GECF

Gas Exporting Countries Forum

Global Gas Outlook

2050

9th Edition

March 2025

GECF

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Countries Forum

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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 March 2025, 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

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Foreword

Foreword

"Prediction is very difficult, especially when it concerns the future," a quote often attributed to the Nobel laureate physicist Niels Bohr, resonates profoundly today, as the world entered an era of unprecedented uncertainty across geopolitical, economic, environmental, technological, and even societal dimensions.

First, seismic shifts in trade, energy, and environmental policies, coupled with geopolitical realignments, are reshaping the fundamentals of global energy markets.

Second, energy security and affordability have reemerged as dominant priorities, taking precedence over sustainability concerns, as nations confront the intricate realities of transforming a vast and interdependent global energy system.

Third, the rapid rise of artificial intelligence (AI) presents both disruptive potential and transformative opportunities across economic and social structures. From the soaring energy demand of power-intensive data centers to the paradox of efficiency-driven consumption, the enhancement of total factor productivity, and the optimisation of oil and gas operations, AI's full impact on the energy landscape remains complex and difficult to fully predict.

It is against this complex backdrop that we have pursued the Global Gas Outlook (GGO), remaining steadfast in analysing energy systems through the lens of sustainable development and the fundamental drivers of demographic expansion, economic growth, rising standards of living, and efficiency gains.

The findings of the GGO confirm our argument that no single energy source or technology can fulfill the diverse, ever-evolving energy needs of the world. Instead, an integrated energy mix, tailored to the unique circumstances and priorities of individual countries, regions and cities, must be devised to ensure a balance of energy security, affordability, and sustainability.

2024 lent further credence to these convictions, as global consumption of oil, gas, coal, and even wood soared to record levels despite rapid renewable growth, with natural gas accounting for 40% of the incremental energy demand, the highest share of any fuel.

We are convinced, now more than ever, that natural gas is not just a bridge to the future; it is an integral part of the future. Indeed, natural gas demand is expected to grow by 32% by 2050, showing no peak in sight. It increases in all regions except Europe, due to its energy policies and deindustrialisation.

Natural gas remains vital for clean cooking in low-income countries, coal-to-gas switching in emerging economies, grid stability for renewables, power-hungry AI data centers, decarbonisation in transport and hard to abate industries, and food security via fertiliser production.

Meanwhile, the epicenter of natural gas supply is shifting, with the Middle East, Eurasia, and Africa projected to contribute nearly 90% of global production growth by 2050. LNG trade is set to double, enhancing global market flexibility.

The GGO also dispels the myth that we could stop investing in natural gas. Meeting the colossal demand requires hefty investments of USD 11.1 trillion in upstream and midstream projects.

The Sustainable Energy Scenario demonstrates that there is a pathway to ensure a balance between energy security, affordability, and sustainability, without leaving people behind. It emphasises the complementary roles of natural gas and renewables in addressing energy poverty and fostering socio-economic empowerment in low-income countries, while advancements in decarbonisation technologies, such as carbon capture, utilisation, and storage (CCUS), and the growth of blue hydrogen production significantly help reduce greenhouse gas emissions.

GECF member countries, endowed with vast natural gas resources and technological expertise, stand at the forefront of this evolving energy landscape. By 2050, their contribution is poised to approach half of the global natural gas production. The Algiers Declaration, adopted at the 7th GECF Summit of Heads of State and Government, underscores the critical role of natural gas as a catalyst for just and sustainable energy transitions, enabling economic growth, social progress, and environmental protection.

Finally, I extend my gratitude to the dedicated GECF team for their tireless efforts in producing this insightful report. I also thank the GECF Technical and Economic Council, Member Country experts, and all contributors whose invaluable insights have enriched this GECF Global Gas Outlook edition.

Eng. Mohamed Hamel
Secretary General

Executive Summary

Executive Summary

The world in 2050 will be different from today, with the global population increasing by 1.8 billion, urbanisation accelerating, and demographic ageing reshaping societies

The global demographic landscape is undergoing a profound transformation, with the centre of population growth shifting toward low- and middle-income regions, particularly Africa and South Asia. At the same time, the world is becoming increasingly urbanised, older, and more fragmented as shrinking household sizes and ageing populations reshape economic structures, labour markets, and resource consumption patterns. These demographic shifts will have far-reaching implications for global energy demand, urban infrastructure, and social policies over the coming decades.

The global population is projected to grow from 8 billion in 2023 to 9.8 billion by 2050, with Africa alone accounting for 60% of this increase. Conversely, Europe and East Asia will continue experiencing population declines and ageing demographics. Urbanisation is set to rise to 68%, as the global urban population expands from 4.6 billion to 6.6 billion, driving higher energy consumption in cities and increasing demand for electricity, transport, and infrastructure. Importantly, Africa's working-age population is expected to surge by 90%, contributing 78% of the worldwide increase, positioning the region as a key driver of global labour force expansion.

Meanwhile, developed economies are projected to experience a growing reliance on migration to sustain labour markets, with the share of immigrants rising from 12% to nearly 20% by 2050. Globally, the number of households is set to increase by 35%, expanding from 2.3 billion in 2023 to 3.1 billion by 2050, outpacing overall population growth.

The global economic landscape is set to undergo profound changes by 2050, with the economy doubling in size, its nucleus shifting to the Asia Pacific, and AI transforming all sectors

Profound transformations across demographic, economic, geopolitical, environmental, and technological dimensions will shape the global economy's long-term trajectory. By 2050, these structural shifts will redefine economic frameworks, labour markets, and resource distribution, creating unprecedented opportunities while posing complex challenges to achieving sustainable, inclusive, and equitable growth.

Global GDP is projected to expand by USD 101 trillion, reaching USD 206 trillion by 2050, with an average annual growth rate of 2.5%. The Asia Pacific region is set to lead this expansion, increasing its share of global GDP to 42%, while Europe and North America's contributions are expected to decline to 17% and 25%, respectively. By the 2040s, non-OECD economies are projected to surpass OECD countries, driven by the rapid economic ascent of China, India, and developing economies in Africa, Latin America, and the Middle East.

Technological advancements, particularly in artificial intelligence (AI) and robotics, will boost global productivity and efficiency by 2050. AI-driven automation and data analytics will revolutionise the manufacturing, healthcare, agriculture, and energy sectors, optimising resource utilisation and driving economic competitiveness. These breakthroughs will likely enhance industrial output and service efficiency and accelerate digital financial inclusion and sustainable development, despite the risks of employment and the society at large.

Natural gas is increasingly receiving policy support as a crucial solution to the energy trilemma

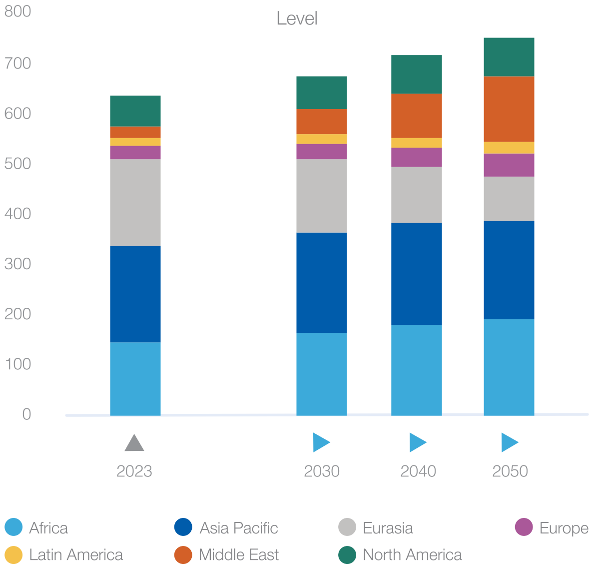
In 2024, global energy policies have strengthened support for natural gas, recognising its role in energy security, industrial competitiveness, and emissions reduction. Despite ambitious commitments at COP28, economic and geopolitical imbalances hindered progress on climate goals in 2024. Although COP29 marked a privotal moment in climate negotiations by finalising the long-debated rules for carbon trading, it resulted in a weak agreement on climate finance and saw limited progress on mitigation measures. However, the finalisation of Article 6 carbon market mechanisms holds promise, potentially driving investments in low-carbon LNG and CCS technologies.

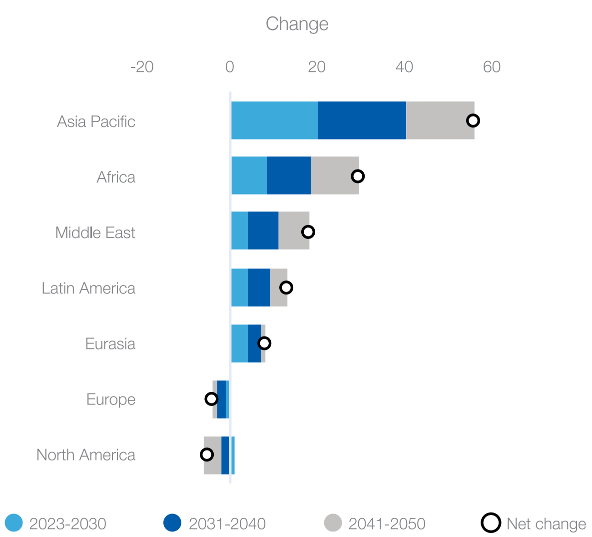
Regionally, the United States and China expanded policies to support gas-fired power generation, with the United States streamlining permits for Combined Cycle Gas Turbine (CCGT) plants and China prioritising gas-fired power for AI-driven industrial hubs. India reinforced natural gas as a flexible backup for renewables, expanding gas-fired peak shaving plants to meet high summer electricity demand. At the same time, Europe strengthened gas storage mandates for winter resilience. In Latin America, new tax incentives and LNG infrastructure expansion in Brazil and Colombia addressed hydropower shortages, ensuring grid stability. Middle Eastern and North African governments increased investments in gas-fired desalination, with hybrid gas-renewable desalination projects gaining policy support. The IMO 2024 emissions regulations accelerated LNG adoption in shipping and trucking, prompting new LNG bunkering hubs and fuel incentives in China, India, and the EU. In Sub-Saharan Africa, policy-driven LPG expansion programs in Nigeria, Ghana, and Kenya were introduced to transition households from biomass to cleaner cooking fuels.

Global primary energy demand is projected to grow steadily, driven by economic expansion in developing countries

Global primary energy demand is projected to increase by 18% over the forecast period, rising from 635 EJ in 2023 to 750 EJ by 2050, with no peak expected. Asia Pacific will drive nearly half (49%) of the total demand growth, followed by Africa at 25%. While the share of fossil fuels is set to decline from nearly 80% in 2023 to 64% by 2050, they will remain the foundation of global energy supply. Natural gas demand is expected to grow by 32% by mid-century, surpassing coal as the second-largest energy source by the late 2030s and converging with oil at 26% of the energy mix by 2050. Renewables are set to be the fastest-growing energy source, expanding from just 3% in 2023 to 17% by 2050, reflecting increasing investment and policy support.

Global primary energy demand outlook by region, 2023-2050 (EJ)





Source: GECF Secretariat based on data from the GECF GGM

Final energy demand is projected to increase from 424 EJ in 2023 to 539 EJ by 2050, representing a 27% overall growth, outpacing the expansion of the primary energy supply. Electricity's share in final energy consumption is set to rise significantly, reaching 30% by 2050, up from 21% in 2023, driven by widespread electrification across industries, transport, and residential sectors. This surge in electricity demand will lead to a doubling of the global power generation capacity. Natural gas-fired generation will supply 12% of the incremental demand, reaffirming its role as a flexible and dispatchable energy source crucial for balancing intermittent renewables.

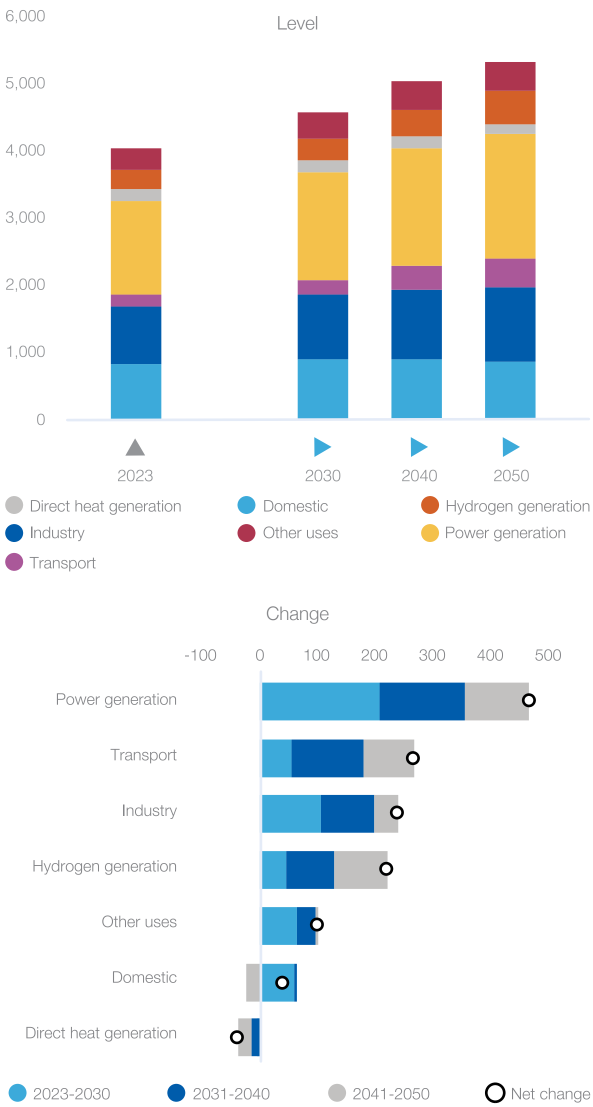
Hydrogen demand is forecast to grow rapidly, rising from 97 MtH_2 in 2023 to 257 MtH_2 by 2050. Green and blue hydrogen are leading the expansion, projected to reach 108 MtH_2 (42%) and 87 MtH_2 (33%), respectively. As global decarbonisation efforts intensify, hydrogen is set to transition into a critical energy carrier, particularly in transportation, power generation, and heavy industry. The integration of hydrogen-based solutions in industrial applications and grid-scale energy storage will further support its long-term adoption.

Global energy-related emissions are expected to decline by 23%, reaching 31.2 $GtCO_2e$ by 2050, with Asia Pacific leading the reduction effort, accounting for 77% of total emission savings. Despite this, the region is set to remain the largest emitter, contributing 45% of global energy-related CO_2 emissions by 2050. The power generation sector, currently the biggest source of emissions at 13.2 $GtCO_2e$ in 2023, is expected to undergo the most substantial decline, dropping by 52% to 6.9 $GtCO_2e$ by 2050, reflecting the accelerated transition toward low-carbon electricity sources and improved energy efficiency.

Natural gas demand is expected to grow steadily, with no peak in sight

Natural gas demand is projected to increase from 4,018 bcm in 2023 to 5,317 bcm by 2050, representing 32% growth over the forecast period. Its share in the global energy mix will rise from 23% to 26%. The power sector is expected to drive this expansion, adding 475 bcm (1.1% per annum) to reach 1,866 bcm. Industrial demand, including feedstock applications, is expected to grow by 238 bcm (0.9% per annum) to 1,095 bcm, maintaining its position as the second-largest source of natural gas consumption. Natural gas demand for hydrogen production is also set to rise significantly, with consumption exceeding 480 bcm by 2050, reflecting blue hydrogen's growing role in decarbonisation strategies. The share of natural gas in final energy

Global natural gas demand outlook by sector, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM
Note: 1) Industry includes gas used as energy fuel and feedstock as well as for grey hydrogen generation and the production of liquid fuels;
2) Transport includes road transport and marine bunkers;
3) Other uses include gas demand for energy industry own use, for rail and pipeline transport.
4) Domestic sector includes residential, commercial and agriculture sectors.

consumption is projected to reach 16% by 2050, slightly increasing from 15% in 2023, despite shifting consumption patterns. A gradual transition is underway, with natural gas use shifting from direct consumption in end-use sectors toward transformation sectors such as power generation and hydrogen production, reinforcing its role in supporting cleaner energy systems.

With the exception of Europe and North America, natural gas demand is set to continue expanding across all other regions. Asia Pacific is projected to surpass North America as the largest natural gas-consuming region within this decade, maintaining its lead through mid-century. The region is expected to witness a 710 bcm increase in demand, accounting for 55% of the total net growth by 2050, outpacing all other regions. The Middle East will closely follow, contributing nearly 24% of the global demand increase, as its consumption rises from 554 bcm in 2023 to 865 bcm by 2050, reflecting increasing industrialisation and expanding energy-intensive sectors. Africa is poised for the strongest relative growth, with natural gas demand more than doubling (+126%) to reach 385 bcm by 2050, driven by accelerated energy access initiatives, industrial expansion, and economic development. Latin America will also experience substantial growth, adding 125 bcm to reach 275 bcm by 2050, accounting for nearly 10% of the global net increase, solidifying its role as an emerging natural gas market.

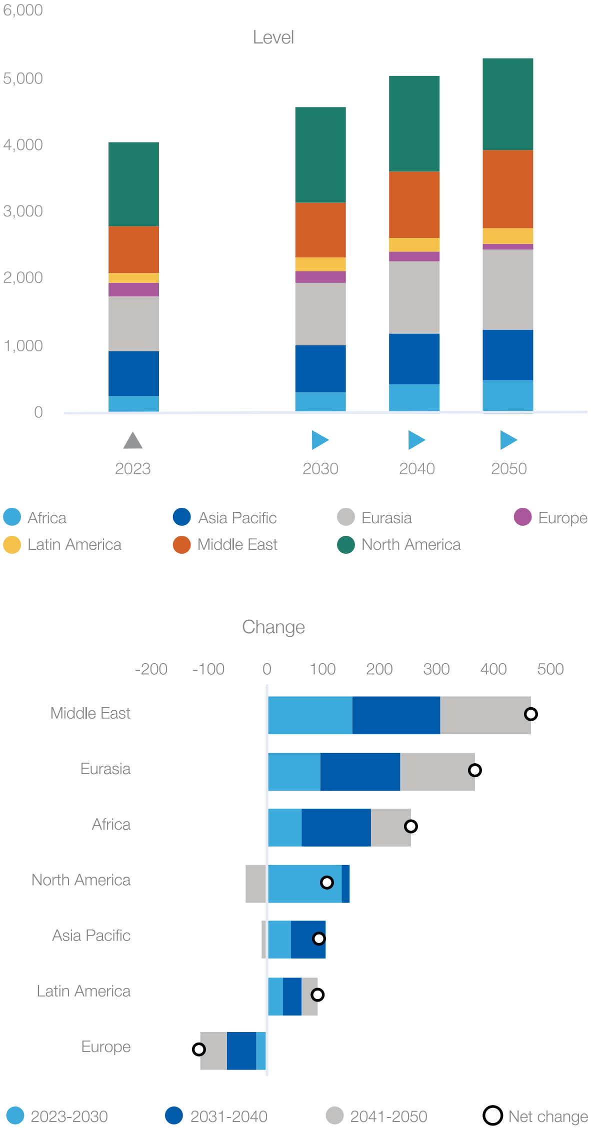
Despite initial growth in natural gas demand in North America through 2030, the region is expected to peak thereafter, followed by a gradual decline by 2050, as mature markets shift toward lower-carbon alternatives and efficiency improvements reduce consumption. Europe's demand is anticipated to continue declining over the coming decades, falling by 154 bcm to 309 bcm by 2050, reflecting its energy policies and deindustrialisation. These trends underscore natural gas's dual role—acting as a transition fuel in Europe and a destination fuel in developing regions where infrastructure, energy security, and economic priorities drive long-term reliance on natural gas.

The center of gravity in global natural gas production will shift toward the Middle East, Eurasia and Africa by 2050

The global natural gas supply landscape is undergoing a fundamental shift, with production increasingly concentrated in non-associated conventional gas resources, primarily in the Middle East, Eurasia, and Africa. In contrast, North America's unconventional gas production is expected to peak at 1,205 bcm in the 2030s before gradually declining to 1,126 bcm by 2050 due to the maturation of key shale plays and a slowing expansion of new developments. Meanwhile, new projects, including yet-to-find (YTF) resources, are forecast to account for 81% of total global gas production by 2050, highlighting their critical role in offsetting natural decline from mature fields and sustaining long-term supply growth.

Natural gas production is transitioning toward a more geographically diverse supply base. Although North America remains the largest producer, currently supplying 31% of global gas, its growth trajectory is slowing, with an expected 107 bcm increase over the forecast period. As other regions ramp up production, North America's share of global supply is projected to decline to 26% by mid-century.

Global natural gas supply outlook by region, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

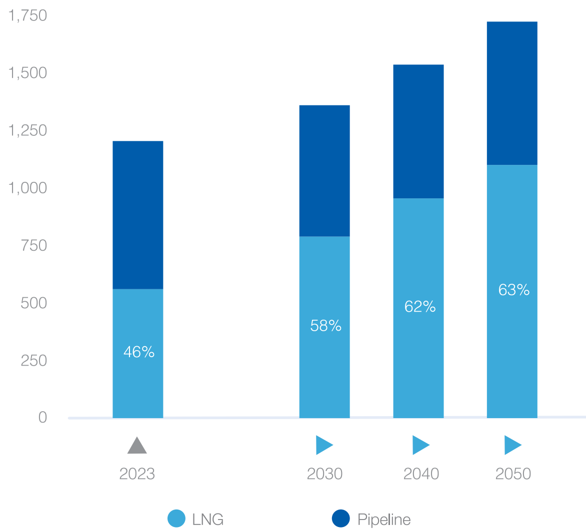
Africa, Eurasia, and the Middle East, which collectively accounted for 44% of global supply in 2023, are set to experience a hefty 1,072 bcm increase in Output in 2050, making up 87% of the total global supply expansion. This reflects their rising dominance in global production dynamics. This transformation is driven by large-scale investments in LNG infrastructure, the development of untapped gas fields, and production expansions in resource-rich regions, reinforcing their role as the new global natural gas supply center.

The global natural gas trade landscape is set to undergo a structural transformation driven by the growing dominance of LNG

The global natural gas trade landscape is undergoing a structural transformation, evolving into a more competitive, efficient, and interconnected market. Global trade volumes are projected to expand by 44% between 2023 and 2050, reaching 1,743 bcm, equivalent to one-third of global gas demand. Liquefied natural gas (LNG) is set to dominate international trade, with volumes expected to double to 800 Mt, accounting for 63% of traded gas by mid-century. While pipeline trade is forecast to decline initially, moderate growth is anticipated as Eurasian exports shift from Europe to the Asia Pacific, driven by China's rising demand and the realignment of supply routes.

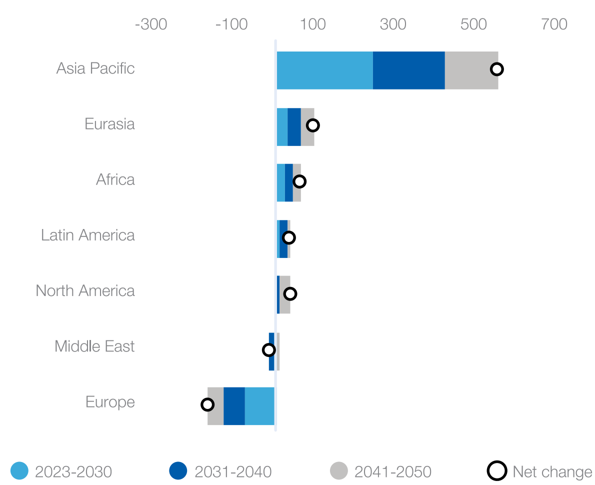
Eurasia and North America will drive export growth, with North America expanding LNG capacity and Eurasia increasing both LNG and pipeline exports.

Global natural gas trade outlook by flow type, 2023-2050 (bcm)



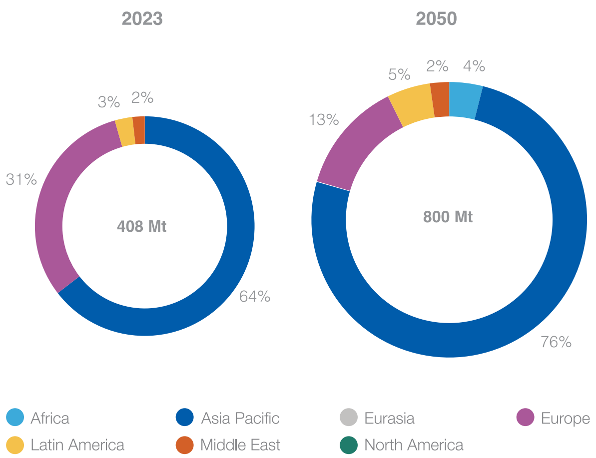
Source: GECF Secretariat based on data from the GECF GGM

Natural gas imports change outlook by region, 2023-2050 (bcm)



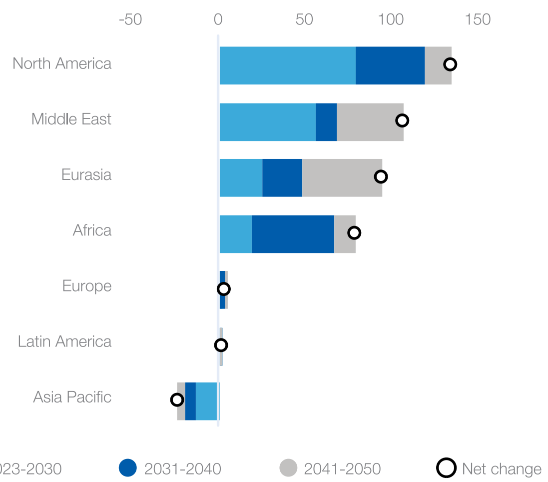
Source: GECF Secretariat based on data from the GECF GGM

Global LNG imports market share outlook by region, 2023-2050 (%)



Source: GECF Secretariat based on data from the GECF GGM

Regional LNG exports change outlook by decade, 2023-2050 (Mt LNG)



Source: GECF Secretariat based on data from the GECF GGM

Africa is emerging as a major supplier, leveraging its vast, untapped reserves and new LNG projects. At the same time, the Middle East will maintain steady exports through long-term supply contracts and expanded LNG infrastructure. In contrast, Europe's gas exports will decline sharply, reflecting falling domestic production and stricter energy transition policies. Latin America and Asia Pacific will remain limited exporters, with Asia Pacific firmly positioned as a net importer, reinforcing its dependence on external suppliers.

These trends underscore the growing role of emerging gas producers and the pivotal importance of LNG infrastructure in shaping the future of global gas trade as markets become more flexible, resilient, and increasingly driven by Asia's expanding demand.

The Asia Pacific region is set to dominate LNG imports, accounting for 76% of global volumes by 2050, with China, South Asia, and Southeast Asia driving demand growth. The region is expected to contribute 88% of the total net increase in global LNG imports, adding 343 Mt, solidifying its status as the primary destination for LNG cargoes. In contrast, Europe's LNG imports are projected to decline by 22 Mt bcm due to the region's energy policies and de-industrialisation, reducing their share from 31% in 2023 to 13% by 2050. However, it will remain the second-largest LNG importer.

Global LNG export patterns are set to evolve significantly from 2023 to 2050, with North America leading supply growth, expanding by over 133 Mt to capture 27% of the global market, supported by new liquefaction projects and expanded capacity. The Middle East will follow closely, increasing exports by approximately 106 Mt, driven primarily by Qatar's large-scale capacity expansions. Eurasia's LNG exports are set to reach 16% market share, led by Russia's new liquefaction projects. Africa is expected to emerge as a key LNG supplier, adding around 80 Mt, supported by major developments in Mozambique, Nigeria, Senegal, and Mauritania. These changes are poised to create a more diversified, competitive, and resilient LNG export landscape.

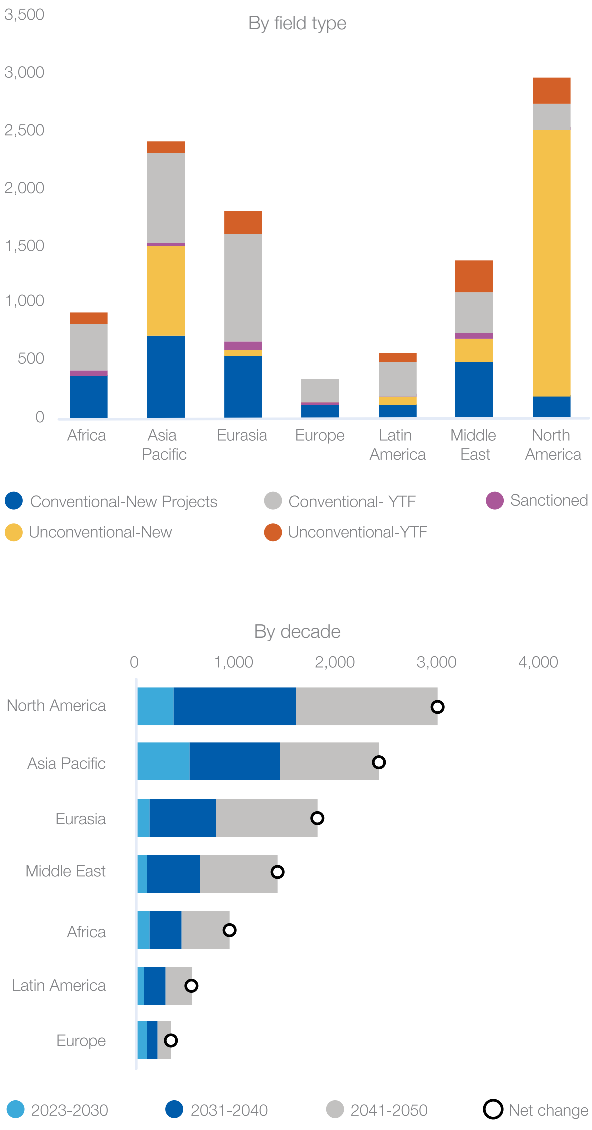
Cumulative global natural gas investments to reach USD 11.1 trillion by 2050

The long-term marginal cost for natural gas is projected to rise, particularly at the higher-cost end, as the industry increasingly relies on more complex and harder-to-develop resources. This trend underscores the growing need for expanded production from long-cycle, non-associated conventional greenfield projects and discovered and yet-to-find (YTF) resources to sustain supply. Cumulative natural gas investments are expected to reach USD 11.1 trillion over the forecast period, with 94% allocated to upstream activities and 6% to midstream infrastructure, emphasising the capital-intensive and long lead time of gas projects and the crucial need for security of demand.

North America and Asia Pacific are projected to lead global upstream investments, accounting for 28% and 23% of total capital spending, respectively, reflecting their focus on developing unconventional resources and sustaining existing production levels. Meanwhile, despite accounting for just 14% of global upstream investment, the Middle East is set to contribute one-fifth of cumulative production, benefiting from lower decline rates and cost-efficient resource development. These dynamics highlight the evolving investment landscape in natural gas, where the balance between cost, resource availability, and production efficiency will shape the long-term trajectory of global supply.

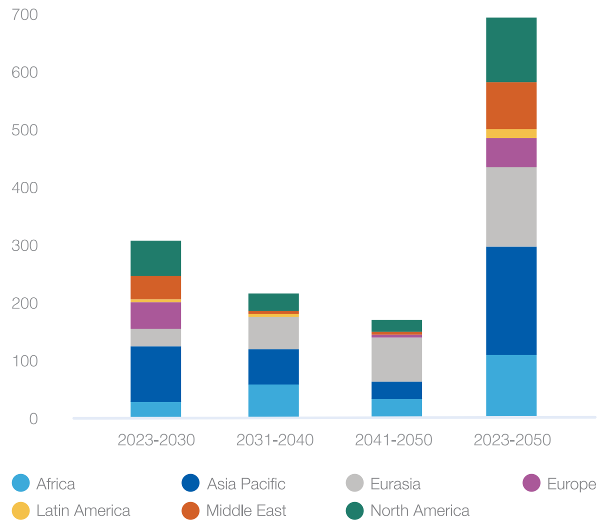
The global shift in natural gas trade, driven by the growing dominance of LNG, is increasing the need for

Regional CAPEX requirement, 2023-2050 (real USD billion, base year = 2023)



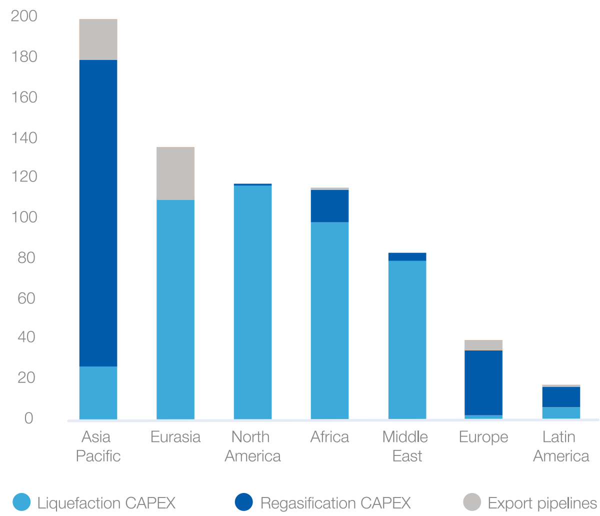
Source: GECF Secretariat based on data from the GECF GGM

Global gas midstream CAPEX outlook by region, 2023-2050 (real USD billion, base year = 2023)



Source: GECF Secretariat based on data from the GECF GGM

Cumulative midstream gas CAPEX requirment by region, 2023-2050 (real USD billion, base year = 2023)



Source: GECF Secretariat based on data from the GECF GGM

substantial investments in midstream infrastructure to support supply expansion and trade efficiency. Between 2023 and 2050, global midstream natural gas investments, encompassing liquefaction, regasification, and export pipelines, are projected to reach approximately USD 700 billion. Liquefaction projects will account for 62% (USD 435 billion) of total midstream investment, with North America and Eurasia leading development, Africa emerging as a key supplier, and the Middle East leveraging its cost advantages to strengthen its global export position.

The Asia Pacific region is set to dominate midstream capital spending, commanding nearly USD 200 billion (28% of total investments), reinforcing its role as the largest gas-consuming region. The region will also lead regasification investments, accounting for 71% of the USD 214 billion allocated for LNG import capacity expansion, driven by surging demand in China, India, and Southeast Asia. These trends underscore the growing interconnectivity of global gas markets, with LNG infrastructure investments playing a pivotal role in shaping long-term trade flows and supply resilience.

Natural gas, combined with advanced decarbonisation technologies such as CCUS, offers a viable pathway for balanced energy transitions

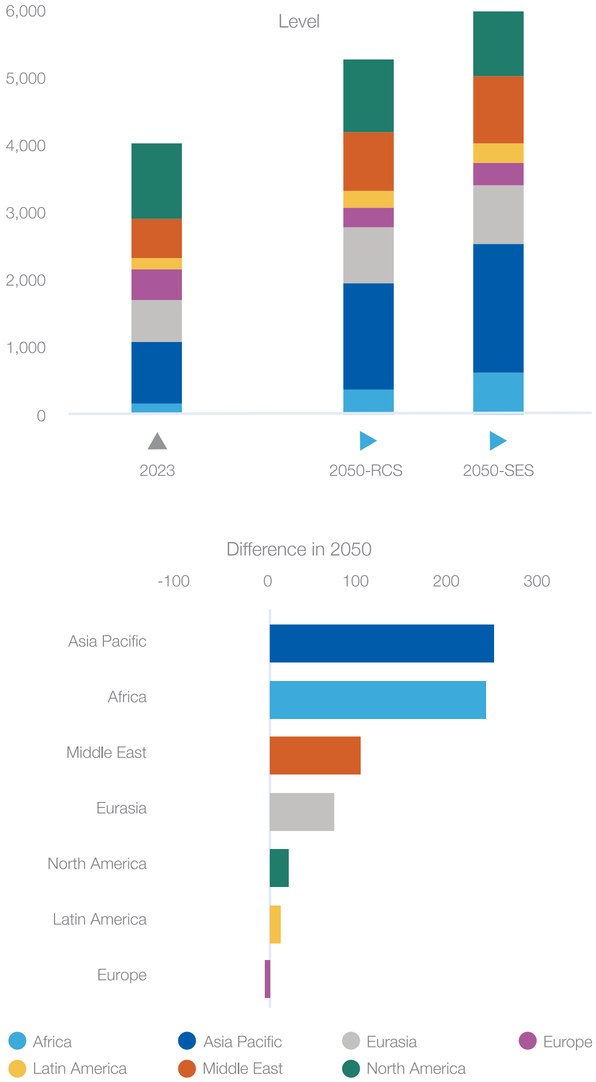
The Sustainable Energy Scenario (SES) presents a comprehensive pathway that emphasises natural gas's pivotal role in meeting rising global energy demand while advancing the UN Sustainable Development Goals (SDGs), particularly universal energy access and reducing the energy system's environmental footprint. The SES highlights how natural gas, in combination with advanced decarbonisation technologies such as CCUS, can effectively lower emissions while ensuring energy security and affordability in a transitioning energy landscape.

Projections under the SES indicate that global primary energy demand will grow by 22% from 2023 levels, increasing by 140 EJ to reach 775 EJ by 2050. This exceeds the 18% growth projected under the Reference Case Scenario (RCS), reinforcing the strong link between economic expansion and energy consumption, particularly in low- and middle-income countries. Natural gas demand in the SES is expected to grow substantially, expanding by 1,967 bcm to reach 5,997 bcm by 2050, marking a 49% increase, significantly surpassing the 32% rise in the RCS. As a result, natural gas is set to become the dominant energy source, overtaking oil and coal by mid-century to emerge as the leading fuel in the global energy system. By 2050, natural gas is projected to account for 28% of the global energy mix, nearly two percentage points higher than in the RCS, further solidifying its long-term role.

The SES also envisions a steeper decline in global energy-related emissions, with CO_2 equivalent emissions projected to drop from 40.6 Gt in 2023 to 26.9 Gt by 2050, marking a 34% absolute reduction, which is significantly deeper than the 23% decrease under the RCS. A key driver of this reduction is the rapid expansion of CCUS deployment, with its contribution to emissions mitigation rising from 41 $MtCO_2e$ in 2023 to 7.2 $GtCO_2e$ by 2050, a 5.2 Gt increase compared to the RCS. Natural gas-based CCUS is expected to play the most significant role, delivering 3.6 Gt of emissions reductions by 2050, which is 2.9 Gt higher than in the RCS, accounting for 57% of the total additional CCUS-driven emissions savings between the two scenarios.

These findings underscore the SES's vision of a balanced and feasible energy transition pathway, where natural gas serves as both a stabilising force for energy security and a critical enabler of deep decarbonisation facilitated by technological advancements and infrastructure expansion.

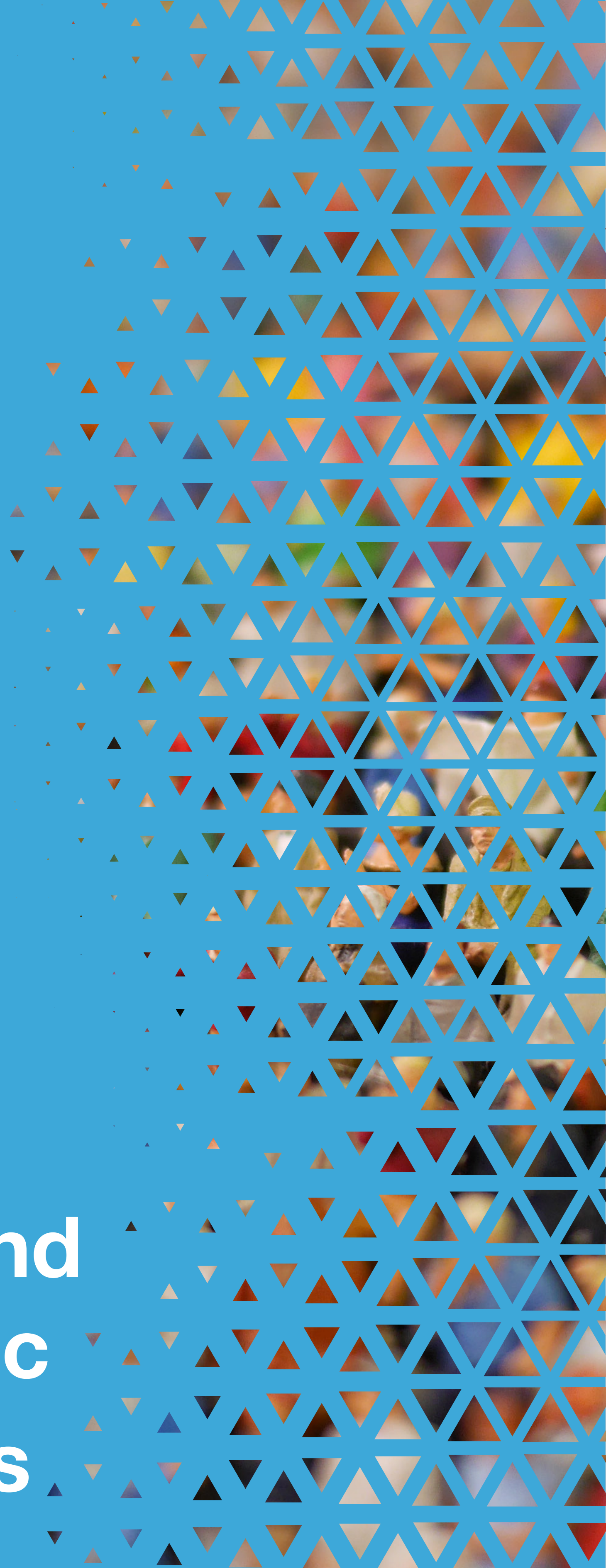
Global natural gas demand outlook by region in RCS and SES (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Chapter 1

Economic and Demographic Assumptions



Highlights

- The world's population is projected to grow from 8 billion in 2023 to 9.8 billion by 2050. Africa is anticipated to drive around 60% of this growth, while Europe and OECD Asia Pacific are expected to experience population declines and ageing demographics.
- By 2050, the global urbanisation rate is anticipated to rise to 68%, making 12 percentage points increase compared with 2023 levels. Africa and the Asia Pacific are forecast to contribute 41% each to the incremental growth in the urban population.
- The proportion of people aged 65 and older is projected to rise from 10% in 2023 to 16% by 2050, reaching a total of 1.5 billion worldwide, signifying a major demographic shift.
- Global GDP is projected to grow by USD 101 trillion in real terms from 2023 to 2050, reaching USD 206 trillion by mid-century. This represents an average annual growth rate of 2.5%, slightly below the 2.9% average observed over the past 27 years.
- The service sector is expected to increase its share of global GDP from 66% in 2023 to 68% by 2050, while the industrial sector's share is projected to decline slightly from 22% to 21%, reflecting ongoing structural transitions.
- Asia Pacific and Africa are poised to be the fastest-growing regions in 2023–2050, with annual GDP growth rates of 4.4% and 3.3%, respectively. Asia Pacific's share of global GDP is expected to rise to 42% by 2050, marking an 8 percentage points increase from 2023 level.
- Brent crude oil real price is assumed to average 80 USD per barrel during 2023–2030, increase to 85 USD per barrel in 2031–2040, and reach 90 USD per barrel in 2041–2050. These price levels reflect progressively higher cost of supply.
- By 2050, natural gas real prices are expected to stabilise, shaped by production costs, decarbonisation policies, and shifting demand. Prices in real terms are forecast to reach 4 USD/MMBtu at Henry Hub, 9.8 USD/MMBtu in Europe, and 10 USD/MMBtu in Asia by 2050.
- The number of countries with operational carbon markets is expected to grow from 38 in 2023 to 54 by 2050. This expansion aligns with rising carbon prices, with EU ETS carbon price assumed to reach 140 USD per ton of CO_2 by 2050, driven by intensified global efforts to mitigate climate change.

1.1 Population and demographics outlook

Over the past few decades, global population dynamics have undergone profound transformations, marked by declining fertility rates, rising life expectancy, and an increasing median age. These shifts reflect significant advancements in healthcare, improved living standards, and evolving socio-economic conditions. However, the pace and nature of these changes vary significantly across regions, creating stark contrasts in population growth and structure. While high-income regions such as Europe and East Asia are experiencing population stagnation or decline, low- and middle-income regions, particularly in Africa, South Asia, and Central Asia, continue to grow rapidly. This divergence underscores a critical demographic divide between the global North and South (Table 1.1).

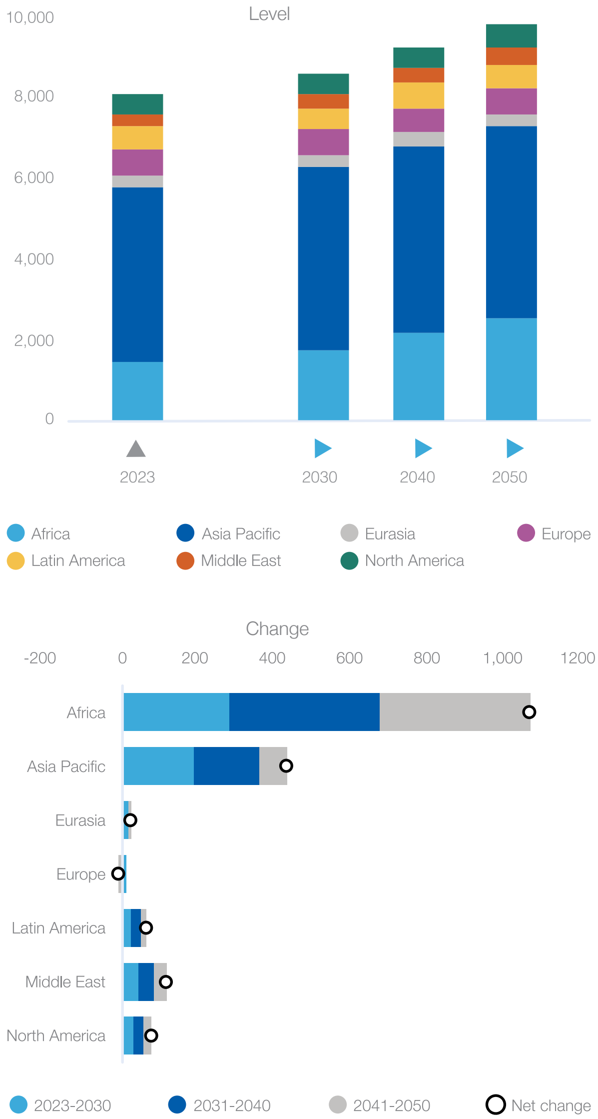
This divide is evident in the projections for global population trends. **According to the 2023 revision of the World Population Prospects by the United Nations Department of Economic and Social Affairs (UNDESA), the global population is projected to grow from 8 billion in 2023 to 9.8 billion by 2050, reflecting a slowdown compared to the 2.3 billion increases recorded between 1996 and 2023.** From 1990 to 2024, the global fertility rate decreased from 3.3 children per woman to 2.3. It is projected to further decline to 2.1 by 2050.

However, this growth will be unevenly distributed across regions. As shown in Figure 1.1, Africa is set to account for 61% of the global population increase, while regions like Europe and East Asia will face ageing and declining populations.

Africa, with a population representing 18% of the global total in 2023, is expected to experience the fastest population growth worldwide, surging by more than 70% and accounting for 26% of the global population by 2050. This rapid growth is primarily supported by the region's high fertility rate of 4.7 children per woman, significantly above the global average of 2.3 children per woman in 2023-2050. The continent also has a youthful

Figure 1.1

Global population outlook by region, 2023-2050 (millions)



Source: 2023 Revisions of United Nations World Population Prospects

Table 1.1

Global population outlook by region, 2023-2050 (millions)

Region	2023	2030	2040	2050	Change, 2023 - 2050
Africa	1,460	1,733	2,120	2,514	1,055
Asia Pacific	4,333	4,512	4,681	4,757	424
Eurasia	290	300	304	309	19
Europe	633	639	638	629	-4
Latin America	536	554	581	595	58
Middle East	283	322	362	396	113
North America	503	529	556	575	72
World	**8,038**	**8,589**	**9,241**	**9,774**	**1,736**

Source: 2023 Revisions of United Nations World Population Prospects median age of 18.8 years, ensuring that large cohorts will continue to enter reproductive age. Furthermore, life expectancy, which increased from 50 years in 1990 to 63 years in 2023, is projected to rise to 68 years by 2050, supporting population growth despite expected gradual declines in fertility rates. By mid-century, over 90% of Africa's population growth is projected to take place in Sub-Saharan Africa, where the population is predominantly young, with a median age of 18, significantly lower than the global median of 31.

The **Asia Pacific** region, currently home to 54% of the global population, has been a key driver of global demographic expansion, with its population increasing by 1.5 billion between 1996 and 2023. However, the region is projected to experience a significant slowdown in growth, adding only 424 million people by 2050 to reach a total population of 4.76 billion. This deceleration is driven by a dramatic decline in fertility rates, which fell from 4.5 children per woman in 1960 to 2.1 in 2023 and are expected to decrease further in many countries. For instance, China's fertility rate has plummeted to 1.2 children per woman, and South Korea's is among the lowest globally at 0.84, both well below replacement levels. In contrast, rising life expectancy, which increased from 57 years in 1960 to 74 years in 2023, is projected to exceed 78 years by 2050 in many countries. However, these trends have resulted in rapidly ageing populations, particularly in East Asia, where median ages are expected to reach 49 years in Japan and 44 years in South Korea by 2050, reshaping the region's demographic profile.

Meanwhile, demographic trends in **Eurasia** reveal stark regional contrasts. The region's population is projected to grow modestly, increasing by 19 million to 309 million by 2050. CIS countries, including Russia, Ukraine, Belarus, and Moldova, are expected to experience population decline, with Russia's population falling from 145 million in 2023 to 133 million by 2050. This decline is driven by persistently low fertility rates, averaging 1.5 children per woman, and modest life expectancy improvements. Russia's life expectancy is projected to rise from 73 years in 2023 to 75 years by 2050. In contrast, Central Asia, including Uzbekistan and Kazakhstan, is forecast to grow significantly, with its population increasing from 77 million to 104 million. This growth is supported by higher fertility rates of around 2.9 children per woman and a youthful median age below 30.

Europe is the only region projected to experience a population decline, peaking at 640 million in the early 2030s before falling to 630 million by 2050. Persistently low fertility rates (around 1.5 children per woman) and an ageing population, with over 30% aged 65 or older by 2050, drive this trend. The region's median age, already the highest globally at 44 years, is expected to exceed 47 years, underscoring its demographic challenges. Germany and Italy are among the countries expected to face the most significant population declines.

In **Latin America**, population growth is slowing significantly. The region's population, currently accounting for 7% of the global total, is projected to grow by just 11% to 600 million by 2050, starkly contrasting the 34% growth observed from 1996 to 2023. Fertility rates have fallen sharply, from 2.9 children per woman in 1996 to approximately 1.8 in 2023, now below replacement levels. Meanwhile, life expectancy has risen steadily, from 70 years in 1990 to over 75 years in 2023, and is expected to reach 79 years by 2050. As a result, the region's median age, currently 32 years, is projected to exceed 40 years by 2050, reflecting an ageing population and increasing dependency ratios. Brazil will remain the most populous country in the region, although its population growth rate is expected to slow considerably.

The **Middle East**, the second-fastest-growing region after Africa, is projected to grow by 10% from 2023 to 2050, reaching just under 400 million people and accounting for 4% of the global total. This growth is driven by moderate fertility rates of three children per woman, above the global average of 2.3. Life expectancy has also risen, from 65 years in 1990 to over 74 years in 2023. It is projected to reach 78 years by 2050.The region's median age, currently 27 years, is anticipated to rise to 35 by 2050. Iran and Saudi Arabia are expected to see the most significant contributions to this growth, driven by their youthful populations and improving healthcare systems.

In **North America**, population growth is projected at 14%, with the total population increasing by 72 million to reach 575 million by 2050. The United States will contribute approximately 64% of this growth, with its population expected to rise from 334 million in 2023 to approximately 380 million by 2050. Mexico, with its relatively younger population and higher fertility rates compared to the United States and Canada, is projected to account for approximately 30% of the region's growth, adding around 22 million people to reach a population of approximately 158 million by 2050. Canada is also projected to experience steady growth, driven primarily by immigration, which remains a key factor in offsetting its low fertility rates. Fertility rates in the region currently average 1.7 children per woman, below replacement levels, while life expectancy is forecast to rise from 79 years in 2023 to over 82 years by 2050.

The population transitions discussed above reveal a profound shift in the centre of gravity for global population growth, increasingly moving toward low- and middle-income regions. In the coming decades, regions such as Africa, South Asia, and Central Asia are poised to account for most of the global population growth, offering opportunities to harness their demographic dividend. However, these regions face significant challenges, including the need to provide education, healthcare, and infrastructure for growing populations while pursuing sustainable development. In contrast, high-income regions must grapple with ageing populations, workforce shortages, and economic stagnation, necessitating innovative policies to address these challenges.

Finally, these transformations extend beyond mere numbers. **The global population is becoming increasingly urbanised, older, and relatively lonelier.** These profound qualitative changes will reshape the global economy and energy landscape, influencing consumption patterns, labour markets, migration and demand for resources. The following sections explore these key demographic trends and their broader implications.

1.1.1 Rapid urbanisation

Aspiring to achieve higher standards of living and improved quality of life, billions of people have migrated from rural areas to cities over the past few decades, reshaping global demographics and urban landscapes. United Nations estimates that the global urban population increased by approximately 2 billion people between 1996 and 2023, with the Asia Pacific region accounting for 56% of this growth. This massive demographic shift has driven the rise of megacities (cities with population exceeding 10 billion inhabitants), with their numbers surging from 14 in 1996 to 33 in 2023. These megacities have become densely populated hubs of economic and social activity, driving soaring demand for energy-intensive civil services such as transportation, sanitation, water supply, and public utilities.

This demographic shift is expected to persist over the next 27 years, with the **global urban population projected to grow from 4.6 billion in 2023 to 6.6 billion by 2050, marking a substantial 45% increase** (Figure 1.2). By 2050, the global urbanisation rate is forecast to reach 68%, an increase of 12 percentage points compared to 2023.

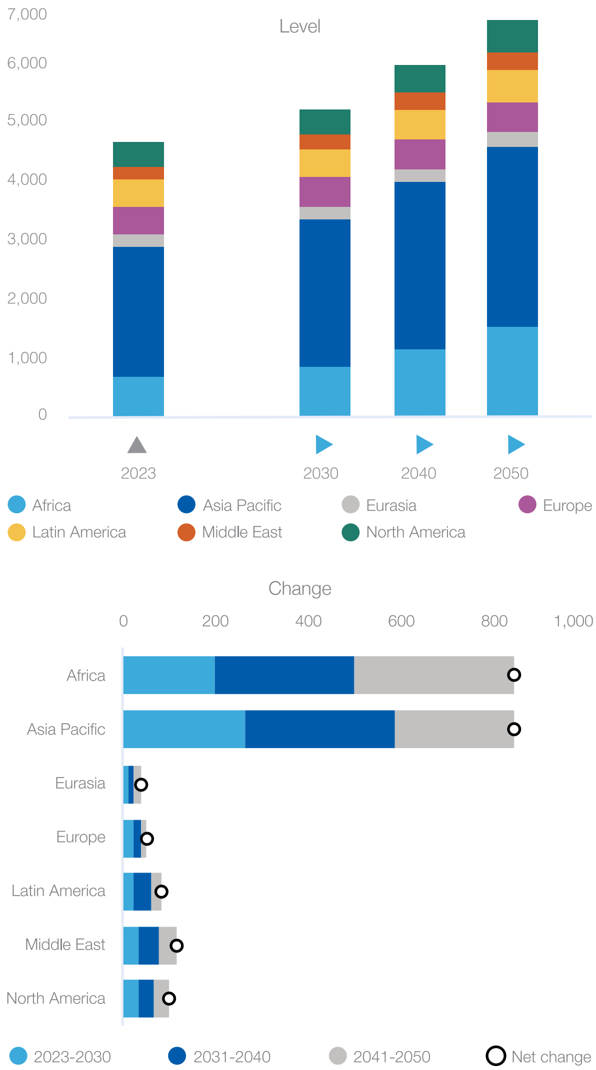
Regionally, Africa and the Asia Pacific will be the primary drivers of this growth, each contributing 41% of the total incremental rise in urban population. Despite this rapid expansion, these regions will remain the least urbanised globally, with urbanisation rates projected to reach 60% in Africa and 64% in the Asia Pacific by 2050. These figures reflect these regions' significant yet uneven transformation toward urban-centric societies.

The number of megacities is also set to rise sharply, with Africa expected to witness the highest increase. Driven by accelerating urbanisation and population growth, the continent's megacities–such as Lagos, Cairo, and Kinshasa–are expanding rapidly, with new megacities emerging across West and East Africa. By 2050, Africa is projected to account for a significant share of the world's new megacities, reflecting its dynamic urban transformation. This trend will present immense opportunities and challenges, including the need for massive infrastructure investments, enhanced energy access, and sustainable urban planning to accommodate the growing urban populace effectively.

In contrast, North America, Latin America, and Europe are expected to experience the most minor increases in

Figure 1.2

Global urban population outlook by region, 2023-2050 (millions)



Source: The 2023 Revision of United Nations World Urbanisation Prospects

urban population by 2050, primarily due to their already high urbanisation rates. United Nations projections indicate that by 2050, urbanisation rates in North America, Latin America, and Europe will reach 89%, 88%, and 84%, respectively. These trends highlight the saturation of urban growth in highly urbanised regions and underscore the shifting centre of global urbanisation toward developing regions where growth remains robust and transformative.

1.1.2 Ageing population

Globally, population demographics are shifting toward an older age structure, with the share of individuals aged 65 and above projected to rise from 10% in 2023 to 16% by 2050, reaching 1.5 billion people. This transition is driven by declining birth rates and increasing life expectancy, reflecting advancements in healthcare and improved living standards. Correspondingly, the global median age is expected to increase from 31 years in 2023 to 36 years by 2050. Simultaneously, the old-age dependency ratio - the number of old people (adults over 65) per 100 working-age individuals (15–64 years)- is projected to rise from 16% in 2023 to 26% by 2050, illustrating the growing economic and social pressures on the working-age population to sustain an ageing society.

However, this global shift toward an older age structure is not uniform across regions, with Africa emerging as a notable exception due to its youthful demographic profile. Unlike Europe, North America, and East Asia, where ageing populations dominate, **Africa's working-age population is projected to grow by an impressive 90% between 2023 and 2050, contributing 78% of the global working-age population increase** (Figure 1.3). Starting from a 16% share of the global working-age population in 2023, Africa is expected to account for one in four working-age individuals globally by 2050. By then, Africa's working-age population is forecast to surpass 1.5 billion, placing it on par with India (1.4 billion) and far exceeding China (1 billion). This demographic trend positions Africa as a pivotal contributor to the global labour force, offering significant potential for economic growth, provided adequate investments are made in education, healthcare, and job creation to harness this demographic dividend.

