm at Urengoyskoye, and 9bcm at Dobycha Yamburg. Additionally, the Eastern Gas Program added another 7 bcm through expansions at Chayandinskoye and Kovykinskoye.

Russia's long-term growth is underpinned by expanded export capacity to China and increased LNG liquefaction. The proposed Power of Siberia-2 (PoS2) pipeline serves as a critical enabler, facilitating the redirection of Western Siberian gas to the Chinese market. This project is designed to revitalise the Yamal hub, particularly the Bovanenkovskoye field. Consequently, volumes are expected to rebound from the current 70 bcm level to surpass the 2021 peak of 110 bcm, sustaining an upward trajectory well beyond 2040. Simultaneously, LNG expansion centred on Arctic LNG-2 and Sakhalin-2 remains vital. These developments will leverage resources from the Utrenneye field on the Gydan Peninsula and offshore Sakhalin, respectively.

Exploration and licensing priorities have been realigned to support this geographic pivot, with efforts concentrated in Eastern Siberia and the Far East. The primary objective is to identify and substantiate the reserves required for new Asian export pipelines. Furthermore, the government is actively advancing comprehensive geological studies of the vast Arctic continental shelf.

Russia's production is projected to reach 848 bcm by 2040 and 977 bcm by 2055. Key risks include the technical complexity of Arctic developments, the immense capital requirements for new infrastructure, and geopolitical uncertainty regarding long-term export agreements. Nonetheless, Russia's 2050 energy strategy prioritises the domestic development of proprietary technologies and capabilities to overcome these constraints.

Turkmenistan's natural gas production experienced a 2.8% decline in 2024, with output falling to 74 bcm from the 76 bcm produced in 2023, reflecting the country's dependence on limited export routes and ongoing infrastructure constraints. Yet the country remains a key regional supplier.

Most of the existing production base is anchored by the Galkynysh field's first phase, which reached a plateau of 30 bcm in 2021. By 2030, production is set to rise to 82 bcm, dependent on the timely execution of Galkynysh Phase 2, which will add another 30 bcm of capacity. According to Rystad Energy, the drilling activities for this phase are underway. However, this phase is contingent on the commissioning of the Central Asia-China Line D pipeline. Longer-term expansion toward 2055 relies on Galkynysh Phase 3, for which an MoU was signed with ADNOC in early 2025, with production expected in the second half of 2030s. This gas is ultimately destined for new export routes, primarily the TAPI pipeline to Pakistan and India. However, the realization of the TAPI project faces significant financial and geopolitical hurdles.

To support long-term growth and diversify its upstream portfolio, Turkmenistan is intensifying efforts to attract new foreign investment to its offshore acreage. In 2025, the government signed a key MoU with Petronas to conduct exploration studies across five South Caspian blocks (11, 12, 16, 21, and 23). According to Rystad Energy, this strategy aims to reverse stagnation in the South Caspian exploration by promoting assets with existing well data. Over the long term, production is forecast to reach 141 bcm by 2055, though success will depend on the development of critical infrastructure and expanded export routes.

Uzbekistan's production continued its decline in 2024, falling to 42 bcm, a 4.5% decrease from 44 bcm in 2023, driven by persistent decline at existing fields and ageing infrastructure. The downward trend is expected to persist in 2025, with production forecast to fall further to 41 bcm. Production at Uzbekneftegaz remains concentrated around the Mubarek and Shurtan processing centres, which rely mainly on 1980s-era fields including Shurtan, Zevardi, Alan, and Dengizkul.

Exploration activity, which had been subdued with no large discoveries in recent years, has seen some initial signs of international interest. In July 2025, Azerbaijan's SOCAR signed a PSA with Uzbekneftegaz to explore for hydrocarbons in the Ustyurt region. This followed a renewed push by the government in May 2025 to attract foreign investment, which also included new agreements with service companies for advanced field development technologies in the region. Over the long-term, without a major exploration success, production is set to decline to 18 bcm by 2055.

5.4.4 Europe

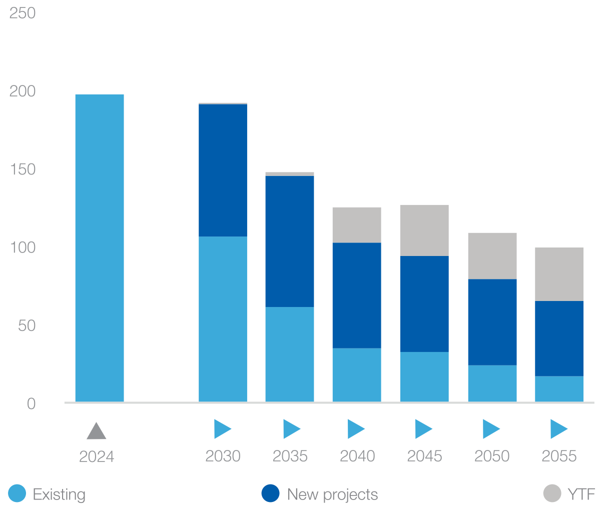
European natural gas production reversed its 2023 decline and increased by 3 bcm to 199 bcm in 2024, driven primarily by Norway's record gas production and Türkiye's accelerating ramp-up at the Sakarya field These gains more than offset steep declines across legacy producing basins in the Netherlands and the United Kingdom. However, this modest recovery does little to alter the profound structural contraction under way in Europe's upstream sector. Current production is 127 bcm below the 2004 peak of 326 bcm, reflecting two decades of accelerating field maturity, a dwindling reserve base, now representing only 1% of global reserves, chronic underinvestment in brownfield optimization and greenfield development, and policy frameworks that have systematically discouraged exploration across much of Western Europe.

The energy security crisis in 2022 has prompted several governments to reorientate policies in favour of domestic production. Germany reversed its 2021 pledge to halt new North Sea drilling permits by approving cross-border reservoir development with the Netherlands in July 2025, signalling recognition that indigenous supply carries strategic value beyond purely economic considerations. Similarly, the Netherlands negotiated agreements to increase North Sea output, despite decades of policy momentum aimed at accelerated basin decommissioning. Yet these policy shifts come too late to reverse the structural decline trajectory already embedded in the region's mature resource base and aging infrastructure.

Despite renewed emphasis on domestic supply security, European production is forecast to continue its prolonged decline, falling to 193 bcm by 2030, 128 bcm by 2040 and 100 bcm by 2055 (Figure 5.15). Europe's share of global supply drops from 5%

Figure 5.15

Europe's natural gas production outlook by project type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

in 2024 to 2% by 2055. The sharpest contraction occurs between 2030 and 2040 as volumes from the Norwegian Continental Shelf roll over from their current plateau. Legacy fields in Norway, led by the giant Troll complex, will see steepening natural decline curves that newer developments like Haltenbanken East and Yggdrasil can only partially offset. Declines in the UK and the Netherlands are even more pronounced; North Sea and onshore reserves are depleting with minimal replacement from sanctioned projects. This lack of reinvestment stems from regulatory uncertainty, fiscal instability and rising decommissioning pressures that crowd out development capital.

The continent's production landscape is undergoing a geographic reorientation from the North Sea and Western European basins toward the emerging Black Sea and Eastern Mediterranean regions. While traditional producers face sharp declines, Cyprus and Türkiye are set to increase volumes throughout the outlook period. Supply is projected to ramp up post-2030; consequently, these nations are expected to account for 16% of Europe's total by 2035, rising to 36% by 2055.

Norway, as Europe's largest natural gas producer, saw a rebound in production in 2024 by 9 bcm 5o 134 bcm. This growth was led by the Troll project, which increased its output to 47 bcm from 40 bcm in 2023. This marks a sharp turnaround from 2023, when the country's overall production fell by 5.2% due to essential maintenance at the Troll field and the Kollsnes gas processing plant, a facility that handles over 40% of the nation's gas exports.

Norway's production base is anchored in mature, infrastructure-intensive fields entering advanced stages of exploitation. Troll dominates current supply and

Chapter 5

is expected to sustain a plateau of around 40 bcm annually until 2030, through development of Troll West gas reserves and continuous optimization, maintaining its position as Norway's anchor field through the energy transition. Major operators shoulder the burden of sustaining production through intensive brownfield investment focused on prolonging field life, mitigating decline rates through advanced subsurface monitoring, and maximizing recovery efficiency. However, accelerating field maturity, increased unplanned maintenance outages, and high production drawdown strategies risk shortening ultimate field life.

Unlike the United Kingdom, Norway's tax incentives introduced during 2020-2022 catalysed a wave of FIDs that enabled projects to reach construction phase. Haltenbanken East came online in 2025, and the second phase is planned for 2029, while Yggdrasil is scheduled for 2027 start-up with a plateau of 5.6 bcm per year, representing the most significant near-term additions. Nonetheless, many legacy fields are projected to cease operations throughout the 2030s as reserves exhaust and infrastructure reaches end of life, creating a pronounced decline that new projects cannot fully offset.

Exploration activity sees sustained commitment despite diminishing returns. Rystad Energy reports Norway added 240 million boe of discovered resources in 2024 and has uncovered over 280 million boe in 2025, on the back of finds by Aker BP, Vaar Energi, and Equinor. Discovery sizes and success rates, however, continue to fall as the Continental Shelf matures, shifting the focus from frontier Barents Sea plays to lower-risk near-field exploration.

Norway's production is projected to decline to 39 bcm by 2055, representing around 70% reduction from the 2024 level. This reflects fundamental structural challenges including accelerating decline rates at mature fields, infrastructure constraints that could strand near-field discoveries and tie-back opportunities, and insufficient new project volumes to offset depletion. This decline has profound implications for European energy security and will fundamentally reshape Europe's gas trade.

The **United Kingdom**'s European natural gas production reversed its 2023 decline and increased by 3 bcm to 199 bcm in 2024, driven primarily by Norway's record gas production and Türkiye's accelerating ramp-up at the Sakarya field These gains more than offset steep declines across legacy producing basins in the Netherlands and the United Kingdom. However, this modest recovery does little to alter the profound structural contraction under way in Europe's upstream sector. Current production is 127 bcm below the 2004 peak of 326 bcm, reflecting two decades of accelerating field maturity, a dwindling reserve base, now representing only 1% of global reserves, chronic underinvestment in brownfield optimization and greenfield development, and policy frameworks that have systematically discouraged exploration across much of Western Europe.

The energy security crisis in 2022 has prompted several governments to reorientate policies in favour of domestic production. Germany reversed its 2021 pledge to halt new North Sea drilling permits by approving cross-border reservoir development with the Netherlands in July 2025, signalling recognition that indigenous supply carries strategic value beyond purely economic considerations. Similarly, the Netherlands negotiated agreements to increase North Sea output, despite decades of policy momentum aimed at accelerated basin decommissioning. Yet these policy shifts come too late to reverse the structural decline trajectory already embedded in the region's mature resource base and aging infrastructure.

Despite renewed emphasis on domestic supply security, European production is forecast to continue its prolonged decline, falling to 190 bcm by 2030, 128 bcm by 2040 and 100 bcm by 2055 (Figure 5.15). Europe's share of global supply drops from 5% in 2024 to 2% by 2055. The sharpest contraction occurs between 2030 and 2040 as volumes from the Norwegian Continental Shelf roll over from their current plateau. Legacy fields in Norway, led by the giant Troll complex, will see steepening natural decline curves that newer developments like Haltenbanken East and Yggdrasil can only partially offset. Declines in the UK and the Netherlands are even more pronounced; North Sea and onshore reserves are depleting with minimal replacement from sanctioned projects. This lack of reinvestment stems from regulatory uncertainty, fiscal instability and rising decommissioning pressures that crowd out development capital.

The continent's production landscape is undergoing a geographic reorientation from the North Sea and Western European basins toward the emerging Black Sea and Eastern Mediterranean regions. While traditional producers face sharp declines, Cyprus and Türkiye are set to increase volumes throughout the outlook period. Supply is projected to ramp up post-2030; consequently, these nations are expected to account for 16% of Europe's total by 2035, rising to 36% by 2055.

The outlook to 2055 expects a continued decline in the United Kingdom's gas production. Given the declining reserves observed over the past two decades, the ongoing maturation of producing fields, and the fiscal and political uncertainties, suggest gas production could drop to 15 bcm by 2055.

Türkiye continued the ramp-up of its domestic gas production, centred on the Sakarya field in the Black Sea. Output doubled in 2024 to reach 2 bcm, supported by rapid growth from the field's initial development phase. Production is expected to rise to 3 bcm in 2025, with Phase 2 scheduled to come online in 2026. Together, the phases underpin a growth in national output toward 18 bcm during the 2030s.

Beyond Sakarya, Türkiye has identified multiple additional Black Sea discoveries that will be developed as tie-backs to existing infrastructure. The recent Göktepe discovery, estimated to hold 75 bcm of resources, is TPAO's third major find since 2020, following Amasra and Çaycuma.

Türkiye is also moving to develop unconventional resources. In 2025, TPAO entered a partnership with Continental Resources and TransAtlantic Petroleum to explore shale gas potential in the Diyarbakır Basin, targeting the Dadaş formation.

Regulatory support has remained strong. Türkiye issued 76 exploration licences in 2024, exceeding the target of 50 and signalling continued commitment to upstream expansion.

Türkiye's production is forecast to reach 25 bcm by 2055, driven by Sakarya, new Black Sea discoveries, and emerging unconventional development.

Cyprus is emerging as a potential natural gas producer in the Eastern Mediterranean. Despite having no commercial production to date, the country is actively developing offshore resources from the Herodotus and Levantine basins.

Cyprus has discovered approximately 340 bcm of reserves since 2011 across multiple ultra-deepwater fields, with no FIDs taken to date. The Chevron-operated Aphrodite field remains closest to development. Additional major discoveries include Glaucus field, and Block 6, encompassing significant resources including Cronos, Zeus, and Calypso, with Cronos positioned as the priority development given its superior economics and potential for fast-track development via subsea tie-in to Eni's Zohr field infrastructure.

The outlook expects the county to reach 10 bcm by 2055. In the absense of domestic gas demand, achieving this production figure will require continued cooperation with Egypt to utilise the Idku and Damietta LNG plants, alongside favourable European market conditions.

Romania's gas production rose slightly in 2024 to 10 bcm. A major turning point is expected in 2027, when the Neptun Deep project is scheduled to begin production in the Black Sea. Neptun Deep is expected to lift output to around 15 bcm by 2030, a reversal of the multi-decade decline since Romania's 1983 peak of nearly 40 bcm.

The country's existing production base on mature onshore fields in the Transylvanian and Pannonian basins that face accelerating natural decline rates. The recently completed Midia Development project delivers approximately 1 bcm, representing one of few bright spots in shallow-water offshore development. Thus, the entire Romanian production outlook hinges on Neptun Deep, expected to reach peak production of around 8 bcm by 2029.

Over the long term, natural gas production is set to see consistent decline after Neptun project enters its mature phase. Consequently, the outlook expects Romania's production to fall to 9 bcm by 2055.

Natural gas production in the **Netherlands** continued its rapid decline in 2024, falling 16% to 10 bcm. This marks a steep contrast with the 2013 peak of 90 bcm, when the Groningen field alone produced 57 bcm before its accelerated closure.

Recent government efforts aim to stabilise output temporarily by collaborating with private operators to reinvigorate exploration and maintain production at current levels in the medium term. Nevertheless, production is still expected to cease during the first half of the 2040s.

5.4.5 Latin America

Latin America experienced a modest growth of 1 bcm in 2024 and reached 149 bcm driven by Argentina that experienced a strong growth of 3 bcm supported by production growth from Vaca Muerta shale that compensated the decline from Bolivia, Brazil, and Trinidad and Tobago.

The region's production is projected to expand by 42% to 217 bcm by 2055, driven by Argentina's unconventional gas development and offshore associated gas projects in Brazil. With this production trajectory, the region will maintain its share in global gas production at 4% of global gas production by 2055.

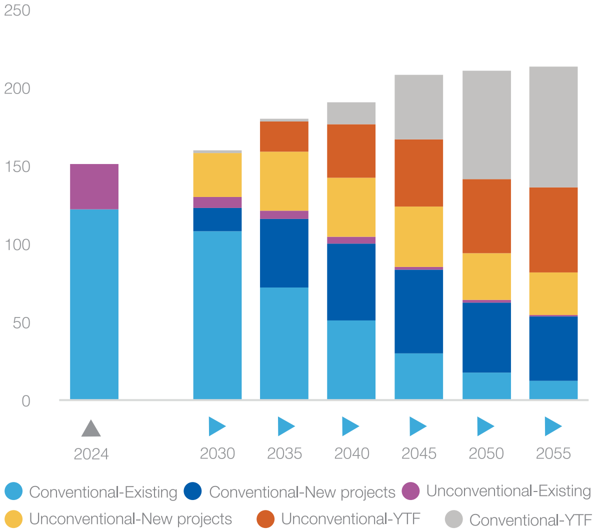
Argentina's Vaca Muerta shale basin remains the cornerstone of this expansion, supported by continued infrastructure investments. Brazil's offshore associated gas trajectory hinges on major pre-salt oil developments, particularly the Raia Project in the Santos Basin targeting first gas in 2028, alongside optimization of existing mega-projects like Mero and Buzios. Trinidad and Tobago contributes critical near-term additions through Cypre project, Manatee development, and the and Calypso development, which that includes five deepwater discoveries.

Unconventional gas production is set to lead the regional growth, rising 3.5% annually through the outlook and contributing 85% of incremental supply. The share of unconventional gas production rises from 19% in 2024 to 38% in 2055. As in the Asia Pacific region, Latin America's long-term outlook depends heavily on YTF resources, which are projected to supply 61% of the region's gas production by 2055 (Figure 5.16).

Argentina's natural gas sector has undergone a profound transformation over the past decade, driven by unconventional gas production growth from the Vaca Muerta shale. National production continued to grow in 2024, reaching 43 bcm in 2024, up from 40 bcm in 2023. It is estimated to reach a record 49 bcm in 2025, surpassing the previous all-time high of 47 bcm in 2006.

Figure 5.16

Latin America's natural gas production outlook by project type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Unconventional production now dominates Argentina's supply mix. In 2014, unconventional gas accounted for only 4 bcm, or 12% of national output. By 2024, this had risen to 28 bcm, representing 65% of total production. Vaca Muerta is the core of this expansion, supplying 23 bcm, 52% of the country's gas in 2024. The 18% year-on-year increase in unconventional output was supported by a 20% rise in new gas wells brought online, an 11% increase in drilling activity, and longer lateral lengths. Although drilling efficiency has improved, cycle times remain longer than in the US Permian Basin, suggesting further optimisation potential.

Conversely, conventional gas production has declined consistently since its 2006 peak, a trend accelerated by the depletion of major legacy fields such as Loma de la Lata and Aguada Pichana. Looking ahead, Argentina's gas production landscape will be increasingly dominated by unconventional sources, with conventional fields playing a diminishing role.

Exploration activity remains focused on expanding Vaca Muerta acreage, with companies like Capex securing exploration rights for Cinco Saltos Norte in the Rio Negro province, committing nearly USD 7 million toward early-phase work, while YPF also picked up two additional blocks in the La Angostura Sur region.

Argentina's gas production is projected to reach 76 bcm by 2040 and 88 bcm by 2055, driven overwhelmingly by Vaca Muerta. Realising the country's export ambitions will require continued infrastructure development. The Oldelval Duplicar oil pipeline expansion became operational in 2024, indirectly supporting growth in associated gas production. The reversal of the Northern Gas pipeline was completed in 2024 enabling Vaca Muerta gas to reach Brazilian customers, and the Perito Francisco Pascacio Moreno pipeline was commissioned in 2023, to transport gas from Vaca Muerta to the Buenos Aires province, addressing domestic demand. Chapter 6 will examine Argentina's emerging role as a pipeline and LNG exporter in detail.

Brazil produced 20 bcm of gas in 2024, with supply dominated by associated gas from pre-salt oil fields in the Santos and Campos basins. The country's production base exhibits both strength and inefficiency: gross output exceeds 56 bcm but infrastructure bottlenecks and limited gas gathering capacity force operators to reinject around 54% of gas produced.

Production is expected to grow to 31 bcm by 2030 and 43 bcm by 2040, driven primarily by major pre-salt oil developments delivering substantial associated gas volumes as oil production ramps up through the 2030s. The Raia project represents the cornerstone development for expanding ultra-deepwater associated gas production in the Santos Basin, targeting first gas in 2028 with plateau capacity contributing significantly to the national supply. Additional contributions will come from the Mero field optimization, the Buzios expansion phases, and the Atapu development. In the Campos Basin, the second phase of the Peregrino field, including the Peregrino C platform and new wells connected to existing infrastructure, will sustain mature basin associated gas production through enhanced water processing capacity.

The 5th Permanent Offer bid round in 2024 awarded 34 blocks, demonstrating continued industry interest in gas-bearing acreage. Bumerangue discovery in August 2024 in pre-salt carbonates represents a significant gas-rich find, validating continued pre-salt exploration. Infrastructure-led exploration opportunities, leveraging Brazil's 45 operating FPSOs and substantial spare processing capacity could unlock new tie-back developments across the Santos and Campos basins.

Brazil's gas production is set to reach 47 bcm by 2055. However, achieving this will require addressing technical, commercial, and regulatory challenges. Reserve replacement remains critical, through drilling success at gas-bearing prospects in frontier regions, improvements in recovery to maximise associated gas production at mature oil fields, and investments in pipelines to remove infrastructure constraints.

Trinidad and Tobago's natural gas production outlook presents a trajectory of initial growth followed by gradual decline, with production maintained at 26 bcm in 2024 before expanding to 35 bcm by 2030, declining to 31 bcm in 2035, and returning to 26 bcm by 2055. The country's producing fields, primarily in the Columbus Basin, including Cassia C, Savonette, and legacy assets like Hibiscus and Amherstia, are mature, experiencing natural decline rates of 5-8% annually.

The production growth to 2030 is supported by a robust development pipeline led by major international operators. BP's recently commissioned Cypre project delivers 2.6 bcm at peak, while the Ginger development, which took FID in 2025, will contribute around 4 bcm from 2027. Shell's Manatee project, sanctioned in 2024, targets 6 bcm of plateau production from 2027. The most significant long-term driver is Woodside's Calypso multi-field development encompassing five discoveries across deepwater blocks, targeting FID by 2026.

Exploration momentum has accelerated through successive licensing rounds following an eight-year hiatus. The 2021 Deep/Ultra Deep-Water Round, 2022 onshore rounds, and 2023 Shallow Water Competitive Bid Round attracted renewed interest from majors including BP, Shell, and EOG Resources. The 2025 Deep Water Competitive Bidding Round offers 26 offshore blocks, representing the country's most ambitious exploration drive since 2014. Recent discoveries include the Frangipani gas find in the East Mayaro block, highlighting continued prospectivity in the Pliocene Mayaro formation. Cross-border opportunities with Venezuela, including the Dragon field and Loran portion of the Lordan-Manatee structure, represent major upside potential, but remain dependent on sanctions relief and bilateral agreements.

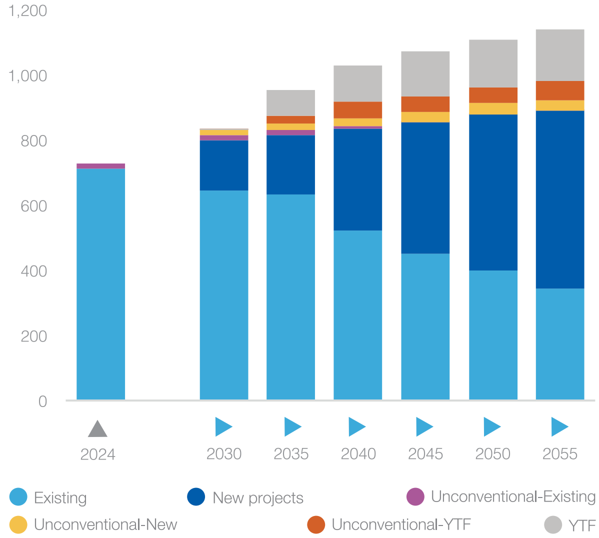
5.4.6 Middle East

Natural gas production in the Middle East extended its multi-decade growth trend, rising by 30 bcm to reach 731 bcm in 2024. This increase was driven by the commissioning of multiple large-scale projects across Saudi Arabia, the UAE, and Iran, alongside the continued optimisation of associated gas capture from substantial oil operations. Since 2004, the Middle East has achieved extraordinary growth, adding 450 bcm of new supply. This represents the second-largest historical increase after North America, underscoring a deliberate strategy to monetise vast conventional gas reserves that account for 43% of global total.

Production is projected to continue rising steadily through the outlook, surpassing 1,000 bcm by the second half of 2030s and 1,145 bcm by 2055, representing an addition of 414 bcm, the largest supply increase of any region (Figure 5.17). As a result, the Middle East's share of global production is expected to expand to 21% by 2055, up from the current 18%. This growth will be driven by Qatar's ambitious North Field projects, lifting LNG capacity to 142 Mt annually by the early 2030s, alongside the UAE's Ruwais LNG project, doubling the country's export capacity by 2032, and Saudi Arabia's continued development of large-scale conventional and unconventional gas. Qatar, Saudi Arabia, Iran, and the UAE will lead gas production growth through the outlook.

Figure 5.17

Middle East's natural gas production outlook by project type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

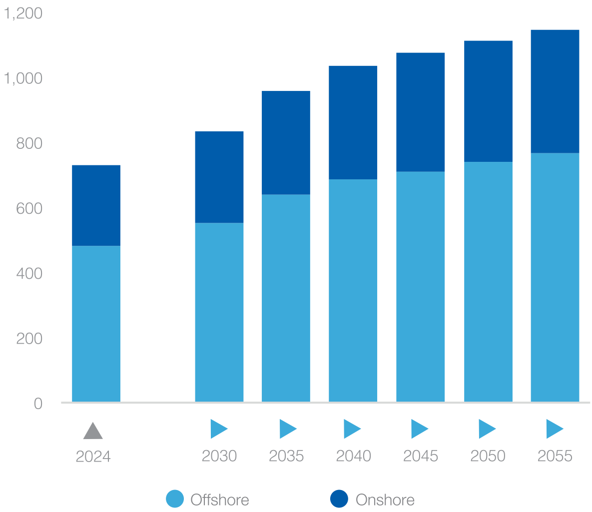
Conventional gas will remain the foundation of the region's supply, accounting for 97.5% of production in 2024 and adding a further 343 bcm by 2055. Growth will be led by Qatar, Iran, Iraq, and Saudi Arabia, supported by some of the world's largest accumulations, including Qatar's North Field and Iran's South Pars.

Much of the region's conventional supply base consists of associated gas produced at its major oil fields. Much of the UAE's gas reserves are associated with oil production, particularly from the Bab, Bu Hasa and Asab fields, while Saudi Arabia has progressively expanded facilities for processing large volumes of associated gas alongside the development of non-associated gas fields. Additionally, gas flaring rates have declined significantly across the region, with Saudi Arabia maintaining flaring rates below 1% of gross gas produced, while Iraq has increased gas production through enhanced gas capture initiatives.

Unconventional production is set for significant growth, rising from 18 bcm in 2024 to 90 bcm by 2055. The number of countries with unconventional output is projected to expand from two, Oman and Saudi Arabia, to five with the addition of Iran, Bahrain, and the UAE. Saudi Arabia's Jafurah Basin development represents the region's flagship unconventional play. The development faces high costs, but the high condensate-to-gas ratio supports its commercially viability. It will also make large volumes of new gas available to the domestic market; displacing liquids currently used in the power sector.

The gas outlook in the Middle East hinges on successful development of existing reserves and accessing international markets through the expansion of LNG

Figure 5.18
Middle East's natural gas production outlook by field location, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

infrastructure. Unlike Asia Pacific and Latin America, the region's long-term outlook is not heavily dependent on YTF resources, which account for only 17% of projected supply in 2055.

Around two-thirds of the region's production in the Middle East is currently offshore, and offshore fields will remain dominant through 2055, accounting for 66% of total supply in that year. Onshore and offshore production are set to experience annual growth rates of 1.3% and 1.5% respectively through the outlook. Offshore gas production is projected to reach 765 bcm by 2055, continuing to dominate with a share of at around 67% of the region's total production (Figure 5.18) With its massive North Field expansion projects, Qatar will lead this offshore growth. Iran will also add significant production from South Pars over the outlook. Similarly, the UAE is projected to significantly contribute by developing major projects such as the Hail & Ghasha field, Dalma Gas, and the promising discoveries in Offshore Block 2.

Iraq's natural gas production continued to expand significantly in 2024, with production reaching 23 bcm, up 19% from the 19 bcm produced in 2023. The growth was primarily driven by continued progress in key developments, including the Basrah gas project, with additional contributions from the Pearl and Halfayah developments.

The project pipeline features multiple strategic projects targeting production growth through 2030. The USD 10 billion Gas Growth Integrated Project aims to capture associated gas from the Ratawi field and gas from the neighbouring Majnoon and West Qurna fields. Previously stalled non-associated gas fields including Akkas and Mansuriyah, have secured new operators, contributing to the projected 10 bcm increase in non-associated gas production by 2030.

The government has conducted consecutive licensing rounds since 2023, awarding 20 onshore blocks primarily to Chinese companies, though major international operators participated but secured limited acreage. Moreover, Iraq continues preparing the seventh bid round focusing on previously unawarded gas exploration blocks from the sixth round. Additionally, Iraq holds an estimated 110 tcf (3.1 tcm) of recoverable gas classified by Wood Mackenzie as low-cost resources. Production is projected to reach 67 bcm by 2055, according to the outlook.

Saudi Arabia's natural gas production grew sharply in 2024 and reached 90 bcm, supported by the full year impact of South Ghawar unconventional development and the expansion of the Hawiyah gas plant. Saudi Arabia is pivoting strongly towards gas. Gas-focused drilling has expanded rapidly, with the number of wells drilled in gas and condensate fields increasing nearly four-fold in four years. Additionally, 2025 marks the launch of the Jafurah unconventional project that will drive growth towards Saudi Aramco's goal of increasing gas production by 60% from the 2021 level by 2030.

Jafurah represents the centrepiece of Saudi Arabia's long-term gas strategy. Phase 1 is expected to begin production by the end of 2025 and reach 22 bcm by 2030. Aramco has allocated over USD 100 billion lifecycle investment for Jafurah, including USD 25 billion in Phase 2 contracts, positioning the project as the largest shale gas development outside North America.

In parallel, the Kingdom is expanding its gas processing capabilities, including through the expansion of the Haradh gas-oil separation facility and upgrading it with gas gathering facilities. Additionally, associated gas from oil expansions like Zuluf and Marjan will contribute to production growth together with Shah Gas Expansion Phase 2, which is nearing FID.

Saudi Arabia's exploration activity has intensified significantly. The country has achieved high success rates in finding new gas reserves in existing hydrocarbon-bearing basins, particularly in the Ghawar area and deep reservoirs in the Arabian Gulf. A recent success came in April 2024, when Saudi Aramco announced 12 oil and gas discoveries in the Eastern Province and Rub Al Khali basin. Key unconventional target areas include Northern Arabia, South Ghawar, and Jafurah.

Saudi Arabia is projected to reach 194 bcm by 2055, with unconventional gas projected to reach 64 bcm, representing 33% of total gas production by 2055.

Qatar's gas production increased by 2% in 2024 to reach170 bcm, driven by the Barzan project. The development pipeline centres on three major North Field expansion phases that will drive production growth over the outlook. The North Field East, scheduled for 2026 start-up, will add 32 Mtpa LNG capacity, followed by North Field South in 2028, supplying an extra 16 Mt, and North Field West, contributing another 16 Mtpa by 2030, raising total capacity to 142 Mtpa.

Given the substantial size of the North Field, exploration activity remains limited, with Qatar focusing on maximising recovery from existing proven resources rather than seeking new discoveries. The country lifted its 12-year development moratorium on the North Field in 2017, signaling confidence in the field's long-term sustainability and production potential. According to Wood Mackenzie, the recoverable gas volumes in the North Field were upgraded in 2024 to over 2,000 tcf (56 tcm).

Over the long term, Qatar's production is projected to reach 244 bcm by 2030 and 328 bcm by 2055. The focus on expansion and sustainability reflects Qatar's strategic approach to energy development, balancing growth with responsible resource management.

Gas production in Oman has shown steady growth since 2020. It rose by 3 bcm, or 8.3%, in 2024 to 43 bcm, supported by higher output from the Marsa LNG project, which contributed an extra 2 bcm during the year. There were also capacity gains from the debottlenecking of the domestic gas transmission network, including major pipeline expansions and loop installations under OQ Gas Networks' infrastructure upgrade program. These projects, such as the South Grid Debottlenecking Phase 2 and the Saib Project in Dhofar, are designed to increase throughput capacity, alleviate transmission constraints, and ensure reliable supply to meet rising domestic and export demand.

The country regularly hosts exploration licensing rounds and currently has 18 open blocks, most of which are in underexplored offshore areas. Three onshore exploration blocks, Block 38, Block 74 and Block 15, were awarded in 2024. Direct award opportunities are available for onshore blocks 43A, 43B, 66, 73, 75 and 76. Notably, blocks 38 and 74 are in the southern part of the Rub Al Khali Basin, near Block 6, which is Oman's largest hydrocarbon producer.

The outlook forecasts Oman to reach 50 bcm by 2030 then decline toward 41 bcm by 2055. For this outlook to materialise, intensive exploration activities are considered essential as YTF resources are projected to account for 75% of total gas production in 2055.

The **UAE** continued its upward trajectory in natural gas production, recording double-digit growth in 2024 as gas production rose by 12% to reach 62 bcm. This increase was driven primarily by the production ramp-up at the Habshan and Asab assets.

The outlook for the UAE is anchored by three transformational projects that will reshape the country's gas landscape. The Dalma Gas project, sanctioned in 2021, as part of the broader Hail & Ghasha ultra-sour gas programme, commenced production in 2025. The larger USD18 billion Hail & Ghasha project reached FID in October 2023 with first gas expected in 2028, involving development of several offshore ultra-sour gas fields that present significant technical challenges and high costs due to their sour gas composition. These developments are critical to supporting the USD 5.5 billion Ruwais LNG project, which will add 9.6 Mtpa of LNG capacity. Ruwais LNG will be the first LNG facility in the Middle East to be powered entirely by zero-carbon electricity renewables and nuclear grid. Additional projects include the Umm Shaif Gas Cap development and expansion of the existing Shah gas development.

Beyond conventional expansion, the UAE's unconventional resource base presents a game-changing opportunity. The country is estimated to hold 13 tcm in unconventional resources, requiring development through tight and shale oil formations. The country has identified three major shale source rock formations: the Qusaiba shale, and the Diyab and Shilaif formations. Over the long term, the UAE's gas production is projected to reach 91 bcm by 2055.

5.4.7 North America

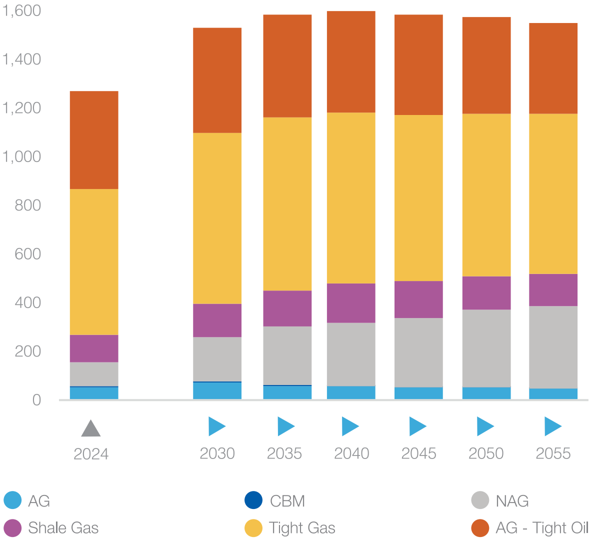
Natural gas production in North America experienced a slight growth of 5 bcm in 2024, following a much stronger gain of around 50 bcm in 2023. Regional supply reached 1,266 bcm and accounted for 31% of the global gas production. The United States remained the dominant contributor with 1,066 bcm, maintaining stable production levels. This was despite low non-associated gas production, which was offset by growth in associated production, supported by high oil prices. Canada accounted for most of the regional growth in 2024, reaching 190 bcm, driven primarily by unconventional development in the Montney Play. North America in 2024 highlighted the increasing influence of crude oil economics on associated gas production and the sensitivity of non-associated gas drilling to natural gas price levels.

North America's production is projected to peak at 1,595 bcm by 2040 before entering gradual decline, with production expected to fall to 1,543 bcm by 2055, as the continent's premier unconventional basins mature. This outlook represents an upward revision compared to the previous edition of the Global Gas Outlook, reflecting stronger anticipated domestic demand, increased momentum in the sanctioning of LNG export projects in the United States, and technical improvements that enhanced productivity (Figure 5.19).

Growth through 2040 will be supported by continued expansion of US LNG export capacity, debottlenecking of infrastructure in constrained basins, and the development of United States and Canadian LNG projects. However, the post-2035 decline trajectory is driven by the maturation of premier shale plays, requiring

Figure 5.19

North America's natural gas production outlook by hydrocarbon type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

a shift towards tier-two and tier-three locations with higher breakeven costs.

Despite being the largest gas producing region along the forecast, its share in global gas production is set to decline to 28% by 2055, down from 31% in 2024. This is due to higher gas growth in Eurasia and the Middle East.

North America's natural gas production in 2024 remained dominated by unconventional resources at around 1,120 bcm, representing 88% of the region's total while conventional production from existing fields contributing the remaining 149 bcm.

Existing unconventional fields are projected to decline from 1,120 bcm in 2024 to 640 bcm by 2030, representing an average annual decline rate of approximately 10%. By 2055, these fields contribute only 37 bcm by 2055. Existing conventional production follows a similar trend, declining from 149 bcm in 2024 19 bcm by 2055. In total, existing assets are forecast to decline by approximately 1,210 bcm between 2024 and 2055, defining the substantial replacement challenge facing the region's upstream sector.

New unconventional projects constitute the core driver for production replacement and growth through the outlook period. These projects are set to scale to 1,060 bcm by 2055. Total unconventional production in North America is set to plateau at 1,280 bcm during 2030s then decline towards 1,160 bcm by 2055. This reflects the sector's transition from core to secondary acreage after the maturation of the premier shale basins, where well productivity typically declines 20-30% and drilling and completion costs may rise due to more complex geology, greater well depths, or extended lateral requirements. The economic threshold for these secondary acreages generally requires higher Henry Hub prices in the range of USD 4.5/MMBtu to generate acceptable returns, compared to less than USD 3/MMBtu for core locations in premier plays.

The increasing contribution of new unconventional supply creates structural dependencies on both drilling efficiency and commodity price realisations. Associated gas production from oil-directed drilling in liquids-rich plays, particularly the Permian Basin, represents a growing proportion of total supply. This production stream responds primarily to crude oil economics rather than natural gas fundamentals, introducing oil price sensitivity into the gas supply outlook. Industry analysis indicates that WTI prices below USD 60/bbl result in reduced drilling activity in oil-directed programs, potentially impacting around 100 bcm of associated gas. Conversely, non-associated gas drilling responds directly to natural gas prices and requires sustained Henry Hub support above basin-specific breakeven levels to justify continued large-scale capital deployment.

New conventional projects provide supplementary volumes but remain considerably smaller in scale than unconventional development in North America. These projects are expected to contribute 260 bcm by 2055, reflecting selective exploitation of remaining conventional opportunities.

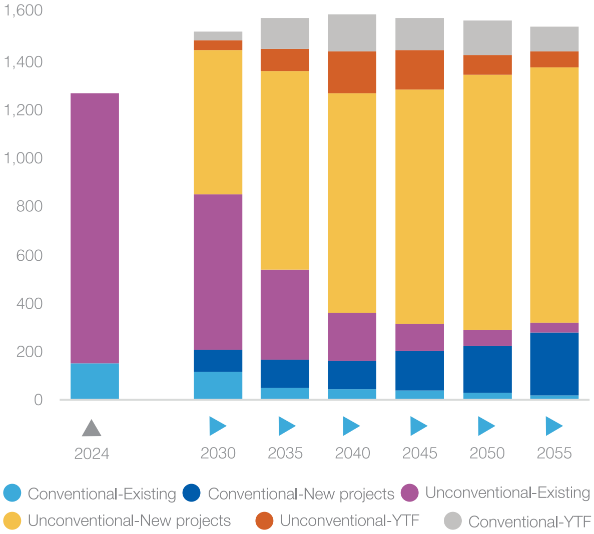
YTF resources contribute modest volumes through the outlook period. These reflect potential discoveries in extensions of known unconventional plays or entirely new concepts not yet producing. Future exploration upside lies primarily in testing play extensions into structurally complex areas, deeper horizons, or regions with limited infrastructure that have historically deterred development.

Reaching the projected 2040 peak of 1,596 bcm requires sustained execution on several fronts. First, operators must maintain drilling activity sufficient to add 1,080 bcm of new unconventional production by 2040, necessitating consistent capital allocation despite commodity price volatility. Second, infrastructure development must keep pace with production growth, particularly in basins where pipeline takeaway capacity currently constrains production potential. The Marcellus/Utica region and Permian Basin both face intermittent capacity constraints that limit the ability to transport gas to markets. Third, the industry must successfully develop secondary acreage at scale, which requires continued technical optimization to maintain well productivity and control costs as operators move beyond core locations.

The post-2030s production decline to 1,543 bcm by 2055 reflects the maturation of unconventional basins as operators exhaust tier-one and tier-two areas. This decline occurs despite continued additions from new unconventional projects. New project additions

Figure 5.20

North America's natural gas production outlook by project type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

increasingly serve to offset declining production from the existing unconventional projects rather than generating production growth. During the second half of 2030s, the major unconventional basins are forecasted to reach their peak production (Figure 5.20).

Relative to the previous edition, the outlook incorporates upward revisions for production, particularly for the 2030–2040 period. Three factors drive this revision. First, demand projections have strengthened, with power sector gas consumption expected to increase more rapidly than previously forecast due to datacenter development and ongoing coal-to-gas switching dynamics. This demand support provides greater confidence in price levels sufficient to incentivize continued drilling investment. Second, LNG export capacity additions have accelerated, with multiple projects reaching FID since the previous outlook. These projects expand market access for North American gas and reduce dependence on domestic demand. Third, technical performance improvements have exceeded expectations, with operators demonstrating continued success in reducing drilling and completion costs while maintaining or improving well productivity through extended lateral designs and enhanced completion techniques.

The outlook carries execution risks in several areas. Regulatory frameworks must remain stable enough to permit necessary pipeline construction and LNG export facility development. Commodity prices must sustain levels sufficient to justify development of secondary acreage, with natural gas prices around or above USD 4.5/MMBtu representing a critical threshold for accessing substantial non-core inventory. International market dynamics must remain favourable to North American LNG exports, maintaining price spreads that justify the capital intensity of liquefaction infrastructure while competing with alternative supply sources in key demand markets. Potential shifts in trade flows driven by geopolitical de-escalation or changes in European supply preferences could alter the competitive position of North American LNG. The growing proportion of associated gas within the production mix introduces additional structural risk, as this supply component responds primarily to crude oil economics rather than natural gas market fundamentals (See Box 5.1).

Natural gas production in the **United States** was stable in 2024, holding at 1,066 bcm. This stability, however, masked significant basin-level variation, as 14% growth in the Permian Basin was counteracted by a decline in Haynesville volumes. Growth in the Permian Basin was driven by associated gas, supported by 2024 crude oil prices exceeding the USD 62–64/bbl breakeven range estimated by the Federal Reserve Bank of Dallas. Conversely, the decline in Haynesville non-associated gas resulted from reduced drilling activity; active rig counts dropped by 35% due to low Henry Hub spot prices averaging USD 2.2/MMBTU. Consequently, the number of wells drilled in the Haynesville fell by 30% year-on-year. At these price levels, drilling the deep Haynesville formation became less economical than in shallower unconventional basins, such as Appalachia (Marcellus and Utica), where production experienced mild growth.

Despite the stability in 2024, 2025 estimates for 2025 indicate a growth of around 40 bcm. The increase is driven by the ramp-up of the Plaquemines LNG, continued associated-gas growth from the Permian basin, and the full year operation of critical infrastructure including the Marathon pipeline, Gator Express, and Gillis Access, that helped to debottleneck the Permian and Haynesville.

The outlook projects United States gas production to reach 1,272 bcm by 2030, then continue growing at a slower pace to reach 1,306 by 2035. Around 2035, production in almost all the major unconventional basins is expected to have peaked, after which production is set to decline to 1,218 bcm by 2055. This edition of the Global Gas Outlook revises the United States' outlook upward relative to the previous year, reflecting three drivers. First, stronger domestic demand growth, particularly in the power sector due to datacentre expansion. Second, accelerated growth in LNG export projects. Third, technical improvements, including expanded adoption of extended-reach laterals, which Rystad Energy reports have limited productivity degradation in the Permian Basin and reduced drilling and completion costs by around 10%, alongside improved productivity per rig.

The outlook for the United States inherits technical, commercial and market risks. Technical challenges include accelerating base decline rates in core acreage

Chapter 5

within premier shale plays, necessitating development of tier-two and tier-three locations characterized by higher breakeven costs and lower productivity. Wood Mackenzie estimates that accessing substantial non-associated gas inventory outside the lowest-cost Permian and top-tier Haynesville acreage would require Henry Hub prices above USD 4.5/MMbtu. Meanwhile infrastructure constraints, particularly pipeline takeaway bottlenecks in the Northeast Marcellus/Utica region and Permian Basin, limit near-term growth despite competitive resource economics. Commercial risks centre on low oil prices that could threaten Permian associated gas production. According to Rystad Energy, WTI prices below USD 60/bbl could eliminate approximately 120 bcm of such production, as operators prioritize capital discipline and reduce drilling activity to maintain shareholder distributions over volume growth. Global trade dynamics introduce further uncertainty. Shifts in trade policies in the United States influence international gas pricing and LNG export economics through changes in tariffs, evolving trade agreements, and geopolitical tensions, affecting competitiveness of United States LNG in Asian and European markets while shifts in bilateral relationships affect long-term offtake contract negotiations and project sanctioning decisions.

Canada's natural gas production continued its upward trend in 2024, reaching 190 bcm, a 2.6% increase driven by unconventional production growth in the Montney Play in the Western Canada Sedimentary basin, where production reached 103 bcm. In June 2025, Canada produced its first LNG for export from the LNG Canada facility. In 2025, natural gas production is set to reach 202 bcm for the first time, supported by an extra 10 bcm of production from the Montney Play.

Canada's development pipeline is anchored by LNG export projects and the continued expansion of unconventional resources. Approximately 12 Mtpa of LNG capacity is targeting FID by 2026.

Exploration activity reveals a sharp divergence between onshore unconventional successes and offshore setbacks. The latter has hindered Canada's frontier aspirations, persisting despite government efforts to stimulate bidding. Rystad Energy data indicates that of the 16 offshore exploration wells drilled since 2020, only three resulted in hydrocarbon discoveries. Meanwhile, onshore licensing focuses on extending unconventional plays. Operators are acquiring acreage adjacent to proven Montney and Duvernay production to optimize horizontal drilling efficiencies and mitigate geological risk.

Similar to the previous edition of the outlook, natural gas production is set to reach 270 bcm by 2040 and 290 bcm by 2055. This outlook is highly dependent on the performance of the Montney play.

Box 5.1 The shifting dynamics of natural gas supply in the United States amid evolving oil dependencies and price sensitivities

The United States became the world's largest natural gas producer in 2024, with output reaching 1,066 bcm. Yet the more important story is not only the scale of production, but the changing structure of that supply. Over the past decade, growth has been increasingly underpinned by low-cost associated gas from oil-directed basins, above all the Permian. This has helped suppress marginal supply costs and has made a growing share of United States gas production less responsive to gas prices, because supply decisions are increasingly driven by oil economics rather than by gas market signals.

This structural shift has important implications for the medium-term outlook. The Permian remains a major engine of growth, but infrastructure constraints and tighter flaring regulations suggest that the pace of associated gas expansion will gradually moderate. As this happens, a larger share of incremental supply will need to come from non-associated dry-gas basins, particularly Haynesville. These volumes sit higher on the cost curve, implying firmer Henry Hub prices over time. At the same time, expanding global LNG supply is expected to narrow the spread between Henry Hub and international benchmarks such as TTF and JKM, reducing LNG netbacks and affecting the competitiveness of United States liquefaction projects.

This box examines these dynamics and their implications for global gas market stability.

The rise of associated gas

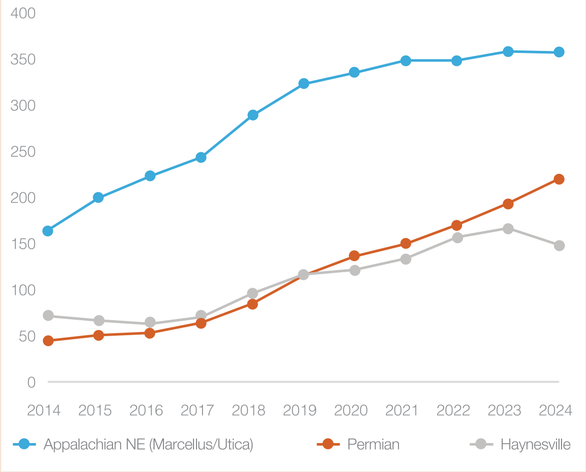
This box focuses specifically on the changing balance between associated and non-associated gas. The shift has been pronounced. In 2014, output from oil-directed basins, principally the Permian, but also the Eagle Ford, Williston and Denver-Julesburg, accounted for approximately 25% of total gas production in the United States. By 2024, that share had risen to 38% (Figure 1).

This increase has not primarily been driven by gas-directed drilling. Rather, it reflects the maturation of wells in oil-producing basins. As reservoir pressure declines, the gas-oil ratio (GOR) rises. In the Delaware sub-basin, the GOR has reached 4,677 scf/bbl, while in the Midland sub-basin it has risen to 2,977 scf/bbl (Figure 2). As a result, existing wells contribute growing volumes of gas even when drilling activity slows.

This creates a counterintuitive degree of supply inelasticity. When oil prices fall and drilling moderates, fewer new, lower-GOR wells enter the production mix. The basin therefore becomes increasingly weighted toward older, gassier wells, which raises the average GOR and helps sustain gas output. During the 2020 demand contraction, when Brent averaged USD 43/bbl, the Permian GOR increased by 450 scf/bbl year-on-year. In effect, associated gas provides a supply floor that cushions the market even during periods of weaker oil activity.

Figure 1

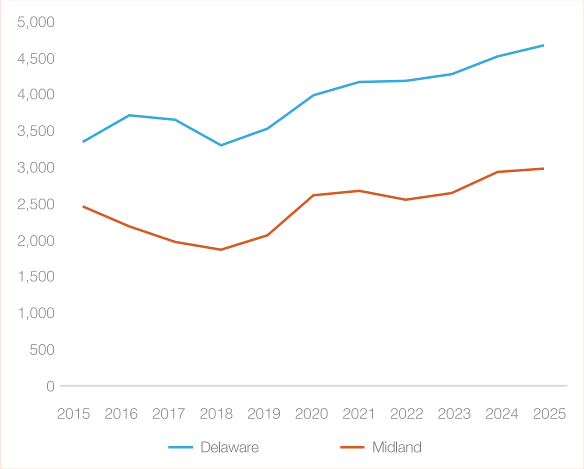
Gas production in the major United States basins (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 2

Permian Basin Gas-Oil-Ratio (scf/bbl)



Source: GECF Secretariat based on data from the GECF GGM

Constraints on non-associated gas growth

Non-associated dry-gas basins remain critical to United States supply. Appalachian Northeast (Marcellus/Utica) and Haynesville together accounted for around 47% of total production in 2024. However, their growth profile has changed markedly.

In Appalachian Northeast, the key constraint is no longer resource availability but infrastructure. Despite very large undeveloped resources, production in the Marcellus and Utica has plateaued near 357 bcm, primarily because pipeline takeaway capacity to demand centres remains limited. The effect on growth is clear: the basin added 159 bcm between 2014 and 2019, but only 34 bcm between 2019 and 2024 (Table 1).

Haynesville plays a different role. It is the principal price-responsive basin in the United States market and acts as the main marginal source of supply. Production expanded rapidly in 2022, when Henry Hub prices averaged USD 6.4/MMBtu and supported aggressive development. But this momentum proved reversible. As prices fell to USD 2.2/MMBtu in 2024, activity moderated sharply. Haynesville therefore confirms its role as a basin that can respond quickly to demand growth, but only when prices are high enough to support new drilling.

Table 1

Historical contribution of major United Sates basins to natural gas supply over the past decade (bcm)

	Incremental production			
Basin	**2014**	**2024**	**2014-2019**	**2019-2024**
Appalachian NE (Marcellus/Utica)	164	357	159	34
Permian	45	220	71	104
Haynesville	71	148	45	32

Source: GECF Secretariat based on data from the GECF GGM

A tighter cost structure for future supply

These trends point to a more complex pricing environment. Brent crude near USD 60/bbl is close to the threshold at which associated gas growth becomes vulnerable. At the same time, Henry Hub prices in the USD 3–4/MMBtu range remain below the roughly USD 4.5/MMBtu generally required to incentivise secondary dry-gas acreage. Existing wells can continue producing because operating costs are often below USD 1.5/MMBtu, but sustained low prices erode full-cycle economics and constrain new upstream investment. In other words, associated gas is exposed to oil market weakness, while non-associated gas still lacks sufficient price support for broad-based expansion.

The cost structure of United States gas supply reinforces this conclusion. Figure 3 shows breakeven prices for projects starting in the 2020s and 2030s. Across the major basins, costs rise as operators exhaust core inventory and move into less productive acreage. Projects starting in the 2020s in the Permian and Appalachian basins remain largely below USD 3.50/MMBtu. By contrast, many 2030s developments require USD 4.50–6.00/MMBtu to be economic. Although around 80% of remaining United States gas resources are accessible at full-cycle costs below USD 4/MMBtu, realising this potential will require either sustained price support or infrastructure investment to unlock constrained basins.

Implications for the outlook

The first implication is that United States gas supply is becoming more dependent on oil market conditions. With nearly 40% of production now linked to oil-directed drilling, crude prices have become a major determinant

Chapter 5

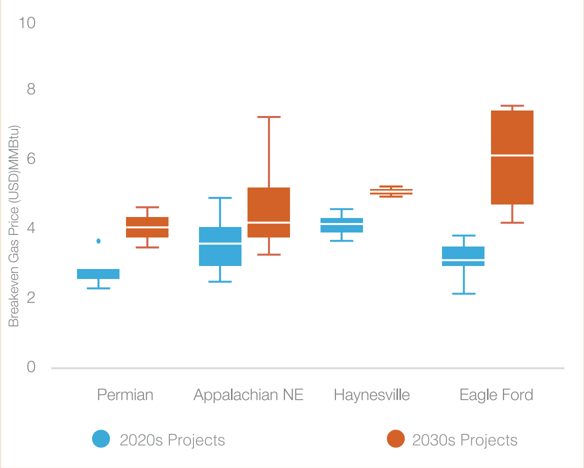
of gas supply dynamics. Rising GORs provide short-term resilience, but a sustained period of oil prices below USD 60/bbl would gradually weaken drilling activity and slow associated gas growth. Gas supply prospects are therefore increasingly shaped by oil fundamentals rather than by gas prices alone.

The second implication is that the composition of marginal supply is shifting. Between 2019 and 2024, the Permian alone contributed around 104 bcm of incremental production, more than the combined additions from Appalachian Northeast and Haynesville. Looking ahead, however, the expansion of associated gas is expected to moderate, while Appalachian growth remains constrained by infrastructure. As a result, a growing share of incremental supply will need to come from higher-cost dry gas. This matters because projected demand growth to 2030, driven by both domestic power generation and LNG feedgas requirements, is substantial, at around 200 bcm. The issue is therefore not whether supply can grow, but at what cost. The answer points to upward pressure on Henry Hub prices over the medium term.

The third implication extends to global markets. United States gas supply, and particularly associated gas, has become an important part of the global LNG supply stack. When oil prices are high, stronger oil-directed drilling can boost associated gas output, loosen gas balances and weigh on prices. When oil prices weaken, the opposite can occur, tightening both domestic and global markets. At the same time, the expected expansion of LNG supply worldwide is likely to compress the spread between Henry Hub and international benchmarks such as TTF and JKM. Narrower spreads would reduce LNG netbacks and could weaken the relative competitiveness of United States liquefaction projects. In this context, the evolution of United States supply costs will matter not only for Henry Hub, but also for the stability of global gas trade.

Figure 3

Breakeven gas price for major basins in the United States for projects starting up in 2020s and 2030s



Source: GECF Secretariat based on data from the GECF GGM

5.5 Upstream natural gas capex requirements

In 2024, upstream natural gas investment stabilised under a more disciplined capital allocation regime that prioritised reliability while selectively supporting growth. Upstream capex reached USD 185 billion, representing an increase of around 8% compared with USD 171 billion in 2023. This spending pattern suggests that operators continued to balance the maintenance of legacy production with targeted development of new projects where economics, infrastructure availability, and market pull, often linked to LNG value chains, were strongest. Overall, the sector is neither returning to the high-investment cycle of the early 2000s nor repeating the deep austerity of 2020. Instead, it reflects a more balanced trajectory shaped by energy security considerations, cost discipline, and selective expansion.

Looking ahead, the projection for upstream gas capex requirement implies a sustained, exceptionally high global capital spending required over the forthcoming 3 decades. **During 2025–2055, cumulative upstream capex requirement is estimated at USD 11.6 trillion (real terms, base year = 2025), averaging roughly USD 350 billion per year.** The estimate is an upward revision from the earlier forecast of USD 10.4 trillion, primarily reflecting higher unit costs and a growing dependence on higher-cost supply sources, particularly unconventional and YTF resources, to meet rising forecasted demand.