In contrast, Europe's working-age population is projected to continue declining in absolute terms and as a share of the total population, falling from 64% in 2023 to 58% by 2050, reflecting a shrinking labour force. Meanwhile, Europe's total population is projected to decline over the coming decades, becoming both smaller and significantly older, with the elderly cohort (65 years and above) rising from 21% in 2023 to 29% by 2050.

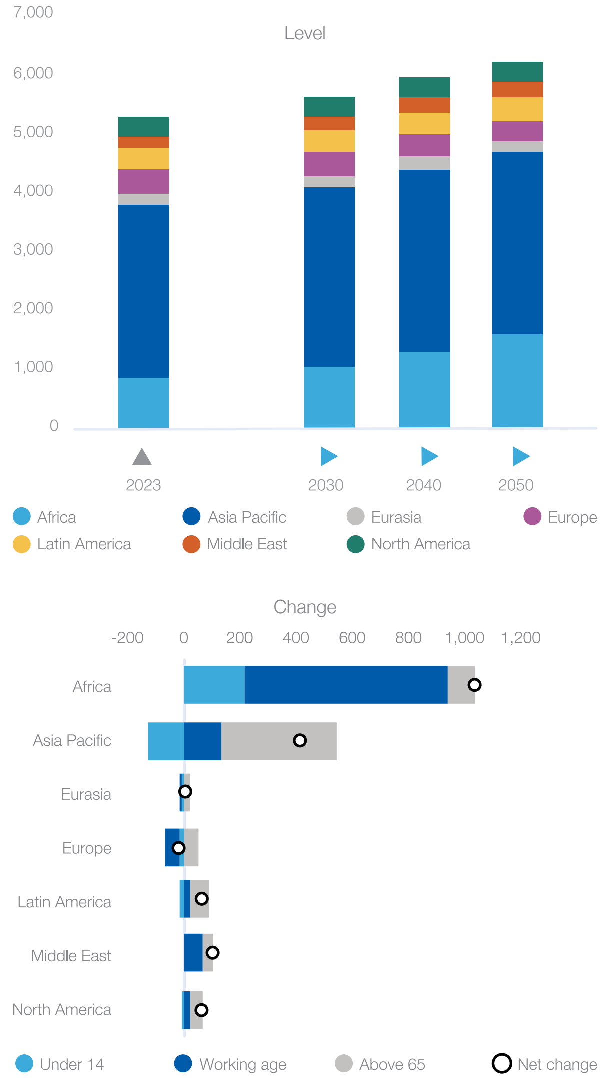
The challenges associated with Europe's ageing population are further underscored by its rising old-age dependency ratio, expected to climb from approximately 33% in 2023 to 50% by 2050. This means there will be one person aged 65 or older for every two working-age individuals. This sharp increase places a growing economic burden on the shrinking labour force to support a rapidly expanding elderly population, amplifying pressure on pension systems, healthcare services, and social welfare programs.

1.1.3 Enhanced migration

Migration is poised to become an increasingly significant factor in shaping global population and labour dynamics by 2050, mainly as regional demographic imbalances intensify. In developed regions, where population decline due to low fertility rates and ageing demographics is expected to accelerate, migration will play a critical role in sustaining population levels and supporting economic growth. **By 2050, migration is projected to account for nearly all net population growth in advanced economies, which face shrinking labour forces and rising dependency ratios.** For instance, the share of immigrants in developed countries is anticipated to rise

Figure 1.3

Global working-age population outlook by region, 2023-2050 (millions)



Source: 2023 Revisions of United Nations World Population Prospects

from 12% in 2023 to nearly 20% by 2050, reflecting the growing reliance on migration to address demographic challenges.

In contrast, developing regions will remain key sources of migration as economic disparities, climate change, and political instability drive people to seek better opportunities abroad. Despite the significant outflow, the youthful and rapidly growing populations in regions such as Sub-Saharan Africa and South Asia are expected to sustain high natural growth rates, limiting the impact of emigration on overall population growth.

By 2050, the total number of international migrants worldwide is projected to reach 350 million, up from 284 million in 2023, accounting for approximately 4% of the global population. A significant proportion of these migrants - estimated at over 65% - will be labour migrants, driven by demand in sectors such as healthcare, technology, and infrastructure in developed regions. Migrants will increasingly serve as a vital source of innovation and productivity in ageing economies, contributing to economic stability and growth.

For host countries, migration offers substantial benefits, including mitigating labour shortages, increasing tax revenues, and driving innovation. By 2050, immigrants in developed economies are expected to account for over 30% of the workforce in critical sectors, such as technology and healthcare. For source countries, remittances - projected to surpass USD 1 trillion annually by 2050 - will remain a critical financial inflow, supporting economic development and household incomes.

1.1.4 Declining household size

Household projections are instrumental in forecasting energy demand, particularly in residential and commercial sectors. **The number of households globally is anticipated to grow by approximately 35% between 2023 and 2050, outpacing the projected 22% increase in the global population during the same period.** This equates to an addition of about 790 million households, expanding from 2.3 billion in 2023 to 3 billion by 2050 (Figure 1.4).

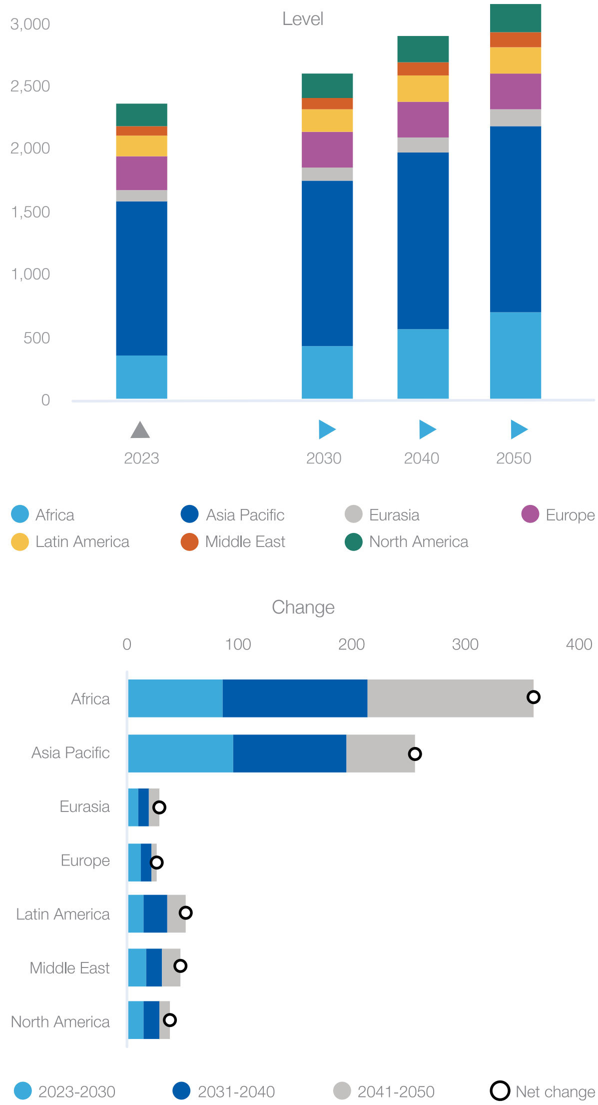
A significant portion of this growth will occur in Africa and the Asia Pacific, accounting for over 75% of the global net increase in households. Specifically, Africa is projected to add nearly 350 million new households, driven by high population growth, urbanisation, and a relatively youthful demographic profile. The Asia Pacific region will contribute an additional 260 million households by 2050, reflecting economic development, increasing urbanisation, and declining household sizes in many countries. Other regions, such as Latin America and the Middle East, will also experience moderate growth in household numbers. In contrast, developed regions like Europe and North America will see marginal increases due to population stagnation or decline.

The average household size globally is expected to decrease from 3.5 persons per household in 2023 to 3.2 by 2050, underscoring a global shift toward smaller, more individualised living arrangements. This trend is driven by rising single-person households, particularly in urbanised and developed regions, due to increasing incomes, changing social norms, and a preference for independent lifestyles. Ageing populations, especially in Europe, East Asia, and North America, contribute to more elderly individuals living alone or in smaller family units. Declining fertility rates, particularly in the Asia Pacific, Middle East, and parts of Africa, result in fewer children per household. Increased female workforce participation as more women pursue careers and independent lifestyles also contributes to smaller family units.

These household trends have far-reaching implications

Figure 1.4

Global number of households outlook by region, 2023-2050 (millions)



Source: 2023 Revisions of United Nations World Population Prospects

for energy consumption patterns and infrastructure planning. Smaller households often consume more energy per person due to less sharing of appliances, heating, and cooling systems. This dynamic could drive higher energy intensity in residential settings, mainly urban areas. Smaller and more diverse households may exhibit different energy usage patterns, including increased reliance on individual heating, cooling, and electronic appliances, particularly in regions with growing urban populations. The rapid growth of households in Africa and the Asia Pacific is expected to drive substantial increases in residential energy demand, particularly for electricity and natural gas.

The shift toward smaller households also affects housing space requirements, urban planning, and utility provisioning. With 610 million new households expected in Africa and the Asia Pacific, investments in housing, energy infrastructure, and utility networks will be critical to meet growing demand sustainably. At the same time, developed regions may focus on optimising energy efficiency in smaller households and ageing populations.

1.2 Economic growth assumptions

Energy demand is fundamentally driven by the dynamic relationship between economic growth and the value-added contributions of various economic sectors. The GECF Global Gas Model (GGM) treats economic activity trajectories across regions and sectors as exogenous inputs. This section examines these baseline assumptions, providing an overview of the underlying rationale and the evidence supporting their inclusion in the model.

1.2.1 Current developments and short-term outlook

Fiscal and monetary policies heavily influence the short-term outlook for the global economy. Current forecasts indicate that the global risk of stagflation - a combination of economic stagnation and high inflation - has eased significantly. Consumer and business confidence is improving, and inflation gradually converges toward central bank targets. This trend allows central banks to pivot towards expansionary monetary policies, including reducing interest rates to encourage investment and consumption. However, fiscal policy presents a contrasting narrative. Burdened by substantial debt, governments are increasingly turning to contractionary measures such as higher taxes and spending cuts to manage their liabilities. While these fiscal adjustments are necessary for long-term debt stability, they risk imposing constraints on economic growth in the near term.

Global economic growth is expected to stabilise at 2.7% in 2024 and 2025, slightly higher than the rate observed in 2023. This stability, however, masks underlying regional disparities. OECD economies are poised for modest improvement, while non-OECD countries will likely experience slight slowdowns due to cyclical and structural factors alongside geopolitical uncertainties. In the OECD region, economic growth is projected to improve marginally, supported by steady recoveries in key economies. For example, the United States is forecast to grow at 2.7% in 2024, driven by robust consumer spending and strong labour markets. Growth is expected to slow to 1.9% in 2025 as the delayed effects of higher borrowing costs weigh on economic activity. Europe, on the other hand, faces a slower recovery path. The euro area is expected to grow by 1% in 2024, following a subdued 0.7% in 2023, with a slight improvement to 1.7% in 2025. Persistent weaknesses in manufacturing and ongoing energy market challenges continue to hamper the region's recovery. In Japan, modest growth is anticipated, with projections of 1% in 2024, up from 0.9% in 2023, reflecting steady domestic demand, fiscal stimulus, and strong exports in high-tech sectors.

In contrast, non-OECD countries are projected to grow at an average rate of 4.1% in 2024 and 2025, down slightly from 4.2% in 2023. China is a major contributor to this slowdown, with growth projections revised down to 4.6% in 2024 and 4.0% in 2025. China's housing market struggles, weak consumer confidence, and broader structural challenges dampen domestic growth and create ripple effects across global trade and supply chains. However, India presents a more optimistic picture, with growth expected to reach 6.8% in 2024 and 6.5% in 2025, supported by strong domestic demand and ongoing structural reforms.

Cyclical factors are pivotal in shaping this global outlook. As inflation declines, central banks are likely to adopt more accommodative monetary policies, which could boost investment and consumption. Nevertheless, the lagged effects of earlier monetary tightening, particularly on interest-sensitive sectors such as housing and capital investment, remain a drag on economic activity. Adding to these challenges, the constrained fiscal stance in many economies limits governments' ability to provide counter-cyclical support through increased spending or targeted stimulus, further dampening economic momentum. Policymakers face a challenging balancing act, needing to support growth while maintaining price stability during this transitional period.

Structural challenges add another layer of complexity to the growth landscape. In OECD economies, ageing populations and shrinking workforces limit potential output, though technological advancements, especially in artificial intelligence (AI) and digitalisation, offer opportunities for productivity gains. Meanwhile, despite benefiting from younger populations, non-OECD countries often grapple with inadequate infrastructure and policy uncertainties, constraining their ability to fully leverage growth opportunities.

Geopolitical uncertainties further complicate the global economic outlook. Trade disruptions, commodity price volatility, higher tariffs and rising protectionism create headwinds for international economic cooperation. These factors strain fiscal and economic stability while undermining the efficiency of supply chains, exacerbating the vulnerabilities faced by advanced and developing economies.

Despite these challenges, there is upside potential to global economic growth. Accelerated technological advancements, particularly in digitalisation and AI, promise to transform economies and enhance productivity across sectors. Additionally, a faster-than-anticipated decline in inflation could enable central banks to reduce interest rates earlier, fostering higher levels of investment and consumption. However, these prospects are counterbalanced by persistent risks, including financial market volatility, geopolitical imbalances and retaliatory tariffs which could tighten global financial conditions and disproportionately affect economies with significant external financing needs.

1.2.2 Long-term economic growth prospects

The long-term trajectory of the global economy is set to be shaped by profound transformations across demographic, economic, geopolitical, environmental, and technological dimensions. By 2050, these trends are anticipated to fundamentally alter the structure of economies, labour markets, and resource allocation, presenting unprecedented opportunities and complex challenges for achieving sustainable, inclusive, and equitable growth.

Central to these transformations is the ongoing demographic transition. The world is experiencing profound shifts, marked by ageing populations in developed economies and rapid population growth in developing regions, particularly Africa and developing Asia (See Section 1.1). While the latter regions are projected to account for most of the global population increase by 2050, ageing populations in advanced economies are placing immense pressure on public finances through unfunded liabilities such as pensions and healthcare costs. Declining fertility rates and shrinking labour force exacerbate fiscal burdens, limiting the government's capacity to address other pressing challenges.

By 2050, the relationship between population growth and GDP is expected to weaken globally, signalling a shift in the drivers of economic output. Historically, economic growth was closely tied to population expansion, as larger populations provided both labour and consumption that drived economic activity. However, this correlation is diminishing as economies increasingly rely on productivity improvements, technological advancements, and capital investment rather than demographic expansion. This decoupling is anticipated to contribute to growing disparities in per capita income among countries, reflecting uneven access to these transformative drivers.

Accompanying these demographic trends is the shifting balance of global economic power. By the 2040s, non-OECD economies are expected to surpass OECD economies in GDP terms, with their share of global output continuing to grow. The rise of the Global South will be led by countries such as China and India, which will remain key engines of growth alongside emerging consumer markets and industrial hubs in the Africa, Latin America, and Middle East. However, structural barriers such as inadequate infrastructure, policy uncertainty, and limited access to capital could hinder these regions from fully realising their economic potential. Proactive investment, governance reforms, and international partnerships will be critical to overcoming these challenges and fostering sustainable growth.

Adding to this transformation is **strengthening regional economic cooperation within the Global South**, counteracting the retreat from globalisation and the rise of protectionism. Alliances such as BRICS, MERCOSUR in Latin America, the Gulf Cooperation Council (GCC), the Association of Southeast Asian Nations (ASEAN), the African Continental Free Trade Area (AfCFTA), and the Regional Comprehensive Economic Partnership (RCEP) are expected to deepen economic integration, promoting intra-regional trade, investment, and technology sharing leading to reinforced South-South Partnerships. These partnerships hold the potential to create robust economic blocs, reducing reliance on traditional Western markets and challenging the dominance of global financial institutions. Furthermore, initiatives like BRICS' proposed cross-border currency and alternative payment systems aim to reshape the global financial architecture, offering alternatives to dollar-dominated trade and enhancing monetary sovereignty for emerging economies.

Amid this economic transformation, debt sustainability will remain a critical challenge. By 2050, public debt levels in advanced economies are projected to rise further, driven by ageing populations and escalating healthcare and pension costs. At the same time, many developing economies, already burdened by debt incurred for infrastructure development and energy transition investments, will face fiscal constraints limiting their ability to invest in education, technology, and climate resilience. Moreover, persistently high inflation is expected to maintain elevated interest rates, increasing the cost of debt servicing and amplifying fiscal pressures for both developed and developing economies. Governments may need to resort to higher taxes to manage ballooning debt burdens, further straining household expenditures and eroding disposable income. Rising global interest rates and tightening financial conditions could exacerbate these vulnerabilities, particularly for countries dependent on external financing, jeopardising their long-term fiscal stability and development prospects.

Climate change will further compound these challenges, presenting a persistent threat with far-reaching economic and social consequences by 2050. Rising temperatures and extreme weather events are expected to disrupt agriculture, infrastructure, and livelihoods, particularly in vulnerable regions such as Africa and South Asia. These disruptions will likely trigger climate-induced migration, heightening competition over resources such as land, water, and food and straining geopolitical stability. Coordinated global action on climate adaptation and mitigation will be essential to address these cascading effects and ensure resource security.

Energy transformations will strive to balance energy security, affordability and sustainability. These nationally determined energy transformations will require using all fuels and technologies. Furthermore, it should address the energy needs of regions with limited access to financial and technological resources, especially in low-to-middle-income countries. The global energy transformation will demand trillions of dollars in investments, reshaping economies, trade dynamics, and resource dependencies. If not managed equitably, this transformation risks exacerbating inequalities and increasing energy poverty. Just, inclusive, and orderly transformations, supported by technological innovation and international collaboration, will be essential to achieving a sustainable energy future.

Technological advancements, particularly in AI and digitalisation, will also transform the global economy by 2050. AI is projected to drive significant productivity growth, enabling efficiency gains across manufacturing, healthcare, agriculture, and energy sectors. PwC's Global Artificial Intelligence Study estimates that AI could contribute up to USD 15.7 trillion to the global economy by 2030. Automation and robotics will increasingly take over routine and complex cognitive tasks, reducing labour costs and accelerating economic output. However, these advancements bring with them far-reaching societal and economic consequences.

The societal and economic impacts of AI's proliferation cannot be overstated. Automation is expected to displace millions of jobs globally, particularly in low- and middle-skill roles, exacerbating income inequality. While AI will create new opportunities in tech-intensive fields, the persistent skills gap, especially in developing countries, will remain a significant barrier. Ethical concerns, including algorithmic bias, data privacy, and the concentration of AI capabilities among a few dominant players, will also require robust governance frameworks. Without careful management, the AI arms race could deepen inequalities and erode trust in these transformative technologies.

Digitalisation will further decentralise economic activity, with blockchain, cloud computing, and the Internet of Things (IoT) enabling new business models and transforming global supply chains. By 2050, digital platforms are expected to be central in facilitating trade, education, and healthcare, particularly in underserved regions. However, the persistent digital divide and concentration of innovation in a few advanced economies risk leaving many developing regions further behind, exacerbating global inequalities and undermining inclusive development.

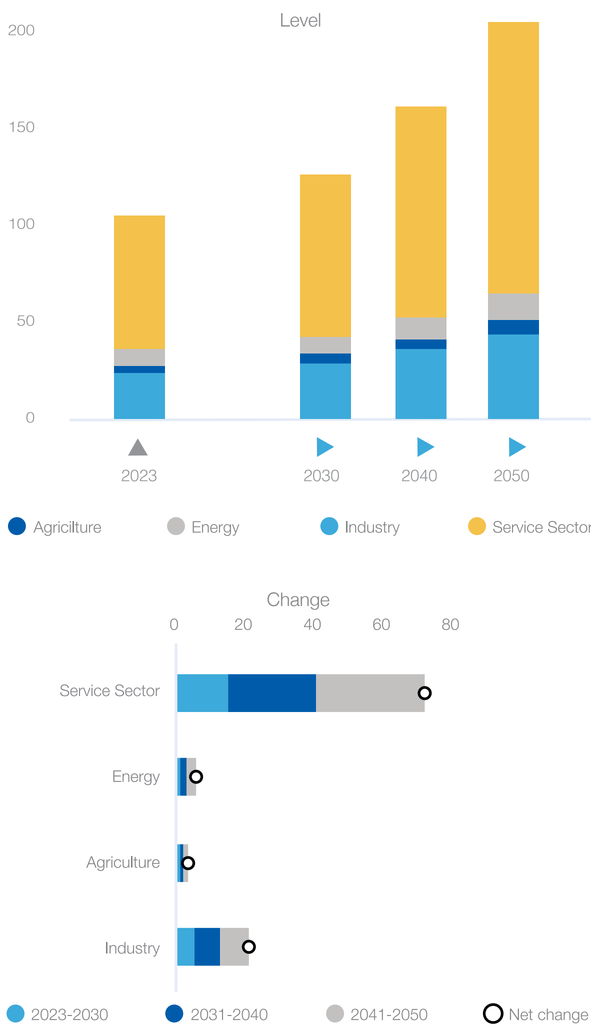
Driven by the above factors, global GDP is projected to grow by USD 101 trillion in real terms between 2023 and 2050, reaching a total of USD 206 trillion by mid-century. This represents an average annual growth rate of 2.5%, marking a modest deceleration from the 2.9% annual growth recorded over the past 27 years. The slowdown reflects the natural maturation of economic activity as the global economy expands, with diminishing marginal returns on capital investment and labour contributing to the declining growth trend amid a total factor productivity boost supported by technological advancement.

Over the long term, non-OECD countries are expected to outpace OECD economies in annual economic growth, though both regions are forecast to experience a general deceleration. OECD countries are projected to reach approximately USD 100 trillion by 2050, supported by a steady annual growth rate of 1.6%. In contrast, non-OECD economies are expected to grow at a more robust annual rate of 3.5%, reaching USD 106 trillion by 2050 and accounting for 52% of global GDP. According to our projections, this shift highlights the increasing economic influence of non-OECD countries, whose collective GDP is anticipated to surpass that of OECD economies in the early 2040s.

From a sectoral perspective, the service sector is poised to play an increasingly dominant role in global economic growth. As illustrated in Figure 1.5, the service sector's share of global GDP is expected to remain the largest contributor, rising from 66% in 2023

Figure 1.5

Global GDP outlook by sector, 2023-2050 (real USD trillion, base year = 2023)



Source: GECF Secretariat based on data from the GECF GGM

to 68% by 2050. Conversely, the industrial sector's contribution to global value-added creation is forecast to decline marginally, from 22% to 21% over the same period. This structural transformation reflects the growing prominence of services as the primary driver of economic activity.

Several factors underpin this trend. Rapid advancements in digitalisation and technology drive growth in knowledge-intensive service industries such as finance, healthcare, education, and professional services. Additionally, rising urbanisation and increasing income levels in emerging economies are increasing demand for service-oriented sectors such as entertainment, travel, and hospitality. The global transition to a low-carbon economy further incentivises investment in service-oriented solutions, including energy efficiency consulting and renewable energy services, over traditional industrial activities. Meanwhile, advanced economies are shifting from manufacturing-driven growth to high-value service industries as their industrial bases mature and evolve.

An analysis of incremental contributions further underscores this transition. **The service sector is projected to account for over 70% of global value-added creation between 2023 and 2050**, while the industry sector's contribution is expected to experience a modest decline, albeit with absolute growth. These dynamics signal a broader transformation of the global economy toward a service-dominated structure, reflecting technological advancements and shifting consumer and policy priorities worldwide.

Projections indicate that global per capita GDP in real terms is projected to grow at a steady annual rate of 1.8% by 2050, surpassing USD 21,000 per annum. This rate is comparable to the 1.7% yearly growth recorded over the past 27 years, marked by higher population and GDP growth rates. Despite similar per capita growth rates, the dynamics are shifting past growth was driven by both rising population and economic output, while future gains are expected to stem primarily from advancements in technology, efficiency, and structural economic changes.

1.2.3 Long-term economic growth outlook by region

In 2023, the Asia Pacific region played a pivotal role in the global economy, accounting for 34% of the world's GDP, the largest share among all regions. North America and Europe followed, contributing 30% and 23%, respectively. In contrast, Africa and Eurasia remained the smallest contributors, each representing just 3% of global GDP, highlighting their relatively modest roles in the global economic structure (Table 1.2).

Looking ahead, the Asia Pacific region's share of global GDP is projected to grow significantly, reaching 42% by 2050, a figure double its share in 1996. This surge underscores the region's rising prominence, driven by robust growth in its services and industrial sectors and its continued role as a global economic powerhouse. In comparison, the shares of North America and Europe are expected to decline to 25% and 17%, respectively, reflecting slower growth trajectories and demographic challenges. Meanwhile, Africa's share is forecast to grow modestly, increasing to 5% by 2050, signalling gradual progress in its economic contributions (Figure 1.6).

The Asia Pacific region's economic rise is expected to account for more than half of the total increase in global GDP by 2050. In contrast, North America's contribution will remain significant but smaller, driven by high-value service industries, including technology, healthcare, and finance. These trends reflect a shifting global economic landscape, with Asia Pacific emerging as the dominant force while other regions face varying growth challenges and opportunities.

In contrast, Europe's contribution to global GDP is anticipated to decline significantly, making up just over 10% by 2050. Compared to historical trends, this sharp reduction is primarily attributed to demographic

Table 1.2

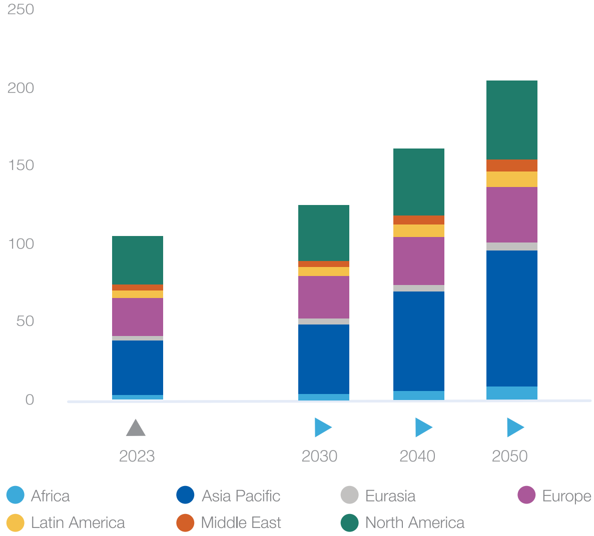
Global GDP outlook by region, 2023-2050 (real USD billion, base year = 2023)

	2023	2030	2040	2050	Change, 2023 - 2050	Growth (%, p.a.)
Africa	2,859	3,871	6,015	9,340	6,481	4.4
Asia Pacific	35,206	45,286	64,019	86,724	51,518	3.3
Eurasia	2,842	3,378	4,198	5,077	2,235	2.1
Europe	24,306	27,052	31,099	35,749	11,443	1.4
Latin America	5,118	6,062	7,915	10,323	5,205	2.6
Middle East	3,278	4,161	5,542	7,381	4,103	3.0
North America	31,290	36,189	43,008	50,985	19,696	1.8
World	**104,898**	**125,999**	**161,796**	**205,580**	**100,682**	**2.5**

GECF Secretariat based on data from the GECF GGM

Figure 1.6

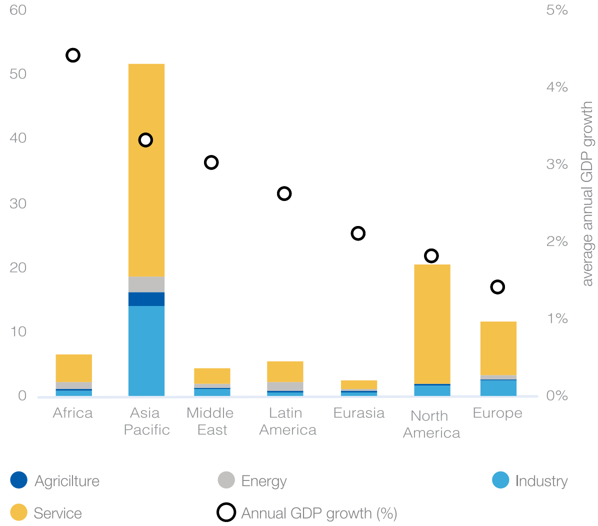
Global GDP outlook by region, 2023-2050 (real USD trillion, base year = 2023)



Source: GECF Secretariat based on data from the GECF GGM

Figure 1.7

Global GDP outlook by region, 2023-2050 (real USD trillion, base year = 2023)



Source: GECF Secretariat based on data from the GECF GGM

challenges, including ageing populations and shrinking labour forces, constraining economic growth potential. However, Europe is expected to maintain its competitive edge in innovation, sustainability, and high-value manufacturing, ensuring its continued relevance in the global economy despite these challenges.

As illustrated in Figure 1.7, Europe is projected to have the most conservative long-term annual growth rate, at 1.4% over the next 27 years. This forecast is 0.4 p.p. lower than the growth experienced between 1996 and 2023. Similarly, North America's long-term growth rate is expected to slow to 1.8% annually, reflecting a deceleration in potential long-term output growth compared to historical trends.

Meanwhile, Latin America is forecast to achieve a long-term annual economic growth rate of 2.6%, closely aligning with the global average over the forecast period. This steady growth reflects the region's gradual integration into global markets and its potential to contribute meaningfully to the evolving global economic landscape. Eurasia is projected to exhibit a more modest growth trajectory, with an annual growth rate of 2.1%. In contrast, the Middle East is expected to grow at a stronger pace of 3% annually, driven by economic diversification efforts, expanding energy investments, and rising trade ties with Asia and other emerging markets.

While the global economy is projected to grow by USD 101 trillion, this growth does not imply an equitable distribution of wealth across regions. As illustrated in Figure 1.8, regional income disparities remain stark. For example, in 2023, **Africa accounts for approximately 18% of the global population, yet its per capita income in real terms is about USD 1,950 per year - nearly one-sixth of the global average. In contrast, North America, home to 6% of the global population, boasts an income per capita of around USD 62,000 per person - about 31 times higher than Africa's. This disparity contributes to a global Gini index of 62% in 2023, reflecting significant inequality in income distribution among countries.**

Looking ahead to 2050, shift in per capita GDP distribution among regions is projected. **The global average per capita income is expected to rise substantially, reaching USD 21,000 per person - a 1.8% annual growth from 2023.** The Asia Pacific region, driven by rapid economic growth, is forecast to surpass the Middle East, Latin America, and Eurasia in per capita GDP, ranking just behind Europe and North America. Despite its considerable population expansion, Africa is also set to experience notable growth, with per capita income expected to double by 2050.

Improvements in the per capita income of lower-income regions, such as Africa and developing Asia, are projected to contribute to a slight reduction in global income inequality between countries. This trend is reflected in the anticipated decline of the global Gini index to 59% by 2050, signalling modest progress toward a more balanced distribution of wealth across regions.

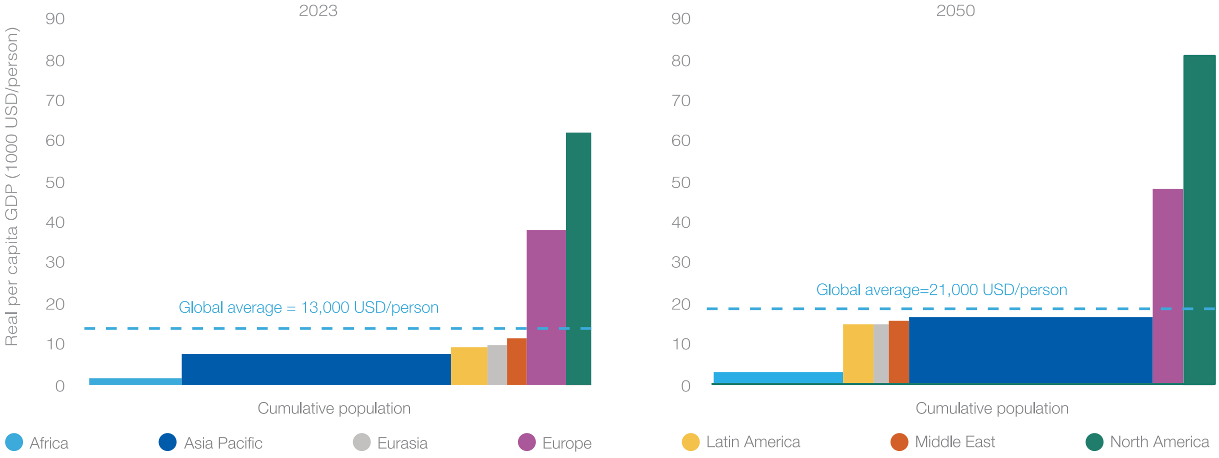
The next section of this chapter is dedicated to the economic growth prospects of each region, providing insights into their trajectories.

1.2.3.1 Africa

Africa, accounting for approximately 3% of the global economy in 2023, is projected to see its economic growth moderate to 4.3% in 2025, following a stronger

Figure 1.8

Regional real GDP per capita outlook, 2023 and 2050 (real 1000 USD/person, base year = 2023)



Source: GECF Secretariat based on data from the GECF GGM

recovery in 2024, estimated at 4.5%. This outlook reflects persistent structural challenges unique to the region. Tight domestic and external financing conditions continue to constrain economic activity, leaving many countries unable to secure or afford adequate funding. Rising public debt levels and escalating debt servicing costs redirect resources from essential development priorities, further impeding progress. Persistent inflation, weak governance, and socio-political instability also exacerbate the region's vulnerabilities. These pressures are compounded by the growing impacts of climate change, which intensify natural disasters, disrupt agricultural productivity, and strain critical infrastructure, posing significant risks to sustainable growth.

Within this context, North Africa, representing around 28% of Africa's total economy in 2023, is poised for substantial economic transformation over the coming decades. Long-term projections indicate that the region will achieve an annual growth rate of 3.5% by 2050, reflecting steady progress compared to its historical performance over the past 27 years. In the medium term, North Africa is expected to grow at an average annual rate of 3.8% by 2030, driven by structural reforms, increased investments, and regional integration. This robust medium-term performance is anticipated to establish a strong foundation for sustained development, even as growth rates naturally moderate over the longer term.

Egypt stands out as key growth drivers among the North African economies. Egypt, the largest economy in the sub-region, is projected to maintain a long-term annual economic growth rate of 3.9%, solidifying its position as an economic powerhouse. By 2050, Egypt is expected to contribute over half of North Africa's GDP, supported by its expanding population, infrastructure investments, and efforts to diversify into energy, manufacturing, and technology sectors.

Sub-Saharan Africa, meanwhile, is forecast to achieve an annual economic growth rate of 4.7% over the long term, a notable acceleration compared to the historical average of 3.9% recorded between 1996 and 2023. Although starting from a lower economic base, this sustained growth underscores the region's increasing dynamism and potential. By 2050, this growth is expected to elevate Sub-Saharan Africa's contribution to the continent's total GDP to nearly 80%, a significant increase from its 2023 level.

Within Sub-Saharan Africa, East Africa emerges as a standout sub-region, hosting some of the continent's fastest-growing economies, including Kenya and Mozambique. The broader East African sub-region, excluding these two countries, is projected to achieve over 6% annual GDP growth by 2050. Kenya and Mozambique are forecast to record impressive growth rates of 6.1% and 5%, respectively. Similarly, the West African sub-region is expected to experience significant economic expansion, driven by standout performers such as Mauritania and Senegal. The long-term average growth rate for West Africa is projected at 5.2% per annum, emphasising the region's increasing prominence in shaping Africa's economic landscape.

However, the region's largest economies, Nigeria and South Africa, which collectively accounted for 38% of Sub-Saharan Africa's GDP in 2023, are expected to grow more modestly over the next three decades. This slower pace of growth is anticipated to reduce their combined share of Sub-Saharan Africa's GDP to 25% by 2050, signalling a shift in economic power dynamics as smaller, faster-growing economies rise in prominence.

1.2.3.2 Asia Pacific

The Asia Pacific region, the largest contributor to the global economy in 2023, is expected to sustain its position as a leading growth driver, expanding at rates above the global average in the medium-to-long term. In 2023, the region experienced robust real GDP growth of 4.4%, reflecting its economic resilience. However, growth is projected to moderate to 4.0% in 2024 and further to 3.8% in 2025. This deceleration is primarily attributed to the slowdown in China, a critical player in the region's economic performance. As the largest economy within Asia Pacific, China accounts for over half of the region's GDP, making its economic trajectory pivotal to the region's overall growth dynamics.

China's economic growth rebounded strongly in 2023, achieving a rate of 5.2%, a significant recovery from the 2.9% recorded in 2022, affected by stringent pandemic-related restrictions and global economic uncertainties. Despite this recovery, the forecast decline in growth rates reflects structural challenges, including demographic shifts, a shrinking labour force, and the need to transition from an investment-led to a consumption-driven economy. These factors are anticipated to weigh on China's growth momentum, with ripple effects on the broader Asia Pacific region. **China's average annual economic growth is projected to reach 3.6% over the outlook period.**

The Asia Pacific region is projected to sustain solid economic growth in the near term, driven by robust domestic demand in emerging economies such as India and steady performance in OECD Asia economies like Japan. Key sectors, including technology and manufacturing, continue to benefit from global demand for products like semiconductors and renewable energy components. However, the region faces notable headwinds, including a deceleration in China's economy, influenced by challenges in its property sector and structural adjustments toward a more consumption-driven growth model. Rising protectionism and geopolitical imbalances further complicate the economic landscape, potentially disrupting supply chains and increasing costs. Despite these challenges, proactive policy measures, increased regional trade cooperation, and a growing focus on innovation and infrastructure investment are expected to underpin the region's growth trajectory in the short term.

The OECD Asia Pacific region is projected to maintain an average economic growth rate of 1.3% annually in 2023-2050, aligning with historical patterns for the sub-region. However, significant shifts in economic contributions among member countries are expected to redefine the regional landscape. Australia is forecast to lead the region's growth, with a robust annual expansion of 2.1%, driven by its strong performance in renewable energy, technology, and services sectors. Conversely, Japan, which represented over half of the region's GDP in 2023, is projected to grow at a more subdued rate of 0.6% annually, reflecting the ongoing challenges of an ageing population and labour force decline. These dynamics are set to transform the region's economic structure. Japan's share of the OECD Asia Pacific economy is anticipated to drop to 45% by 2050, while Australia's share rises to 28%, marking a substantial 6 percentage points increase from 2023.

The non-OECD East Asia region, which currently accounts for approximately one-quarter of global GDP, is projected to experience a significant moderation in its economic growth over the 27 years. Long-term projections estimate an average annual growth rate of 3.7% through 2050, a marked decline from the exceptional 7% average growth achieved over the past 27 years. This deceleration reflects structural changes, including ageing populations, slowing productivity growth, and transitioning from export-driven economies to more consumption-led models.

China and India dominate the economic landscape within this region, jointly contributing over 90% of its GDP and shaping its future direction. While experiencing a slight slowdown, India is set to remain the fastest-growing economy in non-OECD East Asia, with a projected long-term annual growth rate of 5.2% by 2050, driven by its expanding workforce, digital transformation, and domestic market development. On the other hand, China's economic growth is forecast to decelerate sharply, with an annual long-term rate of 3.4% - a substantial drop from the 7.9% it averaged between 1996 and 2023. This slowdown reflects structural adjustments in its economy, including a shift away from heavy industry and real estate dependence, combined with demographic challenges and rising debt levels.

Southeast Asia, representing around 11% of the Asia Pacific region's GDP in 2023, is expected to sustain steady economic growth over the long term, albeit slightly slower than in recent years. The region's annual growth rate is projected to average 3.9% by 2050, supported by economic diversification, strengthening regional trade partnerships, and rising domestic consumption. Among the standout performers, Cambodia and Viet Nam are anticipated to achieve the highest growth rates in the region, with both countries forecast to expand at an impressive 5.4% and 5.5% annually, respectively. Robust manufacturing sectors, technological advancements, and continued integration into global value chains will likely drive their rapid growth.

Indonesia, the largest Southeast Asian economy, accounted for 36% of the region's GDP in 2023 and is positioned for sustained long-term growth. The country is expected to grow at a solid annual rate of 4.2%, reflecting its strong domestic demand, resource-based industries, and significant investments in infrastructure and technology. These projections underscore Southeast Asia's economic resilience and adaptability as it continues to leverage opportunities in regional cooperation and global trade to maintain its position as a dynamic and evolving economic hub.

1.2.3.3 Eurasia

Following economic contraction, Eurasia began to rebound in 2023, with GDP growing by 4%. This recovery is expected to gain momentum, with growth rates projected to reach 3% in 2024 and 2.8% in 2025. The gradual improvement reflects the region's efforts to stabilize its economies amid external and internal challenges.

In 2023, Russia, which accounts for approximately 70% of Eurasia's GDP, exceeded expectations with GDP growth surpassing 3%. This strong performance was driven by robust domestic demand, increased private consumption, and heightened investment activity, supported by a resilient labour market. However, persistent inflation prompted the central bank to adopt tight monetary policies, putting pressure on household consumption and private investment. Looking ahead, Russia's GDP growth is forecast at 3.6% in 2024, driven by easing inflationary pressures and significant public investments in infrastructure and energy sectors.

In the long term, Eurasia's average annual GDP growth is projected to stabilise at 2% by 2050, reflecting the region's gradual economic expansion. Russia, as the largest economy in the region, is expected to grow at an average annual rate of 2%, supported by its abundant resource base in energy and mining, strategic investments in infrastructure, and ongoing diversification efforts. However, the region's growth will also be shaped by the strong performance of smaller, fast-growing economies.

Uzbekistan is anticipated to lead the region in growth, with a remarkable long-term annual GDP growth rate of 4% through 2050. This impressive trajectory is driven by the country's pro-market reforms, expanding energy exports, significant investments in the energy sector, and its strategic location as a logistics hub for the Belt and Road Initiative. Similarly, Kazakhstan is poised to enhance its role in the region, with its share of Eurasia's GDP projected to rise to 12% by 2050, an increase of nearly 2 percentage points from 2023. Kazakhstan's growth is underpinned by substantial investments in its energy sector, advancements in agriculture, and its critical role as a supplier of raw materials and minerals essential to global industries. Together, these dynamics highlight the evolving economic landscape of Eurasia, where diverse growth trajectories among countries are shaping the region's future economic potential.

1.2.3.4 Europe

Europe's economic recovery is gaining momentum, supported by declining energy prices, easing supply chain disruptions, and improving consumer confidence. However, persistent headwinds such as high core inflation, geopolitical instabilities, and slow productivity growth continue to restrain the region's growth potential. Projections for 2023 indicated modest growth at 0.7%, with expectations of a slight improvement to 1% in 2024. These trends highlight the need for structural reforms to address fragmentation in labour and product markets, ensure energy security, and accelerate energy transitions. Furthermore, wage growth in response to tight labour markets is expected to support household incomes, gradually translating into increased consumption, albeit cautiously, as uncertainty keeps savings rates elevated.

In the medium term, Europe's economic trajectory hinges on successfully recalibrating monetary and fiscal policies. Gradual easing of monetary conditions is anticipated to enhance investment, while fiscal consolidation efforts aim to rebuild buffers and address rising public debt. Countries with robust services sector are positioned to benefit more immediately, while manufacturing-intensive economies face prolonged recovery due to weaker external demand. As Europe navigates these challenges, sustained investments in innovation, integration of value chains, and policy harmonisation are critical to fostering long-term resilience and inclusive growth.

OECD Europe, accounting for nearly 97% of the continent's economic activity in 2023, is projected to grow at an average annual rate of 1.4% through to 2050. This growth aligns with historical trends but reflects enduring structural challenges with lasting impacts. Ageing populations, declining labour force participation, and sluggish productivity growth are central to this moderate trajectory. These issues are further compounded by the ongoing energy transitions, which demands significant investments in renewable energy and decarbonisation technologies alongside the broader economic consequences of geopolitical fragmentation. Moreover, the deindustrialisation of key economies, such as in France, Germany, Italy, and the United Kingdom, has led to concerns over the erosion of industrial competitiveness and innovation, potentially weakening their collective contribution to Europe's GDP. This shift from manufacturing to service-oriented industries underscores a structural transformation that risks undermining the region's long-term economic resilience. Türkiye, in contrast, is poised to become a notable economic player in the region, with a projected long-term growth rate of 3.2%. Its robust performance is underpinned by a younger demographic profile, a growing industrial base, and its strategic location as a bridge between Europe and Asia. As Türkiye strengthens its industrial and trade capabilities, its regional economic influence is expected to grow substantially by 2050.

Unlike OECD Europe, non-OECD Europe contributes a smaller share to the continent's overall economic output and is projected to experience stronger long-term growth. By 2050, the region is expected to achieve an average annual growth rate of 2.3%. Romania, the largest economy within this group, is anticipated to maintain a steady growth trajectory, with a long-term annual growth rate of 2.2% through 2050. This consistent performance is expected to solidify Romania's position, accounting for over 46% of non-OECD Europe's GDP by mid-century.

1.2.3.5 Latin America

A complex interplay of resilience and emerging challenges shape Latin America's economic growth in 2023 and 2024. The region has rebounded more strongly than expected from the pandemic, with GDP growth improving from 1.7% in 2023 to 1.9% in 2024. This recovery is driven by robust domestic demand and effective policy measures; however, it remains moderated by external pressures and the lingering effects of tight monetary policies aimed at controlling inflation.

While soaring commodity prices in recent years have significantly boosted the region's economies, shifting global dynamics are tempering this momentum. Commodities such as oil, minerals, and agricultural products remain central to the region's economic landscape, but external challenges are mounting. China's economic slowdown has created uncertainties in global demand, posing risks for commodity-exporting countries in Latin America. At the same time, changes in the composition of economic growth in the United States - with a greater reliance on non-tradable and service sectors - have negatively impacted the region's trade balance. Furthermore, inflation, although on a downward trend, remains elevated. Structural issues, such as high market concentration and subdued productivity gains, persist, underscoring the critical need for competition and innovation to support long-term economic growth.

Looking ahead to mid-century, Latin America's real GDP is projected to grow at an average annual rate of 2.6%, a marked acceleration compared to historical trends. Structural factors, including demographic advantages, significant investments in the energy sector, and deeper regional trade integration, will fuel this growth. A young and expanding workforce, coupled with strategic investments in education and skills development, has the potential to enhance productivity and innovation significantly. Additionally, the global transition toward renewable energy positions Latin America as a major supplier of critical minerals such as lithium and copper and renewable energy resources, leveraging its abundant natural wealth. Strengthened regional trade partnerships and diversification of trade links are expected to enhance economic resilience and create larger, interconnected markets. Urbanisation and the rise of the middle class will further drive demand for housing, infrastructure, and consumer goods, creating dynamic centres of economic activity.

Brazil and Argentina remain pivotal to the region's economic trajectory, collectively accounting for 55% of Latin America's GDP in 2024. Brazil, benefiting from strong agricultural exports, robust industrial output, and structural reforms, has shown resilience and improved growth prospects. Long-term projections indicate Brazil will sustain an annual average growth rate of 2.3%, supported by steady investment flows and expanding domestic demand. Despite recent economic volatility, Argentina is forecast to recover strongly, driven by rising exports, infrastructure development, and macroeconomic stabilisation efforts. Its long-term annual growth rate is projected at 2.5%, reflecting foundational improvements in its economic framework. The stable contributions of Brazil and Argentina to the region's GDP underscore their central roles in anchoring Latin America's economic expansion as it navigates challenges and opportunities in the decades ahead.

1.2.3.6 Middle East

In 2023 and 2024, the Middle East's economic growth is driven by diversification efforts, robust non-oil sector performance, and strategic investments in the energy sector. The region's GDP growth stood at 0.9% in 2023, subdued because of uncertainties heightened by the conflict in the region, but anticipated to rise to 2.2% in 2024. Nonetheless, GCC countries have maintained stability by expanding non-oil sectors, such as real estate, technology, and tourism, which are expected to underpin growth in the medium term. Oil-importing countries benefit from improvements in agriculture and manufacturing, though challenges such as elevated inflation, conflict, and fiscal vulnerabilities weigh on their recovery. Additionally, the Middle East is capitalising on global decarbonisation trends by advancing renewable energy projects, particularly in solar and hydrogen, positioning itself for sustainable growth. However, structural inefficiencies and geopolitical risks remain key constraints on the region's economic potential.

The Middle East's long-term average annual growth rate is projected to reach 3% by 2050, reflecting a moderate slowdown compared to the historical average of 3.7% between 1996 and 2023. This deceleration is influenced by the maturing economies of key oil and gas exporters, including Qatar, Saudi Arabia, and the UAE, which are expected to collectively account for over 55% of the region's GDP through mid-century. Long-term growth rates for these countries are forecasted at 3%, 3.2%, and 3.4%, respectively, signalling a gradual easing of economic momentum as these economies transition from reliance on hydrocarbons to more diversified economic models.

Efforts toward economic diversification are expected to play a critical role in shaping the region's future growth trajectory. Investments in non-oil sectors, particularly in manufacturing, renewable energy, and advanced technology, are anticipated to improve the share of non-hydrocarbon revenues. Initiatives such as Saudi Arabia's Vision 2030, Qatar's National Vision 2030, and the UAE's Industrial Strategy are fostering expansions in key sectors like tourism, logistics, hydrogen, and high-tech industries. Moreover, the region's strategic location supports its global trade and logistics hub role. At the same time, large-scale infrastructure projects and foreign direct investment aim to enhance long-term economic resilience.

1.2.3.7 North America

In 2023 and 2024, North America's economic growth remains underpinned by robust consumer spending, resilient labour markets, and significant investments in technology and infrastructure. The United States, as the largest economy in the region, benefits from strong domestic demand supported by low unemployment and steady wage growth. Moreover, the Federal Reserve's recent monetary easing following the recent inflation reduction is supporting expansion. In Canada, economic growth is sustained by steady consumer confidence, a stable housing market, and substantial investments in the energy sector and digital transformation despite facing global economic uncertainties. Meanwhile, nearshoring initiatives, industrial diversification, and integration into regional supply chains increasingly support Mexico's growth. Across the region, public and private sector investments in energy-related and digital infrastructure provide further momentum. Despite these positive drivers, inflationary pressures and evolving global trade dynamics pose headwinds, requiring adaptive fiscal and monetary policies to maintain economic stability. North America's GDP growth is estimated at 2.5% for 2023, with a slight increase to 2.6% projected for 2024.

From a long-term perspective, North America's growth trajectory faces transformative challenges as traditional drivers of prosperity weaken amid shifting global and domestic dynamics. Declining investment and total factor productivity growth, combined with rising costs of capital and innovation, are eroding the region's capacity for sustained economic expansion. Demographic shifts, particularly an ageing population and slower labour force growth, further constrain long-term growth potential. While advancements in automation and artificial intelligence hold promise, they have yet to offset these demographic pressures fully. Moreover, widening income inequality and a contracting middle class threaten consumer spending and socio-economic stability, critical pillars of economic resilience.

Persistent inflation and the prospect of "higher for longer" interest rates add additional pressures, constraining both business investments and household consumption. Rising public and private debt levels exacerbate fiscal vulnerabilities and heighten susceptibility to financial shocks. At the same time, climate-related disruptions and the global energy transition necessitate significant investments in green infrastructure and clean technologies to ensure future economic sustainability.

By 2050, the United States is expected to see its share of the global economy decline by 5 percentage points to 20%, reflecting the rise of rapidly expanding emerging markets. However, the United States is anticipated to maintain a dominant and stable role within North America, contributing approximately 87% of the region's economic output throughout the forecast period. By 2050, long-term United States growth is forecast at 1.8% annually, a marked deceleration compared to its historical average from 1996 to 2023, driven by demographic constraints and slowing productivity. In contrast, Canada and Mexico are poised for relatively stronger growth during similar time frames, with annual rates of 1.7% and 2.2%, respectively. Canada's growth will be fuelled by investments in the energy sector, technology, and immigration policies to mitigate labour force declines. Mexico is expected to benefit significantly from nearshoring trends, regional supply chain integration, and reforms targeting industrial diversification and infrastructure development, positioning it as an increasingly influential player in North America's 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.

In the Global Gas Model (GGM), prices for crude oil, natural gas, and carbon emissions are treated as exogenous variables. This chapter 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. Table 1.3. presents the assumptions for crude oil, natural gas and carbon prices.

1.3.1 Crude oil prices

In 2024, the oil market reflects the interplay of short-term recovery and emerging challenges that shape near-term price dynamics. Oil demand, which rebounded strongly following China's reopening and robust consumption in non-OECD countries, has stabilised but faces significant pressures. Going forward, China's economic slowdown and broader global economic uncertainties are tempering oil demand growth. Additionally, persistent inflation and tighter monetary policies constrain economic activity and oil consumption. Brent crude oil price is projected to remain below USD 80 per barrel through 2025, reflecting these short-term challenges and moderated demand growth.

On the supply side, OPEC+ has played a critical role in stabilising the market through strategic voluntary production cuts, successfully reducing OECD inventories and maintaining price balance. Meanwhile, United States oil production, while resilient, is constrained by declining drilling activity and increasing operational costs, signalling a slowdown in output growth. These factors characterise a short-term market defined by constrained supply growth and tempered demand expansion.

Over the long term, the oil market dynamics will shift significantly, shaped by structural demand and supply factors. On the demand side, while overall growth is expected to moderate, the petrochemical industry will become a key driver of oil consumption. Demand for petrochemical feedstocks will remain robust, driven by the increasing need for plastics, fertilisers, and chemicals in developing and emerging economies. This non-combustion use of oil is less affected by energy transition policies compared to sectors such as transportation, where electrification and efficiency improvements are reducing oil dependence. **Furthermore, developing economies will dominate long-term demand growth due to industrialisation, urbanisation, and rising living standards, highlighting the importance of these markets in sustaining future oil consumption.**

On the supply side, long-term trends reflect the growing challenges of maintaining adequate production levels. The natural decline in output from existing oil fields will necessitate significant investments in new capacity to offset depletion. Greenfield developments, including high-cost unconventional United States shale operations and yet-to-find reserves, will play an increasingly prominent role in meeting demand. However, these projects inherently carry higher marginal production costs, increasing oil prices. Additionally, inflationary pressures on critical materials such as steel and copper, driven by competition with renewable energy infrastructure projects, will further elevate production costs. Carbon pricing policies and stricter environmental regulations in major economies will also contribute to rising production expenses, compounding the challenges for oil producers.

The financial landscape will also influence long-term oil supply. High interest rates and shifting investor preferences in light of energy transitions' uncertainties have increased the cost of capital for oil projects. Investors are demanding higher returns to compensate for risks associated with long-cycle projects. This recalibration of risk preferences has slowed the pace of new capacity development, further limited future supply, and exerted additional upward pressure on prices.

Despite these complexities, the oil market is expected to adapt, maintaining a delicate balance between the need for sustained investment and the realities of a transitioning energy landscape. Long-term projections suggest a steady increase in Brent crude oil price as the market adjusts to the widening gap between supply and demand. **Real Brent price (base year = 2023) is forecast to average USD 80 per barrel during 2023–2030, rise to USD 85 per barrel in 2030–2040, and reach USD 90 per barrel in 2040–2050** (Table 1.3). These price levels reflect a combination of constrained supply and evolving demand patterns, underscoring the structural and transitional forces influencing oil prices. This comprehensive outlook highlights the enduring relevance of oil while reflecting the transformational shifts that have redefined its place in the global energy system.

1.3.2 Natural gas prices

In 2024, global natural gas prices exhibited relative stability compared to 2023, with notable regional variations. In the United States, Henry Hub prices averaged USD 2.19 per MMBtu, marking a 14% decline from the previous year. This drop was driven by sustained high domestic production, moderate demand, and ample storage levels. In Europe, the TTF benchmark price averaged USD 14 per MMBtu in December 2024, reflecting a seasonal increase due to winter demand and heightened competition for LNG cargoes. In Asia, NEA spot LNG prices reached USD 14 per MMBtu in early 2025, indicating a recovery in demand, largely driven by rising Chinese LNG imports and steady consumption growth from emerging economies like India, Thailand, and the Philippines.

While these price levels suggest a more balanced market, global gas markets remain exposed to supply risks. The next wave of LNG liquefaction projects, crucial for meeting future demand, has faced delays and is now expected to come online around 2027 due to project setbacks. Additionally, potential extreme weather events and geopolitical uncertainties continue to reinforce market tightness, leaving prices vulnerable to sudden disruptions.

Table 1.3

Crude oil, natural gas and carbon prices assumptions, 2023-2050 (USD, base year = 2023)

Prices	Benchmark	Unit	2023	2023-2030	2031-2040	2041-2050
Crude oil	Brent crude oil	USD 2023/bbl	83	80	85	90
Natural gas	Asian import gas price	USD 2023/MMBtu	16.8	9.0	9.8	10.0
	European import gas price	USD 2023/MMBtu	17.6	8.1	9.3	9.8
	United States, Henry Hub	USD 2023/MMBtu	2.6	3.0	4.0	4.0
Carbon	European ETS	USD 2023/t CO_2	92	87	100	144

Source: GECF Secretariat based on data from the GECF GGM
Note: 2023 is the base year and included in the table as the reference

Looking beyond the immediate horizon, the long-term trajectory of natural gas prices will be shaped by structural shifts in supply, demand, and the broader energy landscape. On the supply side, the natural decline of existing gas fields will necessitate a sustained wave of investments in greenfield developments. These projects, particularly in unconventional reservoirs and offshore fields, come with elevated marginal production costs, which may exert upward pressure on prices. Moreover, the inflationary pressures on key materials such as steel, copper, and equipment, compounded by rising labour costs, will further elevate upstream capital expenditures. The capital-intensive nature of the industry, coupled with sustained high-interest rates and stricter carbon pricing mechanisms, will challenge the pace of capacity expansion. Methane abatement policies and climate regulations will add additional layers of complexity, particularly as these measures intensify post-2030.

On the demand side, natural gas will continue to play a pivotal role in the global energy transition, driven by its inherent flexibility and lower carbon intensity compared to coal and oil. In developing economies, natural gas will be indispensable for displacing coal in power generation, supporting industrial growth, and meeting the energy needs of expanding urban populations. Additionally, the petrochemical sector is poised to become a major driver of long-term natural gas demand, as the need for plastics, fertilisers, and chemicals grows in tandem with global industrialisation. The versatility of natural gas in complementing intermittent renewable energy sources, such as wind and solar, will also cement its position as a cornerstone of the energy mix in the decades ahead.

An important development expected to shape the long-term natural gas markets is the increasing integration of markets and the transition toward hub-based and spot pricing mechanisms. As LNG continues to grow as a share of global gas trade, markets are converging with greater liquidity and flexibility, reducing reliance on long-term oil-indexed contracts. The rising prominence of spot and hub-based pricing mechanisms, particularly in Asia, is anticipated to exert downward pressure on natural gas prices by fostering competition and transparency. This trend is supported by the increasing ability of LNG to bridge regional market disparities, with the United States and Qatar leading efforts to expand flexible supply options. By mid-century, the price formation mechanisms in natural gas markets are likely to reflect a higher degree of alignment, driven by greater market integration and the diversification of supply sources.

The role of LNG as a critical component of global trade will further define the natural gas markets. LNG offers unparalleled flexibility, enabling suppliers to respond to regional price differentials and changing demand patterns. The expansion of liquefaction capacity, particularly in the Qatar, Russia and United States, will help stabilise global markets in the medium term, although competition for LNG between Asia and Europe is expected to sustain elevated price levels and periodic volatility.

By mid-century, natural gas prices are expected to stabilise at levels that reflect the interplay of production costs, decarbonisation policies, and evolving demand patterns. Real natural gas prices (2023 base year) are projected to rise steadily to USD 4/MMBtu at Henry Hub, USD 9.8/MMBtu in Europe, and USD 10/MMBtu in Asia by 2050. These levels will ensure the economic viability of new projects while accommodating the structural changes inherent to the energy transitions. The increasing integration of natural gas markets and the transition to transparent, competitive pricing mechanisms will likely temper long-term price increases, offering resilience and adaptability in a rapidly transitioning energy landscape.

1.3.3 Carbon prices

In 2023, carbon markets experienced significant advancements, marked by increased carbon pricing mechanisms and expanding coverage of greenhouse gas (GHG) emissions. Over 75 carbon pricing instruments, including carbon taxes and emissions trading systems (ETSs), are now operational, collectively covering approximately 24% of global GHG emissions. Revenues generated from these mechanisms reached an unprecedented USD 104 billion, underscoring their growing role in funding climate mitigation efforts. Recent entrants like Indonesia, Türkiye, and Viet Nam have further broadened the global carbon pricing landscape. Indonesia launched its carbon tax, while Viet Nam is set to operationalise its ETS in 2028, signalling the growing momentum in developing economies. Advanced markets are also refining their frameworks, with the EU expanding its ETS and piloting the Carbon Border Adjustment Mechanism (CBAM). At the same time, China enhances the scope of its national ETS by integrating total emissions and linking it to a carbon credit system.

Despite this progress, the adoption of carbon pricing remains uneven, with high-income countries leading the charge. Europe, in particular, has positioned itself as a global leader, with its ETS covering energy-intensive sectors and aviation alongside new measures like CBAM to address carbon leakage. In North America, state-level initiatives like California's ETS showcase regional leadership without a federal framework. However, other regions, such as Africa and South Asia, lag significantly due to economic and institutional constraints. This fragmented adoption highlights the disparity in capacity to implement robust carbon pricing, leaving a substantial share of global emissions outside regulatory mechanisms.

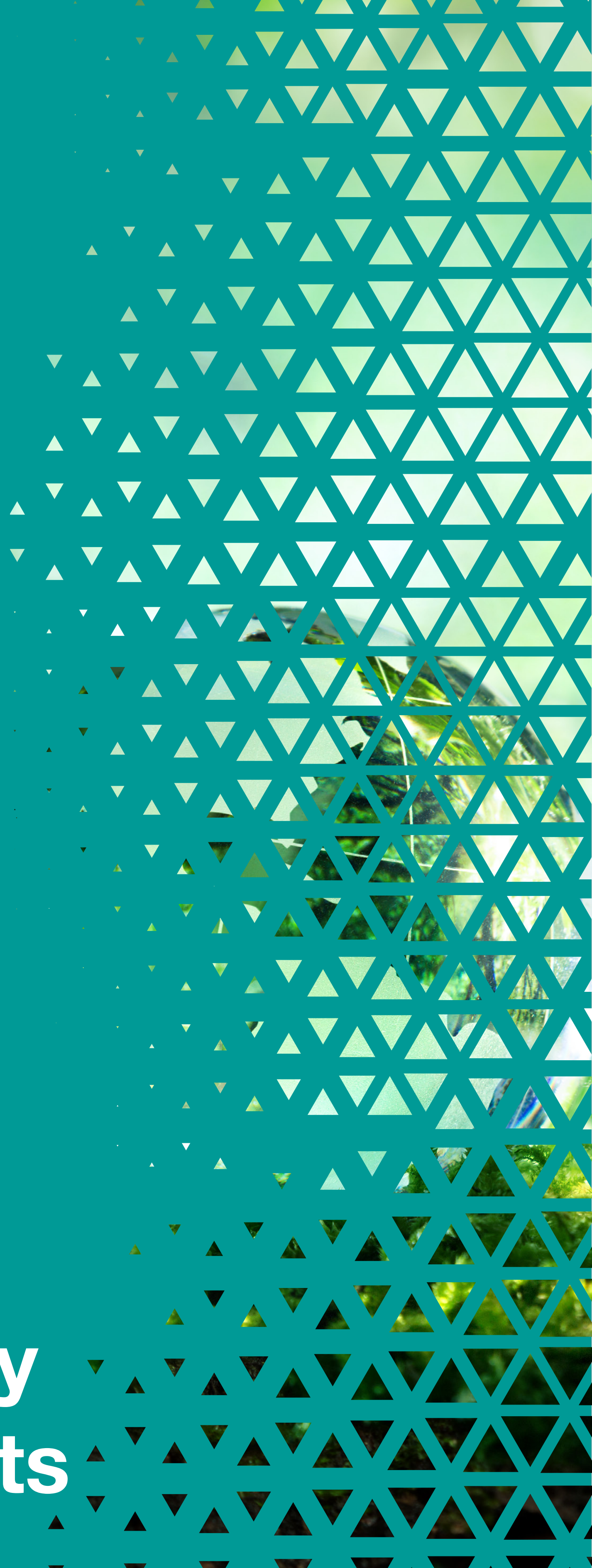
Looking ahead to mid-century, the long-term prospects of carbon pricing point toward increasing coverage and rising price levels as pivotal elements of global climate policy. As countries intensify their decarbonisation efforts to align with the Paris Agreement goals, carbon pricing instruments are expected to expand geographically and sectorally. Sectors such as agriculture, shipping, and residential heating, which remain largely outside the purview of carbon pricing, are anticipated to be integrated into future frameworks. This increased coverage will be critical for driving emissions reductions in hard-to-abate sectors while ensuring a more comprehensive approach to carbon mitigation.

As of 2023, 38 countries had developed carbon markets, accounting for 32 of these initiatives, with Europe leading the way. Projections indicate this number will rise to 54 by 2040, stabilising at that level by mid-century.

Carbon markets are expected to remain fragmented throughout the forecast period, with substantial variations in carbon pricing across regions. In the EU Emissions Trading System (ETS), the benchmark carbon price is assumed to rise steadily, reaching USD 144 per ton of CO_2 by 2050. This increase is essential for encouraging investments in advanced technologies such as Carbon Capture, Utilisation, and Storage (CCUS) and accelerating the transition to cleaner energy systems. Moreover, higher carbon prices will enhance the economic feasibility of coal-to-gas switching, a key strategy for reducing emissions in Asian economies that continue to rely heavily on coal for power generation.

Chapter 2

Energy Policy Developments



Highlights

- Despite ambitious commitments at COP28, economic and geopolitical imbalances hindered progress on climate goals in 2024. Although COP29 marked a privotal moment in climate negotiations by finalising the long-debated rules for carbon trading, it resulted in a weak agreement on climate finance and saw limited progress on mitigation measures.
- Strong drivers have solidified natural gas's role in the global energy system, ensuring its continued expansion. Energy security, rising electricity demand, and evolving industry needs are universal factors, but regional dynamics have also influenced growth.
- In advanced economies, the primary driver for natural gas policy support has been its role in balancing renewable energy and ensuring grid stability, particularly as power demand from AI-driven data centres rises.
- In regions like Latin America, droughts have increased reliance on gas for electricity, while the Middle East and North Africa depend on gas-powered desalination for water security. Sub-Saharan Africa is transitioning to natural gas for clean cooking, and stricter emissions regulations are boosting LNG demand in shipping and heavy-duty transport.
- In 2024, the rebalancing of natural gas supply and demand set the stage for growth, strengthened by favourable policies and investments in natural gas infrastructure. Countries worldwide recognised the pivotal role of natural gas in power generation and energy security, evident in their substantial investments in natural gas production, pipelines, LNG import terminals, and gas-fired power plants.
- Countries have strengthened methane emissions regulations, with the EU setting rules to reduce methane leaks by 2030, the G7 targeting a 75% reduction by 2030, and more countries joining the Global Methane Pledge for mitigation efforts.
- The global LNG markets witnessed a shift toward flexible contract terms, driven by the growing need to accommodate the intermittency of renewable energy sources and varying power demand.
- The new United States administration has prioritised domestic energy production, LNG exports, and deregulation, reversing climate rules that limited natural gas expansion. New executive orders have streamlined pipeline and LNG terminal approvals, reinforcing the United States's global natural gas supplier role.

This chapter explores the evolving interplay between global and regional energy policies, specifically focusing on the natural gas sector. Available, affordable, versatile, and flexible, natural gas is a fundamental component of the global energy mix and operates at the intersection of diverse policy objectives. These include addressing the need for reliable and affordable energy while advancing decarbonisation, reducing indoor pollution and improving urban air quality, promoting energy efficiency, and fostering low-carbon technology development.

By analysing this dynamic policy landscape, the chapter provides valuable insights into how energy policies shape the trajectory of the natural gas sector. It highlights the sector's unique ability to address energy security, environmental sustainability, and socio-economic development, showcasing its pivotal role in achieving a balanced, equitable, and low-carbon energy future.

2.1 Global developments and trends

The policy transformations of 2023 and 2024 reflect a broader global shift in energy governance, driven by the lessons learned from **the 2022 energy crisis.** That crisis, triggered by geopolitical imbalances and supply chain disruptions, **elevated energy security as a central priority for policymakers worldwide.** Governments responded with strategic initiatives to enhance domestic energy resilience, address regional supply vulnerabilities, and reduce dependence on volatile global markets. These policy responses varied across regions, reflecting differences in economic structures, resource endowments, and energy strategies. For example, Europe strengthened policy support for renewables and sought to diversify its energy import sources, while India and China placed greater emphasis on coal and renewable energy production. Meanwhile, many countries globally adopted policies to increase domestic oil and gas production.

As the tensions of the energy crisis eased, many countries began critically reviewing and re-evaluating their previous policies. At the global level, the results of the first Global Stocktake (GST) under the Paris Agreement, along with the UN SDG 2023 Progress Report published in mid-2023, highlighted the world's deviation from its intended trajectory in achieving collective goals, prompting countries to refocus on their long-term objectives. Overcoming global challenges demands closer cooperation among nations, and **despite the heightened geopolitical tensions and economic uncertainties of 2023, international collaboration has proved remarkably resilient in several key areas.**

Notably, **growing South-South cooperation emerged,** with coalitions like BRICS, the Shanghai Cooperation Organization, and the G77 plus China strengthening their influence in global energy governance. The push for equitable access to development financing and technology transfers became a key agenda item in multilateral discussions, reflecting the shifting balance of power in the international energy landscape.

Additionally, the G20 reached a landmark consensus on climate action and financing reforms for development institutions to support climate actions, reflecting a rare alignment between developed and developing countries. Regional organisations such as the African Union, ASEAN, and CELAC also intensified cooperation, developing shared strategies for energy transitions and economic sustainability.

The pinnacle of global cooperation emerged **at COP28, where countries reached an agreement on an energy package** designed to achieve long-term climate change goals. COP28 marked a pivotal moment in global climate governance, setting clear objectives for greenhouse gas mitigation. As illustrated in Figure 2.1, the agreement outlined specific measures, including the phasedown of unabated coal power and the elimination of inefficient fossil fuel subsidies. A key commitment from the conference was the collective goal to triple renewable energy capacity and double energy efficiency improvements by 2030. Additionally, for the first time, the agreement introduced a long-term transition strategy for all fossil fuels, acknowledging that this shift must be just, orderly, and equitable. It provided developing countries with greater flexibility, allowing them to transition at a pace that aligns with their economic realities while ensuring inclusivity in climate action. The outcomes of COP28 also acknowledged the role of transitional fuels alongside low-emission technologies such as CCUS and blue hydrogen in enhancing energy security and supporting the transition to a lower-carbon energy system.

The outcomes of COP28 are expected to intensify pressure on countries to elevate their mitigation targets, accelerating the adoption of low-carbon energy systems. Amidst this transition, low-carbon fuels such as natural gas are positioned to capitalise on emerging opportunities. As the most viable alternative to coal and an ideal complement to renewables, natural gas offers a crucial solution towards achieving cleaner energy systems. Therefore, the push to "triple renewable energy capacity globally" and "phase out unabated coal power" by 2030, as outlined in COP28's final document, presents favourable prospects for the gas sector. Recognising the role of transitional fuels in COP28, widely interpreted as a positive signal for natural gas, can reinforce its position in the future energy system. Furthermore, the support extended to low-emission technologies such as CCUS and blue hydrogen is expected to catalyse investments in these technologies. This, in turn, will create opportunities for their advancement within the natural gas sector, driving innovation and fostering sustainable growth for natural gas. By fostering advancements in these areas, COP28 outcomes offer a pathway for the natural gas sector to align with global climate goals while ensuring its role in supporting sustainable economic growth.

2.1.1 Key policy themes in 2024

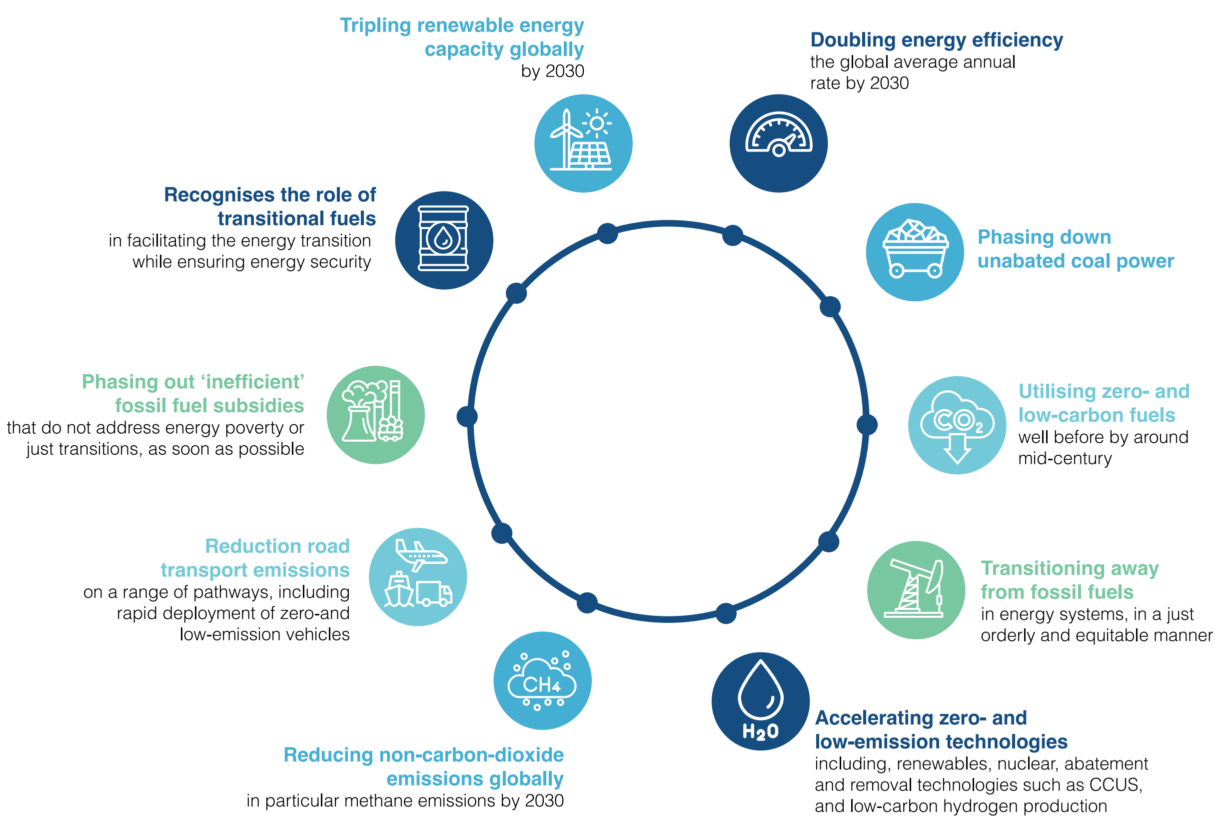
Economic and geopolitical imbalances reshaped political dynamics in 2024, forcing countries to balance immediate economic pressures with long-term global objectives. Nonetheless, the primary drivers of energy policy remained energy security, industrial competitiveness, the need for stable and affordable energy supplies and decarbonisation. Governments prioritised expanding domestic energy production, strengthening infrastructure resilience, and securing long-term supply agreements to reduce dependence on volatile imports. At the same time, technological advancements in carbon capture, battery storage, and AI-driven energy management gained prominence in policy discussions. Governments increasingly incorporated these innovations into national energy strategies, recognising their potential to accelerate decarbonisation and economic growth.

Energy security remained a top priority as governments aimed to shield their economies from price volatility and supply disruptions. This resulted in a more diversified energy strategy in which countries invested in multiple energy sources and expanded domestic energy production to maintain resilience. Natural gas continued to be positioned as a transitional and long-term fuel, with policies supporting LNG infrastructure expansion, flexible gas generation, and industrial gas usage. Meanwhile, nuclear energy gained renewed interest, with several countries committing to extending reactor lifetimes and investing in small modular reactors (SMRs) to provide stable, low-emission baseload power.

As renewables expanded, policymakers prioritised support for making the grid more adaptable. Governments directed funding toward grid modernisation, transmission networks, and interconnections to integrate more renewables. However, grid stability and supply security concerns led to greater policy support for flexible power generation. Many economies strengthened policies supporting gas-fired generation, recognising its role in balancing intermittent renewable energy, meeting peak electricity demand, and ensuring system reliability.

Figure 2.1

Ambitious global mitigation goals established at COP28



Economic and geopolitical imbalances dampened climate ambitions and the energy transitions. Despite some signs of inflation easing, the global economic landscape remained fragile in 2024. Policymakers cautioned that while recovery efforts were underway, inflation remained uncontained, and uncertainties, amplified by geopolitical instabilities and trade disruptions, left many economies vulnerable. These pressures strained energy security and affordability, forcing countries to grapple with the difficult task of addressing immediate economic needs while pursuing long-term climate goals.

This balancing act was further complicated by shifting political dynamics. In 2024, over 60 national elections took place, including the Taiwanese general election in January and the United States presidential election in November, reshaping energy and climate policies worldwide. Political discourse increasingly framed climate action as a potential burden on economic stability, particularly amid rising energy costs and energy security concerns. As a result, many governments scaled back or adjusted their environmental goals, reflecting the challenges in achieving net-zero emissions while maintaining economic competitiveness.

The most significant challenge to global energy transitions now comes from the new United States administration. The shift in the United States administration, with the Republican victory in November, cast uncertainty over the future of the Paris Agreement's goals. The new administration issued executive orders prioritising fossil fuel expansion, including fast-tracking oil and gas leasing, easing regulatory restrictions on fossil fuel production, and revising environmental standards.

These policy changes heightened concerns about the future of green energy subsidies under the Inflation Reduction Act (IRA). They raised fears of a rollback in incentives that have driven renewable energy growth and industrial decarbonisation investments.

At the same time, the urgency of climate action continued to intensify. Climate-induced extreme weather events and the United Nations' announcement that global temperatures had reached a record 1.45°C above pre-industrial levels reinforced the need for more ambitious policies. As countries prepared to submit their third iterations of Nationally Determined Contributions (NDCs 3.0), discussions turned toward balancing sustainability with energy security, affordability, and economic growth. The updated NDCs were expected to reflect enhanced commitments to climate action, but significant uncertainties clouded the path forward. At COP29, however, only a handful of countries presented their new NDCs, a stark contrast to the anticipated global participation. This limited submission stemmed from growing concerns over the future of the Paris Agreement and climate finance. As climate finance negotiations intensified in the lead-up to COP29 (See Box 2.1), tensions between developed and developing economies deepened. Disputes over funding commitments, technology access, and climate justice have stalled progress in key areas, revealing fundamental divides between wealthier countries and emerging economies. The rise of protectionist policies in some developed countries, including new trade restrictions on critical minerals and green technologies, has further complicated international cooperation, potentially undermining the pace of global energy transitions.

Box 2.1 Outcomes of COP29

The 29th session of the Conference of the Parties (COP29) to the United Nations Framework Convention on Climate Change (UNFCCC) took place in Baku, Azerbaijan, from November 11 to 22, 2024, with a primary focus on climate finance. Countries faced a critical deadline to agree on a new climate finance goal to replace the existing commitment for developed countries to provide USD 100 billion annually to developing countries by 2025. As expected, financial discussions revealed deep divisions among parties. Beyond the new climate finance goal, COP29 addressed other key areas, including advancing last year's mitigation package, finalising Article 6 rules, and progressing on adaptation targets. Below are the primary outcomes of COP29.

Climate finance architecture

Nine years after the commitment made at COP21 in Paris, governments convening at COP29 in Baku have finally established a new collective quantified climate finance goal (NCQG) for the post-2025 period.

Developing countries, unified in their demand for USD 1.3 trillion annually in climate finance, stressed that most funding should come from public sources and be delivered on a "grant-equivalent" basis. However, negotiators ultimately settled on a looser call, urging all actors in the global community to work to scale up climate finance to developing countries from a wide range of sources, including private investment, to at least USD 1.3 trillion per year by 2035.

In addition to the USD 1.3 trillion goal, developed countries agreed to take the lead in mobilising at least USD 300 billion annually by 2035. This target mirrors the USD 100 billion per year goal set for 2020-2025, encompassing public funds, private finance mobilised by the public sector, and alternative sources. However, unlike the earlier goal, which was entirely the responsibility of developed countries, the final agreement only asks developed countries to "take the lead," leaving the goal open for contributions from other parties. The agreement also permits developing countries to include their financial contributions toward the goal voluntarily. Additionally, it allows the entirety of climate finance provided by multilateral development banks (MDBs) to developing countries to be counted rather than limiting it to the portion explicitly attributed to developed countries.

While no overarching goal for public finance provision was established, governments committed to efforts aimed at tripling the annual outflows from UNFCCC climate funds by 2030, compared to 2022 levels. These funds include the Global Environment Facility, the Green Climate Fund, the Fund for Responding to Loss and Damage, the Adaptation Fund, the Least Developed Countries Fund, and the Special Climate Change Fund. In 2022, outflows from these funds amounted to USD 1.74 billion, necessitating an increase to at least USD 5.2 billion per year by 2030 to meet the new target.

Mitigation

Another major point of discussion in Baku was how to take forward COP28's landmark mitigation package, which was concluded under the first "global stocktake" outcomes. Efforts to build upon the mitigation package stalled, and parties disagreed on how to take forward the so-called "UAE consensus" on the mitigation package, with talks being pushed to next year. Proposals to convene an annual dedicated space on energy transitions, agree on new goals for storage and grids, and produce annual progress reports on the transition away from fossil fuels were rejected. Countries did not agree on a call to phase out fossil fuel subsidies, and a draft text calling governments to reduce fossil fuel infrastructure investments was rejected. However, countries did manage to find agreement on the remaining sections of Article 6 on carbon markets, meaning all elements of the Paris Agreement have been finalised nearly 10 years after it was signed.

Countries also reached a significant agreement to establish a four-year work plan (2026–2030) to address the effects of carbon-cutting policies, specifically focusing on their cross-border impacts. This new framework provides a formal platform within UN climate negotiations to evaluate and discuss trade-related climate measures, including mechanisms like the EU's Carbon Border Adjustment Mechanism (CBAM). The CBAM has sparked considerable debate as it imposes carbon costs on imports based on their carbon emissions, which some argue could lead to trade tensions or be seen as protectionism.

Adaptation

At the recently concluded climate talks in Baku, discussions on adaptation yielded limited substantive outcomes due to persistent divergences among parties, with further work deferred to next year. The primary focus was the Global Goal on Adaptation (GGA), particularly on developing indicators to measure progress toward targets agreed upon last year. A key takeaway from the adopted Baku GGA decision is the inclusion of the Means of Implementation (MOI) language despite strong opposition from several developed countries. Parties also agreed on a framework of up to 100 globally applicable indicators, allowing countries to select from this menu based on their national circumstances while ensuring progress toward achieving the agreed targets can be effectively measured.

Loss and damage

Loss and Damage discussions remained a focal point at COP29, building on last year's establishment of a dedicated fund at COP28. This year's most contentious issue was whether loss and damage should be included under the new climate finance goal (NCQG). Ultimately, the parties decided against its inclusion. While the final NCQG text mentions loss and damage three times, it only acknowledges existing gaps in addressing the issue. It emphasises the need for public, grant-based finance, leaving further negotiations for the future.

Trade barriers imposed by developed countries on China's affordable green technologies could equalise the energy transition pace between the Global North and South. China's aggressive market penetration with affordable green technologies, such as electric vehicles (EVs), solar panels, and batteries, faces resistance from developed nations and some emerging markets. Countries like the United States, the EU, South Korea, and Japan have launched anti-dumping investigations and are considering imposing tariffs on Chinese imports. While these measures may increase the costs of clean technologies and potentially slow energy transitions in these regions, the resulting surplus of these products will likely accelerate adoption in other parts of the world, particularly in developing countries, as they become more accessible and affordable.

Decarbonisation remained a dominant policy theme, but policy shifts became more nuanced. While governments continued to expand wind, solar, and energy storage investments, they also acknowledged the limits of intermittent renewables. As a result, green hydrogen policies gained momentum, particularly in the EU, Japan, and Australia, where governments strengthened incentives for electrolyser deployment and hydrogen infrastructure development. Additionally, CCUS initiatives were expanded, with financial support increasing to enhance the commercial viability of carbon capture in fossil fuel-dependent industries. More economies also introduced higher efficiency standards and electrification policies to decouple energy demand growth from emissions.

The AI boom is poised to increase global energy demand. The rapid proliferation of AI applications, including energy-intensive data centres, challenges policymakers to ensure sustainable and reliable power supplies. The government encourages tech companies in the United States to invest in climate-friendly power generation to address these rising demands. Initiatives under consideration include utilising small modular reactors (SMRs) for nuclear energy and exploring clean alternatives such as geothermal energy. However, despite policy support, no new nuclear plants are currently under development, highlighting the gap between ambitions and execution.

Other regions are responding differently to the energy demands posed by AI. After lifting its moratorium on new data centres in 2023, Singapore is proceeding cautiously to protect its energy grid, while Ireland has imposed restrictions on new data centre connections until 2028. Japan projects a 35% to 50% increase in electricity output by 2050 to meet AI-related demands and has prioritised a decarbonisation strategy focused on renewables and nuclear power. However, the intermittent nature of renewables, the high costs and public scepticism surrounding nuclear energy remain significant challenges. While advancements in battery storage technologies offer some promise, they currently lack the scale required for grid reliability.

These constraints highlight the role of natural gas as an optimal fuel in addressing the energy demands associated with AI. Natural gas offers a stable, reliable, and comparatively cleaner source of energy that can complement renewable sources and provide continuous power to data centres. Unlike renewables, which face intermittency issues, or nuclear energy, which requires long lead times and substantial investment, natural gas can be deployed quickly and flexibly to meet immediate energy needs.

The vital role of natural gas in addressing the energy trilemma was widely recognised in international forums. As countries navigated an increasingly complex landscape shaped by climate change, the transformative rise of AI, and escalating geopolitical tensions, they engaged in dialogue and coordination through platforms such as the G7, G20, and BRICS, as well as initiatives like the United Nations Pact for the Future. In energy, climate, and sustainability discussions, natural gas remained a key focus, reflecting its significance in global energy strategies.

At the G7 Summit, world leaders reaffirmed their commitment to phasing out unabated coal power by the early 2030s, submitting new climate targets before COP29, and cutting methane emissions from fossil fuels by 75% by 2030. However, discussions acknowledged the short-term necessity of public investments in natural gas to ensure energy stability during the transition. In contrast, the BRICS summit 2024 emphasised energy access and just energy transitions. BRICS leaders called for a balanced and pragmatic approach, opposing unilateral climate measures that could disadvantage emerging economies. Their declaration reaffirmed the importance of natural gas in supporting flexible, resilient energy systems while highlighting the need for affordable and technology-neutral solutions to emissions reductions. Similarly, the Pact for the Future, adopted at the United Nations Summit for the Future in 2024, reinforced commitments to the 2030 Agenda and the SDGs. The pact reaffirmed COP28 mitigation targets and recognised the role of transitional fuels in facilitating the energy transition and ensuring energy security.

The evolving regulatory landscape in 2023 and 2024 underscores the critical interplay between national policies, international commitments, and technological advancements. As governments continue to refine their energy strategies, natural gas will likely play a central role in facilitating the transition toward cleaner energy sources while ensuring economic and energy security. The commitments made at COP28, combined with ongoing market and policy shifts, will shape the trajectory of the natural gas industry, reinforcing its position as both a transitional and a destination fuel in the global energy system.

2.1.2 Policy support for natural gas

In 2023, the market began stabilising as the global gas supply chain adapted to new realities. European countries, significantly impacted by disruptions, diversified their energy sources by increasing LNG imports from alternative suppliers and enhancing their infrastructure to handle higher LNG volumes. Meanwhile, major exporters such as the United States, Qatar, and Australia ramped up production to meet growing demand, particularly in Asia and Europe, resulting in a more balanced supply landscape. This section discusses the major drivers and policy trends shaping the gas sector.

Strong drivers secured natural gas's key role in the global energy system. Strong drivers have solidified natural gas's role in the global energy system, ensuring its continued expansion. While energy security, rising electricity demand, and evolving industry needs are common factors, regional dynamics have also shaped its growth.

In advanced economies, natural gas plays a critical role in balancing intermittent renewable energy and ensuring grid stability amid the rapid electrification of industries. Even countries with ambitious renewable energy targets have acknowledged the essential role of natural gas in ensuring backup and grid stability. For example, Germany secured EU approval for financial support to gas-powered plants to stabilise the grid during low renewable energy output periods. In 2024, the German government announced tenders for 10 GW of new gas-fired power capacity, underscoring the critical need for natural gas alongside renewables. Similarly, the United Kingdom launched plans to replace ageing plants with

5 GW of new or refurbished gas capacity, emphasising its importance in supporting growing renewable energy integration.

In the United States and China, surging power demand from AI-driven data centres and expanding digital infrastructure have reinforced the need for reliable gas-fired generation. To address this surge, United States energy policies are facilitating the development of natural gas-fired power plants with integrated CCUS to supply reliable electricity for data centres. In collaboration with technology firms, ExxonMobil is advancing projects that aim to deploy CCUS-equipped gas plants in key data centre hubs. The Inflation Reduction Act has also incentivised low-carbon gas-fired generation by extending tax credits for CCUS technology, making natural gas a viable option to meet AI-driven electricity demand while maintaining emissions reduction targets. In China, the government is expanding its LNG import capacity and accelerating pipeline network development to ensure a steady gas supply for power plants supporting the growing digital economy. The country is constructing 51.5 GW of new gas-fired power plants and has revised its Gas Use Regulation to lift restrictions on gas plants in coal-rich areas. This regulatory change prioritises "economic" gas-fired peak-shaving plants to balance intermittent renewable energy sources. Provinces such as Guangdong and Jiangsu, major data centre clusters, have introduced policies favouring natural gas over coal to mitigate air pollution while ensuring grid stability.

The rising reliance on air conditioning due to extreme weather conditions has driven up electricity demand, reinforcing the role of natural gas as a backup for intermittent renewables. In India, peak summer electricity demand has surpassed 240 GW, exacerbated by prolonged heatwaves that have increased cooling needs in urban centres. The government has ramped up gas-fired peak load plant installations to provide flexible generation capacity. Policies under the National Electricity Plan have allocated financial incentives for gas-fired plants to operate as grid stabilisers, supporting renewables during peak demand periods. Similarly, in Europe and North America, harsh winter conditions have intensified the need for gas-fired heating systems, particularly as the electrification of heating accelerates. Countries like Germany and the United Kingdom have integrated demand-response mechanisms with gas plants to manage seasonal spikes in electricity consumption. The United States has introduced new rules to ensure gas availability for power generation during winter storms, recognising the fuel's critical role in preventing grid failures similar to those experienced in Texas in 2021.

Latin America has witnessed increased reliance on natural gas for electricity generation due to the impacts of recurrent droughts on hydropower output. In Brazil, hydroelectric reservoirs have been operating at critically low levels, prompting the government to expand LNG import infrastructure to compensate for lost hydro capacity. The National Energy Plan 2050 has incorporated new regulations to streamline LNG terminal permitting and increase gas storage facilities to enhance energy security. Colombia has also faced severe water shortages, forcing grid operators to ramp up gas-fired power plants to prevent blackouts. The Colombian government has enacted fiscal incentives for new gas-fired projects under the 2024 Energy Transition Law to bolster energy supply diversification while integrating more renewables into the grid. In leveraging its Vaca Muerta shale gas reserves, Argentina has prioritised the expansion of natural gas pipelines to increase domestic supply and reduce reliance on imported LNG, ensuring long-term electricity stability.

The Middle East and North Africa region has seen soaring electricity demand for water desalination, reinforcing the role of natural gas in power generation. In Saudi Arabia and the UAE, desalination accounts for up to 10–15% of total electricity consumption, prompting both countries to expand gas-fired power generation. Saudi Arabia's Vision 2030 includes gas-to-power projects with CCS to lower emissions, while the UAE's Energy Strategy 2050 prioritises hybrid gas-renewable desalination plants, integrating gas turbines with solar thermal to enhance efficiency and reduce carbon intensity. In North Africa, Algeria has increased gas-fired power capacity to sustain desalination infrastructure, while Morocco prioritises renewable-powered desalination but maintains gas as a backup source. Algeria has also expanded LNG regasification terminals to secure long-term natural gas imports.

In Sub-Saharan Africa, transitioning from traditional biomass to LPG and natural gas for clean cooking has become a policy priority, driven by health, environmental, and energy security concerns. Nearly 900 million people in the region lack access to clean cooking fuels, leading to severe indoor air pollution and deforestation. Nigeria and Ghana have launched large-scale LPG distribution programs, offering subsidies and financial incentives to accelerate household adoption. The African Development Bank (AfDB) has partnered with several governments to enhance LPG accessibility through financing mechanisms, subsidies, and policy support. While AfDB's initiatives focus on expanding LPG adoption and affordability, direct investment in import terminals and storage infrastructure is primarily driven by public-private partnerships and national energy programs. Kenya has introduced regulatory frameworks to attract private sector investment in LPG distribution, reducing costs and improving accessibility. In South Africa, LPG adoption is being expanded in informal settlements to replace biomass, supporting government efforts to reduce emissions and deforestation.

The transportation sector has emerged as a significant driver of LNG demand, particularly for heavy-duty trucks, marine vessels, and bunker fuel. The International Maritime Organisation (IMO) 2024 emissions regulations have accelerated the adoption of LNG as a low-sulphur fuel alternative for global shipping fleets. Major shipping companies, including Maersk and CMA CGM, have expanded LNG bunkering operations, with new fuelling hubs established in Singapore, Rotterdam, and Houston. The European Union's Fit for 55 policy has reinforced LNG adoption in freight transport by mandating the construction of LNG refuelling stations along major transport corridors. China has implemented LNG truck incentives, with policies supporting expanding LNG refuelling infrastructure to facilitate the transition of long-haul transport fleets. India's National Gas Mobility Policy aims to replace 30% of diesel trucks with LNG-fuelled alternatives by 2030, significantly cutting emissions in freight transportation.

As the energy transitions evolve, natural gas remains a pillar of energy security and industrial competitiveness, with governments worldwide enacting policies to expand gas infrastructure, diversify supply sources, and ensure long-term investment stability. Despite regulatory shifts and global economic uncertainties, natural gas continues to play a central role in balancing sustainability, affordability, and security in energy transitions.

The foundations for renewed growth in natural gas markets were firmly established. In 2024, lower prices and improved supply fundamentals fuelled a recovery, with natural gas becoming more affordable across various sectors. This rebalancing of supply and demand set the stage for a growth phase supported by favourable policies and investments in natural gas infrastructure. Countries worldwide increasingly recognised natural gas's pivotal role in power generation and energy security, reflected in their substantial investments in pipelines, LNG import terminals, and gas-fired power plants.

Globally, the expansion of natural gas pipelines is reshaping energy connectivity across regions. North America, East Asia, South Asia, Sub-Saharan Africa, Eastern Europe, and Latin America are all actively developing or planning gas pipeline projects to meet rising energy demand. In 2024, Ukraine, Moldova, and Slovakia unveiled plans for a natural gas corridor connecting Greece to Northern Europe. Nigeria and Equatorial Guinea signed an agreement to build a new pipeline in Africa. Meanwhile, Argentina is addressing domestic bottlenecks to improve gas distribution and begin exports, while Brazil has intensified efforts to identify new pipeline routes for gas imports from Argentina. On a larger scale, Russia and China are advancing negotiations for the Power of Siberia-2 gas pipeline, which has become increasingly important. Russia pivoted toward China as a key customer, signing a memorandum with Iran to supply gas pipelines.

The expansion of LNG infrastructure complements pipeline developments, with new import terminals being built across multiple regions. Asia, already the largest LNG importer, is leading investments in new LNG regasification capacity, spearheaded by China and India. Other countries, including Germany, Taiwan, Brazil, Italy, the Philippines, and Viet Nam, are also making significant investments in LNG import infrastructure. As new LNG terminals come online, alongside expanding pipeline networks and the development of gas-fired power plants, they will further support the growing demand for natural gas.

Countries intensified their policy support for natural gas production. In 2024, numerous countries announced plans to enhance gas production, signalling a renewed commitment to stabilising energy supplies and fostering economic growth. Some countries, like the Netherlands and New Zealand, reversed previous restrictions to boost their natural gas output. The Netherlands, for example, aimed to increase production in the North Sea while pledging not to impose additional national limitations on extraction. Similarly, New Zealand announced plans to lift its ban on offshore exploration, recognising the need to attract investment in its oil and gas sector.

Beyond lifting restrictions, many countries introduced incentives and regulatory adjustments to stimulate natural gas production. Indonesia, for instance, unveiled measures to revitalise its oil and gas sector, including reactivating idle wells and reviewing its fiscal policies to attract investment in unconventional resources. Suriname offered a ten-year tax-free period from the start of production to encourage exploration of a significant gas discovery off its coast. These strategies reflect a broader trend of governments actively supporting gas development through targeted policies and economic incentives.

Meanwhile, several countries called oil and gas companies to boost exploration and investment. Norway and China urged firms to increase exploration efforts. At the same time, Australia announced its Future Gas Strategy, which outlines plans to enhance natural gas development and maintain exploration commitments in alignment with its net-zero goals. Australia emphasised that this strategy aims to support both its domestic energy needs and those of its export partners, highlighting the strategic role of natural gas in global energy transitions.

Exploration activities have expanded globally, with exploratory drilling projects emerging across various countries, including Egypt, Iraq, Malaysia, Bangladesh, Brazil, China, Indonesia, Namibia, Pakistan, South Korea, Suriname, and Uganda. These initiatives underscore a worldwide trend toward discovering and tapping into new gas reserves to meet growing energy demands and mitigate potential supply disruptions.

In addition to exploration efforts, several countries outlined broader ambitions to develop their natural gas resources further. Countries such as Nigeria, Qatar, Cyprus, Guyana, Ivory Coast, Mexico, Saudi Arabia, and South Africa expressed commitments to reinforce production. Each of these countries aims to leverage its resources for domestic consumption and export, underscoring the dual role of natural gas in addressing local energy needs and providing much-needed export revenues.

The growing integration of renewables and the variability in power demand drive a notable shift toward flexible LNG contracts. In 2024, the LNG market saw increased buyer demand for shorter-term and more adaptable agreements to manage fluctuating energy needs. This trend is supported by the intermittency of renewable energy sources and changing climate conditions, making energy consumption patterns increasingly unpredictable. For instance, Japan's nuclear restarts and expanded renewable capacity reduce LNG demand, necessitating contracts that accommodate such variability. Similarly, China requires flexible arrangements to maintain balance in its energy mix. While some producers are beginning to offer such terms, long-term commitments remain essential for financing new projects.

Countries are increasingly prioritising regulations on methane emissions. In recent years, global efforts to address methane emissions have intensified. The EU has adopted landmark rules, effective from 2030, requiring oil and gas suppliers to reduce methane leaks. In the United States, environmental reforms targeting drilling on public lands include increased fees for oil and gas companies, mandatory leak detection and repair plans, and penalties for flaring or venting methane. However, the new United States administration is likely to rescind these measures.

At the global level, the G7 countries have collectively committed to reducing methane emissions from fossil fuel operations by 75% by 2030. At COP28, methane emissions were explicitly addressed in the final decision, urging significant reductions in non-carbon dioxide emissions by the decade's end. This aligns with commitments from 52 prominent oil and gas companies that signed the Oil and Gas Decarbonisation Charter, pledging to eliminate routine flaring and achieve near-zero methane emissions by 2030. The coalition includes national oil companies, independent producers, and major international firms, signalling a broad commitment across the industry.

In parallel, more countries have joined the Global Methane Pledge, including Angola, Kazakhstan, Kenya, Romania, Turkmenistan, and Azerbaijan, bringing the total to 156 signatories. The World Bank has also launched the Global Flaring and Methane Reduction (GFMR) Partnership, supported by an initial fund of USD 250 million for detection and cleanup programs in major methane-emitting developing countries. This evolving regulatory landscape reflects a growing consensus on curbing methane emissions in the natural gas sector. The industry can be crucial in mitigating climate change while ensuring energy security by tackling these emissions.

2.2 Policy drivers and developments in the key markets

To understand the evolving dynamics of global energy policies, it is essential to examine the key markets driving the transformation of this sector. This analysis focuses on four pivotal players in the global energy landscape: China, India, the United States and the European Union. Each of these markets holds a distinctive position and plays a critical role in shaping the future of energy. By delving into these regions, we aim to identify recent trends in general energy policies while offering a closer look at natural gas-specific strategies, including notable regulations and policy developments introduced in 2023 and 2024. **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.**

2.2.1 China

China's natural gas policy landscape reflects a delicate balancing act. On the one hand, the government aims to expand natural gas usage to diversify the energy mix, reduce reliance on coal, address urban air pollution, and meet climate targets. On the other hand, these ambitions are constrained by growing import dependence, global price volatility, and a rapidly evolving energy market. While China has accelerated its clean energy transition in 2024–2025, installing a record 357 GW of wind and solar and surpassing its 1,200 GW target ahead of schedule, natural gas remains crucial for stabilising the energy system. The Energy Law, effective January 1, 2025, provides a legal framework for energy governance, prioritising renewables while ensuring the continued role of natural gas. China is boosting LNG imports from Russia, Qatar, and the United States as part of its supply security strategy while investing in domestic gas fields and LNG terminals to reinforce natural gas's role in its energy mix.

China's approach to natural gas has evolved through successive Five-Year Plans. The 13th Five-Year Plan (2016–2020) positioned natural gas as a key solution for urban air quality and cleaner heating fuel, targeting coal-to-gas conversions for households, commercial users, and industries. However, domestic production growth fell short of expectations, particularly in the shale gas sector, while demand surged, increasing reliance on LNG imports. This over-reliance led to a more cautious approach in the 14th Five-Year Plan (2021–2025), which emphasised gas storage capacity expansion,

Table 2.1

Primary government aims in the energy sector

	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 Utilising zero- and low-carbon fuels, well before by around mid-century	Aiming at energy security and decarbonisation by Boosting energy efficiency Increasing domestic production Reducing dependence on imports Transitioning towards cleaner energy alternatives
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 182 bcm per year by 2030 Infrastructure development for natural gas with a USD 67 billion investment plan over the next five to six years to enhance natural gas availability, boost imports (regasification capacity to 70 Mtpa by 2030 and 100 Mtpa 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 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 by 45% by 2030 compared to 2005 levels Achieving carbon neutrality by 2070 Establishing a carbon market
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

	China	Europe	United States
	All-of-the-above energy strategy Prioritising renewables and coal with trading mechanisms to cut energy use and CO_2 emissions and tax credits to support low-carbon development Targetting 84% domestic self-sufficiency by 2025 Deriving 25% of energy from non-fossil sources by 2030	Enhancing energy transition efforts to achieve dual goals: Diversifying its energy sources and advancing emissions reduction initiatives.	Direct significant funding to advance clean energy Catalysing growth in decarbonisation technologies
	230 bcm of domestic gas production by 2025 Aiming for gas storage capacity of 55-60 bcm by 2025 Encouraging new gas-fired peak-shaving facilities Expand natural gas imports through pipelines and enhance domestic pipeline infrastructure	Expanding LNG imports from multiple sources LNG to provide +50 bcma of added gas supply Pipeline gas demand of at least +10 bcma EUR 10 billion investment in LNG infrastructure by 2030 to diversify suppliers	Expansion of LNG exports facilities Streamlining of project permitting process Allocation of funding for CCUS Implementation of levies on methane emissions
	Maximising coal's role as the primary energy source, boosting domestic coal supplies (4.2 billion tonnes of raw coal production by 2025) and investing in coal power Increasing domestic oil and gas production while limiting energy imports	Strengthened environmental restrictions on coal-based activities Phasing out coal by 2040	Allocation of funding for CCUS
	Aiming for a new electricity system with increased renewables and storage Accelerating renewable energy adoption Promoting green consumption	Targeting 42.5% by 2030 CO_2-free electricity by 2040, with over 90% of power generated from renewables and nuclear energy	Backed by production and investment tax credits Establishment of technology-neutral credits Aim for 100% carbon-free electricity by 2035 30 GW offshore wind capacity target by 2030
	10% of power generation by 2035 and 18% by 2060, with 400 GW capacity	Include nuclear power plants as eligible investments for green labeling	Financial assistance up to USD 15/MWh Implementation of state zero-emission credit programs
	100-200 kt of hydrogen 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 MtH_2 by 2040, and 50 MtH_2 by 2050
	Dual carbon goals: Reaching peak carbon emissions by 2030 and achieving carbon neutrality by 2060 18% reduction in CO_2 intensity by 2025 Expanding the emissions trading scheme and strengthening penalties for non-compliance in energy-intensive sectors.	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 Implementation of Methane Emissions Reduction Regulation, CBAM, and EU ETS revision Capturing 280 million tons of CO_2 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	GHG emissions reduction by 26%-28% compared to 2005 by 2025 and by 40% by 2030 Mandating CCUS or low-emission hydrogen adopting for coal plants and new gas generators by 2032 A methane fee for major oil and gas producers
	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

targeting an increase from 26 bcm in 2020 to 55–60 bcm by 2025. Following the 2022 global energy crisis, policymakers adjusted coal-to-gas conversion policies to focus on supply stability rather than rapid expansion. The 2023 government work report reinforced this shift, stating the need to "strictly control the expansion of projects replacing coal with natural gas." However, falling international gas prices and a robust industrial recovery in 2023 prompted renewed growth in gas consumption, particularly in power generation, to address renewable intermittency.

As the 14th Five-Year Plan nears its conclusion, policymakers are recalibrating strategies to align natural gas consumption with emissions reduction targets. A key step in this process was the 2024 revision of the Natural Gas Utilization Policy, refining the classification of gas usage. The original framework, introduced in 2007 and updated in 2012, prioritised residential cooking and heating, natural gas vehicles (NGVs), and public facilities while permitting industrial applications such as coal-to-gas conversion. Gas-fired power plants, particularly in coal-producing areas, were largely restricted. The 2024 update introduced notable changes, including prioritising "economic" gas-fired peak-shaving power plants to support renewable energy integration. Additionally, the prohibition on gas-fired power plants in coal-rich regions was lifted, reflecting a shift in energy priorities. At the same time, restrictions were introduced on hydrogen production from gas, except in refineries and chemical plants—and ammonia production in favour of green hydrogen initiatives.

The government's 2024 policy notice further emphasised expanding gas-fired peak-shaving plants, retrofitting coal plants, and deploying dispatchable renewable energy to enhance grid flexibility. These developments indicate an increasing role for natural gas in balancing China's power grid despite an overall prioritisation of renewables. Industrial demand for natural gas is also rising, driven by the need for cleaner fuels in sectors like metal smelting, glass manufacturing, and chemicals. These industries are crucial to China's batteries, electric vehicles (EVs), and solar panel supply chains, ensuring that natural gas remains an important industrial energy source.

An emerging focus in China's natural gas strategy is the expansion of LNG-powered heavy-duty trucks, which play a growing role in decarbonising freight transport. In response to tightening emissions regulations and fuel efficiency standards, the government has actively promoted LNG as an alternative to diesel for logistics and long-haul trucking. By 2023, China had the world's largest fleet of natural gas vehicles, exceeding 1.6 million, including over 500,000 LNG-powered heavy-duty trucks. The 15th Five-Year Plan (2026–2030) is expected to further accelerate LNG trucking adoption by expanding refuelling infrastructure, introducing financial incentives for fleet upgrades, and enforcing stricter emissions targets in the transport sector. This policy direction aligns with China's broader energy strategy to reduce oil imports and leverage its growing LNG supply. Additionally, research and pilot projects on hybrid LNG-hydrogen trucks are underway, exploring their potential to cut emissions in freight transport further, though widespread deployment remains in the early stages.

China's evolving natural gas policy framework underscores its role as a transitional fuel in its energy mix. While residential use remains prioritised, natural gas applications in power generation, industrial processes, and transportation are expanding. As China works toward its carbon peaking goal by 2030 and net-zero emissions by 2060, natural gas will remain essential in balancing the energy transition. The development of China's carbon market, currently limited to the power sector, is set to expand to emissions-intensive industries such as steel, non-ferrous metals, and building materials, creating incentives for cleaner energy use.

Despite these advancements, challenges remain. Volatile gas prices limited domestic production, and the rapid growth of renewable energy poses ongoing hurdles. Successfully navigating these complexities will require a balanced approach between domestic policy, global market trends, and long-term energy transition goals. Expanding LNG trucking, increased gas storage capacity, and strategic LNG imports will be key to maintaining supply security and positioning natural gas as a bridge fuel in China's decarbonisation pathway.

2.2.2 India

The twin objectives of decarbonisation and energy security guide India's energy policy. As one of the world's largest and fastest-growing economies, India faces the challenge of managing rising energy demand while ensuring sustainability. While coal remains the dominant part of the energy mix, the government has set ambitious goals, including achieving 500 GW of renewable energy capacity by 2030 and sourcing approximately 50% of installed energy capacity from non-fossil fuels. The country also plans to triple its nuclear power capacity by 2032, with 7,000 MW of new capacity under construction. In parallel, India is promoting natural gas as an enabling fuel, introducing key policies in 2024 and 2025 that expand renewable capacity while increasing natural gas use. Initiatives such as the Pradhan Mantri Surya Ghar Muft Bijli Yojana, targeting 10 million solar rooftops, and the addition of 35 GW of solar and wind capacity reflect a commitment to clean energy. At the same time, the expansion of LNG regasification terminals and pipeline networks is a critical part of efforts to increase natural gas's share in the energy mix from the current 6.3% to 15% by 2030.

India has undertaken significant market reforms to accelerate the transition to natural gas. Since setting its target in 2016, the government has introduced measures such as market liberalisation for select upstream producers, formula-based gas pricing, and enhanced investments under the Hydrocarbon Exploration and Licensing Policy and Open Acreage Licensing Policy. These policies have improved investor confidence, facilitated greater private sector participation, and laid the foundation for long-term gas market expansion. In 2024, the government reinforced its commitment to natural gas infrastructure by announcing a USD 67 billion investment plan over the next five to six years. This funding aims to increase domestic gas availability, enhance LNG imports, expand pipeline connectivity, and strengthen the city gas distribution network. By early 2024, the city gas network covered 98% of the population, and additional bids were announced to extend gas access to remote and underdeveloped regions. The government has also committed to providing 7.5 million free LPG connections to women-led households over the next three years, reinforcing its focus on energy equity.

A key factor shaping India's future natural gas demand is the rising electricity consumption for air conditioning, driven by urbanisation, rising incomes, and extreme heat waves. The heat waves of 2024 have intensified the strain on the electricity grid, significantly increasing the demand for cooling. Government projections indicate that India's cooling-related electricity demand will triple by 2030, requiring urgent measures to ensure grid stability. Natural gas-fired power plants are increasingly being considered as a flexible and reliable backup to intermittent renewable energy sources, particularly during peak summer months when power shortages are most acute. In April 2024, the government directed gas-fired power plants to ramp up generation to mitigate electricity shortfalls caused by extreme heat. This policy shift has led to increased LNG imports and additional gas storage capacity development to maintain supply security. In response to this emerging challenge, India has introduced energy efficiency policies, including the Energy Conservation Building Code, which mandates efficiency standards for cooling systems to reduce stress on the grid. The government is also providing incentives for gas-fired peaking load plants, which can operate flexibly to stabilise electricity supply during periods of high demand. Expanding LNG regasification capacity is another priority, with new terminals under development to accommodate the rising need for natural gas in the power sector.

India's natural gas strategy also expands beyond power generation and industrial applications into transportation. The government is accelerating the adoption of LNG in freight transport by developing more than 1,000 LNG fuelling stations along national highways. This initiative is expected to facilitate the transition of a third of long-haul trucking fleets from diesel to LNG over the next five to seven years. The government has allocated 0.5 million cubic meters of domestic gas daily for this effort, sufficient to power approximately 50,000 LNG trucks in the next two to three years. Financial incentives have been introduced to encourage fleet owners to transition from diesel to LNG, and city gas networks are being expanded to include dedicated refuelling corridors. While compressed natural gas (CNG) remains a key fuel for urban transport, LNG is emerging as the preferred option for long-haul freight due to its superior fuel efficiency and extended driving range. These efforts align with India's broader energy security strategy, which seeks to reduce dependence on imported oil while leveraging LNG supply contracts.

Natural gas is also playing a larger role in industrial decarbonisation, gradually replacing naphtha, fuel oil, and diesel in sectors such as steel, cement, chemicals, and fertilisers. India is advancing its carbon market as part of its broader environmental commitments. It is focused on the power sector but is set to expand to emissions-intensive industries such as steel, non-ferrous metals, and building materials. This expansion is expected to incentivise cleaner energy usage and reinforce the role of natural gas as an enabling fuel. Despite these advancements, challenges remain, particularly in managing global LNG price volatility and ensuring that domestic gas production keeps pace with demand. Renewable energy deployment is accelerating, and although natural gas remains a key fuel, its long-term role in India's energy system will depend on sustained price competitiveness and strategic investments in LNG infrastructure.

India's energy strategy reflects a carefully balanced approach to decarbonisation, energy security, and economic growth. While renewables are at the core of the country's energy transition, natural gas remains essential in stabilising the grid, supporting industrial processes, and fuelling transportation. The increased electricity demand for air conditioning, driven by intensifying heat waves, has reinforced the importance of gas-fired power generation and LNG imports as part of India's evolving energy landscape. By expanding LNG infrastructure, strengthening market reforms, and promoting industrial and transport applications, India is positioning natural gas as a crucial transition fuel while maintaining its commitment to long-term clean energy goals.

2.2.3 The United States

The United States' energy transition has gained momentum in recent years, driven by landmark legislation such as the Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA). These initiatives aim to propel the country toward its climate goals by incentivising clean energy investments. The IRA, in particular, has had a transformative impact on the United States' clean energy sector. Originally estimated to cost USD 369 billion over ten years, demand for clean energy projects has pushed projections to as much as USD 1 trillion, reflecting the surge in investments backed by tax credits and subsidies.

Utility-scale solar installations are expected to lead the growth in United States power generation through 2025, driving demand for battery storage to optimise renewable energy assets. However, the country is likely to fall short of its 30 GW offshore wind capacity target by 2030, with projections suggesting that only about 14 GW will be operational. Factors such as supply chain constraints, permitting delays, and rising project costs have slowed progress. The challenge is further compounded by a new administration that does not prioritise offshore wind, making it even less likely that the original target will be met.

At the same time, the government is strengthening nuclear energy by expanding tax credits for nuclear technologies and addressing sector security costs. Efforts include reviving retired nuclear plants, adding reactors to existing sites, and streamlining the permitting process for new projects. These initiatives underscore nuclear energy's critical role in achieving the goal of 100% carbon-free electricity by 2035.

The rapid growth of data centres and AI applications in the United States is driving a significant increase in electricity demand, with estimates suggesting that data centres could account for up to 10% of total United States electricity consumption by 2030. To address this challenge, the administration has prioritised permitting new Combined Cycle Gas Turbines (CCGTs), which offer higher efficiency and lower emissions than traditional fossil fuel power plants. The United States currently has over 450 GW of natural gas-fired capacity, with plans for an additional 20 GW of CCGT projects in development to meet rising demand. Since natural gas remains the most reliable and scalable firm power source, policy strategies supporting infrastructure expansion and streamlined permitting processes are crucial to ensuring a stable electricity supply for AI-driven energy loads. Carbon capture technologies are increasingly being integrated into new gas-fired power projects to align with long-term emission reduction goals while maintaining grid stability.

To further align with sustainability objectives, federal and state policies have accelerated investment in CCUS technologies, particularly by large digital companies with significant energy footprints. The Inflation Reduction Act and the bipartisan infrastructure law have introduced tax credits and incentives such as the 45Q tax credit, which provides up to USD85 per ton for captured and stored CO2. Companies like Microsoft, Google, and Amazon have pledged multi-billion-dollar investments in CCUS to offset their natural gas power consumption emissions, leveraging these incentives to develop low-carbon energy solutions. Moreover, partnerships between tech firms and energy providers are emerging to deploy CCUS-integrated gas plants, ensuring data centres remain operational while adhering to corporate net-zero commitments. These policy-driven initiatives position natural gas with CCUS as a cornerstone for reliable and sustainable power in the AI-driven economy.

The regulatory landscape in the power sector has also evolved to align with these ambitious targets. New standards introduced in 2023 required natural gas and coal plants to adopt CCUS technologies or low-emission hydrogen. Although initial regulations excluded existing natural gas plants, stricter rules finalised in 2024 mandated CCUS implementation for coal plants and new gas generators by 2032. Additionally, the administration introduced measures to restore confidence in the voluntary carbon offset market, addressing concerns over offset projects' credibility and failure to deliver promised emissions reductions.

Despite these advancements, the New US administration has initiated pushback, resulting in the rollback of some climate regulations. For instance, auto emissions standards were eased by adopting a "technology-neutral" approach. This allowed automakers to meet targets through gas-electric hybrids and advanced gasoline technologies rather than mandating a rapid shift to electric vehicles (EVs). These adjustments and excluding existing natural gas plants from stringent emissions controls highlight the complexities of balancing climate action with economic and political pressures.