Amid persistent long-term price uncertainty, the outlook indicates that upstream natural gas capex requirement remains resilient. The global gas system that underpins industrial activity, power systems, and traded energy commodities depends on continuous reinvestment to offset natural field declines, sustain deliverability, and replace maturing production. Accordingly, upstream spending is less a discretionary growth option than a structural requirement for maintaining supply. In this context, natural gas is expected to further consolidate its role as a key fuel for systems seeking to balance electricity security, industrial competitiveness, and emissions efficiency.

Risks nevertheless remain material and will shape investment pathways even if they do not eliminate the underlying capex requirement. Tightening financing conditions, evolving methane regulations, and stricter capital discipline will increasingly influence project selection and cost of capital. Geopolitical developments may alter LNG flows, sanction regimes, and upstream approvals, while technological progress in low-carbon alternatives could reduce gas growth potential in some end-use segments beyond 2055. These factors change where and how capital is deployed, but they do not remove the need for sustained investment to maintain supply capacity.

Against this backdrop, the RCS indicates that upstream natural gas capex requirements will not only remain large in volume but will also evolve in structure and direction. Between 2025 and 2055, three trends are expected to define this shift: a gradual rebalancing between offshore and onshore developments, a steady increase in unconventional supply, and a growing emphasis on brownfield redevelopment, life-extension, and lower-emissions projects.

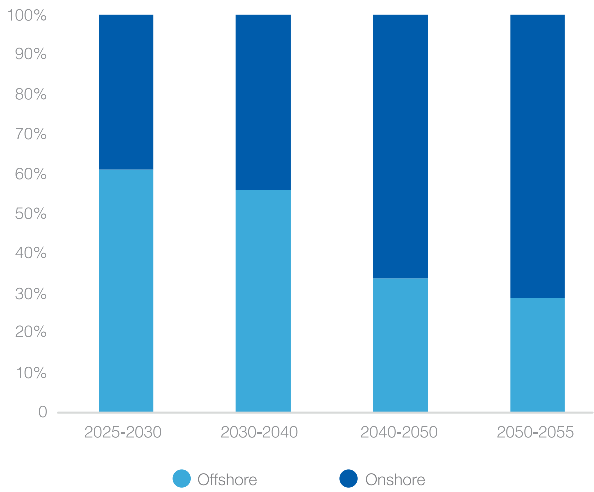
From 2025 to 2030, offshore developments are projected to dominate, with approximately 55–60% of required upstream capex directed to offshore, export-linked (including LNG-linked) supply. Key contributors include Qatar's North Field expansion, offshore developments and tie-ins in Australia, and incremental connectivity projects in West Africa and the Eastern Mediterranean. Offshore projects are favoured in the near term because they are often integrated with established liquefaction and export infrastructure, supporting relative resilience under price volatility. The remaining 40–45% is expected to target onshore developments, particularly shale and tight gas in the United States, Canada, China, and parts of the Middle East, providing flexible, short-cycle supply for both LNG feedgas and domestic markets (Figure 5.21).

Within this evolving location split, conventional resources maintain a position of clear dominance in global upstream gas capital expenditures, consistently outperforming unconventional investment even as the latter matures. In 2025, conventional resources (including shallow and deepwater projects) are estimated to account for more than 70% of upstream gas capex, consistent with the scale of established supply corridors and mature offshore development portfolios. As major conventional basins mature and the most accessible reserves are progressively depleted, the share of unconventional investment rises steadily. However, despite this upward trend conventional assets remain the bedrock of global upstream investment, maintaining their dominance even as the industry integrates more short-cycle and shale-based supply.

By 2030–2040, unconventional and tight gas projects are projected to account for 32–38% of global upstream investment, supported by the operational resilience of shale developments in the United States and Canada, alongside emerging unconventional basins in China, Argentina, and the Middle East. This shift is enabled by technology transfer, improving completion techniques, and the role of long-term LNG contracting in supporting revenue visibility. North America's abundant resource base and integrated infrastructure sustain activity even under moderate price environments. In Asia, policy support and domestic supply security objectives facilitate incremental growth in shale and tight gas. In

Figure 5.21

Global upstream capex requirements by location, 2025–2055



Source: GECF Secretariat based on data from the GECF GGM

the Middle East, unconventional programs expand in areas such as Jafurah and the Ghawar margins, as well as Oman's Khazzan basin. Even with this growth, conventional gas remains dominant through the 2030s, supported by low-cost offshore supply.

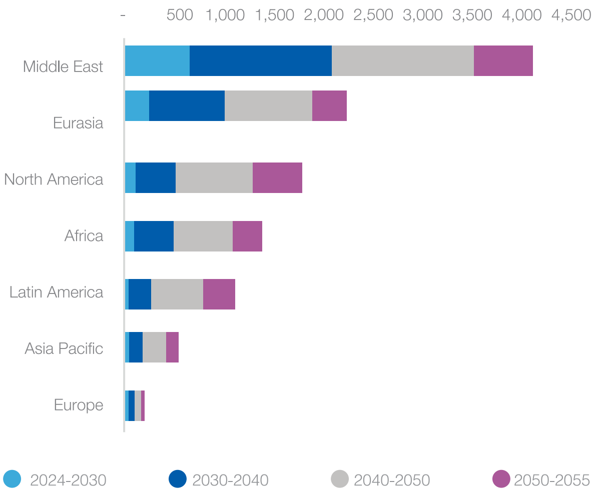
At the final phase of the outlook, 2040–2055, conventional capital spending is projected to remain the largest share at 58–65%. Although the capital spending gap narrows slightly as unconventional share reaches 35–42%, the fundamental balance does not flip. This persistent dominance is emphasised by significant geological, hydrological, and regulatory constraints that limit the expansion of unconventional resources outside of specific regions like North America and parts of China, leaving the heavy lifting of global gas supply to conventional resources.

Regional required capex projection patterns reflect differences in resource endowment, fiscal frameworks, infrastructure readiness, and geopolitical conditions (Figure 5.22). **North America**, led by the United States, remains the global hub for short-cycle gas. Its shale basins continue to supply domestic markets and support LNG exports at competitive cost, making the region the largest unconventional centre globally. Over the outlook period, North America is projected to account for an average of about 36% of global upstream gas investment. Basin depth and resource quality enable a high degree of responsiveness to price signals and demand shocks, while investment dynamics are strongly influenced by investor discipline and capital allocation frameworks.

In the **Middle East**, required upstream capital spending remains resilient due to exceptionally low production costs and a strategically advantageous position in

Figure 5.22

Regional upstream capex requirements, 2025–2055 (real USD billion)



Source: GECF Secretariat based on data from the GECF GGM

global LNG supply chains. Qatar's continued expansion and Saudi Arabia's unconventional programs support investment. By 2055, upstream capex required in the region is projected to represent roughly 19% of global spending requirement. High reservoir productivity, supportive financial frameworks, and persistent export demand reinforce the region's role as a low-cost anchor for global supply, even under accelerating energy transition pressures.

Upstream capex required in **Asia Pacific** increases markedly, driven by long-term structural switching from coal and fuel oil to gas in parts of the region, as well as the need to underpin LNG demand growth. By 2055, the region is projected to reach about 16% of global required upstream capex. Supply growth is increasingly supported by tight gas and redevelopment programs in Australia, Malaysia, and Indonesia, alongside further unconventional development in China. This trend is complemented by infrastructure expansion, LNG import terminals, storage, and transport corridors, which supports the emergence of gas as a backbone for urban and industrial development.

By 2055, **Eurasia** is projected to account for around 12% of global upstream capex. Amid reorientation of export toward east, arctic resources require large capital outlays and face intense environmental scrutiny, which slows development despite substantial reserves.

Africa is expected to pursue a selective but increasingly consequential upstream expansion. Investment remains more volatile and price-sensitive than in lower-cost regions, but the continent's role in global LNG supply grows steadily. By 2055, Africa is projected to represent about 10% of the required global upstream gas capex.

While Algeria and Egypt continue measured offshore and onshore development aligned with fiscal conditions and export economics, additional capacity growth increasingly depends on major deepwater and LNG-linked hubs, Mozambique, Mauritania, Senegal, and Namibia among them. Project progress hinges on the ability to mobilise capital for offshore transport and processing infrastructure, alongside reforms that ease infrastructure access constraints. Africa's strategic relevance increases as importing regions seek diversified supply portfolios.

In **Latin America**, upstream capital spending transitions from expansion-led growth toward a more efficiency- and emissions-aware trajectory, with Brazil and Argentina leading. Capex rises moderately as offshore infrastructure integrates with LNG capacity and unconventional developments scale selectively. Average capex over the forecast period remains concentrated in offshore brownfield programs and unconventional resources, sustaining a regional share of roughly 5% of global upstream capital spending by mid-century.

Europe, by contrast, is the only region projected to experience an absolute contraction in upstream spending. By 2055, Europe's share falls to around 2% of global upstream capex, reflecting basin maturation, tighter methane and emissions standards, and competition from imported LNG and pipeline gas. Remaining investment prioritises extending North Sea asset life and repurposing infrastructure where feasible, including potential conversion to CO_2 transport or hydrogen-blending applications.

Beyond the regional allocation of capital, the composition of upstream spending shifts progressively from growth-oriented expansion to sustaining base production. By the mid-2040s, a growing portion of capex is allocated to reservoir pressure maintenance, enhanced recovery, short-cycle drilling, and facility renewal. Natural decline rates, often in the range of 4% to 9% per year in large conventional basins, imply that substantial capex is required simply to maintain output. In parallel, higher processing requirements (including compression and separation) associated with sourer or CO_2-rich gas streams increase capital intensity over time.

Technological progress influences both costs and environmental outcomes. Digitalisation and predictive analytics can reduce unscheduled downtime and lower maintenance costs in upstream facilities. AI-enabled seismic interpretation may improve exploration success rates and reduce commercial risks associated with YTF resources. Methane-abatement technologies, such as continuous monitoring systems and advanced leak-detection methods, strengthen compliance with evolving methane policy frameworks (including in the EU), thereby supporting sustained market access for exporters.

As the energy system advances toward deeper decarbonisation, natural gas remains a balancing fuel that supports reliability in increasingly electrified and renewable-heavy grids. It also contributes to industrial transition pathways, particularly through blue hydrogen in regions with cost and infrastructure advantages, supporting decarbonisation of fertiliser and refining value chains without undermining output. This reinforces the strategic importance of sustained upstream investment: even where gas demand stabilises or declines in final energy use over the long term, the systemic value of reliable gas availability can rise during periods of seasonal stress and supply disruption.

From an energy security perspective, expanding LNG trade improves diversification and resilience for importing regions, including Europe. However, this security benefit depends on continuous upstream supply and timely investment. As importing regions diversify away from concentrated supply sources, the value of new LNG trains, particularly in Africa, the Middle East, and North America, rises, increasing the importance of upstream spending as a prerequisite for stable, secure import strategies.

Overall, upstream capex requirement prospects show strong resilience to risk. While methane compliance costs, project execution delays, tighter financial terms, and cost inflation (including labour and equipment constraints) can affect timing and project selection, the outlook does not suggest a contraction in upstream capex even toward the end of the horizon. Rather, upstream gas transitions from a phase dominated by capacity expansion to one centred on sustainability of supply, where maintaining a broad, geographically diversified production base requires capital mobilisation of comparable scale to expansion.

By 2055, upstream natural gas remains an annual commitment of hundreds of billions of dollars and a key contributor to economic development, industrial competitiveness, grid reliability, and decarbonisation pathways. Asia emerges as a major demand-linked investment centre; the Middle East consolidates its role as a low-cost global anchor; North America sustains the unconventional backbone of flexible supply; Africa increasingly shapes the next wave of LNG export capacity; Eurasia contends with export constraints; and Europe continues a structural decline. Collectively, these shifts reinforce a central conclusion: the resilience of global gas supply depends on sustained, long-term upstream capital commitment, which is expected to remain integral to the global energy security landscape through 2055 and beyond.

Natural Gas Trade Outlook

6

Highlights

- Global natural gas trade is projected to expand significantly, rising from 1,211 bcm in 2024 to 1,767 bcm by 2055, increasing the traded share of global gas demand from 29% to around one-third. This points to deeper cross-border interconnectivity and greater interdependence across global gas markets.
- LNG remains the principal driver of trade growth, with volumes increasing from 406 Mt (560 bcm) in 2024 to 837 Mt (1,155 bcm) by 2055. By mid-century, LNG is expected to account for around 65% of total gas trade, reinforcing market liquidity, flexibility, and global integration.
- A substantial wave of new LNG supply is set to reshape market conditions through 2030, with global LNG supply expected to exceed 620 Mt. This expansion, led primarily by the United States and followed by Qatar, is expected to place downward pressure on prices in the medium term.
- Current GECF Member Countries are projected to strengthen their position in global gas trade, with natural gas exports rising to around 845 bcm by 2055 and their market share increasing from 40% in 2024 to 48%. Their LNG exports are expected to reach 445 Mt, lifting their share of global LNG exports from 47% to 53%.
- Asia Pacific's LNG procurement is expected to become markedly more extra-regional. Intra-regional sourcing declines from around 48% in 2024 to about 14% by 2055, while the Middle East, North America, and Eurasia together emerge as the dominant suppliers to the region.
- Europe's LNG sourcing is projected to become increasingly concentrated on North America, whose share rises from around 45% in 2024 to about 70% by 2055. Over the same period, Africa's share declines from about 18% to around 9%, despite relatively stable absolute volumes.
- North America is set to emerge as the leading LNG-exporting region, with exports rising from 86 Mt in 2024 to 283 Mt by 2055. Its share of global LNG exports correspondingly increases from 21% to around 34%, supported by sustained liquefaction expansion and mature commercial arrangements.
- The Middle East remains a core pillar of global LNG supply, with exports increasing from 96 Mt in 2024 to around 189 Mt by 2055. Its global export share remains broadly stable at around 23–24%, with incremental volumes increasingly directed toward Asia Pacific demand growth.
- Global non-speculative LNG liquefaction capacity is projected to reach 998 Mtpa by 2055, representing a net increase of roughly 479 Mtpa over the outlook period and highlighting the scale of investment required to support rising seaborne gas trade.
- Global non-speculative LNG regasification capacity is projected to increase from 1,084 Mtpa in 2025 to 1,604 Mtpa by 2055, implying an addition of 520 Mtpa. This expansion reflects a largely front-loaded build-out of import infrastructure before 2030, particularly in Asia, to ensure market access, flexibility, and security of supply.
- Cumulative midstream capital expenditure over 2025–2055 is estimated at USD 735 billion, dominated by LNG infrastructure: USD 483 billion for liquefaction and USD 191 billion for regasification, compared with USD 61 billion for new long-distance pipelines.

6.1 Natural gas trade overview

Global natural gas markets entered 2024 still shaped by the after-effects of the 2022 supply shock and the ensuing reorientation of trade flows. Following the acute demand adjustment in Europe, international gas trade stabilised but remained structurally altered, with LNG functioning more explicitly as the marginal balancing instrument across regions. LNG demand recovered in 2024, led by emerging Asian markets, while global LNG trade reached 406 Mt, broadly unchanged from 2023, linking 22 exporting and 48 importing countries. The Asia Pacific region remained the largest exporter with 282 Mt, up 19 Mt year-on-year, while global liquefaction capacity increased by 6.5 Mtpa, reaching 494 Mtpa by end-2024, with the United States, Qatar, and Australia maintaining their positions as the world's leading LNG exporters. This combination of stable aggregate trade volumes and shifting regional balances highlights a market that is no longer defined primarily by net volume growth, but by the reallocation of flexible supply and the changing geography of incremental demand.

In 2025, growth momentum moderated as mild weather and economic headwinds softened consumption in several major importing markets, yet regional trajectories diverged markedly. During the first half of 2025, Europe's LNG imports increased by roughly 24% year-on-year, while China's LNG imports declined by about 19%, reflecting uneven demand recovery, contrasting inventory dynamics, and differences in domestic supply substitution. Supply additions, driven mainly by new liquefaction ramp-ups in North America, continued to push incremental volumes into global markets, reinforcing more competitive spot dynamics and narrowing seasonal arbitrage opportunities. Global LNG supply is estimated to rise by about 7% (around 28 Mt) in 2025, largely due to project ramp-ups and FID-backed expansions reaching operational phases. Importantly, the observed market response in 2025 also underscored the distinction between nameplate capacity and effective deliverability: commissioning constraints, start-up performance, feedgas availability, and maintenance schedules can materially delay the translation of new capacity into sustained export volumes, thereby amplifying the sensitivity of near-term balances to operational timing rather than to capacity additions alone.

Against this background, contracting behaviour remained robust through 2024 and into 2025 as buyers sought to rebuild supply security while preserving flexibility, and sellers aimed to underpin capital-intensive expansions with bankable offtake. Total contracted volumes in 2024 reached 68 bcma, rising 27% from 2023, and increased to 83 bcma when including pre-FID projects, reflecting strong commercial activity across both committed and prospective capacity. The contract mix continued to evolve toward flexibility and portfolio optimisation, with destination-flexible contracts accounting for 48% of total active volumes and portfolio players expanding their share to 42%. On the supply side, the Middle East led contracting activity, driven by Qatar's North Field expansion, which alone represented 38% of total signed volumes, while North America's share increased through pre-FID agreements that reinforced confidence in its expanding export capacity. These developments indicate a market in which long-term contracting and flexibility are co-evolving: long-tenor commitments remain important for project bankability and supply assurance, while destination flexibility and portfolio management increasingly determine how LNG is optimised and redistributed across regions in response to short-term shocks.

While LNG market liquidity and hub-based pricing have deepened since 2022, recent experience has also highlighted that physical logistics, particularly shipping, can impose binding constraints even when aggregate supply appears sufficient. In 2024–2025, LNG shipping became a primary channel through which disruptions propagated across basins, as route risks and chokepoint limitations increased voyage distances and round-trip times, tightening effective vessel availability through higher tonne-mile demand. Constraints associated with key transit corridors and episodic disruptions to established routes reduced the speed at which cargoes could be repositioned between Atlantic and Pacific markets, thereby lowering short-run market responsiveness. These constraints were compounded by operational bottlenecks at both ends of the value chain: on the export side, berth availability, weather-related interruptions, and commissioning-phase variability limited load-out flexibility; on the import side, regasification send-out capacity, pipeline connectivity, storage optimisation, and terminal scheduling constraints meant that nominal regas capacity did not always translate into effective absorption during periods of peak call. The practical consequence is that the LNG market's headline flexibility is increasingly conditioned by shipping and terminal operability, making near-term balances more sensitive to logistics friction than in the pre-2022 period.

Geopolitics continued to play a pivotal role in shaping trade flows and operational decisions across 2024–2025. Elevated tensions in key producing regions, disruptions and risk premia affecting critical shipping corridors, and uncertainty surrounding pipeline transit arrangements reinforced energy security priorities among importers and contributed to more conservative procurement and storage strategies. At the same time, exporter strategies increasingly reflected a preference for optionality, either by relying more on LNG to diversify destination exposure or by strengthening eastward integration through pipeline and LNG channels where access to traditional markets is constrained. These dynamics reinforced a structural shift already underway since 2022: the global gas system is becoming more liquid and re-routable through LNG, but also more exposed to short-term shocks originating in geopolitics, logistics, and operational performance.

Recent developments indicate that global LNG trade has stabilised in aggregate volume terms but transitioned into a structurally different regime. LNG's role as the balancing mechanism across regions has strengthened, supported by active contracting and expanded portfolio optimisation, while the system's practical flexibility is increasingly bounded by shipping availability, route security, terminal constraints, and commissioning dynamics. The market is therefore simultaneously more connected and more sensitive: it can redirect supply more rapidly than pipeline-dominant configurations, yet it is more exposed to operational and logistical frictions that can tighten effective availability and transmit shocks across basins.

6.2 Natural gas trade outlook

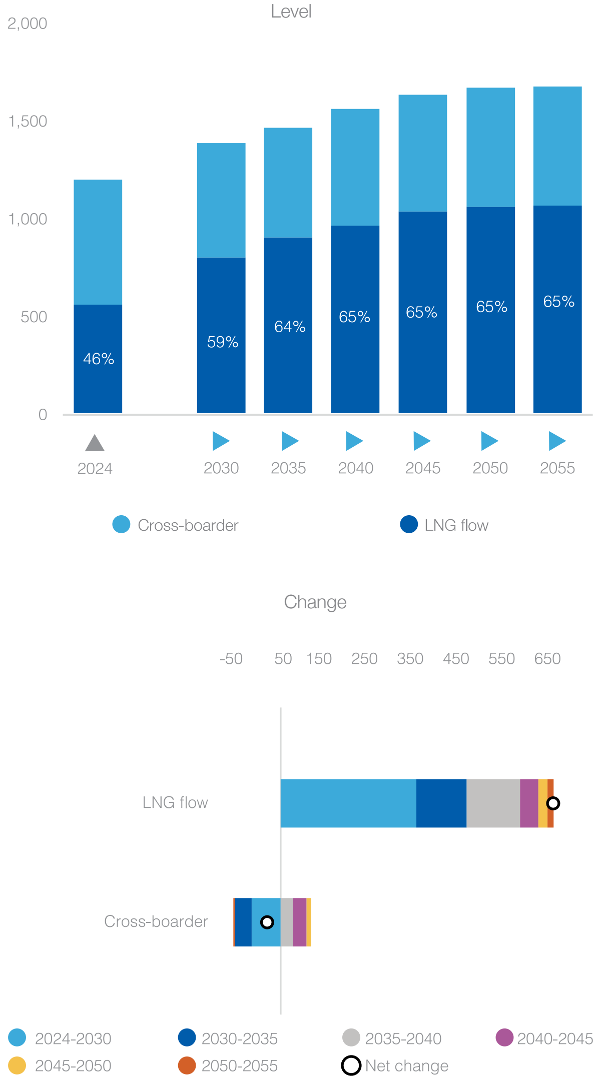
Between 2024 and 2055, global natural gas trade is projected to expand by 46% (38% CAGR), rising from 1,211 bcm to 1,767 bcm (Figure 6.1). Consequently, the share of traded gas in total global demand increases from 29% in 2024 to around one-third by 2055. In parallel, the share of natural gas production allocated to domestic demand is expected to ease from just above 70% in 2024 to roughly two-thirds by mid-century, reflecting a gradual shift toward a more interconnected and trade-dependent global markets. These trends highlight the growing strategic importance of cross-border gas flows and the central role of international trade in balancing regional supply–demand fundamentals over the coming decades.

LNG is set to become the dominant pillar of global natural gas trade, with volumes projected to rise from 406 Mt (560 bcm) in 2024 to 837 Mt (1,155 bcm) by 2055. By mid-century, LNG is expected to account for around 65% of total traded gas, more than doubling its absolute volumes over the outlook period. This expansion highlights LNG's growing role in providing supply flexibility, enabling long-distance cross-regional flows, and strengthening the ability of gas markets to adjust to shifting demand and supply conditions. As infrastructure expands and market frameworks mature, the increasing weight of LNG trade is also expected to reinforce energy security and improve price responsiveness through deeper market liquidity.

By contrast, pipeline trade is projected to remain broadly stable, averaging around 606–616 bcm from 2045 onward. The rising LNG share therefore reflects a structural transformation in global gas trade, with liquefaction and regasification capacity increasingly shaping market integration and resilience. By 2055, LNG is firmly established as the backbone of international gas flows and a key enabler of a more interconnected global gas system.

Figure 6.1

Global natural gas trade outlook by flow type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

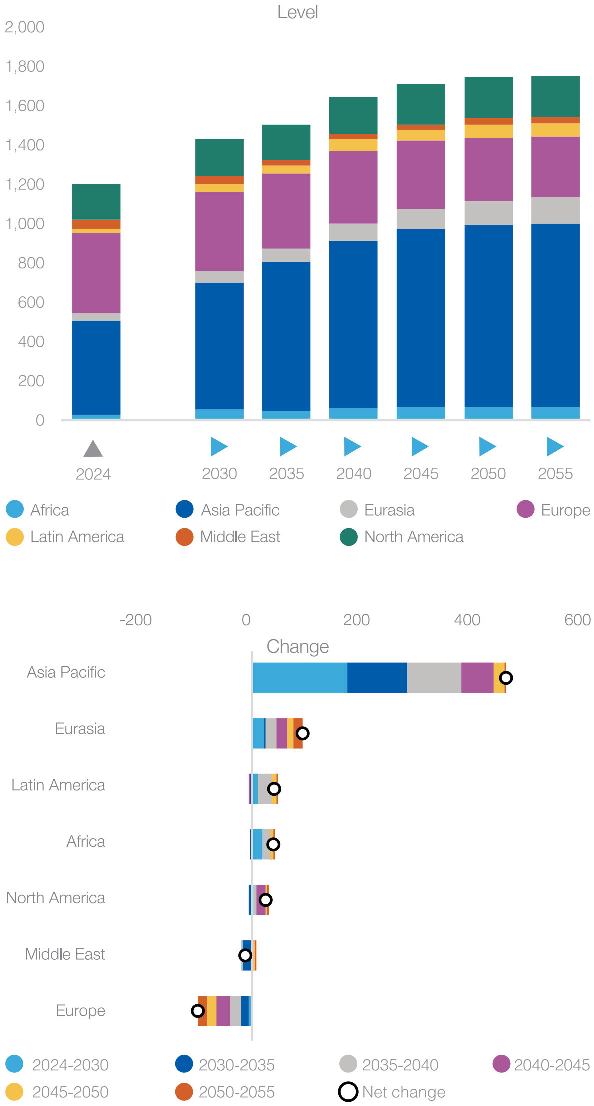
Note: includes all inter-regional and intra-regional trade; intraregional trade refers to trade that occurs within a particular region or geographical area

The expansion of global gas trade is primarily driven by widening regional supply–demand imbalances. The import landscape is undergoing a pronounced geographic shift, with Asia Pacific emerging as the main engine of import growth, while Europe's role gradually declines (Figure 6.2). Total imports in Asia Pacific are projected to increase from 479 bcm in 2024 to 941 bcm by 2055, an absolute gain of 462 bcm, the largest among all regions. This growth is underpinned by rising electricity demand and electrification, expanding industrial activity, decarbonisation policies, particularly the shift away from coal, and limited growth in domestic gas supply in several key markets.

Chapter 6

Figure 6.2

Global natural gas imports outlook by region, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Import growth also accelerates from a smaller base in other emerging regions. Africa's imports are expected to nearly triple, increasing from 23 bcm in 2024 to 63 bcm in 2055, while Latin America rises from 26 bcm to 69 bcm, supported by infrastructure build-out and growing gas demand in power generation and industry.

Within Asia Pacific, demand and trade patterns are increasingly shaped by developing subregions. China, Southeast Asia, and South Asia are set to become the primary drivers of import growth, particularly for LNG, positioning Asia Pacific as a pivotal force in global gas markets. China plays a distinctive dual role, emerging as both the largest LNG importer and a major destination for pipeline gas, notably from Russia and Central Asia. This reflects not only strong energy and electricity demand growth, but also strategic policy priorities to diversify supply sources, enhance energy security, and accelerate the transition away from coal.

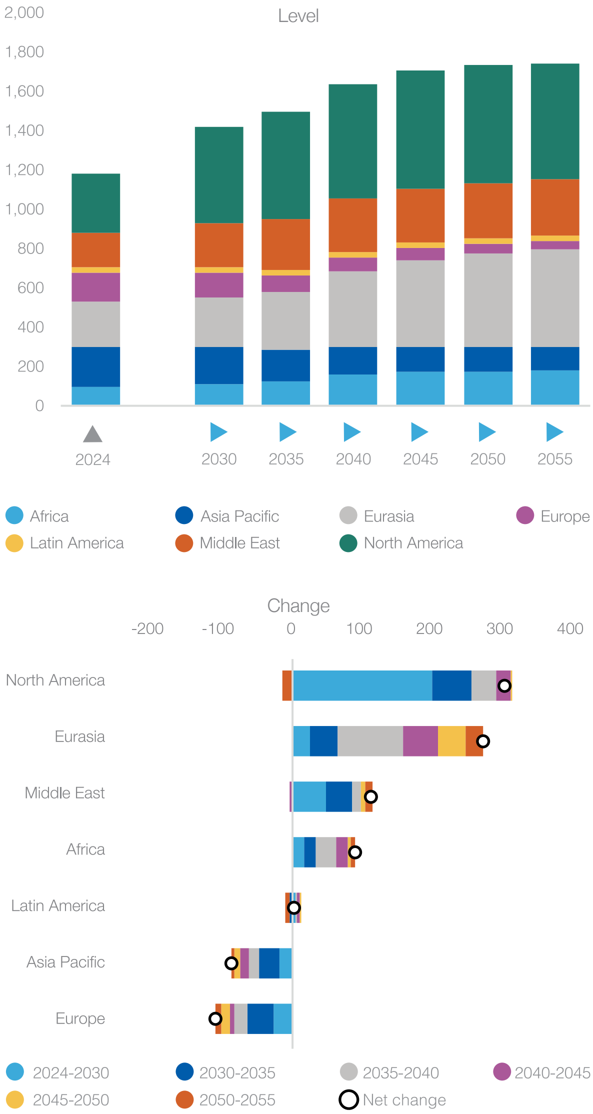
In contrast, Europe's natural gas imports are projected to decline from 410 bcm in 2024 to 313 bcm by 2055 (a reduction of 97 bcm), reflecting structural changes driven by energy efficiency improvements, renewable deployment, and policy-led decarbonisation. Eurasia records a sizeable increase, with imports rising from 44 bcm to 136 bcm, while North America remains broadly stable at around 185–212 bcm, consistent with its strengthening position as a net exporter. The Middle East shows a decline followed by partial recovery, falling from 44 bcm in 2024 to 27 bcm by 2040, before edging up to 33 bcm by 2055, reflecting the interplay between domestic demand growth and expanding export commitments.

North America and Eurasia are projected to lead global export growth over the outlook period. While global natural gas exports increase by around 573 bcm between 2024 and 2055, an expansion of approximately 39%, the bulk of this growth remains concentrated in a small number of key exporting regions. North America further consolidates its role as the world's largest exporter, with export volumes projected to double to around 600 bcm by 2055. This allows the region to maintain roughly 34% of global exports, up from 25% in 2024. The expansion is primarily underpinned by rapid growth in LNG liquefaction capacity, supportive market structures, and sustained investment in export-oriented infrastructure. Eurasia records the fastest export growth, with volumes more than doubling from 235 bcm in 2024 to about 506 bcm by 2055, raising its share of global exports from 20% to 29%. Much of this increase materialises after 2030, supported by the commissioning of new pipeline corridors and LNG capacity that deepen connectivity between Russia and Central Asia and key Asian demand centres (Figure 6.3).

Asia Pacific and Europe continue a structural shift from exporting regions toward greater import dependence. In Asia Pacific, exports are projected to decline from 207 bcm in 2024 to around 121 bcm by 2055, reducing the region's share of global exports from 17% to about 7%. This sustained contraction reflects rapid growth in domestic demand, maturing upstream basins, and limited prospects for material new supply additions. As a result, major markets, including China, Japan, the Republic of Korea, and much of Southeast Asia, further consolidate their positions as net importers, reinforcing the region's growing reliance on LNG to meet rising energy and electricity needs. Europe's decline is even more pronounced. Exports are projected to fall from 153 bcm in 2024 to just 43 bcm by 2055, cutting Europe's global export share from 13% to slightly above 2%. This trajectory is driven by ongoing depletion of North Sea resources, structural production

Figure 6.3

Global natural gas exports outlook by region, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

declines, particularly across legacy basins, and the EU's deepening decarbonisation agenda, which accelerates the phase-down of domestic gas output while increasing dependence on external supplies for residual demand.

Latin America is projected to retain a modest and broadly stable role in global gas exports amid rising domestic demand and shifting policy priorities. Export volumes increase only marginally, from 23 bcm in 2024 to around 25 bcm by 2055, implying a decline in the region's share of global exports from about 2% to roughly 1% as other regions expand more rapidly. While incremental export potential may emerge from developments such as Argentina's Vaca Muerta and Brazil's pre-salt resources, these gains are largely absorbed by strengthening domestic consumption and policy efforts to enhance energy security and supply adequacy. Consequently, Latin America's contribution to global natural gas exports remains limited, with export growth lagging well behind the large-scale expansion projected in North America and Eurasia.

In 2024, global natural gas demand was approximately 4,134 bcm, of which about 1,211 bcm was traded internationally via LNG and pipelines. Current GECF Member Countries supplied around 481 bcm of this traded volume, including 261 bcm as LNG, equivalent to roughly 40% of global gas trade that year. Looking ahead to 2055, global natural gas demand is projected to reach 5,417 bcm, with international trade expected to rise to around 1,767 bcm. Over the same period, current GECF Member Countries are anticipated to supply approximately 845 bcm of traded gas, increasing their share of global gas trade to around 48%.

6.2.1 Pipeline natural gas trade outlook

By 2055, global pipeline gas trade evolves into a more multipolar system in the gas market, marked by Europe's declining role, Asia's rapid ascent as the primary demand centre, and Eurasia's strengthened export dominance.

Europe's role in global pipeline gas trade contracts dramatically as demand, supply, and industrial activity weaken. Global pipeline gas trade continues to decline through 2030, driven primarily by Europe's structural shift away from pipeline imports. Europe, the world's largest importer in 2024 with 130 bcm of net pipeline inflows, undergoes profound transformation. Norwegian supplies remain stable and are anticipated to decline over the long run, while Russian pipeline imports have already fallen sharply in recent years. By 2055, Europe's share of global gross pipeline imports is anticipated to decline sharply, from around 42% in 2024 to roughly 15%, as net pipeline inflows fall to 66 bcm and gross imports contract in line with weakening regional demand, which drops from 276 bcm in 2024 to 93 bcm by 2055. This downward trajectory reflects the region's accelerating shift toward renewables, sustained efficiency gains, and competitive pressures that continue to displace energy-intensive industries. As a result, Europe's capacity to secure substantial new pipeline volumes remains limited.

Asia Pacific becomes the primary driver of global pipeline import growth, led overwhelmingly by China's rapidly expanding demand and new regional supply corridors. Asia Pacific's share of global pipeline gas trade continues to expand strongly, with the region's net pipeline imports rising from 71 bcm in 2024 to 137 bcm by 2055, making it the fastest-growing pipeline import market worldwide. China becomes the world's largest pipeline gas importer, accounting for the overwhelming majority of Asia Pacific's inflows by mid-century. This expansion is supported by growing supply corridors from Russia and Central Asia: in 2024, China imported 31 bcm from Russia and 33 bcm from Turkmenistan. Volumes rise further as the Power of Siberia 1 pipeline reaches its full extended 44 bcma capacity and Russia's Far East pipeline contributes an additional 12 bcma. Over the long term, the planned 50 bcma Power of Siberia 2 pipeline would significantly strengthen west-east flows, while the proposed 30 bcma Central Asia-China Pipeline D remains far less certain due to unresolved commercial, geopolitical, and security challenges. Turkmenistan's diversification strategy also includes the long-planned TAPI pipeline (Turkmenistan-Afghanistan-Pakistan-India), designed for up to 33 bcma, which, if realised, would further integrate Central Asian gas with growing South Asian demand.

Eurasia becomes the central axis of global pipeline gas trade, leading both intra- and interregional export flows while simultaneously expanding its role as a major intraregional importer. Eurasia's role strengthens on both sides of the trade equation. Its share of global pipeline exports expands as net exports rise from 145 bcm in 2024 to 183 bcm by 2055, driven by major Russian and Central Asian supply routes increasingly oriented toward Asia. At the same time, Eurasia becomes an increasingly important pipeline gas importer, with regional demand growing from 44 bcm in 2024 to 136 bcm by 2055. Import needs are propelled by industrialisation and population growth in Kazakhstan and Uzbekistan, with Uzbekistan's requirements expected to continue rising strongly through mid-century. As flows shift decisively eastward, Eurasia's export structure becomes ever more Asia-facing, reshaping global pipeline trade patterns.

North America is anticipated to maintain a stable and integrated pipeline trade position supported by growing US- Mexico flows. North America's role in global pipeline gas trade remains steady through 2055, supported by a highly interconnected regional network and a closely balanced supply-demand profile. Regional demand rises only marginally from 183 bcm in 2024 to about 210 bcm by 2055, with supply converging to a similar level. Within the region, pipeline trade continues to deepen as Mexico's growing import needs are increasingly met by rising US exports, reinforcing the integration of the North American gas market. These dynamic complements the United States' position as the world's largest LNG exporter. The sustained expansion of liquefaction capacity across the United States, Canada, and Mexico, coupled with ongoing modernisation of cross-border pipeline infrastructure, enhances the structural efficiency and integration of North America's natural gas system.

The Middle East, Africa, and Latin America collectively maintain modest and regionally concentrated roles in global pipeline gas trade through 2055. Africa remains a net-exporting region, though at declining levels, with pipeline exports narrowing from 41 bcm in 2024 to 16 bcm in 2055 as domestic demand edges upward and supply softens.

The Middle East maintains its position as a major net exporter, with net outflows increasing from 17 bcm in 2024 to 25 bcm by 2055. Pipeline trade is initially supported by supply from Qatar, Iran, and the Eastern Mediterranean; however, as Qatar's pipeline corridors diminish over time and its exports shift almost entirely toward LNG, Iran and Israel emerge as the principal providers of regional pipeline supply. Despite this structural shift, overall pipeline trade remains steady, while LNG continues to underpin the region's broader export strategy.

Latin America's pipeline gas trade gradually reconfigures through 2055 as demand rises faster than domestic supply, widening the region's structural import needs. Bolivia's long-standing pipeline exports to Brazil and Argentina decline steadily with maturing fields, while Argentina emerges as a new source of regional supply after 2030 as Vaca Muerta production expands and north-south pipeline capacity grows. In contrast, Brazil and Chile see increasing dependence on imports as domestic output lags demand, reinforcing a broader shift toward LNG as a complement to constrained pipeline inflows.

By 2055, global pipeline gas trade becomes firmly multipolar, with Europe's declining import role gives way to Asia Pacific's rapid rise as the primary demand centre and Eurasia's strengthened dominance in supply. North America remains stably integrated through deepening US - Mexico flows, while the Middle East, Africa, and Latin America maintain modest, regionally focused patterns. Overall, global pipeline flows pivot decisively toward Asia, reshaping the structure of trade by mid-century.

6.2.2 LNG imports outlook

Global LNG imports are set to rise sharply over the long term, climbing from about 406 Mt in 2024 to nearly 837 Mt by 2055, an increase of roughly 431 Mt, or more than doubling of current levels. This sustained expansion underscores LNG's growing importance in energy security strategies worldwide, as more countries seek flexible, diversified and lower-carbon supply options. Asia Pacific remains the dominant anchor of global LNG demand, while Europe continues to rely on LNG as a structural component of its supply mix. Emerging growth in Africa, Latin America and the Middle East further broadens the geographical footprint of LNG demand, reinforcing a more multi-regional and resilient global import landscape by 2055 (Table 6.1).

Global LNG import demand is expected to broaden markedly by 2055 as more countries integrate LNG into their energy systems. The pool of LNG-importing countries is projected to expand from 48 today to over 60 by mid-century, reflecting wider adoption across Asia, the Middle East, and parts of Africa. This growing

Table 6.1

Global LNG imports outlook by region, 2024-2055

	Levels (Mt)				Change (Mt)	Growth (% p.a.)	Share (%)		
	2024	**2030**	**2040**	**2050**	**2055**	**2024-2055**	**2024- 2055**	**2024**	**2055**
Africa	3	20	28	28	31	28	8.0%	1%	4%
Asia Pacific	282	394	513	566	582	300	2.3%	70%	69%
Eurasia	0	0	0	0	0	0	0%	0%	0%
Europe	98	163	188	171	159	62	1.6%	24%	19%
Latin America	13	23	38	44	44	31	3.9%	3%	5%
Middle East	9	19	17	20	20	11	2.7%	2%	2%
North America	2	2	1	1	1	-1	-0.7%	0%	0%
Total	**406**	**620**	**785**	**829**	**837**	**431**	**2.3%**	**100%**	**100%**

Source: GECF Secretariat based on data from the GECF GGM

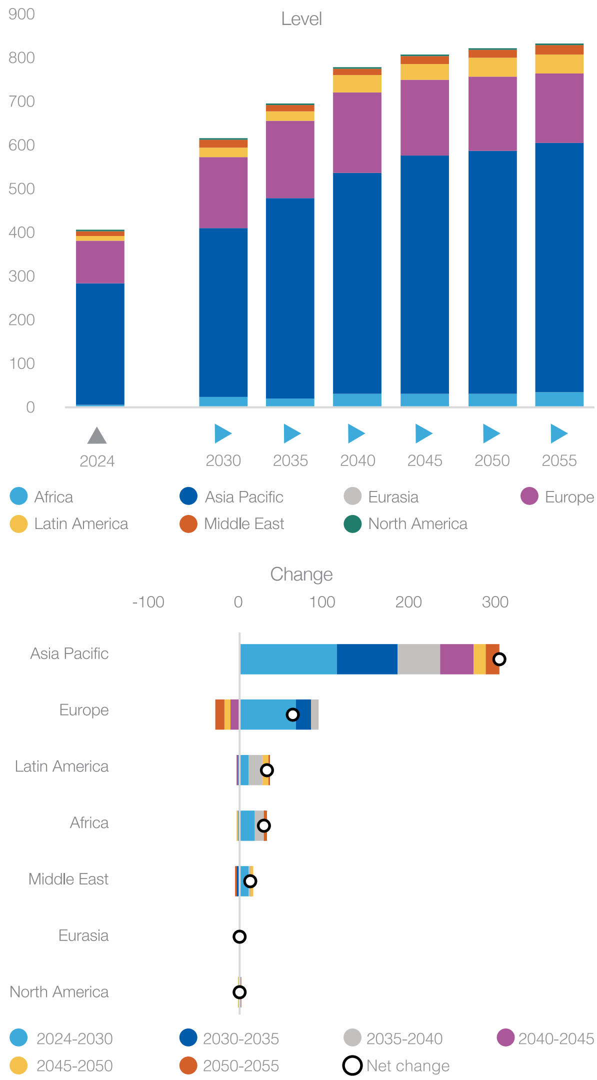
geographic spread will deepen market diversity, with Asia, especially fast-growing South and Southeast Asian economies, remaining the core destination for global LNG flows and accounting for the bulk of future import growth.

The **Asia Pacific** region remains the driving force behind global LNG demand and is expected to retain it's dominance in the decades ahead. In 2024, it absorbed nearly 70% of global LNG imports, and its influence is anticipated to expand further as regional consumption climbs to almost 582 Mt by 2055. This long-term rise is supported by rapid industrialisation, urban growth, and continued coal-to-gas switching in major economies such as China, India, and countries across Southeast Asia. Although LNG imports continue to increase significantly, the overall pace of natural gas import growth moderates over time as efficiency improvements, incremental increases in domestic production in some markets, and stronger renewable competitiveness gradually slow expansion after the mid-2030s. Even with this moderation, Asia Pacific remains the primary engine of global LNG import growth, accounting for nearly 70% of the net increase in global LNG imports between 2024 and 2055, cementing its role as the main destination for new LNG supply and the central pillar of global LNG trade (Figure 6.4).

Europe's LNG import trajectory shows steady growth in the near term, followed by a gradual long-term decline. In 2024, Europe imported 98 Mt, representing 24% of global LNG demand. Imports are projected to rise to 163 Mt by 2030, increasing the region's share to 26%. Beyond 2030, European LNG imports are expected to grow more slowly, peaking before gradually declining to 159 Mt by 2055, equivalent to 19% of global LNG trade. This long-term reduction reflects accelerating decarbonisation, expanded renewable capacity, and structurally lower gas consumption across the power, industrial, and residential sectors. Despite the declining share, Europe remains the world's second-largest LNG-importing region through 2055, maintaining a key role

Figure 6.4

Global LNG imports outlook by region, 2024-2055 (Mt LNG)



Source: GECF Secretariat based on data from the GECF GGM

Chapter 6

in global LNG markets even as Asia Pacific increasingly drives long-term demand growth (Figure 6.5).

Asia Pacific and Europe remain the principal hubs of global LNG demand, accounting for approximately 94% of imports in 2024 and maintaining nearly 88% by 2055. Although import growth gradually extends to emerging markets in Africa, Latin America and the Middle East, Asia Pacific and Europe continue to represent the dominant share of global LNG trade.

Outside the major LNG-importing regions of Asia Pacific and Europe, demand is set to grow most rapidly in Africa, Latin America, and the Middle East. In Africa, imports are projected to rise from 3 Mt in 2024 to 31 Mt by 2055, representing the fastest pace increase globally outside Asia, driven largely by Egypt and South Africa as both countries turn to LNG to stabilise power supply and meet growing electricity needs. In Latin America, LNG imports expand from 13 Mt to 44 Mt over the same period, supported by LNG-to-power requirements and the variability of hydropower generation, particularly in Brazil and Chile. The Middle East is expected to more than double its imports from 9 Mt to 20 Mt, reflecting rising electricity demand and industrial consumption, with Bahrain and Kuwait accounting for the bulk of the region's increase.

North America's LNG import requirements remain negligible over the entire outlook period, underpinned by its large domestic gas base and strong export capacity. Eurasia likewise records no LNG import demand, as the region continues to rely entirely on abundant indigenous resources and well-established pipeline networks.

6.2.3 LNG exports outlook

The global LNG market is entering the third and largest supply expansion wave in its history, driven overwhelmingly by the United States and Qatar, with additional contributions from Canada and Mozambique. Global LNG supply is expected to exceed 620 Mt by 2030. Around 200-220 Mtpa of incremental capacity globally is currently under construction between 2025 and 2030. The United States leads this expansion, increasing its liquefaction capacity by 90-95 Mtpa, as major new projects, Golden Pass, Plaquemines LNG, Port Arthur LNG, Rio Grande LNG, Corpus Christi Stage 3, Woodside Louisiana LNG and several additional terminals move into operation. Qatar will add around 48 Mt of new capacity over the same period through the North Field East and North Field South projects, rising to 64 Mtpa of total expansion by 2035 once the North Field West phase is completed.

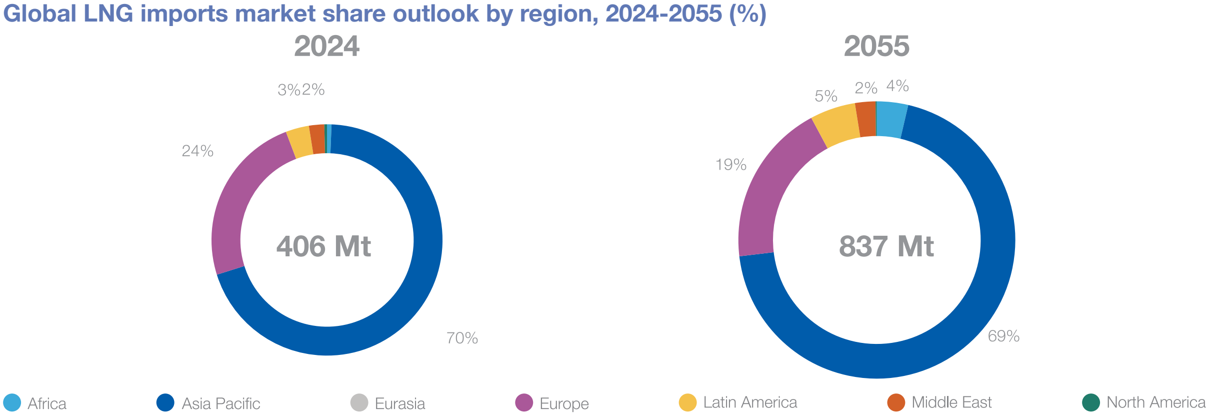
Canada and Mozambique together could add about 35-40 Mt of new LNG liquefaction capacity by the early 2030s, with each contributing on a significant but distinct scale. Canada's additions, driven by LNG Canada Phase 1 at 14 Mtpa, Woodfibre LNG at 2.1 Mtpa, and Cedar LNG at 3.3 Mtpa, total roughly 19-20 Mtpa. Mozambique is expected to contribute a further 16-17 Mtpa through the restart of the Mozambique LNG onshore project at 13.1 Mtpa and the Coral Norte FLNG unit at around 3.5 Mtpa, complementing the already-operational Coral South FLNG.

The rapid build-out of destination-flexible LNG is expected to intensify competition among exporters, place sustained downward pressure on spot prices, and boost interregional LNG trade flows, especially toward Asia and Europe. While China, India, and Southeast Asia are expected to absorb much of the new supply, their demand remains highly price-sensitive, and Europe's long-term LNG needs are moderated by accelerating renewable deployment despite declining Russian pipeline imports.

Compared with earlier investment cycles, the third LNG wave features larger project scale, lower-cost resource bases, broader commercial flexibility, and wider adoption of emissions-reduction technologies. The increasing deployment of carbon-neutral cargo frameworks and more optional contract structures marks a clear departure from the rigid oil-indexed contracts of previous cycles. By the mid-2030s, the combined United States,

Figure 6.5

Global LNG imports market share outlook by region, 2024-2055 (%)



Source: GECF Secretariat based on data from the GECF GGM

Qatar, Canada, and Mozambique contributions will form the backbone of global LNG supply growth, firmly establishing this as the largest and most transformative LNG expansion wave in industry history.The two previous LNG waves laid the foundation for today's global LNG system and illustrate how the industry has evolved. The first LNG wave (2000s-early 2010s) was driven by rapid Asian demand growth and supply diversification needs, with large greenfield projects in Qatar, Australia, Nigeria, and Southeast Asia, typically under long-term oil-indexed contracts with destination restrictions. The second wave (mid-2010s-late 2020s) emerged from the US shale revolution, adding over 100 Mtpa of new capacity from projects such as Sabine Pass, Cameron LNG, Corpus Christi, and Freeport LNG, alongside Australia's coal seam gas (CSG)-based megaprojects. This period introduced flexible Henry Hub-linked LNG and deepened global spot market liquidity. The third wave now surpasses both in scale and strategic impact, reshaping global LNG market dynamics through mid-century.

LNG exports are set to grow substantially over the next three decades. The number of exporting countries is projected to remain broadly stable, rising only slightly from 24 today to around 25 by 2055, as a few new entrants offset the gradual exit of some existing suppliers. Recent additions include Mexico, which began LNG exports in 2024 through the Altamira FLNG project with a capacity of roughly 1.4 Mtpa, followed by Senegal and Mauritania in early 2025 with the start-up of the 2.5 Mtpa GTA Phase 1 FLNG development. Canada also entered the global LNG exporter group in 2025 with the commissioning of LNG Canada Phase 1, a major 14 Mtpa liquefaction project that marks the country's first large-scale LNG exports and immediately positions it as a significant new supplier to Asia. The core group of established exporters is expected to remain active throughout the outlook period, while North America strengthens its position to become the world's leading LNG-exporting region by mid-century.

Global LNG exports rise from 406 Mt in 2024 to 837 Mt by 2055, with growth concentrated in North America, Eurasia, the Middle East, and while Africa steadily strengthen their roles as emerging suppliers (Table 6.2). In contrast, Asia Pacific's export position declines and Latin America and Europe remain comparatively small contributors. By mid-century, North America, the Middle East, Eurasia and Africa together form the core of an increasingly diversified and resilient global LNG export system. **North America** is positioned to become the world's leading LNG-exporting region by 2055, overtaking both the Middle East and Asia Pacific. It is projected to be the single largest contributor to global LNG supply growth, adding nearly 197 Mt and recording the largest regional increase worldwide (Figure 6.6). As a result, North America's share of global LNG exports rises from 21% in 2024 to around 34% by 2055 (Figure 6.7), with export volumes increasing from 86 Mt to 283 Mt over the period. This expansion is driven predominantly by the United States, complemented by additional capacity from Canada and, to a lesser extent, Mexico. Sustained investment in liquefaction projects, continued build-out of export infrastructure, and the expansion of long-term commercial arrangements with key importing markets underpin North America's emergence as a central pillar of the global LNG market through mid-century.

The **Middle East** is expected to maintain a strong upward trajectory in LNG exports, consolidating its position as the second-largest exporting region after North America by mid-century. Its share of global LNG exports is anticipated to sustain, from 24% in 2024 to around 23% by 2055, supported by a steady increase in export volumes as the region expands from 96 Mt to about 190 Mt over the outlook period. Much of the acceleration occurs in the 2020s and early 2030s, reflecting large-scale capacity additions already under construction or committed. Qatar remains the anchor of regional supply growth, driven by the North Field East, North Field South, and North Field West expansions, which together lift the country's liquefaction capacity

Table 6.2

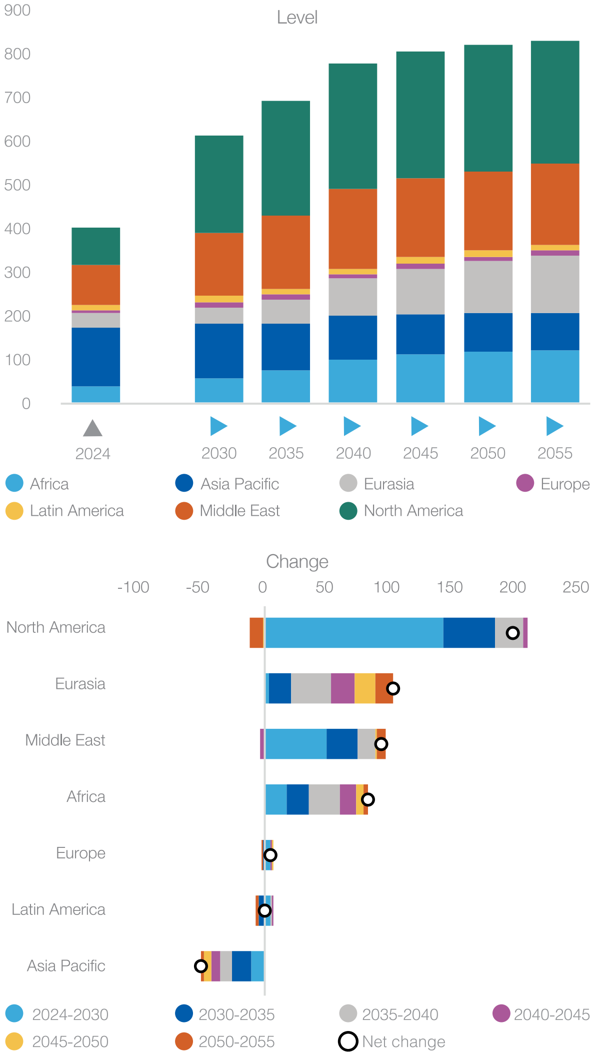
Global LNG exports outlook by region, 2024-2055

	Levels (Mt)					Change (Mt)	Growth (% p.a.)	Share (%)	
	2024	2030	2040	2050	2055	2024-2055	2024-2055	2024	2055
Africa	38	56	98	117	120	82	3.7%	9%	14%
Asia Pacific	136	126	102	89	86	-50	-1.5%	34%	10%
Eurasia	34	38	86	121	136	102	0.0%	8%	16%
Europe	5	10	10	11	11	6	2.3%	1%	1%
Latin America	11	16	14	15	13	2	0.4%	3%	2%
Middle East	96	145	184	182	189	93	2.2%	24%	23%
North America	86	228	291	294	283	197	3.8%	21%	34%
Total	**406**	**620**	**785**	**829**	**837**	**431**	**2.3%**	**100%**	**100%**

Source: GECF Secretariat based on data from the GECF GGM

Figure 6.6

Global LNG exports outlook by region, 2024-2055 (Mt LNG)



Source: GECF Secretariat based on data from the GECF GGM

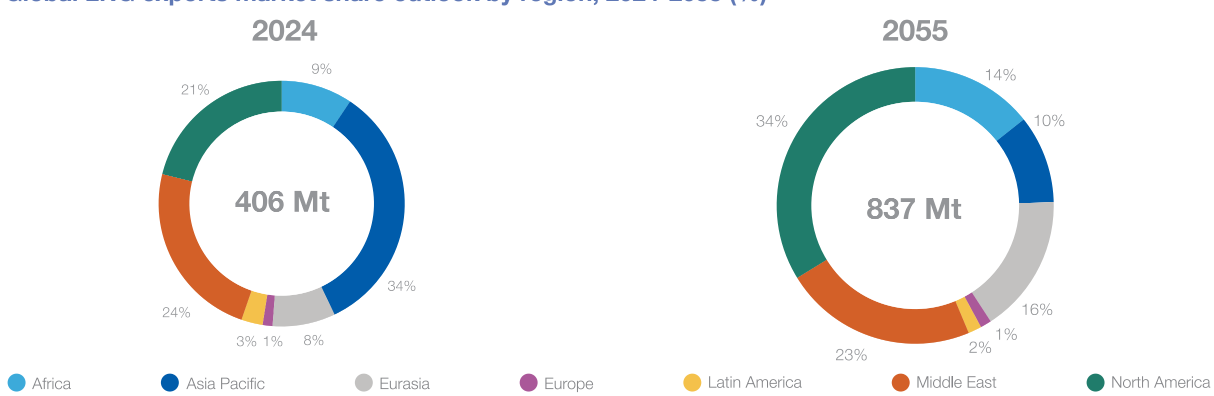
to unprecedented levels by the mid-2030s. The UAE and Oman also play increasingly important roles, with ADNOC's Ruwais LNG project and Oman LNG debottlenecking initiatives enhancing regional export flexibility. These developments reinforce the Middle East's enduring strategic importance as a reliable LNG supplier to Asia Pacific and Europe, particularly as global buyers seek long-term, low-emission, and cost-competitive supply.