More recently, a significant shift in policy direction has emerged following President Donald Trump's announcement on January 20, 2025, to withdraw the United States from the Paris Agreement. This move signals a deprioritisation of climate initiatives and a reversal of domestic and international climate diplomacy progress. Domestically, this policy realignment is expected to boost support for the oil and gas industries, leading to expanded production and regulatory rollbacks that could slow the transition to clean energy. Additionally, tariffs on Chinese EVs, batteries, and other key imports have introduced new challenges for decarbonisation efforts. By increasing costs for critical renewable energy technologies, such as solar panels, these trade measures could hinder progress toward achieving the 100% carbon-free electricity target by 2035, further complicating the broader energy transition strategy.

Due to these challenges, natural gas continues to play a pivotal role in the United States power system. As other sectors reduce gas consumption, the power sector has emerged as the primary driver of natural gas demand, leveraging its reliability to address supply shortfalls from renewables. The increasing energy needs of data centres, backed by the rapid expansion of AI, are also expected to drive further demand for natural gas in the coming years.

At the same time, the United States is expanding its position as a global leader in LNG exports, with the majority of new LNG liquefaction capacity growth between 2024 and 2030 expected to occur in the United States. This trend has been further boosted by President Donald Trump's issuance of an executive order in January 2025 titled "Unleashing American Energy," which directed the United States Department of Energy to end the pause on LNG export permit applications. This action reversed the moratorium implemented during President Joe Biden's administration, thereby resuming the processing of pending LNG exports. To position natural gas as an environmentally friendly fuel, the administration is collaborating with global energy firms to develop standards for certified natural gas, which would include low- or no-carbon certifications based on emission reductions or carbon offsets. This initiative is part of a broader strategy to expand LNG exports to Europe while addressing climate concerns. In 2023, the United States joined forces with other governments, including Australia, Canada, Japan, and South Korea, to reduce methane emissions across the LNG value chain. These efforts culminated in a voluntary international framework for measuring and verifying emissions from natural gas operations.

Building on these initiatives, the United States introduced a methane fee 2024 for major oil and gas producers, targeting facilities emitting more than 25,000 $MtCO_2e$ annually. Starting at USD 900 per ton in 2024 and rising to USD 1,500 per ton by 2026, the fee aims to reduce methane emissions while raising revenue for environmental programs. A rule finalised in 2023 bans routine flaring from new wells, requires regular leak monitoring, and establishes third-party oversight for identifying methane releases from "super emitters."

Taken together, natural gas remains a cornerstone of the United States energy system, balancing the intermittency of renewables while addressing growing electricity demand from data centres and broader electrification efforts. Expanding LNG exports, developing certified natural gas standards, and implementing methane regulations reflect the country's evolving strategy to align natural gas use with its decarbonisation goals. However, the new United States administration is expected to rescind these policies to facilitate more hydrocarbon investments.

2.2.4 The European Union

The European Union (EU) has undertaken a series of targeted policy measures in 2024 and 2025 to strengthen energy security, advance decarbonisation objectives, and reduce dependence on external fossil fuel supplies. A key development was the expiration of the EU gas price cap on January 31, 2025, signalling a return to market-driven pricing mechanisms as energy markets stabilised. In parallel, efforts to diversify the region's energy mix have intensified. The EU navigates the dynamic energy landscape of 2024; its priorities remain centred on strengthening energy security and advancing climate goals. However, the EU's climate agenda is facing increasing political resistance, particularly in sectors like agriculture and traditional industries, which are under pressure from growing competition with China's green technology exports. In response to widespread farmers' protests and political pushback, the EU has adjusted some of its plans to maintain public support and protect European industries, diluting specific green policies.

For instance, in January 2024, EU lawmakers approved a two-year delay in implementing sector-specific rules requiring the oil, energy, and mining industries to disclose detailed environmental, social, and governance (ESG) factors. This decision was justified as a means to reduce regulatory burdens on companies, reflecting the broader political sensitivities surrounding the EU's climate initiatives.

Despite these challenges, the EU made substantial progress on key climate policies in 2024. Early in the year, it unveiled three cornerstone documents redefining its decarbonisation roadmap: the 2040 Climate Target, the Net Zero Industry Act (NZIA), and the Industrial Carbon Management Strategy. Collectively, these policies aim to reduce net greenhouse gas emissions by 90% by 2040, bridging the gap between the EU's 55% reduction target for 2030 and its goal of climate neutrality by 2050. To meet these targets, the electricity sector must become nearly CO2-free by 2040, with over 90% of power generated from renewables and nuclear energy. Coal is to be phased out, while natural gas is expected to remain part of the mix for industry, buildings, and power generation, and oil will continue dominating transportation.

The Industrial Carbon Management Strategy outlines a vision for scaling up carbon capture and removal technologies, targeting 280 million tons of CO_2 captured annually by 2040 and around 450 million tons by 2050. Meanwhile, the NZIA bolsters EU industrial competitiveness by supporting technologies such as renewable energy, battery storage, carbon capture, and grid infrastructure. By 2030, the NZIA aims to meet 40% of the EU's technology needs with domestically produced solutions, helping Europe compete with the United States and China.

In July 2024, the EU adopted the Corporate Sustainability Due Diligence Directive (CS3D), a significant milestone in the rapidly evolving ESG landscape. This directive establishes a framework for companies to address risks and adverse impacts on human rights and the environment within their supply chains. It is a key tool in the EU's efforts to achieve the objectives of the European Green Deal and the Paris Agreement, targeting large EU-based companies and non-EU companies with substantial turnover within the EU (see Box 2.2).

In addition to these broad strategies, the EU has advanced specific measures to decarbonise the transportation sector. It set a target for new heavy-duty vehicles to reduce emissions by 90% by 2040, requiring manufacturers to sell significant numbers of electric and hydrogen-powered trucks to offset the emissions of CO_2-emitting vehicles. This builds on the EU's 2023 policy banning new CO_2-emitting cars by 2035. Stricter air pollution limits and mandates for building renovations to improve energy efficiency were also adopted, underlining the EU's focus on reducing emissions across all sectors.

Recognising the importance of energy security, the EU is expanding green power imports through partnerships with regions such as the Middle East and North Africa (MENA). Key projects include the 3.6 GW Xlinks subsea link between Morocco and Great Britain, the 600 MW ELMED interconnector between Italy and Tunisia, and the EuroAsia and EuroAfrica interconnectors, which link Israel-Greece and Egypt-Cyprus-Crete, respectively. These projects aim to enhance renewable energy imports but face challenges such as rising costs and the implications of the EU CBAM, which will take effect in 2026.

However, the gap between policy ambitions and actual progress remains significant. Many EU member states struggle to meet their 2030 targets, and legally binding 2050 climate neutrality goals appear increasingly challenging. Following the June 2024 elections, a more divided European Parliament emerged, with lawmakers split over the direction of climate policy. Some factions are advocating for revising the 2035 ban on combustion engine cars and delaying the EU Commission's forthcoming 2040 emissions reduction proposal. This political fragmentation has slowed momentum on ambitious climate goals at a time when accelerating decarbonisation efforts is critical.

Natural gas remains a key component of the EU's energy strategy, with significant policy developments shaping its future. The Gas and Hydrogen Package, first introduced under the Fit for 55 initiatives, was revised in 2024 to integrate lessons from the 2021–2023 energy crisis. The newly adopted Renewable and Natural Gases and Hydrogen (RNGH) Directive and the RNGH Regulation establish a regulatory framework for building, repurposing, and decommissioning natural gas and hydrogen infrastructure. These measures include provisions to prohibit new long-term contracts for unabated fossil gas beyond 2049, in line with the EU's 2050 net zero target, while incentivising the use of renewable and low-carbon gases through tariff discounts.

The RNGH Regulation incorporates elements from emergency legislation enacted during the energy crisis to ensure energy security, such as tariff discounts for natural gas storage and LNG facilities. However, specific measures, such as mandatory demand aggregation and gas storage targets, were excluded to avoid disrupting market dynamics.

Finally, the EU enacted legislation to limit methane emissions in fossil fuel imports starting in 2030, placing pressure on international suppliers to reduce methane leaks. Major exporters to the EU must enhance operational practices to comply or face penalties.

Balancing ambitious climate policies with energy security and political realities will be crucial as the EU moves forward. While significant progress has been made, shifting political dynamics and uneven implementation across member states pose ongoing challenges to achieving the bloc's decarbonisation goals.

Box 2.2 The Corporate Sustainability Due Diligence Directive (CSDDD)

The Corporate Sustainability Due Diligence Directive (CSDDD) introduces significant changes to business responsibilities in the EU regarding human rights, environmental standards, and climate change. it is a very ambitious new law that will critically impact many multinational companies active in the EU.

The CS3D covers companies incorporated under the law of a Member State ("EU companies") and companies incorporated under the law of a third country ("non-EU companies"), as per Table 1.

Under the CS3D, companies must adopt due diligence policies to identify, prevent, mitigate, and address adverse impacts on human rights and the environment in their operations, subsidiaries, and business partner operations. These adverse impacts are defined by international treaties ratified by EU member states. The policies will cover direct and indirect business partners and include upstream and downstream value chain activities. Due diligence obligations include assessing impacts, integrating policies into risk management, preventing and mitigating impacts, providing remediation, engaging stakeholders, maintaining

Table 1

The Scope of CSDDD

	EU Companies	Non-EU Companies
a	Companies with over 1,000 employees and over EUR 450 million in net worldwide turnover.	Companies with more than EUR 450 million in net turnover within the EU.
b	Ultimate parents of groups that meet above thresholds on a consolidated basis.	Ultimate parents of groups that meet above thresholds on a consolidated basis.
c	Companies involved in franchising or licensing agreements in the EU have over EUR 22.5 million in royalties and a net worldwide turnover of more than EUR 80 million.	Companies involved in franchising or licensing agreements in the EU have over EUR 22.5 million in royalties and a net turnover of more than EUR 80 million.

Source: European Commission

a complaints mechanism, and monitoring policy effectiveness. Companies are also required to report publicly on their due diligence measures.

Companies covered by the CS3D will also be required to adopt and implement a climate change mitigation transition plan (the "Climate Plan"), which must include specific features to ensure that the company's business model and strategy are aligned with":

Key objectives

- The transition to a sustainable economy
- Limiting global warming to 1.5°C, in accordance with the Paris Agreement
- Achieving climate neutrality as outlined in the EU Climate Law, including intermediate and 2050 targets
- Addressing, where applicable, the company's exposure to coal, oil, and gas-related activities

Implementation timeline

- Time-bound targets every 5 years, starting in 2030 and extending to 2050
- Encompassing scope 1, 2, and 3 GHG emissions reductions

Decarbonisation Strategies & Funding

- Detailed actions and technologies for emission reduction
- Quantified investments and funding to support the implementation of the transition plan
- Clearly defined leadership roles and annual progress reporting
- The Climate Plan must be updated annually, providing detailed progress towards achieving the company's targets

The directive requires EU member states to establish rules or penalties for violations of national laws implementing the directive, ensuring they are effective, proportionate, and dissuasive. The infringement's nature, gravity, duration, impacts, past violations, financial gains, remedial actions, and mitigating factors are key considerations for imposing penalties. Mandatory penalties include financial fines and public statements for non-compliance. Fines are based on a company's net worldwide turnover, with a minimum threshold of 5% of the turnover in the prior financial year.

The CS3D will be rolled out in phases, beginning in 2027, for companies with at least 5,000 employees and EUR 1.5 billion in turnover. In 2028, it will apply to those with 3,000 employees and EUR 900 million in turnover, and by 2029, it will cover all remaining in-scope companies.

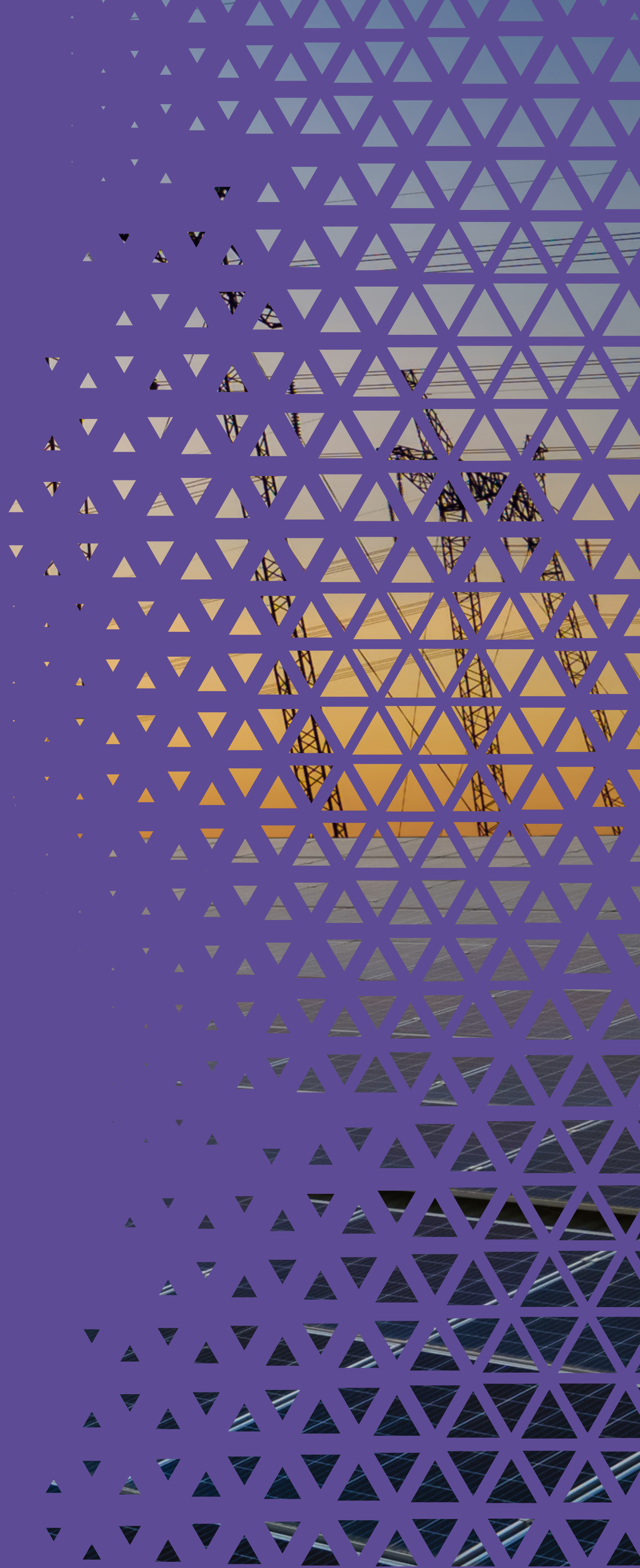
The CSDDD is a bold legislative initiative introducing stringent obligations for companies operating within or significantly engaging with the EU market. It requires businesses to adopt comprehensive due diligence policies and climate transition plans, with substantial penalties for non-compliance.

However, the directive has raised concerns, particularly among developing countries, due to its potential conflict with the Common But Differentiated Responsibilities (CBDR) principle, as recognised in international climate agreements. This principle emphasises developed and developing countries' differing capabilities and responsibilities in addressing global challenges like climate change.

Like objections against the EU's CBAM, the CSDDD may be criticised for disproportionately burdening businesses in low—and middle-income countries. While the directive applies uniformly to EU and non-EU companies meeting specific thresholds, it overlooks the unique challenges developing countries face, such as limited financial and technological resources.

The directive's broad scope, encompassing value chain oversight and climate transition mandates, could impose significant compliance costs on companies from developing countries. Additionally, the requirement to address scope 3 emissions—indirectly associated with a company's operations—may disproportionately impact businesses in resource-intensive sectors prevalent in these economies.

The CSDDD risks deepening economic disparities and undermining the spirit of international collaboration in achieving sustainability goals. Its extraterritorial reach will surprisingly penalise companies investing to satisfy EU energy needs. Its result will be an isolation of the EU energy market, leading to an even more detrimental energy price differential with the US and other economies, thus accelerating the ongoing deindustrialisation.



Chapter 3

Energy Demand Outlook

Highlights

- Under the RCS, primary energy demand is forecast to grow from 635 EJ in 2023 to 750 EJ, reflecting 18% growth over the forecast period.
- Final energy demand is projected to increase from 424 EJ in 2023 to 539 EJ by 2050, growing at an annual rate of 0.9%. The share of electricity in final energy demand is projected to increase from 21% in 2023 to 30% by 2050, driven by electrification trends across various sectors.
- Asia Pacific is set to dominate global energy demand growth, contributing approximately 56 EJ, or 49%, to the total increase between 2023 and 2050. Africa follows as the second-largest contributor, accounting for one-fourth of the global growth during this period.
- Despite a declining share, hydrocarbons are expected to remain the backbone of the global primary energy mix, accounting for 64% of total energy demand by 2050, down from nearly 80% in 2023.
- Natural gas demand is forecast to grow at an average annual rate of nearly 1%, or 32% cumulatively, surpassing coal as the second-largest energy source by the late 2020s and converging with oil's share by 2050.
- Renewable energy demand is projected to grow sixfold, increasing from 22 EJ in 2023 to 131 EJ by 2050. Renewables' share of the global energy mix is expected to rise from 3% to 17% over the same period.
- Global domestic electricity generation is anticipated to nearly double, from 29,512 TWh in 2023 to 56,689 TWh by 2050. Natural gas-fired generation is expected to meet about 12% of the incremental global electricity generation over this period.
- Hydrogen demand is projected to experience a sharp increase, rising from 97 Mt H_2 in 2023 to 257 MtH_2 by 2050. Asia Pacific and Europe are forecast to dominate global hydrogen demand by mid-century, collectively accounting for above 70% of total consumption.
- By 2050, global blue hydrogen production is expected to reach 87 MtH_2, representing 33% of total hydrogen output. Natural gas-based blue hydrogen will dominate, accounting for 70 MtH_2 of this total.
- Global energy-related emissions, after peaking at 40.6 GtCO_2e in 2023, are forecast to decline by 23% to reach 31.2 GtCO_2e by 2050. The Asia Pacific region is expected to lead this effort, contributing an impressive 77% of the total emissions reductions.
- Energy efficiency is projected to improve globally at an average annual rate of 2.4% from 2023 to 2050. The Asia Pacific region is forecast to exceed the global average, achieving a remarkable 3.1% improvement in energy efficiency by 2050.

3.1 Global energy demand outlook

In 2023, primary energy demand increased by 1.5% compared to 2022. Consumption reached record levels across all major fuels, including natural gas, oil, and coal, reflecting a resurgence in structural energy use growth following the disruptions and volatility of the prior year. The Asia Pacific region played a pivotal role in this growth, driven by robust economic recovery as countries continued to emerge from the impacts of the COVID-19 pandemic.

Climate change policies continue to redefine the energy sector, even as the focus on energy security and affordability, heightened by the global energy crisis of 2022, remains a top priority for policymakers worldwide. In response, the deployment of renewables and cleaner technologies has gained unprecedented momentum. However, these solutions face challenges such as higher full-cycle production costs and reliance on variable weather conditions, highlighting the intricate balance required to achieve reliable energy transitions while meeting pressing global energy demands.

The drive for low-carbon energy solutions necessitates a holistic approach that balances economic growth, social progress, and environmental protection. Energy transitions cannot rely on singular solutions but require multidimensional strategies that accommodate the diverse energy needs of regions and sectors. In this context, the RCS adopts a pragmatic and realistic framework, emphasising a balanced energy security, affordability, and sustainability perspective. This approach ensures that energy systems remain resilient and inclusive while advancing progressively toward long-term climate and energy goals.

Hydrocarbons remain integral to achieving long-term energy objectives, with oil and gas comprising 52% of the global energy mix in 2050. They are vital in addressing energy poverty and ensuring consumers worldwide access to reliable and affordable modern energy. Among hydrocarbons, natural gas, the cleanest-burning option, stands out as a key enabler of energy security and a cornerstone of just, equitable, and orderly energy transitions. Its relatively high energy density, availability, versatility, flexibility, and lower air pollutants and greenhouse gas (GHG) emissions position it as a critical energy source in shaping a resilient, inclusive and sustainable energy future.

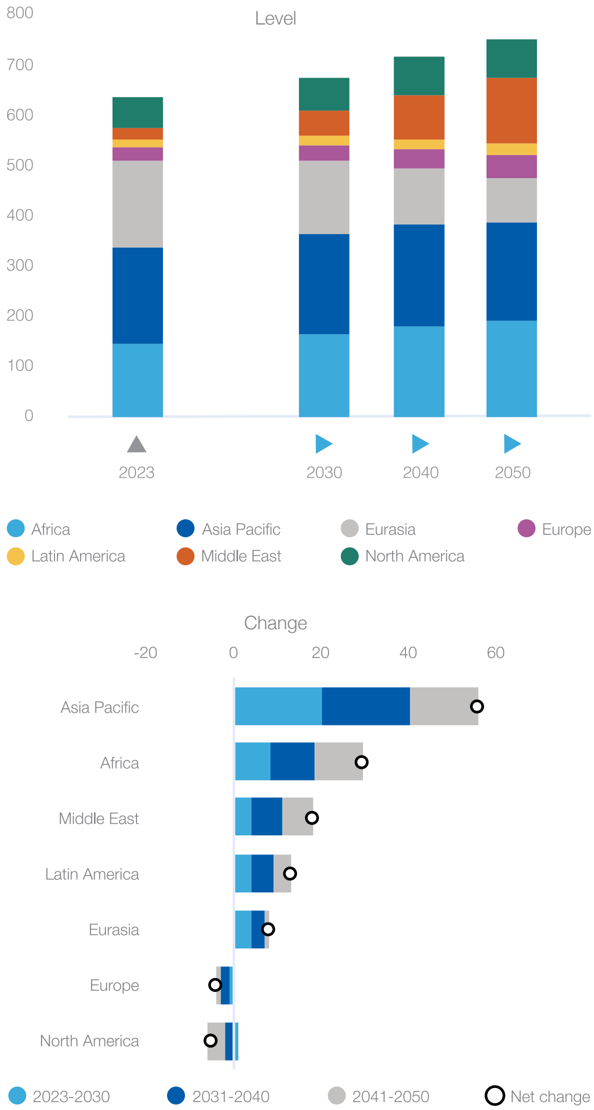
Global primary energy demand is projected to grow by 18%, or nearly 0.6% annually, increasing from 635 EJ in 2023 to 750 EJ by 2050 (Figure 3.1). This growth represents significantly slower growth compared to the historical average of 1.8% observed over the past 27 years. The deceleration is primarily driven by remarkable advancements in energy efficiency, coupled with moderating population growth and a gradual slowing of economic growth.

Energy efficiency improvements are anticipated to be a cornerstone of this transformation. Primary energy intensity (measured in Purchasing Power Parity, base year =2023) is projected to decline by a hefty 2.4% annually between 2023 and 2050, far exceeding the historical reduction rate of 1.6% annually over the last ten years. This accelerated decline is underpinned by the growing impact of technological innovation driven largely by digital transformation, policy measures, and structural shifts toward less energy-intensive economic activities.

Future energy demand growth is expected to be significantly tempered by substantial gains in energy efficiency, the increasing electrification of end-use activities, and a global economic shift toward less energy-intensive service sectors. **RCS projects that**

Figure 3.1

Global primary energy demand outlook by region, 2023-2050 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

electricity will account for 30% of total final energy demand by 2050, up from 21% in 2023, underscoring the pivotal role of electrification in shaping energy consumption patterns. Simultaneously, the transition of global GDP toward service-oriented activities (see Chapter 1, Section 1.2) further reduces the energy intensity of future economic growth.

Technological advancements, particularly in digitalisation and AI, are central to improving efficiency, streamlining processes and optimising energy use across industries. However, these same advancements are also expected to exert upward pressure on energy demand by enabling new applications and driving economic growth. This dual impact highlights the intricate balance between efficiency gains and the potential for rising energy requirements as technological progress unfolds in the coming decades.

Advancements in energy efficiency and reductions in energy losses across the supply chain are expected to drive a faster growth rate for final energy demand than primary energy demand over the forecast period. **Final energy demand is projected to increase from 424 EJ in 2023 to 539 EJ by 2050, representing an annual growth rate of 0.9%**. This outpaces the growth rate of primary energy demand by 0.3 percentage points, reflecting substantial improvements in minimising energy losses before reaching end users.

A regional breakdown of primary energy demand growth reveals that approximately 56 EJ, or **49% of the global net increase between 2023 and 2050, is projected to originate from the Asia Pacific region.** This growth is primarily driven by fast-growing economies in non-OECD East Asia, such as India, and in Southeast Asia, including Indonesia. These regions are experiencing significant urbanisation and a rapid shift toward higher living standards. Africa is projected to be the second-largest contributor to global primary energy demand growth by 2050, adding 29 EJ, which represents one-fourth of the total net increase worldwide.

No other region rivals Asia Pacific and Africa regarding incremental energy demand growth. The Middle East and Latin America are expected to experience increases of approximately 18 EJ and 13 EJ, respectively, driven by robust economic expansion and favourable demographic trends. In contrast, Eurasia is projected to see the smallest rise in energy demand, with an addition of around 8 EJ. This modest growth is largely attributed to significant advancements in energy efficiency and relatively low population growth in the region (Table 3.1).

In Europe, energy demand is projected to continue declining through the end of the outlook period, decreasing by approximately 4 EJ by 2050. This reduction is driven by moderate economic growth, de-industrialisation, a declining population, and the adoption of more efficient technologies, supported by energy policies targeting carbon neutrality and enhanced energy efficiency. In contrast, primary energy demand in North America is expected to peak in the latter half of the 2030s, followed by a gradual decline. The reduction is projected to be steeper than in Europe, estimated at 5 EJ, with the majority of the decline occurring in the United States. Key factors behind this trend include a slowly growing population, decelerating economic expansion, significant advances in energy efficiency—particularly in road transport—and the increasing deployment of renewable energy technologies.

In the context of inter-fuel competition, hydrocarbons are expected to remain dominant in the global primary energy mix, contributing 64% by 2050, down from nearly 80% in 2023. Oil will continue to be a crucial energy source, though its share in the global mix is projected to decline from about one-third to nearly one-fourth. Coal's contribution is anticipated to decrease significantly, from

Table 3.1

Global primary energy demand outlook by region, 2023-2050

	Levels (EJ)				Change (EJ)	Growth (% p.a.)	Share (%)	
	2023	2030	2040	2050	2023-2050	2023-2050	2023	2050
Africa	37	45	55	66	29	2%	6%	9%
Asia Pacific	295	315	335	351	56	1%	46%	47%
Eurasia	45	49	52	53	8	1%	7%	7%
Europe	76	75	73	72	-4	0%	12%	10%
Latin America	29	33	38	42	13	1%	5%	6%
Middle East	39	43	50	57	18	1%	6%	8%
North America	114	115	113	109	-5	0%	18%	15%
Total	**635**	**675**	**716**	**750**	**115**	**1%**	**100%**	**100%**

Source: GECF Secretariat based on data from the GECF GGM

Table 3.2

Global primary energy demand outlook by fuel type, 2023-2050

	Levels (EJ)				Change (EJ)	Growth (% p.a.)	Fuel share (%)	
	2023	2030	2040	2050	2023-2050	2023-2050	2023	2050
Natural gas	145	163	180	191	46	1.0%	23%	26%
Oil	192	202	201	192	0	0.0%	30%	26%
Coal	170	142	111	88	-82	-2.4%	27%	12%
Nuclear	30	33	40	47	17	1.7%	5%	6%
Hydro	15	18	20	23	8	1.6%	2%	3%
Renewables	22	49	88	131	109	6.6%	3%	17%
Bioenergy	61	68	76	77	16	0.9%	10%	10%
World	**635**	**675**	**716**	**750**	**115**	**0.6%**	**100%**	**100%**

Source: GECF Secretariat based on data from the GECF GGM

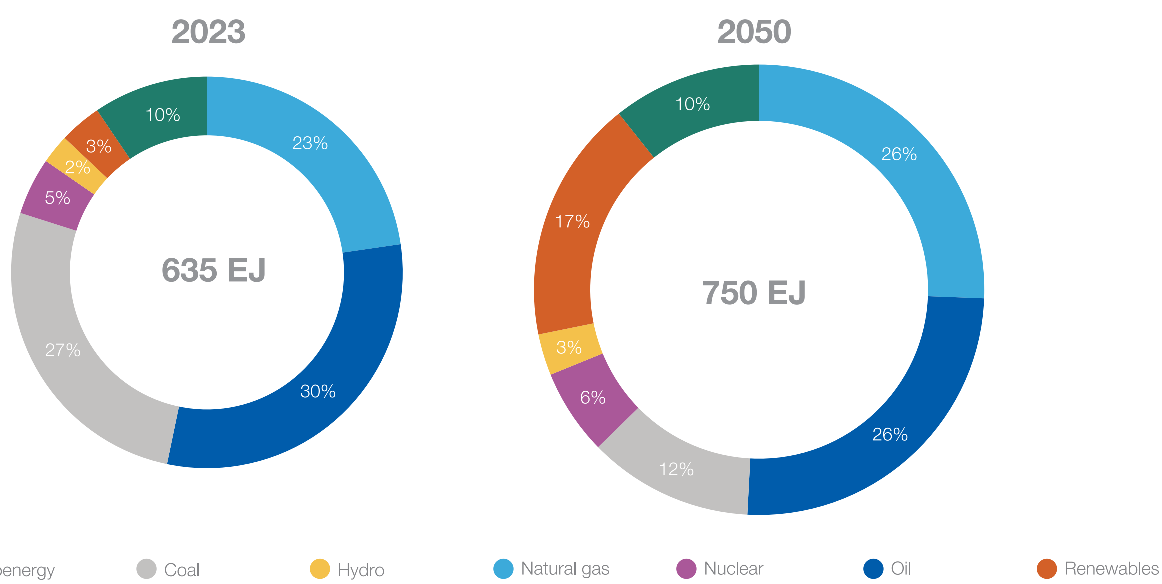
27% to just 12% over the outlook period. Meanwhile, natural gas, which accounts for 23% of global primary energy demand, is forecast to rise to nearly 26% by 2050 (Table 3.2).

Enhanced decarbonisation initiatives and zero-carbon pledges are expected to drive a substantial shift toward non-hydrocarbon energy sources, creating a more diversified global energy mix by 2050. **Renewables are at the forefront of this transformation, with their share projected to increase from 3% in 2023 to over 17% by mid-century**, supported by advancements in solar and wind. Nuclear and hydropower are expected to remain key contributors to the global energy mix, accounting for 6% and 3% by 2050, respectively. This underscores continued investments in low-carbon and reliable energy sources to support long-term energy security and sustainability. Global bioenergy demand is also forecast to rise, contributing 10% to the energy mix by 2050. This growth is primarily driven by the increasing adoption of modern biomass technologies, such as biofuels and biogas, substituting traditional biomass over the forecast period (Figure 3.2).

Energy transitions are gaining momentum globally, with natural gas and renewables emerging as central pillars

Figure 3.2

Global primary energy mix outlook, 2023 and 2050 (%)



Source: GECF Secretariat based on data from the GECF GGM
Note: Bioenergy includes traditional and modern biomass. Renewables include solar, wind, tidal and geothermal energy.

in meeting future energy needs (Figure 3.3). Natural gas, in particular, stands out as a versatile and reliable energy source, facilitating the transition to cleaner energy systems. Its ability to replace carbon-intensive fuels like coal, coupled with its role in complementing intermittent renewable energy sources, positions it as a critical enabler of sustainable development.

The environmental benefits of natural gas are being amplified by significant technological advancements and policy-driven innovations. CCUS technologies are becoming increasingly cost-effective, enabling the capture of emissions at various stages of the natural gas value chain. Similarly, advanced methane abatement technologies mitigate fugitive emissions, addressing one of the key challenges in maintaining natural gas's sustainability credentials. These measures collectively enhance the environmental credentials of natural gas, reinforcing its role as a cornerstone in achieving global climate goals.

Moreover, natural gas is unlocking new frontiers in decarbonisation through its role in producing blue hydrogen. This low-carbon hydrogen, derived from natural gas with integrated CCUS, could be a game-changer for hard-to-abate sectors such as steel, cement, and chemicals, where high-temperature processes are essential. This expanding role underscores natural gas's ability to address complex industrial challenges while contributing to broader climate objectives.

Natural gas demand is projected to grow at an average annual rate of 1.0%, increasing from 145 EJ in 2023 to 191 EJ by 2050, a significant rise of 32%. This growth is underpinned by robust policy initiatives aimed at improving air quality, reducing GHG emissions, and accelerating the shift from oil and coal to cleaner natural gas. Additionally, natural gas's inherent flexibility and its role as a reliable backup for solar, wind, and hydropower, particularly during low output or drought, further boost its demand. Universal clean cooking initiatives also contribute to this upward trend, as natural gas increasingly replaces traditional biomass and other polluting fuels.

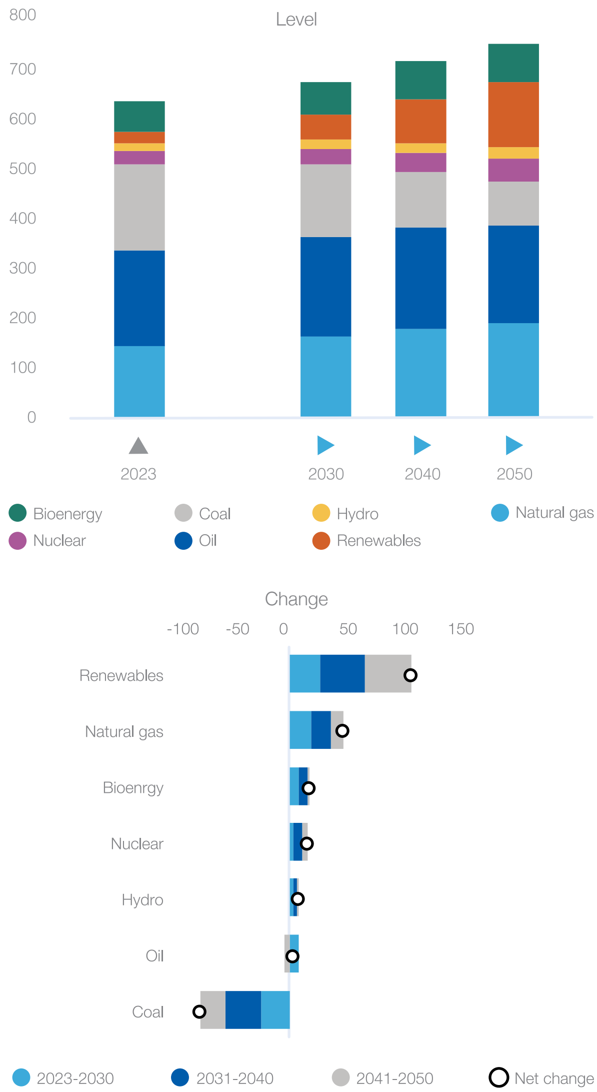
Our projections indicate that in 2027, natural gas will surpass coal to become the second-largest energy source globally. This milestone reflects its expanding relevance in the energy landscape as countries prioritise cleaner and more reliable energy systems. Oil demand is expected to continue growing until 2030 before stabilising in a prolonged plateau. By 2050, natural gas is projected to converge with oil in terms of demand, reflecting its growing role in the global energy mix while maintaining near parity with oil as a key energy source.

3.1.1 Oil

After the extreme volatility in global oil markets during the COVID-19 pandemic, oil demand in 2023 rebounded sharply, exceeding pre-pandemic levels, driven by a surge in economic activity, particularly in China, and increased industrial and transportation demand. However, the trajectory of future oil demand faces growing challenges. Sluggish economic growth, particularly in advanced economies, dampens industrial activity and freight demand while the global transition toward low-carbon energy systems accelerates. The adoption of electric vehicles, supported by declining battery costs and robust policy incentives, is expected to reduce oil consumption in the transport sector. Stricter environmental regulations and the increasing competitiveness of alternative fuels are further reshaping energy markets, particularly in regions prioritising decarbonisation. However, the growing demand for petrochemical products, which rely heavily on oil as

Figure 3.3

Global primary energy demand outlook by fuel type, 2023-2050 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

a feedstock, is expected to offset oil consumption declines, stabilising the overall oil demand outlook.

Building on these dynamics, **global oil demand is projected to grow throughout this decade, rising from 192 EJ in 2023 and stabilising at a prolonged plateau of approximately 200 EJ** by the end of the outlook period (Figure 3.4). The change from historical links in oil consumption and GDP is driven by significant efficiency improvements across industries, domestic energy use, and the transport sector, supported by policy initiatives promoting the adoption of alternative fuels such as electricity, natural gas, biofuels, and low-carbon hydrogen.

The transport sector, which currently accounts for the largest share of oil consumption, is anticipated to see a modest decline in its contribution to oil demand, falling to 57% by 2050 compared to 60% in 2023. The power generation sector is also expected to reduce its reliance on oil significantly. While oil products still play a role in power generation in regions such as the Middle East, Latin America, and Africa, their usage is projected to decline, particularly in the Middle East. By 2050, oil-based power generation is projected to be limited to select oil-producing countries in Latin America and Africa, primarily utilised as a backup or during peak demand periods. Consequently, the share of oil demand attributed to power generation is forecast to fall to just 1% by 2050, down from 4% in 2023.

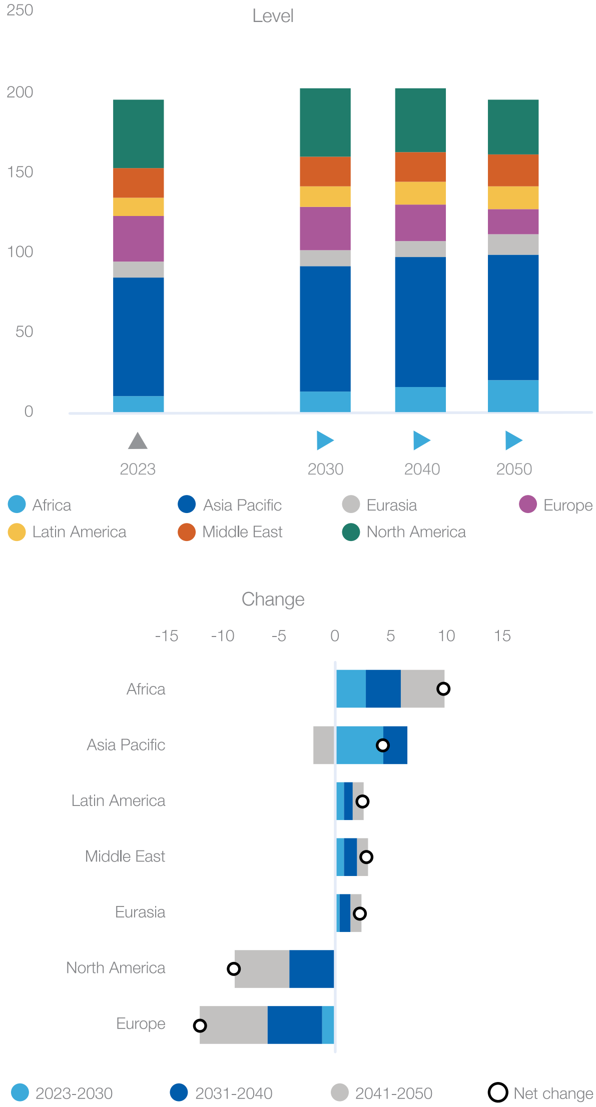
These bearish trends are expected to outweigh the continued growth in oil use as a feedstock for petrochemical manufacturing, which is poised to see a significant rise in its share of oil demand—from 13% in 2023 to 23% by 2050. This growing petrochemical demand reflects the sector's resilience and increasing importance in the global energy landscape, even as oil demand growth slows down in other sectors.

The outlook for oil demand varies significantly by region and country. Declining demand is primarily concentrated in Europe and North America and select OECD Asian countries such as Japan and South Korea. This decline is largely driven by a shrinking fleet of diesel and gasoline-powered passenger cars and heavy trucks as these regions increasingly adopt alternative energy sources and electric vehicles. Europe is expected to lead this decline, with oil demand in the region projected to fall by 12.6 EJ—a 45% reduction—between 2023 and 2050. By the end of the forecast period, oil's share in Europe's energy mix is anticipated to drop to 21%, down 16 percentage points from 2023 levels.

In contrast, developing markets are set to drive global oil demand upward, with India, China, Southeast Asia, and Sub-Saharan Africa leading the growth. Africa is poised to become the fastest-growing region for oil demand, with an annual growth rate of 2.6% projected through 2050, effectively doubling its market share to 10%. A key contributor to this increase is the transition

Figure 3.4

Global oil demand outlook, 2023-2050 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

from traditional biomass to liquefied petroleum gas (LPG) to address the clean cooking deficit across the continent. Meanwhile, China is expected to surpass the United States as the world's largest oil consumer by the mid-2030s and maintain its leading position throughout the forecast period. It is also noteworthy that oil demand in North America is projected to peak in the latter half of the 2020s, followed by a gradual decline as the region transitions further toward renewable energy and advanced efficiency measures.

3.1.2 Coal

Global coal demand has experienced significant fluctuations in recent years. Concerns over energy security, amplified by the energy crisis in 2022, have led some countries to reconsider coal as a reliable and secure option to meet immediate power needs. In 2023, coal use surged to a record high, driven primarily by robust growth in China and India. Notably, China approved nearly 220 GW of new coal capacity over the past two years and began constructing an additional 70 GW in 2023. India, too, remains heavily dependent on coal to meet its rapidly rising electricity demand and is projected to increase its reliance on coal in the near term.

However, this renewed interest in coal is expected to be temporary. Global energy and climate policies, coupled with regulations targeting CO_2 emissions reductions, continue to place significant pressure on phasing out unabated coal usage worldwide. A structural decline in coal demand is anticipated to resume, supported by fuel-switching initiatives and intensified efforts to cut emissions and improve air quality. The growing adoption of alternative cleaner energy sources, including natural gas, renewables, and nuclear power, is expected to limit coal-fired plants to peak load operations, gradually diminishing coal's share in the power generation mix.

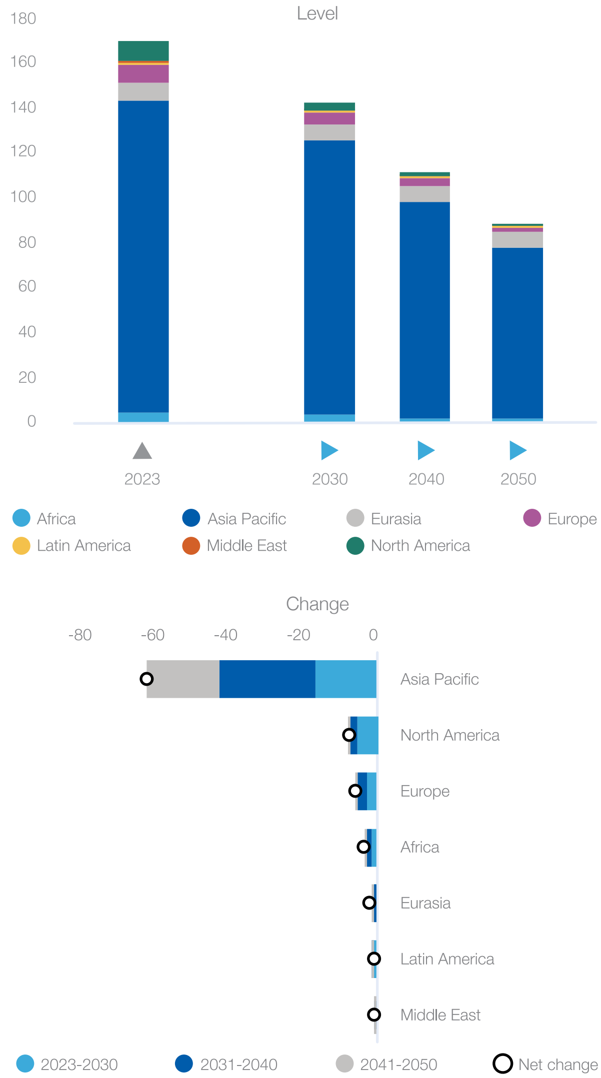
The RCS projects a significant decline in global coal demand over the outlook period, falling from 170 EJ in 2023 to 88 EJ by 2050. This decline represents an annual average reduction rate of 2.4% (Figure 3.5), sharply contrasting the 2.2% yearly growth observed between 1996 and 2023. The steepest reduction is expected in the power generation sector, which is forecast to account for nearly 80% of the total decline in coal demand. Additionally, coal use in the residential segment is set to decrease steadily, driven by clean air quality policies and the adoption of cleaner energy sources. Industrial coal consumption is also projected to decline, albeit at a slower pace.

Coal demand is anticipated to follow a declining trend across all regions, but the scale and pace of this decline vary significantly. **Asia Pacific is expected to lead in absolute terms, accounting for 77% of the total global reduction in coal demand between 2023 and 2050.** This will significantly drop coal's share in the region's energy mix, from 47% in 2023 to 22% by 2050. However, despite this substantial decrease, Asia Pacific will remain the largest coal-consuming region globally. Key economies like India continue to rely on coal for energy security and to meet rising electricity demand. In contrast, coal use in China, Japan, South Korea, and Australia will drive much of the regional decline, reflecting shifting policy priorities and environmental commitments.

On the other hand, North America and Europe are expected to see the fastest momentum for coal demand reduction, with annual declines of 9.4% and 4.7%, respectively. These regions are expected to reach minimal volumes of coal consumption by 2050 as they phase down unabated coal in line with ambitious climate goals. The majority of reductions in these regions will occur before 2040, supported by aggressive policy

Figure 3.5

Global coal demand outlook by region, 2023-2050 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

measures like the Inflation Reduction Act (IRA) and Environmental Protection Agency (EPA) regulations in the United States. The rapid expansion of renewables and access to affordable natural gas further accelerate the replacement of coal in power generation.

3.1.3 Nuclear

Nuclear energy is experiencing a resurgence after a decade of limited growth following the Fukushima disaster. Many countries are now reconsidering nuclear power as a critical component of their energy strategies, recognising its ability to provide reliable, carbon-free electricity while enhancing energy security and supporting climate goals. This renewed interest is underpinned by increasing policy support, exemplified by a December 2023 pledge from over 20 countries to triple global nuclear capacity by 2050. Long-time nuclear energy users, including Japan, South Korea, France, and the United States, are extending the lifetimes of existing reactors and reversing previous phase-out policies. At the same time, countries such as China, India, Russia, Iran, the United Kingdom, and various EU member states are advancing new nuclear projects. Emerging economies like Bangladesh, Egypt, Kazakhstan, Saudi Arabia, Turkmenistan, Türkiye, and Poland plan to incorporate nuclear energy into their power systems by mid-century.

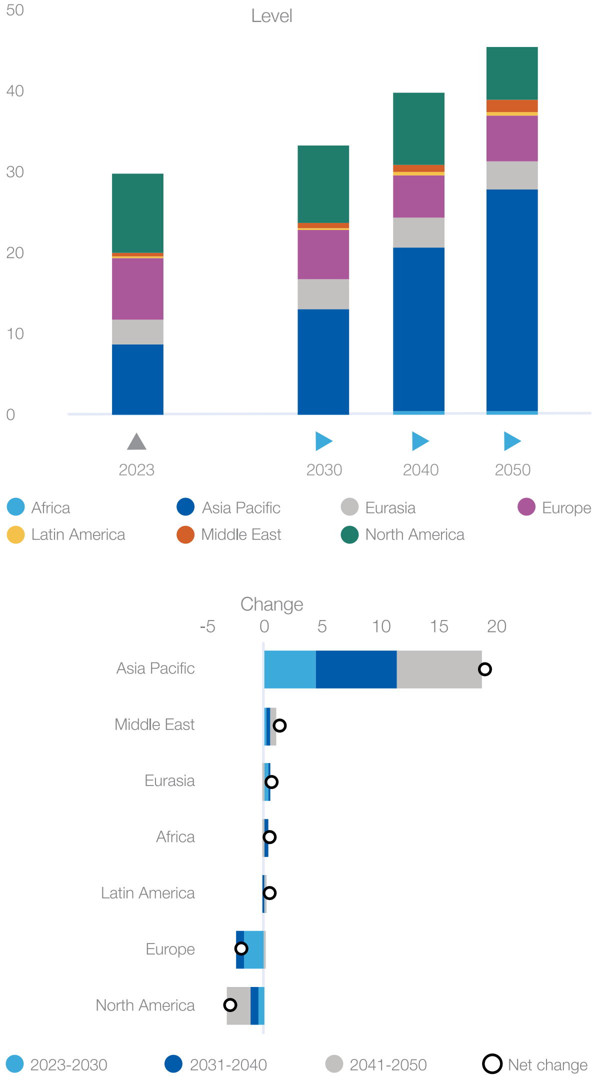
Small modular reactors (SMRs) generate significant interest due to their shorter construction timelines, reduced costs, and adaptability, making them appealing to various countries. Additionally, nuclear power is gaining attention for its potential to produce yellow hydrogen, generated through nuclear-powered electrolysers, which could play a significant role in decarbonising industries. Nuclear energy is also increasingly viewed as a key solution to meet the surging energy demands of hyperscale data centres, further strengthening its relevance in the evolving energy landscape.

The RCS projections indicate that nuclear energy demand will grow significantly, increasing from 30 EJ in 2023 to 47 EJ by 2050, a rise of 1.7% per annum (Figure 3.6). However, this growth will be uneven across regions. North America and Europe are expected to experience a decline in nuclear demand due to the permanent shutdown of ageing plants, with their combined share of global nuclear demand falling from 58% in 2023 to 27% by 2050. In contrast, the Asia Pacific region is forecast to become the dominant player, doubling its share of global nuclear demand from 29% to 60% over the same period. This shift is driven largely by ambitious programs in China and India. China, in particular, is poised to become the global leader in nuclear power by the early 2030s, overtaking the United States. By 2050, nuclear power is projected to account for 12% of China's energy mix, up from 3% today, equating to over 5,800 TWh of electricity annually. This underscores its central role in China's long-term decarbonisation efforts.

Despite this momentum, the future of nuclear energy is not without challenges. Safety regulations remain stringent, often leading to delays and increased costs for new projects. The unresolved issue of nuclear waste management continues to pose environmental and logistical hurdles, while uncertainties surrounding the decommissioning of ageing plants add further financial complexity. Public opposition to nuclear energy, which has diminished in recent years, could resurge in the event of a nuclear incident, potentially slowing its progress. Additionally, nuclear plants' high capital costs and long construction timelines may undermine their competitiveness compared to rapidly advancing renewable energy technologies and natural gas-fired power generation.

Figure 3.6

Global nuclear demand outlook, 2023-2050 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

3.1.4 Hydro

Hydropower remains the leading source of carbon-free electricity, contributing over 15% to global power generation in 2023. Rising electricity demand continues to drive interest in hydropower projects, with approximately 590 GW of capacity in various stages of development worldwide. This includes around 214 GW dedicated to pumped storage hydropower (PSH), highlighting the increasing importance of hydropower in supporting the global transition to sustainable energy systems.

However, hydropower faces significant barriers that constrain its growth potential. High upfront costs for construction and installation often make it less competitive compared to rapidly advancing renewable technologies like wind and solar. Environmental concerns, including the disruption of ecosystems, biodiversity loss, and displacement of communities, have intensified scrutiny and opposition, delaying many projects. Moreover, hydropower's reliance on consistent water flow makes it highly vulnerable to climate change, with recurring heatwaves, droughts, and changing precipitation patterns threatening its reliability and efficiency. Geopolitical tensions over shared water resources and growing public resistance to large-scale dams further exacerbate these challenges.

The RCS projects global hydropower demand to grow by 1.6% per year, increasing from 15 EJ in 2023 to 23 EJ by 2050 (Figure 3.7). This expansion is primarily driven by developing large-scale hydropower plants, particularly those utilising conventional reservoirs, in the developing economies of Asia Pacific, Africa, and Latin America. These regions benefit from robust electricity demand growth and still-untapped hydro resources, making hydropower a strategic priority. Additionally, globally, pumped hydro facilities are gaining importance as a key technology to complement intermittent solar and wind generation, ensuring grid stability and energy reliability.

On a regional level, Asia Pacific leads global hydropower demand growth, driven by China, India, Pakistan, and Indonesia. China remains the world's largest producer of hydroelectricity, leveraging its extensive hydro infrastructure and ongoing capacity expansions. By 2050, nearly half of the global hydro demand is projected to originate from the Asia Pacific region, representing a 3 percentage points increase from 2023. In Sub-Saharan Africa, hydropower demand is poised to rise significantly, contingent upon accelerated access to financing for infrastructure development. Similarly, Latin America is expected to grow substantially, supported by new projects in hydropower-rich countries like Brazil, Venezuela, and Paraguay, which continue to harness their vast water resources.

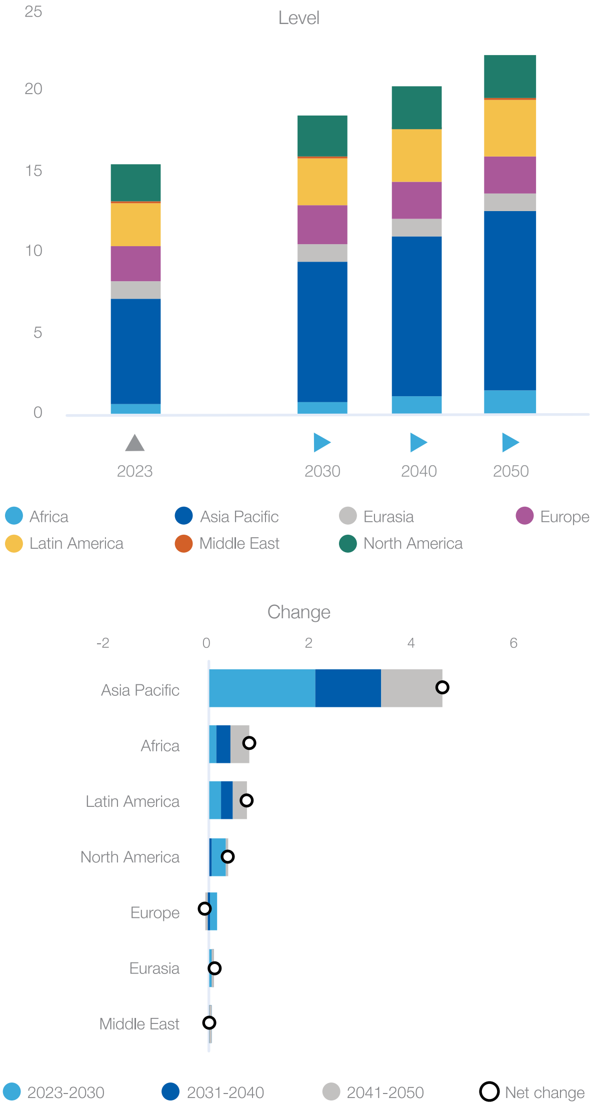
In contrast, hydropower demand in other regions, such as North America and Europe, is expected to experience only modest growth, as most viable resources have already been utilised. These regions increasingly focus on expanding solar and wind capacities, which align better with their long-term energy transition goals. Nonetheless, hydropower remains critical globally, not only as a clean energy source but also as a tool for balancing renewable energy integration and ensuring energy security.

3.1.5 Renewables

Renewable energy has experienced unprecedented growth in recent years, with nearly **510 GW of new capacity added globally in 2023, marking a record-breaking annual increase compared to 290 GW in 2022.** Solar photovoltaic (PV) led the surge, driven by declining costs, improving efficiency, and strong policy incentives that continue to attract substantial investment. The economic competitiveness of solar PV and wind

Figure 3.7

Global hydro demand outlook, 2023-2050 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

energy has further accelerated their adoption, particularly as countries seek to meet rising electricity demand and achieve decarbonisation targets. This surge underscores the significant progress in scaling up renewable energy as a cornerstone of global energy transitions.

However, this remarkable progress represents only the initial, more straightforward phase of energy transitions. While solar and wind technologies have achieved impressive deployment, the hard stuff lies ahead. Meeting the goals of the Paris Agreement and other climate commitments will require addressing complex challenges, such as integrating intermittent renewables into power grids, decarbonising industrial heat processes, and establishing new supply chains for advanced technologies like low-carbon hydrogen and long-duration energy storage. These hurdles are particularly pronounced in developing and emerging economies, where infrastructure and technical capacity are often insufficient to support large-scale deployment and implementation.

Global and national policies are stepping up to address these challenges and accelerate the transition. At COP28, governments pledged to triple global renewables capacity, with major economies targeting at least a 50% increase in renewable capacity or generation by 2030. These ambitious targets are embedded in strategic plans and policy frameworks, including the EU's national energy and climate plans, China's 14th Five-Year Plan, India's National Electricity Plan, Japan's 6th Strategic Energy Plan, South Korea's draft 11th Basic Plan for Power Supply and Demand, and various United States state-level renewable portfolio standards. Such commitments signal a strong policy-driven push toward a sustainable energy future, but their success hinges on addressing the underlying technical, infrastructural, and systemic challenges that remain.

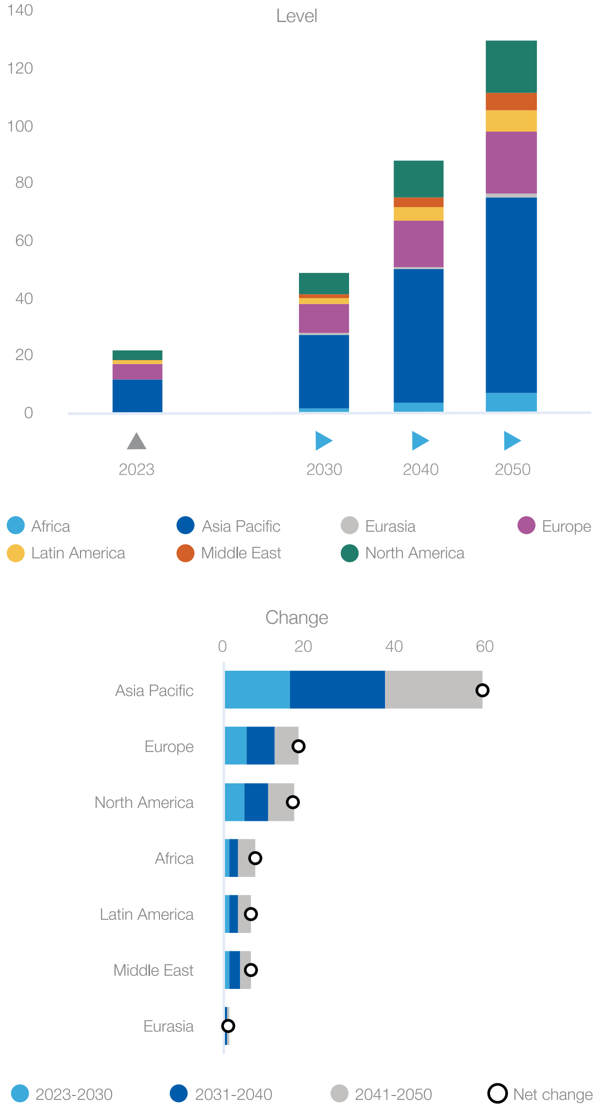
The RCS projects that global renewable energy demand will multiply approximately sixfold over the outlook period, rising from 22 EJ in 2023 to 131 EJ by 2050 (Figure 3.8). This remarkable growth is driven by the rapid deployment of solar photovoltaic (PV) systems, onshore wind, and, to a lesser extent, offshore wind installations. Additionally, the increasing use of green hydrogen, which relies on dedicated renewable power sources, is expected to contribute significantly to the rise in renewable energy demand. This surge reflects a global commitment to decarbonising energy systems, supported by falling technology costs, carbon-neutrality policies, and initiatives to expand and modernise critical infrastructure, particularly power grids.