Eurasia emerges as one of the fastest-growing LNG export regions, with its share of global supply increasing from 8% in 2024 to 16% by 2055. Export volumes more than triple over the period, reflecting a pronounced long-term expansion driven largely by Russia's diversification strategy. While initial growth is moderate, a stronger uplift materialises after 2030 as new liquefaction capacity comes online. Russia accelerates the build-out of LNG infrastructure in response to structural shifts in its pipeline export markets, prioritising deliveries to China, India, Türkiye, and other Asian buyers. Key projects underpinning this trend include the expansion of Yamal LNG, progress on the Arctic LNG portfolio, and new developments along Russia's Pacific coast, which enhance shipping flexibility and reduce reliance on European routes. The region's growing LNG capability reflects a broader reorientation of Eurasian gas trade, positioning it as a meaningful additional source of LNG supply in the global market, particularly in the 2035-2055 period.

Africa is set to experience substantial growth in LNG exports, strengthening its role as an increasingly important supplier to Asia and Europe. The continent's share of global LNG exports rises from 9% in 2024 to 14% by 2055, supported by a threefold increase in output. Most of this expansion occurs in the 2030s, led overwhelmingly by Mozambique, which becomes Africa's largest LNG exporter by mid-century. This growth is driven by the continued operation of Coral South, the addition of Coral Norte FLNG, and the full ramp-up of the Mozambique LNG and Rovuma LNG onshore projects as security conditions improve. Nigeria also reinforces its position through NLNG Train 7 and

Figure 6.7

Global LNG exports market share outlook by region, 2024-2055 (%)



Source: GECF Secretariat based on data from the GECF GGM

new FLNG capacity, while Senegal and Mauritania advance the GTA and BirAllah developments. Additional potential from Eastern Africa may further support regional supply in the later years. Improved regulatory frameworks, new partnerships with international energy companies, and continued investment in upstream and liquefaction infrastructure will be essential for sustaining Africa's expansion. With geographic proximity to both Atlantic and Indian Ocean markets, Africa becomes an increasingly flexible and strategically important LNG supplier by mid-century.

In 2024, twelve of the world's twenty LNG suppliers were among current GECF Member Countries. Collectively, they supplied around 189 Mt of LNG, meeting approximately 47% of global LNG demand. Over the outlook period, LNG trade among current GECF Members is expected to expand significantly. This growth is supported by continued financial and technological progress that is lowering barriers to LNG adoption and enabling a wider range of importing markets. As global natural gas demand rises, LNG is increasingly becoming a strategic commodity, with growing implications for the political and economic positioning of gas-producing countries. **By 2055, LNG exports from current GECF Member Countries are projected to reach around 445 Mt, representing roughly 53% of global LNG exports.**

6.2.4 Regional LNG flows outlook

Given the structural shifts in global LNG demand and supply, the geographical pattern of LNG trade is expected to undergo a significant reconfiguration. As outlined, Asia Pacific and Europe will remain the two principal LNG-importing regions over the coming decades, with Asia Pacific's share increasing as Europe's relative weight gradually declines. This shift will reshape global LNG trade flows and alter traditional supply dependencies.

Table 6.3 presents regional LNG net imports from 2024 to 2055 and highlights the scale of the transition. Asia Pacific remains the centre of global LNG demand, with net imports projected to more than triple from 146 Mt in 2024 to 495 Mt by 2055. Europe, by contrast, records a more moderate change over the period. On the supply side, Africa, Eurasia, the Middle East, and North America continue to be net LNG exporters. The largest increases in net exports are projected in North America (197 Mt), Eurasia (102 Mt), and the Middle East (82 Mt), reinforcing their expanding role in meeting incremental global LNG demand. Although the LNG balance in Latin America is close to equilibrium in 2024, the region is projected to shift further toward net imports, with net import requirements rising by around 30 Mt over the forecast period to reach 31 Mt by 2055.

In 2024, as illustrated in Figure 6.8, around 48% of Asia Pacific's LNG imports were sourced within the region, underscoring the continued importance of intra-regional supply, primarily from Australia and Indonesia. The Middle East accounted for nearly 28% of Asia Pacific's LNG supply, followed by North America (11%) and Eurasia (6%). However, as LNG import requirements expand and regional LNG production declines, this sourcing pattern is expected to shift markedly over the coming decades.

By 2055, Asia Pacific's intra-regional LNG sourcing is projected to fall sharply to just 14%, with the shortfall increasingly met by suppliers outside the region. The Middle East, North America, and Eurasia emerge as the dominant sources of LNG for Asia Pacific. By 2055, the Middle East is projected to supply 27% of Asia Pacific's LNG imports, followed by North America at 25% and Eurasia at 20% (Figure 6.9). These changes signal a fundamental reorientation of Asia Pacific's LNG procurement toward a more globally diversified supplier base, supported by expanded regasification infrastructure and a stronger reliance on long-term contracting to secure supply reliability in an increasingly interconnected and competitive LNG market.

Table 6.3
Global LNG net imports outlook by region, 2024-2055 (Mt)

	Levels (Mt)					Change (Mt)
	2024	2030	2040	2050	2055	2024-2055
Africa	-36	-37	-70	-89	-89	-53
Asia Pacific	146	267	411	477	495	349
Eurasia	-34	-38	-86	-121	-136	-102
Europe	92	152	178	160	148	56
Latin America	2	7	24	28	31	29
Middle East	-87	-126	-167	-162	-169	-82
North America	-84	-226	-289	-293	-282	-198

Source: GECF Secretariat based on data from the GECF GGM

Figure 6.8

Regional LNG flows by region, 2024 (Mt LNG)

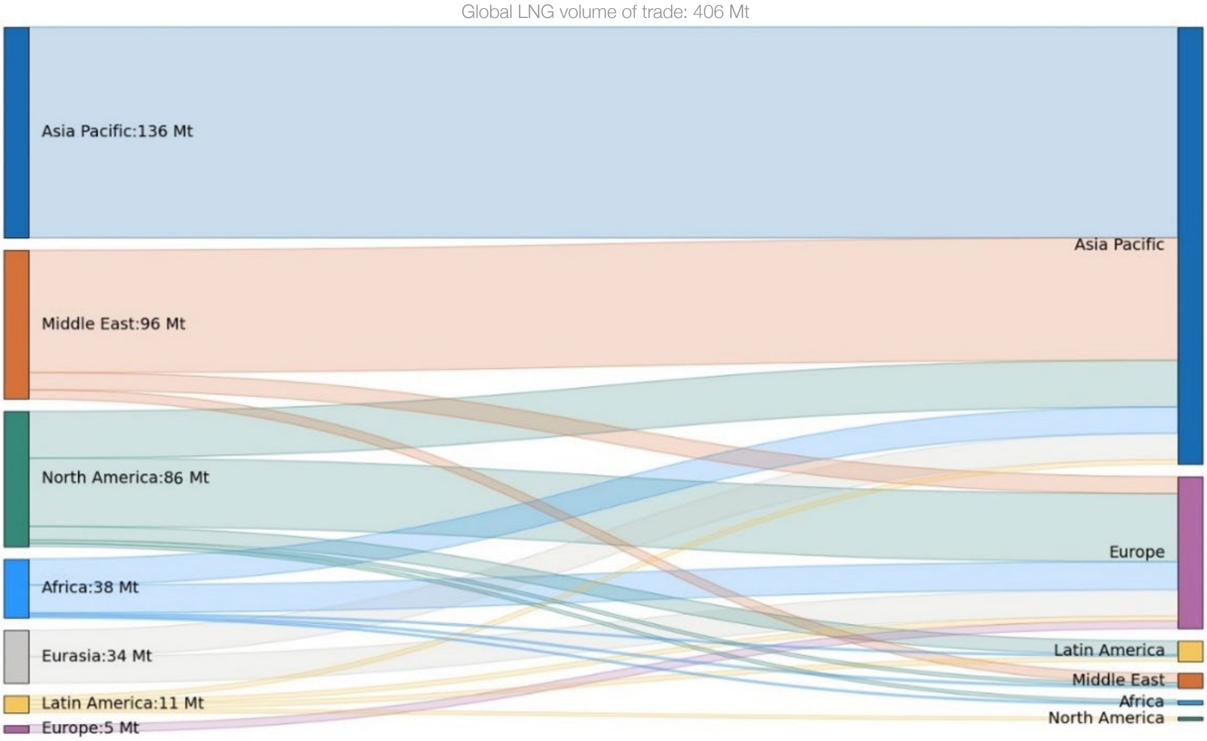
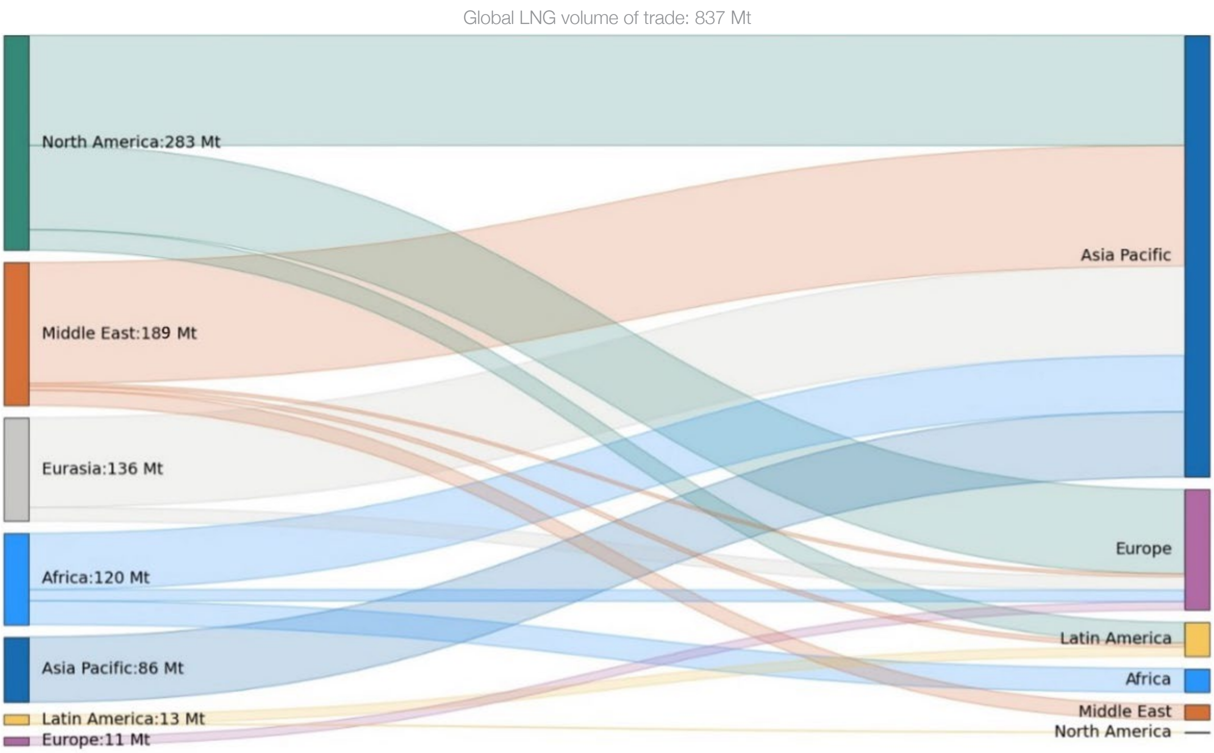


Figure 6.9

Regional LNG flows outlook by region, 2055 (Mt LNG)



Source: GECF Secretariat based on data from the GECF GGM

As the second-largest LNG import market, Europe sourced nearly 45% of its LNG imports from North America in 2024, making it the region's largest supplier. Africa followed with 18%, while the Middle East and Eurasia played more limited roles in meeting European LNG demand. **By 2055, North America is projected to further consolidate its position, supplying around 70% of Europe's LNG imports. Africa's share is expected to decline to 9%, although its absolute export volumes remain broadly stable.**

In contrast, the Middle East and Eurasia are expected to increasingly prioritise LNG exports to Asia, limiting their long-term contribution to Europe's supply. With the Middle East focusing on the growing Asia Pacific market and Eurasia redirecting incremental volumes to China and other Asian demand centres, their shares in Europe's LNG imports are projected to remain minimal over the coming decades. Overall, these developments reflect a broader transformation in global LNG trade: Europe becomes increasingly anchored to transatlantic and African supply, while Asia Pacific remains the principal growth hub for LNG demand.

6.3 Natural gas trade balance outlook

Global natural gas trade undergoes significant restructuring through 2055, driven by widening regional imbalances in supply and demand. **Asia Pacific remains the world's largest net-importing region, with net imports soaring by nearly 553 bcm as domestic output declines and demand accelerates.** Europe moves in the opposite direction, with net imports gradually easing as renewables, efficiency gains and structural industrial changes reduce long-term gas consumption. Latin America becomes the only region to shift from net exporter to net importer as domestic demand outpaces production (Table 6.4).

On the export side, **North America emerges as the largest net-exporting region over the outlook, recording the strongest growth in export surplus and consolidating its role as a leading global LNG supplier through expanding capacity across the United States, Canada and Mexico.** Eurasia maintains a significant export position with flows increasingly redirected Asia as long-term demand shifts eastward. The Middle East continues to scale up exports, supported by large LNG additions in Qatar and the UAE, while Africa's export growth levels off after the 2050s as more gas is absorbed by domestic markets. Overall, global gas trade becomes increasingly anchored in transpacific and transatlantic corridors, with Asia emerging as the central destination for long-term LNG demand (Figure 6.10).

Africa's net exports grow but gradually moderate. Africa's net gas exports rise steadily through the 2030s, supported by LNG developments in Mozambique, Nigeria, Senegal, Mauritania and Angola. However, the pace of export growth slows over time as a growing share of the region's gas is redirected toward domestic consumption. Net exports increase from 68 bcm in 2024 to 119 bcm in 2055, but rising demand in power generation, industry and urban sectors progressively limit the volumes available for export. This reflects a broader structural shift in which Africa's expanding internal energy needs increasingly shape the trajectory of its gas trade.

Asia Pacific's net imports surge further. Asia Pacific remains the world's largest net-importing region and experiences the strongest long-term growth in import requirements. Net imports rise from 267 bcm in 2024 to 820 bcm in 2055, driven by declining regional production, rapid energy demand growth, and expanding reliance on LNG. By mid-century, Asia Pacific increasingly depends on supply from North America, the Middle East, and Eurasia, reinforcing its position at the centre of global gas trade.

Eurasia remains the second largest net-exporting region. Eurasia maintains the second largest net-exporting

Table 6.4

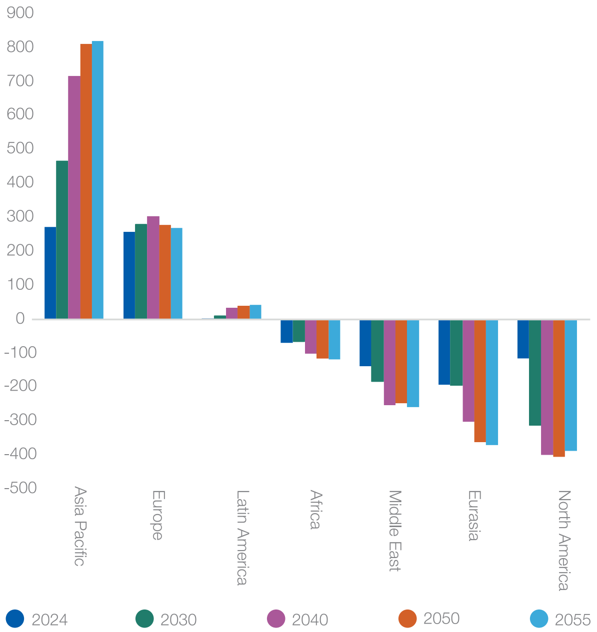
Regional natural gas balance (net imports) outlook, 2024-2055 (bcm)

	2024	2030	2040	2050	2055	2024-2055 change
Africa	-68	-67	-100	-115	-119	**-50**
Asia Pacific	267	466	716	812	820	**553**
Eurasia	-191	-195	-301	-361	-370	**-179**
Europe	260	280	303	277	271	**10**
Latin America	-1	10	33	39	44	**45**
Middle East	-141	-184	-252	-248	-257	**-117**
North America	-128	-312	-399	-404	-388	**-261**

Source: GECF Secretariat based on data from the GECF GGM

Figure 6.10

Regional natural gas balance (net imports) outlook, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

position globally, with net exports expanding from 191 bcm in 2024 to 370 bcm in 2055. This growth is supported by rising LNG capacity and the redirection of long-term pipeline flows toward Asian markets. As Europe's import needs decline, Eurasian exports become increasingly concentrated on China, India, and other emerging Asian economies.

Europe's net imports gradually increase by 2040s before entering into a shallow decline thereafter. Europe's net imports grow from 260 bcm in 2024 to 271 bcm in 2055, reflecting lower gas demand driven by renewable energy expansion, efficiency gains, and shifts in industrial activity. While gas retains a role in seasonal and system balancing, Europe's reliance on external supply decreases over time. Its import mix becomes more concentrated around North American LNG, complemented by smaller volumes from Africa.

Latin America is anticipated to transition from a marginal net-exporting position to a structurally net-importing region over the outlook period. After shifting into equilibrium in 2024, region's net import requirements are projected to rise significantly from (-1) bcm to 44 bcm by 2055, as demand growth - particularly in the power, industrial and residential sectors - outpaces domestic production. As the supply-demand gap widens, the region is expected to rely increasingly on LNG inflows from North America, reinforcing regional energy integration and trade linkages.

Middle East strengthens its exporting position. The Middle East reinforces its role as a major exporting region, with net exports increasing from 141 bcm in 2024 to 257 bcm in 2055. This expansion is driven by Qatar's multi-phase LNG capacity additions and further contributions from the UAE and Oman. With Asia Pacific emerging as the fastest-growing demand centre, Middle Eastern exports become increasingly oriented toward Asian markets.

North America posts the strongest export growth. North America records the largest increase in net exports globally, anticipated to surge from 128 bcm in 2024 to 388 bcm in 2055. This growth is led by the United States, supported by new Canadian LNG volumes after 2025 and Mexico's contributions. North America's expanding liquefaction capacity strengthens its role as a key long-term supplier to both Asia Pacific and Europe.

6.4 Natural gas trade infrastructure prospects

Global investment in gas infrastructure, both LNG and pipelines, is expected to expand steadily through 2055, driven by rising liquefaction capacity in major exporting regions and accelerating regasification build-outs in key demand centres. Through 2030, the bulk of spending concentrates on new LNG liquefaction projects in North America, the Middle East, and Africa, alongside substantial regasification additions in Asia Pacific. While the pace of LNG infrastructure growth moderates after 2040 as markets become more mature, targeted expansions continue to support long-term supply diversification. Export-oriented pipeline development is projected to advance through mid-century, particularly in Eurasia and Asia Pacific, underpinning new trade corridors and reinforcing the structural reorientation of global gas flows toward Asian markets.

6.4.1 LNG liquefaction

By the end of 2025, global liquefaction capacity reached 519 Mtpa. In 2024, FID activity slowed sharply, with approvals falling from more than 55 Mtpa of new LNG capacity in 2023 to just 14.8 Mtpa. This included 9.6 Mtpa from Ruwais LNG Trains 1 and 2, 1 Mtpa from Marsa LNG Train 1, 1.2 Mtpa from Genting FLNG, and 3 Mtpa from Cedar FLNG 1. In 2025, however, momentum recovered strongly. The removal of the United States regulatory pause on non-FTA LNG approvals under the new United States administration catalysed a rapid normalisation of project advancement. As a result, by November 2025, the United States had already recorded a substantial resurgence in sanctioning activity, with approximately 81 bcm (59 Mtpa) of LNG capacity reaching FID, forming the core of an estimated 65 Mtpa of global FIDs in 2025.

This significant expansion places the market in a comfortable position to meet demand through 2030. Yet the continued rise in FID activity, building on the 2025 approvals together with those projected in 2026 and 2027, raises concerns about potential medium-term oversupply. These commitments are set to trigger another wave of LNG capacity, with new volumes expected to come on stream in the early 2030s, reshaping global supply dynamics. Such a surge could intensify competition among suppliers and exert renewed downward pressure on gas prices, thereby complicating project economics and long-term contract negotiations.

At present, North America leads the expansion, accounting for 50% of total under-construction capacity, with 113 Mtpa currently under development. The Middle East is the second-largest contributor, with 57 Mtpa of liquefaction capacity under construction by 2030. Africa and Eurasia are also expected to expand their LNG production capabilities, adding 24 Mtpa and 20 Mtpa, respectively, equivalent to 11% and 9% of the total. Asia Pacific is expected to add 8 Mtpa to global under-construction liquefaction capacity, representing a relatively small share of overall growth. In total, LNG export capacity under construction in the United States and other regions is projected to add around 225 Mtpa to global supply by the end of the decade.

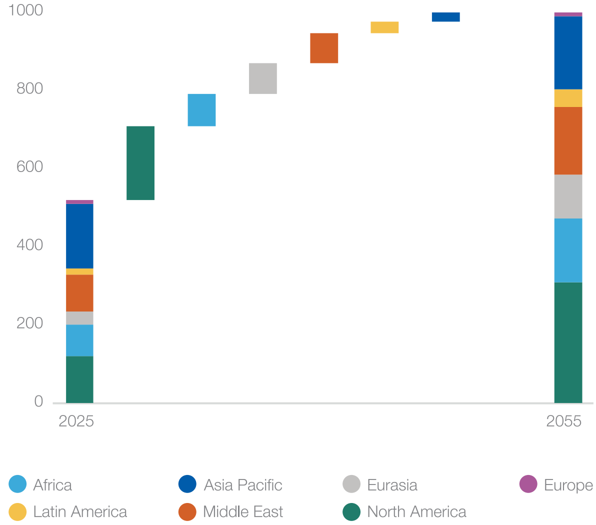
By the end of 2025, global LNG liquefaction capacity, including existing, under-construction, and proposed facilities, is projected to reach 998 Mtpa by 2055, exceeding expected LNG supply of approximately 837 Mt. This expansion represents a net increase of 479 Mtpa in liquefaction capacity over the forecast period, highlighting the scale of infrastructure investment and the shifting supply dynamics across key producing regions.

North America, Africa, and the Middle East are projected to lead global liquefaction capacity growth, accounting for approximately 39%, 17%, and 16% of total additions by 2055, respectively. In North America, this expansion is driven by large-scale LNG projects in the United States, Canada, and Mexico, further consolidating the region's position as the leading global LNG supplier. Africa's growth reflects major new projects in Mozambique, Nigeria, Mauritania, and Senegal. These additions strengthen Africa's position as a long-term LNG supplier to both Europe and Asia, broadening the global supply base. In the Middle East, Qatar's North Field expansions, alongside growing contributions from the UAE and Oman, are expected to deliver a significant increase in regional liquefaction capacity (Figure 6.11).

Eurasia also makes a significant contribution, accounting for around 16% of global liquefaction capacity growth. The region's expansion is driven primarily by Russia's LNG ambitions and ongoing Arctic LNG developments. By contrast, Asia Pacific plays a much smaller role in liquefaction growth, contributing around 5% of total global additions by 2055. Although the region currently hosts some of the world's largest operational liquefaction capacity, declining feed-gas availability from maturing production basins constrains new investment. As a

Figure 6.11

Global LNG liquefaction capacity outlook by region, 2025-2055 (Mtpa)



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

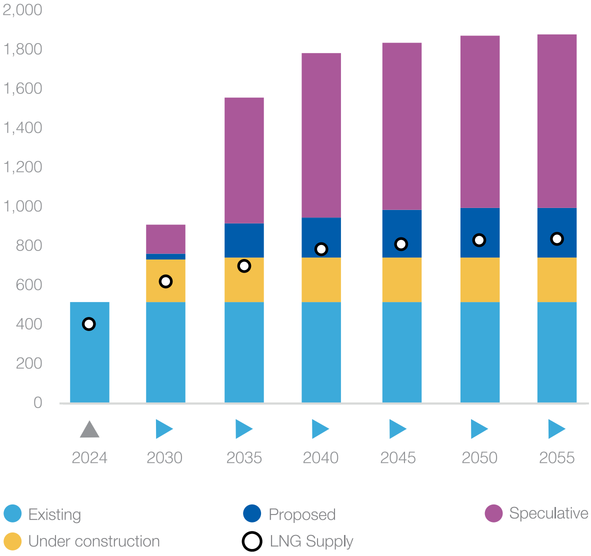
result, Asia Pacific is expected to rely increasingly on imported LNG rather than expanding its own liquefaction infrastructure. Latin America is projected to add around 29 Mtpa of new liquefaction capacity over the outlook period, led mainly by Argentina's Vaca Muerta development and Trinidad and Tobago's expansion plans. Meanwhile, Europe's liquefaction capacity remains broadly unchanged, reflecting the region's policy-driven transition away from domestic fossil-fuel production and its growing dependence on LNG imports rather than new export projects.

By the end of 2025, current GECF Member Countries had 242 Mtpa of LNG liquefaction capacity in operation and a further 93 Mtpa under construction. Together, they represented 47% of global existing liquefaction capacity. In addition, Member Countries currently hold 140 Mtpa of proposed pre-FID capacity. **Looking ahead, these additions are projected to lift total LNG liquefaction capacity across current GECF Members to around 481 Mtpa by 2055, equivalent to 48% of expected global liquefaction capacity.**

According to Rystad Energy, global speculative LNG liquefaction capacity, defined as capacity from proposed but unsanctioned projects whose realization remains uncertain, stood at around 880 Mtpa at the end of 2025, highlighting the massive volume of potential new supply still under consideration with potential to come online by 2055. North America accounted for 61% of this capacity, followed by Eurasia with 17%. North America's dominant share reflects its unique combination of abundant low-cost gas resources, established liquefaction hubs, strong pipeline infrastructure, and advantageous access to both Atlantic and Pacific markets. In contrast, Eurasia's

Figure 6.12

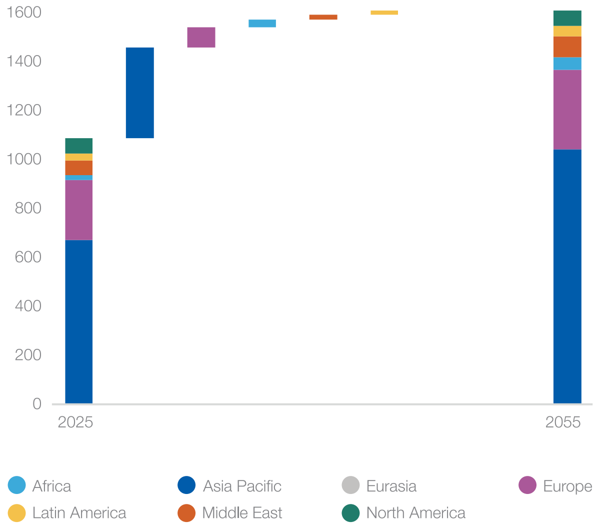
Projected global LNG exports and liquefaction capacity by project status, 2024–2055 (Mtpa)



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

Figure 6.13

Global LNG regasification capacity outlook by region, 2025-2055 (Mtpa)



Source: GECF Secretariat based on data from the GECF GGM

sizeable speculative capacity is largely driven by Russia's vast resource base and strategic push to expand LNG exports, although its realisation remains significantly more uncertain due to short-to-medium term constraints affecting project execution, financing, and shipping availability.

Over the longer term, an increasing mismatch is expected to emerge between projected global LNG export volumes and currently committed liquefaction capacity. Figure 6.12 shows that **forecast LNG exports approach the combined capacity of existing and under-construction facilities by 2035 and surpass it from 2040 onward, implying that a timely conversion of part of the currently proposed pre-FID portfolio into sanctioned capacity will be essential to maintain sufficient liquefaction availability for future export flows.** This requirement is reinforced by the structural characteristics of LNG projects, notably their high upfront capital requirements, long lead times to commissioning, and exposure to execution risks. The issue becomes more acute in the context of an anticipated medium-term LNG overhang, which could depress prices and discourage upstream and midstream investment precisely at the stage when additional capacity needs to be approved. In the absence of timely sanctioning, the global LNG market could face a significantly tighter supply-demand balance later in the outlook, as export growth increasingly exceeds committed liquefaction capacity and erodes the buffer needed for system flexibility and supply security.

6.4.2 LNG regasification

Global regasification capacity, including existing, under-construction and proposed facilities, is set to rise from around 1,084 Mtpa in 2025 to around 1,604 Mtpa by 2055, driven primarily by Asia Pacific, which adds the majority of new capacity and is anticipated to reach around 1037 Mtpa by 2055. Europe expands more moderately, increasing to just about 326 Mtpa, while Africa, Latin America and the Middle East register smaller but steady additions. North America and Eurasia show virtually no growth, reflecting their exporter-oriented market structures. Overall, regasification growth becomes increasingly upfronted before 2035 and Asia-centred, with Europe remaining the secondary hub and other regions contributing selectively (Figure 6.13).

Asia Pacific continues to dominate global regasification expansion, accounting for the largest share of new capacity additions by 2025. China led this growth with four new terminals and one expansion, followed by India's new West Coast terminal. Emerging markets, including Hong Kong, Viet Nam, and the Philippines, continued to rely on FSRUs to rapidly establish LNG import capabilities. Looking ahead to 2055, Asia Pacific is expected to drive around 70% of all new regasification capacity, underpinned by rising LNG demand in China, India, Southeast Asia, and other fast-growing economies. Between 2024 and 2029 alone, about 68% of all capacity under construction or in commissioning will be located within the region, reinforcing Asia Pacific's strategic shift toward diversified and secure LNG supply pathways.

Europe remains the second-largest driver of global regasification growth, reflecting its policy-led pivot toward LNG to diversify away from pipeline gas. In 2025, Europe added multiple new FSRUs and expanded existing terminal capacity, with Germany leading through the commissioning of three new units, followed by additional terminals in France, Finland, Italy, Türkiye, Belgium, and Spain. Over the long term, Europe is projected to contribute 17% of global regasification capacity growth through 2055, with most additions concentrated before 2030 as countries seek to strengthen energy security and build strategic redundancy into their import systems. By 2029, Europe accounts for 15% of global capacity under construction, highlighting the region's continued emphasis on import diversification and supply resilience.

Outside Asia Pacific and Europe, regasification capacity growth remains more limited and targeted. Africa, Latin America and the Middle East collectively contribute only a small share of long-term capacity additions, reflecting their focus on domestic gas production and exports rather than large-scale LNG import infrastructure. Nonetheless, specific markets such as Brazil, South Africa, Bahrain, and Kuwait are investing in new terminals to meet rising electricity demand and enhance system flexibility. Meanwhile, North America and Eurasia are not expected to see significant regasification expansion through 2055. North America remains an LNG export powerhouse with minimal need for import infrastructure, while Eurasia continues to prioritise LNG production and export development rather than expanding receiving capacity. Together, these trends highlight an increasingly region-differentiated LNG landscape, with Asia Pacific and Europe driving global regasification growth and other regions expanding only where required by domestic energy needs.

According to Rystad Energy, speculative regasification capacity stood at 159 Mtpa at the end of 2025, highlighting the substantial volume of potential uncertain import infrastructure that remains at a pre-investment stage. This capacity is heavily concentrated in Asia Pacific, which accounts for around two-thirds of the global total, reflecting the region's central role in prospective LNG demand growth over the long term. The prominence of Asia Pacific in speculative regasification capacity is consistent with the region's expanding energy requirements, continued urbanisation and industrialisation, and the expected rise in LNG use to support power generation, industrial demand, and broader fuel diversification strategies. Within the region, India represents the largest share of speculative regasification potential, followed by China, Thailand, and Viet Nam.

6.5 Natural gas trade outlook by region

6.5.1 Africa

Natural gas represents a vital yet largely untapped opportunity for driving Africa's long-term energy and economic development. Beyond its domestic value in supporting power generation and industrialisation, natural gas, particularly through expanded and sustained LNG exports, offers a strategic pathway for mobilising revenue, attracting investment, and financing infrastructure across the continent, especially in Sub-Saharan Africa.

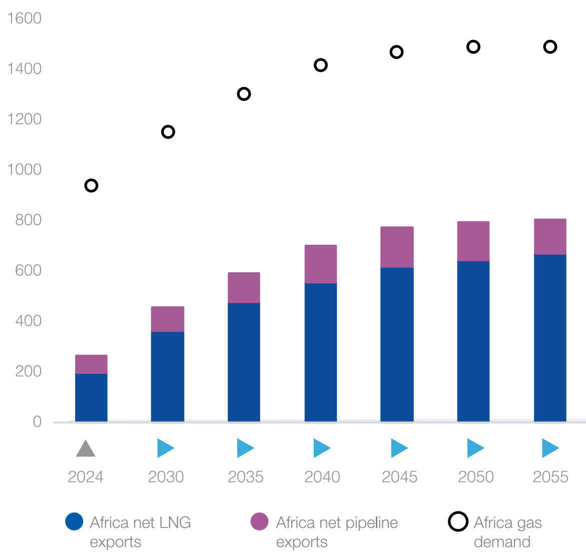
Africa's natural gas potential is vast, supported by major exploration successes across both mature and frontier basins. In 2024, Africa's natural gas production reached roughly 244 bcm, with net exports amounting to 68 bcm for the year. Most exports came from GECF Member Countries, including Algeria, Angola, Egypt, Equatorial Guinea, Mozambique, and Nigeria. Despite holding massive recoverable reserves, particularly in Mozambique's Rovuma Basin and in Nigeria's Niger Delta, much of this resource base remains undeveloped, highlighting Africa's untapped opportunity for growth.

By 2030, Africa remains a net exporter of natural gas, with a regional surplus of about 67 bcm. Algeria and Nigeria continue to lead the continent's exports, contributing around 43 bcm and 21 bcm respectively, while Mozambique emerges as a new growth driver with roughly 20 bcm of exports supported by its expanding LNG projects. On the import side, Egypt becomes Africa's largest gas importer, relying increasingly on pipeline inflows and LNG supplies to meet rising domestic demand. South Africa and Tunisia also record moderate import growth, reflecting the growing role of gas in their power generation and industrial sectors.

Looking ahead, Africa's net export balance strengthens as new LNG capacity comes online, particularly across Sub-Saharan regions. Net exports are projected to rise to about 100 bcm by 2040, 115 bcm by 2050, and 119 bcm by 2055 (Figure 6.14). Mozambique is poised to become the region's leading LNG exporter

Figure 6.14

Africa natural gas demand and net exports outlook by flow type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM
Note: Regional LNG exports and imports include intraregional trade

by 2030, emerging as a major continental hub with exports nearing 80 bcm by mid-century. At the same time, aggregate gas imports are expected to exceed 60 bcm by 2055, led mainly by Egypt and South Africa, as domestic consumption expands and energy diversification accelerates.

In 2024, Africa remained a net exporter of pipeline natural gas, with total regional exports of about 41 bcm against a demand of 19 bcm, resulting in a net export balance of 21 bcm. The continent's pipeline trade is heavily concentrated in North Africa, particularly Algeria and Libya, which together account for nearly all the exported volumes to Europe through long-established infrastructure. Algeria alone exported about 34 bcm, maintaining its position as the leading African pipeline gas supplier, Libya contributed an additional 1.4 bcm of exports, primarily through the Greenstream pipeline to Italy. On the import side, Egypt, South Africa, and Tunisia stood out as the main pipeline gas importers. Egypt imported roughly 10 bcm, largely to meet growing domestic demand and balancing needs, while Tunisia and South Africa imported smaller volumes.

Europe and North Africa share a deep-rooted history of gas cooperation, built on geographic proximity and decades of shared infrastructure. Since the 1970s, Algeria, Libya, and Egypt have been key suppliers of natural gas to Europe through pipelines such as TransMed, Medgaz, and GreenStream, complemented by LNG exports from Algeria and Egypt. As Europe accelerates its decarbonisation agenda, this traditional energy linkage is undergoing a transformation. While LNG trade from Africa to Europe is expected to expand, pipeline gas growth will remain limited due to capacity constraints and rising domestic demand in North Africa.

In 2024, African gas played a vital role in stabilizing EU supply, driven mainly by exports from Algeria and other North African countries, which together accounted for 18% of the EU's total LNG imports. Algeria's pipeline deliveries to Italy fell to a four-year low of about 21 bcm via the TransMed pipeline, while exports to Spain reached a record 9.1 bcm through Medgaz. Despite this strong performance, the long-term growth of African gas exports to Europe remains constrained by limited infrastructure capacity and rising domestic demand across producing countries.

Africa's pipeline gas exports are forecast to gradually decline from around 32 bcm in 2030 to about 21 bcm by 2040, stabilising near 16 bcm by 2050-2055 as production from mature North African fields tapers off. Algeria and Libya will continue to anchor export volumes, mainly supplying Europe, while pipeline imports are expected to rise from 16 bcm in 2030 to around 24 bcm by 2050, driven by increasing domestic demand in Egypt, Ghana, and Tunisia. This marks a structural shift from Africa's historical role as a net exporter toward a more balanced regional gas market.

Beyond the current outlook, Africa holds significant infrastructure potential that could transform regional gas dynamics. Despite today's limited network, comprising the Algeria, Tunisia link, the West African Gas Pipeline (WAGP), and the Mozambique-South Africa pipeline (ROMPCO), future projects could expand cross-border trade and improve energy security. Proposed developments such as the Nigeria-Morocco pipeline, Trans-Saharan Gas Pipeline, and extensions of southern and eastern African corridors could deepen intra-African integration, diversify supply routes, and accelerate the continent's transition toward a more connected and resilient gas infrastructure system.

In 2024, Africa accounted for roughly 9% of global LNG trade, exporting about 38 Mt, with 17.9 Mt sent to Europe and 16.9 Mt to Asia Pacific markets, highlighting the continent's growing role as a flexible supplier linking Atlantic and Pacific demand. That year also marked the entry of new African LNG exporters: the Republic of the Congo shipped its first cargo from the Congo LNG/ Marine XII offshore project, while Senegal and Mauritania commenced production at the Greater Tortue Ahmeyim (GTA) LNG project, which loaded its first LNG cargo in early 2025. On the import side, Africa received a modest 3 Mt of LNG, mainly by Egypt and Mauritania. Egypt remained the continent's principal LNG importer, bringing in cargoes primarily to offset seasonal domestic gas shortages.

Africa's share of global LNG supply is set to rise steadily, increasing from 9% in 2024 to 14% by 2050-2055, driven by expanding production in Mozambique, Tanzania, Senegal Mauritania, Nigeria, and Angola, supported by sustained output from Algeria, Angola and Equatorial Guinea.

By 2030, Africa will reinforce its role as a major LNG exporter, with net exports of about 37 Mt driven by rising output from Nigeria and Mozambique, which together will account for over half of the continent's supply, alongside new contributions from Mauritania and Senegal. By 2040, Africa's net LNG exports are set to reach around 70 Mt, driven by rising production from Mozambique and new Eastern African projects, with Mozambique alone accounting for nearly 40% of total Africa's LNG supply. By 2050-2055, Africa's net LNG exports reach 89 Mt, Mozambique is expected to solidify its position as the continent's leading LNG powerhouse, accounting for almost half of Africa's exports producing around 58 Mt annually, while Tanzania in Eastern Africa and Senegal and Mauritania in Western Africa emerge as important complementary export hubs.

Meanwhile, South Africa is projected to lead Africa's rising LNG import demand, with total imports across the continent reaching nearly 31 Mt by 2055 as gas use in power generation and industry expands. This trajectory underscores Africa's dual role as a global LNG powerhouse and an emerging integrated regional gas market, balancing export growth with increasing domestic consumption and enhanced cross-border energy links.

In 2024, Europe was the primary destination for Africa's LNG exports, receiving 18 Mt, nearly half of total volumes, followed closely by Asia Pacific with 17 Mt. This pattern, however, is expected to evolve considerably. Africa's LNG exports to Asia Pacific are projected to rise sharply, reaching 65 Mt by 2040 and peaking at around 79 Mt before slightly easing by 2055, reflecting the region's growing gas demand and continued investments in import capacity. In contrast, exports to Europe are set to decline from 18 Mt in 2024 to around 14-15 Mt by mid-century, as Europe's gas consumption moderates amid decarbonisation and diversification away from hydrocarbons (Figure 6.15).

At the same time, intra-African LNG trade is emerging as a new growth area. From negligible volumes in 2024, it is expected to increase to about 19 Mt by 2040 and grow by one and half times to 28 Mt by 2055, signalling deeper regional integration and expanding regasification infrastructure across the continent. Overall, Africa's LNG trade structure is poised for a strategic realignment, shifting its focus from Europe toward Asia and intra-continental markets, in line with evolving global demand centres and regional energy transitions.

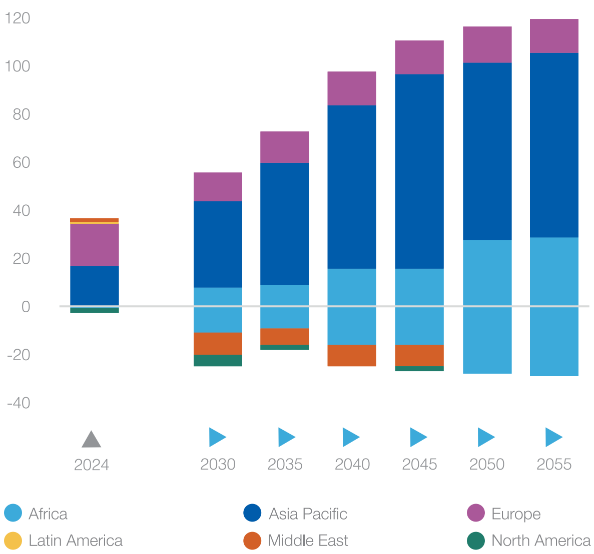
By the end of 2025, Africa's LNG liquefaction capacity reached approximately 81 Mtpa (Figure 6.16), with volumes distributed across Algeria, Angola, Cameroon, Congo (Brazzaville), Egypt, Equatorial Guinea, Mozambique, Mauritania, Nigeria, and Senegal. Algeria and Nigeria remained the continent's key LNG producers.

Africa has become one of the world's key regions for floating LNG (FLNG) developments, enabling countries to monetize offshore gas fields quickly while avoiding the high costs and long construction timelines associated with onshore liquefaction terminals. This technology has proven particularly valuable for nations with deep-water resources or limited domestic infrastructure. As of 2025, Africa hosts four major FLNG projects with a combined liquefaction capacity of nearly 9 Mtpa, underscoring the continent's growing strength in offshore LNG development. Cameroon's Hilli Episeyo FLNG, operated by Perenco, established Africa's first floating liquefaction capability with 2.4 Mtpa, while Mozambique's Coral South FLNG, operated by Eni, contributes a substantial 3.4 Mtpa as the region's largest FLNG unit. Congo (Brazzaville) became a new LNG exporter in 2024 with the start-up of the 0.6 Mtpa Tango FLNG and is poised to expand its offshore output to 3 Mtpa once the 2.4 Mtpa Nguya FLNG is commissioned by the end of 2025. Early 2025 also saw the launch of the 2.5 Mtpa Greater Tortue Ahmeyim FLNG Train 1, jointly developed by Senegal and Mauritania, further strengthening West Africa's emerging role in global LNG supply.

Africa is advancing a significant portfolio of LNG projects under development, with 24 Mtpa of new liquefaction capacity currently under construction across both floating and onshore facilities. A major milestone in this expansion was the FID taken in 2025 for Eni's Coral North FLNG, a 3.4 Mtpa floating unit in Mozambique that will become the second FLNG facility in the Rovuma Basin when it starts up in 2028. Other projects progressing include the 2.4 Mtpa Congo Marine XII FLNG 2, scheduled for 2026 and set to further boost Congo (Brazzaville)'s offshore LNG output, and

Figure 6.15

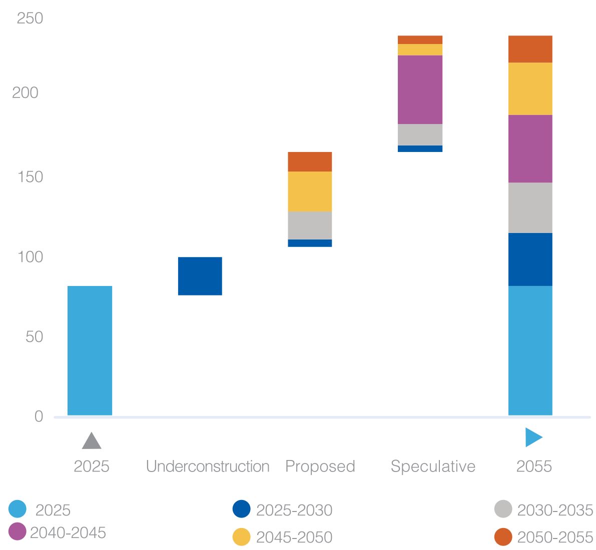
Africa LNG exports (+) by destination and imports (-) by origin outlook, 2024-2055 (Mt)



Source: GECF Secretariat based on data from the GECF GGM

Figure 6.16

Africa LNG liquefaction capacity outlook, 2025-2055 (Mtpa)



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

Chapter 6

Perenco's 0.7 Mtpa Gabon LNG, expected online in 2027 and poised to make Gabon a new LNG exporter. TotalEnergies is also advancing two large-scale onshore trains, Mozambique LNG Area 1 Trains 1 and 2, each with 6.44 Mtpa of capacity and targeting start-up in 2029, representing the country's most substantial long-term LNG investment. Additionally, NLNG Train 7 in Nigeria, an 8 Mtpa onshore expansion planned for 2027, will reinforce Nigeria's position as Africa's largest LNG supplier.

Africa's LNG liquefaction capacity, excluding speculative projects, is expected to expand significantly, rising to around 164 Mtpa by 2055, more than double its current level. Capacity growth is projected to be led by major developments in Congo (Brazzaville), Mauritania and Senegal, Mozambique, and Nigeria, underscoring Africa's increasing weight in the global LNG supply portfolio. In addition, proposed pre-FID projects contribute approximately 59 Mtpa of further potential capacity, predominantly in Mozambique, with smaller contributions from Mauritania and Senegal. This suggests that a meaningful share of Africa's future LNG growth remains contingent on the timely sanctioning of planned projects. Beyond this, Rystad Energy identifies around 72 Mtpa of speculative liquefaction capacity in Africa, primarily in Nigeria and Tanzania, pointing to considerable longer-term upside potential. Overall, the continent's LNG outlook reflects a combination of expanding committed capacity and a sizeable pipeline of future opportunities, supported by abundant gas resources but still subject to investment, execution, and market-related uncertainties.

As illustrated in Figure 6.17, the long-term African LNG outlook points to an increasing structural imbalance between projected export requirements and available liquefaction capacity. Forecast LNG exports are expected to converge with the aggregate capacity of existing and under-construction facilities by 2035 and to move beyond committed capacity from 2040 onward, implying a progressive tightening in liquefaction availability. This indicates that the projected expansion in African LNG exports is increasingly contingent on new project sanctioning, as the current base of committed capacity will not be sufficient to accommodate the expected growth trajectory over the longer term. Accordingly, the timely maturation of part of the current pre-FID portfolio into operational liquefaction capacity will be essential to preserve adequate export headroom. In this respect, the figure highlights a clear sequencing challenge: because LNG projects are characterized by high upfront capital requirements and extended lead times to commissioning, investment decisions will need to be taken sufficiently in advance to avoid a structural capacity bottleneck later in the outlook.

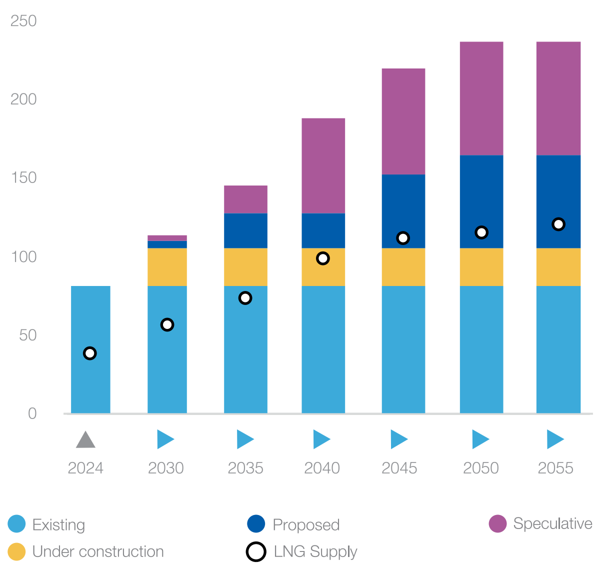
LNG developers in Africa face a range of country-specific challenges, including security risks, infrastructure gaps, regulatory hurdles, and financing constraints. To fully unlock the continent's LNG potential, timely execution and accelerated project delivery will be essential, particularly as competition strengthens from established exporters with stable infrastructure and clear regulatory frameworks. In Mozambique, large-scale onshore developments such as TotalEnergies' Mozambique LNG and ExxonMobil's Rovuma LNG are central to this effort, offering the potential to transform East Africa into a major LNG hub once operations resume. In the near term, Africa can further enhance exports by maximising the utilisation of existing facilities and expanding the use of floating LNG (FLNG) solutions, provided that feed-gas supply and security conditions remain stable.

As of 2025, **Algeria** continues to play a pivotal role in Europe's natural gas supply, having delivered around 50 bcm through both pipelines and LNG in 2024. Pipeline flows, primarily via Medgaz to Spain and TransMed to Italy, accounted in this year for roughly 34 bcm, while LNG exports contribute the equivalent of 11.6 Mt annually, supported by Algeria's 25.3 Mtpa liquefaction capacity at Arzew, Bethioua and Skikda. While export volumes have faced slight declines, Algeria's strategic value, particularly for Southern Europe, remains high, thanks to its established infrastructure, flexibility between pipeline and LNG delivery, and proximity to the key European market. Algeria is expected to remain a significant natural gas supplier to Europe through both pipelines and LNG exports until 2055, with gross gas exports of about 16-17 bcm.

Angola's LNG exports reached around 3.7 Mt in 2024, marking a notable shift in trade patterns as most volumes were redirected toward Asian markets. Europe's

Figure 6.17

Projected Africa's LNG exports and liquefaction capacity by project status, 2024–2055 (Mtpa)



Source: GECF Secretariat based on data from the GECF GGM and Rystad Energy share dropped sharply to 27%, compared with 84% in 2023, reflecting tighter European demand, improved Asian spot pricing, and more competitive Atlantic Basin flows. Angola LNG continues to operate its 5.2 Mtpa single-train plant, which is fed by associated gas from the Kizomba A and B and Saxi/Batuque fields. While no new liquefaction expansions are planned in the near term, ongoing upstream optimisation and stable associated-gas output are expected to support long-term exports of around 5 Mtpa through 2055, reinforcing Angola's steady, though modest, role in global LNG supply.

Egypt is positioning itself as a strategic natural gas hub at the crossroads of Africa, the Middle East, and Europe, underpinned by its infrastructure, geographic advantage. Egypt is undergoing a notable shift in its natural gas balance, transitioning from exporter to a seasonal importer as domestic production declines and power demand intensifies.

In 2024, the country exported only 0.8 Mt of LNG while importing about 2.5 Mt, reflecting tighter upstream supply and rising summer electricity requirements that reduced utilisation at the Idku and Damietta liquefaction plants. This prompted Egypt to resume LNG imports in late 2024 and continue into 2025 to stabilise the grid, marking a structural adjustment in which the country relies on imported LNG during peak demand while still exporting when conditions allow. Egypt has deployed a large fleet of FSRUs at Ain Sokhna and Damietta, giving it around 18.4 Mtpa of active regas capacity and another 7.4 Mtpa under development. This brings total potential capacity to about 25.8 Mtpa, though such volumes are typically needed only during 4-5 peak summer months. The fleet includes units from Höegh, Energos and BOTAS, with additional vessels like Höegh Gandria and Energos Force enhancing seasonal flexibility.

Cyprus and Egypt strengthened their gas-cooperation framework in 2023-2024 and continued advancing it in 2025, confirming plans to route Cypriot offshore gas, initially from Aphrodite and later Cronos, via pipeline to Egypt for liquefaction at Idku and Damietta and subsequent re-export. Although commercial volumes have not been disclosed, both sides reiterated in 2025 that the partnership will ensure steady multi-year flows and reinforce Egypt's position as the Eastern Mediterranean's LNG hub. Looking ahead, Egypt is expected to maintain a combined import-export model, with LNG exports stabilising at around 5-6 Mt annually through mid-century.

Over the long term, Egypt is expected to remain a net gas exporter, with net imports projected to reach 23–25 bcm by 2050-2055, up from around 12 bcm today. Its overall gas balance will continue to be supported by steady and gradually increasing regional pipeline inflows, which will enhance supply security for the domestic market and help sustain stable operations at its LNG liquefaction plants.

Equatorial Guinea directs most of its gas output to LNG exports through the 3.7 Mtpa EG LNG plant on Bioko Island, in operation since 2007. In 2024, the country exported around 3.1 Mt of LNG, more than 80% of which was shipped to Asia Pacific markets, and it is expected to maintain exports of roughly 2.2 Mt annually through 2055. In 2025, Equatorial Guinea made significant progress toward becoming a regional LNG hub by advancing the Gas Mega Hub (GMH) initiative, supported by new agreements with Marathon Oil and Chevron's Noble Energy E.G. Ltd on the Aseng Gas Project, as well as additional upstream cooperation with ConocoPhillips. The GMH, situated north of Bioko Island near the maritime borders with Cameroon and Nigeria, aims to integrate regional gas resources and consolidate the country's strategic role in West Africa's LNG value chain.

Mauritania and **Senegal** are emerging as new LNG producers in West Africa, led by the Greater Tortue Ahmeyim (GTA) project operated by BP and Kosmos Energy. The first FLNG unit, with a capacity of 2.5 Mtpa, entered commercial service in early 2025 under a long-term 20-year offtake agreement with BP. Work is progressing on GTA Phase 2, which is expected to lift total output toward 5 Mtpa in early 2030s, with longer-term expansion potential reaching up to 10 Mtpa as additional offshore reserves are developed.

Beyond GTA, both countries are assessing two major deep-water LNG developments - Yakaar-Teranga in Senegal and Bir Allah in Mauritania - each initially designed for up to 10 Mtpa and potentially coming online between 2030 and 2040. Combined, these projects could raise Mauritania-Senegal LNG capacity to roughly 30 Mtpa by 2050. Current projections indicate that LNG output from the two countries will grow steadily, reaching around 2 Mt by 2030, about 8 Mt by 2040, and approximately 15 Mt by 2055, firmly positioning the region as an emerging West African LNG hub.

Mozambique is set to become Africa's largest LNG producer from the mid-2030s onward, underpinned by the vast offshore reserves in Areas 1 and 4 of the Rovuma Basin. The country entered the global LNG market in 2022 with first exports from the 3.4 Mtpa Coral South FLNG - and in 2024 Mozambique exported 3.4 Mt of LNG, reflecting full utilisation of this initial floating unit. Momentum accelerated in 2025 with the final investment decision for Coral Norte FLNG (3.55 Mtpa), scheduled to start production in 2028. The Mozambique LNG project led by TotalEnergies (12.9 Mtpa, expandable above 40 Mtpa) has lifted force majeure and already restarted construction early 2026, with first LNG expected around 2029. Meanwhile, ExxonMobil's Rovuma LNG project (18 Mtpa) is advancing more slowly, with FID expected in 2026 and potential start-up in the early 2030s. Altogether, these developments position Mozambique for one of the world's largest LNG capacity expansions over the next two decades.

Long-term projections indicate that Mozambique's LNG output will rise steeply from 3.4 Mt in 2024 to around 15 Mt by 2030, 29 Mt by 2035, 39 Mt by 2040, and more than 50 Mt by 2045. Output is expected to reach roughly 54 Mt by 2050, increasing further to 58 Mt by 2055, firmly establishing Mozambique as a leading global LNG exporter. By 2040, Mozambique's LNG capacity is expected to reach around 40 Mtpa, supported by Coral North FLNG, both Mozambique LNG (Area 1) trains, and the first two Rovuma LNG (Area 4) trains. By 2050-2055, total capacity rises to about 60 Mtpa, solidifying the country's position as one of the fastest-growing LNG exporters globally.

Nigeria's LNG industry continues to expand around the long-established Bonny Island complex, which exported 13.8 Mt of LNG in 2024 from its 22.3 Mtpa NLNG plant. Medium-term growth will be anchored by NLNG Train 7, which will add about 8 Mtpa of new capacity and is expected online by 2027, lifting total nameplate capacity close to 30 Mtpa. Additional upside comes from UTM Offshore's 2.8 Mtpa FLNG project, planned offshore OML 104, with an FID targeted for 2026 and first LNG anticipated in 2029. These projects form the core of Nigeria's strategy to expand gas monetisation, curb flaring, and strengthen LNG exports, which are projected to rise to around 18 Mt by 2035 before gradually decline to 12-13 Mt by 2050-2055 as growing domestic gas demand - driven by population growth, industrial expansion, and rising power needs, absorbs a larger share of available feedgas. Regionally, Nigeria also plays a role in West African gas integration through the West African Gas Pipeline (WAGP), which delivered roughly 1 bcm of Nigerian gas to Ghana in 2024, supporting power generation and enhancing supply security across Benin, Togo, and Ghana along the 680-km corridor.

South Africa imported 4.4 bcm of gas in 2024, entirely via pipeline from Mozambique, but plans to expand this to 17-19 bcm by 2050-2055 to support rising power demand, coal-to-gas switching, and its 2050 net-zero target. With the RAMCO pipeline expected to wind down around 2030 as supply declines, the country's future gas needs will be met almost entirely through LNG imports. To prepare, Southern Africa is advancing a new LNG import network, including Mozambique's Matola FSRU and several proposed South African terminals at Richards Bay, Ngqura, and Saldanha Bay, along with additional Zululand Energy projects slated for 2028-2030. These developments aim to strengthen regional energy security and support both gas-to-power and industrial growth. Richards Bay is the most advanced of these projects, with initial capacity of about 2.5 Mtpa and planned expansion to 5 Mtpa. The terminal is being developed by Vopak and Transnet Pipelines under a 25-year concession, with progress including land allocation, a signed Terminal Operator Agreement, and a two-phase buildout starting with an FSU-based system.