Despite these advances, scaling renewable energy faces substantial challenges, particularly in the power sector. A key issue is intermittency, as solar and wind power depend on variable weather conditions and cannot consistently meet demand. This intermittency necessitates the development of substantial backup generation capacity and deploying advanced energy storage solutions to ensure grid stability. However, many power grids, especially in emerging economies, are not equipped to handle the variability of renewables, with outdated infrastructure and limited capacity for managing decentralised energy sources. Modernising these grids requires significant investment and the development of resilient supply chains for critical materials, such as lithium, cobalt, and rare earth elements. Natural gas is expected to be critical in addressing these challenges during the transition. Its flexibility, low fixed costs, and ability to provide on-demand power make it an ideal partner for renewable energy, helping to stabilise grids during periods of low solar or wind output.

From a regional perspective, renewable energy demand is poised for robust growth across all regions, driven by ambitious policy commitments, rapid technological

Figure 3.8

Global renewables demand outlook, 2023-2050 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

advancements, and increasing investment flows. **The Asia Pacific region will remain at the epicentre of this transformation, accounting for 53% of the global incremental demand between 2023 and 2050.** The share of renewables in the region's energy mix is projected to rise to 20% by 2050, a nearly fivefold increase from 2023. This remarkable growth is led by China and India, propelled by their ambitious carbon neutrality targets for 2060 and 2070, respectively.

Europe is expected to contribute 15% of the global increase in renewable energy demand, with renewables projected to account for 32% of Europe's energy mix by 2050, a substantial rise from 7% in 2023. This expansion is supported by the REPowerEU program and the decarbonisation goals enshrined in the EU's

Green Deal. These initiatives prioritise a swift transition from hydrocarbons through investments in solar, wind, and energy storage, coupled with the electrification of industries and transportation. Similarly, North America is experiencing a robust surge in renewable energy development, with renewables anticipated to make up 17% of the region's energy mix by 2050, up from just 3% in 2023. This growth is driven by the Inflation Reduction Act (IRA), which provides substantial incentives, including generous tax credits, to accelerate the deployment of wind and solar capacities and foster investments in emerging technologies such as low-carbon hydrogen and advanced energy storage.

The Middle East and Africa are also gaining significant momentum in renewable energy deployment, albeit from a lower base. These regions are forecast to achieve impressive annual growth rates of 13.1% and 10%, respectively, backed by their vast solar and wind potential and increasing investments in infrastructure. Many countries leverage these resources to diversify their energy portfolios, expand energy access, and promote sustainable economic growth. While challenges such as financing and grid capacity remain, the Middle East and Africa are positioned to emerge as key players in the global renewable energy landscape in the decades ahead.

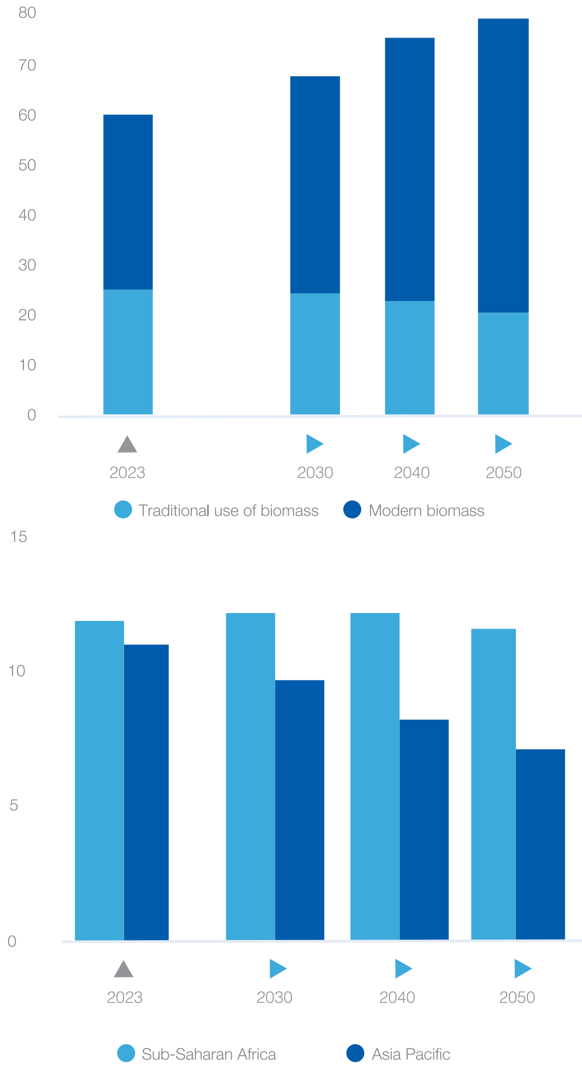
3.1.6 Bioenergy

Global bioenergy demand, including both traditional and modern biomass, reached approximately 61 EJ in 2023, highlighting its critical role in global energy systems. Traditional biomass, such as wood, dung, and crop residues, accounted for 42% of this demand, primarily used for cooking, heating, and lighting in off-grid residential settings across developing regions. However, these practices contribute to significant health issues, particularly from indoor air pollution, environmental degradation through deforestation, and inefficient energy use. **Over the forecast period, total bioenergy demand is projected to grow by 0.9% annually, reaching 78 EJ by 2050** (Figure 3.9). This growth is expected to be accompanied by a shift toward modern biomass, driven by global efforts to address energy poverty, improve health outcomes, and mitigate environmental impacts.

Traditional biomass demand is expected to decline by 18% over the forecast period, falling to around 19 EJ by 2050. This reduction will be most pronounced in Asia Pacific, where countries like China and India are implementing robust programs to phase out polluting energy sources for cooking and heating, focusing on improving air quality and public health. China's Clean Heating Plan and India's Ujjwala Scheme are pivotal examples of policies designed to replace traditional biomass with cleaner alternatives like LPG and solar energy, leading to significant reductions in traditional biomass usage. However, Sub-Saharan Africa presents a contrasting narrative. While efforts to expand access

Figure 3.9

Global bioenergy demand outlook, 2023-2050 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

to clean cooking solutions are ongoing, rapid population growth and rising household energy needs are expected to sustain high levels of traditional biomass consumption. This dual trajectory highlights the need for accelerated deployment of modern and cleaner energy solutions, such as biogas and solar power, to address energy poverty and support the UN's Sustainable Development Goal 7, which seeks universal access to affordable, reliable, and sustainable modern energy.

On the other hand, modern biomass is poised for substantial growth, with demand expected to rise by 68% to 58 EJ by 2050. This surge is driven by the adoption of advanced bioenergy technologies across regions, particularly in China, India, the United States, Europe, Brazil, and emerging Sub-Saharan African markets. Decarbonisation policies, the substitution of traditional biomass, and energy security concerns are key factors underpinning this expansion. In the power generation sector, modern biomass is increasingly used for co-firing in thermal power plants, enabling cleaner electricity generation while leveraging existing infrastructure. Residential and transport sectors are also projected to increase modern biomass usage significantly. In transport, liquid biofuels like biodiesel and bioethanol will be critical in reducing greenhouse gas emissions, supported by government incentives, expanded blending mandates, and ambitious decarbonisation goals. Additionally, sustainable aviation fuels (SAF) are emerging as a crucial solution for decarbonising long-haul aviation, given their compatibility with existing aircraft and fuelling infrastructure.

Biogas and biomethane, though more minor contributors to bioenergy demand today, are expected to expand dramatically over the coming decades. Biomethane, in particular, is gaining momentum as technological advancements, supportive regulatory frameworks, and narrowing cost differences with natural gas enhance its competitiveness. The European Union has set ambitious biomethane production targets as part of its broader strategy to secure low-emission, domestically produced gas supplies. Similarly, the United States, China, and India are emerging as significant players in biomethane development, driven by strong policy support, infrastructure investments, and increasing energy security needs.

Despite its transformative potential, realising bioenergy's full promise will require overcoming several challenges. Infrastructure limitations, financing constraints, and the uneven pace of technological adoption across regions could hinder progress. Moreover, bioenergy's sustainability depends on managing land-use impacts, ensuring that feedstock production does not conflict with food security or lead to deforestation. Policymakers and industry stakeholders must adopt integrated strategies to balance these competing priorities, fostering innovation, expanding access, and ensuring that bioenergy plays a central role in the global energy transitions.

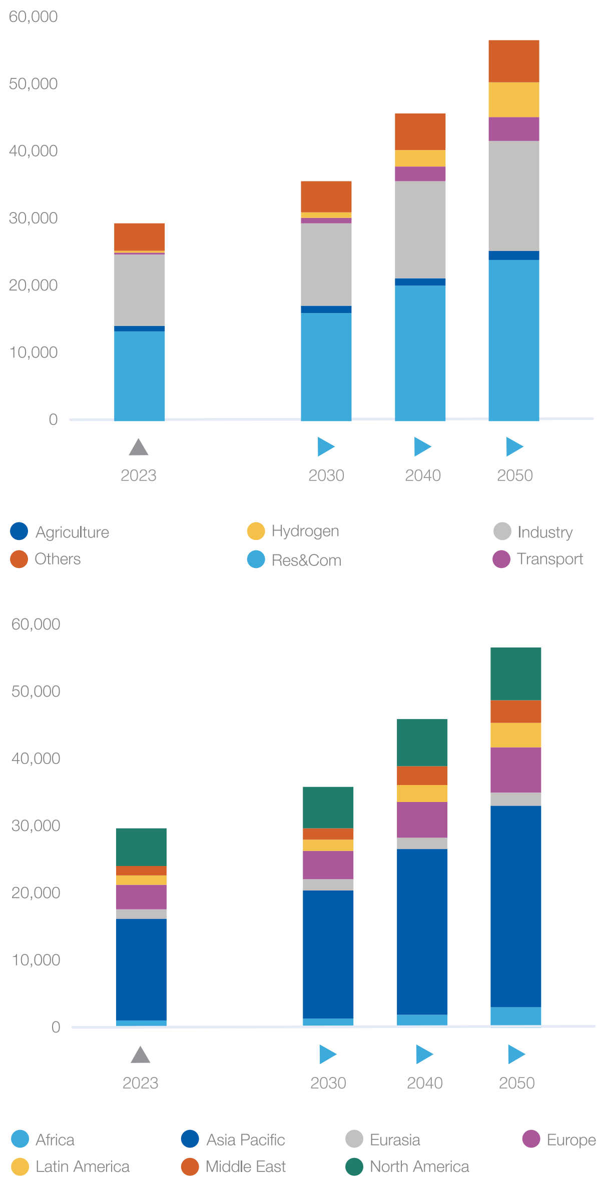
3.2 The outlook for electricity demand and generation

Global electricity generation grew by 2.5% in 2023, aligning with the average annual growth rate observed over the past decade. This consistent expansion, which significantly outpaces total global final energy demand growth, highlights the accelerating shift toward electrification within energy systems. Electrification is emerging as a key driver of energy transitions worldwide, underpinning the increasing reliance on electricity to power industrial activities, residential needs, and advanced technologies.

Over the past 27 years, global electricity demand has risen by 2.8% per annum, reaching 29,543 TWh in 2023. Asia Pacific region has been the primary contributor, accounting for nearly 87% of this increase, driven by rapid industrialisation, urbanisation, and electrification of industrial processes in countries like China, India, and Southeast Asia. The growing adoption of appliances, cooling systems, and urban infrastructure has further increased this demand. **As illustrated in Figure 3.10, our projections indicate that global electricity demand will rise by nearly 2.4%% annually by 2050, reaching approximately 56,693 TWh.** This substantial increase of 27,150 TWh highlights transformative shifts in the global

Figure 3.10

Global electricity demand outlook by sector and region, 2023-2050 (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

energy landscape, driven by population growth, rising living standards, an expanding service sector, increased industrial output, and energy and environmental policies prioritising the substitution of molecules with electrons. Anticipated improvement in energy access in regions like Sub-Saharan Africa will also contribute significantly to this upward trend. This surge in electricity demand is expected to affect all regions, with developing economies accounting for roughly 60% of the increase. The Asia Pacific region will continue to lead this growth, backed by economic expansion, increased electrification of transportation, and substantial investments in renewable energy infrastructure.

The residential and commercial sectors are currently the most significant contributor to the electricity demand. They are projected to maintain their position through 2050, driven by a substantial 80% growth over the outlook period. Together, these sectors are expected to account for approximately 39% of the total increase in electricity consumption by 2050. This growth is primarily supported by rising demand for heating, cooling, and the increasing adoption and replacement of household electric appliances, supported by energy and environmental policies, rapid urbanisation, and a rising number of households globally. The electrification of household heating, mainly through the adoption of heat pumps, is a cornerstone of this transformation, reinforced by climate change mitigation strategies and decarbonisation goals. However, widespread deployment faces notable challenges, including high upfront costs for heat pump systems and significant expenses related to retrofitting older buildings or upgrading power grids to accommodate the increased load.

In the commercial sector, electricity demand is increasingly driven by the rapid growth of data centres and AI applications. Since 2020, global electricity consumption from data centres has grown at an average annual rate of 20%, albeit from a low base, surpassing 400 TWh in 2023 (excluding cryptocurrency contributions) and accounting for 1.6% of global final electricity demand. This share is projected to exceed 2.5% by 2030. However, the long-term trajectory of electricity demand from data centres and AI remains uncertain, influenced by exponential increases in compute workloads, the growing adoption and complexity of AI advances in energy efficiency, and the ongoing expansion of data centre infrastructure (see Box 3.1).

Adding to this uncertainty is the reinforcing bidirectional relationship between AI, as a general-purpose technology, and economic value creation across multiple sectors. This connection introduces further complexity into projections, as AI's integration into diverse industries could significantly alter energy demand patterns. Despite these uncertainties and the potential for high and low sensitivity scenarios in data centre growth, data centres and AI are expected to maintain a relatively small share of global electricity demand. Consequently, broader electricity demand trends are unlikely to be significantly impacted by this segment's growth trajectory in the near future.

The industrial sector is poised to become the second-largest driver of electricity demand growth, with consumption projected to increase by nearly 1.6% per annum over the forecast period, contributing to 22%

Box 3.1 The electricity demand implications of AI and data centre expansion

The global electricity demand for data centres and AI applications is set to grow significantly, supported by the rapid digitalisation of industries, the increasing complexity of AI workloads, and the expansion of cloud computing. As businesses and governments accelerate the adoption of AI-driven solutions, electricity consumption in data centres is becoming a major energy concern. Global data volumes are projected to reach 335 zettabytes annually by 2030, more than five times the level recorded in 2020, leading to an exponential rise in computational workloads. AI is increasingly recognised as a general-purpose technology with transformative applications across various sectors, including autonomous systems, healthcare diagnostics, financial modelling, and industrial automation. This growth in AI-driven processes has dramatically increased the power intensity of data centres, particularly in hyperscale facilities that process massive amounts of real-time data.

Unlike traditional digital workloads, AI model training and inference require exponentially higher computational resources, leading to a surge in energy consumption. Training a single large-scale AI model can demand tens of thousands of megawatt-hours (MWh), and inference tasks continue to consume substantial amounts of electricity once models are deployed. While past improvements in hardware and cooling efficiency have helped mitigate power consumption growth, future efficiency gains are expected to slow, making it increasingly difficult to offset rising electricity demand. The Jevons Paradox, which states that efficiency improvements often lead to greater overall consumption, suggests that AI adoption will accelerate even further as computing power becomes more affordable, driving up electricity needs.

AI and data centre electricity demand outlook

Estimating the future electricity demand of AI and data centres is highly uncertain due to the fast-evolving nature of AI technology, unpredictable adoption rates, and policy interventions. While companies are investing in more energy-efficient semiconductor chips, advanced cooling systems, and AI-optimised power management, the projected increase in workloads could outpace efficiency gains. Forecasts suggest that by 2027, AI-related power demand could reach between 85.4 TWh and 134 TWh annually, depending on the pace of AI adoption and technological advancements in energy efficiency. This represents a multi-fold increase from current levels, signalling a pressing need for reliable and scalable energy solutions.

Policymakers and energy planners are grappling with meeting rising electricity demand while maintaining emissions reduction targets. AI-driven workloads are placing new constraints on grid stability, requiring strategic investments in power infrastructure, backup generation, and energy storage systems. The rapid growth of hyperscale data centres in major tech hubs such as the United States, China, and the European Union is prompting governments to introduce policies that incentivise both renewable energy integration and gas-fired peak load plants to ensure grid reliability. The interplay between AI adoption, energy efficiency, and regulatory frameworks will ultimately shape the future trajectory of electricity demand.

Three scenarios for AI-driven electricity demand

Given the significant uncertainties and based on available information about existing data centres and industry growth estimates, the GECF has developed three scenarios to project future electricity consumption for data centres and AI by 2030. This analysis draws on historical trends in the industry, computing workloads, and internet traffic while accounting for the increasing computational intensity and widespread adoption of AI models. Each scenario reflects different trajectories for data centre growth, AI adoption and energy efficiency improvements (Figure 1.).

1. Base Case Scenario

Assumptions: The base case represents the most likely scenario. AI adoption grows steadily, with moderate increases in data centre capacity to meet the expanding demand for cloud services, storage, and AI applications.

Energy efficiency: Energy efficiency improvements, such as advanced cooling systems and more efficient hardware, are implemented at a moderate pace, helping to offset some of the increased demand. We assume that power efficiency gains, which slowed to around 2% from 2020 to 2023, will remain modest throughout this decade.

Outcome: The base case projects electricity demand to grow from an estimated 414 TWh in 2023 to 1,135 TWh by 2030, representing an annual growth rate of 14.4%. This reflects a balanced progression of AI workload expansion and improvements in data centre efficiency. The forecast also suggests that the data centre sector will account for 3.6% of global final electricity consumption by 2030, up from the current 1.6%.

2. Low Case Scenario

Assumptions: In this scenario, AI adoption is slower than anticipated, and growth in data generation is less pronounced. The demand for cloud services and data centre expansion is more limited, reducing the overall need for additional capacity.

Energy efficiency: Significant advancements in energy-efficient hardware and cooling technologies lower electricity consumption per unit of data processed. Furthermore, the rapid integration of renewable energy drives investments in complementary technologies like energy storage or AI-driven load optimisation, indirectly enhancing energy efficiency. Compared to a base case, we assume an efficiency assumption acceleration of about 5-7% during 2024-2030.

Outcome: The low case projects electricity demand to grow by an average of 8% per annum, reaching 770 TWh by 2030, with the sector's contribution rising to 2.5% of the total electricity demand. In addition to the early adoption of energy-efficient technologies and renewables, this scenario anticipates reduced data centre expansion due to grid constraints.

3. High Case Scenario

Assumptions: This scenario assumes rapid growth in AI adoption, exponential data generation, and the widespread use of computationally intensive AI models. There is also a strong demand for cloud services and hyperscale data centres, significantly increasing data centre capacity.

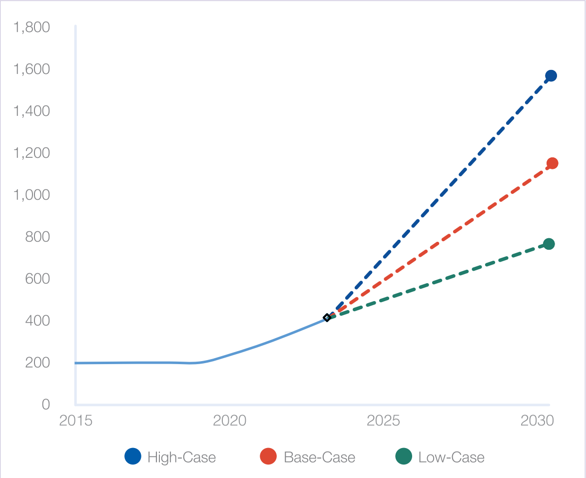
Energy efficiency: In this scenario, advancements in energy-efficient technologies and cooling systems are slower than in Base Case, resulting in higher electricity consumption per unit of data processed. This scenario assumes near-zero annual efficiency gains.

Outcome: The high case projects a steep rise in electricity demand to about 1,560 TWh by 2030, corresponding to a 19% annual growth rate, as data centres expand rapidly to meet surging AI workloads and data processing needs, with almost negligible progress in efficiency improvements. As a result, the data centre sector is set to account for nearly 5% of global electricity consumption by 2030.

The regional distribution of electricity demand growth by 2030 is expected to be predominantly driven by Asia Pacific region, North America, and Europe across all scenarios. Asia Pacific is expected to grow fastest due to

Figure 1

Forecast for global data centre and AI electricity demand (TWh)



Source: GECF secretariat based on data from the GECF GGM

rapid digital transformation, rising data consumption, 5G networks and IoT expansion, and government initiatives promoting AI adoption. China's significant investments in digital infrastructure and India's growing tech services sector will significantly contribute to rising electricity consumption.

With its leadership in hyperscale data centres and cloud service providers, North America is also forecast to be a major contributor. The United States continues to see strong adoption of cloud-based services and AI across sectors like finance, healthcare, and tech. Its well-developed grid infrastructure, coupled with access to abundant natural gas resources, supports this trend. Furthermore, competitive state tax incentives and ongoing investment in AI research and development by large tech companies ensure sustained growth in electricity demand. Similarly, Europe is projected to see strong growth in electricity demand from data centres up to 2030, with a significant number of additional data centres planned. The region's ambitious energy efficiency targets and prioritising the integration of renewable energy will balance electricity consumption and environmental goals.

It should be underscored that this analysis focuses on the additional electricity demand arising from the growth of AI data centres and their expanding infrastructure. However, it is essential to note that the broader economic impact of AI, including the increased energy consumption driven by productivity gains across various sectors, will also drive electricity consumption higher.

of the total increase in electricity demand by 2050. This expansion is propelled by the growing adoption of electric technologies for low-temperature industrial processes, such as food processing, alongside the gradual electrification of high-temperature applications in sectors like steel and iron production. The transition from traditional boilers and furnaces to electric alternatives further underscores the sector's shift toward energy efficiency and decarbonisation.

In parallel, **the transport sector, currently a minor player in electricity consumption, is expected to experience a transformative eightfold increase in demand by 2050, accounting for 12% of the total growth in electricity consumption.** This remarkable surge is primarily driven by the rapid electrification of transportation, supported by the widespread adoption of electric vehicles (EVs). Aggressive policy incentives, EV technology advancements, and the charging infrastructure expansion are key enablers of this growth, marking a significant shift in the energy landscape.

Although hydrogen generation currently accounts for a negligible share of global electricity consumption, it is projected to become a significant driver of electricity demand by 2050, emerging as the third-largest contributor. Over the outlook period, electricity demand for hydrogen production—including both dedicated sources, such as off-grid renewables, and non-dedicated, grid-connected sources—is expected to grow by nearly 5,000 TWh, reflecting an average annual growth rate of 15%. **By 2050, hydrogen production is anticipated to comprise 9% of global electricity demand, playing a pivotal role in decarbonising hard-to-abate sectors.** However, this rapid growth underscores the inherently energy-intensive and relatively inefficient nature of hydrogen generation, particularly green hydrogen, when compared to other energy carriers.

In response to the expansion of electricity demand, global domestic electricity generation is projected to nearly double, increasing from approximately 29,512 TWh in 2023 to almost 56,689 TWh by 2050 (Figure 3.11). This massive growth will be accompanied by a significant transformation of the power generation mix as the global

Figure 3.11

Global electricity generation outlook and fuel shares, 2023-2050 (TWh)

Source: GECF Secretariat based on data from the GECF GGM

shift toward low-carbon energy sources intensifies. Coal, the largest source of global electricity generation, is set to experience the steepest decline over the long term. While rising electricity demand and energy security concerns have supported coal generation in recent years, particularly in Asia Pacific, where countries like China and India continue to build new coal-fired power plants relying on domestic coal supplies, this resurgence is expected to be short-lived. As global climate commitments remain steadfast, **coal's share in the power generation mix is forecast to plummet from 35% in 2023 to just 8% by 2050.** Incorporating CCUS technologies at selected coal-fired power plants offers a viable pathway to extend their operational lifespans while aligning with environmental goals. CCUS captures CO_2 emissions produced during combustion for storage or industrial use, significantly reducing the carbon footprint of coal-based electricity generation. However, the scalability of CCUS is limited by high implementation costs, energy demands, and the need for robust infrastructure, which restricts its widespread adoption.

In addition to CCUS, co-firing coal with hydrogen or ammonia has emerged as a promising solution to reduce emissions from coal-fired power plants. Ammonia, a carbon-free fuel, and hydrogen, particularly green or blue hydrogen, can be blended with coal to lower CO_2 emissions during combustion. Countries like Japan and South Korea are at the forefront of exploring and piloting this technology, viewing it as a transitional measure to decarbonise coal-fired power generation. While co-firing shows potential, challenges such as high fuel costs, infrastructure readiness, and limited hydrogen availability may hinder its large-scale deployment in the near term.

Hydropower is expected to experience annual variability due to fluctuations in precipitation and air temperatures, but its overall trend points toward gradual growth over the long term. However, this growth will lag behind the global average increase in power generation, leading to a decline in hydropower's share of the global energy mix from 14% in 2023 to 11% by 2050. Similarly, nuclear power is projected to grow steadily, supported by favourable policy frameworks and the commissioning of new reactors. Despite absolute increases in output, the proportional contributions of both hydropower and nuclear energy to the global power generation mix are expected to decline modestly, although less steeply than coal. By 2050, nuclear share is projected to decrease from 9% to 7%, reflecting the evolving dynamics of the global energy transition as renewable sources like solar and wind continue to expand at a faster pace.

Renewables, particularly solar photovoltaic (PV) and wind, are poised to dominate the global energy landscape, with their combined share of power generation expected to soar from 14% in 2023 to nearly 53% by 2050. This remarkable growth, averaging approximately 6.8% annually over the outlook period, will generate 29,842 TWh by mid-century. The expansion is driven by ambitious decarbonisation policies and substantial investments in renewable energy capacity in leading markets such as China, India, the European Union, and the United States, aiming to meet rising electricity demand while reducing emissions. Despite this rapid progress, integrating such a large share of intermittent renewables into the energy mix presents significant challenges. Achieving a reliable and resilient power supply will require transformative advancements in grid infrastructure, increased system flexibility, and scalable energy storage solutions.

Despite an absolute level increase, gas-fired power generation is expected to experience a gradual decline in its contribution to global electricity generation. Natural gas is projected to account for 17% of global electricity generation by 2050, down from 22% in 2023. **Gas-fired generation is projected to meet approximately 12% of incremental global electricity demand over the forecast period, underscoring its role as a flexible and dispatchable energy source.** This flexibility is critical for balancing the variability of renewable generation. Moreover, the deployment of CCUS technologies at natural gas-fired plants is expected to accelerate, with retrofitting initiatives commencing in the 2030s. These advancements will enable natural gas to contribute to low-carbon electricity generation, supporting global emissions reduction targets.

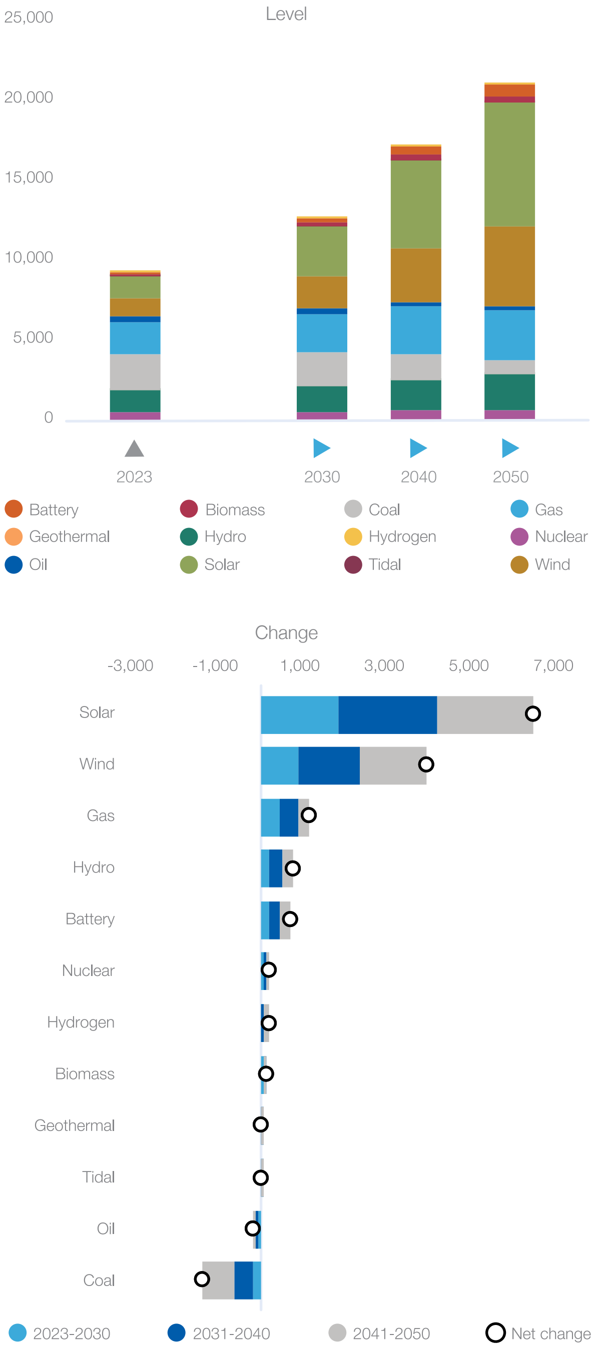
Decarbonisation strategies include co-firing hydrogen or ammonia with natural gas in thermal power plants. Three new hydrogen co-firing plants are under construction in the United States, and several existing gas turbine plants have successfully tested hydrogen-ammonia fuel blends. Progress in hydrogen-based power generation is expected in markets such as South Korea, Japan, China, the United Kingdom, and select EU countries. However, hydrogen co-firing and hydrogen fuel cell-based generation remain in developmental stages, with limited deployment expected within the outlook period.

Global installed power generation capacity is projected to double, rising from approximately 9,200 GW in 2023 to 21,165 GW by 2050, marking a transformative shift in the global energy landscape. This growth highlights a reduction in average capacity utilisation rates, declining from 37% in 2023 to 30% in 2050, as the increasing penetration of intermittent renewable energy sources, particularly solar and wind, reshapes the electricity mix. The transition reflects the global push toward decarbonisation and the electrification of energy systems prioritising renewable energy deployment (Figure 3.12).

Solar and wind energy are set to drive this capacity surge, collectively accounting for approximately 88% of net capacity additions during this period. Solar energy, in particular, is expected to surpass all other energy sources by 2030 to become the most significant contributor to global installed capacity, maintaining its dominance through 2050. This rapid expansion underscores the pivotal role of solar power in energy transitions,

Figure 3.12

Global power generation capacity outlook, 2023-2050 (GW)



Source: GECF secretariat based on data from the GECF GGM

supported by advancements in technology, declining costs, and robust policy incentives. Significant capacity growth is anticipated in key regions, including China, India, the United States, Brazil, Germany, Indonesia, and Saudi Arabia, as these countries implement large-scale renewable energy projects to meet growing demand and climate goals.

Natural gas-fired power capacity is forecast to increase steadily from 2,015 GW in 2023 to 3,170 GW by 2050, representing 15% of total installed capacity by mid-century. This growth will be concentrated in markets such as China, Indonesia, Nigeria, the United States, Saudi Arabia, and Viet Nam, where gas-fired plants are pivotal in addressing energy security and grid flexibility requirements. This underscores the enduring relevance of natural gas in the evolving energy system, even as the global power generation mix undergoes significant transformation toward low-carbon sources.

By 2050, global battery power generation capacity is projected to experience a remarkable increase, growing nearly tenfold from 81 GW in 2023 to 803 GW in 2050. This rapid expansion will significantly enhance the role of batteries in the global power generation landscape, with their share of installed capacity rising from less than 1% in 2023 to 4% by 2050. This growth reflects a strategic response to the rapid penetration of intermittent renewable energy sources, such as solar and wind, within the emerging global power system.

As solar and wind deployment accelerates, their inherently lower load factors and capacity utilisation rates present challenges that go beyond simple integration into the energy mix. These limitations drive up the average cost of electricity production compared to traditional power plants and amplify the need for enhanced system flexibility, which is essential for maintaining electricity security. Solar and wind generation variability further compounds these challenges, requiring significant investments in grid infrastructure, backup generation capacity, and advanced energy storage technologies to ensure a reliable power supply.

While technologies such as batteries, cross-border grid interconnections, and demand-side responses contribute to stabilising the grid, they remain insufficient for addressing long-duration and seasonal storage challenges. This underscores the crucial role of dispatchable, low-emission power sources like natural gas. With its operational flexibility and rapid responsiveness, natural gas effectively bridges the gap created by renewable intermittency, stabilising grids during periods of low renewable output and meeting peak demand. By complementing solar and wind energy, natural gas ensures both reliability and resilience in power systems while supporting the broader transition to a low-carbon energy future.

3.3 The outlook for hydrogen demand and generation

Hydrogen continues to be considered a cornerstone of the global energy transition, offering versatile applications across transportation, industry, and power generation while contributing to decarbonisation goals. However, the past year has seen significant setbacks that have slowed its momentum. High production costs, particularly for green hydrogen generated via renewable energy, have hindered its competitiveness against hydrocarbons, leading to delays and cancellations of key projects. Policy uncertainties and regulatory ambiguities have also contributed to investor hesitancy, with tax incentives and strategic goals often criticised for lacking clarity or feasibility. Furthermore, ambitious targets for hydrogen production and deployment in regions like the EU have been labelled as overly optimistic, highlighting the challenges of scaling infrastructure and supply chains within the foreseeable future.

Current projections in the RCS indicate a significant increase in hydrogen demand, rising from 97 MtH$_2$ in 2023, where low-carbon hydrogen accounts for less than 1 MtH$_2$, to 257 MtH₂ by 2050. This estimate is, however, 41 MtH$_2$ lower than the forecast in the previous edition. Two key drivers underpin this growth: the steady expansion of hydrogen's traditional use as a feedstock in industries such as chemicals and refining and its emerging role as an energy carrier in hard-to-decarbonise sectors. These new applications—spanning industrial processes, transportation, and power generation—illustrate a shift in hydrogen's position within the global energy landscape, transitioning from a niche industrial input to an enabler of energy transitions.

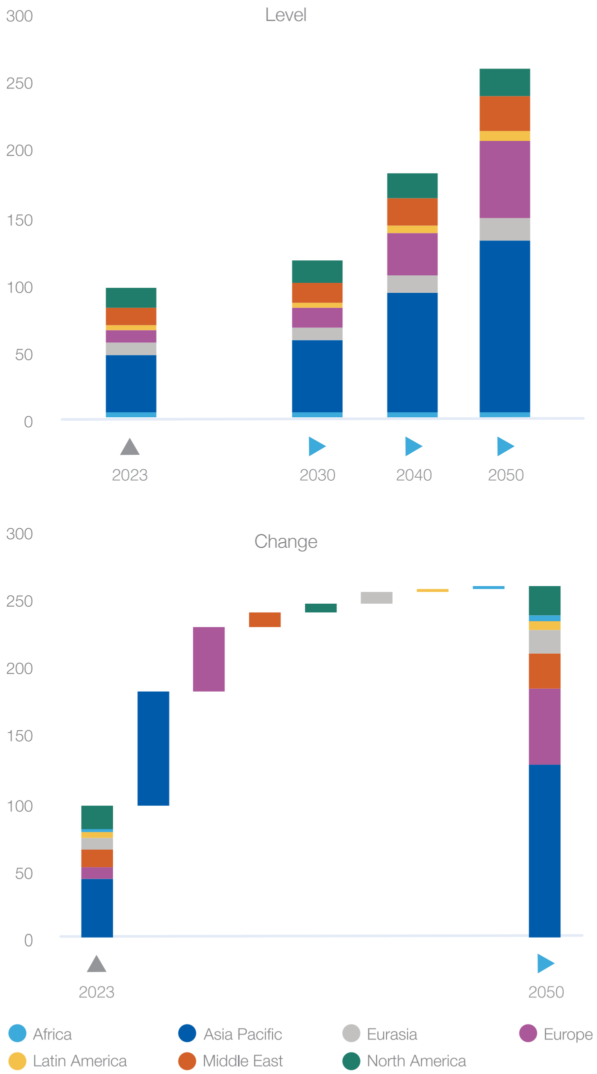
In 2023, Asia Pacific, North America, and the Middle East were the leading regions driving global hydrogen demand, contributing 45%, 16%, and 14% of total consumption, respectively. China accounted for 29% of global hydrogen demand as the largest single consumer, driven by its extensive industrial base and reliance on hydrogen as a feedstock.

Looking ahead to 2050, the landscape of hydrogen demand is expected to shift significantly, with Europe emerging as a key driver. This change will be propelled by ambitious policies promoting low-carbon hydrogen to achieve decarbonisation targets and reduce energy-related emissions. **Asia Pacific and Europe are forecast to dominate global hydrogen demand by mid-century, collectively accounting for more than 70% of total consumption, with Asia Pacific contributing 50% and Europe 22%.** As illustrated in Figure 3.13, both regions are projected to experience substantial growth in hydrogen demand over the forecast period. Asia Pacific is anticipated to see an increase of 84 MtH$_2$, maintaining its leadership in hydrogen consumption due to continued industrial expansion and investments in clean energy technologies. Meanwhile, Europe's hydrogen demand is expected to rise by 48 MtH$_2$, driven by the widespread adoption of low-carbon hydrogen across industries, transportation, and power generation. This underscores its role as a critical region in the global hydrogen transition.

In 2023, global hydrogen demand was predominantly driven by traditional applications, primarily as a feedstock and within the industrial sector. Hydrogen's primary

Figure 3.13

Global hydrogen demand outlook by region, 2023-2050 (MtH$_2$)



Source: GECF Secretariat based on data from the GECF GGM

use was in petrochemical production and oil refineries, accounting for a substantial 83% of total demand. The industrial sector, particularly the iron and steel industry, consumed an additional 16%, underscoring hydrogen's established role in energy-intensive industries. Emerging applications, such as power generation and transport, constituted only a small fraction of total demand, reflecting their nascent stage of adoption.

Looking ahead, the outlook anticipates significant growth in both traditional and emerging uses of hydrogen. Hydrogen is anticipated to transition into a more significant energy carrier, especially in sectors like transportation, power generation, and heavy industry, driven by the global push for decarbonisation. Applications in fuel cell electric vehicles (FCEVs), sustainable aviation fuels (SAF), and hydrogen-based power generation are expected to gain momentum, supported by technological advancements and policy incentives. Despite these advancements, hydrogen's role as a feedstock is projected to remain the largest driver of demand growth, particularly in the chemical, fertiliser, and refining sectors.

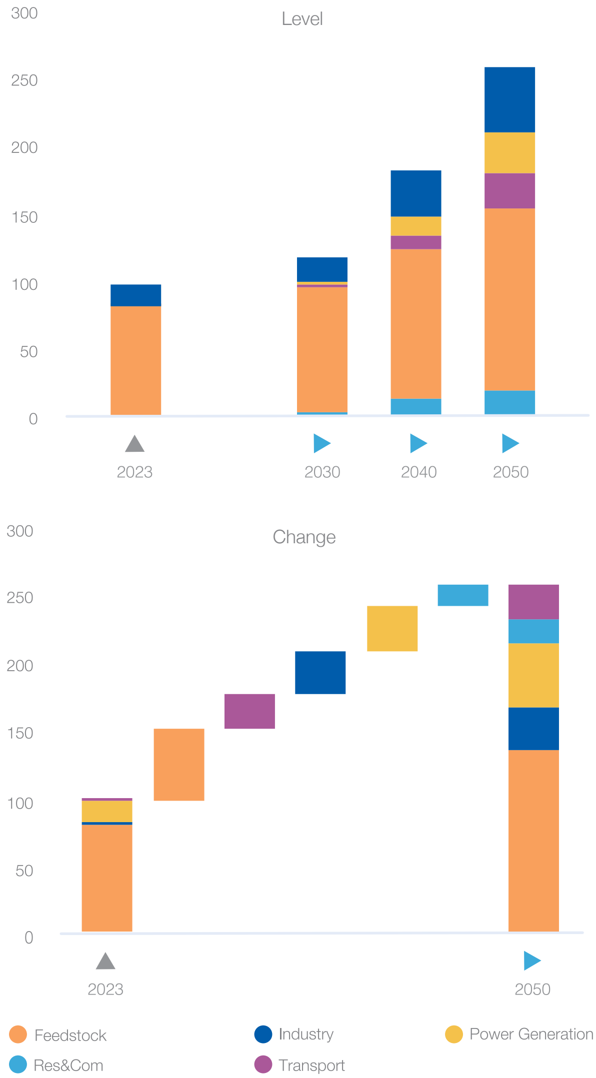
Hydrogen's role as a feedstock for chemical and refinery operations is projected to remain a primary driver of demand, accounting for 52% of global hydrogen consumption by 2050, equivalent to 135 MtH_2. This represents a 2% average annual increase from 2023 levels, underscoring the sustained reliance on hydrogen for industrial applications. By mid-century, its use as a feedstock is anticipated to align closely with its role as an energy carrier, reflecting balanced growth across both established and emerging applications (Figure 3.14).

Hydrogen is expected to see selective deployment in the transport sector, particularly through derivatives such as ammonia, methanol, and e-fuels. Demand in this sector is forecast to reach 26 MtH_2 by 2050, accounting for 10% of global hydrogen consumption. However, scaling hydrogen applications in transportation remains technically and economically challenging, especially in maritime shipping. Key constraints include ammonia's toxicity, hydrogen's wide flammability range, and the substantial costs and logistical complexities associated with large-scale storage infrastructure. In road transport, hydrogen's utilisation is expected to concentrate on heavy-duty applications, particularly long-haul trucking, where its high gravimetric energy density and rapid refuelling capabilities offer a clear advantage over battery-electric solutions. Despite these targeted advancements, the limited adoption of hydrogen across the broader transport sector, coupled with uncertainties in technology development and regulatory frameworks, has led to a downward revision of hydrogen demand projections compared to earlier assessments.

The power generation sector represents a complex and evolving landscape for hydrogen utilisation in its pure form. Hydrogen consumption in power generation is projected to surge from a modest 0.4 MtH_2 in 2023 to 30 MtH_2 by 2050, accounting for 12% of global hydrogen demand. This growth underscores hydrogen's emerging role in decarbonising the power sector and enhancing grid stability in the face of increasing reliance on variable renewable energy sources. The integration of hydrogen into power generation is anticipated to begin gradually around 2030, initially through small-scale hydrogen blending into natural gas grids. This approach allows existing infrastructure to be utilised while reducing carbon emissions from gas-fired power plants. Over time, as technology and infrastructure mature, hydrogen is expected to play a more important role as a standalone fuel in power plants designed specifically for hydrogen combustion or fuel cell applications.

Figure 3.14

Global hydrogen demand outlook by sector, 2023-2050 (MtH_2)



Source: GECF Secretariat based on data from the GECF GGM

Hydrogen also holds significant potential as an energy storage medium, addressing one of renewable energy's critical challenges: balancing supply and demand. By converting surplus electricity from renewable sources like wind and solar into hydrogen via electrolysis, it can be stored and later reconverted into electricity during periods of low renewable output. This capability enhances the flexibility and reliability of power systems, particularly as renewables expand their share of the energy mix.

The industrial sector is poised for substantial growth in hydrogen utilisation, with demand projected to reach 49 MtH_2 by 2050—an increase of 33 MtH_2 from current levels. This growth is set to elevate the industrial sector's share of total hydrogen demand to 19% by mid-century, driven primarily by China and Europe, where hydrogen is increasingly viewed as a sustainable solution for decarbonising energy-intensive industries, particularly steel manufacturing. Hydrogen's role in transforming steel production is expected to expand through two primary pathways. First, as a direct replacement for coal in iron ore reduction processes, hydrogen offers a cleaner, carbon-neutral alternative to traditional methods, significantly reducing emissions. Second, integrating hydrogen-natural gas blends into blast furnaces is gaining momentum, facilitated by advancements in hydrogen generation technologies and improved cost competitiveness.

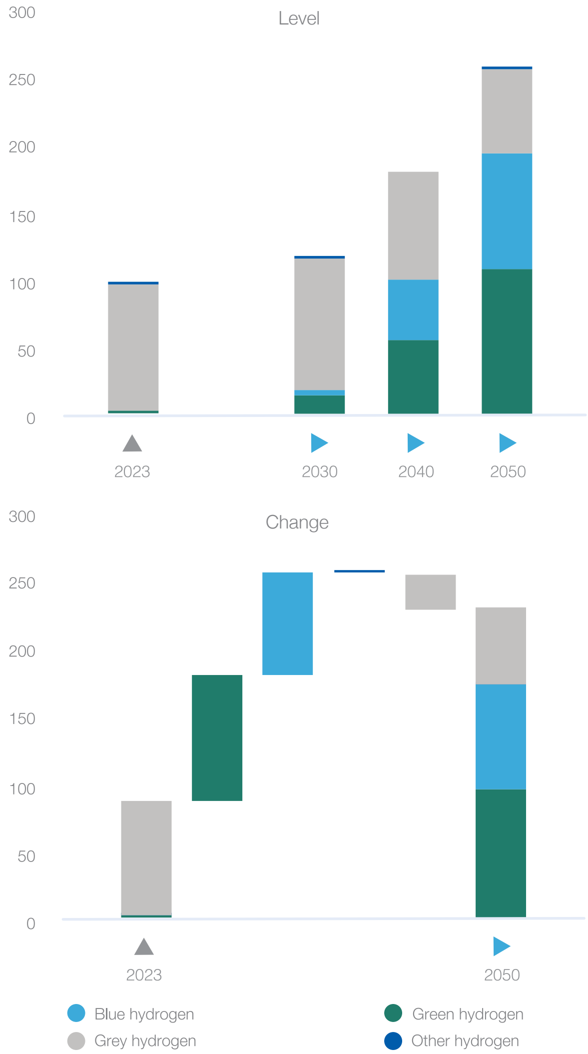
In contrast, the residential and commercial sectors are projected to make a comparatively modest contribution to hydrogen demand, accounting for only 7% of total consumption by 2050. This limited adoption in building applications, such as space and water heating, is attributed to several challenges. Safety concerns related to hydrogen handling in densely populated areas, lower system efficiency compared to alternative solutions, higher upfront costs, and the need for extensive infrastructure upgrades are significant barriers. Currently, electric district heating systems and advanced natural gas installations provide more efficient and cost-effective solutions for meeting building energy needs. Nevertheless, hydrogen is expected to carve out niche applications in these sectors. Hydrogen-natural gas blends for heating, fuel cell systems for combined heat and power (CHP) generation, and hydrogen-derived ammonia for specialised applications are projected to grow steadily. By 2050, hydrogen demand in the residential and commercial sectors is anticipated to reach 17 MtH_2, demonstrating its potential to complement existing energy solutions in targeted applications while contributing to broader decarbonisation efforts.

In 2023, hydrogen production was dominated by grey hydrogen, produced predominantly through steam methane reforming (SMR) processes that rely on natural gas and release significant CO_2 emissions. Grey hydrogen accounts for the vast majority of global hydrogen output, while low-carbon alternatives, such as green and blue hydrogen, represent less than 1% of total production. This highlights the early stage of the global shift toward cleaner hydrogen technologies and the considerable challenges still ahead.

Looking ahead, the RCS anticipates a transformative shift in hydrogen production, with green hydrogen, produced via water electrolysis powered by renewable energy sources, poised for significant growth. **By 2050, green hydrogen production is projected to reach 108 MtH_2, accounting for approximately 42% of global hydrogen output** (Figure 3.15). This remarkable expansion is driven by the confluence of several key factors: the declining costs of renewable energy, technological advancements in electrolysers, and robust

Figure 3.15

Global hydrogen generation outlook by technology, 2023-2050 (MtH_2)



Source: GECF Secretariat based on data from the GECF GGM

policy frameworks supporting decarbonisation initiatives. However, it is important to note that green hydrogen production remains energy-intensive and relatively inefficient compared to other energy carriers, posing challenges in terms of scalability and cost-effectiveness.

Blue hydrogen, produced via natural gas-based processes integrated with CCUS technologies, is also critical in the hydrogen economy. **By 2050, global blue hydrogen production is projected to reach 87 MtH_2, contributing 33% of total hydrogen output.** Natural gas-based blue hydrogen will dominate this category, with 70 MtH_2 expected, highlighting its strategic role as a transitional technology. The advantages of natural gas in blue hydrogen production are twofold: first, CCUS technologies are more cost-effective when applied to natural gas reforming compared to other hydrocarbon-based methods; second, the widespread availability of natural gas, coupled with existing SMR and auto-thermal reforming (ATR) infrastructure, ensures scalability and cost competitiveness, particularly in regions with abundant reserves and established gas networks.

Conversely, grey hydrogen is projected to decline significantly over the outlook period, falling by 30 MtH_2 to 65 MtH_2 by 2050 and representing just 25% of the hydrogen production mix. This decline is driven by rising carbon prices and stringent environmental regulations that make carbon-intensive production methods less economically viable. The shrinking share of grey hydrogen underscores the broader shift in the hydrogen landscape toward low-carbon production pathways.

Hydrogen production from natural gas, encompassing grey and blue hydrogen, is anticipated to reach 110 MtH_2 by 2050, surpassing total global hydrogen output in 2023. Despite the rise of green hydrogen, natural gas-based hydrogen will continue to account for 42% of global production, reflecting its enduring role in the hydrogen supply chain. Existing infrastructure, cost advantages, and the gradual nature of the energy transitions drive this sustained reliance. As the energy transitions accelerate, natural gas-based hydrogen is expected to bridge the gap, complementing the expansion of green hydrogen and supporting global decarbonisation efforts across industries and transportation.

The projected growth in hydrogen trade, increasing from minimal levels to approximately 73 MtH_2 by 2050, representing 28% of global hydrogen demand, reflects a cautious trend rather than an extraordinary development. Most of this growth is anticipated to occur after 2035, contingent on overcoming significant technical and economic barriers. Chief among these challenges are the energy-intensive processes of hydrogen conversion and liquefaction, which remain major obstacles to cost-efficient trade and widespread adoption. The Asia Pacific and Europe are expected to dominate long-term hydrogen imports, accounting for 57% and 41% of global hydrogen imports by 2050, respectively.

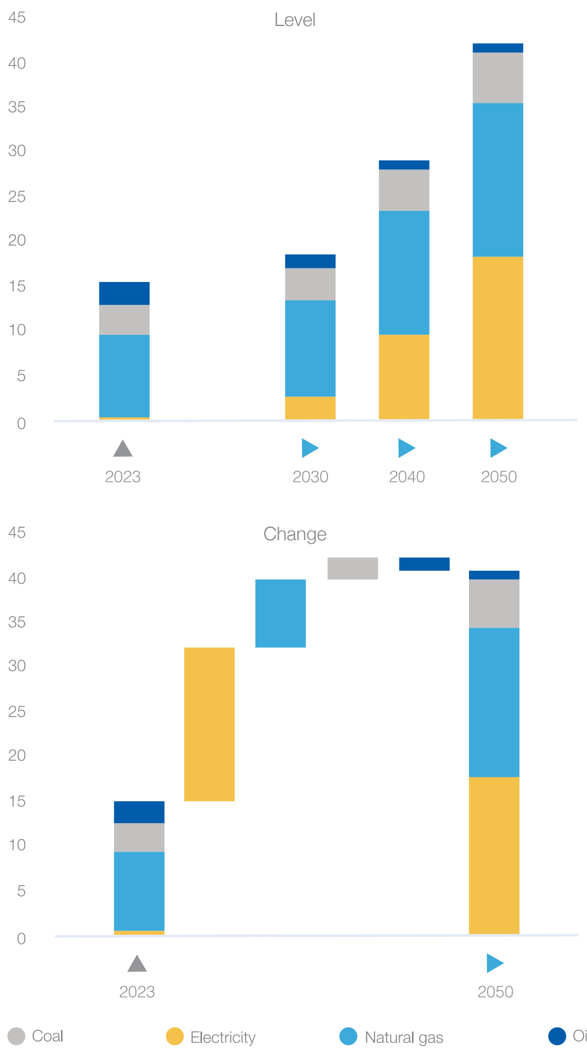
In 2023, the fuel mix for hydrogen production was dominated by natural gas, which accounted for 9.3 EJ, representing 61% of the total fuel input of 15.4 EJ. Coal played a significant role as the second-largest contributor, comprising 21% of the input mix. While oil represented 17% of fuel input for hydrogen production. In contrast, electricity's contribution was negligible, making up less than 1% of the total fuel input for hydrogen production.

Looking ahead to 2050, the fuel input requirements for hydrogen production are projected to undergo an impressive transformation in both scale and composition. Total fuel demand for hydrogen generation is forecast to rise to 42.1 EJ, marking a substantial growth of 26.7 EJ from 2023 levels, a 170% expansion over the outlook period (Figure 3.16). This growth reflects the rising importance of hydrogen in the global energy mix as a critical component of decarbonisation strategies across sectors.

While natural gas is expected to remain a cornerstone of hydrogen production, its share in the overall fuel mix is projected to decline to 41% by 2050 as the industry shifts toward low-carbon production methods. In absolute terms, however, natural gas consumption for hydrogen production will increase significantly, reaching 17.2 EJ by mid-century. Blue hydrogen production will emerge as a major driver, consuming approximately 8.2 EJ of natural gas as CCUS technologies are integrated to reduce emissions. In contrast, grey hydrogen production from natural gas is expected to experience a modest decline, decreasing by 0.9 EJ compared to 2023 levels, as carbon pricing and environmental

Figure 3.16

Global hydrogen fuel input outlook by source, 2023-2050 (EJ)



Source: GECF Secretariat based on data from the GECF GGM

Chapter 3

policies disincentivise high-emission production methods.

Understanding hydrogen's energy losses across the supply chain is essential, particularly for green hydrogen, as these losses directly impact its cost-effectiveness and feasibility for large-scale adoption. Up to 70% of green hydrogen production costs are linked to energy inputs, with additional energy required for compression, conversion, and transportation, further compounding the challenges. These losses also have significant implications for energy system design, as the reliance of green hydrogen on renewable electricity necessitates substantial investment in electricity generation capacity to meet production demands. By 2050, green hydrogen production alone could consume nearly 9% of global electricity demand, equivalent to just over 5,000 TWh, surpassing the current output of low-emissions electricity.

In this context, blue hydrogen presents a complementary and practical pathway to scale hydrogen production while mitigating emissions. Unlike green hydrogen, blue hydrogen is less reliant on renewable electricity, as it utilises the existing natural gas supply chain and CCUS technologies to produce low-carbon hydrogen. This reduces pressure on electricity generation and addresses near-term hydrogen demand more efficiently.

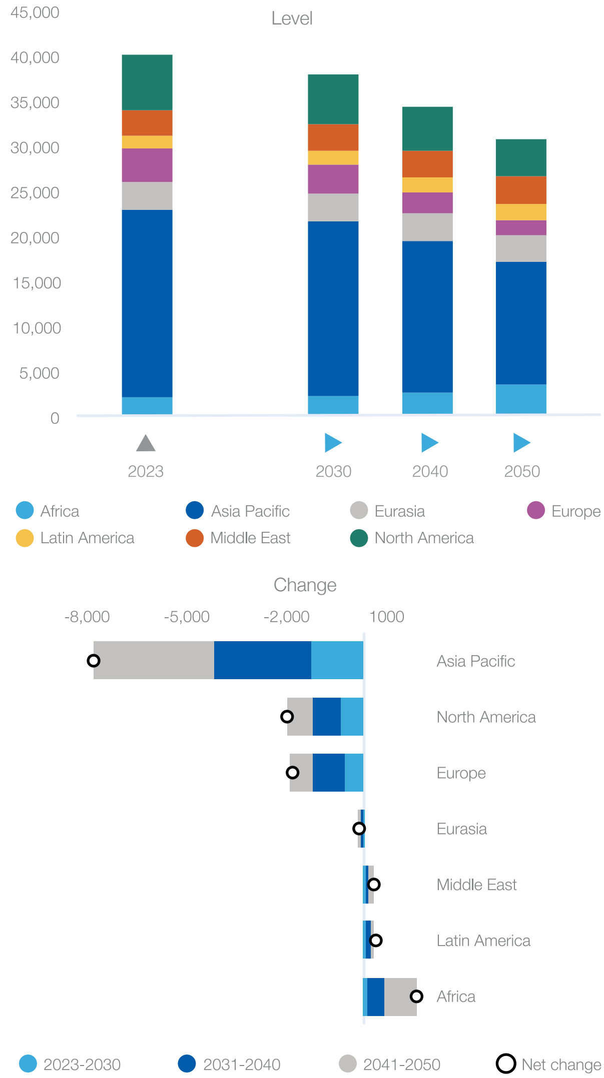
3.4 The outlook for energy-related emissions

In 2023, the rise in primary energy consumption increased energy-related emissions, though at a slightly slower pace. **Global energy consumption grew by 1.5% compared to 2022, while emissions increased by 1.4%, reaching a record high of 40.6 GtCO$_2$e.** The slower rate of emissions growth relative to energy consumption underscores the growing contribution of clean energy sources in the global energy mix. The accelerating adoption of renewable energy technologies and the shift toward lower-carbon fuels are reducing the intensity of emissions in energy consumption.