In **Tanzania**, the speculative USD 42 billion Lindi LNG export terminal, led by Equinor, Shell, and sourcing gas from offshore Blocks 1, 2, and 4, targets an eventual capacity of around 10 Mtpa. The project is advancing toward an FID expected in 2025-2026, with first production likely in the early 2030s, marking a major midterm LNG expansion for East Africa. Lindi LNG is a key mid-term expansion for East Africa, complementing Mozambique's projects and supporting regional gas exports. Eastern Africa's LNG exports are projected to grow from 0 Mt in the early 2020s to 13 Mt by 2040, before slightly adjusting to around 14 Mt in 2050-2055.

6.5.2 Asia Pacific

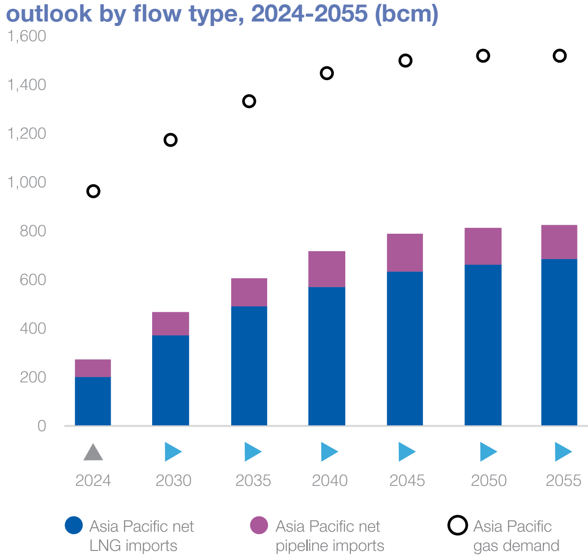
The Asia Pacific region is undergoing rapid economic growth, with energy demand expected to rise by 19% (17% CAGR) by 2055. **Natural gas demand in the region is projected to grow significantly, increasing by 58% (46% CAGR) to reach 1,517 bcm by 2055** (Figure 6.18). Natural gas consumption is projected to grow across all major sectors, with its share in the Asia Pacific energy mix rising from 11% in 2024 to over 15% by 2055.

Natural gas is poised to play an increasingly critical role in the energy and climate strategies of many Asian countries, supporting initiatives to improve air quality, reduce GHG emissions, and enhance the reliability and affordability of energy supplies. Key drivers of this growth include increased electrification and a broader coal-to-gas shift that now extends beyond power generation into major industrial sectors.

Asia Pacific is projected to account for almost 70% of global LNG imports by 2055. LNG imports in the region are forecast to more than double by mid-century, reaching approximately 781 bcm (566 Mt) by 2050 and climbing further to 802 bcm (582 Mt) by

Figure 6.18

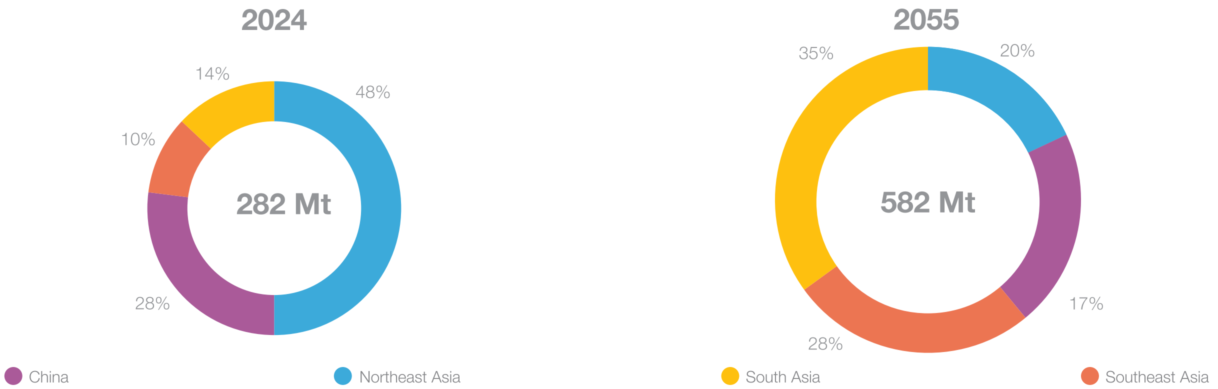
Asia Pacific natural gas demand and net imports outlook by flow type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 6.19

Asia Pacific's LNG imports market share by sub-region, 2024 and 2055 (%)



Source: GECF Secretariat based on data from the GECF GGM

2055. However, many countries face declining domestic production and infrastructure constraints, increasing reliance on LNG imports.

In 2024, the Asia Pacific LNG import market is heavily concentrated in Northeast Asia, which accounts for nearly half of total regional imports with 134 Mt out of 281 Mt (Figure 6.19). China followed with 79 Mt, representing 28%, while Southeast Asia and South Asia contribute 28 Mt (10%) and 41 Mt (14%), respectively. However, by 2055, the region is expected to undergo a significant transformation. South Asia's LNG imports growth almost fivefold, rising to 201 Mt, making it the largest sub-region with a 35% share. Southeast Asia's imports increase 5.7 times to 157 Mt (28%) by 2055. Meanwhile, Northeast Asia's imports decline only marginally to 113 Mt, but dropping significantly its share to 20% of the regional total. China's imports to over double to 169 Mt in 2035 but decrease to 99 Mt with respective declining share of 17%. Overall, Asia Pacific LNG imports are set to more than double from 282 Mt in 2024 to 582 Mt by 2055. This evolving pattern underscores the growing strategic importance of developing Asia in the future LNG trade landscape.

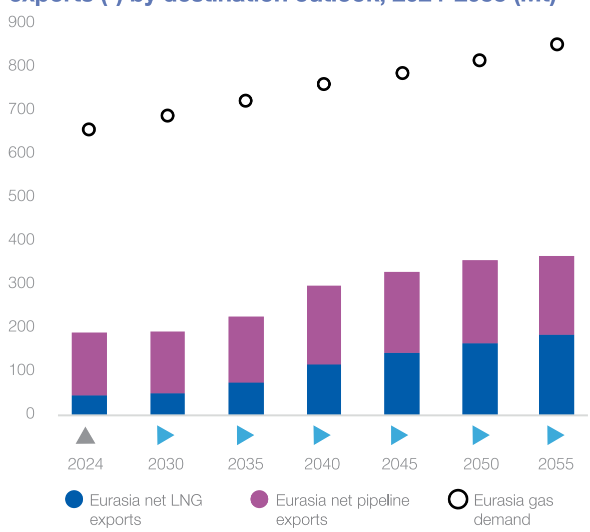
In 2024, Asia Pacific sourced most of its LNG from the Middle East (around 28% of supply), followed by North America at roughly 12%, Eurasia at 6%, and Africa at 4%, with the remainder coming from intra-regional trade. Over time, the region's LNG import profile becomes significantly more diversified. Imports from the Middle East are expected to increase steadily, reaching approximately 170 Mt by 2050 and remaining broadly at this level through 2055. North American LNG supplies to Asia Pacific are expected to increase sharply, climbing to about 145 Mt by 2050 and further to 150 Mt by 2055, solidifying the region's role as a key long-term supplier. Eurasian exports to Asia Pacific are forecast to reach around 92 Mt by 2050 and continue expanding modestly to 104 Mt by 2055. Africa's LNG deliveries, already on a strong upward trajectory, grow nearly sevenfold from 2024 levels, reaching about 73 Mt by 2040 and 72-75 Mt by 2050-2055 (Figure 6.20).

By contrast, intra-regional LNG trade within Asia Pacific is set to gradually decline from about 136 Mt in 2024 to 87 Mt by 2050 and taper further to around 84 Mt by 2055. Overall, this shifting trade landscape underscores the region's growing dependence on external LNG sources, particularly the Middle East, North America, Eurasia, and Africa, while internal Asia Pacific LNG exchanges steadily diminish over the outlook period.

In 2024, Asia Pacific's regasification capacity stood at 669 Mtpa, with almost 80% concentrated in JKT and China. JKT accounted for 56%, China 24%, and the remaining 20% was in South and Southeast Asia. Japan led with 209 Mtpa, followed by South Korea (144 Mtpa), China (161 Mtpa), and India (53 Mtpa). Over 230 Mtpa of new capacity was under construction in 2025, predominantly in China followed by India, Pakistan and Thailand (Figure 6.21).

Figure 6.20

Asia Pacific LNG imports (+) by origin and LNG exports (-) by destination outlook, 2024-2055 (Mt)

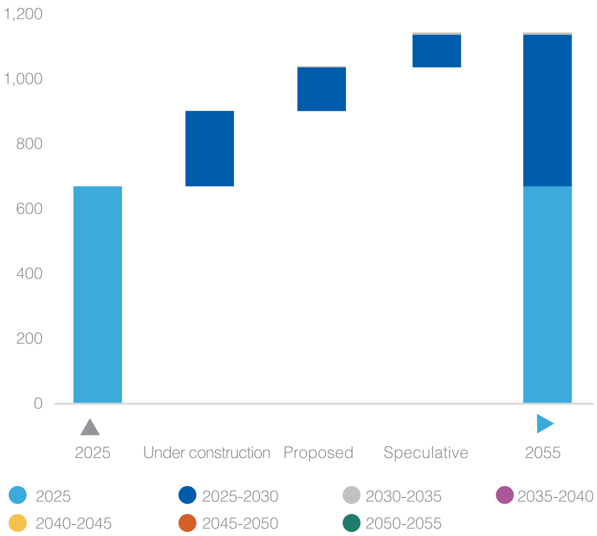


Source: GECF Secretariat based on data from the GECF GGM

Chapter 6

Figure 6.21

Asia Pacific LNG regasification capacity outlook, 2025-2055 (Mtpa)



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

Asia Pacific's LNG regasification outlook is characterized by a strongly front-loaded expansion profile. The region already held around 669 Mtpa of regasification capacity in 2025, confirming its position as the world's largest LNG import market. Most future additions are concentrated in the period to 2030, led primarily by 232 Mtpa of capacity currently under construction. This build-out is dominated by China, where continued coastal terminal expansion supports security of supply, seasonal balancing, and growing gas use across provinces. Additional capacity is also being developed through new FSRUs and onshore terminals in India, Viet Nam, the Philippines, and Thailand, reflecting rising power demand, efforts to reduce coal dependence, and the increasing role of LNG in supporting more flexible electricity systems.

Beyond the projects already under construction, a further 136 Mtpa of regasification capacity is proposed, bringing total identified additions to 368 Mtpa and accounting for around 70% of global LNG regasification capacity additions. Proposed capacity is heavily concentrated in China (41%), Southeast Asia (40%), and India (9%), together representing nearly 90% of all planned additions in the region. By contrast, capacity expansion beyond 2030 appears limited, with only marginal additional projects currently visible, notably Train 2 of the Hsieh-Ho LNG terminal in Chinese Taipei, expected to come on stream by 2032. This indicates that Asia Pacific's regasification expansion is heavily concentrated in the near term, while longer-term additions become progressively more limited and uncertain. In addition, Rystad Energy identifies 106 Mtpa of speculative regasification capacity in the region, predominantly in India, followed by Thailand and China, pointing to further upside potential should market conditions support additional investment.

By 2055, Asia Pacific's regasification capacity, excluding speculative facilities, is projected to reach 1,037 Mtpa, accompanied by a notable rebalancing in the regional distribution of import infrastructure. China is expected to account for 36% of total regional capacity, while South and Southeast Asia together represent around 27%. In contrast, the share of Japan, South Korea, and Chinese Taipei (JKT) declines to roughly 37%, reflecting both the rapid expansion of regasification infrastructure in emerging Asian markets and the gradual decommissioning of part of the capacity base in the more mature Northeast Asian importers.

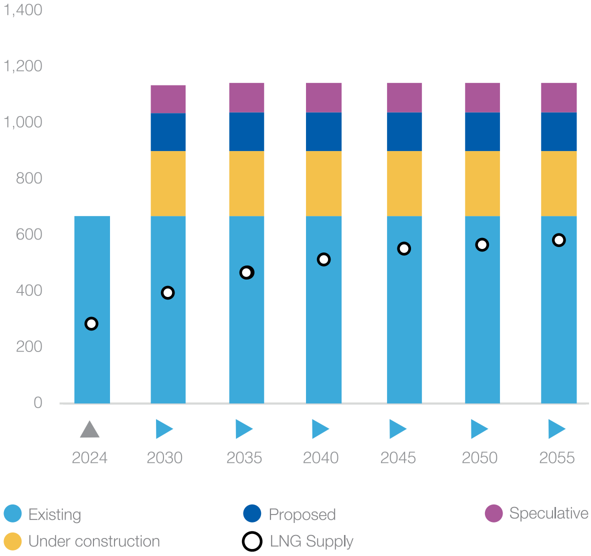
The above transformation in LNG infrastructure is matched by a sharp shift in LNG sourcing patterns. In 2024, nearly 60% of Asia Pacific's LNG imports originated from within the region, while around 20% came from the Middle East. By 2055, however, the Middle East, North America, and Eurasia are projected to provide more than 75% of regional LNG imports, while intra-regional supply falls to around 15–17% as domestic and regional production fail to keep pace with demand growth. Asia Pacific will therefore become increasingly dependent on extra-regional LNG suppliers, even as its regasification infrastructure continues to expand.

Within this broader regional shift, JKT remains strategically important, despite its declining share in total regasification capacity. Japan, South Korea, and Chinese Taipei continue to face a common challenge: advancing decarbonisation while preserving LNG as a key pillar of energy security. In Japan, LNG remains important alongside nuclear restarts; in South Korea, it continues to support a power system serving an industry-intensive economy; and in Chinese Taipei, it underpins the transition away from coal and nuclear generation. Although LNG demand in these markets is expected to plateau or gradually decline over time, LNG is likely to retain a critical balancing function in their power systems, particularly in managing renewable intermittency and ensuring grid stability through mid-century.

As illustrated in Figure 6.22, projected LNG import growth in Asia Pacific is expected to result in a gradual tightening of the region's regasification balance over the outlook period. Based on existing and under-construction infrastructure, average regasification capacity utilisation rises from around 42% in 2024 to approximately 65% by 2055. While this does not in itself imply an immediate capacity shortfall, it does indicate a progressive reduction in available import headroom over time. This is particularly relevant in the case of regasification, where capacity is not expected to operate at very high average utilisation rates, as sufficient spare

Figure 6.22

Projected Asia Pacific's LNG imports and regasification capacity by project status, 2024–2055 (Mtpa)



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

capacity is needed to accommodate seasonal demand fluctuations, peak import requirements, cargo bunching, supply diversification needs, and broader security-of-supply considerations. In this context, the projected increase in utilisation suggests that part of the current pre-FID proposed regasification capacity will likely need to be developed over time in order to preserve adequate flexibility and ensure the region's ability to absorb the required LNG imports over the longer term, particularly from the 2040s onward.

Japan continues to advance its 2050 decarbonisation target and strengthened 2030 emissions-reduction goals, with several policy updates in 2025 signalling a more structured long-term approach to LNG. While the government is accelerating nuclear restarts, expanding offshore wind, and tightening efficiency standards, the 2025 Strategic Energy Plan review reaffirmed that LNG is expected to remain an essential component of Japan's energy system for energy security and grid stability, especially during the transition period. The country also highlighted the need to avoid short-term volatility such as that experienced during the 2021-2022 price spikes and therefore encouraged utilities and trading companies to secure stable, long-term LNG contracts to reduce supply uncertainty, diversify procurement, and hedge against geopolitical risks.

Japan's LNG demand is set to decline steadily as nuclear restarts advance, energy efficiency improves, and overall energy consumption contracts, falling from 67 Mt in 2024 to around 47 Mt in 2050 and 43 Mt by 2055. Yet despite this downward trajectory, Japan will remain a major global importer due to its complete reliance on external gas supplies and the continued need for LNG to stabilise the power system and balance intermittent renewables. Even with declining volumes, Japan remains one of the world's most diversified LNG buyers, underpinned by 45 regasification terminals with a combined capacity exceeding 209 Mtpa. Natural gas will retain a transitional and reliability role, but Japan's stronger pro-nuclear stance, higher renewable ambitions, and 2025 policy adjustments will reinforce the long-term reduction in LNG use, even as maintaining long-term LNG contracts remains a key pillar of the country's energy security strategy.

South Korea depends heavily on imported energy, but unlike Japan its overall energy demand has continued to rise, supporting steady growth in LNG use over the past decade. In 2025, updates to the 10th Basic Energy Plan confirmed that LNG will remain important during the transition, helping to stabilise the power system as renewable capacity expands and nuclear output fluctuates. The government also highlighted the need for long-term LNG contracts to maintain supply security, reduce geopolitical risks, and avoid price volatility shocks. Looking ahead, South Korea's LNG demand is expected to decline slowly rather than sharply, falling from 47 Mt in 2024 to around 42 Mt in 2050 and 41 Mt by 2055. This gradual decrease reflects growing renewable generation, better efficiency, and a modest increase in nuclear power. Most LNG will continue to come from Qatar, Australia, Russia, and the United States. With 144 Mtpa of regasification capacity already in place and another up to 9 Mtpa under construction for completion by 2030, South Korea has ample infrastructure to manage seasonal peaks and system-balancing needs. Although LNG will play a smaller role in the long term, it will remain an essential reliability fuel supporting Korea's energy security and transition goals.

Chinese Taipei is undergoing a major shift in its power mix, with LNG positioned as the backbone of its electricity system as the government moves away from coal and phases down nuclear generation. Recent policy direction in 2025 reaffirmed gas-fired power as a core element of the island's energy-security strategy, aimed at supporting grid reliability while renewable capacity continues to expand. To underpin this transition, Chinese Taipei is strengthening its import and regasification capacity through ongoing terminal expansions and new facilities, ensuring that adequate supply can be secured through long-term contracting and diversified procurement.

Unlike Japan and South Korea, Chinese Taipei's LNG demand is expected to grow steadily rather than decline. Imports are expected to increase from 21 Mt in 2024 to around 28 Mt by 2050 and 29 Mt by 2055, reflecting the central role of natural gas in replacing coal and stabilising the system alongside rising shares of solar and wind. Chinese Taipei currently has 20 Mtpa (22-23 Mtpa effective send-out capability) of regasification

Chapter 6

capacity, set to increase to around 26 Mtpa once two ongoing projects are completed, with further growth expected as the island continues expanding its LNG infrastructure. While the island remains exposed to supply and geopolitical risks due to its limited domestic options, LNG will continue to serve as a critical reliability and transition fuel, supported by expanded regasification infrastructure and a stronger policy commitment to securing stable volumes over the long term.

China's natural gas demand continues to rise as the country deepens its shift toward cleaner energy, reduces coal reliance, and advances its dual-carbon goals of peaking emissions before 2030 and achieving carbon neutrality by 2060. While coal remains central to the energy mix, natural gas plays an increasingly important role in improving air quality, supporting industrial efficiency, and balancing the rapid growth of renewable energy. Domestic gas output has expanded substantially; however, production growth is becoming more challenging and costlier as unconventional resources take a larger share. Even with domestic output projected to reach around 335 bcm by 2040, supply will remain insufficient to fully meet demand. As a result, import dependence is expected to increase gradually toward 2035, before stabilising at approximately 45-50% of total gas demand over the longer term.

During the 13th Five-Year Plan (2016-2020), China promoted natural gas as a key tool for reducing urban air pollution and diversifying its energy mix. The plan set a target for gas to reach 10% of primary energy consumption by 2020 and 15% by 2030, driving large-scale coal-to-gas switching in northern cities and rapid expansion of pipelines, LNG terminals, and distribution networks. While these measures improved air quality and boosted gas use, they also revealed vulnerabilities: domestic output lagged, storage capacity was limited, and winter shortages in 2017 highlighted risks from rising import dependence and infrastructure gaps.

The 14th Five-Year Plan (2021-2025) reflects a strategic recalibration in response to these experiences. Instead of prioritising rapid demand growth, the emphasis has shifted to strengthening supply security, expanding domestic production, and improving system resilience. A production target of around 230 bcm by 2025 was established, alongside incentives for unconventional resources such as shale and coalbed methane, and a goal of 55-60 bcm of gas storage capacity. Market reforms were deepened with efforts to integrate pipelines under PipeChina and promote hub-based pricing. Importantly, the Plan moderates expectations for gas in power generation, positioning it not as a baseload substitute for coal but as a flexible backup for renewables and a cleaner option in residential and commercial heating. This evolution from the 13th to the 14th Plan illustrates a shift from rapid expansion to consolidation and security - anchoring gas as a transitional but limited fuel in China's broader pathway toward carbon neutrality.

Between 2024 and 2055, China's natural gas demand grows steadily, though at a slower pace after 2040 as efficiency gains, electrification, and stricter emissions frameworks temper consumption. LNG remains essential to meeting this demand. Imports are anticipated to rise from 79 Mt in 2024 to 136 Mt in 2030, reaching a peak of 169 Mt in 2035. Thereafter, LNG demand gradually declines in line with a maturing market, falling to 147 Mt in 2040, 128 Mt in 2045, 115 Mt in 2050, and 99 Mt by 2055, reflecting greater renewable penetration, improvements in gas-to-power efficiency, and slower industrial gas growth.

China is rapidly expanding its LNG regasification and storage infrastructure to support growing import needs and strengthen energy security. Significant investments in new coastal terminals, particularly along the eastern and southern seaboards, are enhancing supply flexibility. At the same time, the development of underground storage facilities is improving the country's ability to manage seasonal demand shifts and maintain resilience against potential supply disruptions or geopolitical risks.

China's LNG regasification capacity is projected to grow substantially from over 161 Mtpa in 2025 to 378 Mtpa by 2055, reflecting the country's continued commitment to expanding its gas infrastructure. The majority of this growth will occur before 2030, with over 161 Mtpa currently under construction and an additional 56 Mtpa in proposed projects for completion within the same period. This front-loaded expansion supports China's goal of strengthening supply security, improving coastal access to imported LNG, and transitioning to a cleaner energy mix amid declining coal use and rising urban gas demand. Beyond 2030, however, the LNG regasification projects pipeline thins significantly, with no new additions identified for the 2041-2055 period. This suggests that China's current focus is on consolidating infrastructure in the near term, while long-term capacity expansion may depend on evolving policy priorities, market liberalisation, and LNG demand trajectories.

To navigate a volatile market and manage their expanding LNG portfolios, Chinese companies are actively increasing their presence in key trading hubs like London and Singapore. This expansion involves both established players like ENN Natural Gas and state-owned giants like China National Offshore Oil Corp (CNOOC) growing their existing teams and expanding their trading desks, and new entrants like utility company China Gas Holdings setting up office in Singapore. China's companies are expected to transition from being primarily net importers to actively participating in both international and domestic trading markets. China is also might emerge as a seasonal supplier to markets such as Southeast Asia, South Korea, Japan, and even Europe. China's flexibility may stem from U.S. LNG contracts, which are free-on-board (FOB) with no destination restrictions, while Qatar, set to be China's largest supplier by 2026, provides traditional contracts limited to specific destinations.

Unlike many emerging Asian markets that rely almost entirely on LNG, China maintains a diversified import structure in which pipeline gas plays an increasingly important and strategic role. Pipeline supplies - primarily from Russia, is set to provide a stable, cost-effective alternative to LNG, particularly for inland provinces that lack access to coastal terminals. By 2055, the share of pipeline gas in China's overall supply is expected to rise from about 17% in 2024 to more than 20% by 2055, supported by substantial expansion of cross-border infrastructure. The planned Power of Siberia 2 pipeline (around 50 bcma) and the Far Eastern pipeline extension (12 bcma) will lift China's total pipeline import capacity to nearly 150 bcma over the long term. These developments underscore China's deepening energy partnership with Russia, anchored by new long-term supply agreements. As a result, pipeline imports are projected to reach around 130 bcm by 2055, bolstering China's energy security and reducing reliance on more volatile spot LNG markets.

With China's net gas imports projected to reach 337-338 bcm in 2035-2040, energy security remains a central strategic priority. Heavy reliance on external supplies exposes the country to price volatility, supply chain disruptions, and geopolitical uncertainty. To address these risks, China is expanding its LNG regasification network, domestic pipelines, and underground storage, while diversifying its supplier portfolio beyond Qatar, Australia, and Russia toward emerging exporters in the Middle East, Africa, and North America. Long-term LNG contracting remains a key tool to reduce exposure to spot-market volatility.

Affordability is a critical constraint shaping the trajectory of natural gas demand in China. Cost considerations dominate decision-making across all sectors. In power, high gas-to-coal price differentials limit the scope for wider deployment beyond flexibility roles. In the residential and commercial sector, continued expansion depends on the affordability of household tariffs and the sustainability of municipal subsidy schemes. In industry, competitiveness pressures make large-scale coal-to-gas switching implausible without substantial incentives.

Natural gas will remain important in China's transition as a cleaner alternative to coal and a flexible back-up to renewables. Gas-fired power generation is set to grow beyond today's levels, though its expansion will increasingly depend on fuel costs, renewable deployment, and tightening environmental policies. Overall, China's gas outlook will be shaped by the balance between energy security and decarbonisation goals, with LNG demand peaking in the mid-2030s before gradually declining toward 2055.

Southeast Asia is undergoing a major transition from a traditional gas-exporting region to a growing net importer, driven by rising energy demand and steadily declining domestic production. Rapid economic growth, industrialisation, and urbanisation, particularly in Viet Nam, Thailand, Indonesia, and the Philippines, are increasing natural gas needs, while maturing offshore fields in Indonesia, Malaysia, and Myanmar fail to keep pace. As a result, LNG is becoming the region's primary source of new supply.

Region's LNG demand is set to grow rapidly, rising from 28 Mt in 2024 to 44 Mt by 2030 as new regasification projects in Viet Nam and the Philippines come online. By 2040, demand nearly doubles to 97 Mt, driven by power-sector needs, industrial expansion, and higher cooling loads linked to climate change. The trend continues through mid-century, reaching 143 Mt in 2050 and 157 Mt by 2055, reflecting Southeast Asia's deepening dependence on seaborne LNG as domestic production declines and no major pipeline alternatives emerge. This trajectory positions the region as one of the fastest-growing LNG demand centres globally, with significant implications for energy security, import infrastructure, and long-term contracting strategies.

South Asia's LNG demand is set for strong long-term growth despite short-term challenges linked to price volatility and reliance on spot markets. In the near term, elevated LNG prices have weighed on imports in Pakistan and Bangladesh, but demand is expected to rebound after 2026 as global prices moderate and power-sector consumption recovers.

India remains the driving force behind South Asia's long-term LNG demand growth. As the country pursues its 2070 net-zero target, natural gas is increasingly promoted as a transition fuel for industry, transport, city-gas networks, and cleaner power generation. This policy direction supports a sharp rise in LNG imports, which increase from 27 Mt in 2024 to 50 Mt by 2030, 58 Mt by 2035, and 83 Mt by 2040. Demand continues to strengthen through mid-century, reaching 98 Mt in 2045, 110 Mt in 2050, and 120 Mt by 2055, reflecting growing energy needs, urbanisation, and declining domestic gas production.

To accommodate this growth, India is set to expand its regasification and pipeline infrastructure significantly, with new terminals planned across both the western and eastern coasts and major upgrades to storage and transmission networks. These developments will be essential in meeting rising consumption and reducing the country's exposure to spot-market volatility.

Pakistan and Bangladesh also contribute to the region's rising LNG demand, driven by growing electricity needs, urbanisation, and tightening air-quality requirements. With limited domestic supply options, LNG increasingly becomes the most reliable and scalable source of gas for both countries' power and industrial sectors. As a result, South Asia emerges as one of the world's fastest-growing LNG demand centres, requiring substantial investment in regasification, pipelines, and storage infrastructure to support rising imports through mid-century.

Australia remains one of the world's major LNG exporters, supported by a mature liquefaction industry and decades of investment. LNG exports reached 79 Mt in 2024 but are projected to decline gradually as offshore fields mature and fewer greenfield projects proceed. Export volumes fall to 73 Mt by 2030, 66 Mt in the mid-2030s, and decline further to 64 Mt by 2045, and 59 Mt by 2055. This trend reflects rising development costs, slowing upstream productivity, and limited new project approvals.

A tightening policy landscape is accelerating this shift. Australia's Safeguard Mechanism and its strengthened emissions-reduction requirements, the Net Zero 2050 strategy, stricter environmental assessments, and methane regulations in Western Australia and Queensland all constrain upstream growth and increase compliance costs. At the same time, domestic supply protection measures such as the ADGSM and state-level reservation policies may further restrict gas available for export. While Australia will remain a key LNG supplier supported by existing assets and targeted backfill projects, the cumulative impact of regulatory tightening and declining resource quality points to a long-term plateau and gradual decline in LNG exports toward 2055.

6.5.3 Eurasia

Eurasia remains one of the world's major gas-exporting regions, anchored by large producers such as Russia, Turkmenistan, Azerbaijan, and Kazakhstan. The region's gas trade continues to be dominated by pipeline exports, reflecting an extensive legacy network that has long connected Eurasian suppliers to markets in both Europe and Asia. Russia remains the largest pipeline exporter, and although geopolitical shifts have reduced westbound deliveries, eastbound flows - particularly to China - have grown in strategic importance. This trend is reinforced by the Central Asia-China pipeline system and planned expansions that will further integrate Central Asian and Russian gas into Asian markets.

At the same time, Eurasia's LNG export capacity is expanding, driven primarily by Russia's growing liquefaction portfolio. Projects such as Yamal LNG and new Arctic LNG capacity provide the region with greater market reach and flexibility, allowing cargoes to be redirected toward Asia and other premium markets. As a result, net LNG exports are projected to increase rapidly in the coming decades, complementing traditional pipeline routes and reducing reliance on fixed regional corridors. Overall, Eurasia's gas trade is undergoing a gradual rebalancing: while long-distance pipeline infrastructure remains the backbone of export flows, LNG is emerging as a crucial flexibility mechanism that enables the region, especially Russia, to adapt to evolving global demand patterns and geopolitical realignment.

Eurasia's natural gas sector is set to expand steadily over the long term, with regional demand rising from 665 bcm in 2024 to 863 bcm by 2055. Export capacity also increases, supported by growth in both LNG and pipeline infrastructure. Net LNG exports are projected to more than triple - from 46 bcm in 2024 to 187 bcm in 2055 - reflecting new liquefaction projects and diversification toward Asian markets (Figure 6.23).

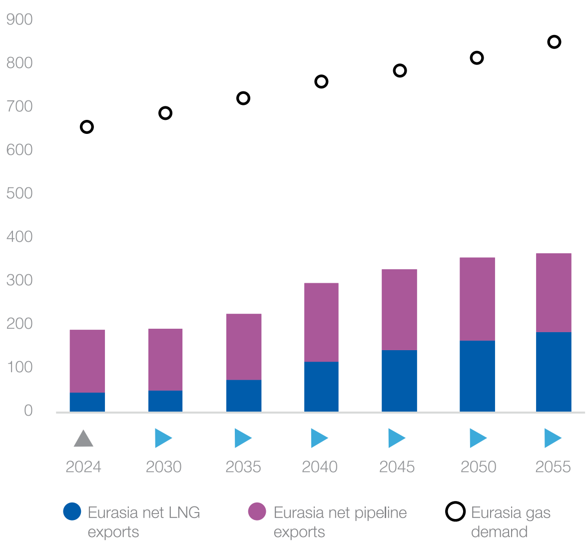
Pipeline exports - long the foundation of Eurasia's gas trade, are anticipated to rise from 145 bcm to 183 bcm over the outlook period. This gradual increase illustrates the resilience of the region's pipeline network and reinforces Eurasia's sustained reliance on extensive eastbound, long-distance corridors as a central channel for its export strategy, even as market dynamics and geopolitical conditions evolve.

In 2024, Eurasia exported roughly 235 bcm of natural gas, with Russia contributing around 66%. Pipeline deliveries dominated the region's export profile, accounting for nearly 80% (about 189 bcm) of total flows. Russia remained the leading pipeline exporter, while Azerbaijan, Kazakhstan, Turkmenistan, and Uzbekistan together supplied an additional 80 bcm, primarily through Central Asian transit routes.

In 2024, Russia remained Eurasia's dominant natural gas exporter, supplying an estimated 155 bcm to international markets. Pipeline exports continued to form the backbone of its outbound flows, totaling around 109 bcm, driven largely by deliveries to China via the Power of Siberia 1 pipeline, exports to Türkiye, and reduced but ongoing supplies to Europe through remaining routes. LNG exports added further volumes, with shipments from Yamal LNG and Sakhalin-2 helping diversify Russia's export portfolio despite geopolitical constraints. Overall, Russia's 2024 export performance reflected

Figure 6.23

Eurasia natural gas demand and net exports outlook by flow type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

a continued strategic pivot toward Asian markets, supported by long-term contracts and expanding infrastructure links.

In 2024, Russia exported an estimated 33.5 Mt of LNG (about 23.5 Mt from Yamal LNG and roughly 10 Mt from Sakhalin-2), with Europe receiving around 16.2 Mt and Asia about 17 Mt. Unlike the gradual declines seen in other parts of Russia's gas trade, LNG deliveries to Europe actually increased, up from 14.4 Mt in 2023 and 14.2 Mt in 2022, as several EU buyers continued to rely on Russian cargoes in the absence of a formal ban. However, in 2025 the European Union has agreed on a gradual phase-out of Russian LNG and pipeline gas imports under its energy diversification strategy. The measures envisage ending LNG purchases by 2027, followed by remaining pipeline supplies later that year.

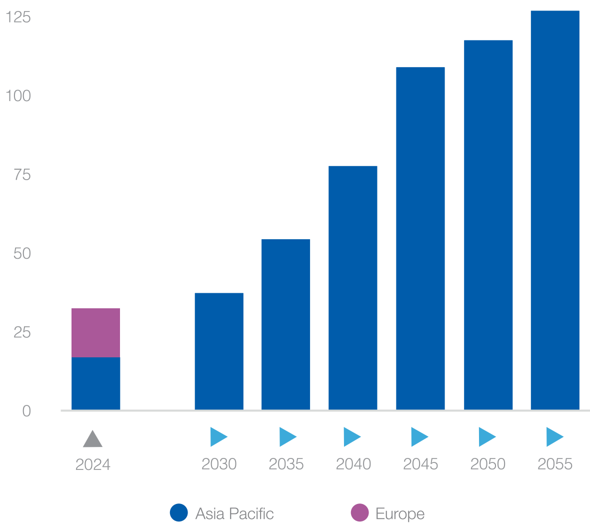
At the same time, Asia maintained a strong share, with sustained uptake from China, India, Türkiye, and other price-sensitive markets. Looking ahead, however, this balance is expected to shift from 2027 onward, redirecting a larger portion of Russian volumes toward Asian markets and further reinforcing Russia's strategic reorientation while supporting utilisation at Yamal LNG and Sakhalin-2. Russia has been actively expanding its export infrastructure with a clear focus on growing its gas presence in the Asia Pacific region. The country is prioritising the scale-up of LNG exports and placing strong strategic emphasis on strengthening its position in key Asian markets, particularly China (Figure 6.24).

Given Russia's exceptionally large gas resource base and its strategic ambition to strengthen its role in global LNG trade, the country's liquefaction build-out is expected to accelerate over the longer term, with the largest increments occurring beyond 2035. From an existing capacity base of approximately 34 Mtpa in 2025, Russia is projected to add around 13 Mtpa of capacity currently under construction by 2030 and a further 7 Mtpa by 2035. Thereafter, the expansion profile becomes increasingly contingent on the advancement of non-committed projects, with roughly 59 Mtpa of proposed capacity potentially entering development during 2035–2045. Beyond this, Rystad Energy data indicates a sizeable speculative liquefaction portfolio of around 151 Mtpa by 2055, with nearly 73% of this volume concentrated in the 2030–2035 window. If all under-construction and proposed projects materialize, **Russia's total non-speculative liquefaction capacity could rise to approximately 113 Mtpa by 2055, placing the country among the leading LNG exporters globally** (Figure 6.25).

However, notwithstanding the projected expansion in Russia's liquefaction capacity, LNG export growth is expected to outpace the increase in available capacity over the longer term. Russia's projected LNG exports converge with committed liquefaction capacity by 2030 and, after 2045, are expected to exceed the combined capacity of existing, under-construction, and proposed facilities (Figure 6.26). This indicates that sustaining the projected export trajectory will require not only the timely sanctioning and development of the current pre-FID proposed project pipeline, but also the eventual materialization of part of the speculative capacity portfolio. In this sense, the long-term adequacy of Russia's LNG export infrastructure will increasingly depend on the conversion of currently non-committed capacity into operational supply, so as to preserve sufficient liquefaction headroom and ensure the effective evacuation of projected export volumes.

Figure 6.24

Eurasia LNG exports outlook by destination, 2024-2055 (Mt)

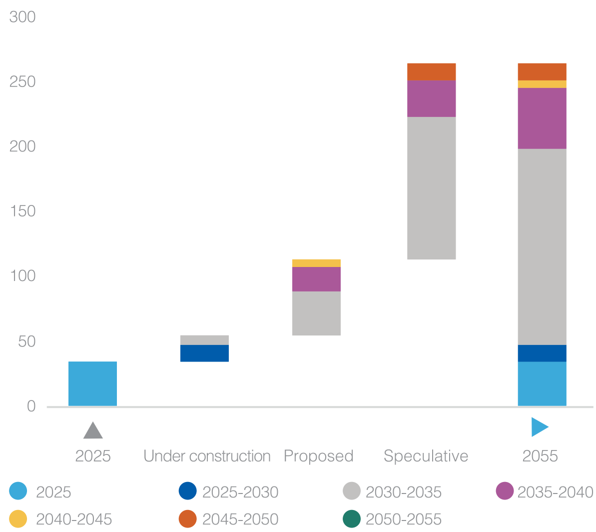


Source: GECF Secretariat based on data from the GECF GGM

Note: Regional LNG exports and imports include intraregional trade

Figure 6.25

Eurasia liquefaction capacity outlook, 2025 - 2055 (Mtpa)

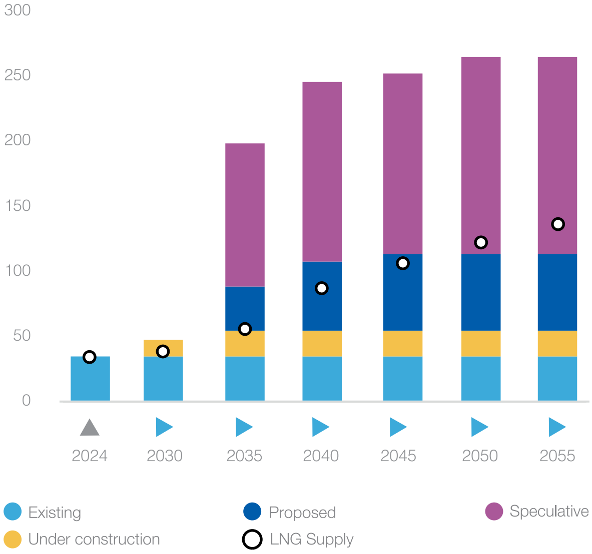


Source: GECF Secretariat based on data from the GECF GGM and Rystad Energy

Chapter 6

Figure 6.26

Projected Eurasia's LNG exports and liquefaction capacity by project status, 2024–2055 (Mtpa)



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

Russia's natural gas exports are projected to rise steadily over the coming decades, increasing from 155 bcm in 2024 to around 185 bcm by 2030, 172 bcm by 2035, 291 bcm by 2040, 317 bcm by 2045, and reaching approximately 348-366 bcm by 2050-2055. This growth is underpinned by major production expansions across the Yamal Peninsula, Arctic fields, East Siberia, and the Far East, which together will significantly strengthen Russia's upstream capacity through 2050.

On the LNG front, Russia is pursuing a major expansion programme driven by Arctic LNG 2 and Ust-Luga LNG, which together add 33 Mtpa of new capacity and are set to more than double the country's current liquefaction capacity by the early 2030s. If all planned projects proceed, Russia's LNG capacity could reach around 113 Mtpa by 2050, positioning the country as the world's third-largest LNG supplier. Correspondingly, LNG exports are projected to rise from about 46 bcm in 2024 to around 52 bcm by 2030, nearly 119 bcm by 2040, and 167 bcm by 2050, increasing further toward 2055.

Russia's long-term energy strategy, the Energy Strategy of the Russian Federation to 2050, officially approved on 12 April 2025, places strong emphasis on expanding LNG production as a central pillar of its future export portfolio. Building on today's output of around 34 Mt, Russia aims to scale LNG production to 90-105 Mt by 2030, 110-130 Mt by 2040, and potentially 110-175 Mt by 2050, depending on the pace of project development and market conditions. These targets reflect the strategic objective to position LNG as a major growth engine for Russia's gas industry, diversify export routes away from pipeline-dependent markets, and secure a stronger foothold in Asia. By 2050, Russia intends to be among the world's top three LNG suppliers, supported by large new liquefaction projects, expanded Arctic capacity, and a more resilient, globally oriented gas export system.

Russia's cooperation with China on expanding and developing new import pipelines further strengthens its gas supply security and diversification strategy. The September 2025 agreements, most notably the 50 bcm Power of Siberia-2 project and the expansion of Power of Siberia-1 to 44 bcm, underscore China's prioritisation of stable, long-term pipeline deliveries within its broader energy security framework. For Russia, these projects help anchor sustained demand in Asia, while for China they reduce reliance on volatile LNG spot markets and enhance the resilience and balance of its long-term gas supply portfolio.

Azerbaijan has been a significant natural gas exporter since the start-up of the Shah Deniz field in 2007, with exports rising steadily to 27 bcm in 2024. Of this volume, 13.4 bcm were delivered to Europe, 10.2 bcm to Türkiye, and 3.3 bcm to Georgia. Azerbaijan expanded its market reach in recent years, beginning gas supplies to Hungary and Serbia in 2023, followed by Croatia in the second half of 2024. The country now aims to supply around 16 bcm of gas to Europe by 2027 - down from an earlier target of 20 bcm. To increase exports further, Azerbaijan is advancing domestic efficiency measures, scaling up renewable energy, and assessing new energy sources and export routes. Additional export growth could be supported through cooperation with neighbours such as Turkmenistan, though achieving this would necessitate substantial investment to expand the TANAP pipeline to 32 bcma and TAP to 20 bcma. Over the long term, from 2024 to 2055, Azerbaijan's natural gas exports are expected to stabilise at around 25 bcm by 2040, maintaining this level through 2055.

In 2024, **Turkmenistan** exported 46 bcm of natural gas via pipeline, with China remaining its largest buyer. Exports are projected to rise substantially, reaching 87 bcm by 2045 and up to 103 bcm by 2055. The country's main export corridor - the 1,830 km Central Asia-China pipeline system (Lines A, B and C) - currently operates at 55 bcma, with a theoretical expansion potential to 85 bcma through the addition of Line D. However, Line D remains highly uncertain, as construction has been suspended since 2017 due to unresolved China–Turkmenistan negotiations over the gas sales agreement. The TAPI pipeline - despite longstanding delays - appears more likely to advance over the long term in Turkmenistan's export planning. Designed to transport 33 bcma (14 bcma to India, 14 bcma to Pakistan, and 5 bcma to Afghanistan), TAPI offers a strategic route for diversifying exports beyond China and unlocking broader South Asian markets. While challenges remain, its inclusion in long-term regional infrastructure plans suggests higher prospects for eventual realization.

6.5.4 Europe

The European Union's current gas market outlook is guided by its broader strategy to diversify supply sources, enhance energy system resilience, and steadily reduce overall gas consumption in line with long-term climate objectives. EU policies emphasise efficiency improvements, increased renewable energy deployment, and the gradual transformation of the gas system through the integration of low-carbon gases such as biomethane and hydrogen. As these structural shifts progress, Europe expects a moderated but still meaningful role for natural gas in supporting power system flexibility, industrial operations, and seasonal heating demand through at least the mid-2030s.

LNG has become an important component of Europe's supply portfolio, providing flexibility and supporting storage filling during periods of tight market conditions. Since 2022, the EU has significantly expanded its regasification capacity, enhancing its ability to source gas from a wide range of global suppliers. European bloc now has ample LNG import infrastructure, enabling more balanced market operations and diversified procurement, while also creating opportunities to optimise existing terminals for future use with low-carbon gases. At the same time, the EU continues to refine regulatory frameworks to ensure infrastructure investments remain aligned with long-term market trends and climate targets.

North Africa, Norway, Qatar, the Eastern Mediterranean, and the United States have all become important contributors to Europe's evolving LNG supply portfolio. The United States, in particular, has strengthened its role as a key supplier, supported by rapid growth in export capacity and the commercial flexibility of US-origin LNG. Looking ahead, Europe is expected to continue pursuing a diversified procurement strategy, combining long-term arrangements with spot and short-term purchases to maintain adaptability. This balanced approach enables European buyers to ensure secure supply while adjusting contract structures and infrastructure planning in line with projected shifts in gas demand through 2040 and up to 2055.

Europe's long-term gas outlook reflects a gradual contraction in overall demand alongside a more diversified and flexible import structure. Despite this decline, Europe is expected to remain the world's second-largest natural gas importer, after the Asia Pacific region, supported by a broad supplier base and well-developed LNG and pipeline infrastructure.

Europe's total gas demand decreases from 460 bcm in 2024 to 370 bcm by 2055, driven by efficiency gains, electrification, and the increasing use of low-carbon gases. As a result, overall import requirements fall accordingly, with net imports declining from 266 bcm in 2024 to around 212 bcm by 2055.

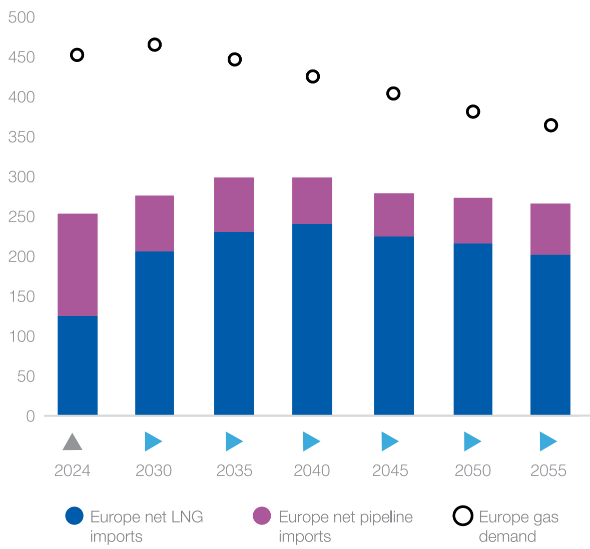
Both pipeline and LNG imports adjust to this structural shift. Pipeline gas demand is anticipated to decline from 276 bcm in 2024 to 93 bcm by 2055, while pipeline supply falls from 145 bcm to 28 bcm, leading to net pipeline imports easing from 130 bcm in 2024 to 66 bcm in 2055. LNG remains a central part of Europe's diversification strategy: LNG demand rises from 135 bcm in 2024 to 259 bcm by 2040, before moderating to 220 bcm by 2055. Net LNG imports remain substantial - 127 bcm in 2024, peaking at 245 bcm in 2040, and staying above 200 bcm by 2055 (Figure 6.27).

Europe's LNG import landscape is anticipated to evolve steadily through 2055, with a broader mix of suppliers but still a clear concentration of volumes from North America. Deliveries from the United States and Canada are anticipated to peak around 2040s at about 151 Mt before easing toward around 123 Mt by 2055, leaving North America as Europe's largest single LNG source. African LNG remains a stable contributor with modest growth, while imports from the Middle East hold relatively steady - reaching around 13 Mt in 2035 and gradually declining toward about 8 Mt by 2055. Eurasian LNG is fully phased out from the late 2020s, and small Latin American flows disappear after 2030, while intra-European LNG movements gradually increase by mid-century. Overall, Europe maintains diversified access to global LNG, though its continued heavy reliance on North American cargoes highlights the importance of sustaining a wide supplier base to support long-term supply resilience (Figure 6.28).

Europe remained one of the most active regions, consolidating the substantial regasification additions made in 2023 and advancing several new projects

Figure 6.27

Europe natural gas demand and net imports outlook by flow type, 2024-2055 (bcm)

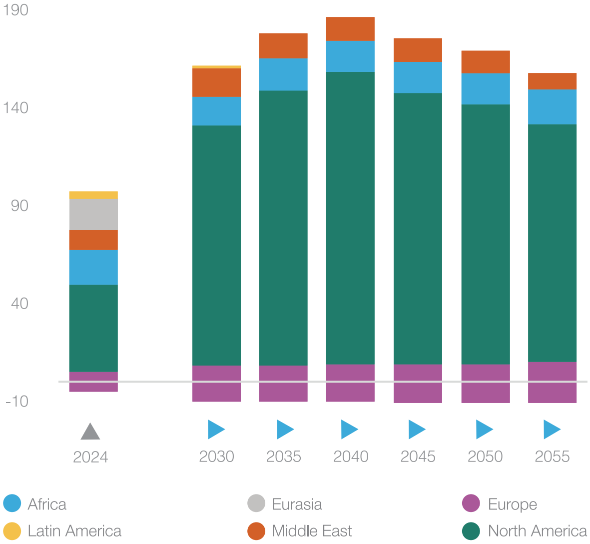


Source: GECF Secretariat based on data from the GECF GGM

Chapter 6

Figure 6.28

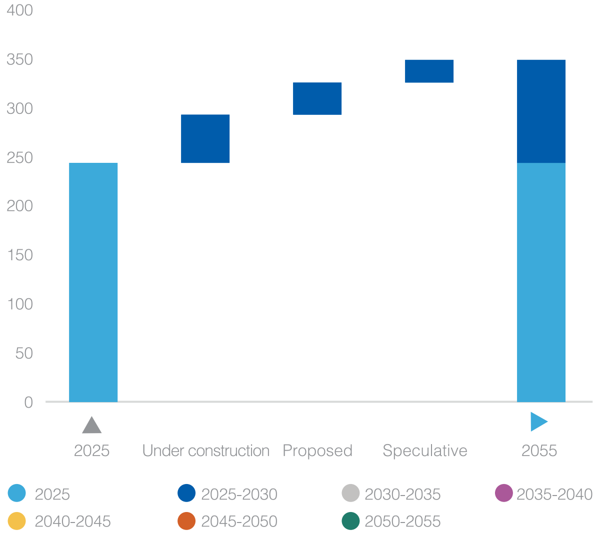
Europe LNG imports (+) by origin and exports (-) by destination outlook, 2024-2055 (Mt)



Source: GECF Secretariat based on data from the GECF GGM
Note: Regional LNG exports and imports include intraregional trade

Figure 6.29

Europe LNG regasification capacity outlook, 2025-2055 (Mtpa)



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

to enhance flexibility and supply security. The strong preference for FSRUs persisted, given their rapid deployment, lower capital requirements, and adaptability to shifting demand patterns. A key milestone in 2024 was the commissioning of the Alexandroupolis FSRU in Greece, a strategically significant terminal with a regasification capacity of around 4 Mtpa that entered commercial operation in October 2024. The project strengthens supply diversification in Southeast and Central Europe and underscores Europe's continued reliance on flexible FSRU-based solutions in its evolving LNG infrastructure landscape.

By 2024, Europe's LNG regasification capacity stood at 244 Mtpa, supported by the rapid rollout of FSRUs and targeted onshore terminal expansions. Looking ahead to 2030, a further 49 Mtpa of capacity is already under construction, roughly half from new FSRU deployments, while an additional 33 Mtpa could be added through proposed projects, driven largely by infrastructure upgrades and new developments in Germany, Greece, Italy and United Kingdom. **Europe's total regasification potential could reach around 326 Mtpa by the end of the decade.** This front-loaded expansion underscores Europe's strategy to maintain a flexible, resilient LNG import system capable of adapting to shifting gas demand and broader supply dynamics. Together, these projects reinforce Europe's strategy to maintain a flexible and resilient LNG import system amid evolving gas demand and supply dynamics (Figure 6.29).

As shown in Figure 6.30, projected non-linear growth in Europe's LNG imports is expected to be adequately accommodated by the region's available committed regasification capacity over the long term. This is particularly the case given the anticipated gradual decline in LNG imports after 2035, which moderates infrastructure requirements and results in a reduction in average regasification capacity utilization over time. Average utilisation of committed regasification capacity is projected to reach around 49% by 2055, compared with approximately 40% in 2024. This indicates that, despite periods of higher import requirements earlier in the outlook, Europe's existing and under-construction regasification infrastructure is expected to provide sufficient headroom to absorb projected LNG imports without creating major long-term capacity constraints.

Germany's gas strategy is shaped by the nuclear phase-out and coal phase-out and the drive to reach climate neutrality by 2045, with gas acting as a key balancing fuel for a power system dominated by renewables. Net gas imports remain high at about 74 bcm in 2024, but decline in line with efficiency gains and electrification to around 64 bcm by 2050 and 59 bcm by 2055. The import structure shifts markedly over time: pipeline net imports fall from roughly 68 bcm in 2024 to 15 bcm in 2035 and negligible volumes by 2055, while LNG net imports rise from about 6 bcm to 60 bcm in 2035 and marginally decline to 58 bcm by 2055. This reflects both the build-out of FSRU and onshore regasification capacity and a deliberate policy to diversify away from traditional pipeline suppliers, even as overall gas use declines.

Norway's role in Europe's gas balance is framed by its position as a mature offshore producer, strong climate targets, and a policy focus on managing resources prudently. In 2024, Norway is a major net exporter of around 124 bcm, almost entirely via pipelines.

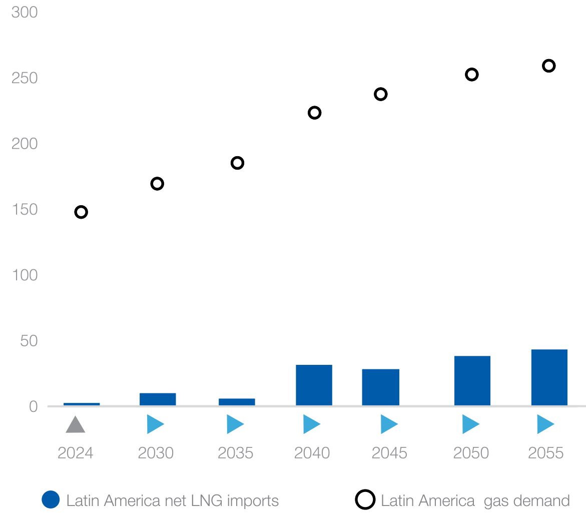
Figure 6.30

Projected Europe's LNG imports and regasification capacity by project status, 2024–2055 (Mtpa)

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

Figure 6.31

Latin America natural gas demand and net LNG imports outlook, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

As production from ageing fields declines and new developments only partly offset depletion, net exports fall to about 68 bcm by 2035 and 27 bcm by 2055. LNG plays only a modest but steady role: Norway remains a small net LNG exporter, with LNG exports equivalent to roughly 5-7 bcm across the period, while pipeline exports continue to dominate flows. This trajectory confirms Norway's status as a reliable but gradually shrinking supplier to Europe over the long term.

Türkiye's gas outlook is closely tied to its ambition to act as a regional energy hub, connecting suppliers in Russia, the Caspian and the Eastern Mediterranean to European and domestic markets, while also pursuing its 2053 net-zero target. Net gas imports stood at about 49 bcm in 2024, are expected to edge up to 59 bcm by 2035, and reach around 70 bcm by 2055, reflecting continued demand growth in power, industry and buildings. Pipeline net imports remain the backbone of supply, rising from about 38 bcm in 2024 to 42 bcm in 2035 and 46 bcm in 2055, underpinned by contracts with Russia, Azerbaijan and Iran. LNG net imports provide an important diversification channel, holding near 13 bcm in 2024 and growing to 17 bcm in 2035 before increasing to roughly 24 bcm by 2055. With five LNG terminals and multiple pipeline connections, Türkiye consolidates its role as both a major end-market and a key transit corridor in the region.

In the **United Kingdom**, the 2024 coal phase-out and strong offshore wind targets increase the importance of gas-fired power as a flexible complement to renewables, even as overall gas demand trends downward. Net gas imports amounted to about 32 bcm in 2024 and are anticipated to decline to 20 bcm by 2055. The country remains closely linked to Norway via pipelines, but the balance gradually tilts toward LNG. Pipeline net imports fall from roughly 11 bcm in 2024 to 6 bcm by 2055, while LNG net imports move from around 11 bcm in 2024 down to 24 bcm in 2035, then decline to about 20 bcm by 2055 as domestic North Sea output continues to decline. With large regasification capacity and interconnectors to continental Europe, the United Kingdom maintains its role as a flexible gas entry point and balancing hub while advancing its longer-term decarbonisation agenda.

6.5.5 Latin America

In Latin America, natural gas demand is expected to grow as the fuel plays an increasingly important role in ensuring energy security. Gas helps balance the variability of hydropower and the growing share of wind and solar, while also replacing coal and oil in power generation. Rising electricity needs, industrial expansion, and, to a lesser extent, greater use of gas in road transport further support demand across the region.

Latin America's natural gas demand rises steadily from 150 bcm in 2024 to 263 bcm by 2055, driven by growing power-sector needs, industrial expansion and the increasing role of gas in balancing hydropower and variable renewables. As domestic production struggles to keep pace, the region's reliance on imported LNG strengthens over time: net LNG imports increase from 3 bcm in 2024 to 10 bcm by 2030, fluctuate around mid-century, and reach 44 bcm by 2055. This highlights a widening gap between demand and supply, reinforcing the importance of both regional production growth - particularly in Argentina - and expanded LNG access to meet future energy security needs (Figure 6.31).