The RCS projects a 23% reduction in energy-related emissions by 2050, declining from 40.6 GtCO$_2$e in 2023 to 31.2 GtCO$_2$e—a slight improvement compared to last year's forecast of 32.1 GtCO$_2$e. This revised projection reflects the strengthening of global policy measures to accelerate the adoption of renewable energy, nuclear power, and carbon removal technologies. As illustrated in Figure 3.17, substantial contributions from key regions shape this anticipated decline, each playing a critical role in steering global emissions downward. The renewed focus on environmental priorities in 2023 catalysed this transition. Governments and industries responded with intensified commitments to decarbonisation, emphasising the expansion of renewable energy capacity, the integration

Figure 3.17

Global energy-related emissions outlook by region, 2023-2050 (MtCO$_2$e)



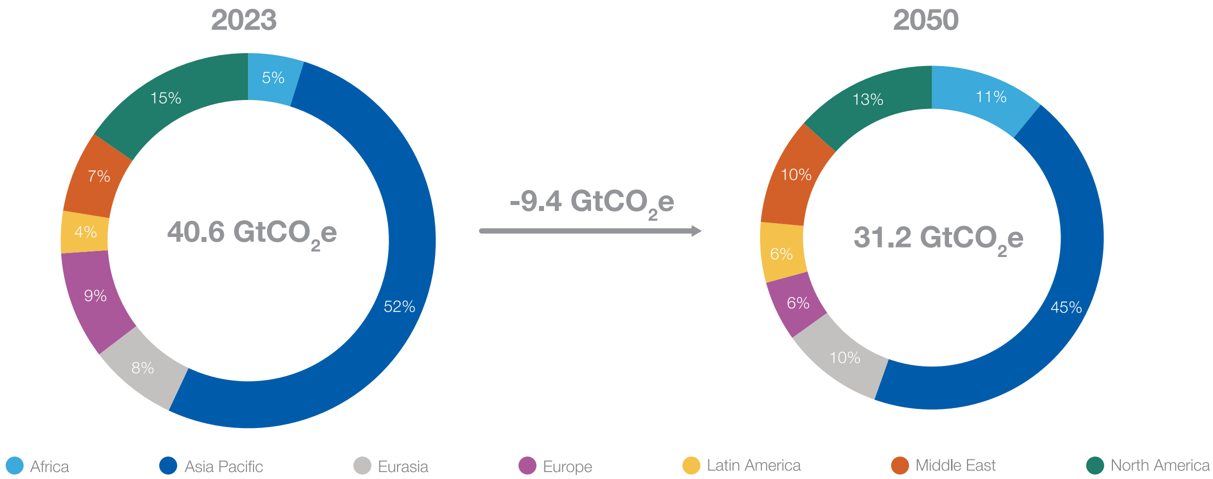
Source: GECF Secretariat based on data from the GECF GGM,
Note: Energy-related emissions include both combustion-related emissions and fugitive emissions of CO$_2$ and methane from energy sector

of low-carbon nuclear technologies, and the deployment of CCUS systems.

A significant milestone was achieved at COP28, where countries committed to transformative directives such as tripling renewable energy capacity and doubling energy efficiency improvements by 2030, phasing down unabated coal, and advancing low-emission technologies. These commitments have intensified pressure on countries to enhance their mitigation targets and accelerate the transition to low-carbon energy systems. Additionally, increased support for technologies like CCUS and blue hydrogen is expected to catalyse significant investments, providing critical momentum for decarbonisation efforts, particularly in hard-to-abate sectors.

Figure 3.18

Projected regional contribution to global energy-related emissions, 2023 and 2050 (%)



Source: GECF Secretariat based on data from the GECF GGM

By 2050, the Asia Pacific region is projected to account for an impressive 77% (-7.3 $GtCO_2e$) of global energy-related emissions net reductions despite being responsible for more than half of the world's primary energy demand growth. This remarkable decarbonisation effort hinges on a large-scale transition from coal, the region's predominant energy source, to cleaner alternatives such as renewables and natural gas. Solar and wind energy are expanding rapidly, with countries like China leading the charge through substantial investments in large-scale renewable projects. With its lower carbon intensity, natural gas plays a vital complementary role, facilitating coal phase-outs while providing the flexibility required to integrate intermittent renewables into power grids. Policies promoting carbon pricing, renewable energy subsidies, and technological innovations further drive this transformation, solidifying Asia Pacific's central role in global decarbonisation efforts.

North America and Europe are also expected to contribute significantly to global energy-related emissions reductions by 2050, with respective declines of -2.1 $GtCO_2e$ and -2 $GtCO_2e$ in global net reduction. As noted earlier, energy demand in these regions is projected to decline during this period, reflecting structural shifts in energy consumption and efficiency gains. Long-standing climate policies, widespread adoption of renewable energy, and advancements in energy efficiency underpin emission reductions in North America and Europe. Electrification of road transport and coal-to-natural gas switching have also played critical roles. In the United States, for example, coal-to-gas switching was the primary driver of emissions reductions in the electricity sector in 2023, enabled by competitive natural gas prices relative to coal since 2022 and the continued retirement of coal-fired power plants.

Conversely, energy-related emissions in Africa (+1.4 $GtCO_2e$), the Middle East (+0.3 $GtCO_2e$), and Latin America (+0.3 $GtCO_2e$) are projected to rise, driven by increasing energy demands and ongoing industrialisation in these regions. Africa's growing population and expanding energy access programs increase emissions, albeit from a very low levels, while industrial and infrastructural developments underpin similar trends in the Middle East and Latin America. In Eurasia, emissions are expected to stay unchanged (-0.1 $GtCO_2e$) over the outlook period.

Figure 3.18 depicts projected regional contributions to global energy-related emissions in 2023 and 2050. **Asia Pacific region emerges as a critical player in global decarbonisation efforts**, while other regions follow diverse trajectories based on their unique economic and energy contexts. In 2023, Asia Pacific dominated global emissions, accounting for 52% of the total, driven by its significant industrial base and reliance on hydrocarbons. North America and Europe followed, contributing 15% and 9%, respectively. In contrast, Latin America, Africa, the Middle East, and Eurasia represented smaller shares of global emissions, with contributions of 4%, 5%, 7%, and 8%, respectively. These disparities underscore the varying levels of economic development stage, energy transitions progress, and policy implementation capacity across regions.

Regions with relatively low current contributions to global energy-related emissions, such as Africa, the Middle East, and Latin America, are projected to see proportionally higher growth in emissions over the coming decades, albeit with smaller absolute increments. In contrast, major emitters like Asia Pacific, Europe, and North America are expected to achieve significant reductions, reshaping the global emissions landscape. By 2050, Asia Pacific region is forecast to remain the largest contributor to global energy-related emissions, though its share is anticipated to decline significantly due to substantial mitigation efforts. Emissions reduction in North America is expected to reduce its share of global energy-related emissions to 15% in 2050. Meanwhile, Africa is expected to rise in the rankings, overtaking Europe to become the third-largest contributor. The Middle East and Eurasia are projected to have similar emissions levels, sharing the fourth position, reflecting the shifting dynamics of global energy-related emissions.

When viewed per capita, the disparities in CO_2 emissions across regions are significant. In 2023, global per capita emissions were estimated at 4.6 tons of CO2 annually. Regions housing the majority of the world's population, Africa, Latin America, and Asia Pacific, record significantly lower per capita emissions. For instance, Africa, representing nearly 18% of the global population, emits less than 1 ton of CO_2 per person annually. This figure starkly contrasts North America, where per capita emissions are approximately 12 times higher, and Europe, with emissions roughly 9 times higher. These disparities underscore the unequal distribution of emissions and the distinct challenges different regions face in addressing climate change.

Future projections present a mixed yet promising outlook. As illustrated in Figure 3.19, **by 2050, global per capita CO_2 emissions are expected to decline significantly to 2.7 tons, driven primarily by aggressive mitigation efforts in Asia Pacific, North America, and Europe.** Europe, in particular, is poised to reduce its per capita emissions to below the global average, reflecting its determination in implementing advanced decarbonisation policies. In contrast, Africa and Latin America are projected to see increases in per capita emissions. By 2050, Eurasia, North America, and the Middle East are expected to maintain per capita CO_2 emissions higher than the global average. These trends highlight the critical importance of tailored regional strategies to achieve equitable and effective progress in global decarbonisation efforts.

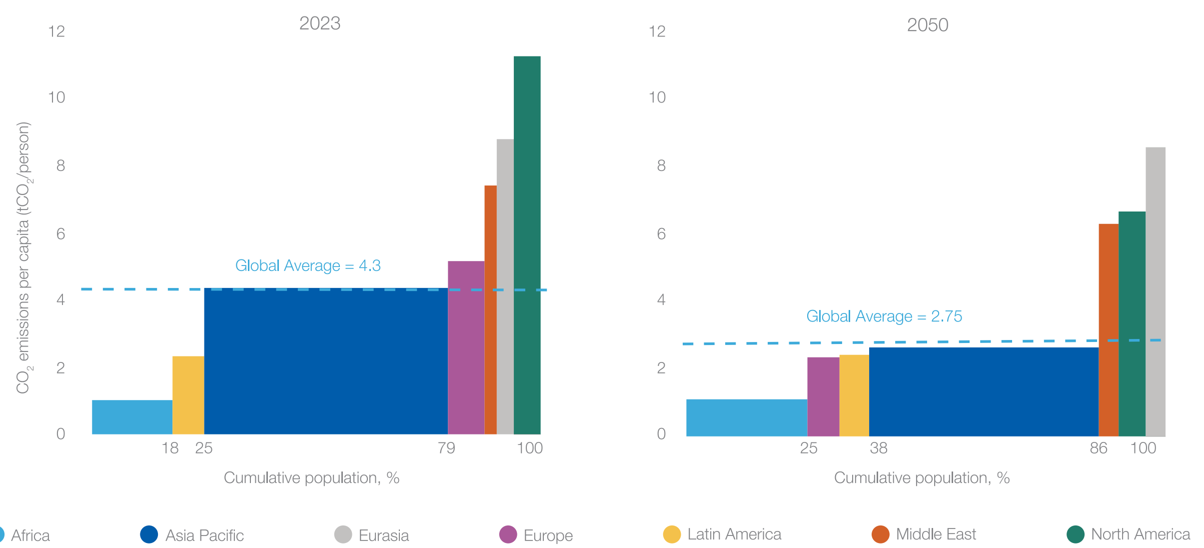
Over the outlook period, despite persistent growth in population, economic activity, and energy consumption, CO_2 emissions are projected to decline by 0.7% per annum, signalling a decoupling of energy consumption from CO_2 emissions. On a global scale, the positive drive exerted by population and economic growth on emissions is expected to be offset by improvements in energy efficiency (higher economic output per unit of energy consumed) and reductions in carbon intensity (lower emissions per unit of energy consumed).

However, these global trends mask significant regional differences driven by varying stages of development. This decoupling trend aligns with global patterns in Europe, North America, and Asia Pacific, where populations are ageing or declining, and economic growth is expected to moderate. In contrast, Africa, the Middle East, and Latin America are projected to experience higher population growth and robust economic expansion, making emissions reductions through energy efficiency improvements and decarbonisation strategies more challenging at their current stages of development. These regions are still in earlier phases of industrialisation, contributing a smaller share to global CO_2 emissions than more developed areas.

To contextualise this disparity, historical emissions provide critical insight into global responsibility for

Figure 3.19

Projected energy-related CO_2 emissions per capita in 2023 and 2050 (tCO_2/person)



Source: GECF Secretariat based on data from the GECF GGM

addressing climate change. Between 1850 and 2020, North America and Europe accounted for 52% 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 4%, 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 3.20 illustrates the sectoral contributions to global CO_2 emissions and their projected trends through 2050. **The power generation sector, the most significant contributor at 13.2 $GtCO_2$ in 2023, is expected to achieve the most significant reduction, declining by 1.1% per annum to 6.9 $GtCO_2$ by 2050.** This transformation is anticipated to be driven by the large-scale adoption of renewable energy sources like solar and wind, the phasing out of coal, improved thermal efficiency, and the transition to less carbon-intensive fuels such as natural gas. While the power sector is set to remain a significant source of emissions until around 2040, its share is anticipated to diminish significantly thereafter.

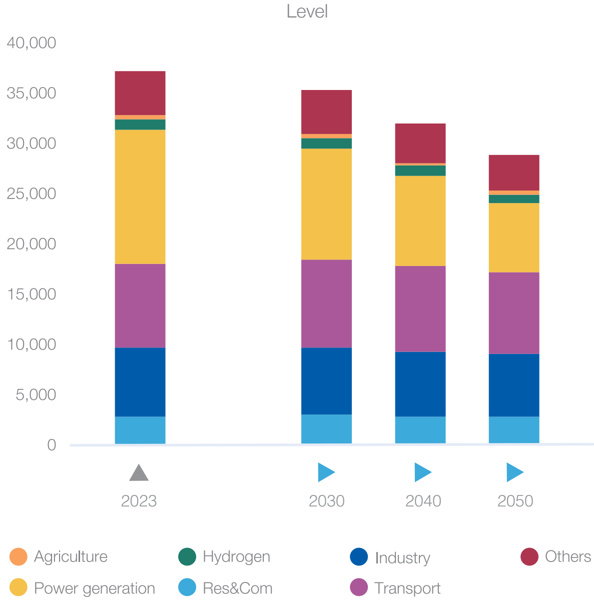
As emissions from the power sector decline, the transport sector is poised to become the dominant source of energy-related emissions by 2050. The transport sector is projected to account for 27% of global emissions, driven by increasing energy demands in freight and aviation. By comparison, the power generation sector's share is anticipated to fall to 22% (down from 34% in 2023), signalling a profound transformation in the global emissions landscape. Meanwhile, the share of the industrial sector is expected to rise to 20%, reflecting the ongoing challenges of decarbonising emissions-intensive processes like cement and steel production.

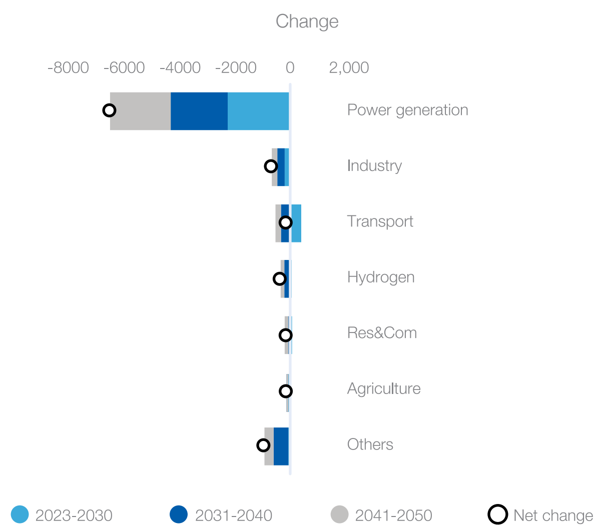
The global shift toward renewable energy, carbon removal technologies, and nuclear power, as outlined by RCS, signifies a transformative phase in addressing climate change. Within this evolving energy landscape, natural gas is an enabling fuel, bridging the emissions gap while facilitating the gradual shift to low-carbon energy systems.

Natural gas stands out as a cleaner alternative to higher-emission fuels like coal and oil. Its carbon intensity is nearly half that of coal and approximately 20% lower than oil, positioning it as a practical solution for immediate and cost-effective emission reductions. Natural gas can significantly lower greenhouse gas emissions while maintaining energy reliability and affordability by directly substituting coal and oil in power generation, industry, and transport sectors. This role is particularly evident in power generation, where

Figure 3.20

Global CO_2 emissions outlook by sector, 2023-2050 ($MtCO_2$)





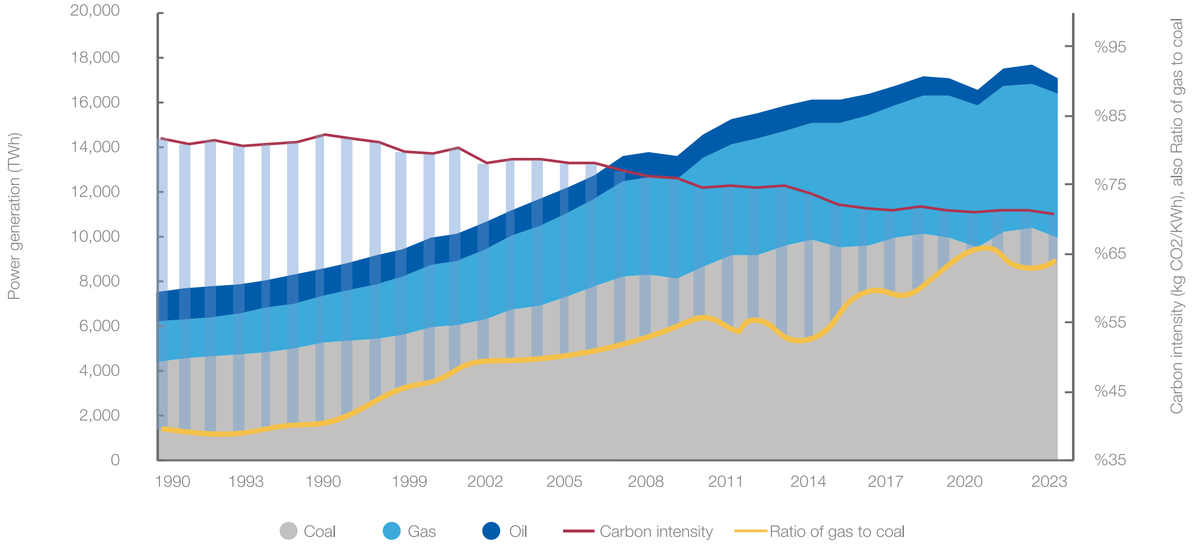
Source: GECF Secretariat based on data from the GECF GGM
Note: Others include district heating, refineries, coke ovens, energy sector own use and losses and fugitive CO_2 emissions

increasing the share of natural gas from 23% in 1990 to 35% in 2023 has led to a marked decrease in the emission intensity of electricity production, from 0.82 to 0.7 $kgCO_2$/kWh. This transition has resulted in cumulative CO_2 savings of 27 Gt over the past three decades.

Figure 3.21 highlights the strong correlation between the rising share of natural gas in the power generation mix (yellow line) and the concurrent decline in emission

Figure 3.21

Fossil fuel-based power generation (TWh), power generation carbon intensity (kg CO_2/kWh, RHS), the ratio of gas to coal in power generation (%, RHS), 1990-2023



Source: GECF Secretariat based on data from the GECF GGM

intensity (red line). This trend underscores natural gas's pivotal role in delivering affordable and reliable power to households and businesses while reducing emissions and air pollution. Moreover, natural gas supports the integration of renewable energy by providing the flexibility and stability required for an increasingly variable power grid, facilitating the transition to a cleaner and more sustainable global energy system. As renewable energy and carbon-neutral technologies scale up, natural gas will remain a vital complementary resource, ensuring grid reliability and acting as a reliable backup for the emerging power system.

The IPCC's Sixth Assessment Report (AR6) underscores natural gas's significant contribution to historical emissions reductions. It attributes the 0.3% annual decline in global carbon intensity from 2010 to 2019 primarily to the shift from coal to gas, the limited expansion of coal capacity, and the growing adoption of renewable energy sources. This transition highlights the importance of natural gas as an enabling fuel in the ongoing energy transitions, reducing emissions while ensuring energy security and reliability.

Renewables play a critical role in reducing emissions intensity, but their development is not progressing quickly enough to meet climate goals. While declining costs, abundant capital, and strong political support have accelerated the global shift toward renewable energy, these sources account for only around 3% of global primary energy demand. Meanwhile, hydrocarbons continue to supply approximately 80% of the world's energy needs, underscoring the scale of the challenge in transitioning to a low-carbon energy system.

Natural gas, often recognised as the cleanest fossil fuel, has significant potential to bridge this gap by facilitating immediate and substantial emissions reductions. Substituting coal with natural gas presents a practical and achievable pathway for lowering emissions in power generation and other sectors. Advancements in CCUS technologies further enhance this potential. By 2050, CCUS is projected to deliver annual global CO_2 savings of 2 Gt, with natural gas accounting for 27% of these reductions. This capacity to lower carbon intensity reinforces natural gas's position as a critical component in mitigating climate change.

Beyond its role in power generation, natural gas is indispensable for decarbonising hard-to-abate sectors where direct electrification remains infeasible. These include industries like steel, cement, chemicals, and long-haul transport. Natural gas also supports the emerging hydrogen economy by enabling the production of blue hydrogen, a cost-effective solution during the transition period. While green hydrogen holds promise for the long term, it remains cost-prohibitive and constrained by the need for renewable electricity in other high-priority applications. In this context, natural gas is essential for scaling hydrogen markets, ensuring progress toward decarbonisation goals while renewable technologies mature. Together, these factors underscore the strategic importance of natural gas as a destination fuel, capable of reducing emissions while supporting the long-term shift to a sustainable, low-carbon global energy system, particularly in the emerging and developing economies.

Addressing methane emissions from natural gas operations is critical to maximising natural gas's environmental benefits. In 2023, methane emissions contributed 8.6% (3.479 GtCO_2e) to the global energy-related emissions, with approximately half originating from the oil and gas sector and the rest primarily from coal. **Although methane emissions are projected to decrease to 2.45 GtCO_2e by 2050, their share of total emissions is expected to remain unchanged, highlighting the need for targeted mitigation efforts**.

Methane emissions are commonly expressed in CO_2-equivalents (CO_2e) to facilitate comparison and integration into GHG inventories. This involves converting methane emissions into the equivalent amount of CO_2 that would produce the same warming effect over a specified time horizon. Methane has a much higher warming potential than CO_2, approximately 28 times over 100 years, but a much shorter atmospheric lifespan, averaging about 12 years compared to centuries for CO_2. This dual nature introduces significant uncertainty into emissions calculations and complicates the assessment of methane's role in climate change. Moreover, the choice of the time horizon (e.g., 20 years or 100 years) significantly affects methane's perceived contribution to warming, influencing policy frameworks and mitigation strategies.

The Global Warming Potential (GWP) metric, introduced in the First IPCC Assessment Report (1990), has become the default standard for comparing emissions of different gases. However, it has notable limitations. The IPCC acknowledges that there is no universally accepted method for fully capturing all relevant factors in a single GWP value and that the exclusive use of a 100-year timeframe lacks a scientific basis. Subsequent studies have shown that **using GWP to convert emissions of short-lived gases like methane into cumulative CO_2-equivalents can misrepresent their contribution to future warming.** Alternative metrics (see Box 3.2) have been developed to address these shortcomings. The IPCC has committed to further refining these methodologies, with a particular focus on short-lived climate pollutants.

The Sixth Assessment Report (AR6) offers key insights into the interplay between GHG mitigation and global temperature trends. It emphasises that achieving net zero GHG emissions under the GWP-100 metric can result in reduced peak global surface temperatures after net zero is reached. However, the sequence in which short-lived and long-lived GHGs are mitigated is critical. If mitigation efforts address both short-lived species, such as methane, and long-lived species, like CO_2, simultaneously, global temperatures are likely to peak and then decline. Conversely, addressing short-lived species earlier than long-lived ones tends to stabilise temperatures near their peak rather than cause significant declines. This underscores the importance of a balanced mitigation strategy that effectively addresses both types of emissions.

AR6 further highlights that achieving net zero GHG emissions does not require the complete elimination of non-CO_2 emissions. For instance, stronger reductions in CO_2 relative to methane under the GWP-100 metric can still lead to declining surface temperatures. This suggests that limiting or gradually reducing non-CO_2 emissions, rather than eliminating them entirely, may suffice to stabilise global temperatures and curb human-induced warming.

This nuanced understanding of GHG dynamics underscores the need for strategic mitigation efforts that account for the unique characteristics of different greenhouse gases. Policymakers must prioritise significant reductions in CO_2 emissions, given their long-term impact on global warming, while managing non-CO_2 emissions like methane to balance short-term climate benefits with long-term stabilisation goals. By adopting a holistic and scientifically informed approach, global climate targets can be achieved more effectively and equitably.

Box 3.2 Methane emission metrics

Emissions metrics evaluate and compare the relative impacts of different GHG emissions over time. These metrics quantify the effect of a specific emission's unit mass on key climate change indicators, such as radiative forcing, global surface air temperature (GSAT) changes, global average precipitation changes, or global mean sea level rise.

There is a cause-and-effect chain linking human activity to emissions, which then lead to radiative forcing, climate responses, and ultimately climate impacts. Each step in this chain relies on inference or modelling frameworks to map causes to effects. Emissions metrics serve as tools to connect emissions of a specific compound to various points further along the chain, such as radiative forcing (e.g., Global Warming Potential, GWP), temperature changes (e.g., Global Temperature Potential, GTP), or other impacts like sea level rise or socio-economic consequences.

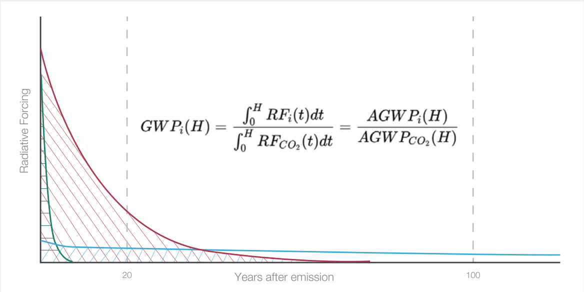
Although variables further along the cause-and-effect chain hold greater policy and societal relevance, they are also associated with higher uncertainty. This is because each step in the chain involves additional modelling systems, each introducing its own level of uncertainty.

IPCC, the United Nations body responsible for assessing climate science, has been working on emissions metrics since 1990. In its First Assessment Report (AR1, 1990), the IPCC introduced the concept of Global Warming Potential (GWP). The report noted that there was no universally accepted methodology for combining all relevant factors into a single metric and a simple approach—GWP—was adopted to highlight the complexities of the concept. GWP evaluates pulse emissions of individual gases by integrating their radiative forcing over a specified time horizon (Figure 2).

The First Assessment Report (AR1) introduced three time horizons—20, 100, and 500 years—for consideration, emphasising that these timeframes had

Figure 2

Estimation of GWP and GTP from emission pulses



Source: IPCC, Assessment Report 5 (AR5)
Note: The Absolute Global Warming Potential (AGWP) is determined by integrating the radiative forcing (RF) from emission pulses over a specified time horizon, such as 20 or 100 years (indicated by vertical lines). The Global Warming Potential (GWP) is calculated as the ratio of the AGWP of a given component (i) to the AGWP of the reference gas, CO_2. The blue hatched area represents the integrated RF from a CO_2 pulse, while the green and the red regions represent example gases with atmospheric lifetimes of 1.5 years and 13 years, respectively.

no inherent significance. A few years later, the 100-year time horizon was adopted for use under the Kyoto Protocol.

In 2007, the Fourth Assessment Report (AR4) reaffirmed that GWP remained the recommended metric for comparing the future climate impacts of emissions from long-lived gases, despite several acknowledged limitations. However, in 2009, the IPCC noted that the suitability of a given metric depends on the primary policy objective and highlighted that GWP was not designed with a specific policy goal in mind. Consequently, alternative metrics might be more appropriate depending on the intended policy goals.

The Fifth Assessment Report (AR5) emphasised that the choice of the most appropriate metric and time horizon depends on which aspects of climate change are most relevant to a specific application. No single metric can fully capture all the consequences of different emissions, and each comes with inherent limitations and uncertainties. AR5 introduced a new metric, the Global Temperature Potential (GTP), which accounts for the temperature response over a selected time horizon.

Similar to GWP, the values of GTP vary depending on the chosen time horizon.

CO_2 has a very long response time in the climate system. When a 100-year time horizon is used, the extended impacts of CO_2 are not fully captured, presenting a challenge when comparing short-lived gases, such as methane, which has a lifetime of approximately 12 years, to long-lived gases like CO_2.

Since AR5, significant advancements have been made in understanding and accounting for the differing behaviours of short-lived and long-lived GHGs. AR6 introduces new metric concepts to address these differences. These metrics are based on the principle that the climate impact of a step change in the emission rate of short-lived GHGs (measured in kg/yr) can be compared to the impact of a one-off pulse emission of CO_2 (measured in kg). For example, while the global surface temperature change caused by a pulse of CO_2 remains relatively constant over time, the temperature change from a pulse of short-lived GHG emissions diminishes over time. In fact, Warming from CO_2 is proportional to its cumulative emissions, whereas warming from short-lived gases depends on their emission rates.

One newly introduced metric is the Combined Global Temperature Potential (CGTP), which links a step change in short-lived GHG emission rates over a specified period to a one-off pulse emission of CO_2. Unlike the standard GTP, which is dimensionless, CGTP is expressed in units of years. This metric exhibits less variation over time compared to the standard GTP. It provides a scaling for comparing changes in short-lived GHG emission rates (in kg/yr) with pulse emissions or cumulative CO_2 emissions (in kg).

The IPCC will continue to assess emission metrics, and the results will guide future decisions by the UNFCCC. The choice of a metric depends on policy goals, principles, and how it is used. Metrics bridge science and policy, requiring ongoing collaboration between scientists and policymakers. Currently, the 100-year GWP is used to calculate the CO_2 equivalent of greenhouse gas emissions in national reporting, but new findings could lead to changes in this approach.

3.5. Energy intensity and consumption per capita prospects

Energy efficiency is critical in decoupling economic growth from energy consumption, enabling economies to produce more while using less energy. The effectiveness of energy efficiency is commonly assessed through energy intensity, a key indicator that measures the percentage decrease in the ratio of primary energy demand to GDP, widely expressed in real USD. This metric provides valuable insights into how effectively energy is utilised in economic activity.

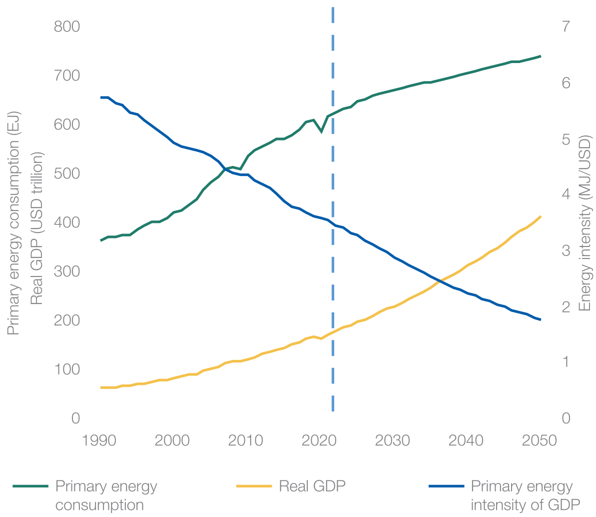
In 2023, global energy intensity improved by 1.7% despite relatively modest economic growth of 3.1% (in PPP terms) and a concurrent 1.5% increase in energy consumption. This reduction aligns closely with the historical trend of energy intensity improvements, which averaged 1.8% annually over the past two decades. Technological advancements, structural economic shifts, and targeted policy measures have driven this improvement over the past years. The phase-out of inefficient industrial facilities, replaced by modern technologies with lower energy intensity, has been pivotal, particularly in energy-intensive sectors like steel and cement. Simultaneously, advancements in building technologies, such as high-efficiency insulation, smart systems, and energy management tools, have significantly reduced energy use in residential and commercial spaces. A global shift toward less energy-intensive industries, coupled with the rapid expansion of the services sector, has further decoupled energy consumption from economic growth. Additionally, stringent energy efficiency policies, such as appliance performance standards and building codes, have accelerated adoption across sectors, while the electrification of processes and the integration of digital tools, like AI and IoT, have enhanced energy optimisation.

The RCS projects a notable improvement in energy efficiency, with energy intensity declining at an average annual rate of 2.4% between 2023 and 2050. By the end of the forecast period, energy intensity is expected to reach 1.8 MJ per USD (PPP, base year = 2023), reflecting a significant decoupling of energy consumption from economic growth. However, as illustrated in Figure 3.22, these substantial advancements will not fully decouple economic activity from energy demand. Primary energy consumption is projected to continue growing through 2050, with no peak in sight within the forecast horizon. This dynamics highlights the complex interplay between efficiency gains and underlying drivers of energy demand, such as population growth, industrial expansion, and rising living standards, particularly in developing economies. While improvements in energy efficiency mitigate the pace of energy consumption growth, they are insufficient on their own to achieve absolute reductions in primary energy demand.

Energy efficiency trends differ markedly across regions and are unlikely to follow a uniform trajectory due to varying economic structures, levels of development, demographic dynamics, climatic conditions, and urbanisation rates. Developed regions with advanced energy systems may focus on incremental efficiency improvements and integrating digital technologies while developing regions face the dual challenge of addressing energy access and reducing energy intensity. These disparities highlight the complexity of global energy efficiency progress, with each region charting its unique path shaped by its specific circumstances and priorities. In 2023, Europe emerged as the most energy-efficient region globally, followed by Latin America. Europe's energy efficiency leadership is attributed to its mature policy frameworks, widespread adoption of advanced energy-saving technologies, and the ongoing shift toward low-energy-intensity service industries. As depicted in Figure 3.23, Europe is projected to retain its position as the most energy-efficient region through

Figure 3.22

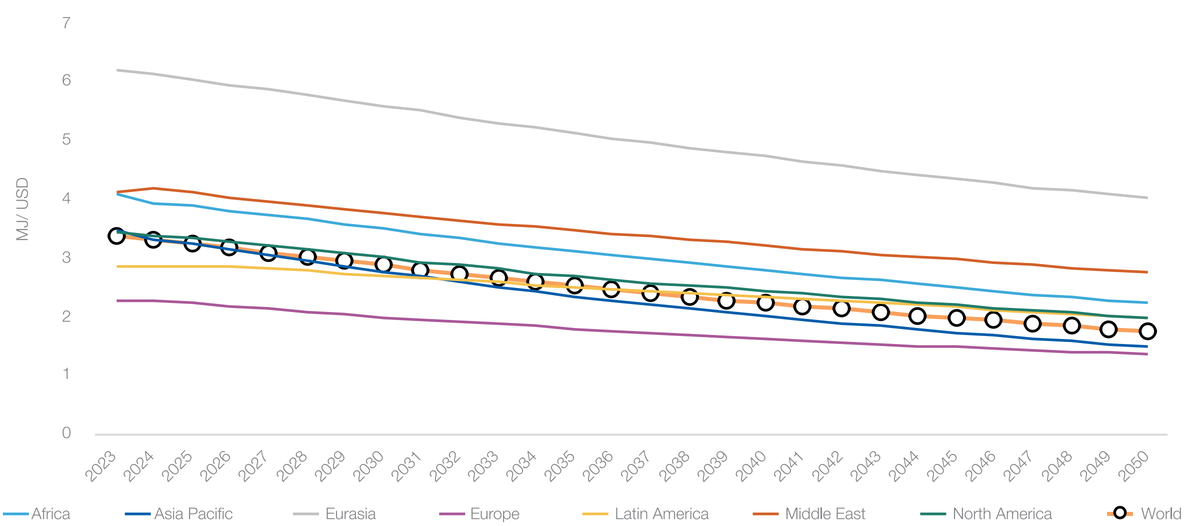
Global energy intensity improvement outlook, 2023-2050



Source: GECF Secretariat based on data from the GECF GGM
Note: GDP in PPP terms (base year = 2023)

Figure 3.23

Projection of regional energy intensity, 2023-2050 (MJ/USD, PPP, base year = 2023)



Source: GECF Secretariat based on data from the GECF GGM

2050, with energy efficiency improving at an annual rate of 1.9%. This gradual pace reflects the region's already high baseline efficiency, where further advancements become progressively more challenging.

In contrast, **the Asia Pacific region is poised for a significant transformation in energy efficiency, with annual improvements of 3.1% forecasted over the outlook period—surpassing the global average.** This robust growth is driven by industrial modernisation, policy mandates for energy conservation, and large-scale investments in energy-efficient infrastructure, particularly in countries like China and India. By 2050, Asia Pacific is expected to become the second most energy-efficient region, overtaking Latin America and closing the gap with Europe.

North America is also set to completely decouple economic activity and energy use, with annual energy efficiency improvements projected at 2%. The region's advancements are supported by stringent efficiency standards in buildings and vehicles, increasing electrification, and a continued shift toward less energy-intensive industries.

Africa stands out as a region experiencing remarkable energy efficiency growth, with a forecasted annual improvement of 2.2%. This progress is underpinned by efforts to modernise energy systems, phase out inefficient biomass use, and expand access to cleaner and more efficient energy sources like natural gas and renewables. By the end of the forecast period, Africa's energy intensity is expected to converge with that of Latin America, surpassing the Middle East and Eurasia.

Despite being the second most energy-efficient region globally in 2023, Latin America is anticipated to see the slowest rate of improvement, averaging 1.3% annually through 2050. This slower pace reflects the region's reliance on existing efficiency practices and limited new technological and policy advancements compared to other regions.

It is important to note that energy efficiency improvements exhibit two fundamental characteristics influencing their effectiveness as a long-term strategy. First, energy efficiency gains are not incremental and unlimited; they approach an upper limit as technologies and processes near their maturity stage in their life cycle. As the "low-hanging fruit" of efficiency improvements is harvested, further advancements become increasingly costly and technically challenging, requiring more sophisticated technologies and substantial investments. This diminishing return poses a significant barrier to achieving continuous progress in energy efficiency, particularly in sectors where efficiency levels are already high. Second, energy efficiency often triggers a rebound effect, where reduced energy costs in the consumption basket lead to increased energy use or related activities, offsetting some of the initial efficiency gains. This effect is particularly pronounced in regions with lower per capita energy consumption, such as Sub-Saharan Africa, where improved energy affordability can drive higher energy demand to meet unmet heating, cooling, or mobility needs.

Despite projected improvements in global energy efficiency, per capita energy consumption is expected to decline slightly by 2050 compared to 2023. Primary energy consumption is forecast to grow at an annual rate of 0.6%, but this will be outpaced by population growth of 0.7% per year, resulting in a marginal annual decline of 0.1% in per capita energy use. This trend reflects the combined effects of modest energy demand growth and the pressures of a growing global population. However, this decline in per capita energy consumption is not necessarily indicative of progress, as it may point to underlying disparities in energy access and consumption patterns, particularly in regions where unmet energy needs remain high.

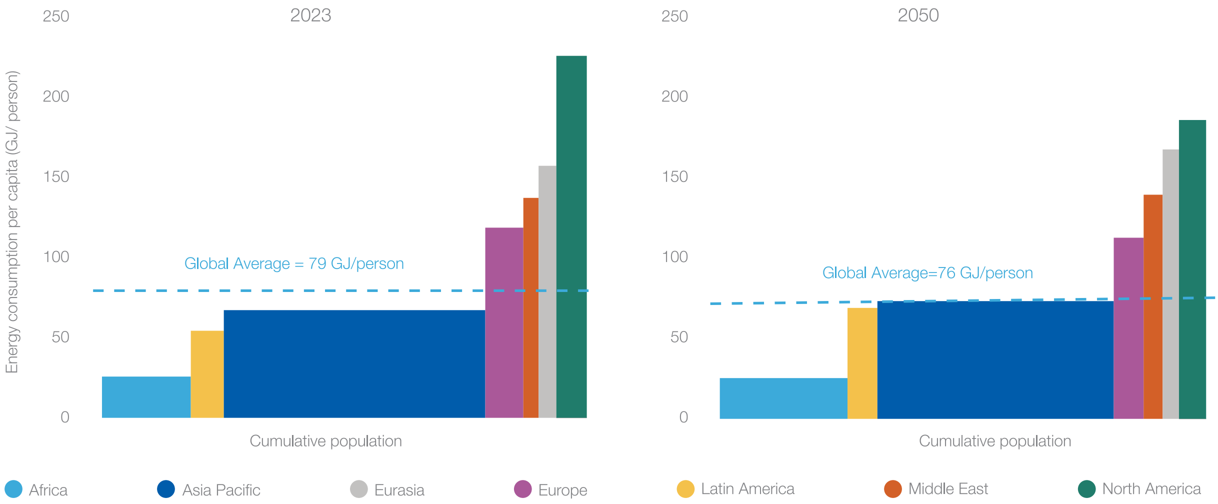
As of 2023, approximately 770 million people worldwide still lack access to electricity, with the majority concentrated in Sub-Saharan Africa, where around 600 million individuals remain without reliable power. Additionally, over 2 billion people globally continue to rely on polluting fuels for cooking, posing severe health risks and environmental challenges. These energy access disparities are particularly critical in regions experiencing rapid population growth, such as Sub-Saharan Africa, further compounding the issue's urgency. While global energy efficiency improvements can moderate energy demand growth, they do not address the fundamental need for equitable access to clean and affordable energy. Bridging this gap requires substantial investments in infrastructure, innovative energy solutions, and targeted policies to ensure inclusive progress toward sustainable development goals.

The global average primary energy consumption per capita, a widely used indicator of energy access, is projected to decline slightly from 79 GJ per person in 2023 to 76 GJ per person by 2050. This modest reduction reflects global energy efficiency improvements, but masks significant regional disparities driven by varying population growth rates, economic structures, and energy consumption patterns (Figure 3.24).

In 2023, per capita energy consumption revealed stark contrasts across regions. Africa recorded the lowest level of primary energy consumption at 25.7 GJ per person, highlighting its severe energy access challenges. Despite being home to 18% of the global population, Africa's energy consumption per capita was approximately 9 times lower than North America, which registered the highest level at 226 GJ per person. Notably, North America accounted for only 6% of the global population but consumed disproportionately high amounts of energy, reflecting its advanced industrial base, widespread electrification, and high living

Figure 3.24

Regional primary energy consumption per capita forecast (2023 vs. 2050) (GJ/person)



Source: GECF Secretariat based on data from the GECF GGM

standards. Similarly, Europe, Eurasia and the Middle East also recorded above-average energy consumption per capita, driven by industrialisation, climatic needs, and energy-intensive lifestyles.

In contrast, Africa, Latin America, and the Asia Pacific region, representing 80% of the global population in 2023, fell below the global average in per capita energy consumption. This disparity underscores a significant inequity in energy access and utilisation. Regions with below-average energy consumption often face challenges such as limited infrastructure, reliance on traditional biomass, and lower economic development, which hinder their ability to achieve equitable energy access.

The projected energy consumption per capita under the RCS scenario indicates that the global average will remain relatively stable through 2050. However, regional energy consumption per capita disparities are expected to persist, though with lower level of regional inequality, reflecting variations in population dynamics, economic structures, and energy access. Europe and North America are forecast to experience per capita energy consumption declines, driven primarily by a faster reduction in primary energy demand rather than population changes. Despite this decline, these regions are anticipated to retain their status as energy-intensive economies, characterised by well-developed transportation networks, high living standards, and industries requiring substantial energy inputs.

Conversely, Eurasia, the Middle East, Asia Pacific, and Latin America are projected to see an increase in energy consumption per capita, reflecting the combined impacts of population growth, urbanisation, and industrialisation. These regions are expected to experience rising energy demand, influenced by expanding energy-intensive industries such as oil and gas production, heavy manufacturing, and industrial processes. While energy consumption per capita in these regions is set to grow, the pace and magnitude of this growth will vary, shaped by regional policies, resource availability, and technological adoption.

Africa presents a unique case. Despite rapid population growth and rising energy demand, the per capita energy consumption increase is projected to remain modest. This reflects the region's ongoing struggle with energy access and reliance on traditional and less efficient energy sources. By 2050, energy consumption per capita in Africa, Latin America, and the Asia Pacific—collectively housing nearly 80% of the global population—is expected to remain below the global average. This highlights the persistent challenge of ensuring equitable access to affordable, reliable, and sustainable energy for all. Addressing this disparity, particularly in Africa, will be critical for achieving global sustainability goals and bridging the gap between energy availability and socio-economic development over the forecast period.

Chapter 4

Natural Gas Demand Outlook

Highlights

- The RCS forecasts a 32% increase in global natural gas demand, rising from 4,018 bcm in 2023 to 5,317 bcm by 2050, reflecting an average annual growth rate of 1%.
- Natural gas demand in the power sector is projected to grow by 1.1% per year, adding approximately 475 bcm to reach 1,866 bcm by 2050. This growth is driven by energy transition policies, the electrification of transport, balancing intermittent renewable sources, and expanding electricity access worldwide. The power sector is expected to remain the primary driver of natural gas demand.
- In the industrial sector, natural gas demand is forecast to increase by 238 bcm, reaching 1,095 bcm by 2050. This sector will retain its position as the second-largest consumer of natural gas, driven by its critical role in manufacturing, petrochemicals, and high-heat industrial processes.
- The transport sector will see demand grow by 3.5% per annum, from 165 bcm in 2023 to 430 bcm by 2050, with the bulk of this growth stemming from the scaling of LNG-powered vehicles and marine vessels.
- The use of natural gas for hydrogen production is expected to grow rapidly, rising from 259 bcm in 2023 to 480 bcm by 2050, as hydrogen becomes a key strategy of decarbonisation strategies in hard-to-abate sectors.
- In Asia Pacific, natural gas demand is projected to grow at an annual rate of 2.0%, increasing from 871 bcm in 2023 to 1,581 bcm by 2050. The share of natural gas in the region's energy mix is expected to rise significantly, from 11% in 2023 to over 16% by 2050.
- Europe's natural gas demand is expected to decline, dropping from 463 bcm in 2023 to 309 bcm by 2050. This reflects a reduction in its share of total energy demand from 21% to 16%, driven by aggressive decarbonisation policies, deindustrialisation, and the growing penetration of renewables.
- In North America, natural gas demand is expected to remain relatively stable, with a moderate rise this decade leading to a prolonged plateau at 1,183 bcm in 2030s before declining slightly to 1,083 bcm by 2050, representing a drop of 77 bcm from 2023 levels.
- In the Middle East, natural gas demand is forecast to grow by 2.0% annually, rising from 554 bcm in 2023 to 865 bcm by 2050. Despite this growth, its share in regional power generation is expected to decline from 73% in 2023 to 61% by 2050, reflecting the rapid penetration of renewables.
- Africa is expected to exhibit the fastest growth globally, with demand increasing by 3% annually, from 170 bcm in 2023 to 385 bcm by 2050. This expansion is anticipated to elevate natural gas's share of the continent's energy mix from 16% today to 21% by 2050, driven by increased energy access and industrialisation.

4.1 Natural gas demand outlook

In 2023, global natural gas demand remained level compared to 2022, a year that had already recorded a 1.5% drop relative to 2021. Although the extreme price surges and volatility of 2022 did not recur in 2023, regional disparities persisted. Lower consumption in Europe was largely offset by higher demand in the Asia Pacific, driven by concerns over energy security and ongoing economic recovery. By 2024, the market had gradually rebalanced and returned to structural growth, with global natural gas demand rising by 2.8% (+115 bcm) to reach a new record of 4,145 bcm—primarily supported by expansion in the Asia Pacific. Early assessments suggest that in 2024, natural gas met around 40% of the increase in world energy demand, outpacing all other fuels.

4.1.1 Recent developments and global natural gas demand outlook

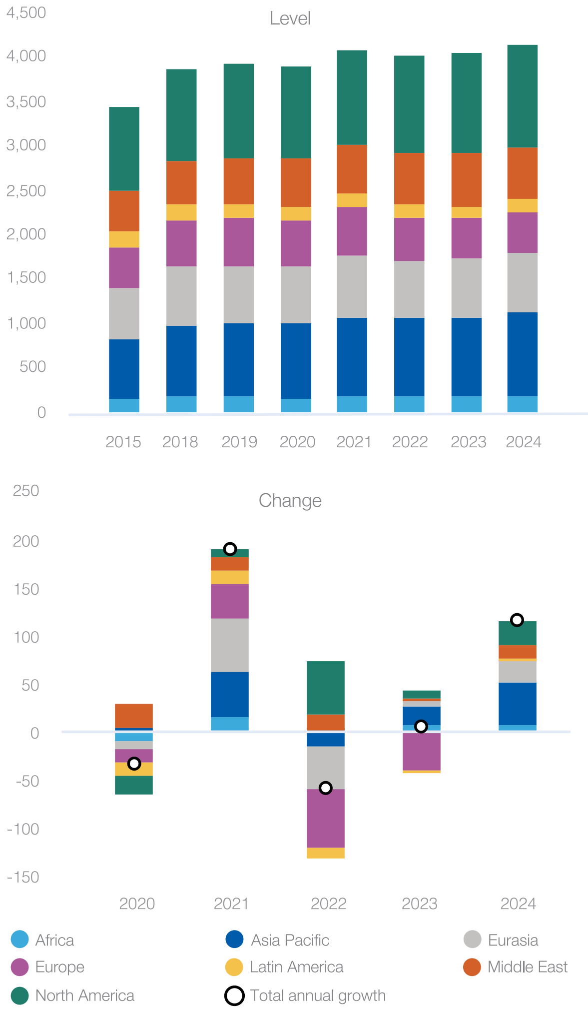
Global natural gas demand stabilised at about 4,018 bcm in 2023, following a 1.5% decline in 2022. Lower prices and a strengthening global economy supported demand growth in the power generation, transport, and industrial sectors, while residential and heating use continued to decrease. Record-high summer temperatures pushed up cooling requirements in many regions, while milder European winters reduced heating needs, tempering the overall rebound. As a result, although demand did partially recover, it remained below 2021 levels.

In 2024, global natural gas consumption increased by 2.8% to a record 4,145 bcm, reflecting both market rebalancing and renewed structural growth. The Asia Pacific region accounted for 45% of this uptick, propelled chiefly by industrial demand and the energy sector's own use. Further boosting natural gas use was the expanding fleets of LNG-fueled trucks and LNG bunkering. Meanwhile, extreme winter weather in the United States and Europe, severe heatwaves in India, and droughts in Brazil and Colombia underscored the necessity of flexible gas supplies for both heating and electricity security (Figure 4.1).

In the Asia Pacific, natural gas demand increased by 21 bcm, or 2.4%, in 2023, making it a key driver of global growth. This recovery was led by China and India, which offset declines in Japan and South Korea. In China, easing COVID-19 restrictions and robust economic growth spurred demand across all consuming sectors. Similarly, in India, declining LNG prices and lower domestic gas prices supported demand recovery in power generation, industrial applications, and road transport, reflecting the country's economic rebound and commitment to cleaner energy sources. However, Japan and South Korea witnessed demand declines due to milder weather, energy-saving measures, increased nuclear power output, and a growing share

Figure 4.1

Global natural gas demand by region, 2015-2024 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

of renewables in their energy mix. **In 2024, natural gas demand in the Asia Pacific region increased by 71 bcm (7.8%), accounting for 70% of global growth. This was mainly driven by the stabilisation of gas prices and a shift from coal to gas.**

North America saw a 9 bcm increase in natural gas demand in 2023 and a 6 bcm increase in 2024, driven largely by the United States. Competitive gas prices and the phase-down of coal-fired plants boosted gas use in power generation. Additionally, the growing share of renewables in the energy mix heightened the need for flexible gas-fired generation to ensure grid stability. This underscores natural gas's vital role as a backup for intermittent renewable energy systems, which are gradually becoming a dominant feature of the global power landscape.

In contrast, Europe's natural gas demand experienced a sharp decline of 40 bcm (-8%) in 2023, followed by

Table 4.1

Global natural gas demand outlook by region, 2023-2050

	Levels (bcm)				Change (bcm)	Growth (% p.a.)	Share (%)	
	2023	2030	2040	2050	2023-2050	2023-2050	2023	2050
Africa	170	229	303	385	215	3.0%	4%	7%
Asia Pacific	871	1,192	1,448	1,581	710	2.1%	22%	30%
Eurasia	650	710	770	820	170	0.9%	16%	15%
Europe	463	424	364	309	-154	-1.4%	11%	6%
Latin America	150	185	238	275	125	2.2%	4%	5%
Middle East	554	636	761	865	311	1.5%	14%	16%
North America	1,160	1,183	1,140	1,083	-77	-0.2%	28%	20%
World	**4,018**	**4,557**	**5,025**	**5,317**	**1,299**	**1.0%**	**100%**	**100%**

Source: GECF Secretariat based on data from the GECF GGM

an additional decline of 10 bcm in 2024, marking the third consecutive year of contraction. A combination of factors contributed to this trend, including warmer-than-average winters, intensified energy-saving measures, and the accelerated transition to renewables. For the first time, wind power surpassed gas-based power generation in the EU, which saw a 13% decline in gas-fired power output. Industrial gas demand in Europe also remained subdued, with little evidence of recovery despite falling prices, reflecting ongoing economic uncertainties and structural adjustments.

In the Eurasia region, natural gas demand, after a modest growth of 3 bcm in 2023, surged by 24 bcm in 2024. The main contribution to this increase came from the domestic sector and fast-growing Asian markets.

Global gas demand is forecast to increase by 32%, reaching 5,317 bcm by 2050, in the RCS (Table 4.1). Key drivers of this growth include population and economic expansion, policies aimed at air quality improvements, GHG emissions reductions, and the increasing use of natural gas to support renewable power system stability. Natural gas is also a critical feedstock for producing fertilisers and chemicals, supporting food production systems worldwide and the broader chemical industry. Furthermore, natural gas is pivotal in providing clean cooking access to underserved regions, aiding the transition from traditional biomass and coal-based cooking fuels to cleaner alternatives, thereby improving public health and reducing indoor air pollution. Additionally, natural gas remains the primary source of reliable and high-temperature heat for industrial processes such as steel, cement, and glass production, where electrification and alternative solutions remain technically and economically unfeasible at scale.

The bulk of future natural gas demand growth is expected to come from fast-growing Asia Pacific region, which is forecast to add 710 bcm and account for 53% of the global net demand growth during the outlook period. The growing emphasis on air quality improvements, coal-to-gas switching, and greenhouse gas reductions positions natural gas as a cornerstone of energy transition strategies for many countries in the region. The Middle East, Africa, Eurasia, and Latin America are also set to experience steady demand growth. In the Middle East, the key factors are the availability of relatively low-cost natural gas for power generation and industrial applications, along with efforts to displace domestic oil consumption. The region is also making significant strides in renewable energy deployment and developing blue hydrogen export markets.

In Africa, natural gas demand is expected to grow at the fastest rate globally, 3.0% annually, driven by accelerated economic development, a rising urban population, and increased electricity demand. Its role in enabling clean cooking access is particularly critical for the continent, where traditional biomass remains a household energy source. The expansion of indigenous gas production offers further opportunities for domestic consumption. Incremental gas demand in Eurasia is expected to come from expanding household gas connections, gas-to-chemicals and petrochemicals production, and the increased adoption of natural gas vehicles. Additionally, blue hydrogen generation is projected to contribute to increased gas use, supported by Russia's strategic initiatives to produce and export low-carbon hydrogen.

In Latin America, growth is supported by domestic gas resources and government policies promoting natural gas in power generation, industrial applications, and transportation. The development of gas-fired generation, including LNG-to-power projects, is a major driver as the region transitions from reliance on fuel oil and hydropower to a more diverse energy mix.

North American demand is forecast to remain resilient, with Mexico leading growth due to significant expansion of gas-fired power capacity. However, demand in the United States is projected to peak and decline after 2030 as the Inflation Reduction Act accelerates the adoption of decarbonisation technologies. Still, natural gas is expected to maintain a strong position in the United States energy mix. In contrast, Europe's natural gas demand is anticipated to continue its declining trend due to increasing policy support for renewables and alternative decarbonisation options. Additionally, deindustrialisation, driven by high energy costs and competitiveness challenges, is further reducing industrial gas consumption, particularly in energy-intensive sectors such as chemicals, steel, and manufacturing. These trends highlight the critical role of natural gas in energy transitions, with its demand dynamics shaped by regional priorities, policy decisions, and technological advancements.

In Europe, natural gas demand is anticipated to decline from 463 bcm in 2023 to 309 bcm by 2050, with average annual decline of 1.4% (Figure 4.2). This reduction will be driven by the energy transition policies shifting from fossil fuels to renewables and hydrogen, as well as improvements in energy efficiency across industries, households and power generation. This trend will be supported by EU's low energy intensity of economics, which is 42% lower than the global average and declined by 4.7% in 2023.

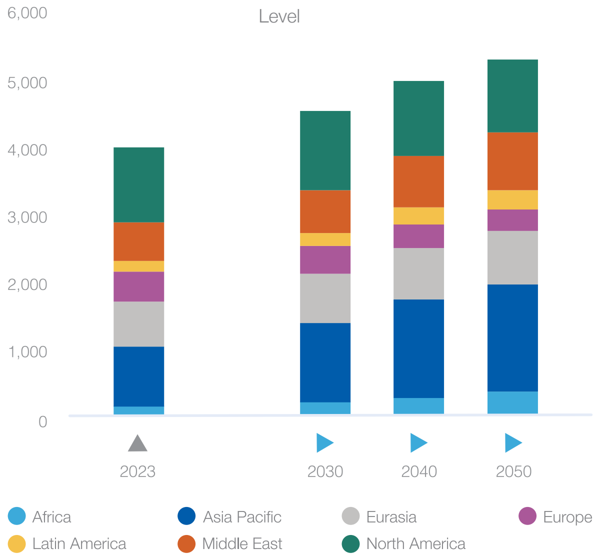
4.1.2 Sectoral trends

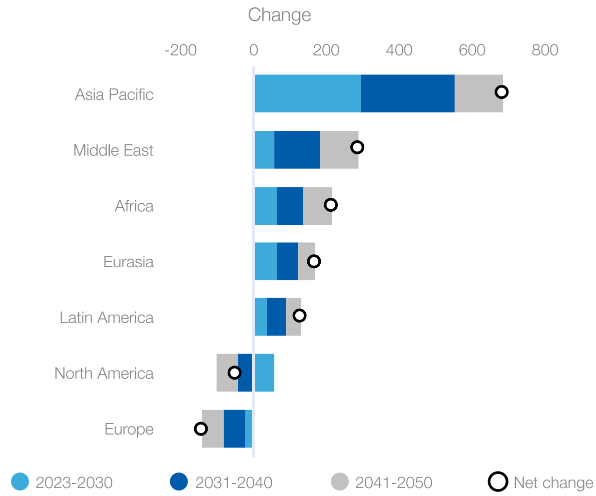
Natural gas is poised to demonstrate its versatility by substituting competing fossil fuels while seamlessly complementing renewables. Ongoing advancements in infrastructure, trade route diversification, and technology are enhancing its competitiveness in established applications while unlocking new opportunities in emerging sectors. These include the digital economy, large-scale air conditioning, desalination, and LNG-fueled transportation, where natural gas offers a reliable, efficient, and lower-emission energy solution. Additionally, blue hydrogen generation is expected to become a major avenue for increased natural gas use, benefitting from deploying low-carbon hydrogen in energy systems.