Most natural gas produced in the region is consumed domestically across power, industry, transport and buildings. Trinidad and Tobago remains the largest exporter, shipped around 10 bcm of LNG in 2024, while Bolivia exports roughly 6 bcm of pipeline gas to Brazil and Argentina. For most other countries, domestic output falls short of demand, making imports a key part of their gas balance.

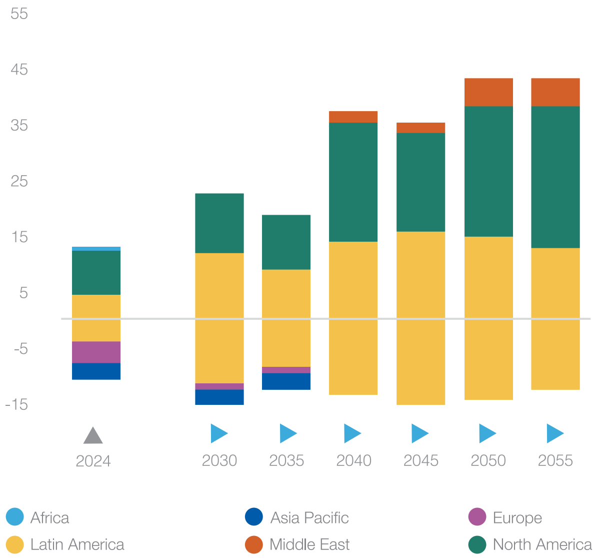
Latin America remains a net importer of natural gas, though the balance differs markedly across countries. Regional net imports amount to around 3 bcm in 2024, rise to 10 bcm by 2030, and reach 44 bcm by 2055 as demand grows in several economies. Argentina moves from a small import position in 2024 to net exports of about 2 bcm by 2030 and 11 bcm by 2055, driven by the expansion of Vaca Muerta. Bolivia continues to supply gas to Brazil and Argentina, but its export surplus declines from around 6 bcm in 2024 throughout to 2055 as output gradually falls. Trinidad and Tobago remains the region's largest LNG exporter, with net exports drifting marginally from 10 bcm in 2024 to around 8 bcm by mid-century, while Peru shifts from exporting roughly 5 bcm in 2024 to near balance by 2040. In contrast, net imports rise steadily in Brazil, climbing from 8 bcm in 2024 to 34 bcm by 2055, and in Chile from 4 bcm to 17 bcm, reflecting growing consumption and the increasing role of gas in balancing renewables and hydropower.

Looking forward, intra-regional trade continues to play a stabilising role. Bolivia's pipeline deliveries remain essential for Argentina and Brazil for most of the forecast, while Argentina's eventual surplus strengthens regional supply security after 2030. Colombia and Venezuela retain significant undeveloped gas potential, though their net balances might improve by mid-century. Growth in Central America and the Caribbean underscores the rising reliance on LNG imports to meet power-sector needs. Overall, Latin America's structural position as a net importer widens towards 2055 despite the emergence of new exporters, shaped by uneven resource distribution, rising electricity demand, and the increasing use of gas to balance hydropower variability and growing renewable energy shares.

Bolivia remains a key supplier of natural gas to Brazil and Argentina, with its dedicated export pipelines forming the backbone of regional gas trade. Exports flow primarily through three systems: the GIJA pipeline to Argentina, the Gasbol line to Brazil, and the Gasyrg connector. While these routes currently absorb nearly all of Bolivia's gas output, future export dynamics will increasingly depend on the evolution of Argentina's pipeline network. Planned expansions - such as the continued development of the Néstor Kirchner Gas Pipeline and associated north-south links - could reshape regional flows over the longer term, potentially reducing Bolivia's export volumes or redirecting them within an expanded Southern Cone gas system. Bolivia is also exploring new market access options, including potential interconnections to Peru's southern gas corridor and

Figure 6.32

Latin America LNG imports (+) by origin and exports (-) by destination outlook, 2024-2055 (Mt)



Source: GECF Secretariat based on data from the GECF GGM

Uruguay's port infrastructure, to broaden its export outlets beyond its traditional markets.

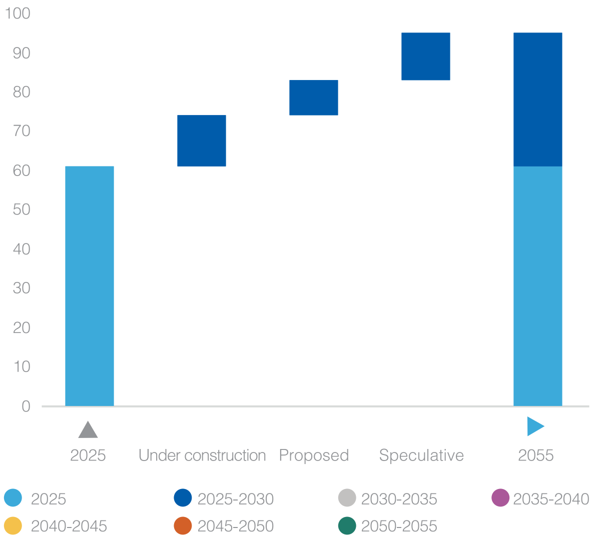
Latin America remains a relatively small but steadily growing player in global LNG trade. **Regional LNG demand increases from 13 Mt in 2024 to 44 Mt by 2055, driven mainly by rising gas use in Brazil, Chile, Central America, and the Caribbean.** LNG supply, however, expands only modestly - from 11 Mt to 13 Mt - resulting in a widening import gap. Net LNG imports rise from 2 Mt in 2024 to 31 Mt by 2055, reflecting growing structural reliance on LNG to meet power-sector needs, back up variable hydropower and renewables, and compensate for declining pipeline exports from Bolivia and Trinidad and Tobago. This reinforces Latin America's emerging but increasingly import-dependent role in global LNG markets (Figure 6.32).

Latin America's LNG landscape is shaped by a small group of exporters and a steadily expanding group of importers. Trinidad and Tobago and Peru remain the region's only significant LNG exporters in 2024, supplying around 7.4 Mt and 3.8 Mt, respectively. Their combined LNG output declines gradually toward 2055, but regional LNG supply is sustained by Argentina, which begins exporting modest volumes by 2030 and becomes the main growth driver after 2035, with exports reaching around 4 Mt by 2055. Venezuela also re-enters the market in the long term, adding small volumes by 2040-2055.

On the import side, LNG demand rises across nearly all subregions. Imports total around 13 Mt in 2024, led by Brazil, Chile, the Caribbean and Central America. By 2035, regional LNG demand peaks at about 19

Figure 6.33

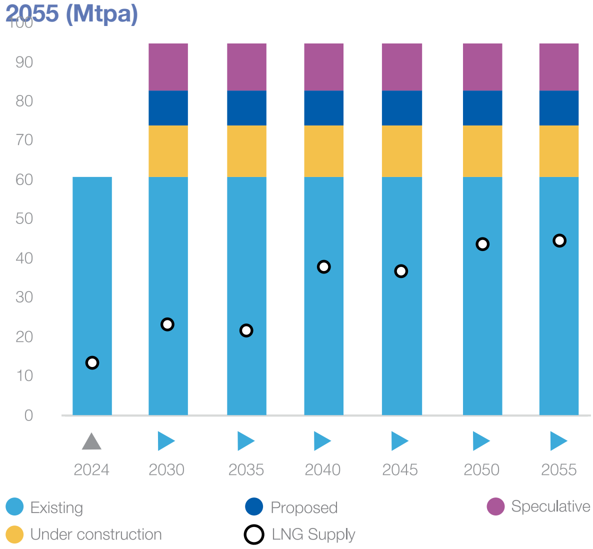
Latin America LNG regasification capacity outlook, 2025-2055 (Mtpa)



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

Figure 6.34

Projected Latin America's LNG imports and regasification capacity by project status, 2024–2055 (Mtpa)



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

Mt, driven by increasing requirements in Chile, the Caribbean, and a temporary rise in Argentina and Brazil. Toward 2055, LNG demand climbs further to nearly 45 Mt, with Brazil emerging as the dominant importer at around 24 Mt, accounting for more than half of total regional LNG imports. Chile remains a major buyer with 8 Mt, while Central America, the Caribbean, and selected South American markets continue to import smaller but steadily growing volumes. Overall, Latin America's LNG balance shifts toward higher import dependency by mid-century, even as new export capacity emerges.

The growing inflow of US LNG into Latin America creates both advantages and pressures. Importing countries gain access to abundant, competitively priced supply that strengthens energy security and diversifies their gas mix. Conversely, regional exporters face rising competition, as lower-cost US LNG challenges their position in both domestic and international markets.

By the end of 2025, Latin America has around 61 Mtpa of LNG regasification capacity. In addition, approximately 13 Mtpa is under construction operationalizing before 2030, while a further 9 Mtpa is identified as proposed capacity for potential development over the outlook period in countries including Aruba, Brazil, Colombia, the Dominican Republic, and Ecuador. Beyond this, Rystad Energy identifies about 9 Mtpa of speculative regasification capacity in the region, predominantly concentrated in Brazil, pointing to a modest but notable longer-term upside in Latin America's LNG import infrastructure (Figure 6.33). As a result, **total non-speculative LNG regasification in Latin America is projected to reach 83 Mtpa by 2055.**

As shown in Figure 6.34, the projected growth in Latin America's LNG imports is expected to be adequately accommodated by the region's committed regasification capacity over the long term. Average utilization of existing and under-construction regasification facilities is projected to rise to around 54% by 2055, up from a very low level of 22% in 2024. Despite this increase, the utilization profile remains moderate, indicating that the region is expected to retain ample regasification headroom throughout the outlook period. This suggests that Latin America's current and committed LNG import infrastructure should be sufficient to absorb the projected increase in LNG imports without giving rise to significant long-term capacity constraints.

Brazil's LNG demand is projected to fluctuate over the outlook period, peaking around 3 Mt in 2035, before expanding again to 24 Mt by 2055, as the country increasingly relies on LNG to complement declining pipeline imports and balance variability in hydropower generation. With no domestic LNG supply across the horizon, Brazil remains one of the region's largest structural LNG importers by mid-century.

Argentina follows the opposite trajectory. LNG demand peaks around 3 Mt by 2035 before falling to zero by 2045, while LNG supply rises from 4 Mt in 2035 to 4 Mt by 2055, enabling the country to transition from a marginal LNG importer to a net exporter. This shift is driven by sustained growth in Vaca Muerta output and the expansion of long-distance pipeline capacity, which together allow Argentina to channel surplus gas into liquefaction and cross-border trade.

Trinidad and Tobago remains the region's most significant LNG exporter over the long term, with LNG supply staying at 9 Mt in 2035 before easing to 6 Mt by 2055 as mature fields decline. Although no LNG demand emerges over the period, export levels remain robust enough to maintain the country's role as a key supplier in the Atlantic basin. Additional offshore developments, including potential inflows from Venezuela's Dragon field, may help stabilise output but not reverse long-term depletion.

Peru's LNG exports gradually diminish over the outlook. LNG supply falls from 1 Mt in 2035 to zero by 2055, reflecting declining upstream gas availability. No LNG demand is recorded through the period, allowing Peru to focus exclusively on managing the decline of its single liquefaction facility.

Venezuela enters the LNG landscape later in the forecast. While LNG demand remains at zero throughout, LNG supply begins rising after 2040, reaching 4 Mt by 2055, linked to potential development of offshore gas reserves and integration with Trinidad and Tobago's LNG infrastructure.

Other regional importers show steady growth. Chile's LNG demand doubles from 4 Mt in 2035 to 8 Mt by 2055, driven by power sector needs and declining domestic supply. The Caribbean region also expands LNG demand from 5 Mt in 2035 to 6 Mt by 2055, reflecting increasing use of gas-to-power across small island systems. Central America maintains modest but persistent LNG demand. Bolivia, Colombia, Ecuador, Paraguay, and Uruguay continue to show no LNG supply and limited or no LNG demand, with Ecuador gradually rising to 3 Mt by 2055.

6.5.6 Middle East

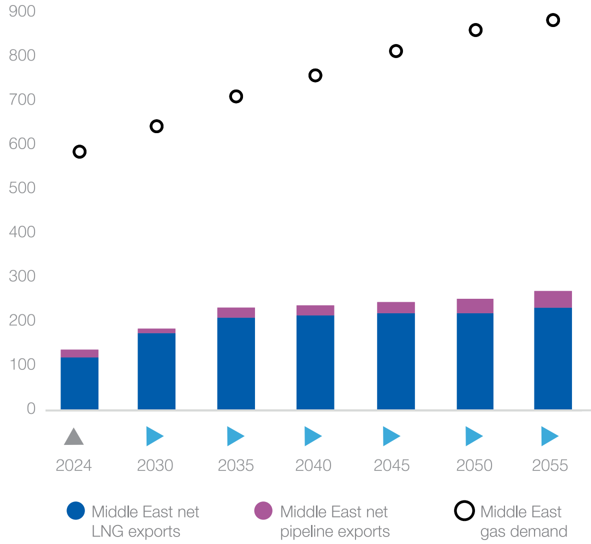
In recent years, natural gas use in the Middle East has expanded steadily, driven by fast-growing populations and energy policies that keep domestic gas prices low. These pricing frameworks, designed to accelerate industrial activity and sustain economic growth, have strengthened the region's reliance on natural gas as a core element of its energy and development strategy.

The Middle East's substantial gas resource base continues to open new avenues for regional and international trade. While LNG exports to Asia and Europe dominate the export profile, pipeline connections, such as those linking Qatar with the UAE and Oman, Iran with Iraq and Türkiye, Armenia and Azerbaijan, and Israel with Jordan and Egypt, support smaller but strategically important intra-regional flows.

LNG will remain the cornerstone of the region's export growth, with Qatar leading this trajectory. Qatar's role as a global LNG powerhouse is set to expand markedly as it advances its large-scale liquefaction programme. By early 2030s, the country aims to increase LNG capacity from 77 Mtpa to around 142 Mtpa, an expansion of roughly 85%, driven by the multi-phase North Field

Figure 6.35

Middle East natural gas demand and net exports outlook by flow type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Expansion, comprising North Field East, North Field South, and North Field West.

This rapid build-out, which may contribute to a more supply-abundant global market later in the decade, will reinforce Qatar's long-term economic strategy and support the objectives of the Qatar National Vision 2030.

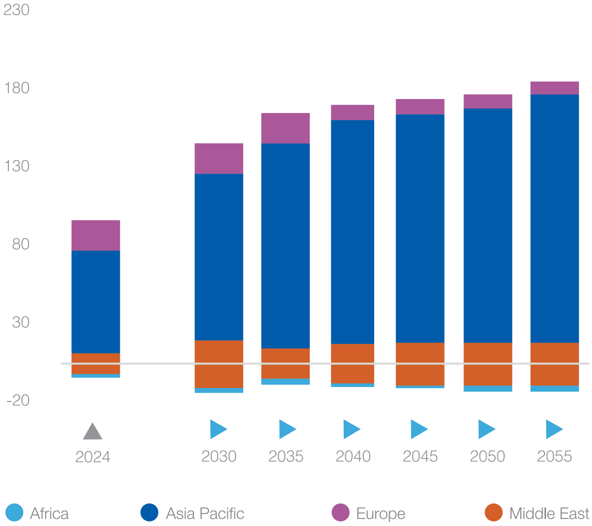
In 2024, the Middle East's net gas exports reached 137 bcm. Projections suggest a substantial increase, with total net exports expected to rise to 270 bcm by 2055 (Figure 6.35). In 2024, the region contributed 95 Mt to global LNG exports, accounting for 24% of the worldwide total. Qatar was the top global LNG exporter, shipping 77 Mt, followed by Oman and the UAE, which exported 11 Mt and 6 Mt, respectively. Qatar notably supplied 12% of Europe's LNG imports, though Europe represented only 19% of its total LNG exports, with Asia remaining the dominant market, receiving 75% of Qatar's LNG.

In 2024, the Middle East imported around 9 Mt of LNG, with Kuwait accounting for the bulk of volumes (7 Mt) and the UAE adding roughly 0.8 Mt. Over the long term, LNG imports are expected to rise moderately, reaching about 14 Mt by 2050, half of which will be taken by Kuwait. In contrast, the region's role as a major global LNG supplier will strengthen substantially. LNG net exports are projected to reach about 188 Mt by 2050, with Asia - particularly the Asia Pacific region - remaining the primary destination, taking around 170 Mt or roughly 85% of Middle Eastern LNG (Figure 6.36).

By the end of 2025, the Middle East has around 95 Mtpa of operational LNG liquefaction capacity, the majority of which is concentrated in Qatar (77 Mtpa),

Figure 6.36

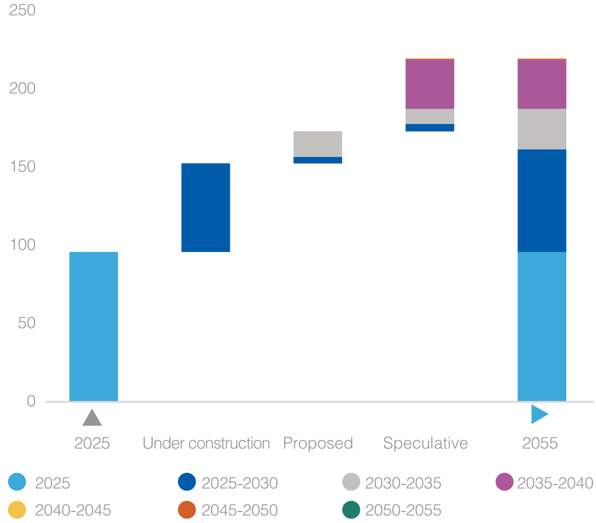
Middle East LNG exports (+) by destination and imports (-) by origin outlook, 2024-2055 (Mt)



Source: GECF Secretariat based on data from the GECF GGM

Figure 6.37

Middle East LNG liquefaction capacity outlook, 2025-2055 (Mtpa)



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

with Oman (11 Mtpa) and the UAE (6 Mtpa) accounting for the remaining established capacity. **Over the period 2024–2050, an additional 77 Mtpa of under-construction and proposed liquefaction capacity is expected to enter the regional pipeline, again dominated by Qatar** (Figure 6.37). The principal source of growth is the North Field expansion program, with North Field East and North Field South already under construction and set to add 48 Mtpa, followed by North Field West, a 16 Mtpa proposed development expected to advance following FID in 2026. Elsewhere in the region, the UAE's 9.6 Mtpa Ruwais LNG project and smaller capacity additions in Oman, including 1 Mtpa under construction and 3.8 Mtpa proposed, contribute additional growth. Rystad Energy further identifies 46 Mtpa of speculative liquefaction capacity in the Middle East by 2055, primarily in Iran and secondarily in Iraq, indicating a meaningful but uncertain longer-term upside. Collectively, these developments reinforce the Middle East's strategic role as a major center of future LNG supply expansion.

Despite the substantial expansion envisaged for liquefaction capacity in the Middle East, the region's projected LNG export profile points to a tightening balance between export requirements and available liquefaction infrastructure over time. As shown in Figure 6.38, projected LNG exports move close to the level of committed capacity by 2030 and, from 2040 onward, rise above the aggregate capacity of existing, under-construction, and proposed facilities. This suggests that the currently identified capacity pipeline will not, on its own, be sufficient to accommodate the full scale of projected export growth over the longer term. Accordingly, maintaining the region's export trajectory will require both the timely advancement of projects currently at the pre-FID stage and the eventual realization of part of the speculative project portfolio. The key implication is that the longer-term deliverability of Middle Eastern LNG exports will increasingly depend on whether currently non-committed capacity can be converted into operational liquefaction supply in time to avoid a structural shortfall in export evacuation capability.

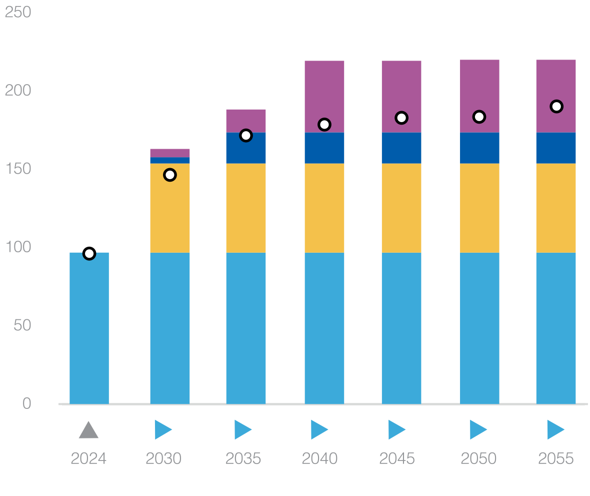
Pipeline gas trade continues to play a complementary but important role in the regional gas balance. The Dolphin Pipeline, connecting Qatar's North Field with the UAE and Oman, remains the largest gas transmission link in the Middle East, with a nameplate capacity of 33 bcma and an estimated utilization rate of about 62%. In 2024, the pipeline delivered roughly 20 bcm under long-term contracts valid until 2032, beyond which flows are expected to terminate unless new arrangements are concluded. In addition, Iranian pipeline exports to Iraq, via two separate routes serving the Baghdad and Basra areas, continue to represent an important element of regional cross-border gas trade.

Qatar will remain the anchor of Middle Eastern LNG supply through 2055, supported by its vast resource base and the phased expansion of its North Field developments. As new liquefaction capacity from North Field East, North Field South, and North Field West progressively comes on stream, Qatar's LNG exports are projected to more than double, reaching around 175 Mt by 2055. This expansion will be the principal driver of the region's growing net LNG export surplus and will further consolidate Qatar's position as the dominant LNG supplier in the Middle East. At the same time, pipeline gas will play a more limited role in the

Chapter 6

Figure 6.38

Projected Middle East's LNG exports and liquefaction capacity by project status, 2024–2055 (Mtpa)



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

regional export mix. The Dolphin Pipeline, despite its significance as the region's largest cross-border gas link, has a nominal capacity of around 33 bcm per year and currently transports about 20 bcm annually, implying far more modest growth potential than LNG. As a result, the Middle East's external gas trade is expected to become increasingly LNG-oriented over the long term, with Qatar accounting for the overwhelming share of incremental export capacity.

The **UAE** is expected to remain a net LNG exporter over the long term, supported by the addition of the 9.6 Mtpa Ruwais LNG project, which will provide a material expansion of the country's liquefaction base. Once fully operational, Ruwais will significantly strengthen the UAE's export capacity and reinforce its position in regional LNG supply. Against this backdrop, UAE LNG exports are projected to rise to around 14 Mt in 2035, before easing slightly and stabilizing at a broadly sustained level of about 12 Mt by 2055. This trajectory suggests that the Ruwais expansion will provide not only a near-term uplift in export volumes, but also a durable foundation for maintaining the UAE's presence in global LNG markets over the longer term. It also indicates that, despite rising domestic gas requirements, the UAE is likely to preserve sufficient supply capacity to sustain a stable export position through mid-century.

Oman's external natural gas trade is expected to remain predominantly LNG-based over the outlook period. In 2024, the country exported around 12 Mt of LNG, with more than 90% of these volumes directed to the Asia Pacific market, confirming the continued importance of Asian demand in underpinning Oman's LNG export position. Over the forecast horizon, LNG exports are projected to remain close to 9 Mt by 2030, before declining gradually to around 7 Mt by 2040 and easing further by 2055. This profile suggests that Oman will continue to participate in global LNG trade as a relatively stable exporter, although its share is likely to moderate over time in the context of expanding capacity elsewhere and evolving domestic gas balances.

The country's LNG export capacity is currently centered on the Qalhat liquefaction complex, which consists of three trains with a combined nameplate capacity of 10.4 Mtpa. This facility remains the core of Oman's gas export infrastructure and the principal channel for monetizing domestic gas resources in external markets. In parallel, Oman is also expanding the functional role of LNG within its gas sector through the development of the Marsa LNG project in Sohar, a 1 Mtpa facility approved under FID in 2024 in partnership with TotalEnergies and expected to commence operations in 2028. Unlike Qalhat, Marsa LNG is designed primarily to serve the marine bunkering segment, positioning it as the first dedicated LNG bunkering hub in the Middle East. The project therefore represents a strategic diversification of Oman's LNG portfolio, extending beyond conventional export markets into downstream marine fuel applications. In technical terms, this broadens the utilization profile of Oman's liquefaction sector and aligns part of the country's LNG infrastructure development with the emerging role of LNG in maritime decarbonisation and fuel-switching within international shipping.

Iran possesses substantial natural gas export potential, underpinned by its large resource base, although the expansion of export volumes remains constrained by domestic demand growth and limited progress on new cross-border infrastructure. In 2024, Iran exported approximately 15 bcm of natural gas, primarily to Iraq and Türkiye, with smaller export volumes to Armenia. While additional pipeline export options toward Oman, Pakistan, Turkmenistan, and India have been discussed over time, these projects have advanced only slowly. Over the outlook period to 2055, Iran's natural gas exports are expected to stabilize at around 10 bcm, indicating that rising production is likely to be largely offset by higher domestic consumption rather than translated into a major increase in net exports. At the same time, Iran's regional role may broaden through transit and swap arrangements. In 2024, Turkmenistan announced plans to raise gas shipments to Iran, while a new 10 bcm per year swap agreement envisaged Iranian onward delivery of equivalent volumes to Iraq. This points to a broader strategic role for Iran within the regional gas system, not only as a direct exporter, but also as an intermediary corridor for the movement of gas between Central Asia and Middle Eastern demand centers.

Iraq has significant natural gas export potential, but it currently remains a net importer, having received around 8 bcm of pipeline gas from Iran in 2024. In spring 2024, Iraq concluded a five-year gas import agreement with Iran covering volumes of 50 mcm/d, reaffirming the critical role of Iranian gas in sustaining Iraq's power sector. At present, Iraq's export capability is constrained by insufficient pipeline infrastructure, limited gas processing capacity, and the absence of LNG export facilities. Nevertheless, if these constraints are progressively alleviated, Iraq could begin exporting LNG after 2030, with volumes potentially rising to around 15 bcm by 2040 before moderating gradually toward 2055. This points to a possible medium- to long-term transition in Iraq's gas trade position, from structural import reliance toward participation in regional and global gas exports.

Despite its central role in global oil markets, **Saudi Arabia** currently consumes its entire natural gas output domestically and does not presently pursue LNG or pipeline gas exports. However, the Kingdom's recent external investments indicate a longer-term strategy aimed at establishing a position in the international LNG value chain. Aramco's 2023 acquisition of a minority stake in MidOcean Energy for USD 500 million, followed by an increase in its holding to 49% by December 2024, represents the company's first material entry into global LNG investment. This was complemented in mid-2024 by non-binding agreements with NextDecade and Sempra, covering a 20-year offtake from Rio Grande LNG and 5 Mtpa from Port Arthur LNG Phase 2, respectively, with the latter also including a potential 25% equity participation. These moves point to a strategic approach centered on portfolio access, equity participation, and long-term offtake rather than near-term domestic export development.

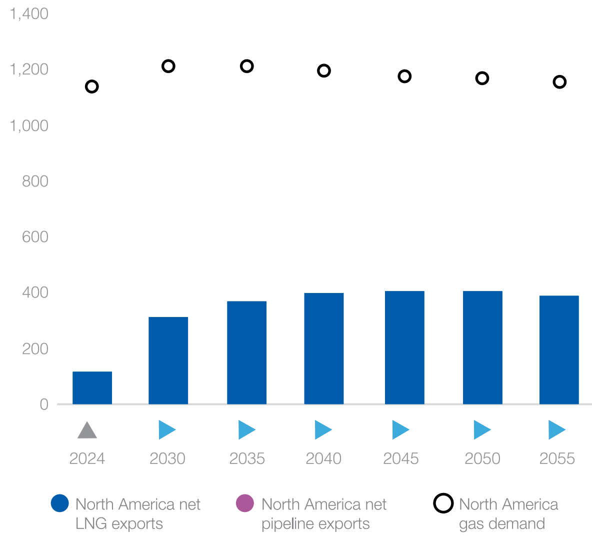
6.5.7 North America

North America remains the world's largest natural gas consumer, and regional demand is expected to grow modestly through the 2030s, supported by continued reliance on gas in the power sector. Coal retirements, rising electrification, and surging electricity needs from AI-driven data centres will all amplify gas-fired generation requirements, particularly in major US power markets such as Texas, the Mid-Atlantic, and the Southeast. These high-load facilities require stable, round-the-clock power that intermittent renewables cannot fully provide, reinforcing the role of combined-cycle and fast-ramping gas turbines. CCUS technologies could also enable gas plants to operate for longer within tightening decarbonisation frameworks. In Canada, gas demand growth will be more moderate but supported by industrial development and LNG-related electricity needs. Overall, these trends ensure natural gas remains a key reliability resource in North America's power system through the 2030s.

LNG becomes the region's dominant export channel, strengthening North America's role as a long-term supplier to global gas markets. **LNG exports rise from about 118 bcm in 2024 to more than 405 bcm**

Figure 6.39

North America natural gas demand and net exports outlook by flow type, 2024-2055 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

by 2050 before moderate easing to 390 bcm by 2055, accounting for all growth in net exports. This expansion enhances North America's integration into global gas trade and supports supply diversification for importing regions through mid-century (Figure 6.39).

North America is entering a new phase of gas market integration driven by rapid LNG capacity expansion and increasingly interconnected regional flows. The United States anchors this transformation, with LNG export capacity rising toward 130-150 Mt by 2030 as major Gulf Coast projects come online, positioning the region as the world's dominant LNG supply hub. Canada contributes through Pacific-facing projects such as LNG Canada, Woodfibre, and the fast-tracked Ksi Lisims LNG, which shift Western Canadian volumes from traditional US pipeline exports to global markets. Mexico, meanwhile, emerges as both a growing importer of US pipeline gas for its power sector and a platform for LNG exports using US gas feedstock, particularly from the Permian and Eagle Ford basins. Together, these developments significantly strengthen North America's role in balancing global LNG markets through mid-century.

In parallel, intra-regional pipeline trade between the United States, Canada, and Mexico continues to evolve as supply centres, demand hubs and export corridors reconfigure. US-Mexico pipeline flows remain the fastest-growing corridor, driven by Mexico's rising electricity demand, industrialisation, and new gas-fired generation, while US-Canada flows adjust as more Canadian supply is redirected toward LNG exports rather than southbound markets. Eastbound US pipeline deliveries to eastern Canada continue to provide essential seasonal balancing, even as the westward shift in Canadian production reshapes trade patterns. Overall, North America becomes more integrated and export-oriented, with LNG playing the central role in global outreach and pipelines ensuring strong, flexible regional connectivity.

In 2024, North America's total natural gas exports reached approximately 300 bcm. Of this volume, nearly 40%, or around 117 bcm (equivalent to 85 Mt), was exported in the form of LNG. These LNG exports originated entirely from the United States and were predominantly destined for European markets, reflecting Europe's strategic shift toward diversified and flexible gas supply sources. Canada entered the LNG export market in 2025 with the launch of the LNG Canada project, located in Kitimat, British Columbia. This landmark facility marks the country's first major LNG export terminal and is designed to serve growing demand in Asia Pacific markets. Meanwhile, Mexico began its LNG export journey in 2024 with the Altamira LNG project, developed by New Fortress Energy. The floating unit, Altamira LNG T1, is located on the Gulf Coast and has an export capacity of around 1.4 Mtpa. These developments position both Canada and Mexico to play a growing role in North America's expanding LNG export capacity, complementing the United States' already significant presence in global gas markets.

Looking ahead, LNG is expected to play an increasingly central role in North America's export profile. By 2030, total exports are projected to surpass 450 bcm, with LNG accounting for over half of this growth. The upward trend continues through 2055, reaching around 487 bcm, with LNG maintaining a dominant share due to its versatility, expanding infrastructure, and strong international demand.

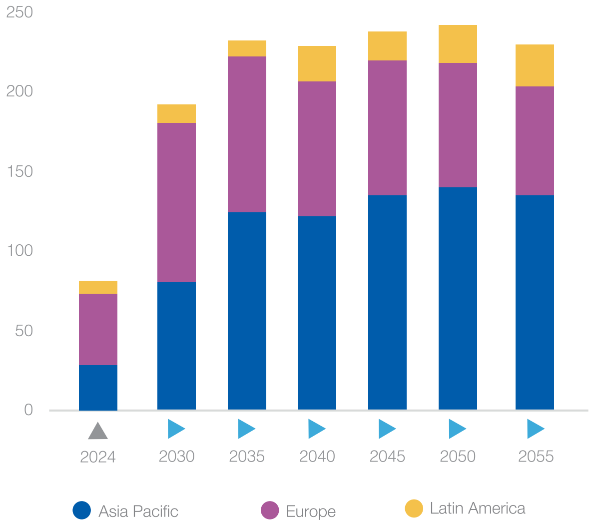
European demand remains a key driver, especially throughout the 2030s, as the region further reduces reliance on pipeline imports from traditional suppliers. Simultaneously, growing LNG demand in parts of Asia and Latin America is expected to diversify North America's export destinations. This long-term outlook underscores North America's strategic position as a leading and reliable global LNG supplier through mid-century and beyond (Figure 6.40).

Globally, continued strength in LNG contracting reflects buyers' increasing emphasis on supply security and reliability. However, the rapid growth in North American LNG production, coupled with the gradual depletion of low-cost resources, could introduce long-term risks. After the mid-2030s, this may lead to higher prices or reduced export capacity from the region.

North America is set to remain a key engine of global LNG supply growth through 2050. Exports are expected to rise from 85 Mt in 2024 to around 192 Mt by 2030, climbing further to roughly 242 Mt by 2050, outpacing most other producing regions over the period.

Figure 6.40

North America LNG exports outlook by destination, 2024-2055 (Mt)



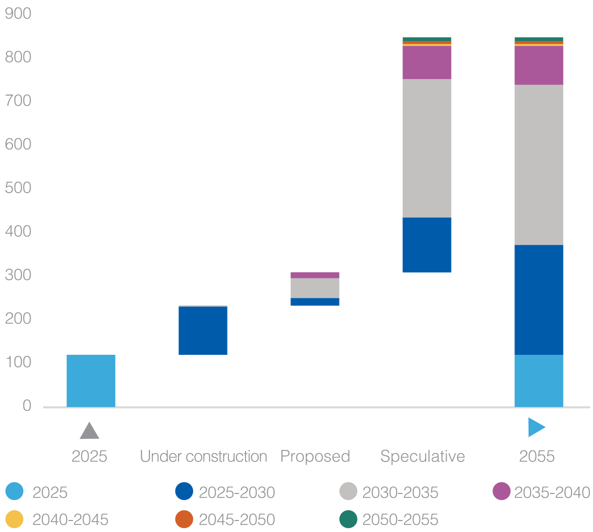
Source: GECF Secretariat based on data from the GECF GGM

The outlook for LNG exports remains robust, underpinned by a sizeable inventory of FID and pre-FID projects concentrated in the United States. Contracting behaviour in 2023-2024 exhibited a clear shift toward extended tenors and higher contracted volumes, signalling sustained market confidence in North American supply optionality. The removal of the U.S. regulatory pause on non-FTA LNG approvals under the Trump administration catalysed a rapid normalisation of project advancement. Consequently, by November 2025 the United States had already recorded a substantial resurgence in sanctioning activity, with approximately 81 bcm (59 Mtpa) of LNG capacity reaching FID - forming the core of an estimated 65 Mtpa of global FIDs in 2025. Parallel progress in Mexican and Canadian LNG developments further reinforces the region's increasingly central role in the future global supply landscape.

As of 2025, North America's operational LNG liquefaction capacity totals about 119 Mtpa, with an additional 113 Mtpa under construction, pointing to a substantial near-term expansion of the region's export base. **A further 75 Mtpa of proposed capacity is expected by 2055, bringing total non-speculative capacity to around 308 Mtpa by 2040, where it broadly plateaus through the end of the forecast horizon.** This flattening of the capacity trajectory after 2045 suggests that, under the current project pipeline, the region may be approaching the limits of its presently identified non-speculative expansion path. At the same time, the existence of around 537 Mtpa of speculative capacity identified by Rystad Energy points to very substantial longer-term upside potential. The expansion is expected to be led overwhelmingly by the United States, which remains the principal driver of global LNG supply growth (Figure 6.41).

Figure 6.41

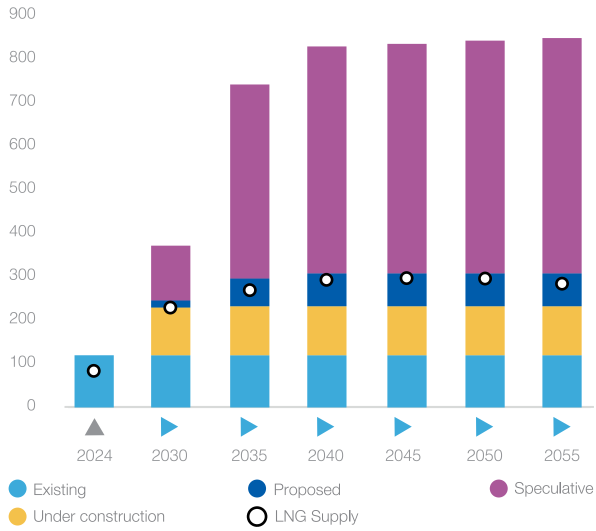
North America LNG liquefaction capacity outlook, 2024-2055 (Mtpa)



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

Figure 6.42

Projected North America's LNG exports and liquefaction capacity by project status, 2024–2055 (Mtpa)



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

However, the projected export profile indicates that liquefaction adequacy may become increasingly tight over time. Figure 6.42 shows that projected LNG exports approach the level of committed liquefaction capacity by 2030, implying that existing and under-construction projects will not, by themselves, be sufficient to accommodate the full scale of export growth embedded in the outlook. Sustaining that trajectory will therefore require the timely progression of part of the current pre-FID portfolio into sanctioned and operational capacity. From a market perspective, this means that the long-term deliverability of North American LNG exports will increasingly depend on whether planned capacity can be converted into effective liquefaction supply in time to preserve adequate export headroom and avoid a structural tightening in evacuation capability.

Canada entered the LNG export market with the launch of its first large-scale terminal, 14 Mtpa LNG Canada Phase 1, which began operations in 2025, marking a major milestone in the country's energy sector. This development positioned Canada, traditionally a pipeline-focused exporter to the United States, as an emerging supplier to global LNG markets, particularly Asia.

As of end-2025, three LNG export projects are under construction in Canada: LNG Canada Phase 1 with two trains, Woodfibre LNG, and Cedar LNG. LNG Canada's first phase is designed for 14 Mtpa, while a potential Phase 2 expansion, adding two additional trains and increasing capacity to 28 Mtpa, remains under consideration for the 2030s. Woodfibre LNG with a capacity of 2.1 Mtpa and Cedar LNG with 3.3 Mtpa are progressing toward planned start-up in 2027-2028. Tilbury LNG Phase 1, a smaller-scale project led by FortisBC, is advancing through regulatory processes and could add around 0.9 Mtpa of liquefaction capacity later in the decade. Meanwhile, proposed projects such as Ksi Lisims LNG and the LNG Canada Phase 2 expansion continue advancing through regulatory and commercial stages. If all active and proposed developments proceed, Canada's LNG export capacity could approach 46 Mtpa by 2050.

Canada, a long-standing net exporter of natural gas, is expected to see its net exports rise from about 60 bcm in 2024 to around 150 bcm by 2055. This trend is driven largely by the expansion of LNG exports, particularly to the Asia Pacific region, with Canada's share of North American LNG exports projected to reach nearly 23% by 2055. The Canadian gas market remains deeply integrated with the United States through an extensive cross-border pipeline network, with most exports flowing to United States regions such as the Midwest, where gas-fired power generation is significant. Pipeline deliveries to the United States, currently at about 89 bcm in 2024, are expected to stabilize at 85 bcm until the mid-2040s, after which they will ease as a larger portion of Canadian gas is redirected toward LNG export commitments.

In 2024, **Mexico** imported approximately 66 bcm of natural gas from the United States via pipelines, a volume expected to increase to 117 bcm by 2055. This growth is driven by a combination of declining domestic production, rising power sector demand, and the country's emergence as a regional LNG exporter. Mexico is strategically leveraging its Pacific coast to tap into LNG export opportunities, benefiting from access to low-cost US gas and its advantageous location for reaching Asia Pacific markets.

Mexico's LNG export is projected to rise to roughly 6 Mtpa by 2055, establishing the country as an increasingly significant supplier in the global LNG market. The build-out of national LNG infrastructure is progressing, beginning with the emerging FLNG hub at Altamira. The first unit, with a capacity of 1.4 Mtpa, commenced operations in 2024 and delivered its inaugural cargo to Europe in October of that year, with up to three FLNG units expected to be in place by 2027. On the Pacific coast, the Energía Costa Azul (ECA LNG) Phase 1 project, converting a former import terminal into an export facility, is advancing toward its planned 2026 startup. Additional growth is anticipated from the Saguaro Energía LNG development in Sonora, which targets 9.4 Mtpa of capacity, with its first phase slated to begin commercial operations in 2030.

In 2024, the **United States** remained a dominant force in global gas markets, with net exports exceeding 132 bcm. This included 85 Mt (118 bcm) of LNG shipments, with the remainder delivered via pipeline to Mexico and Canada. Looking ahead, long-term projections point to continued growth in the US natural gas exports, reaching approximately 426 bcm by 2055. Of this, around 292 bcm (212 Mt) is expected to be in the form of LNG, making up around 69% of total exports. US LNG exports are projected to climb steadily, peaking at 245 Mt in 2035, and easing thereafter to 212 Mt by 2055.

This outlook is supported by a strong pipeline of LNG infrastructure development. Five major liquefaction projects currently under construction, Corpus Christi Stage 3 (10 Mtpa), Golden Pass (18 Mtpa), Plaquemines (20 Mtpa), Port Arthur (13.5 Mtpa), and Rio Grande (17.6 Mtpa), are set to add approximately 80 Mtpa of new capacity between 2024 and 2028. These additions are expected to push total US LNG output toward levels exceeding 255 Mtpa by 2055, forming the foundation for the projected rise in export volumes through 2035 and beyond.

Commercially, the US LNG model continues to emphasise long-term stability and contractual flexibility. Most offtake agreements now extend well into the 2030s, with about 75% sold on a free-on-board (FOB) basis, allowing buyers to redirect or resell cargo depending on market conditions. Between 2024 and 2027, 93 Mtpa of contracts are scheduled for delivery, with around 32% secured by Asian buyers and 26% by European utilities. This shift toward diversified and buyer-driven strategies further strengthens the United States' role as a flexible, responsive supplier within the global LNG landscape.

However, US LNG developers are increasingly challenged by rising cost pressures and logistical constraints that are reshaping project timelines and financial planning. Engineering, Procurement, and Construction (EPC) costs have surged over the past two years, driven by inflation, supply chain disruptions, labour shortages, and the limited capacity of qualified EPC contractors. These factors have led to delays and cost overruns in several high-profile projects, including Golden Pass LNG, which has experienced both schedule slippage and contractor strain.

At the same time, liquefaction tolling fees in the United States have risen sharply, climbing from historical averages of USD 2.0-USD2.3/MMBtu to as high as USD 2.7/MMBtu for newer contracts. This increase reflects not only higher capital and operating expenses but also greater risk premiums being built into project economics. The rise in liquefaction costs, coupled with ongoing inflation and the gradual depletion of low-cost, easily accessible shale gas, is pushing up overall LNG export breakeven prices, which may affect long-term competitiveness, especially in price-sensitive markets.

Adding to these pressures are growing environmental and regulatory expectations. Developers are being called upon to significantly reduce lifecycle emissions, with a strong focus on methane mitigation, carbon intensity monitoring, and certification of responsibly sourced gas (RSG). Compliance with emerging standards, particularly from the European Union's methane regulation and carbon border adjustment mechanisms, is becoming a prerequisite for securing long-term offtake agreements, especially from environmentally conscious buyers.

While US LNG remains well-positioned globally due to its scale, contractual flexibility, and proximity to feed gas, these evolving cost and compliance dynamics introduce meaningful uncertainty. Developers must now balance capital discipline, regulatory alignment, and competitive pricing to ensure long-term market relevance in an increasingly complex global energy landscape.

In analysing the long-term potential for US LNG exports, one of the emerging dynamics shaping the outlook is the expected narrowing of the transatlantic gas price differential. This development could influence the depth and trajectory of the unfolding downward cycle in the global LNG market and, given the United States' role as the marginal LNG supplier, may weigh on LNG investment and export growth (see Box 6.1).

6.6 Global midstream capex requirements

Global midstream natural gas capex requirements are projected to remain substantial through 2055, reflecting the persistent need for supply diversification, market flexibility, and infrastructure resilience. **Over the 2025–2055 period, cumulative midstream investment is estimated at around USD 735 billion (real USD, base year = 2024).** The composition of this spending highlights a structural transition in international gas trade: LNG infrastructure (liquefaction and regasification) absorbs the dominant share of future investment, while incremental long-distance pipeline development plays a markedly smaller role.

Box 6.1 Asymmetric response of US LNG exports to Europe to erosion of the TTF-Henry Hub price signal

Expectations of a narrowing transatlantic gas price differential have become central to the outlook for global LNG trade (Figure 1). Many market narratives anticipate that European hub prices will ease as additional LNG supply enters the market, while Henry Hub prices will firm as marginal production costs rise and domestic demand expands. Because the European premium over United States gas prices is a primary indicator of netback attractiveness for Atlantic deliveries, its erosion has direct implications for United States liquefaction utilization and the volume of United States LNG exported to Europe. In turn, the responsiveness of United States export volumes is a key determinant of the duration and amplitude of a prospective LNG price down cycle: if volumes retreat quickly when the premium compresses, the market rebalances sooner; if volumes remain resilient, oversupply conditions and low prices can persist.

A widely held assumption is that the export response to the European premium is broadly symmetric. Under this view, the same mechanism that raised United States LNG deliveries to Europe when the premium widened should operate in reverse when the premium narrows, leading to a comparable reduction in exports and supporting a price rebound. However, the institutional structure of LNG trade provides reasons to expect an asymmetric adjustment. Liquefaction is characterized by high fixed costs and long term contracting, and a substantial share of revenue is secured through take or pay fees that are largely independent of short term price movements. Portfolio optimization and destination flexibility can further sustain flows during periods of weaker margins, while operational constraints and reliability considerations can limit the pace at which exports contract. These features imply the possibility of downside stickiness: exports may expand strongly when the European premium improves, but decline less when the premium deteriorates.

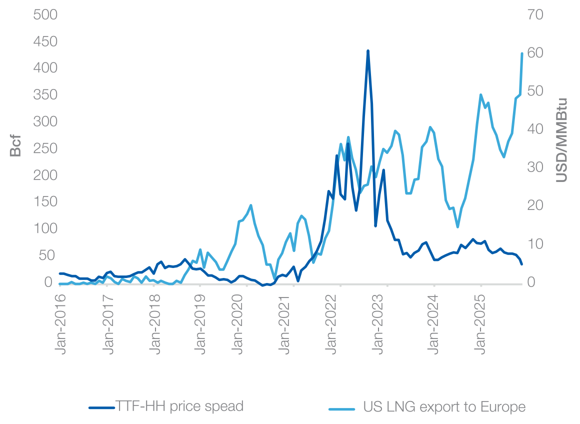
To assess whether this asymmetry is supported by historical evidence, we estimate a nonlinear autoregressive distributed lag model (NARDL), which is designed to capture both short term dynamics and long run relationships while allowing increases and decreases in a driving variable to have different effects. The price signal is measured using a logarithmic transformation of the TTF to Henry Hub price ratio, which facilitates an elasticity interpretation. The model separates cumulative increases from cumulative decreases in this price signal and estimates their long run associations with United States LNG exports to Europe. To account for the fact that United States exports are allocated across regions, we include a diversion control based on United States LNG exports to non EU destinations, thereby capturing global competition for United States cargoes. The estimation uses monthly data over July 2018 to December 2025, the period over which United States LNG exports to Europe are continuously positive in the dataset.

The estimates indicate a materially stronger long run response of Europe directed United States exports to increases in the European price signal than to decreases. The long run elasticity associated with premium strengthening is 0.44, while the elasticity associated with premium erosion is 0.26, and the difference is statistically significant. Interpreted in practical terms, a sustained 10% increase in the TTF to Henry Hub price ratio is associated with an increase in Europe US LNG exports of 4.3% in the long run, whereas a sustained 10% decline in the ratio is associated with a reduction in exports of 2.7%. The model also implies rapid adjustment toward the long run relationship, consistent with short lead times for cargo allocation once contractual and operational constraints are satisfied.

These findings have important implications for trade and price outlooks that rely on symmetric export elasticities. If the TTF–HH premium erodes as expected, a symmetric model would predict a comparatively sharp and timely reduction in United States LNG exports to Europe, accelerating the rebalancing of Atlantic Basin markets and shortening the low price phase of the cycle. The evidence of asymmetric responsiveness suggests that the export response to margin compression is likely to be more muted. As a result, market adjustment may depend more heavily on demand growth, supply delays, or curtailments elsewhere, raising the risk that low prices persist for longer than implied by symmetric elasticities. This asymmetry should be treated as a structural feature of the recent LNG market rather than a short lived anomaly, while also recognizing that future contractual structures, infrastructure constraints, and policy changes could alter the degree of stickiness observed in the historical sample.

Figure 1

US LNG exports to Europe (LHS) and the TTF–Henry Hub price spread (RHS), 2016–2025



Source: Energy Information Administration (EIA)

Chapter 6

Table 1

Long run response of United States LNG exports to Europe to changes in the TTF/HH price signal
(log–log elasticities; controlled NARDL with diversion control; monthly data 2018 to 2025)

Estimated long run effect	Elasticity (long run)	Illustration
When TTF/HH rises (Europe premium strengthens)	0.44	A sustained **10% increase** in TTF/HH is associated with about **+4.3%** higher exports
When TTF/HH falls (Europe premium erodes)	0.25	A sustained **10% decrease** in TTF/HH is associated with about **–2.7%** lower exports
Asymmetry (difference between the two)	0.19	The "upside" response is **materially larger** than the "downside" response

Note: The asymmetry is strongly statistically significant (Wald test $p = 9 \times 10^{-10}$). Exports also adjust relatively quickly toward the long run relationship (error correction term = –0.55, implying much of the adjustment occurs within 1–2 months).

Liquefaction is the single largest capex component, accounting for approximately USD 483 billion (about two-thirds of total midstream spending). Regasification follows at roughly USD 191 billion (around one-quarter), enabling import portfolio diversification and greater system flexibility, particularly in Asia Pacific and Europe. Pipelines represent the residual component at approximately USD 61 billion, reflecting both the maturity of legacy transmission networks and the increasing competitiveness of LNG as the preferred mechanism for interregional gas flows where demand, geopolitics, or routing constraints limit the viability of new cross-border trunklines.

The regional allocation of midstream investment is strongly asymmetric, consistent with the differentiated roles regions play across the international gas value chain (Figure 6.43). Export-oriented regions, Eurasia, North America, Africa, and the Middle East, concentrate the bulk of their capital in liquefaction, collectively accounting for well over two-thirds of global liquefaction capex. Import-oriented regions, Asia Pacific, Europe, and Latin America, allocate the majority of their spending to regasification, together representing more than 90% of global regasification investment. Pipeline capex is comparatively small and highly front-loaded, with meaningful requirements largely confined to Eurasia and Asia Pacific prior to 2035; together, these two regions account for around three-quarters of global pipeline spending, underscoring the limited role of new long-distance pipelines elsewhere.

This distribution signals a sustained shift away from predominantly linear, point-to-point pipeline systems toward a more liquid, portfolio-based LNG market structure. Energy security considerations, changing consumption patterns, and the commercial value of destination-flexible cargoes reinforce LNG's role as the backbone of the evolving global gas system. Consequently, midstream capex increasingly prioritises modular, scalable, and geographically diversified assets, liquefaction trains, import terminals, and associated logistics, expanding optionality and enabling gas access for markets that were previously underserved or structurally dependent on a narrow set of pipeline routes.

The time profile of spending further indicates a multi-decade build-out characterised by episodic "waves" of additions. Periods of accelerated capex typically align with clusters of FID on LNG mega-projects and the emergence of new or expanding export regions (notably North America, East Africa, and parts of the Middle East). Slower phases reflect project maturation, capacity absorption, and periodic rebalancing of supply and demand. Overall, the global midstream system evolves toward higher connectivity, greater redundancy, and improved operational flexibility, with LNG infrastructure increasingly central to the long-term architecture of gas trade and energy transition pathways.

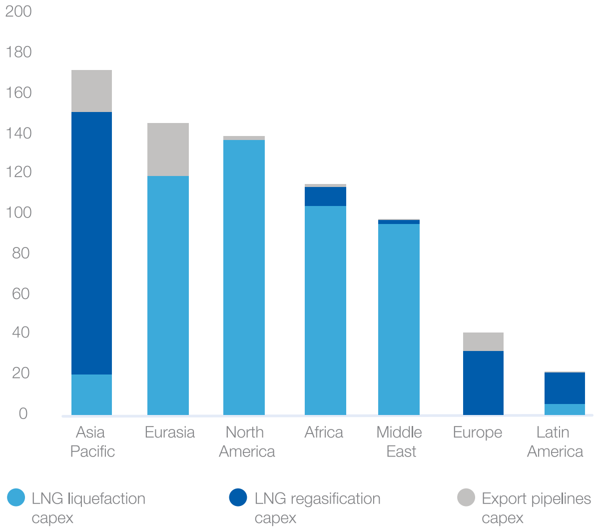
Asia Pacific is the largest midstream investment destination, with cumulative requirements exceeding USD 170 billion over 2025–2055 (roughly one-quarter of the global total). The region is overwhelmingly regasification-driven: more than USD 130 billion (close to three-quarters of regional spending) is allocated to import terminals, reflecting structural reliance on LNG imports and the need to expand and diversify receiving capacity well beyond 2040. Liquefaction and pipeline investments are comparatively limited, each on the order of USD 20 billion, underscoring Asia Pacific's primary role as the core demand centre in a progressively LNG-oriented global market.

Eurasia invests over USD 145 billion (around one-fifth of global spending), with a portfolio heavily concentrated in export infrastructure. Liquefaction accounts for nearly USD 120 billion (more than 80% of regional capex), giving Eurasia one of the highest liquefaction shares globally. Pipeline capex reaches approximately USD 26 billion, representing over 40% of global pipeline investment and exceeding the pipeline requirements of any other region. Regasification investment is effectively nil, consistent with an export-oriented midstream structure anchored in long-distance pipeline corridors and expanding LNG optionality.

North America contributes close to USD 140 billion (just under one-fifth of global total), almost entirely driven by liquefaction. More than USD 135 billion (over 95% of regional capex) is allocated to LNG export infrastructure, reflecting the scale and maturity of the North American

Figure 6.43

Cumulative midstream gas capex requirement by region, 2025-2055 (real billion USD, base year=2024)



Source: GECF Secretariat based on data from the GECF GGM

LNG build-out. Pipeline capex is marginal (around USD 2 billion) and regasification spending is negligible. Investment is notably front-loaded before 2035, after which the profile shifts toward optimisation, debottlenecking, and incremental expansions rather than large greenfield additions.

Africa records cumulative midstream spending exceeding USD 115 billion, positioning it among the most significant midstream investment regions globally. About USD 100 billion (roughly 85–90% of regional capex) is directed toward liquefaction, consistent with the emergence of new LNG export provinces and the monetisation of stranded or underdeveloped gas resources. Africa also stands out among exporter regions for having a non-trivial regasification component (around USD 10 billion), reflecting domestic and regional market development alongside export growth. Pipeline investment remains minimal (below USD 2 billion), indicating limited cross-border trunkline expansion and a strategic preference for LNG-based monetisation and logistics.

The **Middle East** invests just under USD 100 billion (about one-seventh of global spending), with an overwhelmingly export-oriented midstream profile. Liquefaction absorbs more than 95% of the region's total, while regasification and pipelines together remain marginal. This concentration reflects the region's role as a low-cost, large-scale LNG export anchor, with investment typically delivered in targeted, front-loaded phases aligned with long-term contracting and market positioning.

Europe allocates slightly more than USD 40 billion (around 6% of the global total), with investment dominated by import flexibility and security of supply. Regasification accounts for nearly USD 32 billion (close to 80% of regional capex), while pipeline spending of roughly USD 9 billion covers the balance, largely associated with system reinforcement and interconnection rather than new long-distance supply corridors. Liquefaction investment is effectively zero. The investment profile is concentrated in the earlier part of the horizon and declines after 2030 as demand plateaus and decarbonisation accelerates, while maintaining sufficient redundancy to manage seasonal and geopolitical risk.

Latin America represents the smallest regional contributor at around USD 18–20 billion (roughly 2–3% of global spending). Investment is predominantly import-side: regasification of about USD 16 billion constitutes the vast majority of the regional total, consistent with LNG's role in power generation, industrial supply, and hydropower balancing. Liquefaction and pipeline investments remain marginal, reinforcing Latin America's position as an import-oriented, demand-driven midstream market where LNG provides flexibility rather than underpinning large export corridors.

7

Sustainable Energy Scenario

Highlights

- The Sustainable Energy Scenario (SES) represents a development-centred pathway that reconciles accelerated economic and social progress with a Paris-aligned (circa 2°C) long-term temperature objective, while ensuring energy security, affordability, and sustainability across the energy trilemma.

- Global GDP expands from around USD 110 trillion in 2024 to approximately USD 248 trillion by 2055 in the SES, compared with USD 233 trillion in the Reference Case Scenario (RCS). This corresponds to an average annual growth rate of 2.6%, supporting improved energy affordability and stronger convergence across developing regions, particularly Africa.

- Global final energy demand increases from 428 EJ in 2024 to 613 EJ by 2055 in the SES, around 48 EJ higher than in the RCS. The additional demand is primarily driven by transport, industry, commercial activity, and modern residential energy services.

- Global electricity demand in the SES exceeds the RCS by approximately 4,264 TWh by 2055, reflecting accelerated electrification. By mid-century, renewables and natural gas jointly account for nearly 71% of global power generation, with natural gas contributing around 20% to ensure system flexibility and reliability.

- Primary energy demand reaches 785 EJ by 2055 in the SES, representing a 22% (20% CAGR) increase from 2024, compared with 768 EJ in the RCS. Despite a larger energy system, energy efficiency improves more rapidly, with primary energy intensity declining to 1.4 MJ per USD (PPP), compared to 1.5 MJ per USD in the RCS.

- Natural gas becomes the leading primary energy source by 2055, increasing by 48% (39% CAGR) to 221 EJ, around 25 EJ higher than in the RCS, and reaching a 28% share of the global energy mix (compared to 26% in the RCS). In contrast, coal declines significantly to 47 EJ, reflecting continued structural substitution toward gas and renewables.

- Global natural gas demand reaches 6,127 bcm by 2055 in the SES, approximately 708 bcm higher than in the RCS. This growth is driven primarily by the power sector (around 290 bcm), industry (148 bcm), and the residential sector (117 bcm), with the bulk of demand expansion occurring in Asia Pacific and Africa.

- Global natural gas trade expands to 2,144 bcm by 2055, about 377 bcm higher than in the RCS. LNG accounts for approximately 71% of total trade (compared to 65% in the RCS), reinforcing its critical role in balancing geographically uneven demand growth.

- Global energy-related emissions decline from 35.9 $GtCO_2e$ in 2024 to 23.9 $GtCO_2e$ by 2055 in the SES. Cumulative emissions are approximately 10% lower than in the RCS, demonstrating that expanded energy access and economic growth can be achieved alongside meaningful emissions reductions.

- CCUS deployment scales from 50 $MtCO_2e$ in 2024 to 8.9 $GtCO_2e$ by 2055 in the SES, around 7.5 $GtCO_2e$ higher than in the RCS. Natural gas-based CCUS accounts for over 4.3 $GtCO_2e$ of savings by 2055, representing the largest share of additional emissions reductions between the two scenarios.

7.1 Introduction to the Sustainable Energy Scenario (SES)

Energy is not simply one input among many in development; it is a general-purpose enabler that conditions what is feasible across the economy and across public service delivery. Where energy is scarce, unreliable, or unaffordable, economic complexity cannot deepen, productivity cannot scale, and essential services remain structurally constrained. The lived reality of energy poverty is therefore not only "low consumption" in statistical terms; it manifests as health systems that cannot sustain cold chains, schools without lighting or connectivity, water systems without pumping and treatment, firms constrained by poor power quality, and households pushed into time- and health-intensive fuel pathways. In United Nations Sustainable Development Goal (SDG) terms, this is the key mechanism: modern energy services are the enabling condition that makes most social objectives feasible at scale.

From this perspective, the normative ambition of the Sustainable Energy Scenario (SES) is anchored in a minimum-services conception of modern energy. SES is not an argument for high energy use as an end in itself; it is an argument for a development-consistent floor—enough reliable, affordable, and modern final energy to support high human development by mid-century. The floor is expressed in per-capita terms not because per-capita consumption is the objective, but because it is a workable proxy for whether societies can deliver a basic bundle of modern services to citizens and firms. In this sense, the floor provides the bridge between the energy system and the outcomes the energy system is intended to enable.

This framing leads directly to the chapter's central proposition: sustainable development and the decarbonisation of the energy system are not separable agendas. Sustainable development requires a rapid expansion of modern energy services, especially in regions where per-capita energy use remains far below levels associated with broad-based human development. At the same time, long-run development gains become fragile if the energy system evolves in a way that makes climate risks unmanageable; decarbonisation therefore functions as a binding constraint on how the expansion of energy services can be delivered over time. The tension is immediate: the fastest routes to scaling access and productive energy use often rely on proven, scalable infrastructure and dispatchable supply, while the climate constraint pushes the system away from unabated high-carbon fuels. SES is built around the need to reconcile these imperatives without sacrificing reliability or affordability, because unreliable or unaffordable "clean" energy fails the development test, while development pathways that entrench high-emissions dependence fail the sustainability test.

The energy trilemma provides an integrated way to articulate this reconciliation challenge: reliability (security of supply and system stability), affordability (cost-reflective yet socially acceptable access to energy services), and sustainability (local environmental quality and climate constraints). The trilemma is not an abstract triangle; it is revealed through stress. Price spikes, supply disruptions, and grid failures demonstrate that systems optimised for one objective can become fragile in the others. A pathway that is environmentally ambitious but systemically brittle invites political backlash and policy reversal. Conversely, a pathway that secures short-term supply by entrenching high-emissions infrastructure increases exposure to long-run destabilisation through climate impacts, trade measures, and stranded assets. A credible long-term scenario must therefore explain not only a destination, but the governance and investment logic that keeps all three dimensions within politically and economically tolerable bounds over decades.

Within that logic, natural gas plays a pragmatic enabling role in SES. The claim is not that gas is "the" solution, nor that it substitutes for electrification or the scaling of low-carbon energy. The claim is that in many systems—especially those characterised by rapid demand growth, infrastructure deficits, and high exposure to variability—gas provides a distinctive combination of attributes that stabilises the development–transition nexus: dispatchability and flexibility for balancing power systems; scalability for industrial heat and feedstocks; relative speed and modularity of deployment compared with more complex projects; and the ability to displace higher-polluting fuels such as traditional biomass and coal with immediate local health and air-quality benefits. In SES, gas is therefore treated as an enabler of orderly and equitable transitions because it reduces the risk that the transition itself becomes a bottleneck to development. This is also an energy security argument: when political acceptability is conditioned by reliability and cost, fuels and infrastructures that credibly support firm supply and system stability become part of the transition's security architecture.

Scenario framing is essential because the future energy system is inherently uncertain. Uncertainty is not peripheral; it is structural, created by interacting forces such as geopolitical fragmentation, technology learning and supply constraints, the pace of digitalisation and AI-driven electricity demand, climate extremes and adaptation burdens, and the evolution of finance and policy regimes. The function of scenarios is therefore not prediction; it is disciplined exploration—constructing internally consistent worlds that stress-test strategies and clarify the conditions under which certain outcomes become feasible.

Against this background, the RCS remains indispensable as a baseline trajectory grounded in current policy settings, observed market trends, and plausible incremental developments. However, precisely because it is reference-based, it tends to reproduce the constraints that keep per-capita energy services in many developing regions below levels associated with high human development and economic empowerment. This is not a claim that RCS is "wrong"; it is an acknowledgement of what a reference case is designed to do. Many widely cited energy outlooks similarly project substantial progress in electrification and efficiency, yet still leave persistent gaps in per-capita energy services amid rapid population growth and limited investment capacity. The persistence of this gap is itself a critical insight: it suggests that development-consistent energy service levels are unlikely to be reached through incrementalism alone.

This recognition motivates the creation of SES as a normative scenario. SES is designed as a supplement to RCS, not a replacement, because it answers a different question. While RCS asks what the future may look like if current trajectories persist, SES asks what the future must look like—and what enabling conditions must hold—if two objectives are pursued jointly. The first objective is developmental: by 2055, reach a minimum level of final energy consumption per capita consistent with high human development, operationalised as 50 GJ per person (in 2025 terms), and meet a minimum electricity consumption floor by 2055, interpreted as roughly 1,000 kWh per person per year. The second objective is climatic: align cumulative emissions and long-run system evolution with the Paris-aligned ambition of limiting warming to around 2°C above pre-industrial levels by the end of the century. SES therefore functions as a disciplined parallel world: a plausible yet purpose-driven storyline that explores how sustainable development and climate constraints can be reconciled while keeping reliability and affordability within workable bounds.

7.2 SES storyline

SES begins from a political-economy premise: the mid-2020s crystallise a global understanding that energy poverty is not only a social deficit but a systemic risk. As climate extremes intensify and geopolitical competition complicates supply chains, the stability of societies and the legitimacy of institutions increasingly depend on whether energy systems can deliver reliable and affordable services to households and firms. The "polycrisis" framing becomes widely accepted: energy security, food security, fiscal stability, climate impacts, and technological disruption are treated as coupled systems rather than separate policy silos. The implication is that energy policy is no longer framed primarily as a sectoral optimisation exercise, but as development strategy with macroeconomic and security consequences.

In SES, this shift does not produce a naïve return to central planning or a simplistic global-cooperation narrative. Instead, it produces a pragmatic synthesis: the world remains geopolitically competitive, but there is sufficient convergence on the developmental necessity of modern energy access to enable targeted cooperation on finance, technology transfer, and infrastructure standards. This cooperation is not normative idealism; it is risk management. Disorderly transitions and chronic energy poverty generate migration pressures, macro-instability, and conflict risks that spill across borders, making selective cooperation a rational response even in a fragmented world.

The macroeconomic logic of SES follows from this political shift. Compared with RCS, SES implies slightly stronger global growth not because frictions disappear, but because investment in energy and public infrastructure raises productive capacity, reduces losses from outages and fuel insecurity, and enables structural transformation in developing countries. In the calibration used for SES, global growth averages around 2.6% per year, compared with 2.4% in RCS. This difference matters because it reflects the scenario's causal structure: energy access is treated as capital formation and productivity enhancement rather than as consumption subsidy. Growth is supported by electrified public services, logistics upgrades, digitalisation, and gradual expansion of domestic value chains in developing economies. The AI-driven digital economy plays a dual role: it raises electricity demand through data centres, networks, and digital services, while also improving coordination across supply chains, reducing transaction costs, and accelerating technology diffusion. SES therefore treats AI as a structural factor that increases the premium on reliable power systems while improving the productivity of energy and capital.

A defining pillar of SES is the transformation of investment capacity in low-income and lower-middle-income regions, particularly in Africa. Reaching modern energy floors amid rapid population growth in Africa and developing Asia Pacific countries requires a step-change in capital mobilisation—not only for energy supply but also for health, education, water, transport, and governance systems that enable economic empowerment. SES resolves this constraint through a coherent set of enabling conditions. Multilateral development banks and regional institutions undergo mandate and balance-sheet reforms that expand concessional lending, scale guarantees, and mobilise private capital through blended finance. Debt sustainability frameworks evolve so that productive, growth-enhancing infrastructure, especially power grids, clean cooking transitions, and industrial corridors, can be financed without triggering immediate fiscal crises, including through restructuring linked to credible development and energy plans. Risk mitigation becomes more standardised through political risk insurance, currency hedging mechanisms, and regional power purchase frameworks that reduce the persistent risk premium that has historically made capital prohibitively expensive in many African contexts. In parallel, domestic reforms—better revenue mobilisation, transparent procurement, stronger utility governance, and credible tariff structures with targeted social protection—create the institutional conditions required for long-lived infrastructure investment.

Within this enabling environment, the pathway in SES is not "leapfrogging without building"; it is accelerated building: grids, power systems, gas and electricity infrastructure, transport corridors, ports, and industrial clusters. Population growth is treated as both a pressure and a potential demographic dividend, contingent on education and job creation. SES therefore treats energy demand growth as desirable only insofar as it becomes increasingly "productive demand": electricity for SMEs, cold chains, irrigation, processing, digital services, and manufacturing. At the same time, SES explicitly recognises that demographic uncertainty matters for access outcomes even when it appears modest in aggregate energy volumes; for that reason, multiple demographic variants and their implications were examined for both primary and per-capita energy consumption (see Box 7.1).

Energy security in SES is defined more broadly than fuel availability. It includes the resilience of infrastructure to climate extremes, the diversity of supply routes, the stability of prices, and the ability of systems to absorb shocks without widespread curtailment. This broader definition has direct implications for the energy mix. SES does not assume that variable renewables can be scaled without significant system costs, grid expansion, and firm-capacity requirements. Instead, the scenario internalises the costs of intermittency and system balancing in power system decision-making. As wind and solar expand, investments in transmission, distribution, storage, and backup capacity are treated as integral components of total system cost rather than externalities. This prevents reliance on unrealistically low effective costs for very high VRE penetration and creates a coherent economic rationale for firm, flexible capacity that stabilises the system under variability and extreme events.

In this context, natural gas becomes a structural element of energy security rather than a residual fuel. Gas is not framed as a competitor to renewables; it is framed as a complementary system resource. Gas-fired generation provides dispatchable power to support expanding electrification, stabilise grids as VRE shares grow, and meet non-substitutable demand growth associated with digitalisation and critical services. Gas supports industrial development through process heat and feedstocks, and it plays a targeted role in hard-to-electrify transport segments through LNG for heavy-duty vehicles and shipping. This is not presented as ideology; it follows from the scenario's development-first objective. When the priority is to raise energy services per capita quickly and reliably, the energy system must rely on technologies that can be deployed at scale, integrated into grids and industrial systems, and financed under real-world constraints.

SES also assumes that the governance of energy pricing evolves to support both affordability and investment. In many developing regions the barrier is not only physical access but affordability relative to household incomes and the financial fragility of utilities. SES resolves this through differentiated pricing: lifeline tariffs and targeted support for basic household services and clean cooking transitions, paired with cost-reflective pricing for higher-consumption segments and productive users, alongside reforms that reduce losses and improve collection. Broad, untargeted subsidies—often fiscally costly and regressive—are progressively replaced by targeted mechanisms that protect the poorest while maintaining the financial viability required to expand networks. This is a microeconomic foundation of the macro story: without viable utilities and credible tariff structures, the investment surge required for development cannot be sustained.

The sustainability logic of SES is therefore not a single lever but a portfolio. Efficiency improvements reduce energy intensity; electrification shifts demand toward increasingly low-carbon power; renewables and other low-carbon sources expand; coal and traditional biomass are displaced; and residual emissions are managed through selective carbon capture in key sectors and, later in the horizon, an expanding role for carbon dioxide removal. SES recognises that temperature overshoot is plausible when development imperatives drive rapid energy expansion, and it treats overshoot as a risk to be managed through credible long-run pathways for emissions reduction and, where necessary, removals. Direct Air Capture and other removal technologies enter as late-horizon system tools that become economically deployable later in the period, supporting reconciliation of cumulative emissions with long-run temperature goals without being used as justification to delay development.

Finally, SES differs from RCS not only in outcomes but in philosophy. RCS describes a plausible continuation of today's path, including progress in technology and policy but constrained by existing institutions and investment realities. SES describes a world in which development requirements are treated as binding and therefore force the system to mobilise finance, infrastructure, and policy coherence beyond what reference trajectories imply. SES thus expands the analytical space of the Global Gas Outlook by providing a disciplined answer to a question reference cases often leave implicit: what it would take to ensure that the transition is not only lower-carbon, but also development-consistent, equitable, and resilient.

Box 7.1 Population uncertainty and the energy demand outlook

Long-run energy outlooks often treat the United Nations medium-variant population projection as a natural reference case, but it should not be interpreted as a "most likely" trajectory with narrow error bars. Its uncertainty is structural: it rests on assumptions about fertility, mortality (life expectancy), and migration that can deviate persistently from historical patterns and, crucially, compound over time. Fertility outcomes are shaped by shifting socioeconomic conditions (urbanisation, education, labour markets, housing and childcare costs, cultural change, and policy), and small, sustained differences in fertility paths accumulate into large differences in population by mid-century. Mortality is likewise uncertain because it is sensitive to public health capacity, ageing-related disease burdens, shocks, and long-run improvements in prevention and treatment. Migration adds an additional layer of unpredictability through geopolitics, conflict, and climate pressures. Moreover, current and emerging health and biomedical technologies widen the range of plausible demographic futures: rapid progress in screening, chronic-disease management, vaccines, and personalised medicine could accelerate longevity gains, while advances in reproductive medicine (together with changing social norms and economic constraints) could shift realised fertility in either direction. Taken together, these factors mean that the medium variant is best framed as a benchmark assumption, not a certainty, particularly when the analysis extends to 2055.

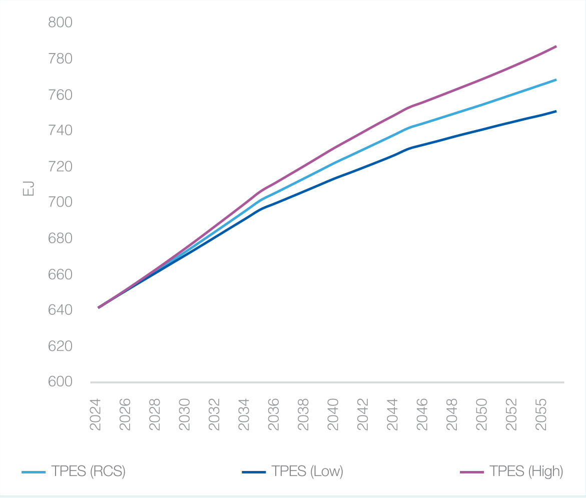
To better understand the implications of demographic uncertainties in our future energy trends, we ran a sensitivity analysis in GGM using the UN low and UN high population variants around the UN medium (RCS) path. Figure 1 and Figure 2 reports the resulting trajectories of total primary energy supply (TPES) and total final energy supply (TFES) in absolute terms (EJ). By 2055, the demographic spread is large: population ranges from 8.94 billion (low) to 10.78 billion (high), around 9.82 billion RCS, an uncertainty of roughly 1.85 billion people by mid-century.

A central result is that, in this configuration, aggregate energy volumes are comparatively insensitive to population uncertainty, especially relative to the demographic spread. By 2055, TPES reaches 768 EJ in the RCS, compared with 751 EJ under the low variant and 788 EJ under the high variant, roughly −2.3% to +2.4% around the RCS despite a near ±10% population deviation. TFES shows a similarly bounded response: 564 EJ (RCS) versus 546 EJ (low) and 575 EJ (high), or about −3.2% to +2.0% around the RCS. The divergence across variants is modest early in the horizon and becomes more visible only toward mid-century, implying that, within this experiment, population uncertainty is a second-order driver of total system energy compared with other forces embedded in the reference trajectory.

The more consequential effect appears when outcomes are viewed through an energy-access lens, where per-capita availability matters. Because TFES responds less than the population, the demographic variants translate into a pronounced spread in final energy per person by 2055: 57.4 GJ/person (RCS) versus 61.1 GJ/person (low) and 53.3 GJ/person (high). This is a 7.8 GJ/person range in 2055 (about a 14.6% gap between the low and high variants). Figure 3 highlights a qualitative difference in the late horizon: in the high-population case, per-capita TFES in 2055 (53.3 GJ/person) is only marginally above its 2024 level (52.6 GJ/person), implying that much of the RCS improvement in per-capita final energy is effectively eroded by demographic dilution. In contrast, the low-population case sustains a clearer rise in per-capita final energy.

Figure 1

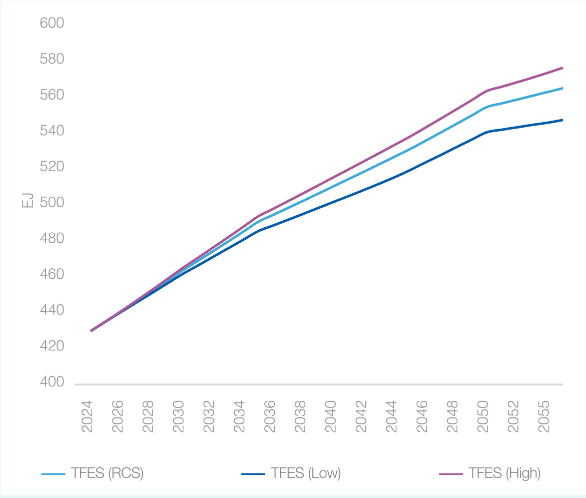
TPES sensitivity to high and low variant population projections



Source: GECF Secretariat based on data from the GECF GGM

Figure 2

TFES sensitivity to high and low variant population projections

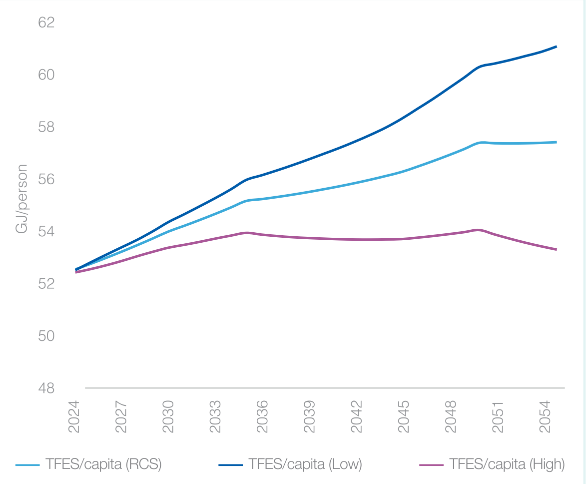


Source: GECF Secretariat based on data from the GECF GGM

Chapter 7

Figure 3

TFES per capita sensitivity to low and high variant population projections



Source: GECF Secretariat based on data from the GECF GGM

These findings carry two policy-relevant insights. First, demographic uncertainty may look "small" when communicated only as an aggregate TPES/TFES range, yet it becomes material when translated into per-capita terms, the metric most directly aligned with energy access, affordability pressures, and distributional outcomes. Second, the high-population variant is an access stress test: maintaining the RCS 2055 per-capita TFES level (57.4 GJ/person) under the high-population path would require TFES of roughly 619 EJ in 2055, about 44 EJ above the 575 EJ delivered in the high-variant outcome shown in Figure 2. In practice, closing such a gap would require some combination of additional system expansion, faster end-use efficiency, reduced losses, and targeted access policies that protect minimum service levels as the population grows. The overall message is that population uncertainty should be treated not merely as a marginal band around total demand, but as a first-order uncertainty for per-capita energy outcomes and access-oriented policy planning toward mid-century.

7.3 SES assumptions

The sectoral assumptions embedded in SES are not ad hoc "pro-gas" adjustments; they are the quantitative expression of the scenario's organising logic. If SES is to reconcile development floors with a Paris-aligned temperature outcome, it must accelerate delivery of modern energy services while preventing a high-emissions lock-in. Natural gas is positioned as a pragmatic enabler because it can deliver scalable, firm, and affordable energy services at speed in systems where reliability and cost remain binding constraints, while the broader policy and technology package constrains emissions intensity through efficiency improvements and the scaling of decarbonisation options. The assumptions therefore reflect three design principles: reliability and affordability are treated as binding constraints, system costs (including balancing and network requirements) are explicitly internalised in power-sector choices, and the expanding role of gas is made compatible with the climate objective through a progressively stronger carbon-management framework at the system level.

The SES assumptions are best understood as structured deviations from the RCS, which remains the descriptive benchmark. Where the RCS reflects continuation of prevailing dynamics and policy commitments, SES introduces stronger development-oriented growth, stronger infrastructure deployment, and stronger emissions-management requirements for the sectors where deep abatement cannot be achieved by electrification alone. SES therefore supplements the RCS by clarifying what must change, and by how much, to jointly satisfy development and climate objectives under trilemma constraints. The key assumptions are summarised in Table 7.1.

7.3.1 Minimum energy threshold assumptions

SES adopts a development-based energy-services floor by imposing a minimum level of final energy consumption per capita consistent with attaining high human development (HDI). Drawing on cross-country empirical work linking energy use to HDI outcomes, the scenario applies a benchmark range of 40–70 GJ/person/year, using 50 GJ/person/year as a practical reference level below which human development is typically constrained and above which improvements in HDI tend to plateau. The floor is treated as a proxy for the ability to deliver essential modern services—health, education, adequate housing and thermal comfort, basic mobility, and productive economic activity—rather than as a welfare metric in itself. Because the relationship between per-capita energy use and welfare weakens as economies become more efficient and shift toward services, SES applies the floor dynamically by adjusting it over time at country level to reflect improvements in energy intensity and end-use efficiency, targeting minimum service availability rather than a rigid consumption quantity. In parallel, given the growing centrality of electrification and non-substitutable electricity services, SES also imposes a minimum per-capita electricity consumption floor by mid-century equal to 1,000 kWh/person to ensure development progress is grounded in access to reliable modern electricity.

7.3.2 Residential and commercial sectors

The residential and commercial assumptions operationalise the development objective while remaining compatible with long-run climate constraints. In many low-income regions, energy poverty is not primarily a lack of total energy; it is a lack of modern energy services. Households rely on traditional biomass for cooking and heating, often with severe health impacts

Table 7.1

Comparing global assumptions in SES and RCS

	RCS	SES
Minimum energy requirement	Not applicable	Per capita final energy consumption: 50 GJ/person (2025 level) Per capita electricity demand: 1000 kWh/person
Carbon prices	**USD 100 per ton of CO_2** by **2040** and exceeding **USD 140 per ton** by **2055**	USD **110 per ton of CO_2** by **2040** and exceeding **USD 160 per ton** by **2055**
The residential and commercial sector	The share of traditional biomass in Africa's energy mix will decline to **18%**	The share of **traditional biomass** in Africa's energy mix will decline to **8%**
		Significant increase in natural gas and electricity grid expansion in Sub-Saharan Africa
	AI-driven energy consumption is projected to contribute approximately **10% to the non-substitutable electricity** demand growth in the **commercial segment** by 2055	**AI-driven energy consumption** is projected to contribute approximately **30% to the non-substitutable electricity** demand growth in the **commercial segment** by 2055
	The coefficient of performance **(COP) for heat pumps: 2.5**	The coefficient of performance **(COP) for heat pumps: 3**
Transport sector	LNG trucks and buses are included as per the policy target announcements	The global fleet of LNG-fueled trucks growth rate: 2023-2030: **10%** 2031-2040: **8%** 2041-2050: **5%** LNG truck efficiency: **25-30 kg of LNG per 100 km** Average annual mileage: **100,000-120,000 km per vehicle**
	LNG-fueled vessels are assumed according to the policy target announcements	The growth in the number of LNG-fueled vessels: 2023-2030: **15%** 2031-2040: **10%** 2041-2050: **5%**
Industrial sector	CCUS applied in the industrial sector according to the policies announced	CCUS implemented by 2055: 75% of energy-related emissions
Power sector	**Average CCGT efficiency** by 2055: **51%**	**Average CCGT efficiency** by 2055: **56-58%**
	New gas-fired capacity: CCGT and Steam turbine with CCUS after 2038	Average CCGT efficiency by 2055: 56-58% New gas-fired capacity: only CCGT with CCUS
	Global **gas-fired power capacity net addition: (+1,153 GW)**	Global **gas-fired power capacity net addition: (+1,335 GW)**
	Global **coal-fired power capacity net addition: (-1,377) GW** with CCUS applied for the remainder	Global **coal-fired power capacity net addition: (-1,791) GW** with CCUS applied for the remainder
	Intermittency-related costs are not included	Including intermittency costs in Levelized Cost of Electricity (LCOE) for variable renewable energy (VRE): • Cost of backup capacity: **+USD 10-30/MWh** • Transmission and distribution expansion costs: **+USD 5-15/MWh** • Curtailment and system balancing costs: **+USD 5-10/MWh**
Hydrogen sector	CCUS applied in hydrogen production: up to 33% in selected countries	CCUS applied in hydrogen production: 80% for all countries
Natural gas trade	Global liquefaction capacity utilisation: **80%** total global liquefaction capacity in 2055: **998 Mtpa**	Global liquefaction capacity utilisation: **83%** total global liquefaction capacity in 2055: **1,340 Mtpa**
	Global regasification capacity utilisation: **50%** Total global regasification in 2055: **1,604 Mtpa**	Global regasification capacity utilisation: **55%** Total global regasification in 2055: **2,020 Mtpa**
Emissions removal	DAC is not included	DAC introduced after **2040s** and scaling to **1.5** $GtCO_2$ by 2055

Source: GECF Secretariat based on data from the GECF GGM

Chapter 7

and low efficiency, while businesses face unreliable electricity that constrains productivity and forces costly self-generation. SES therefore treats the substitution of traditional biomass and the expansion of reliable electricity as direct development interventions.

A key assumption is that the share of traditional biomass in Sub-Saharan Africa's residential energy mix declines more rapidly in SES than in the RCS. In the RCS, traditional biomass remains substantial, declining to 50%; in SES, the share declines to 25%, reflecting a stronger clean cooking transition and wider access to modern fuels. This shift is central to the scenario's equity logic: it yields immediate health and welfare gains, reduces time poverty, and improves productivity, while also reducing pressure on local ecosystems. Natural gas supports this transition directly through expanded fuel availability (including LPG and gas distribution in urban and peri-urban areas) and indirectly through gas-to-power that improves electricity reliability and enables electric cooking options over time.

SES further assumes a significant increase in natural gas and electricity grid expansion in Sub-Saharan Africa. This is deliberately dual: grids must expand for electrification, but electrification only becomes development-enabling when supply is reliable. Where renewable resources are abundant but integration costs, system constraints, and planning capacity are binding, gas provides scalable firm capacity and operational flexibility. In many contexts, it also displaces diesel generation and coal where present, lowering local pollution and improving affordability. Gas infrastructure expansion is therefore not framed as a competitor to electrification; it is framed as a reliability scaffold that makes electrification economically productive and politically durable.

SES also incorporates the structural impact of digitalisation and AI on electricity demand. AI-driven energy consumption is assumed to contribute approximately 30% to the growth in non-substitutable electricity demand in the commercial segment by 2055. This is not merely a volume wedge; it is a shift in load characteristics. AI-related demand is high-availability and power-quality sensitive, raising the value of grid stability and firm capacity. Within SES, this reinforces the role of dispatchable resources as the system scales and networks are strengthened.

In developed countries and urbanising regions, building electrification proceeds through the diffusion of high-efficiency end-use technologies. Heat pump performance improves, with the coefficient of performance rising from 2.5 in the RCS to 3.0 in SES. This increases the feasibility of electrifying thermal services without proportionally increasing electricity demand, improving system efficiency. SES does not assume, however, that electrification eliminates the system role of gas. Instead, the role of gas in buildings is rebalanced over time: direct gas use declines in some segments while gas's system role through power generation and peak/seasonal support grows in importance where climate extremes and network constraints create reliability risks.

7.3.3 Transport sector

Transport assumptions in SES reflect the heterogeneity of decarbonisation options across modes. Passenger transport electrification can proceed rapidly where incomes, charging infrastructure, and grids support it. Heavy-duty freight and shipping face more complex constraints related to range, weight, refuelling infrastructure, and slow fleet turnover. SES therefore positions LNG not as a final decarbonisation endpoint, but as a pragmatic transition wedge that reduces emissions relative to oil-based fuels and improves air quality while longer-term options mature.

In the RCS, LNG trucks are included only in a limited way. In SES, the global fleet of LNG-fuelled trucks grows at an explicit rate: 10% per year during 2024–2030, 8% per year during 2031–2040, and 5% per year during 2041–2055. LNG truck efficiency is assumed at 25–30 kg of LNG per 100 km, with average annual mileage of 100,000–120,000 km per vehicle, reflecting the operational intensity of heavy freight. These parameters embed a storyline in which LNG corridors and refuelling infrastructure scale alongside broader logistics modernisation.

Shipping follows a similar transitional logic. In the RCS, LNG-fuelled vessels are included only in limited form. In SES, the number of LNG-fuelled vessels grows at 15% per year during 2024–2030, 10% per year during 2031–2040, and 5% per year during 2041–2055. This reflects LNG's role as a compliance and fuel-switching option as standards tighten in a sector where immediate deep decarbonisation remains constrained by cost and infrastructure. To preserve climate integrity in this pathway, SES assumes that methane slip is progressively controlled through tighter technology standards and operational practices, safeguarding the emissions advantage of LNG over oil-based fuels.

In developing regions these transport assumptions are also development-relevant. Modern logistics systems are productivity infrastructure: they reduce costs, expand market access, and support industrialisation. In SES, LNG adoption in heavy freight and shipping is therefore linked to corridor development, port modernisation, and industrial cluster formation, reinforcing the internal consistency between higher growth, rising per-capita energy services, and the need for scalable supply chains.

7.3.4 Industrial sector

Industrial development is central to the SES development narrative, particularly for regions seeking to increase economic output and reduce poverty. Industry provides employment, value addition, export revenues, and fiscal capacity, yet it remains difficult to decarbonise because many processes require high-temperature heat and involve process emissions. SES therefore adopts a dual strategy: gas supports industrialisation and competitiveness, while efficiency and CCUS prevent industrial expansion from undermining climate objectives.

Relative to the RCS, SES imposes a transformative shift in industrial carbon management: by 2055, CCUS is implemented such that 75% of energy-related industrial emissions are captured. This assumption implies not only technology availability but institutional capability: CO_2 transport networks, storage licensing regimes, long-term liability frameworks, and monitoring and verification systems must scale. SES therefore implies the emergence of industrial decarbonisation hubs where gas infrastructure, industrial demand centres, and CO_2 storage sites are integrated. The hub logic is essential for plausibility because it reduces unit costs, enables shared infrastructure, and accelerates replication of standardised projects.

Within this architecture, gas plays multiple roles: process heat and feedstock (notably in chemicals and fertiliser), industrial CHP and onsite generation that improve reliability where grids remain constrained, and—over time—feedstock for low-carbon hydrogen as CCUS and hydrogen systems mature. This design allows industrial energy demand to expand while emissions intensity declines, maintaining internal consistency between the development objective and long-run climate constraint.

7.3.5 Power sector

The power sector is where the energy trilemma becomes most binding: electrification increases the economic value of reliability, affordability shapes political legitimacy, and emissions intensity must decline rapidly. SES power-sector assumptions are designed to make high electrification compatible with reliability and the temperature objective. Natural gas is positioned as a principal firm and flexible resource that enables this compatibility, while efficiency improvements and CCUS constrain emissions.

In the RCS, average combined-cycle gas turbine efficiency rises to 51% by 2055. In SES, the assumed efficiency rises to 56–58% by 2055, reducing fuel use per unit of electricity and lowering both costs and emissions. This assumption reflects faster diffusion of best-available technologies and operational improvements enabled by stronger investment and digital monitoring.

SES also strengthens the constraint on the nature of new gas-fired capacity. In the RCS, new gas-fired capacity includes combined-cycle gas turbines and steam turbines, with CCUS applied after 2038. In SES, new gas-fired capacity is assumed to be only combined-cycle gas turbines with CCUS, reducing the risk of long-lived emissions lock-in. In effect, this turns gas from a conventional firm-capacity option into a carbon-managed firm-capacity option, supporting reliability while maintaining scenario credibility against the temperature objective.

These technology choices are paired with large-scale capacity shifts. Global gas-fired power capacity net additions are higher in SES than in the RCS, rising from +1,153 GW to +1,335 GW. At the same time, global coal-fired power capacity net additions become more negative, shifting from −1,377 GW in the RCS to −1,791 GW in SES, with CCUS applied for the remaining coal capacity. This reflects a power-sector logic in which gas accelerates coal displacement while also supporting renewable integration and system stability.

A critical methodological enhancement in SES is the explicit inclusion of intermittency-related costs in the levelised cost of electricity for variable renewables. In the RCS, these costs are not included. SES incorporates system costs: backup capacity costs of USD 10–30/MWh, transmission and distribution expansion costs of USD 5–15/MWh, and curtailment and system balancing costs of USD 5–10/MWh. Internalising these costs changes the economic ordering of options in many systems and strengthens the rationale for flexible firm capacity, particularly in developing regions where network constraints and system fragility can dominate project-level LCOE comparisons.

These power assumptions also embed an energy-security framing. As climate extremes and cyber risks rise, the value of resilient and dispatchable resources increases. Gas-fired power—supported by diversified supply chains and storage—adds resilience that complements renewables and reduces vulnerability to prolonged low-renewables periods. Overall, the power-sector assumptions embody the SES organising logic: renewables grow substantially, but gas remains a key reliability resource, with its emissions increasingly managed through efficiency and carbon capture.

7.3.6 Hydrogen sector

Hydrogen plays a strategic role in SES because it offers pathways to decarbonise segments that are difficult to electrify directly, including parts of industry and potentially segments of transport and seasonal balancing. SES treats hydrogen not as a universal substitute but as an option constrained by cost, infrastructure, and deployment speed. For that reason, SES assumes gas-based hydrogen with CCUS provides the primary scaling pathway in the early-to-mid horizon, enabling low-carbon hydrogen expansion without requiring an immediate, globally lowest-cost green hydrogen system.

In the RCS, CCUS is applied in hydrogen production up to 33% in selected countries by 2055. In SES, the assumption is far stronger: CCUS is applied in hydrogen production at 80% for all countries by 2055. This design choice preserves the scenario's development and security logic while maintaining climate credibility by shifting hydrogen growth toward low-carbon production pathways at scale.

The hydrogen assumption also strengthens the systemic role of gas: gas is not only a fuel and a flexible power resource, but an enabling molecule for low-carbon hydrogen production, which then supports emissions reductions in hard-to-abate segments. In SES, the hydrogen economy therefore acts as a demand anchor for gas in carbon-managed form, supporting investment while accelerating industrial decarbonisation through fuel switching.

7.3.7 Natural gas trade and infrastructure

The SES storyline requires significant expansion of gas trade and infrastructure—especially LNG—because it treats reliability and energy security as binding constraints in fast-growing regions. With accelerating electrification, rapid demand growth in emerging economies, and rising shares of variable renewables, flexible and diversified gas supply chains provide system stability. LNG is central because it allows importing regions to diversify supply sources and enables exporting regions to monetise resources while building domestic value chains.

In the RCS, global liquefaction capacity utilisation is assumed at 80%, with total global liquefaction capacity in 2055 at 998 Mtpa. In SES, liquefaction capacity utilisation rises to 83%, and total global liquefaction capacity in 2055 rises to 1,340 Mtpa. Similarly, regasification capacity utilisation rises from 50% in the RCS to 55% in SES, and total global regasification capacity in 2055 rises from 1,604 Mtpa in the RCS to 2,020 Mtpa in SES. These assumptions reflect a world in which LNG trade becomes more central not merely as commercial optimisation, but as an energy-security mechanism.

For developing regions, particularly in Africa and parts of Asia Pacific, expanded LNG import and regasification capacity becomes a practical pathway to firm electricity supply and industrial fuel switching where domestic production and pipeline connectivity cannot scale at the same pace as demand. In gas-producing African countries, LNG export revenues can strengthen fiscal capacity and foreign exchange, improving feasibility of infrastructure programmes provided governance and reinvestment channels function effectively. SES therefore links trade expansion to development outcomes through an explicit political economy: trade integration supports infrastructure and industrialisation, while the global system benefits from reduced energy poverty and more stable markets.

7.3.8 Methane abatement, CCUS scaling, and late-horizon removals

A development-forward SES still requires a credible emissions-management backbone to remain compatible with the long-run temperature objective. SES therefore imposes cross-cutting assumptions that progressively compress the emissions intensity of a larger energy system rather than relying on suppressed demand.

First, methane emissions are treated as a material constraint. SES implies a world in which monitoring and verification become routine and where regulatory and commercial standards increasingly require demonstrable reductions. This preserves the environmental advantage of gas relative to higher-polluting fuels and supports the legitimacy of gas expansion in power, industry, and transport as part of an orderly transition.

Second, CCUS is treated as infrastructure rather than an isolated technology. Industrial capture at 75% of energy-related emissions by 2055, the requirement that new gas-fired power capacity is deployed with CCUS, and hydrogen capture at 80% by 2055 collectively imply large-scale CO_2 transport and storage networks. The scenario's internal logic is that, as carbon-managed gas expands, shared CCUS infrastructure becomes more economically viable, lowering marginal costs and enabling wider decarbonisation of additional facilities over time.

Third, SES incorporates the risk of temperature overshoot and treats carbon removal as a late-horizon stabiliser rather than an early substitute for mitigation. The scenario assumes removal technologies, including direct air capture (DAC), become economically deployable in the latter half of the 2040s and scaling to 1.5 $GtCO_2$ by 2025 and can assist in managing residual emissions and potential overshoot. Removals are not used to justify delayed mitigation; they are introduced to close the gap between residual emissions and long-run temperature objectives once the system has already shifted toward lower-carbon energy services.

Taken together, the SES assumptions resolve the constraints embedded in the energy trilemma. Reliability is protected through explicit valuation of firm capacity and system costs; affordability is reinforced through system-level planning that avoids brittle, high-cost configurations; and sustainability is preserved through tighter emissions management, especially via CCUS scaling and late-horizon removals that address residual emissions.

7.4 Results

The results of the SES should be interpreted as a consistency set, what must be true about macroeconomic capacity, energy-system scale, technology deployment and market balancing, if development-centred energy-service expansion is pursued while remaining compatible with long-run Paris-aligned temperature ambition. The subsections below follow a deliberate logic: macroeconomic capacity (GDP) establishes investment feasibility; final energy and electricity quantify the scale of energy services delivered; hydrogen and primary energy describe the system architecture and fuel-mix adjustments; natural gas demand, supply and trade show how market balance is preserved under development-driven growth; and the emissions section demonstrates how the scenario reconciles higher energy services with lower cumulative emissions through a portfolio of efficiency, fuel switching, electrification, low-carbon power, targeted abatement and removals.

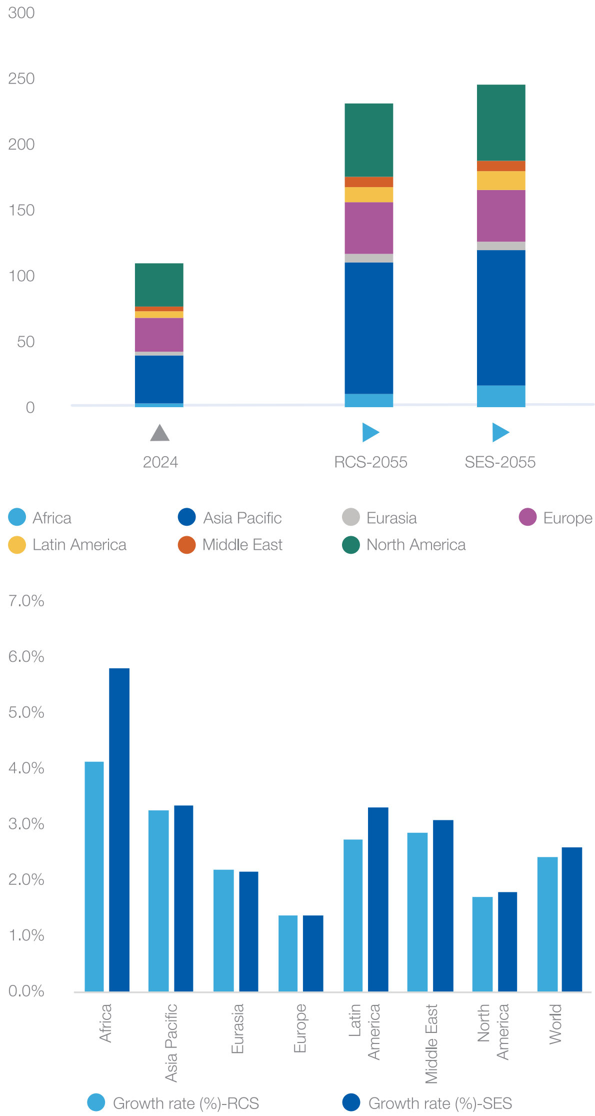
7.4.1 Economic growth

The macroeconomic setting of SES is best understood as an enabling condition rather than a forecast. Because SES is constructed to explore what it would take to reconcile accelerated sustainable development, especially in energy-poor regions, with a long-run trajectory compatible with the Paris Agreement's temperature ambition, GDP cannot be treated as an external backdrop. It is the macro variable that determines whether economies can mobilise the investment volumes required for power-system expansion, modern fuel infrastructure, industrial development, and the public infrastructure that makes energy services productive. In this framing, the SES energy-service floors are not reachable through technology substitution alone; they require a material strengthening of economic capacity in regions where population growth is high and infrastructure deficits are large. The GDP pathway therefore anchors the demand-side feasibility of the scenario's higher service delivery.

At the global level, SES embeds a modest but meaningful uplift in long-run growth relative to RCS. World real GDP (market exchange rate, base year = 2024) rises from about USD 110 trillion in 2024 to around USD 248 trillion by 2055 in SES, compared with USD 233 trillion in RCS. By 2055, global output is therefore about USD 14 trillion higher in SES, or around 6% above the reference trajectory. The corresponding average annual growth rate over 2024–2055 is 2.6% in SES versus 2.4% in RCS. The difference in annual rates may appear small, but its significance lies in compounding and in where it is concentrated. Consistent with a gradual "build-up" narrative, the SES–RCS global GDP gap remains limited in the near term (about 0.9% by 2030) and then widens as infrastructure reliability and productivity gains accumulate (around 2.5% by 2040, 4.7% by 2050, and 6.0% by 2055), which strengthens the plausibility of the pathway (Figure 7.1).

Figure 7.1

Global GDP outlook by region in SES and RCS (real USD trillion, base year = 2024)



Source: GECF Secretariat based on data from the GECF GGM

The defining macroeconomic feature of SES is not uniformly higher growth everywhere, but a rebalancing of growth toward regions where modern energy services must expand the fastest. Africa provides the clearest example. Africa's real GDP rises from about USD 2.5 trillion in 2024 to roughly USD 16.6 trillion by 2055, implying average annual growth of 5.8%, compared with 4.3% in RCS. By 2055, Africa's GDP is therefore about USD 6.7 trillion higher than in the reference trajectory, an uplift of roughly 68% relative to RCS. This is the macroeconomic counterpart of the SES development premise: raising per-capita energy services toward development-relevant floors under rapid population growth requires not only energy supply expansion but a substantial increase in economic output that can finance networks, public infrastructure, and industrial capacity. In SES, Africa's growth is therefore treated as an enabling condition for energy-enabled structural transformation: productive demand, industry, agro-processing, logistics, services and public infrastructure expand alongside household access so that rising energy consumption is increasingly tied to income generation and employment.

Asia Pacific remains the dominant contributor to global output in both scenarios, reflecting its scale and continuing industrial and service-sector growth. In SES, Asia Pacific GDP rises to about USD 104.3 trillion by 2055 compared with USD 101.5 trillion in RCS. The implied average annual growth rate is 3.4% in

Chapter 8

SES versus 3.3% in RCS, leaving the GDP level about 2.7% higher than the reference by 2055. Because the base is large, even this modest differential contributes meaningfully to the global uplift in absolute terms. An important structural implication of SES is therefore one of convergence: Asia Pacific's share of global GDP in 2055 is slightly lower in SES than in RCS (about 42% versus 43%), not because Asia Pacific slows, but because catch-up in Africa and other developing regions is faster.

Latin America also experiences a material uplift in SES. GDP rises from about USD 5.1 trillion in 2024 to around USD 14.3 trillion by 2055 in SES, compared with USD 11.9 trillion in RCS. The average annual growth rate increases from 2.7% to 3.3%, producing a GDP level roughly 19.5% higher than the reference by 2055 and raising Latin America's share of world GDP to about 5.7% in SES (versus about 5.1% in RCS). Within the SES logic, this is consistent with stronger investment in infrastructure and productive sectors that can absorb modern energy services and translate them into higher incomes and competitiveness.

The **Middle East** shows a more moderate but still meaningful GDP increase relative to RCS, with output reaching about USD 8.7 trillion by 2055 in SES compared with USD 8.1 trillion in RCS. The implied growth rate rises from 2.9% to 3.1%, yielding a GDP level about 7.5% higher by 2055, consistent with a scenario in which domestic value creation and industrial activity expand alongside the region's role in global energy supply.

In mature regions, SES does not depend on unrealistic growth accelerations, which strengthens internal credibility. North America grows somewhat faster in SES (average 1.8% versus 1.7% in RCS), reaching about USD 58.2 trillion by 2055, roughly 3.1% higher than the reference level. Europe's growth trajectory is essentially unchanged (about 1.4%), resulting in identical GDP levels by 2055 in SES and RCS (about USD 39.8 trillion). Eurasia is also broadly similar across scenarios. This distribution is analytically important: SES is not constructed as a uniformly "better" world; it is constructed as a world where additional growth is concentrated where it is required to make development-consistent energy-service expansion feasible.

These GDP paths also carry a clear distributional signature. In SES, **Africa**'s share of global GDP rises from about 2.5% in 2024 to about 6.7% by 2055, compared with about 4.2% in RCS. This shift reflects a world that does not accept persistent energy poverty as a long-run equilibrium. At the same time, Asia Pacific remains the anchor of the global economy, and mature economies continue to expand albeit at lower rates. The macroeconomic rebalancing therefore resembles convergence rather than discontinuity.

Finally, the GDP trajectories clarify why SES requires a different energy-system configuration than RCS. Higher GDP in developing regions implies faster growth of industrial output, services and infrastructure provision, which in turn raises demand for reliable electricity, modern fuels and energy-intensive materials. The macro uplift therefore reinforces the scenario's emphasis on scalability, affordability and reliability of energy supply. In SES, higher GDP is both the means and the consequence of accelerated development: it enables the financing of energy and public infrastructure, and it is enabled by the productivity gains that follow when modern energy services become reliable and widespread.

7.4.2 Global final energy demand

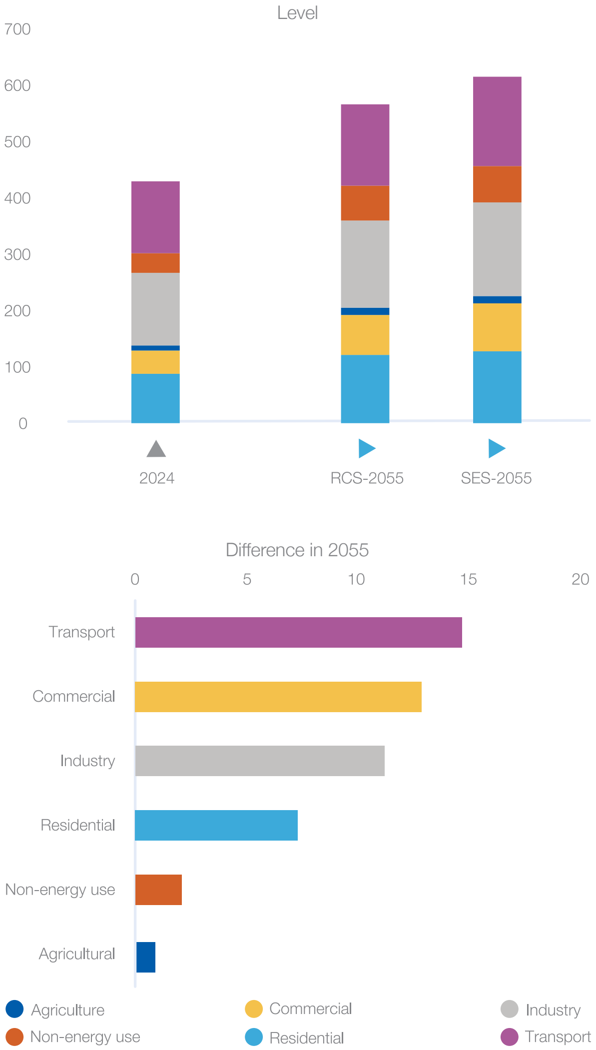
Global final energy demand increases in both scenarios, but the SES expands materially faster because it is constructed around higher delivery of modern energy services rather than demand saturation in energy-poor regions. **Total final energy rises from 428 EJ in 2024 to 613 EJ by 2055 in SES, implying average growth of about 1.2% per year, whereas in RCS it reaches 565 EJ (about 0.9% per year)** (Figure 7.2). The divergence is limited in the near term but widens through the middle decades as access and productive demand deepen: by 2035 global final energy reaches 496 EJ in SES versus 489 EJ in RCS, and by 2045 it reaches 553 EJ versus 530 EJ. By 2055, SES requires roughly 48.5 EJ more final energy than RCS. This time profile is important for plausibility: the additional energy required to close energy-service gaps emerges progressively as infrastructure is built, modern appliances and services diffuse, and economic activity shifts toward higher service and productive energy use.

In the **residential sector**, final energy demand rises from 87 EJ in 2024 to 128 EJ by 2055 in SES, compared with 121 EJ in RCS. The trajectories remain close early on—104 EJ in SES versus 103 EJ in RCS by 2035—but the gap widens as household energy services scale, reaching 116 EJ versus 112 EJ in 2045 and a difference of about 7.2 EJ by 2055. This profile is consistent with a pathway that expands modern household services—clean cooking fuels, appliances, refrigeration, lighting and thermal comfort—especially where service delivery starts from very low levels, while efficiency gains and electrification constrain growth in mature markets. Residential demand is therefore a meaningful contributor to the SES–RCS difference, but not the dominant one: it rises steadily in both pathways, and the SES uplift reflects the depth of the household services gap being closed.

The **commercial sector** is a clearer source of divergence. Commercial final energy grows from 41 EJ in 2024 to 84 EJ by 2055 in SES, compared with 71 EJ in RCS. This indicates that the SES world contains a larger and faster-expanding service economy footprint—education and health systems, municipal services, retail and logistics, offices and public administration—and

Figure 7.2

Global final energy demand outlook by sector, 2024-2055 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

greater energy use associated with digitisation, all rising with incomes, urbanisation and the formalisation of economic activity.

Agricultural final energy remains small in absolute terms but shows a consistent uplift under SES. Demand rises from 10 EJ in 2024 to 13 EJ by 2055 in SES, compared with 12 EJ in RCS. The implication is that agricultural modernisation—mechanisation, irrigation pumping, cold chains and on-farm processing—adds incrementally to final energy in a development-centred pathway but does not drive the global balance.

Industrial final energy grows strongly in both scenarios and contributes materially to the SES–RCS gap. Industry rises from 128 EJ in 2024 to 165 EJ by 2055 in SES, compared with 154 EJ in RCS. These values are consistent with a pathway in which industrial activity expands to meet the requirements of infrastructure build-out and structural transformation—construction materials, manufacturing, chemicals and other energy-intensive outputs—so that even with efficiency improvements, absolute industrial energy use remains on a rising trajectory.

Non-energy use (feedstocks) grows materially in both scenarios but contributes only a small fraction of the SES–RCS difference. Feedstocks rise from 35 EJ in 2024 to 65 EJ by 2055 in SES, compared with 63 EJ in RCS. This indicates that chemical and materials value chains expand in both pathways, but they do not explain most of the additional final energy associated with SES; the dominant drivers lie in energy services and productive energy use rather than feedstock demand.

Transport is the single largest contributor to the SES–RCS difference in final energy by 2055. Transport final energy increases from 127 EJ in 2024 to 158 EJ by 2055 in SES, compared with 143 EJ in RCS. The time profile is instructive: transport demand in RCS effectively plateaus after the mid-2040s, while in SES it continues rising into the 2050s. This indicates that in a development-centred pathway, growth in passenger mobility and freight activity—associated with urbanisation, deeper market integration and higher economic throughput—outpaces the extent to which efficiency and electrification alone can compress total transport energy requirements within the horizon.

Taken together, the sectoral breakdown shows that the additional 48.5 EJ of final energy in SES relative to RCS by 2055 is concentrated in sectors tightly linked to economic participation and welfare outcomes. Transport contributes roughly 30% of the SES–RCS gap by 2055, followed by commercial energy use at about 26%, industry at about 23%, and residential demand at about 15%, with feedstocks and agriculture accounting for the remainder. This composition matters for the internal logic of SES: if final energy expands for development reasons, then climate alignment must be delivered primarily through declining emissions intensity—efficiency, electrification, cleaner power, fuel switching where appropriate, and decarbonisation technologies—rather than through constraining the growth of energy services in regions still converging toward development-consistent thresholds.

7.4.3 Global electricity demand and generation

Electricity demand in SES follows a structurally different trajectory from RCS because electricity is treated not only as a decarbonisation vector but as the backbone of modern service delivery and productive economic activity. In a development-centred pathway, electrification is determined less by aspirational targets than by three binding system conditions: reliability of supply, the speed at which firm capacity and networks can be deployed, and delivered cost competitiveness relative to alternative fuels. Reliability is decisive because electrification becomes a credible substitute in industry, commerce and essential services only when power quality is high and interruptions are rare. Speed matters because the electricity system must absorb new continuous loads—cooling, desalination, digital infrastructure, data centres and AI-enabled services, and electrified mobility—that scale rapidly once infrastructure and incomes rise. Cost competitiveness then governs the pace of substitution, because electrification advances fastest where tariffs remain affordable and network expansion does not impose prohibitive system costs.