As illustrated in Figure 4.3, all sectors of the economy, except direct heat generation, are expected to see an increase in natural gas consumption. However, **power generation remains the primary driver of demand growth, accounting for 37% of the total increase by 2050.** The transport sector, encompassing road, marine, and pipeline transport, follows as the second-largest contributor, representing 20% of the net demand growth. This expansion is largely driven by the transition from gasoline and diesel to CNG and LNG in road transport, alongside the increasing adoption of LNG as a replacement for heavy fuel oil in marine transport. The industrial sector, which includes the direct use of natural

Figure 4.2

Global natural gas demand outlook by region, 2023-2050 (bcm)





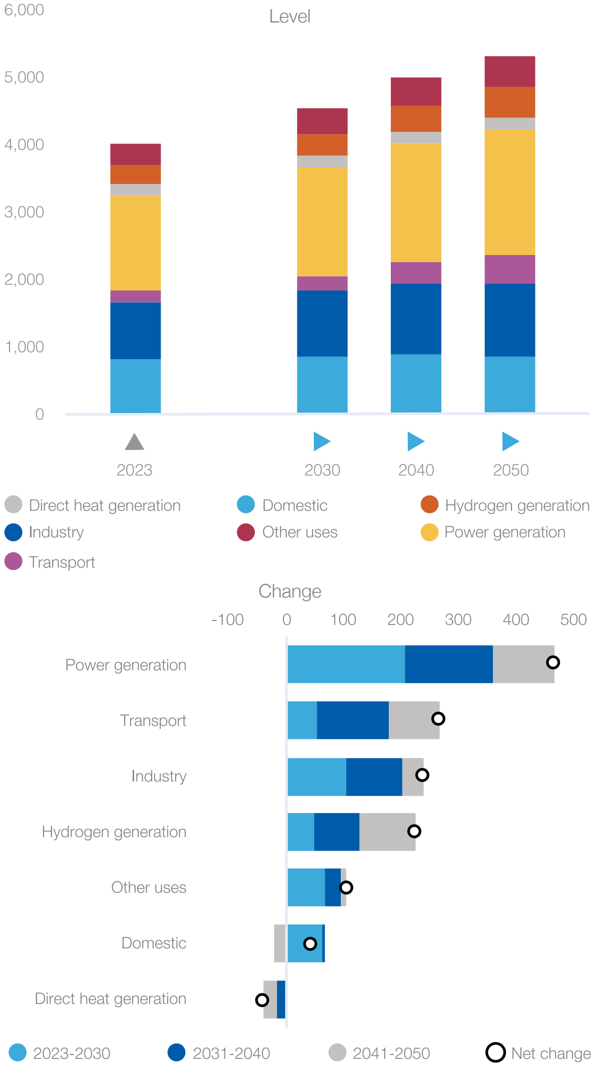
Source: GECF Secretariat based on data from the GECF GGM

gas as both a fuel and feedstock, as well as its role in refinery operations, closely follows, contributing 19% of the overall net growth. **Natural gas consumption in the industrial sector is projected to reach 1,095 bcm by 2050, up from 857 bcm in 2023.** Looking ahead, the industrial sector is set to maintain its position as the second-largest driver of natural gas demand through 2050. Table 4.1. provides an overview of natural gas demand trends by sector. Table 4.2 provides an overview of natural gas demand trends by sector.

Natural gas use in **power generation** is expected to grow by 1.1% annually, adding around 475 bcm and reaching nearly 1,866 bcm by 2050. This increase is driven by rising electricity needs and policies to phase down coal-fired power generation capacity. Moreover, as renewables capture a greater share of the global

Figure 4.3

Global natural gas demand outlook by sector, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM
Note: 1) Industry includes natural gas directly used as fuel and feedstock, as well as input for refineries. 2) Transport encompasses road transport, marine bunkers, rail transport, and pipeline operations. 3) Other uses cover natural gas consumption for the energy industry's own use, along with distribution losses.

power generation mix, natural gas-fired plants play a crucial role and provide essential flexibility and backup support to solar and wind power and hydropower during periods of drought. Regionally, Asia Pacific, where coal-fired generation remains dominant, and Africa, with its high levels of electricity access deficit, are anticipated to make the largest contributions to sectoral demand growth. At the same time, the role of natural gas as a flexible and dispatchable source is expected to be in demand across all regions, even as storage technologies advance. Synergies between natural gas and CCUS technology offer a potential pathway to support low-emission electricity generation, positioning natural gas as an enabling source of energy in decarbonisation strategies. CCUS-equipped gas power plants can significantly reduce GHG emissions by capturing and storing CO_2, while maintaining the flexibility and reliability required to stabilise power grids, particularly with the increasing penetration of intermittent renewable energy sources. New gas plants designed with integrated CCUS systems can achieve higher efficiencies and lower emissions. However, the economic competitiveness of CCUS-equipped plants remains heavily dependent on supportive policy frameworks, including robust carbon pricing mechanisms or emissions trading schemes.

The transport sector, encompassing road, marine, and pipeline transport, is projected to become the second-largest driver of natural gas demand growth, adding 265 bcm at an average annual growth rate of 3.5% over the forecast period, reaching 430 bcm by 2050. The bulk of this growth is attributed to the expansion of the global natural gas vehicle (NGV) market, driven by the shift toward decarbonised mobility. CNG and LNG technologies have emerged as established alternatives, particularly in the heavy goods vehicle (HGV) segment, where LNG-powered trucks offer a cost-competitive and lower-emission alternative to diesel. The rise in NGV adoption is further supported by favourable policies, increasingly stringent environmental regulations, and progressive national and regional restrictions on new diesel and petrol vehicle sales. These factors are accelerating infrastructure development and investment in refueling networks, particularly in regions committed to cleaner transportation solutions. Asia Pacific is expected to lead the growth in natural gas demand for road transport, followed by Eurasia, North America, and African countries.

Similarly, LNG gains momentum in global marine transport. The shipping industry is focused on meeting long-term decarbonisation targets set by the 2023 IMO GHG Strategy, and switching to LNG appears a viable option. LNG has an energy density comparable to Heavy Fuel Oil (22–25 MJ/L for LNG versus 35–40 MJ/L for HFO), along with approximately 30% lower marginal emissions per unit of energy. Alternative fuels such as hydrogen and ammonia remain in early development stages and face technical and commercial challenges. LNG is in a good position to comply with requirements for reduction in the major types of emissions, improve air quality, including within Emission Control Areas, and offer enhanced competitiveness given existing LNG infrastructure and supply chains. Rising orders for LNG-powered vessels sustain high expectations in terms of fuel use globally. Based on data from DNV, by the end of 2024, 641 LNG-powered ships were in operation. According to the orderbook, this number is expected to double by the end of the decade.

In **industry**, natural gas demand is anticipated to increase by 0.9% annually, or approximately 238 bcm between 2023 and 2050, exceeding 1,095 bcm by that date, accounting for nearly one-fifth of global demand.

Among all the regions, Asia Pacific, the Middle East and Eurasia are major contributor to sectoral incremental volumes. Besides traditional drivers, such as continued industrialisation in developing countries and population growth, policies favouring oil- and coal-to-gas switching offer strong opportunity for growth. The rising availability of global LNG supplies also supports this trend. Natural gas retains its place as a primary fuel suited for medium and high-temperature industrial processes, such as steel production, cement manufacturing, glass manufacturing, and petrochemical production. Moreover, this growth reflects increasing gas use as a feedstock, underpinned by the growing need for petrochemicals and fertilisers, with the latter contributing to agricultural sector productivity and food security.

The need for decarbonisation incentives is accelerating, with industries anticipated to invest in cost-competitive, scalable technologies to reduce emissions increasingly. Many natural gas-consuming industries are forecast to use CCUS, thereby enhancing the resilience of this energy source. Adoption of CCUS is set to expand in hard-to-decarbonise sectors such as steel, cement, glass and fertiliser, while the deployment of this technology at a much greater scale is expected in industrial clusters.

Natural gas demand for hydrogen production, encompassing both blue and grey hydrogen, is projected to increase from 259 bcm in 2023 to 480 bcm by 2050, advancing in parallel with the expansion of CCUS infrastructure. While fuel input for grey hydrogen production is expected to decline by 13 bcm over the forecast period due to decarbonisation efforts, blue hydrogen is set to emerge as a key driver of natural gas demand, growing by 220 bcm by mid-century from a currently negligible level. North America is expected to account for roughly a quarter of the total net increase in natural gas demand for blue hydrogen generation, followed by the Middle East, Eurasia, and Europe, which are projected to contribute relatively balanced shares to overall growth. This expansion is driven by national policies promoting the integration of low-carbon hydrogen across power generation, industrial applications, transport, and residential energy systems. As discussed in Chapter 3, blue hydrogen, produced from natural gas with CCUS, is anticipated to play a pivotal role in meeting sustainable hydrogen demand, owing to its cost competitiveness, scalability, and compatibility with existing gas infrastructure. The future growth trajectory suggests the establishment of a globally traded hydrogen market, with blue hydrogen progressively replacing grey hydrogen in industrial applications, reinforcing its role as a transitionary pillar in the decarbonisation of hydrogen production.

Natural gas demand growth in the **domestic** sector is expected to be relatively subdued compared to other sectors, as electricity is set to fuel much of the additional household and commercial space energy needs. Energy efficiency advancements, building retrofits, and alternative heating solutions such as biomethane, low-carbon hydrogen, and renewables further limit natural gas's growth in this area. Consequently, over the outlook period, natural gas use in this sector is forecast to rise modestly by around 40 bcm or 0.2% annually, reaching 866 bcm by 2050. While structural declines are anticipated in Europe and North America, this is likely to be offset by growth in other regions, primarily in Asia Pacific and Eurasia, supported by coal-to-gas switching, expanding city gas distribution networks, and increased household connections. In Sub-Saharan Africa, improving access to clean cooking further drives natural gas demand, ensuring a transition away from traditional biomass in residential energy use.

Table 4.2

Global natural gas demand outlook by sector, 2023-2050

	Levels (bcm)				Change (bcm)	Growth (% p.a.)	Share (%)	
	2023	2030	2040	2050	2023-2050	2023-2050	2023	2050
Domestic	826	885	889	866	40	0.2%	20%	16%
Industry	857	960	1,054	1,095	238	0.9%	21%	21%
Transport	165	218	343	430	265	3.5%	4%	8%
Power generation	1,391	1,606	1,758	1,866	475	1.1%	35%	35%
Direct heat generation	190	189	172	150	-40	-0.9%	5%	3%
Hydrogen generation	259	305	385	480	221	2.3%	6%	9%
Other uses	330	394	424	430	100	1.0%	8%	8%
Total	**4,018**	**4,557**	**5,025**	**5,317**	**1,299**	**1.0%**	**99%**	**100%**

Source: GECF Secretariat based on data from the GECF GGM

Box 4.1 The growing power demand of AI data centres and the critical role of natural gas

The rapid expansion of data centres and AI-driven computing infrastructure is exerting unprecedented pressure on global electricity demand. As hyperscale data centres continue proliferating across major economies, ensuring a stable, flexible, and cost-effective power supply has become a pressing concern. The most attractive power generation options must provide continuous, uninterrupted power, low operational costs, low environmental impacts, and the scalability to accommodate exponential growth in digital workloads. Given these requirements, natural gas-fired generation is emerging as a critical solution, complementing intermittent renewables and providing grid stability while meeting surging energy demand from AI and cloud computing sectors.

In theory, renewables such as wind and solar present an advantage due to their low environmental impact and alignment with corporate sustainability targets. Companies like Google, Microsoft, and Amazon have committed billions of dollars to renewable energy procurement, investing in large-scale power purchase agreements (PPAs) and advancing energy efficiency technologies. However, the intermittent nature of renewables presents a fundamental challenge. Unlike traditional industrial facilities, data centres require near-perfect power reliability, as AI-driven computing loads require uninterrupted, real-time power delivery. While advances in battery storage technologies are promising, these technologies still face economic and technical hurdles that limit their large-scale deployment in the near term.

Nuclear power, another option for providing baseload electricity, offers near zero-emission exploitation and high-capacity factor benefits. However, the high capital costs, long lead times, the risks of nuclear accidents, and persistent regulatory hurdles prevent nuclear from being a near-term solution for addressing AI-driven electricity demand. While Small Modular Reactors (SMRs) are gaining traction as a potential breakthrough technology, commercial-scale deployments remain unlikely before the mid-2030s, limiting their ability to respond to the immediate power needs of data centre expansion.

Coal-based power is at a disadvantage given its high upfront capital cost, limited scalability, low permitting, and environmental impacts in terms of pollutants and greenhouse gas emissions.

Conversely, natural gas has many comparative advantages, such as availability, low capital and operational costs, lower environmental impacts, and the scalability required to accommodate exponential growth in digital workloads. Gas-fired power plants can operate continuesly, ensuring uninterrupted computational processing. Furthermore, gas turbines' fast ramp-up makes them ideal for addressing sudden surges in electricity consumption during AI-driven peak workloads. In regions where full renewable deployment remains constrained by infrastructure limitations, gas-fired power is the most viable option to ensure a stable electricity supply at a lower emissions profile than coal.

The escalating global competition in AI between the United States and China has intensified the demand for reliable and scalable power solutions to support expansive data centre infrastructures. With AI becoming a strategic priority for global economic leadership, these countries are leveraging their energy resources, including natural gas, to avoid delays in scaling up computing capacity. The United States has witnessed major investments in natural gas-fired power plants dedicated to data centres, with projects such as ExxonMobil's planned 1.5 GW gas plant, which will integrate carbon capture to mitigate emissions. Similarly, China is expanding its data centre network with a significant reliance on natural gas, utilising it as an enabling fuel while renewables and nuclear scale up.

The United States administration has emphasised modernising grid infrastructure and accelerating gas-fired generation capacity to ensure stable energy supplies for hyperscale data centres. Additionally, regulatory reforms, including streamlined permitting processes for Combined Cycle Gas Turbines (CCGTs), are being pursued to facilitate the rapid expansion of dispatchable power sources. Likewise, major energy companies have raised concerns about the potential tension between increased United States gas demand for domestic AI expansion and global LNG supply security, underscoring natural gas' growing strategic importance.

Incorporating the scenarios for data centre-driven electricity demand (Base, Low, and High Cases) outlined in Box 3.1, total global power generation—excluding electricity dedicated to green hydrogen—is projected to reach 36,000 TWh, 35,600 TWh, and 36,500 TWh, respectively, by 2030 (Figure 1). This represents an additional 803 TWh (22% growth rate since 2023), 397 TWh (21% growth rate since 2023), and 1,275 TWh (24% growth rate since 2023) beyond the projection for the RCS by 2030. Natural gas-fired generation is expected to account for 40-45% of the incremental electricity demand from data centres, a factor not explicitly considered in the RCS, reinforcing its role as a key enabler of AI and digital expansion.

From a regional perspective, as illustrated in Figure 2, Asia Pacific, North America and Europe will collectively account for 83% of the incremental global electricity demand driven by data centres in 2030, reflecting their dominance in digital infrastructure expansion. This additional demand, not a factor in the RCS, necessitates a diverse fuel input mix across regions to accommodate the rapid growth in AI-driven power consumption. Regional electricity generation trends indicate varying approaches to balancing reliability, scalability, and sustainability, shaping the energy strategies employed to support surging digital infrastructure power needs:

Asia Pacific: Although renewable energy investments are expanding, additional coal-fired power is expected due to cost advantages and existing infrastructure. Natural gas-fired generation is projected to contribute 36% of incremental power demand in 2030, which is crucial in maintaining supply stability while reducing emissions relative to coal-based alternatives.

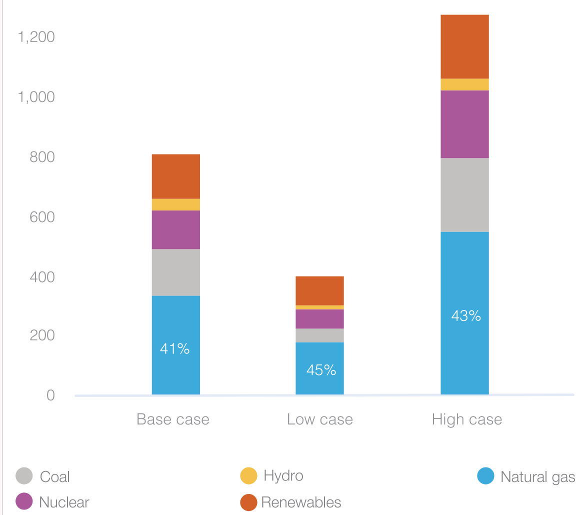
North America: The United States remains at the forefront of AI and cloud computing expansion, with data centre power demand growing at an annualised rate of 7% over the period to 2030. To meet this demand, several new gas power plants have been announced and permitted. ExxonMobil and other energy companies are actively investing in new gas plants, recognising that natural gas provides a faster and more scalable solution compared to nuclear.

Europe: European electricity demand growth is projected to be more balanced between renewables and natural gas. Policy-driven incentives prioritise wind and solar integration into data centre power networks, yet natural gas is set to retain a stabilising role in grid reliability. Given Europe's focus on decarbonisation, emerging solutions such as gas-fired power with carbon capture, utilisation and storage are gaining traction to ensure compliance with environmental mandates while maintaining system resilience.

Looking ahead, the expansion of gas-fired power plants with CCUS technologies will be instrumental in ensuring a sustainable balance between energy security and environmental compliance. Given the rapid evolution of AI-driven electricity demand, policymakers and industry stakeholders will need to prioritise flexible generation capacity, modernised grid infrastructure, and an optimised fuel mix to secure reliable energy for digital transformation. As data centres continue to proliferate globally, natural gas is poised to remain the backbone of AI-driven power generation, providing unmatched flexibility, dispatchability, and scalability to support the accelerating growth of digital infrastructure.

Figure 1

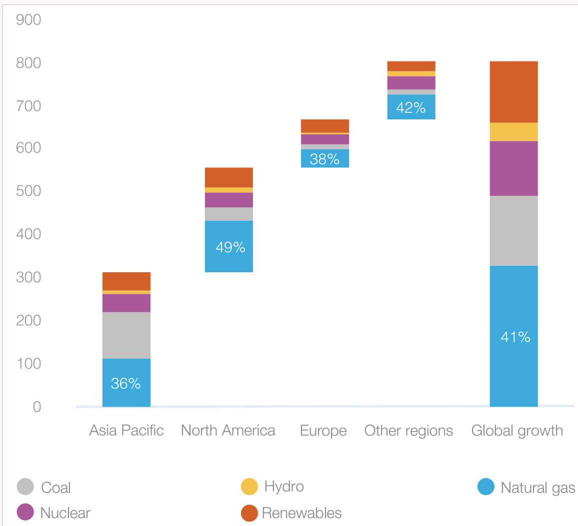
Projected fuel input mix for global power generation increment across Base, Low, and High scenarios by 2030 (TWh)



Source: GECF Secretariat based on data from the GECF GGM

Figure 2

Fuel input mix for reginal electricity generatiom increment between the RES and base case by 2030 (TWh)



Source: GECF Secretariat based on data from the GECF GGM

4.2 Regional trends in natural gas demand

4.2.1 Africa

Africa's natural gas demand is projected to grow at the fastest rate globally, with an impressive annual growth rate of 3%, rising from 170 bcm in 2023 to 385 bcm by 2050. This substantial growth will elevate the share of natural gas in the continent's energy mix from 16% today to 21% by mid-century. Key drivers of this increase include rapid population growth, urbanisation, ongoing industrialisation, and the pressing need to address Africa's significant electricity access gap. These trends are underpinned by the continent's robust indigenous natural gas production, which is expected to meet much of this growing demand, further supporting intra-regional energy integration.

Countries lacking direct access to substantial gas resources are exploring LNG imports to meet their energy needs. Additionally, long-distance pipelines are expected to play a crucial role in enhancing cross-border energy connectivity and distribution. Initiatives like the Trans-Saharan Gas Pipeline and the recently proposed Central African Pipeline System aim to replicate the success of existing networks such as the West African Gas Pipeline and the Mozambique-to-South Africa Pipeline. Emerging gas producers, including Mozambique, Tanzania, Senegal, and Mauritania, are advancing plans to expand pipeline infrastructure and local gas networks to stimulate domestic consumption, even as their projects are largely geared toward exports. This dual approach aligns with Africa's goals of fostering economic growth, improving energy access, and enhancing energy security.

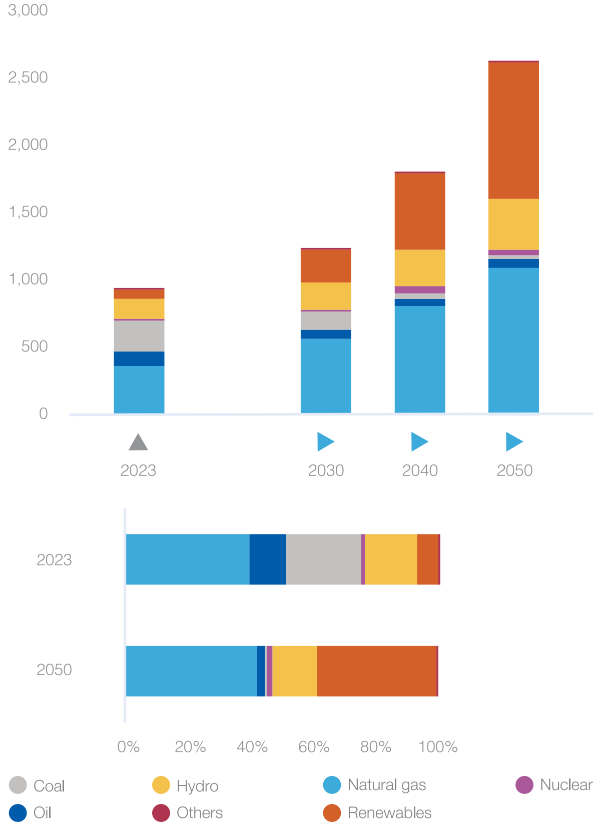
By sector, power generation is set to lead Africa's natural gas demand growth, accounting for an additional 141 bcm, or 66% of the continent's incremental demand, between 2023 and 2050. This surge reflects Africa's ambitions to ensure universal electricity access, with countries such as Nigeria and others in Western and Southern Africa driving demand through expansions of their gas-fired power capacity. Innovative solutions, such as "gas-by-wire" within regional power pools and the development of LNG-to-power projects, further expand opportunities for monetising locally produced gas while improving grid stability and addressing energy security challenges. These initiatives also provide much-needed backup for regions heavily dependent on hydropower, especially during dry spells.

Africa's electricity generation is expected to rise significantly, from 934 TWh in 2023 to approximately 2,630 TWh by 2050, growing at an average annual rate of 3.8%. This dramatic increase reflects efforts to bridge the significant electricity access gap, as an estimated 600 million people on the continent still lack reliable electricity and urban migration and population growth are projected to add nearly one billion by mid-century. Natural gas is forecast to cover around 43% of this growth, with its share in Africa's power generation mix anticipated to reach 42% by 2050. As a cleaner and more flexible alternative to oil and coal, particularly in South Africa and nearby coal-dependent countries, natural gas will complement the expansion of renewable energy projects and drive the energy transitions in the region.

Significant developments in gas-to-power projects further highlight the growing role of natural gas in Africa's energy landscape. In 2023, Ghana signed the 200 MW Bridge Power gas-fired project in Kpone, which aims to meet part of the country's electricity needs by contributing over 7% to its thermal generation capacity. Similarly, Mauritania signed an agreement in 2024 to transition the 180 MW Nouakchott Nord power plant from heavy fuel oil to natural gas, alongside the construction of a new 120 MW gas-fired power station and supporting gas transport infrastructure. In Nigeria, the construction of the Gwagwalada Independent Power

Figure 4.4

Africa power generation outlook, 2023-2050 (TWh)



Source: GECF Secretariat based on data from the GECF GGM
Note: Others include bioenergy, nuclear and hydrogen

Plant (GIPP), a 1,350 MW combined-cycle gas turbine (CCGT) facility, commenced in 2023, aligning with the country's broader goal to increase gas-fired power capacity by 3.6 GW.

Beyond power generation, Africa's natural gas demand is poised to grow steadily across a range of sectors, reflecting the continent's broader economic and developmental priorities. Industrial projects in several Sub-Saharan African countries are set to play a pivotal role, offering strong commercial incentives and driving the expansion of domestic gas markets. Natural gas is expected to meet the increasing demand of gas-intensive industries, such as petrochemicals, methanol production, and fertilisers. The fertiliser sector, in particular, holds immense significance for Africa, as natural gas serves as a critical input in its production. This will strengthen industrial development and enhance food security across the continent by ensuring an adequate supply of agricultural inputs.

Natural gas is projected to make notable advancements in the residential and commercial sectors, especially in Sub-Saharan Africa, where a significant portion of households still depend on traditional biomass for cooking. Increased natural gas adoption in these regions would provide a cleaner and more efficient alternative, helping reduce indoor air pollution and deforestation. North African countries, already more advanced in gas infrastructure, are set to see further growth as the development of transmission and distribution networks enables a larger share of their populations to access the gas grid.

The transport sector also represents a growing opportunity for natural gas demand, driven by the increased penetration of natural gas vehicles (NGVs). Several African countries are rolling out vehicle conversion programs to switch to compressed natural gas (CNG), supported by refuelling infrastructure development. This transition helps diversify the transport energy mix and reduces reliance on liquid fuels, improving air quality and lowering emissions.

However, the role of natural gas across Africa varies widely by region, with significant differences in demand growth and sub-regional contributions. In North Africa, led by major markets such as Algeria and Egypt, natural gas currently accounts for 48% of the energy mix. It is set to remain a mainstream fuel over the outlook period. This stability reflects the sub-region's established infrastructure, domestic production capabilities, and long-standing reliance on natural gas. In contrast, Sub-Saharan Africa, where natural gas comprised just 5% of the energy mix in 2023, is expected to experience transformative growth. By 2050, natural gas is projected to account for 17% of the sub-region's energy mix, driven by industrialisation, electrification, and expanding access to cleaner cooking fuels.

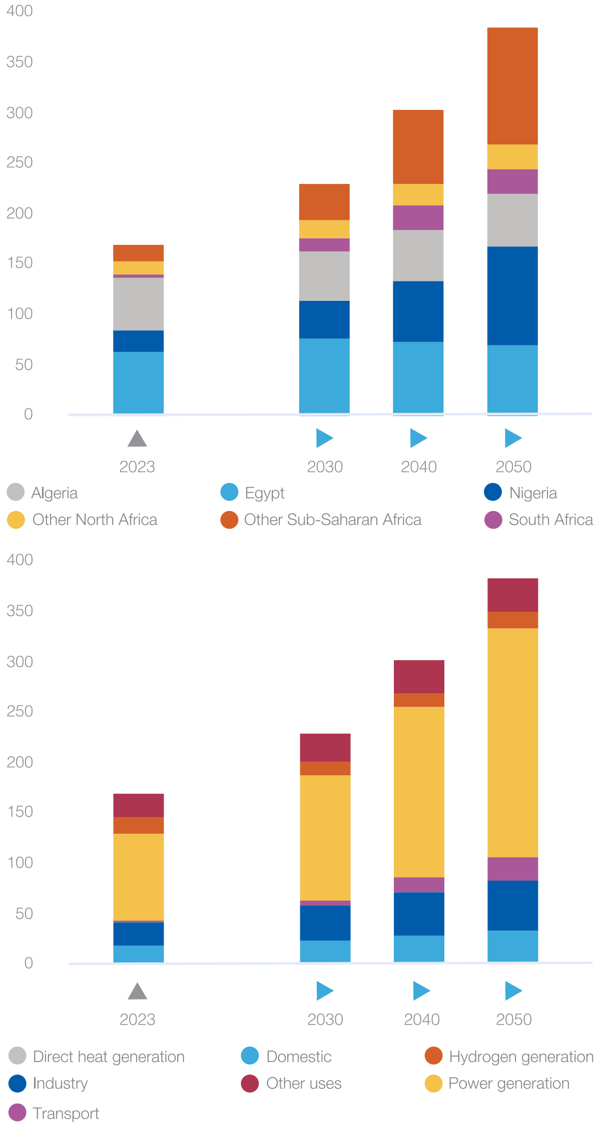
Sub-Saharan Africa is expected to drive nearly 92% of Africa's overall natural gas demand growth through 2050, highlighting the transformative role of gas in addressing the region's energy and development challenges. Increased gas availability, coupled with the development of local markets and infrastructure, will facilitate economic growth, improve energy access, and support sustainability goals. This trajectory is underscored by substantial investment in industrial clusters, urban gas networks, and cross-sectoral applications, all aiming to maximise the benefits of Africa's abundant natural gas resources.

Figure 4.5 illustrates the projected natural gas demand trajectory across African countries, with notable contributions from Sub-Saharan countries in multiple sectors. This growth underscores the pivotal role of natural gas in shaping Africa's energy landscape, fostering industrialisation, improving living standards, and driving regional integration.

In North Africa, natural gas demand is expected to grow modestly, rising from 130 bcm in 2023 to around 145 bcm by 2050. This accounts for only 8% of Africa's overall demand growth, reflecting a more stable and mature market in the region. Algeria, North Africa's second-largest gas consumer and a mature gas market is projected to see relatively stable demand over the

Figure 4.5

Africa natural gas demand outlook, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

outlook period. This stability is driven by the accelerated development of renewable energy, particularly solar power, and the integration of efficient combined cycle gas turbines (CCGTs), which are expected to offset increases in gas consumption across industrial, residential, and commercial sectors. Additionally, blue hydrogen production, while a potential growth area, is unlikely to drive significant increases in Algeria's gas demand, given its emphasis on diversifying energy sources.

Egypt, the region's largest gas consumer, is expected to see natural gas demand rise from 63 bcm in 2023 to about 76 bcm by 2030 followed by an elongated plateau. This initial growth will be driven by rising consumption across industrial, residential, and transport sectors, along with increasing demand for electricity to support economic expansion. Natural gas remains a cornerstone of Egypt's energy policy, particularly as a substitute for oil products, ensuring its role as a key fuel for the foreseeable future. However, post-2030, natural gas demand in Egypt's power sector is expected to stabilise as renewable energy sources gain traction. The commissioning of the 4.8 GW El Dabaa nuclear power plant, developed by Russia's Rosatom, is set to significantly alter the country's power generation mix, further reducing gas demand growth for electricity generation in the long term.

In Sub-Saharan Africa, natural gas demand is forecast to grow significantly, increasing from nearly 40 bcm in 2023 to approximately 240 bcm by 2050, marking one of the most dynamic growth trajectories globally. The power generation sector is expected to account for 73% of the additional demand in the region, reflecting the urgent need to expand electricity access. Gas-fired power capacity in Sub-Saharan Africa is projected to rise from 23 GW in 2023 to approximately 155 GW by 2050, growing at an average annual rate of 7%. This surge will be primarily driven by countries in Western and Southern Africa, which are actively expanding their power generation infrastructure to address chronic electricity shortages.

Beyond power generation, natural gas demand in Sub-Saharan Africa is also expected to grow in the residential sector, particularly as LPG, a clean cooking solution to replace traditional biomass fuels. This shift is critical for improving living standards and reducing indoor air pollution. Additionally, industrial demand is poised to rise, supported by the development of petrochemical, fertiliser, and other energy-intensive industries, which increasingly rely on domestic natural gas supplies.

From a country perspective, **Nigeria** is forecast to lead Sub-Saharan Africa's gas demand growth, adding more than 75 bcm between 2023 and 2050. This growth is largely driven by a substantial increase in gas-fired power generation, spurred by a sharp rise in electricity demand. The industrial sector will also play a pivotal role, particularly with the expansion of petrochemical and fertiliser production facilities. Nigeria's "Decade of Gas" initiative underpins this growth, aiming to monetise the country's vast natural gas resources, attract investments in domestic gas infrastructure, and eliminate gas flaring. The expansion of Nigeria's gas pipeline network is further expected to ensure a more reliable supply to industrial hubs and power plants, bolstering its overall energy system.

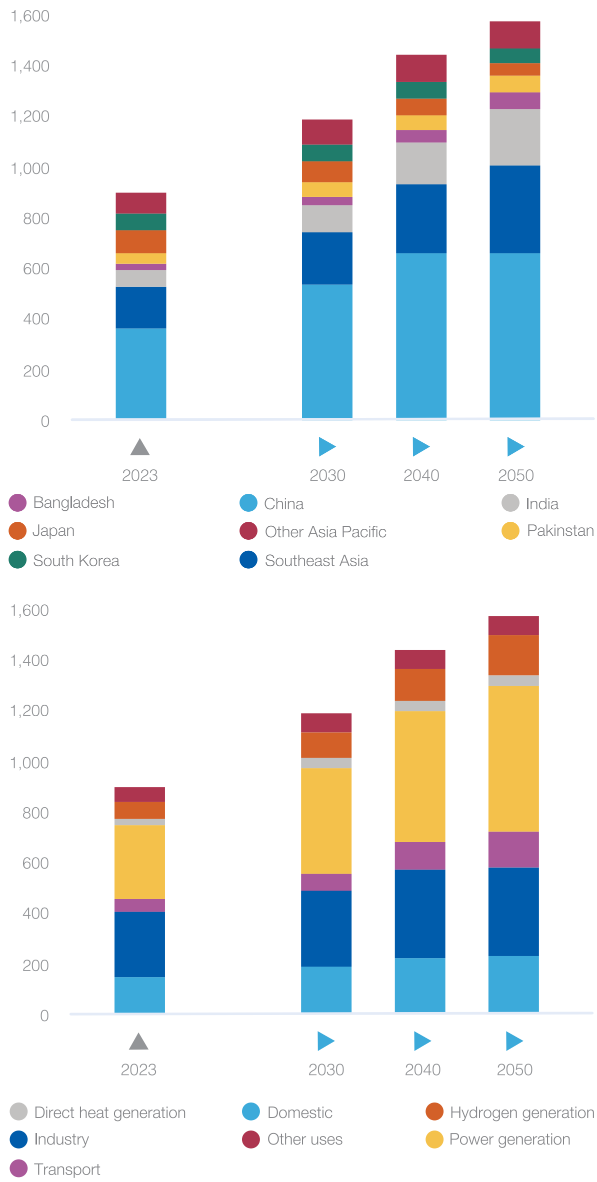
South Africa is another notable contributor, with gas demand projected to increase by over 20 bcm by 2050. The shift away from extensive coal reliance, coal accounted for 83% of electricity generated in 2023, is central to this growth. Gas-fired power projects and LNG-to-power initiatives are anticipated to play a critical role in diversifying the country's energy mix, enhancing grid stability, and reducing its carbon footprint.

4.2.2 Asia Pacific

Natural gas demand in the Asia Pacific region is forecast to grow at an annual rate of 2.2%, increasing from 871 bcm in 2023 to 1,581 bcm by 2050 (Figure 4.6). This growth highlights the pivotal role of natural gas in supporting the region's energy transition goals, driven by priorities such as improving air quality, reducing greenhouse gas emissions, and decreasing reliance on coal, which currently constitutes 47% of the regional energy mix. As Asia transitions toward cleaner energy systems, natural gas is expected to play a critical

Figure 4.6

Asia Pacific natural gas demand outlook, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

role in meeting growing energy needs while enabling sustainable development.

Key factors underpinning this demand include rapid urban population growth, robust economic expansion, and increased electrification. Additionally, extensive infrastructure developments, such as new regasification facilities, expanded pipeline networks, city gas distribution systems, and gas-fired power plants, are creating a foundation for the widespread adoption of natural gas. Policy measures promoting oil- and coal-to-gas switching further accelerate this transition as governments seek to address environmental concerns and enhance energy security. **As a result, natural gas use is expected to increase across all major sectors, and its share in the Asia Pacific energy mix is projected to rise from 11% in 2023 to over 16% by 2050.**

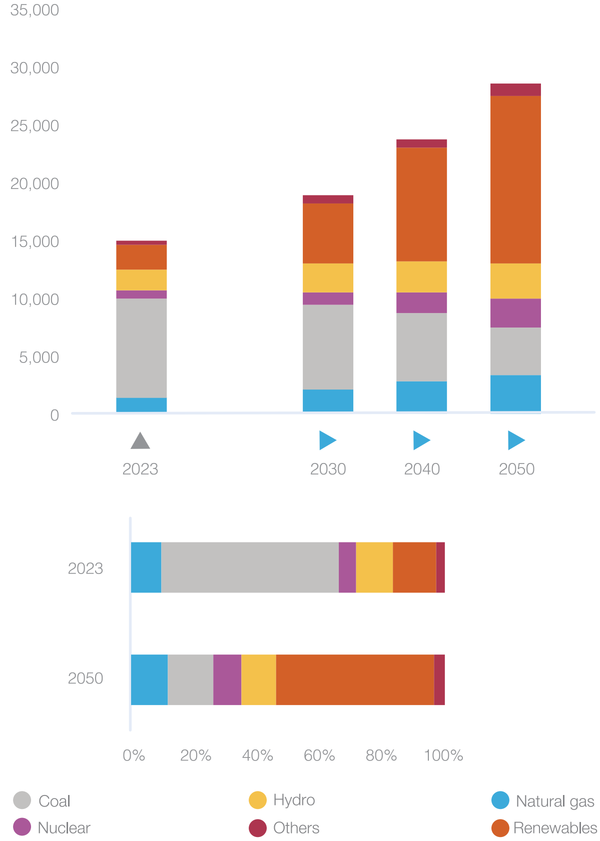
China, India, and Southeast Asia are poised to lead this growth, collectively accounting for the majority of the additional demand. Expanding urbanisation, strong economic recovery post-COVID-19, and policy-driven efforts to phase out coal are expected to sustain robust natural gas consumption in China. India, benefiting from softening LNG prices and domestic gas reforms, is experiencing rising demand across the power, industrial, and transport sectors, reflecting the country's commitment to transitioning to cleaner energy sources. Similarly, Southeast Asia's growing need for energy to support industrialisation and urbanisation underscores the region's increasing reliance on natural gas.

In contrast, Japan and South Korea are expected to see declines in natural gas demand over the outlook period, largely due to nuclear restarts, a growing share of renewable energy, and the integration of imported hydrogen into their energy systems. However, despite these declines, both countries continue to view LNG as a cornerstone of their decarbonisation strategies and energy security frameworks. The flexibility and reliability of LNG provide a vital backup for intermittent renewable energy, ensuring grid stability while supporting long-term energy transitions.

Power generation is expected to play a pivotal role in driving natural gas demand in the Asia Pacific region, accounting for 43% of the total increase in gas consumption through 2050. Gas-fired power generation is widely favoured as a cleaner alternative to coal, aligning with the region's broader goals of energy diversification and long-term decarbonisation. The increasing deployment of renewables, which are intermittent by nature, further pushes the demand for gas-fired generation to provide essential dispatchable capacity and ensure grid stability. Additionally, the integration of CCUS technologies in gas-fired power plants presents a viable pathway for achieving low-carbon flexibility. The region's strong and growing electricity requirements, coupled with significant coal-to-gas switching potential, highlight the sustained

Figure 4.7

Asia Pacific power generation outlook, 2023-2050 (TWh)



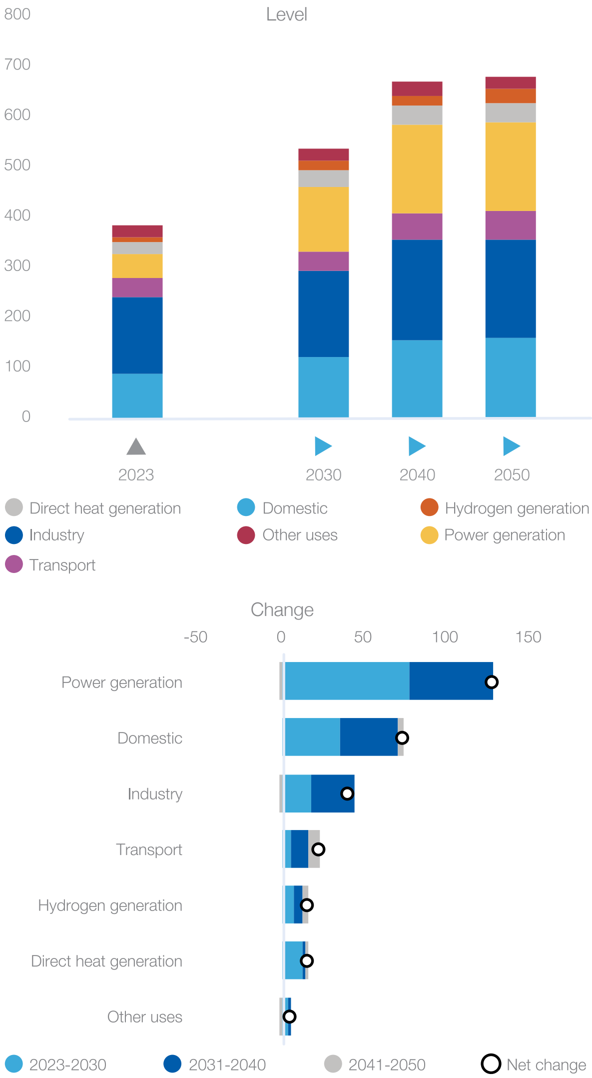
Source: GECF Secretariat based on data from the GECF GGM
Note: Others include oil, bioenergy and hydrogen

importance of natural gas in power generation. Unlike in some other regions, there is no anticipated peak in gas demand for power over the outlook period, reflecting the scale and diversity of Asia Pacific's energy needs. By 2050, natural gas-fired power generation's share is projected to increase from 10% in 2023 to 12%, reinforcing its role as a critical element in the region's energy transition strategy (Figure 4.7).

In the hydrogen, industrial and domestic sectors, natural gas demand in the Asia Pacific region is projected to rise significantly, contributing 14%, 13% and 13% of the region's total demand growth, respectively. The transport sector also emerges as a promising area for natural gas use, driven by initiatives promoting CNG and LNG-fueled vehicles. These efforts are supported by tightening emissions standards and strengthened regional clean air policies. However, the growth patterns will differ by country, reflecting distinct sectoral dynamics. In China, the largest increase in gas demand is expected to come from power generation and the residential and commercial sectors. On the other hand, India's growth is anticipated to be driven primarily by industry, road transport, and power generation. Meanwhile, gas demand growth in Southeast Asia is projected to be

Figure 4.8

China natural gas demand outlook, by sector 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

predominantly power-driven.

In **China**, natural gas demand is forecast to rise from 367 bcm in 2023 to 662 bcm by 2050, representing a robust annual growth rate of 2.2% until the mid-2040s, when demand is expected to plateau. This increase of nearly 295 bcm positions China as the largest contributor to natural gas demand in the Asia Pacific region, accounting for 43% of the incremental growth in the region and 23% of global additional volumes over the forecast horizon. Economic expansion, urbanisation, significant coal-to-gas switching initiatives, extensive infrastructure development, and market reforms are the primary factors driving this growth.

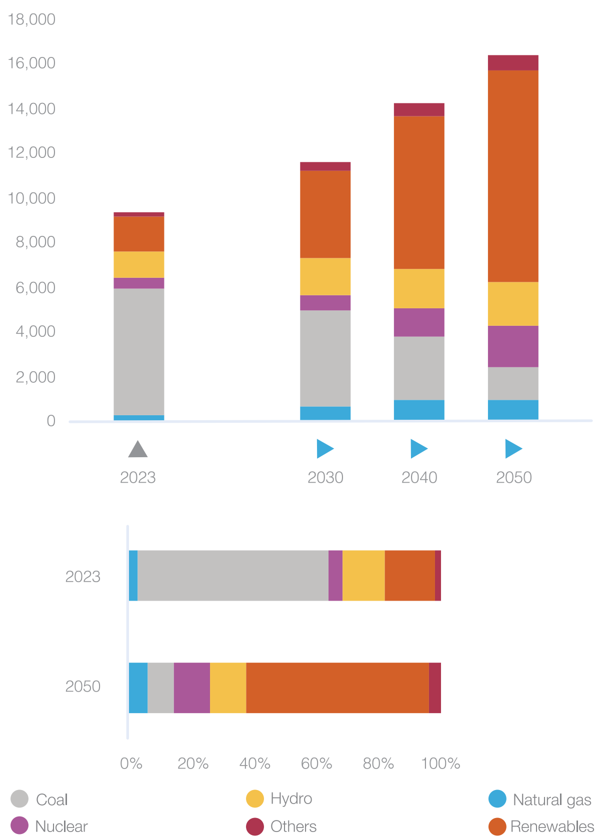
Natural gas is set to play a central role in China's low-carbon energy transition, helping to diversify its coal-dominated energy mix, where coal accounted for 59% in 2023, and supporting efforts to improve air quality in urban centres. Additionally, China's commitment to achieving carbon neutrality by 2060 and its goal of peaking emissions before 2030 provide a strong impetus for natural gas demand to expand over the coming decades.

In China, power generation is set to remain the dominant driver of natural gas demand growth, contributing 42% of the total projected increase. This growth is underpinned by policy initiatives and the need for a flexible power source to complement the integration of renewables into the energy mix. As part of the Natural Gas Utilisation Policy, gas-fired peak-shaving power plants, those with secured gas supplies and economic viability, are designated as a priority category for gas use, emphasising their role in addressing the intermittency challenges of renewable energy.

Electricity generation from natural gas-fired plants is forecast to grow significantly, increasing 3.5 times by the mid-2040s, with an annual growth rate of 6.5%, ultimately reaching nearly 1,000 TWh by 2050. However, gas is expected to account for only 6% of China's total power generation mix by mid-century. In contrast,

Figure 4.9

China power generation outlook, 2023-2050 (TWh)



Source: GECF Secretariat based on data from the GECF GGM
Note: Others include oil, bioenergy and hydrogen

renewable energy sources are projected to see a substantial rise, with their share expanding from 16% in 2023 to 58% by 2050. Over the same period, coal-fired power generation is anticipated to decline sharply, dropping from 61% to just 9% of the mix (Figure 4.9). Despite these long-term trends favouring cleaner energy sources, coal-fired power plants are expected to receive continued approvals for capacity expansion during this decade, reflecting ongoing energy security concerns.

The domestic sector is poised to be significant contributors to natural gas demand growth in China, with consumption expected to rise from 86 bcm in 2023 to 155 bcm by 2050, accounting for 23% of the total increase. This growth is set to be driven by accelerated urbanisation, improving household incomes, and continued coal-to-gas switching, alongside substantial investments in city gas infrastructure. The government has prioritised the use of natural gas for urban households, particularly for cooking and domestic hot water, to improve air quality and living standards. However, beyond 2040, demand in these sectors is projected to stabilise as increased electrification, supported by renewable energy, poses a significant downside risk to long-term gas consumption.

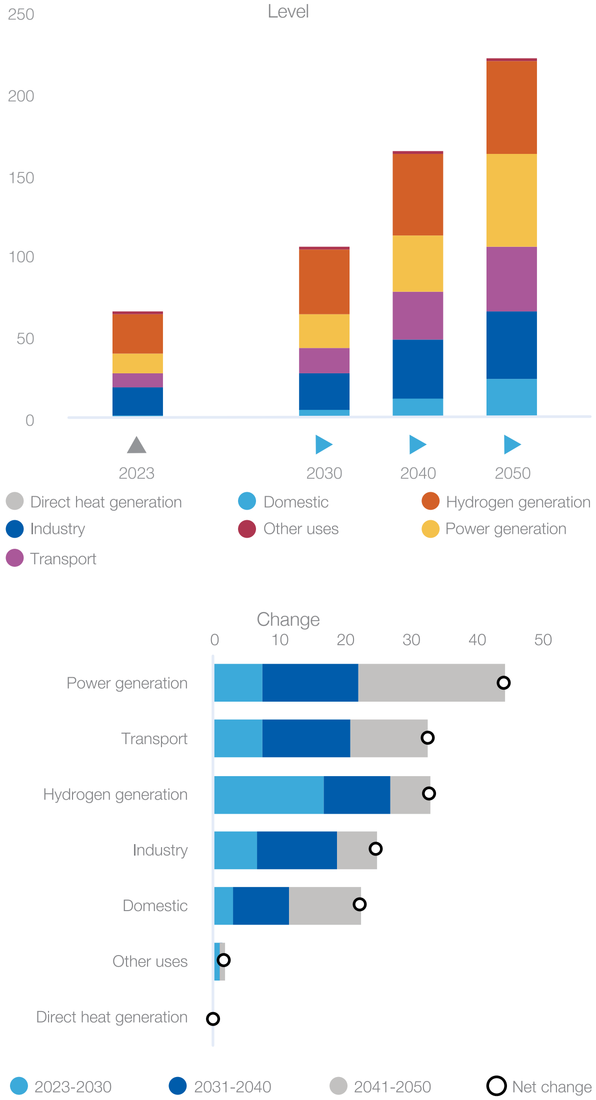
Similarly, gas demand is expected to rise initially in the industrial sector but plateau in the 2040s as China's industrial energy requirements peak. This sector's growth is largely fueled by economic expansion and government mandates for coal-to-gas switching in energy-intensive industries, with significant opportunities in coastal regions. However, the adoption of alternative clean energy solutions, such as renewables and electrification, is expected to curb the long-term growth of gas in the industry.

The transport sector also offers notable opportunities for natural gas demand growth in China, albeit driven entirely by LNG rather than CNG. LNG demand is set to expand in both marine and road transport, supported by China's extensive LNG bunkering infrastructure for ocean-going vessels and inland river networks. In road transport, LNG-fueled heavy goods vehicles are anticipated to dominate growth, driven by the increasing availability of LNG refuelling stations, stringent emissions standards, and restrictions on diesel truck operations to improve urban air quality. In contrast, demand for CNG in vehicles is expected to remain limited as the rapid rise of electric vehicles (EVs) challenges its adoption. EVs are increasingly favoured for passenger cars, taxis, and light commercial vehicles, diminishing the role of CNG in the transport sector.

India's natural gas demand is forecast to grow significantly, rising from 66 bcm in 2023 to 223 bcm by 2050, reflecting an average annual growth rate of 4.5%. This growth is reinforced by extensive policy support and ongoing infrastructure development. Fuel switching to natural gas is a cornerstone of India's Long-Term

Figure 4.10

India natural gas demand outlook, 2023-2050 (bcm)



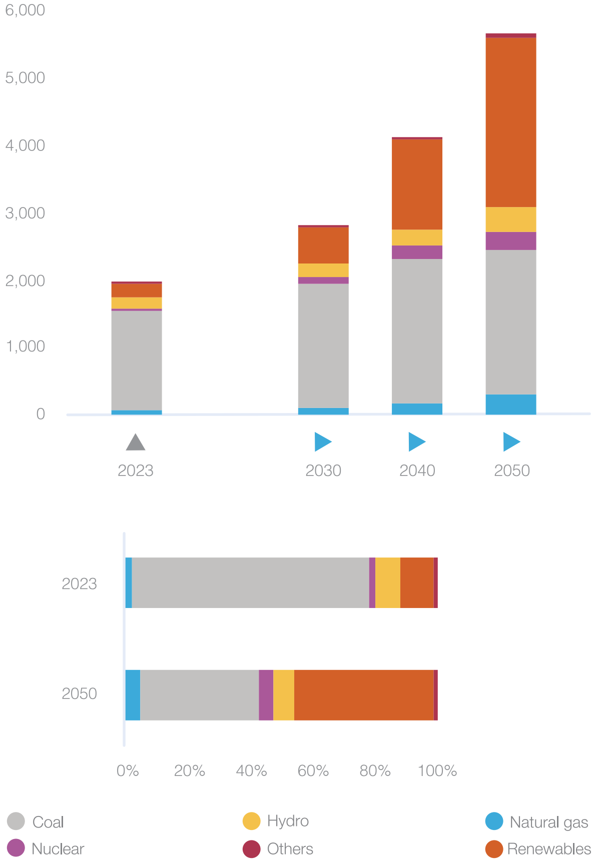
Source: GECF Secretariat based on data from the GECF GGM

Low Emission Development Strategy, announced in November 2022, and the government's goal of increasing the share of gas in the primary energy mix to 15% by 2030 remains a key driver. Complementary objectives, such as improving air quality, transitioning from oil and coal, and achieving net-zero emissions by 2070, further align with the promotion of natural gas.

The development of India's National Gas Grid is a critical enabler for expanding natural gas accessibility. Under the One Nation, One Gas Grid initiative, India is undertaking a massive investment program to expand its pipeline network, aiming to add over 10,000 km to the existing 24,500 km of transmission pipelines. This expansion aims to connect LNG terminals and domestic gas fields to demand centres while eliminating infrastructure bottlenecks. Concurrently, the city gas

Figure 4.11

India power generation outlook, 2023-2050 (TWh)



Source: GECF Secretariat based on data from the GECF GGM
Note: Others include oil, bioenergy and hydrogen

distribution (CGD) network is set to expand rapidly, with the 12th Bidding Round paving the way for increased natural gas usage in residential cooking, road transport, and commercial applications.

In India, the industrial sector is projected to drive the largest share of natural gas demand growth, adding 57 bcm and accounting for 36% of the total increase between 2023 and 2050. This represents an annual growth rate of 3.3%, driven by the expansion of industries such as fertilisers, petrochemicals, ceramics, glass, textiles, and other light manufacturing. The sector presents a strong opportunity to displace liquid fuels, with new pipeline capacity in southern and eastern India supporting industrial growth. To capitalise on this potential, the government has planned the establishment of industrial clusters along pipeline routes to encourage the development of gas-based industries.

Gas demand in India's transport sector is forecast to expand significantly, reaching 40 bcm by 2050, with an average annual growth rate of 6.4%. This sector is projected to account for 20% of the country's incremental natural gas demand over the forecast period. India's commitment to expanding CNG access is among the most ambitious globally. Currently, over 7,000 CNG stations are operational, with plans to increase this number to 17,700 by 2030, ensuring greater availability for consumers. The implementation of Bharat Stage 6 emissions standards, which align with stringent global benchmarks, is expected to further encourage a shift to CNG by promoting cleaner fuel alternatives. This regulatory shift is also driving domestic automakers to diversify their offerings and expand their range of NGV models. In parallel, India plans to develop LNG as a fuel for heavy-duty trucks, positioning LNG as a critical component in decarbonising long-haul road freight.

In the power generation sector, natural gas demand is expected to grow modestly in the near term, as no explicit policy measures incentivise gas-based electricity generation. India focuses on achieving its ambitious target of 500 GW of installed capacity from non-fossil sources by 2030. While there are no plans for a complete phase-out of coal, ongoing developments such as the gradual implementation of carbon pricing mechanisms and the rapid deployment of solar PV and wind power are set to reshape the country's power generation landscape. Coal's share in the electricity mix is anticipated to decline from 75% in 2023 to 38% by 2050, reflecting the increasing penetration of renewables (Figure 4.11).

As the renewable energy sector grows, the role of natural gas in power generation is expected to become more pronounced after 2030. Gas-fired power plants are uniquely positioned to provide the flexibility required to balance intermittent renewable generation, particularly during low wind or solar output periods. By 2050, natural gas demand for power generation is projected to reach 57 bcm, underpinned by the need for reliable, dispatchable capacity to ensure grid stability. However, despite this anticipated growth, the share of gas-fired generation in India's power mix is forecast to remain relatively modest, accounting for just 5% by 2050.

In **Bangladesh**, natural gas demand is forecast to rise significantly, increasing from 28 bcm in 2023 to 64 bcm by 2050, reflecting an average annual growth rate of 3.2%. The power generation sector will primarily drive this growth as the country strives to meet surging electricity demand and commissions new CCGT capacities. The industrial sector, particularly fertiliser, textile production, and the residential segment, will also contribute to the rising demand. Since 2018, Bangladesh has turned to LNG imports to compensate for the decline in indigenous gas production. The country currently operates two FSRUs in Moheshkhali, and further regasification capacity expansions are anticipated. By 2035, LNG is projected to meet approximately 80% of Bangladesh's total gas demand, with this share expected to rise further in subsequent decades as domestic production continues its steep decline.

Bangladesh is diversifying its energy mix to enhance energy security by incorporating nuclear power, renewables and increased power imports from neighbouring countries, particularly hydropower from India, Nepal, and Bhutan. The country plans to achieve 7 GW of nuclear capacity by 2041. While the development of alternative energy sources may moderate gas demand growth in power generation, it is unlikely to displace it entirely, given the robust electricity requirements. Additionally, natural gas remains well-positioned to replace fuel oil in power generation, which accounted for around 18% of the electricity supply in 2023. Over the long term, natural gas is expected to play a pivotal role in meeting Bangladesh's growing electricity needs, maintaining a dominant share of 55% in the power generation mix by 2050, compared to 57% in 2022-2023.

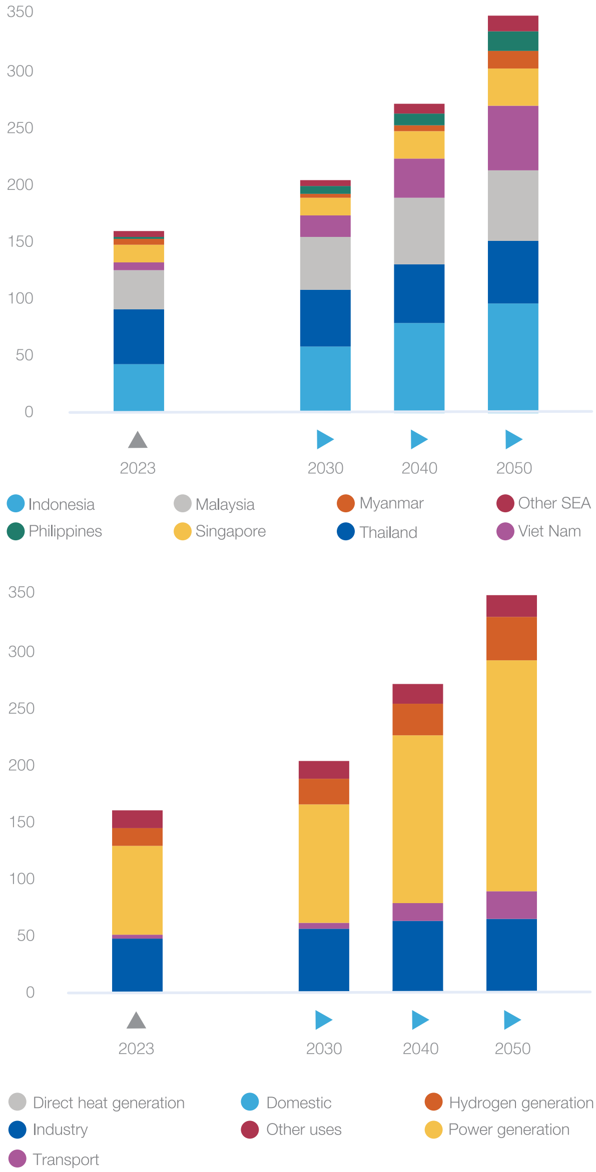
In **Pakistan**, natural gas demand is projected to grow from 39 bcm in 2023 to over 60 bcm by 2050, reflecting an annual growth rate of 1.7%. The industrial, power generation and residential and commercial sectors are expected to contribute relatively balanced shares to this increase. However, the depletion of domestic gas reserves is anticipated to constrain more pronounced growth. Gas-fired power generation will face increasing competition from hydro, nuclear, and renewable energy projects, many of which are supported under the China-Pakistan Economic Corridor (CPEC). Notably, Pakistan has 13 GW of hydro capacity under construction, slated for completion by 2030, with an additional 37 GW in the pipeline. On the nuclear front, Pakistan plans to expand its capacity from 3.5 GW currently to 8.8 GW over the long term.