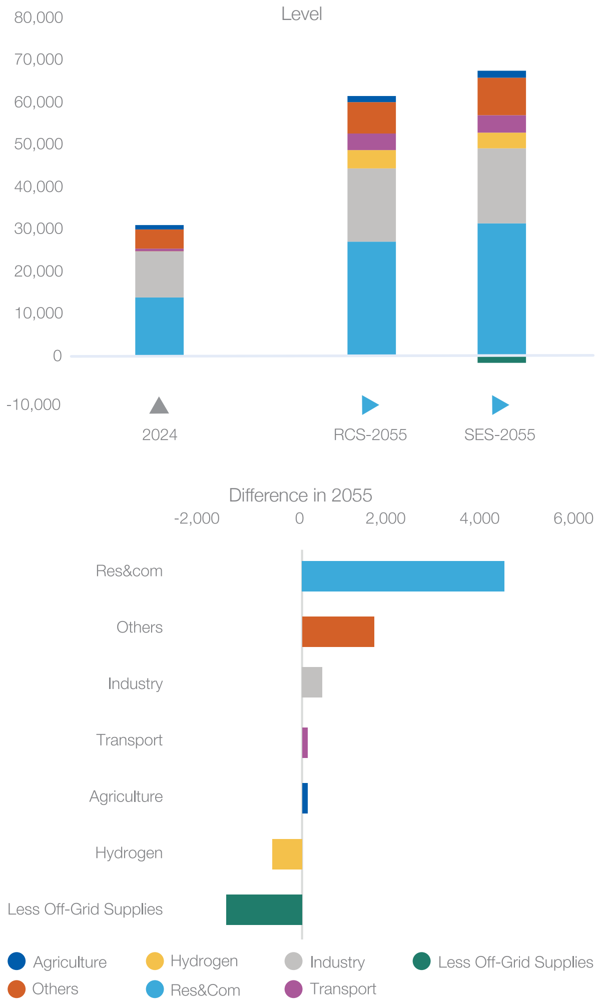
Within this framing, SES implies materially higher electricity demand than RCS by mid-century. **By 2055, global electricity demand in SES exceeds RCS by roughly 4,264 TWh, excluding off-grid sources such as rooftop solar** (Figure 7.3). The headline number masks strong regional divergence. In developing regions, electricity demand expands rapidly as systems move toward universal access, per-capita consumption converges toward minimum modern-service thresholds, and electricity use rises for appliances, cooling, digital connectivity and productive activity. In developed countries, growth is moderated by efficiency gains, demand-side management and building retrofits, even as electrification of transport and heating continues. As a result, global demand growth in SES becomes increasingly driven by development needs and system build-out where electricity remains a scarce enabling input, rather than by incremental growth in already saturated markets.

The sectoral profile reinforces this development logic. In the residential and commercial sectors, electricity demand uplift is nearly 4,300 TWh under SES by 2055, compared with RCS. This reflects the scaling of basic and welfare-enhancing electricity services—lighting, refrigeration, cooling, digital devices—and the expansion of service economies. Commercial electricity demand rises with urbanisation and formalisation through higher activity in healthcare, education, retail, telecommunications and public administration, and through the growing footprint of data services that require continuous, high-quality power.

In industry, electricity demand grows more steadily, around 1.6% annually in SES, adding roughly 435 TWh, compared with RCS in 2055, as electrified motors, process electrification in suitable segments, and digitally controlled production lines become more prevalent in manufacturing and value-added sectors. Agricultural electricity demand also rises as mechanisation, irrigation, cold storage and on-site processing expand, strengthening food security and rural productivity. Hydrogen-related electricity demand increases more cautiously than earlier expectations, reflecting deployment uncertainty and the slower build-out of enabling infrastructure, but the broader trend remains clear: electricity expands primarily because it enables new economic activity and higher welfare, not simply because it replaces fuels one-for-one.

Figure 7.3

Global electricity demand by sector in RCS and SES (TWh)

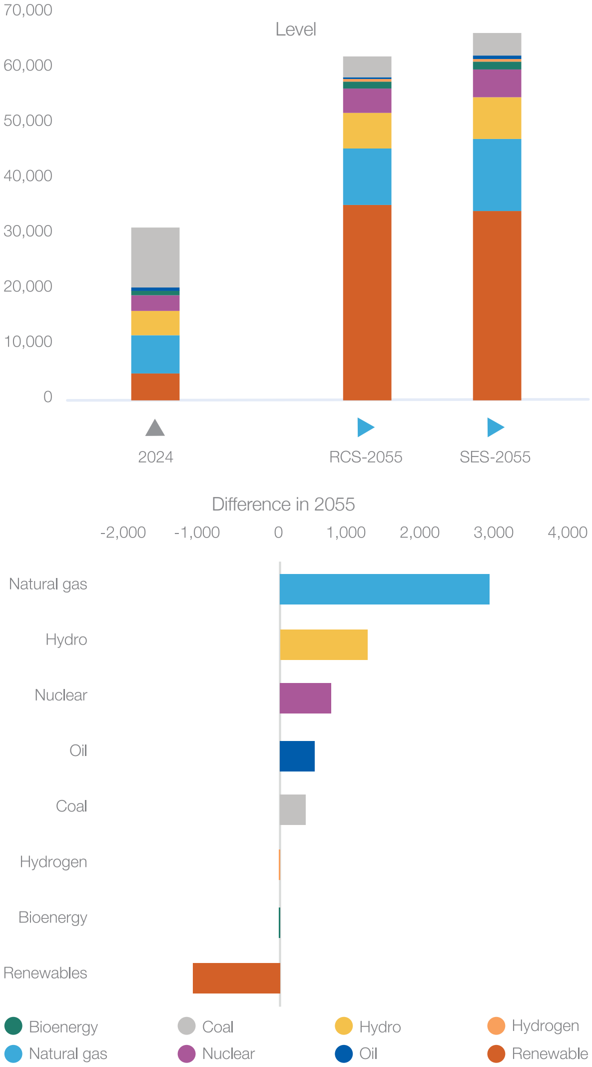


Source: GECF Secretariat based on data from the GECF GGM

Meeting this higher demand requires a supply pathway designed around reliable delivered services rather than nominal capacity additions alone. Domestic electricity generation in SES therefore expands in a way that prioritises dispatchability, affordability and system stability, especially in regions where demand growth is fastest and grids are still strengthening. In this context, renewables and natural gas together retain a dominant role in the generation mix, reaching nearly 71% of global electricity generation by 2055, reflecting their complementary functions: renewables provide large volumes of low-carbon electricity, while natural gas provides firming and flexibility that translate installed capacity into reliable delivered energy services. By 2055, the share of natural gas in global generation reaches about 20% in SES, compared with 16% in RCS and 22% in 2024, indicating that gas remains central to system adequacy even as the mix continues to diversify (Figure 7.4).

Figure 7.4

Global domestic power generation by fuels in SES vs RCS (TWh)



Source: GECF Secretariat based on data from the GECF GGM

The substitution pattern relative to RCS reveals how SES balances development requirements with system constraints. By 2055, natural gas delivers the largest incremental increase in domestic generation, rising by nearly 2,800 TWh relative to RCS. Hydropower also expands materially, contributing an additional 1,178 TWh, while smaller increases are observed in nuclear (688 TWh), oil (455 TWh) and coal (348 TWh) relative to RCS. These increases are offset by lower generation from other sources in SES compared with RCS: renewables are lower by about 1,186 TWh, bioenergy by about 31 TWh, and hydrogen by about 9 TWh. These differences should not be interpreted as renewables failing to expand in SES; rather, they indicate that once the system is required to deliver significantly more electricity services quickly and reliably, least-cost and least-risk optimisation shifts toward a more balanced portfolio, in which additional firm capacity is mobilised alongside renewables, and in which hydro and gas carry a larger share of incremental demand while maintaining reliability.

Cost dynamics underpin this optimisation. Although the levelised cost of wind and solar continues to fall, the system costs of high VRE penetration—grid reinforcement, balancing services, backup capacity, curtailment management and storage deployment—become increasingly material at scale. In many developing regions where transmission and distribution networks, system operators and reserve margins are still being built, the marginal cost of delivering firm electricity from gas can remain competitive when full system costs are considered, particularly when the alternative is under-serving demand or accepting lower reliability. SES therefore implies that gas generation expands not as a principled substitute for renewables, but as a practical complement that enables rapid electrification without reliability penalties that would undermine development outcomes. In this sense, the SES electricity outlook is a systems proposition: higher electricity consumption is the quantitative expression of development progress, and the generation mix is the portfolio solution that makes that progress deliverable, scalable and affordable while the broader scenario framework tightens emissions intensity through the power system and the wider energy economy.

7.4.4 Global hydrogen demand and generation

In SES, hydrogen is treated as a targeted energy carrier whose expansion is concentrated in applications where direct electrification is structurally limited or where molecules are required as feedstock, rather than as a universal substitute across all end uses. This positioning is critical for interpreting the results. **Global hydrogen demand rises from 100 MtH_2 in 2024 to about 236 MtH_2 by 2055, a net increase of 136 MtH_2 over the period and only 7 MtH_2 higher than RCS in 2055.** Hydrogen's share of global final energy reaches about 5.9% by 2055, up from 3.3% in 2024, broadly consistent with the reference trajectory. The key message is therefore not an explosive divergence in total hydrogen volumes; it is that SES delivers development-centred electrification and industrial expansion without relying on unrealistically large hydrogen uptake, while still scaling hydrogen enough to support hard-to-abate segments and strategic industrial value chains.

The regional distribution of hydrogen demand growth is highly concentrated. Asia Pacific accounts for the majority of growth within SES: consumption rises by 79 MtH_2 to reach 127 MtH_2 by 2055, compared with 125 MtH_2 in RCS. Asia Pacific therefore represents about 54% of global hydrogen demand by 2055, a share close to current dominance and broadly aligned with RCS. Outside Asia Pacific, incremental uptake is more dispersed and comparatively modest, with Africa, North

Chapter 7

America and the Middle East contributing additional demand relative to the reference pathway as industrial activity, refining and petrochemicals, and new low-carbon supply chains expand. Quantitatively, hydrogen in SES remains primarily an industrial and system-level instrument—supporting ammonia, refining, chemicals and selected hard-to-abate processes—rather than a mass-market fuel requiring wholesale reconfiguration of end-use infrastructure across all regions.

While total demand differs only slightly from RCS, SES produces a pronounced shift in the production technology mix, which is where its logic becomes most visible. By 2055, SES allocates a larger share of hydrogen supply to blue hydrogen and a smaller share to green hydrogen than RCS, while accelerating the decline of grey hydrogen (Figure 7.5). **Blue hydrogen expands by 102 MtH_2 and becomes the dominant production pathway by 2055, accounting for about 43% of global output in SES (versus 35% in RCS).** This shift reflects SES's emphasis on scalability and affordability under the constraint that power systems are simultaneously required to deliver rapidly rising electricity demand for households, services and productive uses. In that context, blue hydrogen functions as the principal scaling route, leveraging established reforming technologies and the assumed rapid scale-up of carbon capture.

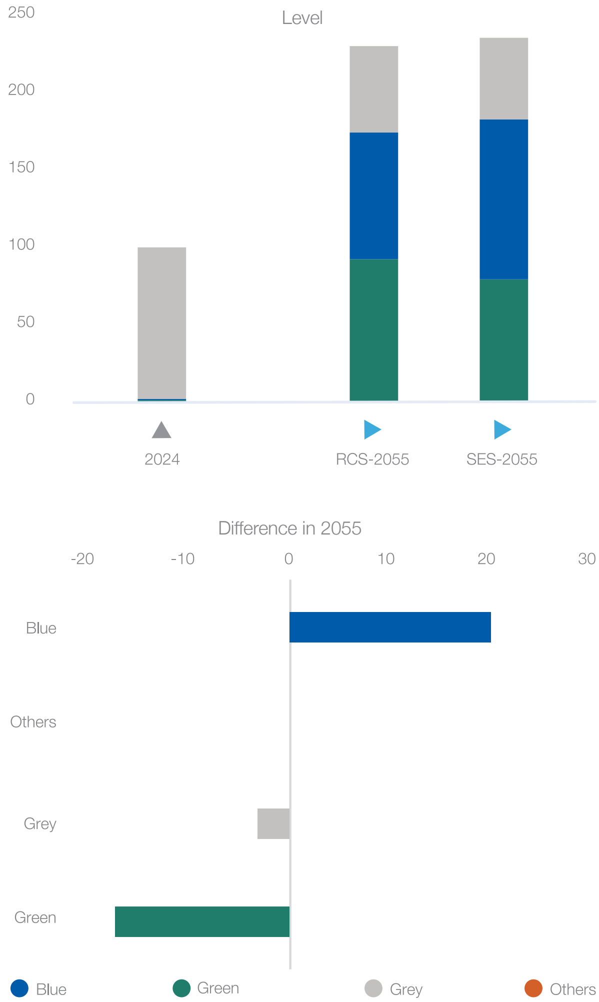
Green hydrogen rises markedly in absolute terms—from 2 MtH_2 in 2024 to 79 MtH_2 by 2055—but remains lower than in RCS (about 92 MtH_2). Consequently, green hydrogen reaches about 33% of global supply in SES by 2055, compared with 40% in RCS. This is a key consistency signal: SES does not assume that renewable-powered electrolysis expands without constraint while the same power system is tasked with universal access, rising per-capita consumption and new continuous loads such as cooling and digital infrastructure. The lower green hydrogen volume is therefore consistent with an optimisation that prioritises allocating renewable electricity to direct electrification and grid decarbonisation where it delivers immediate welfare and productivity gains.

Grey hydrogen declines substantially in SES, falling by 45 MtH_2 to 53 MtH_2 by 2055, around 3 MtH_2 lower than RCS. Grey hydrogen's share drops to about 22% in SES by 2055 (versus 24% in RCS), indicating that unabated production is compressed as low-carbon pathways scale, though not eliminated entirely due to inertia in existing assets, uneven policy and infrastructure conditions, and the economics of retrofit and replacement in some regions. The principal difference relative to RCS is therefore the route to low-carbon hydrogen—more blue, less green—rather than the overall scale of hydrogen demand.

The corresponding fuel and energy inputs reinforce this interpretation. Total input to hydrogen generation rises

Figure 7.5

Global hydrogen generation by technology in SES vs RCS (MtH_2)



Source: GECF Secretariat based on data from the GECF GGM

by 23.4 EJ over the period to reach 40.1 EJ by 2055, compared with 38 EJ in RCS (Figure 7.6). Natural gas becomes the dominant energy input, reaching 17.8 EJ by 2055 in SES, which is 4.5 EJ higher than in RCS, reflecting the larger role of gas-based reforming with capture. Electricity input rises more modestly, reaching 13.7 EJ by 2055 in SES, below the RCS level (around 15 EJ), consistent with lower green hydrogen volumes. Importantly, the rise in gas use for blue hydrogen is partly offset by the decline in grey hydrogen output, so the net change reflects a compositional shift toward captured pathways rather than a simple expansion of unabated fossil-based hydrogen.

Overall, the SES hydrogen outlook assigns hydrogen a disciplined role within a development-centred transition. Hydrogen volumes grow substantially, but remain a minority share of final energy and do not become the

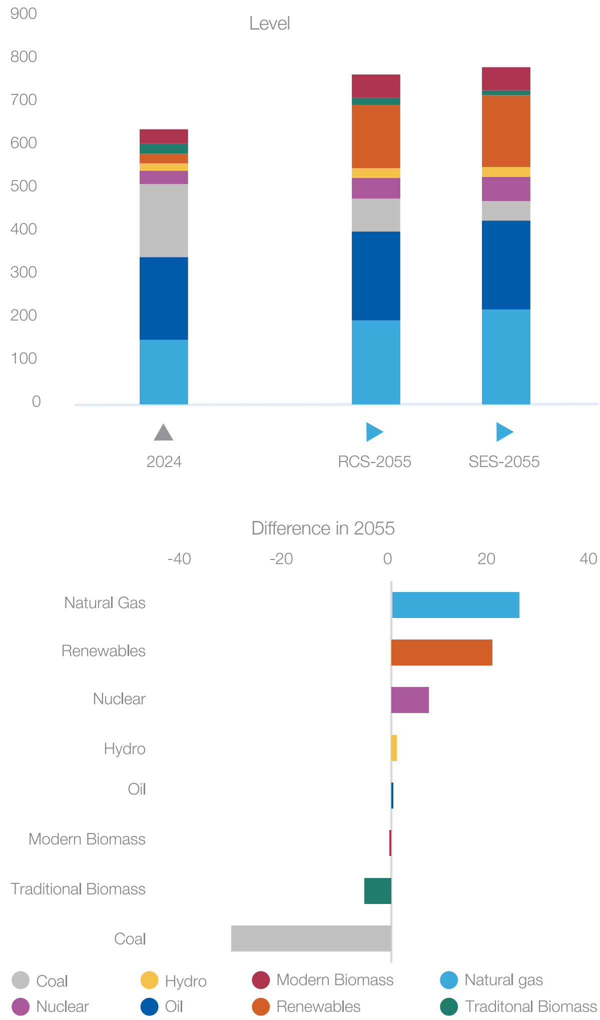
Figure 7.6

Global fuel input for hydrogen generation in SES vs RCS (EJ)

Source: GECF Secretariat based on data from the GECF GGM

Figure 7.7

Global primary energy demand outlook in SES vs RCS by fuel, 2024-2055 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

main driver of system scale-up. The more consequential change is technological: SES shifts the production frontier toward blue hydrogen as the principal scaling route while green hydrogen expands more selectively, constrained by the competing requirement to deploy renewable electricity directly for electrification and power-sector decarbonisation.

7.4.5 Primary energy demand

Global primary energy demand rises from 641 EJ in 2024 to 785 EJ by 2055 in SES, an increase of 144 EJ (about 22%) (Figure 7.7). In RCS, primary energy reaches 768 EJ by 2055, an increase of 127 EJ (about 20%). SES therefore implies a larger energy system in absolute terms, but the divergence relative to the reference pathway remains moderate in the near term and becomes more visible after 2040, consistent with a pathway in which additional demand accumulates as access expands, infrastructure is built and economic activity deepens in regions starting from low levels of modern energy consumption.

At the same time, SES achieves faster economy-wide efficiency improvement, measured through primary energy intensity. Primary energy intensity declines at an average rate of 2.6% per year between 2024 and 2055 in SES, compared with 2.4% per year in RCS, reaching 1.4 MJ per USD (PPP, base year 2024) by 2055 versus 1.5 MJ per USD in RCS. The implication is that economic output rises faster than energy demand, so the world uses less primary energy per unit of GDP even while delivering more energy services. In lower-income regions, part of the efficiency improvement is absorbed through rebound effects: better infrastructure, lower effective energy costs and higher-quality technologies allow previously suppressed demand to materialise, raising consumption while still reducing intensity because energy is being used more productively.

7.4.5.1 Primary energy demand mix

The primary energy mix outcomes show that the additional primary energy required by SES is not delivered through higher fossil energy. Aggregate fossil fuels decline from 514 EJ in 2024 to 473 EJ by 2055 in SES, a reduction of 41 EJ, while in RCS they decline to 480 EJ (a reduction of 34 EJ). Fossil fuels therefore account for about 60% of primary energy in SES by 2055, compared with about 62% in RCS and 80% in 2024. This composition result is central: by 2055 SES has higher total primary energy than RCS (785 EJ versus 768 EJ) while having lower total fossil energy (473 EJ versus 480 EJ). The incremental energy required to support development objectives is therefore supplied by higher non-fossil energy and a sharper reduction in coal, not by expanding the fossil share.

Within this shifting mix, **natural gas** becomes the leading primary energy source by 2055 in SES. Gas rises from 150 EJ in 2024 to 221 EJ by 2055, an increase of 71 EJ. In RCS, gas reaches 196 EJ by 2055. **SES therefore implies 25 EJ more gas than RCS by 2055 and lifts gas to about 28% of global primary energy (versus about 26% in RCS).** This increase is consistent with the sectoral drivers embedded in SES: higher electricity demand and the need for firm generation; stronger industrial activity requiring scalable heat and feedstocks; and faster movement away from traditional biomass toward modern cooking fuels in energy-poor regions. Crucially, the rise in gas does not increase total fossil energy in SES because it is more than offset by the reduction in coal; gas expansion functions as a substitution and system-support mechanism rather than an additive fossil growth pathway.

Renewables exhibit the largest absolute increase in primary energy in SES. Renewable energy rises from 24 EJ in 2024 to 166 EJ by 2055, an increase of 142 EJ, and exceeds the RCS level of 146 EJ by 20 EJ. Renewables therefore reach about 21% of global primary energy in SES by 2055, compared with about 19% in RCS. This is the single largest contribution to non-fossil growth, reflecting the central role of renewables in supplying expanding electricity demand as systems electrify. The SES result also indicates that renewables scale rapidly while still coexisting with substantial requirements for firm and flexible generation, particularly in systems growing quickly and facing binding reliability constraints.

Oil follows a broadly flat trajectory in both scenarios. Oil rises from 193 EJ in 2024 to 205 EJ by 2055 in SES, identical to the RCS level in 2055. Oil's share declines to about 26% by 2055 in SES (from about 30% in 2024), implying a "flat-in-level, declining-in-share" outcome: rising oil demand in some developing regions is broadly offset by faster efficiency gains and substitution elsewhere.

The sharpest structural change is the accelerated decline of coal. **Coal** falls from 171 EJ in 2024 to 47 EJ by 2055 in SES, a reduction of 124 EJ, ending 32 EJ lower than RCS (79 EJ). Coal's share therefore falls to about 6% in SES by 2055, compared with about 10% in RCS. SES achieves a lower-carbon primary energy system primarily through deeper coal displacement, especially where coal-to-gas switching and non-fossil generation expansion can deliver large reductions while preserving reliability. Where coal remains for security and affordability reasons, continued operation becomes increasingly conditional on modernisation and retrofit pathways that reduce environmental impacts and enable lower-emissions operation, rather than on continued expansion of unabated coal use.

Table 7.2

Global primary energy demand by fuel type in RCS and SES (EJ)

	Base	RCS			SES		
	2024	2035	2045	2055	2035	2045	2055
Natural gas	150	176	190	196	181	205	221
Oil	193	201	204	205	205	207	205
Coal	171	135	110	79	126	89	47
Nuclear	30	35	41	48	37	43	55
Hydro	16	19	21	23	20	23	24
Renewables	24	69	106	146	69	119	166
Bioenergy	57	65	71	72	64	67	66
World	641	701	742	768	702	753	785

Source: GECF Secretariat based on data from the GECF GGM

Non-fossil firm energy sources expand more in SES than in RCS. Nuclear rises from 30 EJ in 2024 to 55 EJ by 2055 in SES, compared with 48 EJ in RCS, an additional 7 EJ by 2055. **Nuclear**'s share reaches about 7% in SES, supporting system adequacy and firm low-carbon supply as electricity demand grows and variable renewables expand. **Hydropower** increases from 16 EJ to 24 EJ by 2055 in SES, broadly similar to RCS (23 EJ), indicating steady but constrained growth consistent with site availability and project lead times while still contributing materially to grid stability where capacity can expand.

Finally, **bioenergy** grows more slowly in SES than in RCS, reflecting the development logic of moving households away from traditional biomass. Total bioenergy rises from 57 EJ in 2024 to 66 EJ by 2055 in SES, compared with 72 EJ in RCS, with a share of about 8% in SES versus about 9% in RCS. This aggregate outcome masks opposing components: traditional biomass declines more sharply in SES (consistent with faster clean-cooking transitions), while modern bioenergy expands and remains broadly comparable between the two pathways.

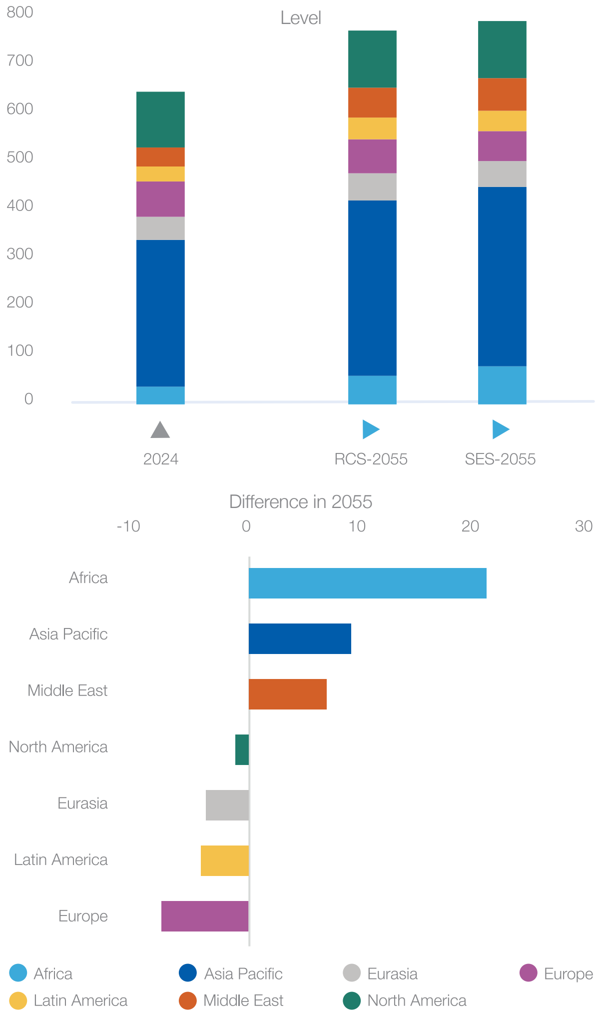
Overall, the primary energy mix results present a coherent picture: SES requires a larger energy system to deliver development-consistent services, but it achieves a faster decline in energy intensity and a more decisive shift in the fuel mix. By 2055, SES reaches higher total primary energy than RCS while reducing fossil energy and lowering the fossil share more sharply—driven above all by deeper coal reduction, stronger renewables and nuclear growth, and a larger role for natural gas as a scalable complement in power, industry and household modernisation.

7.4.5.2 Primary energy demand by region

The regional distribution of primary energy in SES differs materially from RCS because SES is constructed around expanding modern energy services where deficits are greatest, while mature economies progress primarily through efficiency and electrification. By 2055, global primary energy reaches 785 EJ in SES versus 768 EJ in RCS, but the difference is not evenly distributed. In SES, additional primary energy concentrates in regions where per-capita consumption starts from a low base and GDP growth is higher, whereas several mature regions register lower primary energy than in the reference pathway because electrification and efficiency reduce overall primary energy requirements even when electricity demand rises. In level terms, Asia Pacific remains the dominant consuming region in 2055 at about 368 EJ (around 47% of global primary energy), followed by North America at about 118 EJ (15%), Africa at about 79 EJ (10%), the Middle East at about 69 EJ (9%), Europe at about 62 EJ (8%), Eurasia at about 52 EJ (7%), and Latin America at about 40 EJ (5%) (Figure 7.8). This ordering underscores that SES does not

Figure 7.8

Global primary energy consumption outlook by region, 2024-2055 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

imply a uniform rise in energy demand everywhere; it implies a rebalancing toward where poverty reduction, infrastructure build-out and structural transformation remain binding constraints.

Africa is the clearest marker of this rebalancing. Primary energy rises to about 79 EJ by 2055 in SES, around 21 EJ higher than RCS (about 58 EJ). This is sufficient to lift Africa's share of global primary energy to around 10% in SES by 2055, compared with about 8% in RCS, implying that Africa's primary energy weight overtakes Europe's by the end of the horizon. The drivers are broad-based: the increment relative to the reference is not confined to one end use but distributed across transport, power generation, households, the energy sector and industry, consistent with a pathway in which electricity access expands, mobility rises with urbanisation and market integration, modern fuels displace traditional biomass, and industrial activity deepens as economies move toward higher value-added production.

Asia Pacific remains the largest consuming region in absolute terms, but its SES–RCS deviation is comparatively modest. Primary energy reaches about 368 EJ by 2055 in SES versus about 359 EJ in RCS, leaving the region's global share essentially unchanged at around 47% in both pathways. This stability masks internal restructuring. SES implies sharper reduction of coal-based primary energy in the power sector through accelerated coal-to-gas switching and stronger renewables deployment, reducing primary energy requirements in electricity generation relative to a coal-heavier trajectory. That reduction is offset by stronger growth in domestic energy services, transport, industry and hydrogen-related activity. The effect is that SES changes Asia Pacific more in structure than in share: the region remains dominant, but the pathway becomes less coal-intensive and more aligned with electrified development.

The Middle East is the third-largest positive contributor to the SES increment relative to RCS. By 2055, primary energy reaches about 69 EJ in SES, around 7 EJ higher than RCS (about 62 EJ), raising the region's share of global primary energy to about 9% in SES compared with about 8% in RCS. The sectoral profile is concentrated more in power generation and domestic energy use than in industry or transport, reflecting the centrality of electricity demand growth—linked to cooling, urbanisation, population growth and expanding services—in a region where gas is abundant and cost-competitive and where energy-intensive activities remain strategically important.

In **North America**, primary energy is broadly flat relative to RCS by 2055 and slightly lower in level terms. Primary energy reaches about 118 EJ in SES by 2055 compared with about 119 EJ in RCS, lowering North America's global share to around 15% rather than around 16% in RCS. SES allows a near-term uplift driven by rising commercial electricity demand, notably from data centres and AI-related infrastructure, but by the end of the horizon stronger efficiency improvements and electrification of end uses (including heat pump uptake) reduce primary energy requirements enough to offset that load growth. The signal is therefore compositional change rather than volumetric expansion.

Eurasia shows limited divergence, though with a more notable reduction relative to RCS by 2055. Primary energy reaches about 52 EJ in SES compared with about 56 EJ in RCS, leaving its global share at roughly 7% in both pathways. SES contains upward pressures from power generation and industry, but these are moderated by efficiency gains and restructuring that limits additional primary energy requirements compared to the reference case.

Europe is one of the regions where SES yields a clearly lower primary energy level than RCS. By 2055, Europe's primary energy reaches about 62 EJ in SES compared with about 67 EJ in RCS, placing Europe at around 8% of global primary energy in SES versus around 9% in RCS. The divergence is driven by a stronger efficiency pathway for advanced building stock—faster diffusion of high-efficiency technologies including heat pumps and deep retrofits—which reduces primary energy requirements in residential and commercial sectors. This can coexist with rising electricity use because electrification raises end-use efficiency, and because a cleaner power mix reduces primary energy requirements per unit of electricity delivered in primary accounting terms.

Latin America also ends the horizon below RCS in primary energy. Demand reaches about 40 EJ by 2055 in SES compared with about 44 EJ in RCS, corresponding to around 5% of global primary energy in SES versus around 6% in RCS. Within SES, improved efficiency and a stronger shift in the energy mix reduce primary energy requirements relative to the reference, even as modern energy services continue to expand.

Taken together, the regional results show that SES does not produce a uniformly higher-demand world. It produces a world in which additional primary energy concentrates where it is required for poverty reduction, infrastructure build-out and structural transformation—most notably in Africa, and to a lesser extent in the Middle East and Asia Pacific—while several mature regions register lower primary energy than in the reference trajectory because electrification and efficiency reduce primary energy requirements. This uneven distribution is the quantitative expression of the SES premise that development and system transformation must occur simultaneously.

7.4.6 Natural gas demand by sector

The development-centred logic of SES has a direct implication for natural gas demand. **Because SES assumes faster expansion of electricity access, industrial output and modern household energy services than RCS, total gas demand rises to 6,127 bcm by 2055, compared with 5,417 bcm in RCS** (Table 7.3). The gap widens over time, from 117 bcm in 2035 to 426 bcm in 2045 and 711 bcm in 2055, consistent with the idea that infrastructure build-out and productivity effects accumulate and compound through the middle decades.

The sectoral pattern matters as much as the total because it reveals the internal logic of the SES world. The additional 711 bcm of demand in 2055 (SES relative to RCS) is concentrated in three sectors: power generation contributes about 293 bcm (roughly 41% of the difference), industry contributes about 148 bcm (around 21%), and the domestic sector contributes about 117 bcm (around 16%). Together, these explain

Table 7.3

Global natural gas demand by sector in RCS and SES (bcm)

	Base	RCS			SES		
	2024	2035	2045	2055	2035	2045	2055
Domestic	833	888	847	802	903	911	919
Industry	904	1,104	1,177	1,200	1,104	1,252	1,348
Transport	172	274	357	380	301	398	429
Power generation	1,457	1,754	1,962	2,097	1,856	2,163	2,390
Direct heat generation	195	186	167	153	151	171	184
Hydrogen generation	265	305	358	391	301	376	433
Other uses	339	388	397	393	401	420	425
Total	**4,165**	**4,900**	**5,265**	**5,417**	**5,017**	**5,691**	**6,127**

Source: GECF Secretariat based on data from the GECF GGM

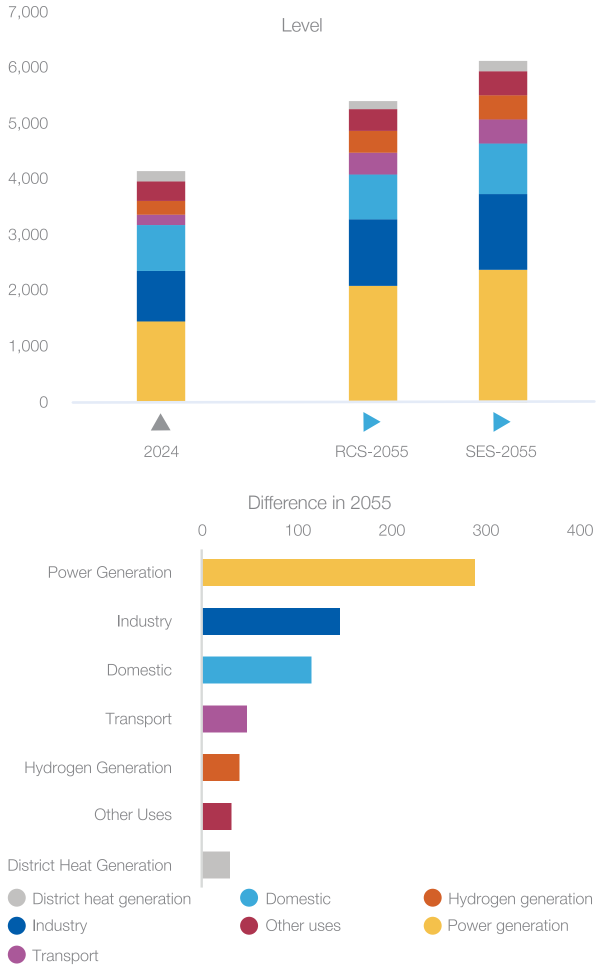
close to four-fifths of the SES–RCS gap. The remainder is distributed across transport (49 bcm, 7%), hydrogen production (42,6% bcm, 5%), other uses such as own-use in LNG and transport/distribution (32 bcm, 5%), and a modest difference in direct heat generation (31 bcm, 4%). Figure 7.9 therefore captures a defining feature of SES: gas demand increases primarily in sectors most tightly linked to development outcomes—reliable electricity, industrial value creation, and household modernisation—rather than in a single niche application.

The **power sector** is the dominant driver because electrification is the central mechanism through which SES delivers modern energy services. Natural gas demand for power rises from 1,457 bcm in 2024 to 2,390 bcm by 2055 in SES (an increase of 933 bcm), while in RCS it reaches 2,097 bcm. The SES uplift of 293 bcm by 2055 reflects not only higher electricity consumption per capita in lower-income countries but also the shape of that demand. In SES, electrification expands rapidly in households and productive sectors, and heat-pump diffusion increases electricity load even where it reduces direct gas use in buildings. In parallel, the continued expansion of data centres and AI-enabled services raises the premium on power quality and reliability. In systems scaling variable renewables, this strengthens the value of flexible, dispatchable generation to stabilise grids and protect affordability by limiting the need for overbuild and excessive balancing costs. Coal-to-gas substitution in parts of Asia Pacific further contributes to the uplift, improving local air quality while supporting flexibility as renewable capacity expands.

Industry is the second-largest source of additional demand because SES assumes faster structural transformation in developing economies. Industrial gas demand rises from 904 bcm in 2024 to 1,348 bcm by 2055 in SES, compared with 1,200 bcm in

Figure 7.9

Global natural gas demand by sector in RCS and SES (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Chapter 7

RCS. The increment of 148 bcm by 2055 is consistent with stronger industrial output growth in lower-income regions, where gas supports process heat and feedstocks in sectors central to productivity and development. SES does not imply stalled efficiency; it implies efficiency improvements occurring alongside rising industrial activity, with CCUS deployment supporting continued gas use in hard-to-abate processes where it remains the most practical scalable option.

The **domestic sector** is particularly revealing because it directly reflects the development mandate. In RCS, domestic gas demand declines gradually from 833 bcm in 2024 to 802 bcm by 2055 as efficiency and electrification reduce direct use in mature markets. In SES, domestic demand rises to 919 bcm by 2055, implying an increase of 86 bcm from 2024 and a 117 bcm uplift relative to RCS. This divergence is driven by a more aggressive transition away from traditional biomass in African households through scaling modern cooking solutions, including LPG and piped natural gas where feasible. This is central to the sustainable development logic because it is closely linked to public health, welfare and time poverty. At the same time, SES captures an important interaction: in Europe and North America, stronger heat-pump adoption reduces direct residential gas demand, but part of the energy service is shifted onto the electricity system, reinforcing the power-sector role of gas as a reliability and flexibility resource.

The **transport sector** becomes more material in SES because the scenario treats hard-to-electrify segments as a binding constraint on an orderly transition. Transport gas demand rises from 172 bcm in 2024 to 429 bcm by 2055 in SES, compared with 380 bcm in RCS. The 49 bcm uplift is modest in share terms but significant in interpretation: it reflects assumed expansion of LNG use in heavy-duty trucking and marine bunkering as a pragmatic route to reduce emissions intensity and local pollution where electrification is slower, while keeping logistics scalable and affordable.

Hydrogen production is another source of incremental gas demand. By 2055, gas demand for hydrogen reaches 433 bcm in SES, up from 265 bcm in 2024 and about 42 bcm higher than in RCS (391 bcm). This reflects hydrogen's growing role in parts of industrial decarbonisation, combined with the assumed rapid scaling of CCUS in hydrogen production that accelerates the shift from grey to blue hydrogen.

Other uses, including own use in liquefaction and regasification, pipeline compressors and distribution losses, rise to 425 bcm by 2055 in SES compared with 393 bcm in RCS. This 32 bcm uplift is a structural consequence of higher demand and a greater role for LNG trade, which imply higher operational fuel use and system losses associated with expanded global gas infrastructure.

Finally, **direct heat generation** remains a small share of total demand but illustrates how SES reshapes end-use choices. Direct heat demand reaches 184 bcm by 2055 in SES, slightly below 2024 (195 bcm), indicating that electrification and efficiency reduce some direct gas heat demand over time. However, it remains above RCS by 2055 (153 bcm), suggesting that in fast-growing regions—particularly in parts of Asia Pacific—urbanisation and district heating or other heat applications sustain a modest role for gas even as other parts of the system electrify.

Overall, the sectoral results underline the core message of SES: gas demand increases because development-driven growth in electricity, industry and modern household services requires scalable and reliable energy source, and gas plays that role in a way that supports affordability and energy security.

7.4.7 Natural gas demand by region

The regional distribution of gas demand in SES indicates where modern energy-service expansion is most binding and therefore where additional gas volumes are required. Table 7.4 shows that the SES–RCS demand gap is concentrated overwhelmingly in developing regions, most notably Asia Pacific and Africa, while mature economies plateau and then decline. In aggregate, global gas demand rises from 4,134 bcm in 2024 to 6,127 bcm by 2055 in SES, compared with 5,417 bcm in RCS. The net difference by 2055 (roughly 710 bcm) is explained primarily by two regions: Asia Pacific contributes about 322 bcm of the SES–RCS gap (around 45%), and Africa contributes about 310 bcm (around 44%). Together, these account for nearly nine-tenths of the additional gas demand in SES, while remaining increases in the Middle East, Eurasia and Latin America are partly offset by lower demand in North America and Europe. The implication is clear: SES is not a uniformly higher-gas world; it is a world where the centre of gravity of gas demand shifts decisively toward regions where development-linked energy services must expand fastest.

Asia Pacific is the largest contributor to the additional demand and becomes the world's largest gas-consuming region by the 2030s. Demand rises from 959 bcm in 2024 to 1,838 bcm by 2055 in SES, compared with 1,516 bcm in RCS (Figure 7.10). The region therefore accounts for around 30% of global gas demand in SES by 2055 (up from roughly 28% in RCS). The role of gas strengthens in the energy mix, rising to about 17% by 2055 (from 11% in 2024). This is a systems outcome rather than a simple fuel preference: SES combines strong electricity-demand growth with rapid scaling of variable renewables, making flexible and dispatchable supply valuable for maintaining reliability as coal declines. Power generation is therefore the dominant outlet for incremental gas demand in the region, positioning gas as an enabling fuel for secure electrification and a stabiliser of the transition away from coal.

Table 7.4

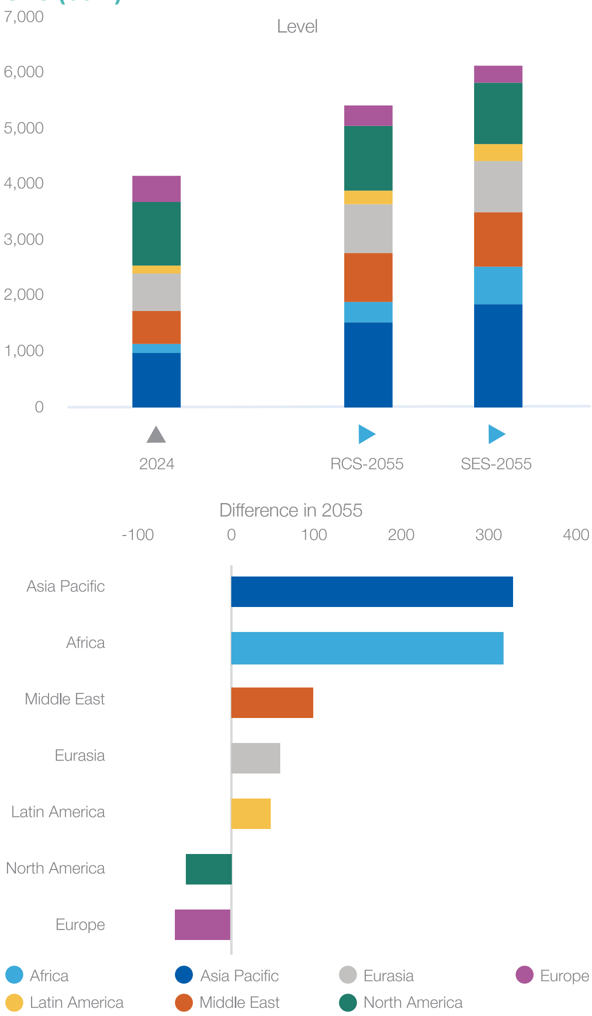
Global natural gas demand by region in RCS and SES (bcm)

	Base	RCS			SES		
	2024	2035	2045	2055	2035	2045	2055
Africa	**175**	239	316	364	351	502	674
Asia Pacific	**959**	1,328	1,495	1,516	1,355	1,686	1,838
Eurasia	**665**	732	797	863	753	854	919
Europe	**459**	453	410	371	452	341	306
Latin America	**147**	194	241	261	201	259	306
Middle East	**590**	722	829	887	702	911	980
North America	**1,139**	1,210	1,176	1,155	1,204	1,138	1,103
Total	**4,134**	**4,879**	**5,264**	**5,417**	**5,017**	**5,691**	**6,127**

Source: GECF Secretariat based on data from the GECF GGM

Figure 7.10

Global natural gas demand by region in RCS and SES (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Africa is the second major pillar of demand growth and the most development-revealing regional result. Demand rises from 175 bcm in 2024 to 674 bcm by 2055 in SES, compared with 364 bcm in RCS—an uplift of roughly 310 bcm. Africa's share of global gas demand rises to around 11% in SES by 2055, compared with roughly 7% in RCS and about 4% today. The role of gas in Africa's energy mix rises to around 34% by 2055 in SES (versus 24% in RCS and 18% in 2024), reflecting that gas supports three transitions simultaneously: electrification, industrialisation and modern household energy services. Two features are particularly important for the SES narrative. First, household and commercial uses become more material than in RCS due to accelerated clean-cooking transitions away from traditional biomass. Second, gas-to-power expands strongly: the gas share in electricity generation rises to about 59% by 2055 in SES (compared with 50% in RCS and 40% in 2024), reflecting the need to scale reliable power quickly while integrating rising shares of renewables. Africa's higher gas demand in SES is therefore framed as a structural requirement of socioeconomic empowerment and dependable energy services, not consumption for its own sake.

The **Middle East** ranks next in absolute growth, though its contribution to the SES–RCS gap is smaller because demand also rises in RCS. Demand rises from 590 bcm in 2024 to 980 bcm by 2055 in SES, compared with 887 bcm in RCS, supporting a global demand share of about 16% by 2055 in SES. Gas remains the backbone of domestic energy systems as power demand grows and industrial diversification continues: gas reaches around 59% of the energy mix by 2055 in SES (versus 54% in RCS), and power generation remains the dominant outlet, with gas supplying around 68% of electricity generation by 2055.

Eurasia shows a more moderate uplift. Demand rises from 665 bcm in 2024 to 919 bcm by 2055 in SES, compared with 863 bcm in RCS—about 56 bcm higher.

Eurasia accounts for about 15% of global demand by 2055 in SES, slightly below its share in RCS because growth elsewhere is faster. Gas strengthens its role in Eurasia's energy mix, rising to about 60% by 2055 in SES (from 51% in 2024), supported by abundant resources and established infrastructure, with power generation and household uses remaining key drivers.

Latin America contributes a smaller but meaningful increment. Demand rises from 147 bcm in 2024 to 306 bcm by 2055 in SES, compared with 261 bcm in RCS—about 45 bcm higher—stabilising the region's global share around 5%. Gas's role in the energy mix expands to about 27% in SES (versus 21% in RCS), with the power sector the dominant driver. Interpreted through the SES lens, this reflects a pragmatic strategy in which gas supports affordability and reliability while enabling gradual switching away from more carbon-intensive options and managing variability in renewable- and hydro-dependent systems.

The contrast with developed regions is deliberate. North America experiences lower demand in SES than in RCS. Demand rises modestly into the 2030s and then declines to 1,103 bcm by 2055 in SES, about 52 bcm lower than RCS (1,155 bcm). North America's share of global demand falls to around 18% by 2055 in SES (versus 21% in RCS and about 28% in 2024), reflecting demand saturation, efficiency improvements and electrification. Gas nevertheless remains structurally important in the system as a flexibility and resilience resource, even as absolute volumes decline.

Europe also sees a pronounced decline under SES, falling to 306 bcm by 2055 compared with 371 bcm in RCS. Europe's share of global demand declines to around 5% in SES (versus 7% in RCS and 11% in 2024). The domestic sector drives the decline as heat pumps and stricter efficiency standards reduce direct gas use, even though gas can retain a balancing role in the power system during periods of low renewable output.

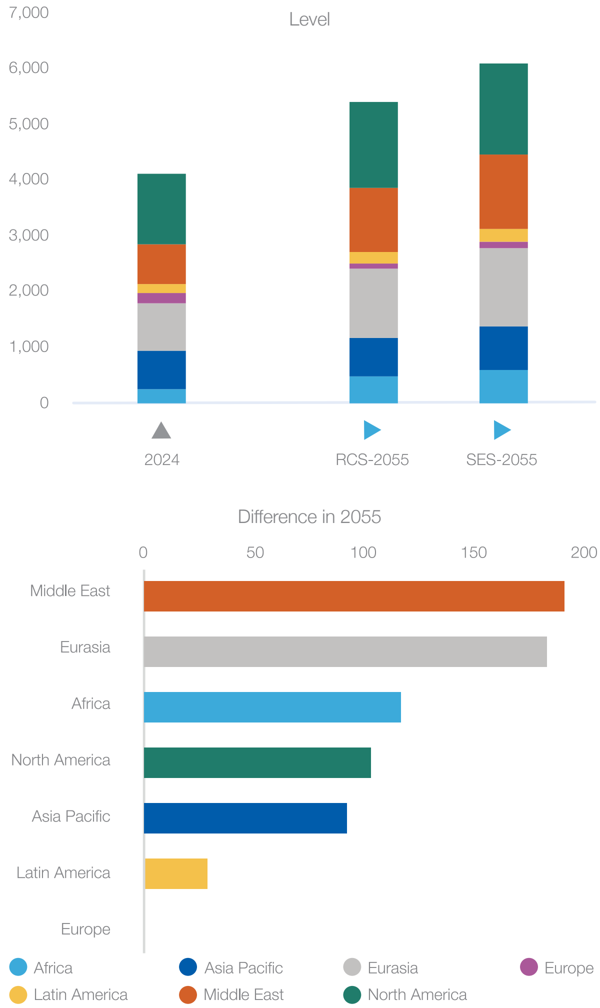
Overall, the regional demand pattern strengthens the internal logic of SES: modern energy-service expansion is scaled where needs are greatest, while mature regions transition through efficiency and electrification without imposing reliability and affordability costs that would destabilise the social contract. The resulting geography, rising demand centred in Asia Pacific and Africa alongside declining volumes in Europe and North America, is therefore the macro-energy expression of SES itself.

7.4.8 Natural gas supply

Higher natural gas demand in SES must be matched by commensurate supply expansion to preserve market balance over the scenario horizon. Figure 7.11 shows that this adjustment is highly uneven across regions. Incremental supply concentrates in a small number of resource-rich basins and established producing provinces, reflecting differences in resource endowment, upstream cost structures, infrastructure maturity, and the ability to mobilise long-tenor investment under uncertainty. **Global gas supply in SES reaches about 6,127 bcm by 2055, roughly 710 bcm higher than RCS.** The composition of incremental supply is therefore a structural signature of the SES world: additional volumes required to support development-driven demand growth are delivered disproportionately by regions with scale, low marginal costs and expanding export optionality.

Figure 7.11

Global natural gas supply outlook by region in SES and RCS (bcm)



Source: GECF Secretariat based on data from the GECF GGM

The **Middle East** emerges as the single largest contributor to the supply uplift. By 2055, production rises to 1,335 bcm in SES versus 1,145 bcm in RCS—an additional 190 bcm by 2055, around 27% of the global incremental supply. In absolute terms, Middle East production grows by around 604 bcm between 2024 and 2055 in SES. The region's share of global supply rises to around 22% by 2055 in SES, compared with about 21% in RCS and around 18% in 2024. This is consistent with continued development of large, competitive projects and strengthening export infrastructure—particularly LNG—alongside domestic utilisation for power generation and industrial development, though realised growth remains contingent on market conditions, project delivery and geopolitical and policy frameworks.

Eurasia ranks second. Production reaches 1,415 bcm by 2055 in SES compared with 1,233 bcm in RCS—an additional 182 bcm, around 26% of the global supply uplift. Output increases by about 559 bcm between 2024 and 2055 in SES. Eurasia's share rises to around 23% by 2055 in SES, broadly similar to RCS, indicating that large Eurasian growth occurs alongside expansion elsewhere. The outlook depends on sustaining field development, expanding trade infrastructure (pipelines and LNG) and adapting to evolving trade patterns, with geopolitical uncertainty and investment conditions remaining decisive determinants.

Africa provides a third major pillar of incremental supply with particular significance in a development-centred scenario. By 2055, African production rises to about 598 bcm in SES, 116 bcm higher than in RCS, accounting for roughly 16% of global incremental supply. Output expands by around 355 bcm between 2024 and 2055 in SES, lifting Africa's share of global supply to around 10% by 2055, compared with about 9% in RCS and around 6% in 2024. This reflects increasing monetisation of Africa's gas resource base through domestic utilisation and export pathways. Domestic use supports reliable power systems, enables industrial activity and processing, and can help displace more harmful fuels in households and small enterprises where appropriate. Export monetisation—particularly LNG where feasible—supports investment inflows and fiscal capacity that can be channelled toward broader infrastructure and public services. Realising this trajectory remains strongly conditional on non-technical factors, including regulatory stability, contract enforcement, project bankability and timely build-out of liquefaction, pipelines and associated infrastructure.

North America remains the largest producing region in absolute terms and contributes materially to the incremental supply, though its global share continues to decline as other regions expand faster. By 2055, North American production reaches about 1,645 bcm in SES, an increase of around 379 bcm compared with 2024, exceeding the approximately 277 bcm increase implied in RCS. North America therefore supplies roughly 102 bcm of additional output by 2055 in SES relative to RCS, contributing around 14% of incremental global supply. Its share falls to about 27% in SES by 2055 (versus roughly 28% in RCS and around 31% in 2024), reflecting faster growth elsewhere.

Asia Pacific also supplies higher volumes in SES than in RCS, even though its global share declines from today. Production reaches about 787 bcm by 2055 in SES, an increase of around 96 bcm from 2024, compared with only about a 5 bcm increase implied in RCS. This translates into an additional 91 bcm of supply by 2055 in SES relative to RCS, around 13% of incremental global supply. Asia Pacific's share is around 13% in both SES and RCS by 2055, down from around 17% in 2024, consistent with depletion in several mature provinces partially offset by new developments. The SES framing also implies rising reliance on interregional trade to meet expanding needs because demand growth outpaces domestic supply.

Collectively, the Middle East, Eurasia, Africa, North America and Asia Pacific account for roughly 96% of the total global increase in gas supply in SES relative to RCS by 2055. The remaining contribution comes primarily from Latin America, which adds about 28 bcm by 2055 relative to RCS (around 4%), supported by offshore development and, where relevant, unconventional potential. Europe does not contribute to incremental supply growth in SES relative to RCS, reflecting resource maturity and structural constraints. Overall, the geography of supply expansion underscores a central implication of SES: meeting development-driven demand growth depends on upstream and midstream delivery at scale in a concentrated set of regions, elevating the importance of investment attractiveness, infrastructure delivery and stable trade linkages as preconditions for market balance.

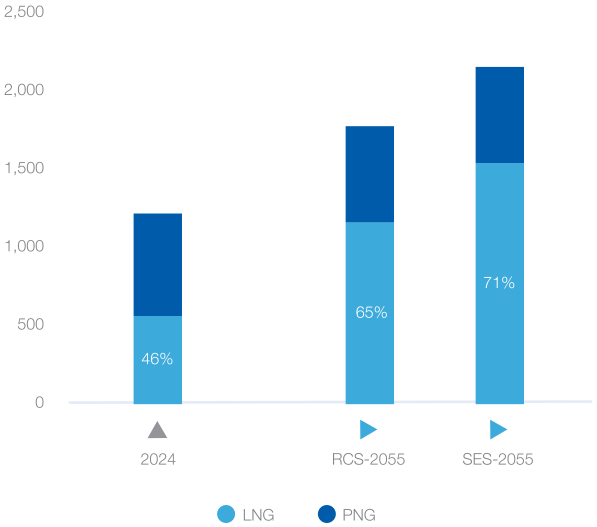
7.4.9 Natural gas trade

The demand–supply balance implied by SES translates into a structurally more connected global gas market than in RCS. **By 2055, total cross-border natural gas trade reaches about 2,144 bcm in SES, around 377 bcm higher than in RCS (1,767 bcm).** This indicates higher trade intensity: traded volumes relative to total demand rise to roughly 35% in SES by 2055, compared with about 33% in RCS. In SES, a larger share of the system's balancing function is performed through international trade because demand growth accelerates in regions where domestic supply and infrastructure cannot fully keep pace, while incremental supply remains concentrated in a limited set of competitive basins.

A defining feature of this expansion is that it is overwhelmingly an LNG story. Figure 7.12 indicates that essentially the entire increase in global gas trade in SES relative to RCS is delivered through LNG, while pipeline trade remains broadly flat and slightly lower than today. LNG trade rises to about 1,532 bcm by 2055 in SES, compared with about 1,155 bcm in RCS. **LNG volumes therefore increase by roughly 972 bcm between 2024 and 2055 in SES and by about 377 bcm relative to RCS in 2055, explaining the full uplift in total trade.** LNG's share of global gas trade rises to around

Figure 7.12

Global natural gas trade outlook by flow type in SES and RCS (bcm)



Source: GECF Secretariat based on data from the GECF GGM

71% by 2055 in SES, up from 65% in RCS and about 46% in 2024. The interpretation is straightforward: as SES prioritises reliable and scalable energy services in high-growth regions, the system leans more heavily on LNG as the most flexible mechanism for interregional balancing, connecting new demand centres to distant supply without requiring long, geopolitically and financially complex pipeline corridors.

The import side confirms the development-centred character of SES. Global LNG imports rise from about 406 Mt in 2024 to about 1,111 Mt by 2055 in SES—an increase of roughly 705 Mt—and about 273 Mt higher than the RCS level in 2055 (837 Mt). Asia Pacific remains the anchor market. Imports rise to about 749 Mt by 2055 in SES, around 167 Mt higher than in RCS, and the region's share settles at about 67% in SES (compared with roughly 69% in RCS and about 69% in 2024). The slight decline in share reflects not weaker demand but the emergence of a second major importing region in SES.

That second region is Africa. LNG imports rise from about 3 Mt in 2024 to about 171 Mt by 2055 in SES—about 141 Mt above RCS in 2055—lifting Africa's share of global LNG imports to about 15%, roughly 11 percentage points higher than in RCS. This is one of the most consequential trade signals in SES. As energy services expand and electricity systems scale, more African markets require additional firm fuel supply to support reliable power generation, industrial activity and infrastructure build-out. In many cases, LNG becomes the practical entry point: modular import terminals can be deployed faster than large pipeline corridors, supply options diversify for countries without sufficient domestic production, and gas-to-power and industrial switching can proceed where reliability is a binding constraint. The scale of LNG growth also reflects real-world constraints: intra-continental pipeline connectivity and upstream development do not uniformly match the geography and speed of demand growth across the continent.

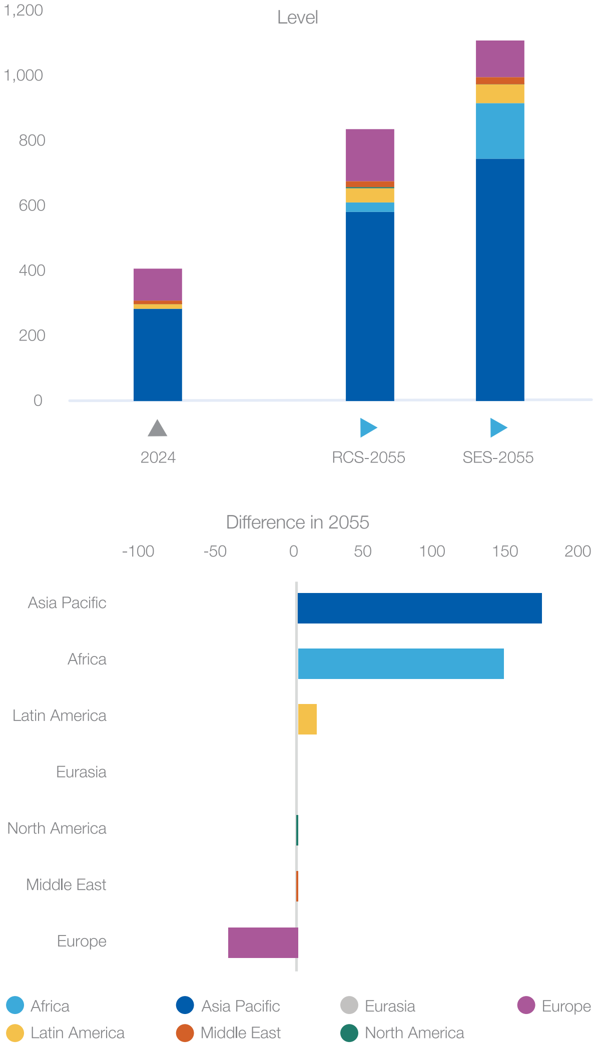
Europe imports less LNG in SES than in RCS, falling to about 113 Mt by 2055 in SES versus about 160 Mt in RCS, while still above 98 Mt in 2024. This reflects dampened demand growth due to efficiency and structural substitution in end-use sectors rather than a complete exit from gas. Latin America records moderate additional growth, rising to about 57 Mt in SES by 2055 versus about 44 Mt in RCS, reflecting incremental demand and limited domestic supply expansion in parts of the region. Overall, LNG in SES becomes less a marginal balancing instrument for mature markets and more a development-enabling instrument for emerging demand centres.

The export side mirrors the supply concentration. Global LNG exports reach about 1,111 Mt by 2055 in SES, about 274 Mt above RCS (837 Mt). The additional export capacity is delivered overwhelmingly by North America, Eurasia and the Middle East. North America provides the largest increment: exports rise to about 395 Mt by 2055 in SES versus about 283 Mt in RCS (an increment of roughly 112 Mt), reinforcing North America's leading position with an export share of about 36% by 2055 (up from roughly 34% in RCS). Eurasia provides the second-largest contribution: exports rise to about 227 Mt in SES versus about 136 Mt in RCS (an increment of roughly 91 Mt), lifting its share to about 20% by 2055 (versus about 16% in RCS and about 8% in 2024). The Middle East contributes a further 71 Mt of net uplift, with exports reaching about 259 Mt by 2055 in SES versus about 189 Mt in RCS, placing the region at roughly 23% of global LNG exports—broadly consistent with RCS and close to its 2024 share.

A particularly revealing outcome in SES is that Africa's LNG exports are essentially unchanged relative to the RCS by 2055, remaining around 120 Mt in both scenarios, even as African LNG imports rise sharply. This combination is not contradictory; it reflects the continent's internal heterogeneity and infrastructure constraints. Some African producers remain export-oriented because they have established liquefaction capacity and upstream projects, while many fast-growing African demand centres lack domestic supply or pipeline connectivity and therefore rely on LNG imports. At the same time, the fact that Africa's export volumes do not rise materially above the RCS while production increases in SES is consistent with a development-centred interpretation: a larger share of incremental African gas production is absorbed domestically and regionally to support power, industry, and energy access objectives rather than being channelled to incremental exports.

Figure 7.13

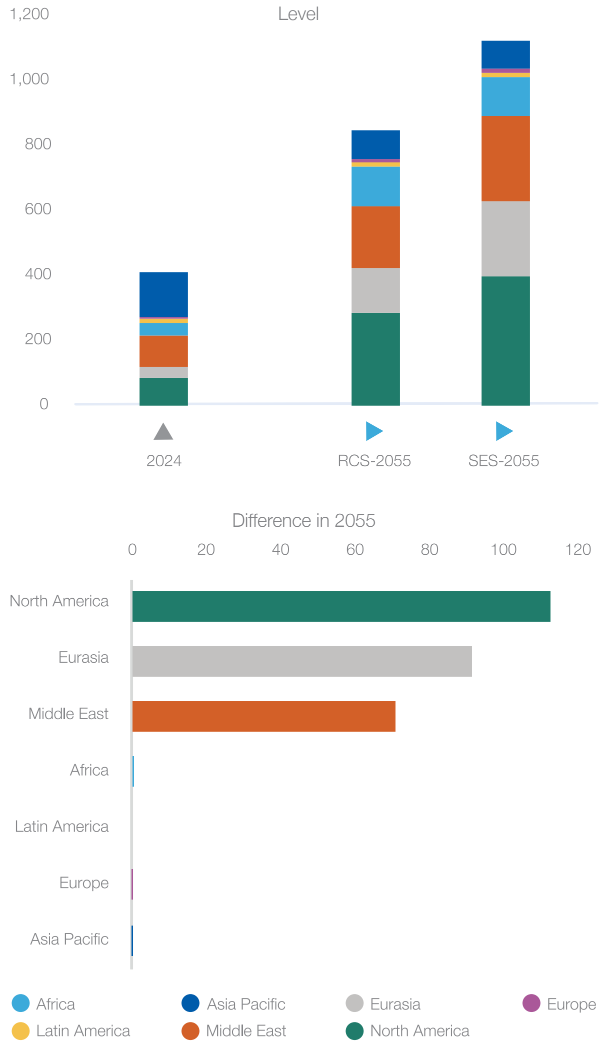
Global LNG import outlook by region in RCS and SES (Mt)



Source: GECF Secretariat based on data from the GECF GGM

Figure 7.14

Global LNG export outlook by region in RCS and SES (Mt)



Source: GECF Secretariat based on data from the GECF GGM

Overall, the trade outcomes reinforce a core message of SES: achieving development-consistent energy-service expansion increases the importance of interregional balancing and infrastructure optionality. LNG becomes dominant not because pipelines cease to matter, but because LNG is better suited to a world where demand growth shifts toward new centres, energy security is defined increasingly by resilience and diversification, and speed of infrastructure deployment becomes decisive for sustaining reliable and affordable energy services.

7.4.10 Energy-related emissions outlook

The emissions results should be read as a feasibility condition within SES. Because SES deliberately scales up energy services and economic activity, lower emissions are not an automatic by-product of slower growth; they are the consequence of a portfolio of structural shifts and technology deployments imposed as enabling conditions of the pathway. The central question is therefore not whether emissions decline in principle, but what combination of efficiency, fuel switching, electrification, low-carbon power and abatement options is required to ensure that higher energy services can coexist with lower cumulative emissions.

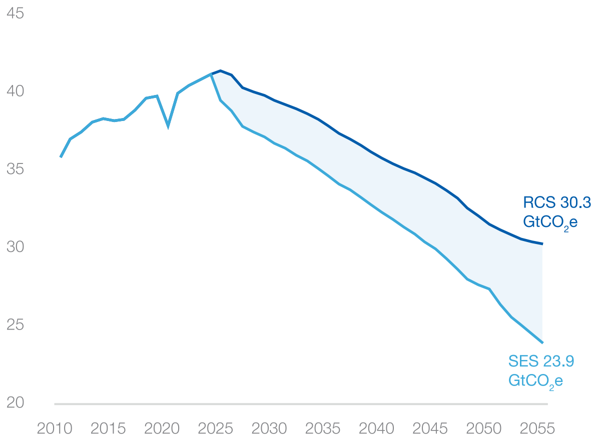
The core result is that cumulative energy-related emissions over the scenario horizon are about 10% lower in SES than in RCS despite a larger energy system and a continued substantial role for hydrocarbons—particularly higher natural gas use—within the transition. The reconciliation is achieved through rapid efficiency improvement and a faster decline in the carbon intensity of energy services. Mechanistically, the pathway depends on five reinforcing channels operating together: efficiency gains that reduce energy per unit of output and per unit of service; structural shifts in the fuel mix, especially coal displacement and coal-to-gas switching where it yields immediate reliability and air-quality benefits; accelerated electrification of final consumption enabled by power-system expansion; rapid scaling of low-carbon electricity, especially renewables, which progressively lowers the emissions intensity of electrification; and large-scale deployment of abatement options for hard-to-abate segments—most notably CCUS and hydrogen—supplemented later by carbon removals such as Direct Air Capture (DAC). No single lever is sufficient on its own; reconciliation requires simultaneous movement across the portfolio because development-driven demand growth would otherwise overwhelm incremental decarbonisation.

In level terms, **the SES pathway implies that global energy-related emissions decline from 41.2 GtCO2e in 2024 to 23.9 GtCO2e by 2055, a reduction of about one-third over the period.** This decline is materially faster than in the RCS, where emissions fall by around 26% over the same horizon. Over the full scenario horizon, cumulative energy-related emissions in the SES amount to 992.9 GtCO2e, which is 116 GtCO2e lower than the RCS. The interpretation of Figure 7.15 is therefore not simply "lower emissions," but "lower cumulative emissions despite higher energy services," which is the defining condition for reconciling development floors with a Paris-aligned long-run constraint. In SES, decarbonisation is not achieved by suppressing development; it is achieved by compressing the emissions intensity of growth and by shifting a rising share of energy demand into carriers and technologies that can be scaled without proportionally scaling emissions.

The regional pattern of savings further clarifies the logic of reconciliation. The emissions reductions achieved in SES relative to RCS are concentrated where today's emissions are highest and where the abatement potential from structural change is largest. As illustrated in Figure 7.16, Asia Pacific accounts for the largest share of global emissions savings, with cumulative emissions about 108 GtCO2e lower in SES than in the RCS. This outcome follows directly from the region's starting point: a large, coal-intensive energy system means that accelerated coal displacement, rapid renewable deployment, and large-scale deployment of point-source abatement options generate large cumulative savings. Yet even in SES, Asia Pacific remains the dominant contributor to global cumulative energy-related emissions, with a share of about 45% (down from roughly 50% in the RCS). The implication is important for credibility: SES does not assume that leadership regions can "disappear" from the emissions picture; it assumes they decarbonise faster than the reference trajectory, but their scale still matters.

Figure 7.15

Global energy-related emission outlook in SES and RCS ($GtCO_2e$)



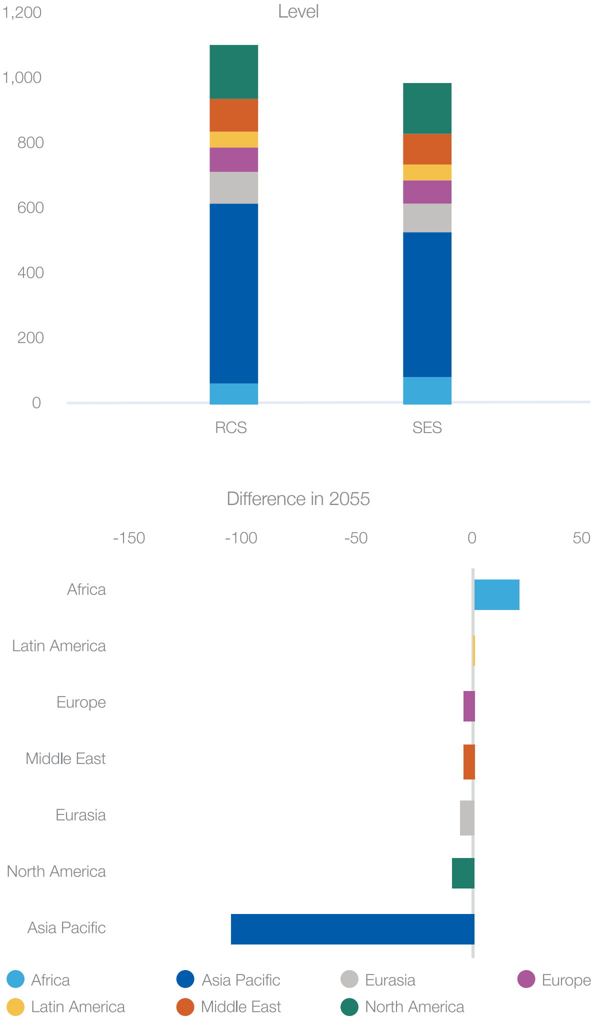
Source: GECF Secretariat based on data from the GECF GGM

Other major regions, North America, Eurasia, the Middle East, and Europe, also achieve meaningful emissions reductions relative to the RCS, although the absolute savings are smaller than those in Asia Pacific, reflecting different starting mixes, different industrial footprints, and different growth dynamics. The contrasting case is Africa, where cumulative energy-related emissions are higher in SES than in the RCS by around 19.6 GtCO2e. This is not a contradiction; it is a deliberate feature of a development-consistent pathway. SES assumes stronger economic growth, faster infrastructure build-out, and higher modern energy service delivery across African economies, outcomes that are difficult to achieve while holding emissions flat when starting from very low levels of modern energy consumption. Importantly, the scenario's equity logic is visible in the numbers. Even with higher cumulative emissions in SES, Africa remains a minor contributor to global totals: in the RCS, Africa, home to roughly a quarter of the global population by 2055, is associated with only about 6% of cumulative energy-related emissions over the horizon, rising to around 8% in SES by then. Moreover, emissions per capita in Africa decline to about 2.54 tCO2e per person by 2055, the lowest among all regions and far below the global average of 4.33 tCO2e per capita. In other words, SES accommodates development-driven emissions growth where energy poverty is most acute, while requiring that the largest absolute reductions occur where emissions are structurally concentrated and abatement opportunities are greatest.

A critical lever that enables this reconciliation in SES is the large-scale deployment of CCUS, especially in sectors where electrification alone cannot deliver deep reductions at the required pace. **Under SES, CCUS deployment scales from about 50 MtCO2e in 2024 to 8.9 GtCO2e by 2055, an increase that is about 7.5 GtCO2e higher than the RCS.** Figure 7.17 shows

Figure 7.16

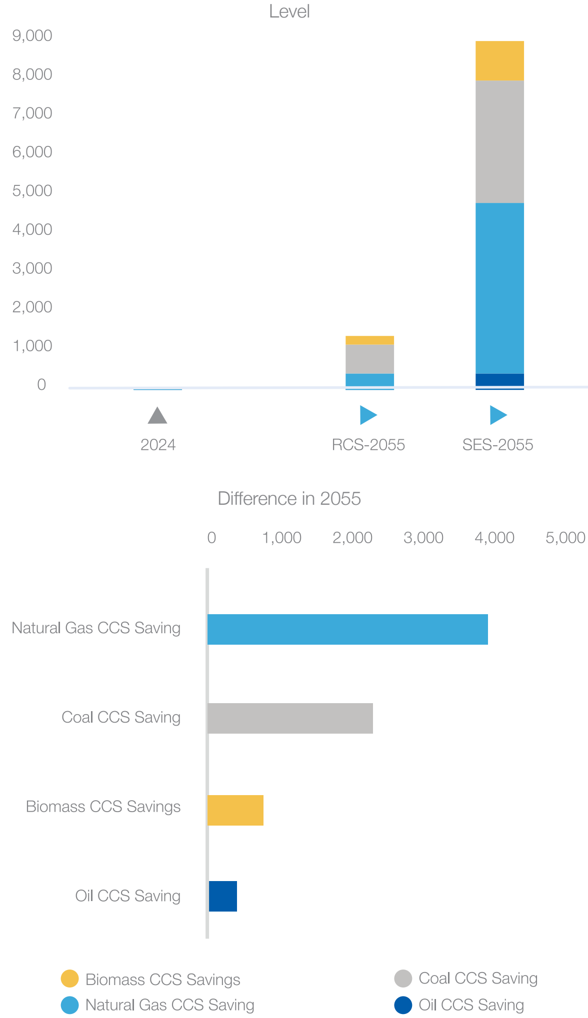
Global cumulative energy-related emissions outlook by region in RCS and SES ($MtCO_2$)



Source: GECF Secretariat based on data from the GECF GGM

Figure 7.17

Global CCUS savings outlook by fuel type in RCS and SES ($MtCO_2e$)



Source: GECF Secretariat based on data from the GECF GGM

that the incremental contribution of CCUS is fuel- and system-specific rather than uniform. Natural-gas-based CCUS delivers the largest additional savings by 2055, reaching over 4.3 $GtCO_2e$ in SES, 3.9 $GtCO_2e$ higher than in the RCS, and accounting for roughly 53% of the additional CCUS-driven savings between the two scenarios. Coal-based CCUS is the second largest contributor, reaching 3.1 $GtCO_2e$ by 2055 in SES, 2.3 $GtCO_2e$ higher than in the RCS, equivalent to about 31% of the incremental CCUS savings. Biomass- and oil-linked applications also contribute, with biomass-related CCUS (often associated with negative-emissions pathways such as BECCS) accounting for around 11% of additional savings and oil-related CCUS around 6%. The broader implication is that SES uses CCUS strategically: it is concentrated where point sources are large, where alternatives are expensive or slow to scale, and where maintaining reliability and industrial output is part of the development objective.

The regional distribution reinforces this interpretation. Asia Pacific accounts for around 63% of total CCUS savings by 2055, reflecting coal-intensive power and industry; within this, a large portion of savings is coal-linked (around 49%), with natural gas CCUS also substantial (around 33%). Outside Asia Pacific, natural gas CCUS becomes the dominant application because gas is the principal flexible fuel and industrial feedstock in many systems. In the Middle East, nearly all of the 649 $MtCO_2e$ of CCUS savings under SES is linked to natural gas applications. In Africa, natural gas CCUS accounts for over 76% of the region's 402 $MtCO_2e$ of total CCUS savings by mid-century, while in North America this share rises to about 84%, capturing around

398 $MtCO_2e$. Across regions, power, heavy industry and hydrogen production are the primary loci of CCUS deployment because they are large point sources and among the hardest segments to fully decarbonise through electrification alone.

Finally, SES explicitly recognises the risk of temperature overshoot and treats carbon removal as a late-horizon stabiliser rather than an early substitute for mitigation. The scenario assumes the introduction of removal technologies such as DAC after 2040, scaling to about 1.5 $GtCO_2$ of removals per year by 2055. It also deliberately excludes additional emissions reductions from nature-based solutions and wider carbon sinks, meaning that the burden of reconciliation is carried primarily by energy-system transformation and engineered removals. Under this framing, and given the remaining carbon budget consistent with limiting warming to around 2°C with a 50% probability, the SES results imply that net negative emissions beyond 2055 would likely be required to lock in end-of-century alignment, particularly if overshoot occurs during the period of fastest development-driven energy expansion. This does not weaken the SES argument; it strengthens it by making the sequencing explicit: development is accelerated now, emissions intensity falls faster than in the reference trajectory, and the system builds the technological and institutional capacity needed to address residual emissions later. In that sense, the emissions outlook is the quantitative expression of SES's core proposition: reconciling sustainable development with the Paris ambition is feasible only if the world couples rapid energy-service expansion with an equally rapid tightening of emissions intensity, supported by a portfolio that includes efficiency, fuel switching, electrification, low-carbon power, targeted CCUS and hydrogen, and scalable removals in the later horizon.

Annex A
Abbreviations and Acronyms

Abbreviation	Definition
ADGSM	Australian Domestic Gas Security Mechanism
ADNOC	Abu Dhabi National Oil Company
AG	Associated gas
AI	Artificial Intelligence
AKK	Ajaokuta–Kaduna–Kano
AMUFERT	Angola Ammonia and Urea Fertiliser project
ARLA-32	Diesel exhaust fluid (32% urea solution) used in SCR systems
ASEAN	Association of Southeast Asian Nations
ATR	Autothermal Reforming
ATR/SMR	Autothermal Reforming / Steam Methane Reforming
bcma	Billion cubic metres per annum
BECCS	Bioenergy with Carbon Capture and Storage
BOTAS	BOTAŞ Petroleum Pipeline Corporation (Türkiye)
BP	British Petroleum plc
CBAM	Carbon Border Adjustment Mechanism
CBDR-RC	Common but Differentiated Responsibilities and Respective Capabilities
CBM	Coalbed methane
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
CDM	Clean Development Mechanism
CFE	Federal de Electricidad
CGD	City Gas Distribution
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CNOOC	China National Offshore Oil Corp
CNY	Chinese yuan
COP	Conference of the Parties
COVID-19	Coronavirus disease 2019
CO_2	Carbon dioxide
CSDDD	Corporate Sustainability Due Diligence Directive
DAC	Direct Air Capture
DG	Directorate-General
DRI	Direct Reduced Iron
EAF	Electric Arc Furnaces
ECA	Energía Costa Azul
ECA LNG	Energía Costa Azul LNG
EG	Equatorial Guinea
EG LNG	Equatorial Guinea LNG (LNG plant)
EIA	Energy Information Administration
EJ	Exajoules
ENER	Directorate-General for Energy (European Commission)
ENN	ENN Natural Gas
EOG	EOG Resources
EPA	United States Environmental Protection Agency
EPC	Engineering, Procurement and Construction
ERD	Extended Reach Drilling
ESG	Environmental, Social and Governance
ETS	EU Emissions Trading System

EU	European Union
EV	Electric Vehicle
FEED	Front-End Engineering Design
FID	Final Investment Decision
FLNG	Floating Liquefied Natural Gas
FOB	Free-on-board
FPSO	Floating Production, Storage and Offloading
FSRU	Floating Storage and Regasification Unit
FSU	Floating Storage Unit
FTA	Free Trade Agreement
GA	Geographical Area
GCC	Gulf Cooperation Council
GDP	Gross Domestic Product
GECF	Gas Exporting Countries Forum
GGA	Global Goal on Adaptation
GGM	GECF Global Gas Model
GGO	Global Gas Outlook
GHG	Greenhouse gas
GIJA	Gasoducto de Integración Juana Azurduy (Bolivia–Argentina pipeline)
GJ	Gigajoules
GMH	Gas Mega Hub
GOR	Gas-Oil Ratio
GTA	Greater Tortue Ahmeyim
$GtCO_2$	Gigatonnes of CO_2
GTL	Gas-to-liquids
GW	Gigawatts
HDI	Human Development Index
HELP	Hydrocarbon Exploration Licensing Policy (India)
HGV	Heavy goods vehicle
HH	Henry Hub
H_2-DRI	Hydrogen-based Direct Reduced Iron
ICE	Internal Combustion Engine
IPCC	Intergovernmental Panel on Climate Change
IRA	Inflation Reduction Act
JKM	Japan Korea Marker
JKT	Japan–Korea–Taiwan
LCOE	Levelized Cost of Electricity
LDAR	Leak Detection and Repair
LMDI	Logarithmic Mean Divisia Index
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MEMR	Ministry of Energy and Mineral Resources
MENA	Middle East and North Africa
MI	Methane Intensity
MiQ	Methane Intelligence (MiQ methane certification initiative)
MJ	Megajoules
MJ/USD	Energy intensity (megajoules per USD of GDP)
MMBtu	Million British thermal units

MOL	MOL Group (Hungarian oil and gas company)
EU MR	EU Methane Regulation
MRP	Malaysian Reference Prices
MRV	Measurement, Reporting and Verification
MtCO2	Million tonnes of CO_2
Mtpa	Million tonnes per annum
MW	Megawatts
NAG	Non-associated gas
NARDL	Nonlinear Autoregressive Distributed Lag
NDC	Nationally Determined Contribution
NE	Appalachian Northeast
NGV	Natural Gas Vehicle
NLNG	Nigeria LNG
NSPS	New Source Performance Standards
NWS	North West Shelf (Australia)
NZIA	Net-Zero Industry Act
OECD	Organisation for Economic Co-operation and Development
OGMP	Oil and Gas Methane Partnership
OML	Oil Mining Lease (Nigeria)
OOOOC	NSPS Subpart OOOOc (US EPA methane regulation)
OPEC	Organization of the Petroleum Exporting Countries
OQ	OQ (Oman energy company)
PIA	Petroleum Industry Act
PLN	Perusahaan Listrik Negara (Indonesia state electricity utility)
PNG	Pipeline natural gas
PNGRB	Petroleum and Natural Gas Regulatory Board
PPP	Purchasing Power Parity
PSA	Production Sharing Agreement
PSC	Production Sharing Contract
PV	Photovoltaic
RCEP	Regional Comprehensive Economic Partnership
RCS	Reference Case Scenario
RNGH	Renewable & Natural Gases and Hydrogen
RUKN	Indonesia's national electricity plan (RUKN)
RUPTL	Indonesia's electricity supply business plan (RUPTL)
SAF	Sustainable Aviation Fuels
SCADA	Supervisory Control and Data Acquisition
SDG	United Nations Sustainable Development Goal
SES	Sustainable Energy Scenario
SGC	Southern Gas Corridor
SKK	SKK Migas (Indonesia upstream oil and gas regulator)
SMR	Steam Methane Reforming
SOCAR	State Oil Company of the Azerbaijan Republic
TANAP	Trans-Anatolian Natural Gas Pipeline
TAP	Trans Adriatic Pipeline
TAPI	Turkmenistan–Afghanistan–Pakistan–India Pipeline
TFES	Total Final Energy Supply
TFFF	Tropical Forests Forever Facility
TFP	Total Factor Productivity

TPAO	Turkish Petroleum Corporation
TPES	Total Primary Energy Supply
TTF	Title Transfer Facility
TWh	Terawatt-hours
UAE	United Arab Emirates
UK	United Kingdom
UN	United Nations
UNFCCC	United Nations Framework Convention on Climate Change
US	United States
USD	United States dollars
UTM	UTM Offshore (company/project developer)
VECM	Vector Error Correction Model
VRE	Variable Renewable Energy
WAGP	West African Gas Pipeline
WMO	World Meteorological Organisation
WTI	West Texas Intermediate
WTO	World Trade Organization
YPF	Yacimientos Petrolíferos Fiscales (Argentina)
YTF	Yet-To-Find

Annex B
Geographical Coverage

Advanced economies

Bulgaria	Latvia	OECD
Croatia	Lithuania	Romania
Cyprus	Malta	

Africa

North Africa	Congo	Southern Africa
Algeria	Eastern Africa	Namibia
Egypt	Eritrea	Zambia
Libya	Ethiopia	Zimbabwe
Morocco	South Sudan	Western Africa
Tunisia	Sudan	Benin
Sub-Saharan Africa	Tanzania	Ghana
Angola	Uganda	Ivory Coast
Central Africa	Equatorial Guinea	Mali
Cameroon	Ghana	Mauritania
Chad	Kenya	Niger
Central African Rep.	Mozambique	Senegal
Dem. Rep. of the Congo	Nigeria	Togo
Gabon		

Asia Pacific

Afghanistan	Indonesia	Palau
Australia	Japan	Papua New Guinea
Bangladesh	Kiribati	Philippines
Bhutan	South Korea	Samoa
Brunei Darussalam	Lao People's Dem. Rep.	Singapore
Cambodia	Macau (China)	Solomon Islands
China	Malaysia	Sri Lanka
Chinese Taipei	Maldives	Thailand
Cook Islands	Mongolia	Timor-Leste
Dem. People's Rep. of Korea	Myanmar	Tonga
Fiji	Nepal	Vanuatu
French Polynesia	New Caledonia	Viet Nam
Hong Kong	New Zealand	
India	Pakistan	

OECD Asia		
Australia	South Korea	
Japan	New Zealand	

Developing Asia		
Afghanistan	India	Palau
Bangladesh	Indonesia	Papua New Guinea
Bhutan	Kiribati	Philippines
Brunei Darussalam	Lao People's Dem. Rep.	Samoa
Cambodia	Macau (China)	Singapore
China	Malaysia	Solomon Islands
Chinese Taipei	Maldives	Sri Lanka
Cook Islands	Mongolia	Thailand
Dem. People's Rep. of Korea	Myanmar	Timor-Leste
Fiji	Nepal	Tonga
French Polynesia	New Caledonia	Vanuatu
Hong Kong	Pakistan	Viet Nam

Developing economies
All other countries not included in the "advanced economies" regional grouping

Eurasia		
Armenia	Kazakhstan	Tajikistan
Azerbaijan	Kyrgyzstan	Turkmenistan
Belarus	Moldova	Ukraine
Georgia	Russia	Uzbekistan

Europe		
Albania	Montenegro	Switzerland
Bosnia and Herzegovina	FYR Macedonia	Türkiye
European Union	Norway	United Kingdom
Gibraltar	Republic of Moldova	
Iceland	Serbia	

European Union

Austria	France	Malta
Belgium	Germany	the Netherlands
Bulgaria	Greece	Poland
Croatia	Hungary	Portugal
Cyprus	Ireland	Romania
Czech Republic	Italy	Slovakia
Denmark	Latvia	Slovenia
Estonia	Lithuania	Spain
Finland	Luxembourg	Sweden

GECF Full Members

Algeria	Libya	Russia
Bolivia	Iran	Trinidad and Tobago
Egypt	Nigeria	Venezuela
Equatorial Guinea	Qatar	United Arab Emirates

GECF Observer Members

Angola	Malaysia	Peru
Azerbaijan	Mauritania	Senegal
Iraq	Mozambique	

Latin America

Antigua and Barbuda	Dominica	Netherlands Antilles
Argentina	Dominican Republic	Nicaragua
Aruba	Ecuador	Panama
Bahamas	El Salvador	Paraguay
Barbados	Falkland Islands	Peru
Belize	French Guyana	Saint Kitts and Nevis
Bermuda	Grenada	Saint Lucia
Bolivia	Guadeloupe	Saint Pierre et Miquelon
Brazil	Guatemala	St.Vincent and Grenadines
British Virgin Islands	Guyana	Suriname
Cayman Islands	Haiti	Trinidad and Tobago
Chile	Honduras	Turks and Caicos Islands
Colombia	Jamaica	Uruguay
Costa Rica	Martinique	Venezuela
Cuba	Montserrat	

Middle East		
Bahrain	Kuwait	Saudi Arabia
Iran	Lebanon	Syria
Iraq	Oman	United Arab Emirates
Israel	Qatar	Yemen
Jordan		
Middle East and North Africa (MENA)		
Middle East and North Africa regional groupings		
North America		
Canada	Mexico	United States
OECD		
Australia	Hungary	Poland
Austria	Iceland	Portugal
Belgium	Ireland	Slovak Republic
Canada	Israel	Slovenia
Chile	Italy	Spain
Czech Republic	Japan	Sweden
Denmark	Korea	Switzerland
Estonia	Luxembourg	Türkiye
Finland	Mexico	United Kingdom
France	Netherlands	United States
Germany	New Zealand	
Greece	Norway	
Southeast Asia		
Brunei Darussalam	Malaysia	Thailand
Cambodia	Myanmar	Viet Nam
Indonesia	Philippines	
Laos	Singapore	

Annex C
Conversion Tables

Conversion factors for energy

Convert from:	EJ	Gcal	Mtoe	MBtu	bcme	Gwh	MtH_2
	Multiplier to convert to:						
EJ		2.388×10^{8}	23.88	9.478×10^{8}	27.78	2.778×10^{5}	8.33
Gcal	4.1868×10^{-9}		10^{-7}	3.968	1.163×10^{-7}	1.163×10^{-3}	3.489×10^{-8}
Mtoe	4.1868×10^{-2}	107		3.968×10^{7}	1.163	11 630	0.35
MBtu	1.0551×10^{-9}	0.252	2.52×10^{-8}		2.932×10^{-8}	2.931×10^{-4}	8.793×10^{-9}
bcme	0.0361	8.60×10^{6}	0.86	3.41×10^{7}		9 999	0.30
Gwh	3.6×10^{-6}	860	8.6×10^{-5}	3 412	1×10^{-4}		3×10^{-5}
MtH_2	0.12	2.866×10^{7}	2.87	1.137×10^{8}	3.33	33 333	

Notes:

- *The energy density of natural gas is based on its lower heating value, which is 50.08 MJ/kg or 36.1 MJ/m³.*
- *Conversions to and from billion cubic meters of natural gas equivalent (bcme) are provided as representative multipliers. However, they may differ from average values obtained when converting natural gas volumes, as country-specific energy densities are used.*
- *Lower heating values (LHV) are used for energy conversions.*
- *The GGO adopts the United Nations' International Recommendations for Energy Statistics (IRES) approach for energy balancing and forecasting. This physical energy content methodology records non-combustible renewables at gross electricity generation and applies standard efficiency assumptions for nuclear, geothermal, concentrating solar, and biomass-based power generation, thereby ensuring internationally consistent energy balances and a more accurate representation of the evolving energy system.*

Conversion factors for natural gas and LNG

Convert from:	bcm	bcf	PJ	Mtoe	Mt LNG	MMbtu	Mboe
	Multiplier to convert to:						
bcm		35.315	36.1	0.86	0.735	34.121	5.833
bcf	0.028		1.019	0.024	0.021	0.996	0.167
PJ	0.0278	0.981		0.02338	0.021	0.9478	0.164
Mtoe	1.163	41.071	41.868		0.855	39.683	6.842
Mt LNG	1.36	48.028	48.747	1.169		46.405	8.001
MMbtu	0.029	1.035	1.050	0.025	0.022		0.172
Mboe	0.170	6.003	6.093	0.146	0.125	5.800	

SI unit multiple prefix:

	Prefix	Size
Kilo	k	10^{3}
Mega	M	10^{6}
Giga	G	10^{9}
Tera	T	10^{12}
Peta	P	10^{15}
Exa	E	10^{18}

Notes:

- *Natural gas represents standard cubic meters (measured at 15°C and 1013 mbar) and has been standarized using a lower (net) heating value of 36.1 MJ/m^3*

Annex D
Definitions

Ammonia (NH_3)

Ammonia (NH3) is a colourless gas with a distinctively pungent smell, used as a high-nitrogen fertiliser in agriculture and as a refrigerant in industrial cooling systems. It is synthesised predominantly by the Haber-Bosch process, which reacts nitrogen from the air with hydrogen derived from natural gas under high pressure and temperature, catalysed by iron.

Announced LNG Project

Refers to a liquefied natural gas (LNG) project that has been publicly announced but has not yet reached a final investment decision (FID). These projects are in various stages of planning and pre-construction, including securing financing, completing environmental assessments, and obtaining necessary regulatory approvals.

Associated Gas

Associated gas is natural gas found in conjunction with oil in oil reservoirs. It can exist dissolved in the oil or as a free gas cap above the oil in the reservoir. The management of associated gas includes re-injection into the reservoir, flaring, or capturing for use as an energy source.

Aviation

Refers to the use of energy, particularly jet fuel and aviation gasoline, in aircraft for the transportation of passengers and goods. This sector includes both commercial and military aviation activities and focuses on the energy requirements necessary for various flight operations.

Biofuels

Biofuels are fuels derived from biological materials, including plant biomass, agricultural by-products, and organic waste. They are renewable energy sources and can be used as substitutes for conventional fossil fuels in transportation, power generation, and heating. Common types of biofuels include biodiesel, ethanol, and biogas, which are produced through processes such as fermentation, transesterification, and anaerobic digestion.

Biomass and Waste

Biomass and waste refer to organic materials used as fuel to generate energy. This includes wood, agricultural residues, and municipal solid waste. These resources can be directly combusted or converted into other energy forms such as methane, ethanol, or biodiesel through various biochemical and thermochemical processes

Bunkers

Bunkers refer to the fuel supplied to ships for international navigation. The term originates from coal bunkers, where the fuel was historically stored. Bunker fuels include heavy fuel oil, marine diesel oil, and increasingly liquefied natural gas (LNG), reflecting the shipping industry's transition towards cleaner fuel options under international regulations

Carbon Capture, Utilisation, and Storage (CCUS)

CCUS is a technology aimed at capturing carbon dioxide (CO_2) emissions from sources like power plants and industrial processes, transporting it to a storage site, and depositing it where it will not enter the atmosphere, typically in deep geological formations. The utilisation aspect involves using captured CO_2 in applications such as enhanced oil recovery or as a feedstock for producing synthetic fuels and chemicalss.

Coal

Coal is a combustible black or brownish-black sedimentary rock composed primarily of carbon along with various other elements, including sulfur. It is extracted from underground or open-pit mines and is used primarily for burning to produce electricity and heat through combustion. Types of coal vary based on carbon content and heat generation, ranging from lignite to anthracite.

Coalbed Methane (CBM)

Coalbed methane is a form of natural gas extracted from coal seams. It is a clean-burning gas used for residential and industrial heating, as well as power generation. The extraction of coalbed methane involves removing groundwater from the seam to reduce pressure and release trapped methane.

Commercial Sector

The commercial sector includes businesses and service-providing facilities and equipment. Energy use in this sector covers heating, cooling, lighting, refrigeration, and operating appliances and machinery necessary for the operations of commercial buildings such as offices, malls, restaurants, and hospitals.

Condensate

Condensate, or natural gas liquids (NGLs), is a mixture of hydrocarbon liquids present in raw natural gas produced from natural gas fields. These liquids are extracted from the gas stream when the temperature and pressure of the gas are reduced. Condensates are valuable as they yield products like naphtha, kerosene, and diesel after refining.

Conventional Resources

Conventional resources refer to oil and natural gas that can be extracted using traditional drilling and pumping techniques. These resources are typically found in large, well-defined reservoirs which can be accessed by standard vertical drilling.

Conversion losses

Conversion losses are the energy losses that occur when primary energy is transformed into secondary energy carriers and delivered energy products. They include, for example, thermal losses in electricity generation, losses in heat production, refinery own-use and processing losses, gas processing and compression energy use, LNG liquefaction and regasification energy requirements, and losses associated with hydrogen production and conversion chains. Conversion losses explain a large share of the difference between primary energy supply and final energy delivered to end users, and their magnitude depends on the technology mix and efficiency of the transformation sector.

Crude Oil

Crude oil is a naturally occurring, unrefined petroleum product composed of hydrocarbon deposits and other organic materials. It can be refined to produce usable products such as gasoline, diesel, and various forms of petrochemicals. Crude oil is extracted through drilling, where it is then transported to refineries to be processed into finished goods.

Decommissioned LNG Project

A decommissioned LNG project refers to a project that has been dismantled and is no longer in operation. Decommissioning involves the safe removal of LNG storage and processing facilities and restoration of the site, often in accordance with environmental regulations.

DES (Delivered Ex Ship) LNG

A contractual term where the seller delivers liquefied natural gas to the buyer at an agreed-upon location (typically a port). The seller assumes all risks and responsibilities until the LNG is offloaded at the destination port, after which the buyer assumes responsibility.

Direct Air Capture (DAC)

Direct air capture (DAC) is a carbon dioxide removal technology that uses engineered systems to extract CO_2 directly from ambient air (rather than from a concentrated exhaust stream) and produce a CO_2 stream suitable for permanent geological storage or for use in products (e.g., synthetic fuels, chemicals, or building materials). Because atmospheric CO_2 is dilute (around 0.04%), DAC requires significant energy input for air handling and for regenerating the capture materials. Two main technical approaches are commonly used: liquid solvent systems that absorb CO_2 and then release it through chemical regeneration, and solid sorbent systems where CO_2 binds to a material and is released through heat and/or pressure changes. DAC should be distinguished from point-source carbon capture: it can in principle be deployed independently of emission sources and can deliver net-negative emissions when the captured CO_2 is permanently stored and the energy used is low-carbon

Direct Heat Generation

Direct heat generation involves Combined Heat and Power (CHP) systems, which generate both electricity and usable heat efficiently, and district heating systems that distribute heat from a central source to multiple buildings, enhancing overall energy efficiency and reducing emissions.

Distributed Energy System

Distributed energy systems refer to a variety of small, modular power-generating technologies that generate electricity at or near where it will be used, such as solar panels, wind turbines, and microturbines. These systems can be standalone or integrated with the grid to provide flexibility and improve the reliability of power delivery.

Domestic Sector

The domestic sector refers to energy consumption within a country's residential, commercial, and agricultural sectors. It includes all energy used by households and services, including heating, cooling, lighting, and operating appliances.

Dry Gas

Dry gas refers to natural gas that primarily consists of methane with few other hydrocarbons or impurities. It requires minimal processing to remove condensates and is used extensively as fuel for heating and electricity generation, as well as an industrial feedstock.

Electric Vehicle (EV)

Electric vehicles use one or more electric motors for propulsion, relying on electrical energy typically stored in rechargeable batteries. EVs can include fully electric vehicles, which run solely on electricity, and hybrid vehicles, which use a combination of electric motors and internal combustion engines.

Electricity Generation

The process of generating electric power from sources of primary energy. For electric utilities in the electrical power industry, it is the first stage in the delivery of electricity to consumers. Other energy sources include solar, wind, geothermal, hydropower, and various forms of biomass.

Electrolysis

Electrolysis is a method of using a direct electric current (DC) to drive an otherwise nonspontaneous chemical reaction. It is commonly used to decompose water into oxygen and hydrogen gas or to extract metals from their naturally occurring oxides or salts, such as aluminium from bauxite ore.

Energy Sector

The energy sector consists of all industries involved in the production and sale of energy, including fuel extraction, manufacturing, refining, and distribution. The main types of energy are electricity, gas, coal, oil, and renewables.

Energy-Related Emissions

Energy-related emissions refer to emissions of greenhouse gases, namely carbon dioxide, resulting from the combustion of fossil fuels such as coal, oil, and gas for energy production. These emissions are a major contributor to global climate change and air pollution.

Enhanced Oil Recovery (EOR)

Enhanced oil recovery is a set of techniques for increasing the amount of crude oil that can be extracted from an oil field. EOR can involve injecting substances like carbon dioxide, steam, or chemicals into an oil reservoir to boost its pressure and stimulate flow, thus increasing the extraction rates.

Feed-In Tariff

A feed-in tariff is a policy mechanism designed to accelerate investment in renewable energy technologies by offering long-term contracts to renewable energy producers, typically based on the cost of generation of each technology. Through the use of feed-in tariffs, governments encourage the adoption of renewable energy by guaranteeing a set price for generated power.

Feedstock

In the context of industrial processes, feedstock refers to raw material inputs used in chemical processes to produce chemical products. Common feedstocks in the petrochemical industry include natural gas, natural gas liquids (NGLs), naphtha, and coal.

Final Investment Decision (FID)

The final investment decision is the commitment of capital to a project or investment, where detailed project evaluations have been completed and the project is considered economically viable.

Flared Gas

Flared gas is the burning of natural gas that is released as a byproduct of oil or gas extraction operations where there are no economical means of transporting it, or it is not feasible to use it for production.

FOB (Free on Board) LNG

Free On Board is a contractual term used in the international trading of liquefied natural gas (LNG), indicating that the seller has an obligation to deliver the gas onto the ship at the specified location, and from that point, the buyer takes ownership, and all risks associated with the transportation of the gas.

Fossil Fuels

Fossil fuels are derived from the anaerobic decomposition of buried dead organisms, containing energy originating in ancient photosynthesis. These fuels include coal, crude oil, and natural gas, all of which are primary sources used extensively in power generation, heating, and transportation.

Gas Works Gas

Gas Works Gas (GWG), also known as town gas or manufactured gas, is a combustible gaseous fuel historically produced in gasworks by converting solid or liquid fuels, most commonly coal, and in some cases oil, into a gas mixture through processes such as carbonisation, gasification, or reforming. It typically contains hydrogen (H_2), carbon monoxide (CO), methane (CH_4) and other light hydrocarbons, along with inert gases, with composition and calorific value varying by feedstock and production technology. Gas Works Gas was widely used for lighting, cooking, heating and industrial fuel before the large-scale availability of pipeline-quality natural gas, and in modern energy statistics it is treated as a manufactured gas distinct from natural gas. Where it is still supplied, it is usually delivered through local distribution networks and should be reported separately from natural gas, particularly in systems that also include blended gases such as biomethane and hydrogen.

Geothermal

Geothermal energy is derived from the natural heat of the earth, which can be sourced close to the Earth's surface or from heated rock and reservoirs of hot water miles beneath our feet. It is used for heating and generating clean electricity.

Hard-to-Abate Industries

Sectors or industries where significant reductions in carbon emissions are particularly challenging due to technological limitations, high costs, or other practical barriers. These sectors often require high-heat processes, have long-lived infrastructure, or have few viable alternatives to fossil fuels.

Heads of Agreement (HoA) in LNG

A non-binding document that outlines the key terms agreed upon between parties during LNG negotiations. It precedes the final sales and purchase agreement and covers terms such as pricing, volume, and delivery specifics.

Heat Plants

Facilities that produce heat for residential, commercial, or industrial use. These plants may operate independently to provide district heating or may be part of a combined heat and power (CHP) system that generates both heat and electricity.

Heavy-Duty Vehicles

Vehicles designed for carrying large loads or performing other heavy-duty tasks. These include trucks, buses, and large commercial vehicles, which typically run on diesel fuel and are significant contributors to transportation-related emissions.

Hydrogen

An energy carrier that can be used in fuel cells to generate electricity or burned directly to produce heat yet emits only water vapour when consumed. Hydrogen can be produced from a variety of resources, such as natural gas, nuclear power, biomass, and renewable power like solar and wind.

Hydropower

Energy is derived from the movement of water, typically through turbines in dams or river systems, to generate electricity. It is one of the most established and cost-effective renewable energy technologies.

In-FEED LNG Project

Refers to the phase in LNG project development where the Front-End Engineering Design (FEED) is being conducted. This phase involves detailed planning and design work necessary to reach a Final Investment Decision (FID).

Industry Sector

The industry sector is the sector of an economy that includes activities such as manufacturing, construction and mining, excluding transportation. It is a major contributor to global energy demand, powering industrial processes, heating, and cooling.

Industry Sector

The sector of an economy is characterised by manufacturing, processing, and construction activities. Energy consumption in this sector is primarily for powering machinery, chemical processes, and production operations.

Intermittency

A characteristic of renewable energy sources like wind and solar refers to their non-constant and unpredictable output dependent on weather conditions, which presents challenges for integrating these sources into the power grid.

International Aviation Bunkers

Fuels provided for international aviation are excluded from domestic fuel statistics. These fuels are used by aircraft departing from one country and arriving in another, highlighting the international scope of these flights.

International Marine Bunkers

Fuels used by ships for international journeys, not included in any single country's national energy consumption statistics. This fuel is used by vessels traveling between different countries, outside of their territorial waters.

Liquids

Liquids refers to petroleum liquids, meaning crude oil and associated liquids that become available to the market (often including condensate and natural gas liquids (NGL) where included), plus refined petroleum products, and refinery processing gains and other hydrocarbons.

Liquefied Natural Gas (LNG)

Natural gas that has been cooled to liquid form for ease of storage or transport. It takes up about 1/600th the volume of natural gas in the gaseous state, making it more cost-effective to transport over long distances where pipelines are not feasible.

Long-Term LNG Contract

A contractual agreement for the supply of LNG over an extended period, typically 10 years or more, provides predictable revenue and supply security. These contracts are crucial for financing the development of LNG infrastructure.

Maritime

Relating to the operation of ships and other vessels that navigate the seas, used for the transportation of goods and passengers over water. This sector includes activities such as shipping, fishing, and leisure boating.

Memorandum of Understanding (MoU) in LNG

A preliminary non-binding agreement expressing the intent between parties to enter into a specific LNG project or transaction. It outlines the basic terms and how the project or business relationship will proceed.

Methanol

A light, volatile, colourless, flammable liquid alcohol used as an antifreeze, solvent, fuel, and a denaturant for ethanol. It is also used to produce formaldehyde and as a feedstock in the manufacture of various chemicals.

Mid-Term LNG Contract

An agreement for the supply of LNG typically lasts between 4 and 10 years. These contracts provide more flexibility compared to long-term agreements, allowing adjustments to market conditions and demand.

Mid-Term LNG Contract

An agreement for the supply of LNG typically lasts between 4 and 10 years. These contracts provide more flexibility compared to long-term agreements, allowing adjustments to market conditions and demand.

Nationally Determined Contributions (NDCs)

Commitments made by countries under the Paris Agreement to reduce national emissions and adapt to the impacts of climate change. NDCs are intended to increase global response to the threat of climate change by setting individual targets for countries to achieve.

Primary Natural Gas

Natural gas is a naturally occurring gaseous mixture of hydrocarbons dominated by methane, produced either from gas reservoirs (non-associated gas) or together with crude oil (associated gas). It may contain varying proportions of ethane, propane and heavier hydrocarbons, as well as non-hydrocarbon components such as CO_2, N_2, H_2S and water vapour. Unless stated otherwise, natural gas in this report refers to processed sales gas meeting pipeline/LNG specifications and excludes separated liquids (condensate and natural gas liquids). For energy conversions, the report applies a representative energy content of 36.1 MJ per m^3 and 50.08 MJ per kg on a LHV basis; these values imply a reference gas density of approximately 0.722 kg/m^3 under the stated conditionse.

Natural Gas Liquids (NGLs)

Components of natural gas are separated from the gas state in the form of liquids. This includes propane, butane, and ethane, which are used as feedstocks for chemical processes or as fuels.

Natural Gas Production

The process of extracting natural gas from earth's subsurface, which involves drilling wells and extracting the gas to the surface where it can be processed or directly marketed.

Natural Gas Production Capacity

The maximum rate at which a natural gas field or a country can produce natural gas under optimal technical and economic conditions is determined by the properties of the reservoir and the technology available.

Natural Gas Proven Reserves

Those quantities of natural gas, which, by analysis of geological and engineering data, can be estimated with a high degree of confidence to be commercially recoverable from known reservoirs under current technological and economic conditions.

New Project Gas Production

The initiation of natural gas production from newly developed fields that were previously untapped, adding to the total production capacity and often involving the deployment of advanced technologies to maximise efficiency and minimise environmental impact.

Non-Energy Use

The use of fuels not for their energy content but for their material properties in products such as plastics, lubricants, and other chemicals. This category includes the use of oil, natural gas, and coal as feedstocks in manufacturing processes.

Nuclear

Pertaining to the technology surrounding the reactions of atomic nuclei, especially the use of nuclear energy for the generation of electricity. Nuclear power plants use nuclear fission to generate heat, which is then used to produce steam to drive turbines that generate electricity.

Oil

A natural, flammable liquid found in rock formations. It is refined into various fuels, including gasoline, diesel, and jet fuel, and used as a base for manufacturing a wide range of chemicals and materials.

Oil Products

Refined products obtained from the distillation and processing of crude oil, including gasoline, diesel, kerosene, and heavy fuels used in energy production, transportation, and various industrial processes.

Oil Sands

Naturally occurring mixtures of sand, clay, water, and a dense form of petroleum called bitumen. Oil sands are mined and processed to extract the bitumen, which is then refined into oil. Despite being a significant source of oil, the extraction and processing are energy-intensive and environmentally challenging.

Petrochemical Feedstocks

Raw materials derived from refining crude oil and processing natural gas are used in the petrochemical industry to produce chemicals and plastics. These include naphtha, ethane, propane, and butane, which are crucial for the production of products ranging from plastics to pharmaceuticals.

Petroleum

Petroleum is a broad term covering naturally occurring hydrocarbons in liquid form and the products derived from them. It encompasses crude oil as the upstream commodity and, once refined or processed, the range of petroleum products used across the economy.

Planned LNG Project

An LNG project that has been approved for development but has not yet been constructed. These projects have passed the initial feasibility and planning stages and have a clear timetable leading to eventual operational status.

Power Generation

The process of generating electric power from primary energy sources, such as coal, natural gas, nuclear, hydro, and renewables. The generated electricity is then transmitted and distributed to end users, playing a crucial role in industrial, commercial, and residential applications.

Pre-FEED LNG Project

The preliminary phase in LNG project development, focusing on assessing the viability of the project. This stage involves preliminary designs and cost estimates to determine if the project should proceed to the Front-End Engineering Design (FEED) phase.

Probable Reserves

Estimates of the amount of oil or gas reserves that are not yet proven but are more than 50% likely to be recoverable. Probable reserves are based on geological and engineering data suggesting the likely presence of hydrocarbons but lack the necessary drilling and production data to be classified as proven.

Proposed LNG Project

An LNG project is in the early stages of development, typically after initial identification and announcement but before detailed planning and feasibility studies have begun. These projects are considered speculative until they proceed to the Front-End Engineering Design (FEED) stage.

Proven Reserves

Volumes of oil and natural gas that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions.

Refinery Feedstocks

The raw materials are processed in a refinery to produce petroleum products. These include crude oil and other inputs like natural gas liquids (NGLs), which are transformed into various refined products such as gasoline, diesel, jet fuel, and petrochemicals through a series of physical and chemical processes.

Renewables

Energy sources that are continuously replenished by natural processes include solar, wind, tidal and geothermal energy. These technologies generate energy with little to no greenhouse gas emissions and are key to sustainable energy strategies.

Reserves

Reserves are estimated quantities of resources anticipated to be economically recoverable from known oil and gas deposits. This term encompasses different classifications, including proven, probable, and possible reserves, based on the certainty of recovery and economic feasibility.

Residential Sector

Pertaining to energy use in private households, covering all energy consumption for lighting, heating, cooking, and electrical appliances in homes. The residential sector is a primary consumer of energy, influencing demand for electricity and natural gas.

Sales and Purchase Agreement (SPA) of LNG

A legally binding agreement between an LNG seller and buyer that specifies the terms of the LNG sale, including quantity, price, delivery schedule, and obligations and rights of both parties. SPAs are critical for the long-term security of supply and price stability in the LNG industry.

Shale Gas

Natural gas is found trapped within shale formations. It is typically extracted using hydraulic fracturing, or "fracking," which involves injecting fluid at high pressure into subterranean rocks to create cracks through which gas can flow into wells.

Short-Term LNG Contract

A contract for the supply of LNG over a short period, usually less than four years. These contracts provide flexibility for buyers to adjust to market conditions and are commonly used to meet temporary surges in demand or to test new supply sources.

Solar Photovoltaic (PV)

Technology that converts sunlight directly into electricity using semiconductors that exhibit the photovoltaic effect. Solar PV systems are used in a range of applications from small-scale residential and commercial installations to large utility-scale solar power stations.

Speculative LNG Project

An LNG project is considered speculative because it has been proposed or conceptually discussed but lacks formal development plans, committed investment, or a definitive timeline. These projects are typically contingent on market conditions, technological advancements, or securing sufficient financial backing.

Stalled LNG Project

An LNG project that has encountered significant delays or obstacles that have halted progress, potentially indefinitely. These challenges can stem from financial issues, regulatory changes, market dynamics, or environmental concerns.

Tight Gas

Natural gas is produced from reservoir rocks with exceptionally low permeability, necessitating specialised extraction techniques, such as hydraulic fracturing, to produce the gas at viable rates. Tight gas is a significant component of unconventional gas resources.

Total Final Energy Demand (TFED)

Final energy demand refers to the energy delivered to end-use sectors for consumption, including industry, transport, residential, commercial and public services, and agriculture. It excludes energy used in transformation processes such as electricity generation, heat generation, refining, and other conversion activities, because those are inputs to produce energy carriers rather than final uses. Final energy demand is often operationalised in energy balances as Total Final Consumption (TFC).

Total Gas Demand

Total gas demand is the gaseous fuel volume or energy actually delivered and metered to end-use sectors through pipeline distribution or dedicated supply arrangements. It includes natural gas and any other gaseous fuels delivered in the same system, including gasworks gas (manufactured gas) where applicable and blends of natural gas with biomethane and hydrogen.

Total Primary Energy Demand (TPED)

Total primary energy demand refers to the amount of energy required in primary form to supply the economy's energy services, taking account of the energy used in transformation sectors and the associated conversion losses. It includes the primary energy inputs used to produce electricity, refined products, hydrogen, heat and other secondary energy carriers, as well as the energy ultimately delivered to end-use sectors. Primary energy demand therefore differs from final energy demand because it captures the upstream and conversion requirements of the energy system, not just the energy delivered to consumers.

Transformation Sector

The transformation sector, sometimes referred to as the energy conversion sector, comprises activities that convert primary energy into secondary energy carriers and energy products. This includes electricity and heat generation, refining, gas processing, LNG liquefaction and regasification as part of the supply chain, hydrogen production, and other conversion processes. Energy used in the transformation sector is not considered final consumption because it is an input required to deliver energy carriers to end users. The transformation sector is central to understanding the relationship between primary energy and final energy, because its technology choices and efficiencies largely determine conversion losses.

Transport Sector

The sector involves the conveyance of goods and passengers via road, rail, air, and waterways. This sector is a major consumer of energy, primarily petroleum products and increasingly biofuels and electricity.

Unconventional Gas Production

The extraction of natural gas from non-traditional reservoirs including shale gas, tight gas, and coalbed methane. These sources require advanced drilling techniques such as horizontal drilling and hydraulic fracturing.

Unconventional Resources

Oil and gas resources are found in geological formations that require technologically advanced methods to extract due to challenges such as abnormal reservoir pressures, extreme reservoir depths, or unusual rock formations.

Under Construction LNG Project

An LNG project that has progressed beyond the planning and final investment decision stages and is currently under physical construction. This phase includes all activities from the groundbreaking to the commissioning of the facility.

Useful Energy

Useful energy is the portion of energy that actually delivers the intended service at the point of use after end-use conversion losses are accounted for. It is conceptually derived from final energy by applying end-use device efficiencies and therefore differs across technologies providing the same service. For example, the useful energy associated with space heating is the heat delivered indoors, not the fuel energy delivered to a boiler; for mobility it is the mechanical work at the wheels, not the energy content of gasoline, diesel or electricity consumed; for cooling it is the cooling effect delivered, not the electricity input to a chiller; and for industrial processes it is the effective process heat or mechanical drive delivered to equipment. Useful energy is not typically measured directly in standard energy balances, but it is an analytically important concept because it links energy consumption to the actual services demanded by households, industry and the broader economy.

Wind

The use of air flow through wind turbines to mechanically power generators for electric power. Wind power, as an alternative to burning fossil fuels, is plentiful, renewable, widely distributed, clean, and produces no greenhouse gas emissions during operation.

Yet-to-Find (YTF)

Refers to the estimated volumes of hydrocarbon resources that are postulated to exist based on geological and geophysical evidence but have not yet been discovered with drilling. These resources represent potential future additions to oil and gas reserves.

GECF

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