Pakistan is expected to rely heavily on imports to address the decline in domestic gas production. While interstate pipeline projects such as the Iran-Pakistan and Turkmenistan-Afghanistan-Pakistan-India pipelines remain under consideration, LNG is projected to bear the brunt of meeting growing demand. Pakistan began LNG imports in 2015, with the commissioning of two receiving terminals at Port Qasim and Karachi, and additional regasification terminals are planned. Critical to supporting this infrastructure is the development of transmission systems, including the 1,100 km-long Pakistan Stream Gas Pipeline, which will connect Karachi to Lahore. This pipeline will play a vital role in ensuring the delivery of additional LNG volumes to northern demand centres and sustaining Pakistan's reliance on natural gas.

In Southeast Asia, natural gas demand is expected to rise significantly, growing from 160 bcm in 2023 to 350 bcm by 2050, representing an annual growth rate of 2.9%. Key contributors to this increase include Indonesia, Viet Nam, Malaysia, and the Philippines, which together are forecast to account for 77% of the additional volumes (Figure 4.12). This growth aligns with the region's robust economic development, rapid urbanisation, and improving living standards, all of which are driving higher industrial activity and electricity demand.

Figure 4.12

Southeast Asia natural gas demand by country and sector (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Southeast Asia's countries have also set ambitious climate goals, with net-zero targets ranging from 2050 to 2065. As part of these commitments, natural gas is poised to play a critical role in displacing coal, which currently dominates the energy mix in many countries, and providing the necessary flexibility to integrate a growing share of renewables. In 2023, natural gas accounted for 17% of the region's primary energy mix and 29% of the power generation mix. These shares are expected to increase as countries ramp up investments in gas infrastructure, including LNG import facilities and pipelines, to support domestic consumption and energy transitions. This dual role of natural gas—a cleaner alternative to coal and a critical enabler of renewable energy integration, underscores its strategic importance in Southeast Asia's evolving energy landscape.

Southeast Asia is projected to transition to a net gas importer around 2029–2030, as domestic gas production either declines or fails to keep pace with rising demand. This shift places LNG imports at the centre of the region's energy strategy, necessitating the rapid expansion of regasification capacity and the establishment of LNG-to-power supply chains. Enhanced interconnectivity and the development of small-scale LNG solutions are expected to play a pivotal role in ensuring stable and accessible gas supplies across the region's diverse energy landscape.

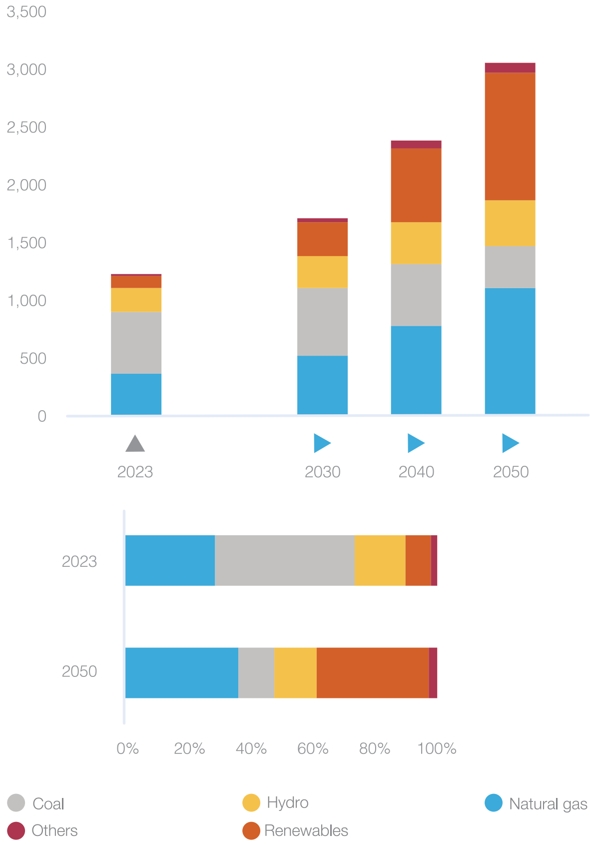
For instance, in March 2024, Indonesia launched operations at the 1.76 GW Jawa-1 power plant, Southeast Asia's largest gas-fired power plant, integrated with a floating storage regasification unit (FSRU). This landmark project highlights the region's increasing reliance on LNG-to-power solutions. Additionally, Indonesia plans to enhance intra-country LNG trade by making gas supply accessible throughout its extensive archipelago, facilitated by small-scale LNG terminals paired with distributed generation units. In Viet Nam, the latest Power Development Plan (PDP VIII) outlines the construction of 13 new LNG power plants with a combined capacity of 22.4 GW by 2030. By 2035, two more LNG power plants with 3 GW capacity are expected to come online. Similarly, countries like the Philippines, Myanmar, and Thailand are advancing plans to deploy LNG-to-power projects, further cementing the role of LNG imports in the region's energy transition.

From a sectoral perspective, power generation is forecast to be Southeast Asia's primary driver of natural gas demand, contributing over 125 bcm, or approximately 66%, of the region's total demand growth between 2023 and 2050. Robust electrification efforts and significant opportunities for coal-to-gas switching underpin this trend, supported by numerous gas-fired power projects, including LNG-to-power schemes. In a notable example, Indonesia's state-owned utility PT PLN announced plans in September 2024 to convert 800 coal-fired steam power plants to gas-fired plants, demonstrating the region's commitment to leveraging natural gas as a cleaner energy alternative.

Policy priorities across Southeast Asia are expected to accelerate a profound transformation of the power sector. While abundant and affordable coal resources remain critical for energy security and affordability, governments are placing greater emphasis on expanding natural gas and renewable energy capacities to address sustainability goals and meet the rapidly growing electricity demand. As a result, gas-fired

Figure 4.13

Southeast Asia power generation outlook, 2023-2050 (TWh)



Source: GECF Secretariat based on data from the GECF GGM

power generation, supported by indigenous gas production and LNG imports, is set to become the region's largest generation source by the early 2030s. This growth is anticipated to facilitate the integration of renewables into the grid, ensuring stability and flexibility as energy systems become more complex. **By 2050, natural gas is forecast to hold a substantial 36% share of Southeast Asia's total power generation mix, reflecting its pivotal role in the region's energy transition** (Figure 4.13).

Industrial natural gas demand in Southeast Asia is expected to account for a substantial portion of the region's overall growth, driven by the increasing use of natural gas in chemical production, fertiliser manufacturing, and various light industrial processes. Natural gas has significant potential to replace oil, coal, and biomass as a source of process heat, particularly in energy-intensive industries. Countries such as Indonesia, Thailand, and Malaysia are forecast to experience the most pronounced growth in industrial gas demand, reflecting their expanding manufacturing bases and industrial diversification.

In the transport sector, marine transportation is poised to become a major driver of natural gas demand growth, supported by rising sales of LNG for international bunkering. Singapore and Thailand are particularly well-positioned to benefit from this trend as they continue to establish themselves as regional gas hubs, leveraging their strategic geographic locations and advanced infrastructure.

In **Japan**, natural gas demand is projected to decline sharply, from 91 bcm in 2023 to 50 bcm by 2050, largely due to structural shifts in the power sector. A key factor in this decline is the country's commitment to accelerating nuclear restarts under its 6th Strategic Energy Plan, which aims to increase nuclear's share of the power generation mix to 20-22% by 2030, up from 8% in 2023. As of October 2024, 13 of Japan's 33 designated reactors, with a combined capacity of over 33 GW, have received local approval for restart, with more reactors anticipated to come online gradually. Additionally, the policy outlines a plan to build "next-generation innovative reactors" to replace decommissioned units and extend the operational life of select plants from 40 to 60 years. For example, in October 2024, Japan's oldest nuclear reactor, Takahama-1 (780 MW), received approval to operate beyond 50 years, marking a significant policy milestone.

The continued expansion of nuclear power is expected to exert substantial downward pressure on natural gas demand for power generation. Gas-to-power use is projected to stabilise between 2030 and 2035, partly supported by decommissioning of inefficient coal-fired plants. Over the longer term, however, the rapid expansion of renewables and the integration of hydrogen and ammonia into gas-based generation are anticipated to reduce natural gas demand further. Declines are also expected in the residential, commercial, and industrial sectors, driven by an ageing population, slower economic growth, and sustained energy efficiency improvements. However, the transport sector offers limited growth potential, particularly through the expansion of LNG bunkering services.

In **South Korea**, natural gas demand is expected to remain relatively stable, declining slightly to below 60 bcm by 2050 compared to 62 bcm in 2023. Demand is forecast to peak at 68–69 bcm in the early 2030s before gradually tapering off. The residential, commercial, and industrial sectors are expected to see declining gas use due to advances in energy efficiency, electrification, and the integration of imported low-carbon hydrogen. However, coal-to-gas switching opportunities are anticipated to sustain LNG demand over the next 10–15 years, particularly as the country phases out coal-fired power plants.

In the power generation sector, gas demand in South Korea faces long-term constraints due to the government's strong support for renewables, the planned integration of hydrogen-based power generation, and ambitious nuclear expansion policies. Following the commissioning of the 1.4-GW Shin Hanul-2 reactor in April 2024, South Korea now operates 26 nuclear reactors. Two additional 1.4-GW reactors (Saeul 3 and 4) are currently under construction and are expected to come online soon. According to the draft 11th Basic Plan for Long-Term Electricity Demand and Supply, the government plans to build three additional nuclear plants (totalling 4.2 GW) by 2038 while increasing the operational capacity of existing reactors. By 2030, nuclear power is forecast to account for 31.8% of the power generation mix, rising to 35.6% by 2038, compared to 29% in 2023.

Despite these developments, LNG will remain a key part of South Korea's generation mix, particularly given the ongoing shutdown of coal-fired plants and the need to maintain grid stability during scheduled reactor outages. In 2023, LNG accounted for 29% of the country's electricity supply, underscoring its enduring importance as a reliable energy source in South Korea's evolving energy landscape.

4.2.3 Eurasia

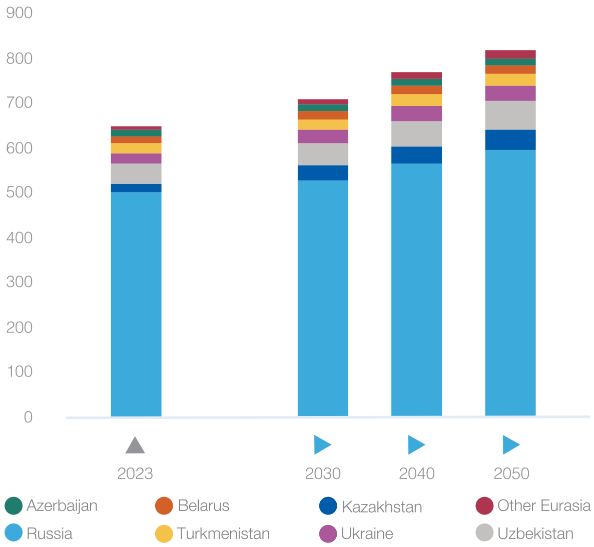
In **Eurasia**, natural gas is projected to maintain its leading role in the regional energy mix, accounting for 51% of total energy consumption in 2023. **Over the outlook period, natural gas demand is anticipated to grow modestly at an average annual rate of 0.9%, rising from 650 bcm in 2023 to 820 bcm by 2050.** This growth reflects a combination of steady industrial expansion, increased household gas connections, and the development of new applications for natural gas. However, the pace of demand growth is expected to be moderated by energy-saving measures, particularly in the power and heat generation sectors, where efficiency improvements will reduce fuel intensity.

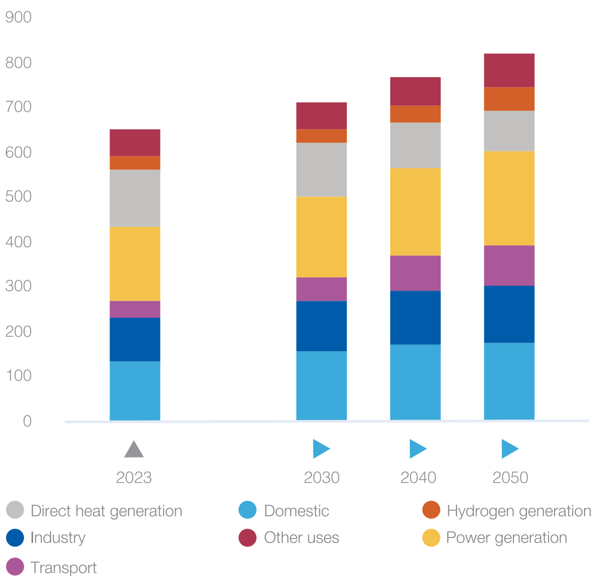
Despite these constraints, several factors are expected to grow natural gas demand. The expansion of natural gas vehicle (NGV) markets, alongside increasing industrial applications such as gas-to-chemicals, petrochemicals, and non-metallic minerals production, will contribute significantly to incremental demand. Moreover, the production of blue hydrogen, driven by the region's abundant gas resources, is emerging as a promising avenue for boosting gas consumption, particularly as global efforts to decarbonise hard-to-abate sectors accelerate.

Russia is expected to account for more than 57% of the projected incremental growth in natural gas demand, reaffirming its position as the largest consumer and producer in the region. Other major contributors include Kazakhstan, Turkmenistan, and Uzbekistan, which together are forecast to account for 27% of the demand increase. These countries are expected to leverage their extensive gas reserves and infrastructure to support domestic economic development while potentially expanding exports to nearby markets (Figure 4.14).

Figure 4.14

Eurasia natural gas demand outlook, 2023-2050 (bcm)





Source: GECF Secretariat based on data from the GECF GGM

Natural gas demand for blue hydrogen production and its derivatives is anticipated to see significant growth, increasing by an estimated 47 bcm between 2023 and 2050. This rise is largely driven by Russia, which aims to leverage its vast CCUS potential in depleted oil and gas fields to support its strategic initiatives for producing and exporting low-carbon hydrogen. Blue hydrogen is seen as a viable option for meeting domestic and export requirements, with the substitution of grey hydrogen in existing industrial applications forming a key part of this transition. In addition, there is growing interest in yellow hydrogen, produced via nuclear-powered electrolysis, although blue hydrogen remains the cornerstone of Russia's hydrogen strategy.

The transport sector is also poised for robust growth, with natural gas demand expected to reach approximately 40 bcm by 2050. This increase will be primarily driven by the expansion of natural gas vehicle (NGV) markets, supported by low gas prices, active promotion of natural gas as a motor fuel, and the growing vehicle fleet. Efforts to build NGV refuelling infrastructure and government-backed initiatives to broaden the adoption of NGVs are expected to support this trend further.

Natural gas demand is expected to follow divergent trajectories in the heat and power generation sectors. Demand for natural gas in heat generation is projected to decline by 37 bcm over the outlook period, primarily due to technological upgrades in the combined heat and power (CHP) fleet, modernisation of heating supply modes, and improved efficiency of gas-fired boilers, especially in Russia. However, this decline will be partially offset by a rise in gas demand for power generation, which is forecast to grow by 47 bcm. The growth in gas-for-power use will be limited by increasing fuel efficiency, commissioning modern CCGTs, accelerated deployment of renewable energy sources, and new nuclear power plants. Nevertheless, natural gas is expected to remain dominant in Russia's power generation mix, which supplied 42% of the country's electricity in 2023.

Russia's overall natural gas demand is projected to increase by 97 bcm or 20% by 2050, underpinned by the ongoing gasification program, rising penetration of gas in road transport, expansion of gas-to-chemicals projects, and the growing production of blue hydrogen. These developments align with the Russian Energy Strategy for 2050, which prioritises maximising the role of natural gas and enhancing the domestic hydrocarbon industry. The gasification program, aiming to raise the gasification rate to 76.7% by 2027 and 83% by 2030, will be a key driver of demand, particularly as it extends to new regions in Eastern Siberia and the Far East.

Industrial applications are another major contributor to demand growth, with gas-to-chemical projects, including the production of methanol, ammonia, and urea, poised to play a significant role. In addition, natural gas is expected to fuel industrial heating and process applications, providing a cleaner alternative to coal and oil. The residential and commercial sectors are also set to benefit from expanded gas infrastructure, while improved gas availability will enhance energy access for consumers in remote and underserved areas.

Despite the broad-based growth, the power sector will see only marginal gas demand increases of around 12 bcm by 2050 due to the modernisation of thermal power plants, greater efficiency in gas-fired generation, and the scaling up of renewables and nuclear power. Nonetheless, natural gas will continue to play a critical role as a flexible and reliable power source, particularly in balancing the grid as renewable energy penetration deepens.

The development of hydrogen technologies represents a high-priority area for Russia's energy policy. Besides export opportunities, there are plans to integrate hydrogen on a large scale into domestic energy-intensive industries, including steelmaking and petrochemicals. This focus positions hydrogen as an important driver of natural gas demand growth over the outlook period, ensuring that Russia remains a key player in the global energy transitions. Demand growth in the industrial, residential, commercial, and transport sectors is expected to increase by over 60 bcm by 2050, underscoring the multifaceted role of natural gas in meeting Russia's economic and environmental objectives.

4.2.4 Europe

Europe is the only region where natural gas consumption is projected to experience a substantial decline, dropping from 463 bcm in 2023 to 309 bcm by 2050, equating to an average annual decline of 1.5%. This trajectory reflects a comprehensive energy mix transformation across all economic sectors, driven by existing policies and the broader decarbonisation agenda. The share of natural gas in the region's total energy demand is forecast to decrease from 21% in 2023 to 16% by mid-century. Key policy initiatives, such as the EU's Fit-for-55 targets and the REPowerEU plan, underpin this trend by promoting energy efficiency, electrification, widespread deployment of renewables, and the adoption of heat pumps (see Chapter 2, EU energy policy section for further details). Over the longer term, the increasing scale of green hydrogen and biomethane adoption further erodes natural gas demand across traditional sectors.

A structural decline in gas consumption is anticipated in almost all sectors, with the exception of hydrogen and transport sectors. Natural gas demand in road and marine transport are expected to be supported by ongoing developments in LNG bunkering and CNG for heavy vehicles. Moreover, emerging clean technologies, including blue hydrogen production and CCUS, are expected to sustain demand for natural gas in this sector, providing opportunities for selective growth in energy-intensive applications.

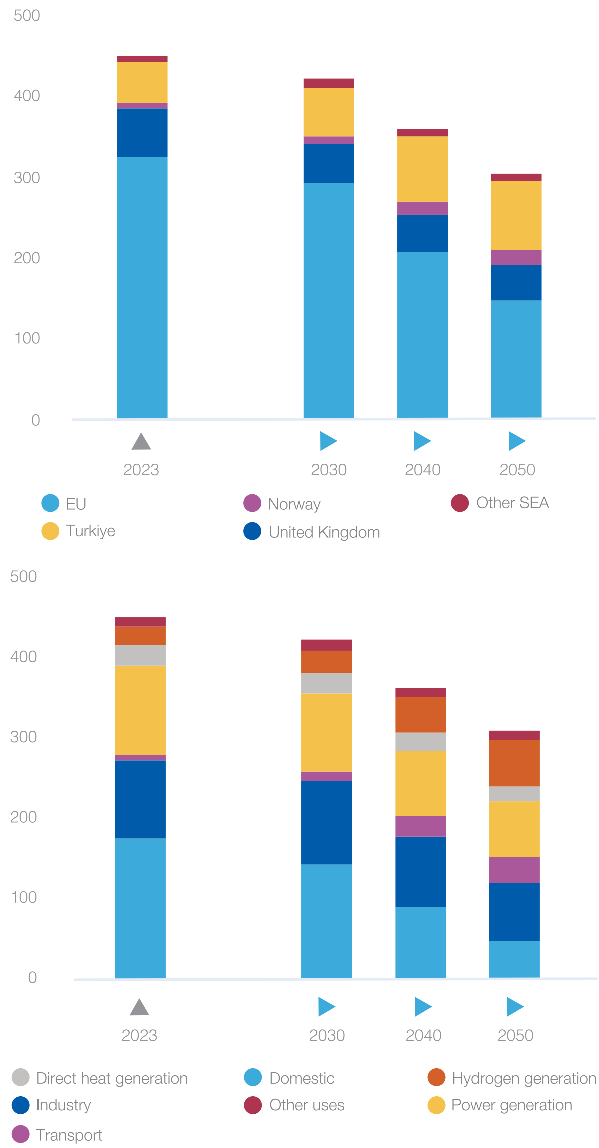
From a country-level perspective, the **EU** as a bloc is projected to see its natural gas demand decline by 175 bcm between 2023 and 2050, representing an annual reduction of 3%. The steepest reductions are expected in major economies such as Germany, Italy, France, and Spain, where aggressive decarbonisation policies, electrification of heating, and renewable energy integration are reshaping energy consumption patterns. Outside the EU, the United Kingdom's natural gas demand is projected to fall by 18 bcm by 2050, largely due to a reduction in power generation and residential gas use, with blue hydrogen production emerging as the primary growth area to offset declines in other sectors.

Norway is similarly expected to see advances in blue hydrogen production, primarily for export markets, particularly post-2030, as it leverages its extensive natural gas resources and CCUS infrastructure. In contrast, Türkiye is poised to be the only country in the region experiencing notable growth in natural gas demand. This expansion is driven by robust economic growth, gas transmission and distribution network expansion, new domestic gas discoveries, and increased import opportunities. Gas demand in Türkiye is expected to be concentrated in the power generation and industrial sectors, supporting its broader energy and industrial development goals (Figure 4.15).

From a sectoral perspective, the domestic sector

Figure 4.15

Europe natural gas demand outlook, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

is projected to experience the most significant decline in natural gas demand, with a reduction of approximately 126 bcm by 2050, representing an average annual decline of 4.8%. This decline is primarily driven by widespread energy efficiency measures, the electrification of space heating, accelerated by installing heat pumps, and the adoption of alternative heating solutions such as biomethane and low-carbon hydrogen. Germany, Italy, and the United Kingdom are leading the reduction, where ambitious policy measures are reshaping the heating landscape. In the United Kingdom, for example, the planned ban on new gas boilers by 2035, coupled with the transition to heat pumps, is expected to significantly reduce gas usage, which accounts for 61% of residential energy consumption.

In the power generation sector, weak electricity demand growth and strong policy momentum for renewables are expected to keep gas-fired power generation subdued in the near term. While opportunities for coal-to-gas switching remain, particularly in high coal-reliant countries such as Germany and parts of Central and Eastern Europe (e.g., Poland, Czech Republic, Bulgaria, and Serbia), the longer-term outlook steadily declines. Gas demand in power generation is forecast to fall from 110 bcm in 2023 to 70 bcm by 2050, driven by increasing renewable capacity and the integration of hydrogen-based generation. Gas-fired power plants, which accounted for 18% of Europe's power generation mix in 2023, will lose market share but are expected to remain a critical component of the energy mix, ensuring grid stability and security as renewable penetration increases.

In the industrial sector, short-term demand is supported by improving economic activity. However, in the long term, natural gas faces growing pressure from the electrification of low-heat industrial processes and the shift toward direct use of low-carbon hydrogen, particularly green hydrogen, in hard-to-abate sectors such as steel and chemicals. Policy support for green hydrogen is gaining momentum, but natural gas coupled with CCUS is anticipated to play a critical role in enhancing the resilience of natural gas demand. CCUS technologies are already central to decarbonisation strategies in Northwest Europe, with key projects such as Norway's Longship/Northern Lights and the Netherlands' Porthos advancing rapidly. United Kingdom is also progressing on decarbonising industrial clusters like the Humber and Teesside by deploying CCUS.

Natural gas demand for hydrogen production is expected to rise amid development of CCUS hydrogen infrastructure. This trend aligns with Europe's broader economy objectives but is expected to scale up in a limited number of countries with access to offshore CO_2 storage. Norway, United Kingdom, and the Netherlands are projected to lead this growth, leveraging their storage capabilities and integrating blue hydrogen into industrial applications, including as a substitute for grey hydrogen. Gas demand for hydrogen production in Europe is forecast to increase by 33 bcm between 2023 and 2050.

The transport sector presents an additional area for modest growth in natural gas demand, with consumption rising by 23 bcm between 2023 and 2050. This increase is primarily driven by the use of LNG as bunker fuel in marine transport and as fuel for heavy goods vehicles. Blending natural gas with biomethane is also expected to create opportunities, particularly for CNG in the passenger car market. In marine transport, growing orders for LNG-powered vessels underline high expectations. At the same time, shipping in the EU's ETS (Emissions Trading System) will likely provide a strong regulatory incentive for shipowners to consider LNG as a fuel of choice. Additionally, establishing a Mediterranean Emissions Control Area (ECA), set to take effect in May 2025, is anticipated to significantly impact LNG refuelling infrastructure expansion in this sub-region.

4.2.5 Latin America

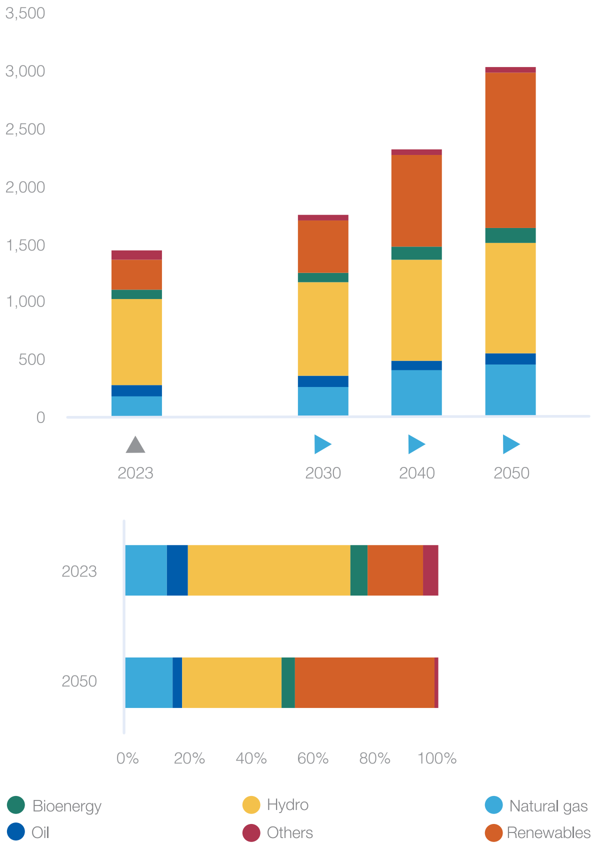
Natural gas demand in Latin America is forecast to grow at an average annual rate of 2.2%, increasing from approximately 150 bcm in 2023 to 275 bcm by 2050. Its share of the regional energy mix is projected to rise from 18% to 23%, reflecting growing efforts to harness domestic gas resources, expand infrastructure, and implement policies that encourage natural gas use across the power generation, industrial, and transport sectors. However, the region's limited pipeline interconnectivity poses challenges to comprehensive gas integration, with most demand growth concentrated in countries with significant gas reserves, such as Argentina, Brazil, and Venezuela. Simultaneously, LNG imports are expected to play an increasingly important role in addressing energy needs and supporting the development of more sustainable energy systems.

The power generation sector is expected to drive much of the natural gas demand growth, accounting for an additional 60 bcm, or 3.3% annual growth, representing over 48% of the region's incremental gas consumption. Brazil, Venezuela, and, to a lesser extent, Argentina, the Caribbean, Peru, and Chile are poised to lead this expansion. Gas-fired power generation, including LNG-based projects, is projected to replace oil-fired plants and reduce dependence on hydropower, which, while essential to the region, remains susceptible to seasonal and climate-related fluctuations. Although renewable energy sources are expected to dominate capacity expansion in alignment with ambitious energy transition targets, the intermittency of renewables creates opportunities for gas-fired power generation to act as a reliable backup and enhance grid stability.

Electricity generation in Latin America is projected to rise from 1,450 TWh in 2023 to 3,050 TWh by 2050, an average annual growth rate of 2.8%. Within this

Figure 4.16

Latin America power generation by fuel (TWh) and fuel shares, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM
Note: Others include coal, nuclear and hydrogen

growing energy demand, gas-fired power generation is forecast to meet 16% of the region's electricity needs. The share of natural gas in the power generation mix is anticipated to grow from 13% in 2023 to 15% by mid-century, while hydropower's share is expected to decline, even as its overall output continues to increase (Figure 4.16). Gas demand for power generation is projected to fluctuate throughout the outlook period, rising during dry seasons when hydropower output is constrained and declining during periods of high rainfall.

The industrial sector in Latin America holds considerable growth potential, with natural gas demand projected to increase by 29 bcm between 2023 and 2050, representing an annual growth rate of 2.3%. This growth is primarily driven by investments in new industrial facilities and expansions in key markets such as Argentina, Brazil, and Colombia. These countries are set to lead industrial demand growth, supported by strong economic prospects, enhanced pipeline infrastructure, and market-oriented reforms that facilitate the adoption of natural gas as a competitive and cleaner energy source for industrial applications.

The transport sector is poised to experience robust growth in natural gas demand, particularly in Argentina and Brazil. NGVs have been well-established due to supportive government policies, increasing domestic gas production, and the widespread availability of refuelling infrastructure. The shift from diesel to natural gas, especially in heavy goods vehicles, is expected to contribute to this growth significantly. Additionally, LNG is projected to gain traction as a bunker fuel, driven by the region's strategic position in global maritime trade and the expansion of regasification infrastructure. The Panama Canal, with its growing importance as a logistics hub, offers a strategic opportunity for LNG adoption in the maritime sector. This development aligns with the global push toward cleaner marine fuels, reinforcing LNG's role in decarbonising international shipping while leveraging the region's geographical and logistical advantages.

Natural gas demand is forecast to grow in the domestic sector, with Argentina expected to dominate this growth. The expansion of transmission and distribution networks is set to increase natural gas penetration, particularly in urban areas. However, consumption in these sectors is expected to remain highly seasonal, peaking during the winter months in the southern hemisphere when heating requirements are highest.

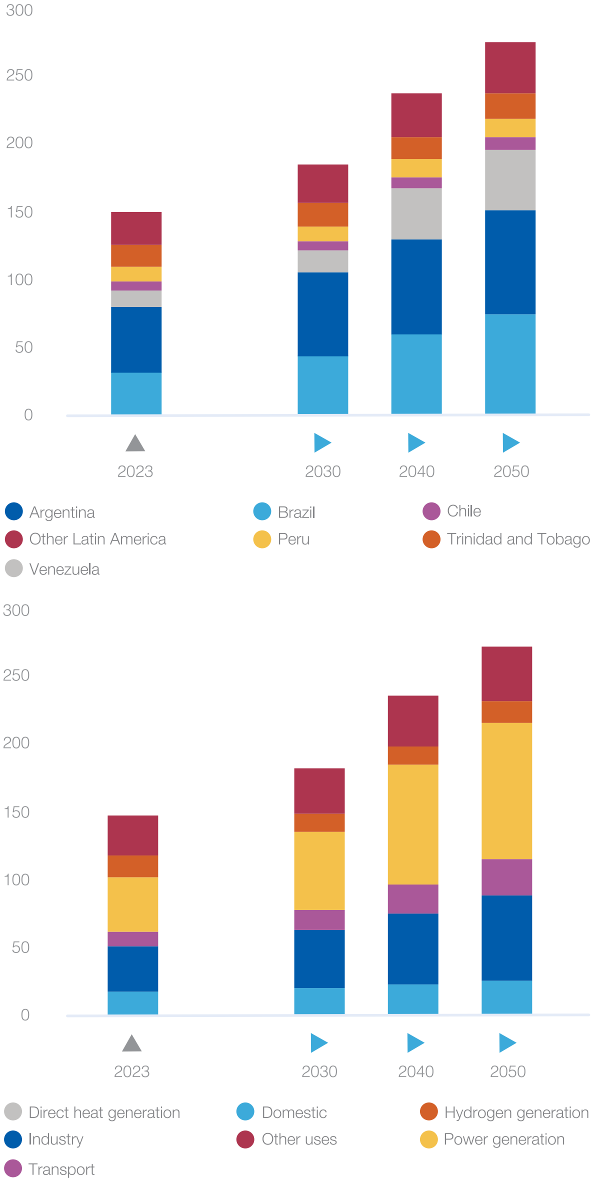
Overall, natural gas demand is projected to increase across Latin America, with Argentina, Brazil, and Venezuela contributing the majority of the growth. Together, these three countries are expected to account for 82% of the total regional increase, with respective shares of 22%, 35%, and 25%. Colombia, Chile, and Peru are also expected to contribute to regional growth, collectively adding around 10 bcm by 2050, representing 7% of the total increase. In Trinidad and Tobago, gas demand is projected to grow modestly, remaining concentrated in industrial applications, particularly as a feedstock for petrochemical production. These trends underscore natural gas's diverse and dynamic role in Latin America's energy landscape, as illustrated in Figure 4.17, highlighting the sectoral and country-level contributions to demand growth across the region.

In **Argentina**, natural gas demand is forecast to grow from 49 bcm in 2023 to 76 bcm by 2050, representing an average annual growth rate of 1.6%. As the backbone of the country's energy mix, currently accounting for 50%, natural gas plays a crucial role in power generation and remains integral to Argentina's economy. This reliance is further reinforced by the anticipated increase in production from the Vaca Muerta shale formation in the Neuquén Basin, one of the world's largest shale reserves. Gas demand is expected to grow across all sectors, with industrial and transport applications leading the expansion.

To facilitate gas flow from Vaca Muerta to domestic markets, Argentina is investing heavily in its transmission

Figure 4.17

Latin America natural gas demand by country and sector ,2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

and distribution infrastructure. Central to these efforts is the Presidente Néstor Kirchner gas pipeline, which has a total planned capacity of approximately 16 bcm per year. This pipeline connects the Neuquén Basin to Santa Fe, traversing the provinces of Río Negro, La Pampa, and Buenos Aires. The first 570-kilometer phase was completed in July 2023, linking the shale play to Buenos Aires and marking a significant milestone in securing domestic gas supply. Additional projects, such as the Mercedes-Cardales pipeline and upgrades to existing infrastructure, aim to optimise the national gas transport system, reduce LNG imports, and minimise reliance on liquid fuels for power generation. These initiatives also pave the way for enhanced regional gas integration, solidifying Argentina's position as a key energy player in Latin America.

In **Brazil**, natural gas demand is set to grow significantly, from 32 bcm in 2023 to 75 bcm by 2050, with an impressive annual growth rate of 3.2%. The power generation sector is expected to be the primary driver of this growth. At the same time, industrial demand also rises notably, partly due to increased domestic production of fertilisers, which aims to reduce the country's dependence on imports. Regulatory reforms and steady economic growth further encourage the adoption of natural gas. In April 2021, Brazil implemented liberalisation measures in its gas sector, promoting competition, vertical unbundling, and lowering domestic gas prices. These reforms, combined with broader market initiatives, are expected to attract substantial investment in gas production and transportation infrastructure, enabling the monetisation of the country's vast pre-salt gas reserves.

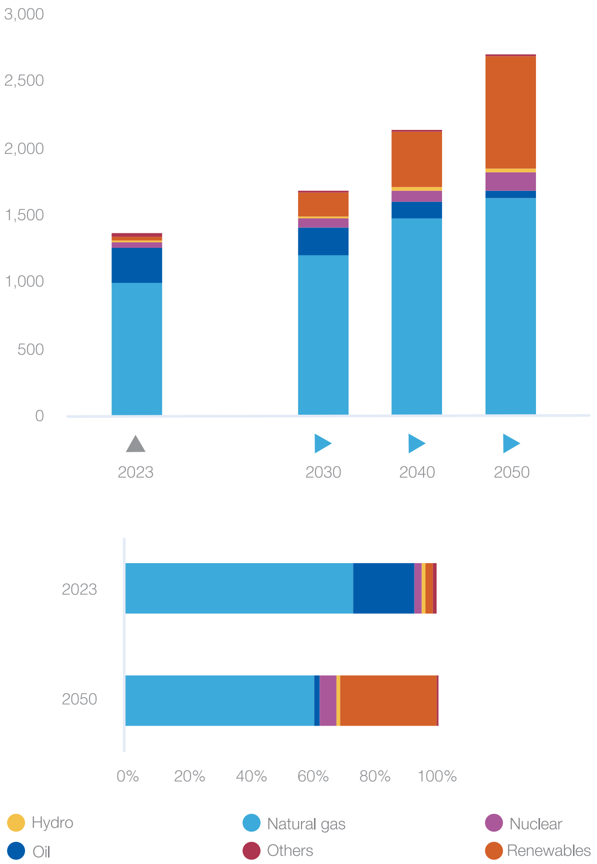
The expansion of gas-fired power generation is set to accelerate, supported by the development of regasification infrastructure that creates favourable conditions for LNG-to-power projects. These initiatives are particularly important as hydropower, the dominant source of electricity in Brazil, faces growing challenges from increasingly unpredictable rainfall patterns. Around 5 GW of gas-fired capacity is under construction, including major projects such as the 1.6 GW GNA II (formerly GNA Porto de Açu III, expected to come online in 2025) and the 600 MW Novo Tempo Barcarena. While gas usage in power generation is forecast to remain somewhat volatile, its share in the power generation mix is projected to rise from around 5% in 2023 to 9% by 2035, with a steady upward trend thereafter. This growth will reduce reliance on hydropower, which accounted for 58% of the generation mix in 2023, and provide the necessary flexibility to support the increasing penetration of renewable energy sources in Brazil's energy system.

4.2.6 Middle East

Natural gas demand in the Middle East is forecast to grow at an annual rate of 1.5%, increasing from 554 bcm in 2023 to 865 bcm by 2050. This growth is underpinned by robust economic expansion, population growth, and shifting away from oil products, particularly in the power generation sector. The region's abundant indigenous natural gas resources will continue to meet rising demand, ensuring energy security and supporting economic diversification. Simultaneously, a strong push for renewable energy deployment in power systems is expected to free up natural gas for higher-value applications, such as industrial use and the production of blue hydrogen and its derivatives. Natural gas, which accounts for 53% of the region's energy mix, is projected to remain the dominant energy source up to 2050.

Figure 4.18

Middle East power generation by fuel (TWh) and fuel shares, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM
Note: Others include coal, bioenergy and hydrogen

The Middle East is positioning itself as a global leader in blue hydrogen production, leveraging its proximity to extensive natural gas reserves. This strategic focus not only enables the production of low-carbon hydrogen but also fosters the establishment and expansion of hydrogen markets. By 2050, 14% of the total incremental gas use in the region is projected to be associated with low-carbon hydrogen production. State-owned companies and government funding are driving the development of hydrogen projects, supported by advancements in CCUS technologies. These initiatives will ensure the long-term viability of the natural gas sector while contributing to global decarbonisation goals.

Across the region, growing demand for natural gas in industry and power generation is expected to account for 57% of the total growth, or an additional 163 bcm by 2050. As an energy source and feedstock, industrial gas use is set to play a pivotal role, adding 83 bcm over the forecast period. Expanding gas-to-chemicals, petrochemicals, fertiliser production, and light manufacturing industries will drive this growth. Natural gas is expected to remain integral to powering water desalination through cogeneration facilities or membrane technologies reliant on electricity.

Electricity generation in the Middle East is projected to double, rising from 1,365 TWh in 2023 to 2,690 TWh in 2050, with an average annual growth rate of 2.5%. Gas-to-power demand will continue to increase, supported by surging electricity needs and policies promoting oil-to-gas switching. However, growth in gas-fired generation is expected to slow in the 2040s as renewable and nuclear capacities expand. While natural gas will remain dominant in the regional power generation mix, its share is forecast to decline from 73% in 2023 to 61% by 2050.

This shift reflects the region's ambitious renewable energy programs and investments in nuclear power. The Middle East has already achieved some of the world's lowest photovoltaic (PV) tariffs, with countries like Saudi Arabia and the UAE advancing their renewable energy strategies through competitive public tenders and auctions. Although solar and wind play a minor role in the regional power mix, by 2050, these sources are expected to contribute 31% of electricity generation, with solar alone accounting for 24%. Wind power is anticipated to remain primarily onshore, leveraging the region's vast flat and barren landscapes, ideal for development.

Natural gas demand is projected to grow in the domestic sector, primarily driven by Iran. Population expansion and efforts to extend natural gas access to rural areas are expected to boost consumption. Policy initiatives to expand the domestic gas grid will continue to underpin this trend, solidifying Iran's position as a major contributor to regional gas demand.

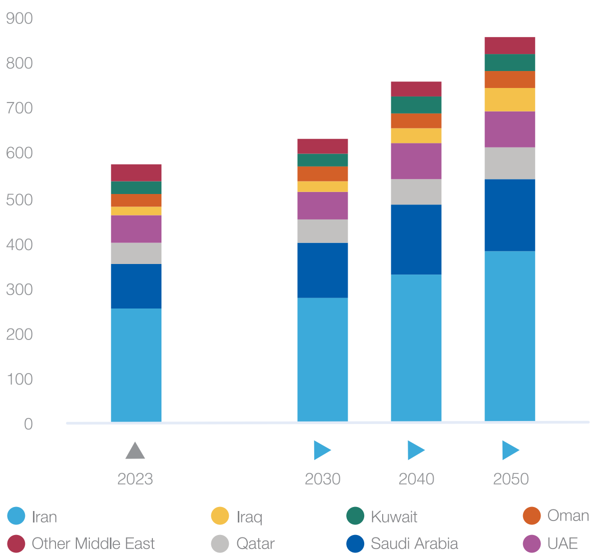
The transport sector is also poised for growth. Iran is expected to lead the way in road transport, benefiting from supportive policies and low CNG prices, making natural gas an attractive alternative to conventional fuels. Saudi Arabia is also set to experience moderate growth in natural gas use in heavy goods vehicles (HGVs) as the country works to reduce domestic oil consumption in transportation. Additionally, LNG is projected to play an increasingly important role as a bunker fuel, with significant opportunities emerging to service LNG-powered vessels along the Europe-Asia shipping routes. This development aligns with global trends toward cleaner marine fuels and positions the region as a strategic hub for LNG bunkering.

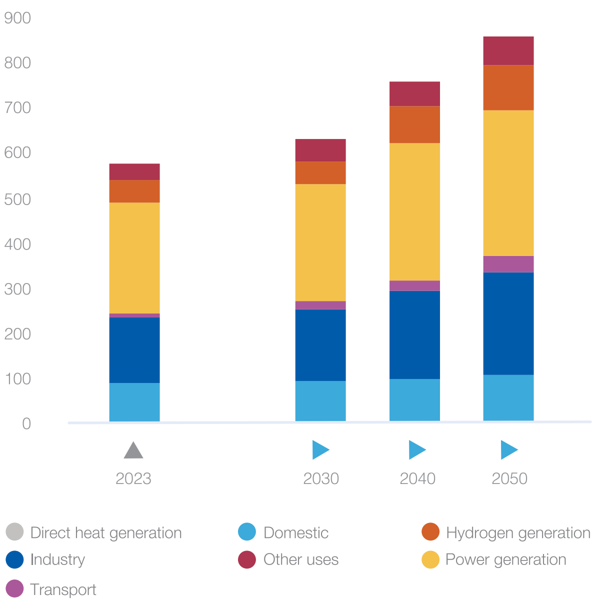
From a country-level perspective, Iran is expected to account for the largest share of regional natural gas demand growth, contributing approximately 45% of the total increase. Saudi Arabia follows with 21%, supported by its economic diversification goals and initiatives to reduce oil consumption across various sectors. Iraq and Qatar are forecast to contribute 12% and 8%, respectively, with Iraq's growth driven by its industrial and power generation sectors and Qatar's demand bolstered by industrial expansion and blue hydrogen production.

In the UAE, which is currently the region's third-largest natural gas market, demand growth is expected to be more moderate over the long term. This reflects the country's rapid progress in renewable and nuclear energy deployment, which will likely limit the expansion of gas-fired generation. However, the UAE presents substantial upside potential for natural gas demand linked to blue hydrogen generation, a key element of its decarbonisation strategy. The sectoral and country-specific dynamics are illustrated in Figure 4.19, highlighting the diverse factors driving natural gas demand across the Middle East.

Figure 4.19

Middle East natural gas demand by country and sector, 2023-2050 (bcm)





Source: GECF Secretariat based on data from the GECF GGM

In **Iran**, natural gas demand is set to increase by 50%, reaching 385 bcm by 2050 or 1.6% year-over-year. The main drivers behind this growth are positive economic development and the country's substantial gas reserves. Iran's high energy intensity and some of the lowest fuel prices globally also provide further impetus for rising demand. Gas use is projected to expand primarily in the power generation and industrial sectors, which together account for 68% of the growth, driven by increasing electricity needs, the development of petrochemical complexes, and the growth of light manufacturing, all of which significantly contribute to the Iranian economy. The residential and commercial sectors are also expected to contribute notably to the additional gas demand. Although more than 95% of the population is already connected to gas grids, the government aims to increase gas availability further, providing access to new rural areas, including those in colder climates.

Iran's power system heavily relies on natural gas, with gas-fired power plants accounting for 70% of installed capacity and 87% of the power generation mix in 2023. Approximately 20 GW of additional gas-fired capacity is in various stages of completion and is expected to come online within the next decade. Gas-fired power will remain the backbone of Iran's electricity supply, supported by oil-to-gas switching policies. However, the increasing deployment of renewables and nuclear energy signals a gradual diversification of the power generation mix, potentially moderating future growth in gas demand for electricity.

Given significant government support, untapped solar and wind resources are projected to begin making inroads. Currently, over 5 GW of solar capacity is under development, and Iran recently unveiled plans to construct 15 GW of solar installations. Additionally, nuclear energy is becoming a strategic focus, with an ambitious target of 20 GW of nuclear capacity by 2041. Construction of major nuclear projects, including a 5 GW plant in Sirik and the expansion of the Bushehr plant, highlights this shift toward energy diversification.

In **Qatar**, natural gas demand is projected to grow by 22 bcm, reaching 71 bcm by 2050, with an annual growth rate of 1.4%. Expanding LNG export production capacity and energy sector-related needs primarily drive this increase. Qatar is also diversifying its gas use by investing in fertiliser production and low-carbon gas-based solutions, including the Ammonia-7 blue ammonia project, expected to begin operations in 2026. However, gas demand in power generation is expected to see only modest growth. Qatar aims to install 4 GW of large-scale solar PV capacity by 2030, reflecting its commitment to renewable energy.

In **Saudi Arabia**, natural gas demand is forecast to grow by 60 bcm, reaching 163 bcm by 2050, with an annual growth rate of 1.8%. Economic and population growth, along with low gas prices and a shift from oil in power generation, are the primary drivers. Saudi Arabia focuses on expanding gas production, particularly through unconventional shale gas development from the Jafurah Basin and enhancements to the Master Gas System infrastructure. Its burgeoning petrochemical industry and plans for blue hydrogen and ammonia production will also drive long-term gas demand. Natural gas demand in Saudi Arabia's power generation sector is expected to grow until 2040 but decline thereafter as oil-to-gas switching opportunities diminish and the deployment of alternative energy sources accelerates. By 2050, the shares of natural gas and oil in the power mix are projected to drop to 43% and 1%, respectively, while renewables and nuclear energy are forecast to supply 48% and 8% of electricity. While Saudi Arabia's renewable energy projects, including 30 GW currently under development, are ambitious, achieving the 2030 target may face delays due to network adaptation challenges.

In the **UAE**, natural gas demand is expected to rise from 61 bcm in 2023 to 80 bcm in 2050, primarily driven by decarbonised hydrogen production. Under its National Hydrogen Strategy, the UAE aims to produce 15 Mt of hydrogen annually by 2050, with blue hydrogen serving as a key transitional fuel. However, this increase in gas demand for hydrogen is anticipated to be partially offset by declining gas use in the power generation sector as nuclear and renewable capacities expand. The UAE is rapidly advancing its renewable energy portfolio. For instance, in 2023, Masdar inaugurated the 2 GW Al Dhafra Solar PV plant, and an additional 4.5 GW of solar capacity is in development at the Mohammed bin Rashid Al Maktoum Solar Park. Solar energy is projected to account for nearly 45% of the power generation mix by 2050, up from 7% in 2023, while natural gas's share is expected to decline from 77% to around 40%.

Natural gas will remain a cornerstone of the Middle East's energy mix, although its role will evolve alongside efforts to diversify energy sources and reduce carbon emissions. The development of blue hydrogen, CCUS infrastructure, and renewable energy will ensure the gas sector's continued relevance in the region's energy transitions. This transformation will be marked by greater integration of renewables, nuclear energy, and hydrogen into the power and industrial sectors, reshaping the energy landscape while maintaining natural gas as a crucial component of the Middle East's energy future.

4.2.7 North America

In North America, natural gas demand is projected to remain relatively stable over the forecast period. Demand is expected to rise moderately this decade, reaching a prolonged plateau of around 1,180 bcm. **After 2030, demand gradually declines to approximately 1,083 bcm by 2050, about 77 bcm below 2023 levels.** However, this overall trend masks noticeable changes in consumption patterns. Canada's increase in natural gas consumption is projected to be moderate. At the same time, strong demand growth in Mexico is offset by a declining trend in the United States, where the gas market is set to enter perpetual contraction after 2030. This contraction is largely driven by the United States Inflation Reduction Act (IRA) amid a focus on decarbonisation and the deployment of clean energy technologies.

Overall, due to affordability, ample supplies, and environmental advantages, natural gas is expected to remain the largest primary energy source in the region, maintaining around 36-37% of the energy mix throughout the forecast period. Notably, the North American gas industry, particularly in the United States, is addressing climate challenges by scaling up options that support deep decarbonisation of natural gas, such as deploying CCUS and offsetting mechanisms. CCUS, in particular, has significant potential, underpinned by substantial CO_2 storage capacities in mature fields. The United States and Canada aim to stimulate CCUS projects through budget allocations and enhanced credits.

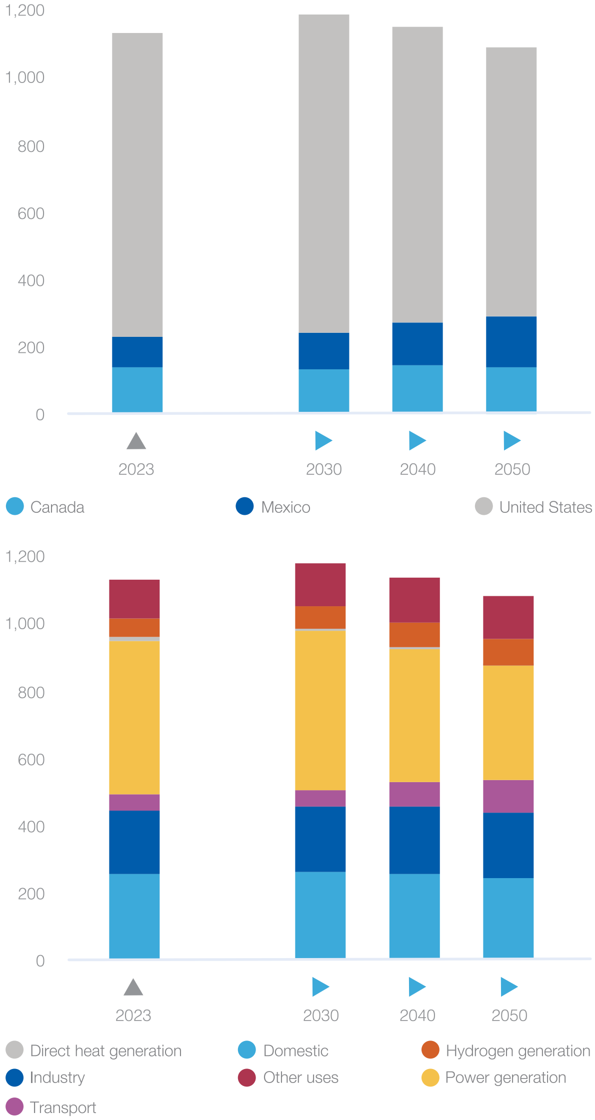
The main drivers for natural gas demand in North America are expected to originate in the transport sector and for hydrogen generation, particularly blue hydrogen production. The ramp-up of LNG export facilities and rising gas production also contribute to increased consumption for energy industry use. As for hydrogen, the United States and Canada are well-positioned to expand blue hydrogen use, given low-cost gas production, policy support, and existing infrastructure for capacity development. An additional 60 bcm of gas is estimated to be required to generate blue hydrogen.

Road and marine transport growth is also considerable, contributing an incremental 38 bcm through to 2050. This trend is predominantly driven by the United States, where the development of the NGV market is a key factor. Increasing natural gas use is encouraged by strengthened emissions standards, policy initiatives, and infrastructure expansion through private sector investment. Due to economic and environmental benefits, the HGV segment is the primary target for continued gas engine conversions. Consequently, as indicated earlier, the areas partially offset demand reductions in other sectors. Figure 4.20 provides an overview of North America's natural gas demand trends by sector and country.

Natural gas is projected to maintain a substantial role in the power generation sector. Even in Canada, where the power system benefits from abundant hydroelectric resources, natural gas offers an opportunity to replace existing coal-fired plants and provide flexibility to renewables. At the regional level, gas demand in this sector is set to rise from 460 bcm in 2023 to 472 bcm in 2030 as more United States coal plants are retired. Gas-

Figure 4.20

North America natural gas demand outlook, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

fired power capacity expansion is anticipated in Mexico and is expected to continue over the entire outlook period. Nevertheless, post-2030, regional gas demand in power generation begins to decline to about 340 bcm by 2050 due to the significant rise in renewables, especially in the United States. Despite this drop, the power generation sector remains the region's largest consumer of natural gas, accounting for 31% of total gas volumes in 2050. However, natural gas's share in the regional power generation mix is projected to decrease sharply, from 40% in 2023 to 24% by 2050 (Figure 4.21).

In the industrial sector, natural gas demand is expected to experience a modest growth and remain resilient. Industrial demand in the region is projected to rise within

Figure 4.21

North America power generation by fuel (TWh) and fuel shares (%)

Source: GECF Secretariat based on data from the GECF GGM
Note: Others include bioenergy and hydrogen

the current and next decade before declining to 195 bcm by 2050. At a country level, Mexico's demand is projected to increase due to economic growth, while the United States and Canada are likely to see flat usage until the mid-2030s, with declines following that period. In the United States, rising GDP and new methanol and petrochemical plants are expected to stimulate gas demand growth in the coming decade. Still, this demand is set to eventually fall due to energy efficiency improvements and the adoption of low-carbon hydrogen. Industrial gas use in combination with CCUS will be crucial to address further GHG mitigation. In the domestic sector, gas demand in the region is anticipated to remain relatively stable through 2050 as efficiency gains and the increasing electrification of heating systems constrain potential growth.

In **Mexico**, natural gas demand is projected to grow from 90 bcm in 2023 to 150 bcm or 1.9% year over year by 2050, driven primarily by the power generation sector and industry, with the former contributing approximately 60% of the total increase. In the power system, natural gas is decisive due to the ongoing strategy of adding numerous CCGTs to the grid. By replacing remaining coal- and oil-fired power plants and providing a reliable base load for rising electricity demand, natural gas-fired generation is expected to supply over 60% of the power generation mix in 2050. This represents a decline from the 65% average of recent years as solar and wind generation is set to grow.

The anticipated growth in gas demand is supported by affordable piped supplies from the United States, cross-border pipeline capacity expansions, and increased exploration and production efforts. Additional network infrastructure within Mexico is essential, with several pipelines, including the Tula-Villa de Reyes and Tuxpan-Tula, under construction to supply gas to new power generation plants and industrial facilities. In June 2024, construction began on the Mayakan Energy Expansion project, traversing the states of Campeche, Chiapas, Tabasco, and Yucatan, aiming to double transportation capacity. Another proposed pipeline is between Los Ramones and Cempoala to supply gas to central Mexico.

In the **United States**, gas demand is projected to peak at around 935 bcm in the early 2030s, driven mainly by large-scale coal-to-gas switching in the power generation sector. After this peak, demand is expected to gradually decrease to approximately 790 bcm by 2050, falling nearly 110 bcm below 2023 levels. This decline is influenced by the anticipated surge in decarbonisation technologies, especially post-2030, as these technologies mature, and clean energy adoption accelerates. Nonetheless, natural gas remains a significant part of the energy mix, projected to keep a share of around 34-35% over the forecast period.

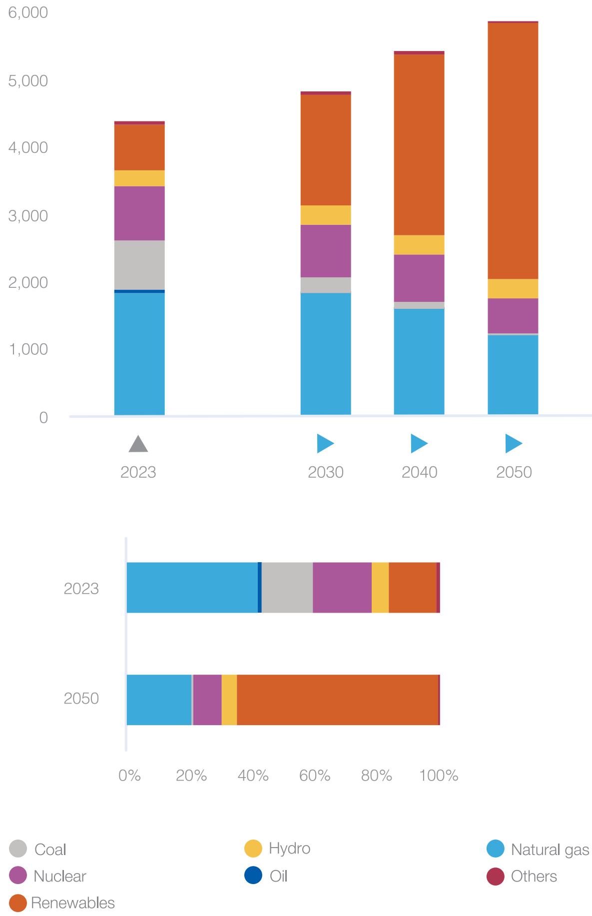
The decline in gas demand is primarily due to shifts within the power generation sector, aligning with the national goal for 100% carbon-free electricity by 2035. In this regard, the IRA, through the establishment of new technology-neutral credits, ensures more confidence for investment in renewable projects and supports nuclear power, including plants that are at high risk of premature retirement.

While fossil fuel-based electricity generation is set to decline (with fossil fuels accounting for 60% of the power mix in 2023, including 42% from natural gas and 17% from coal), achieving a net-zero power sector by 2035 remains challenging. A more realistic target is likely 65% of clean power generation. In the interim, gas-fired generation stands to benefit from the shift away from coal and is anticipated to supply 38% of electricity by 2030. However, its share is expected to fall to 33% by 2035 and 21% by 2050 as renewables expand aggressively (Figure 4.22). The integration of CCGT with CCUS offers a valuable solution to reducing carbon emissions within the US power sector.

Meanwhile, the transport sector and hydrogen

Figure 4.22

The United States power generation outlook, 2023-2050 (TWh)



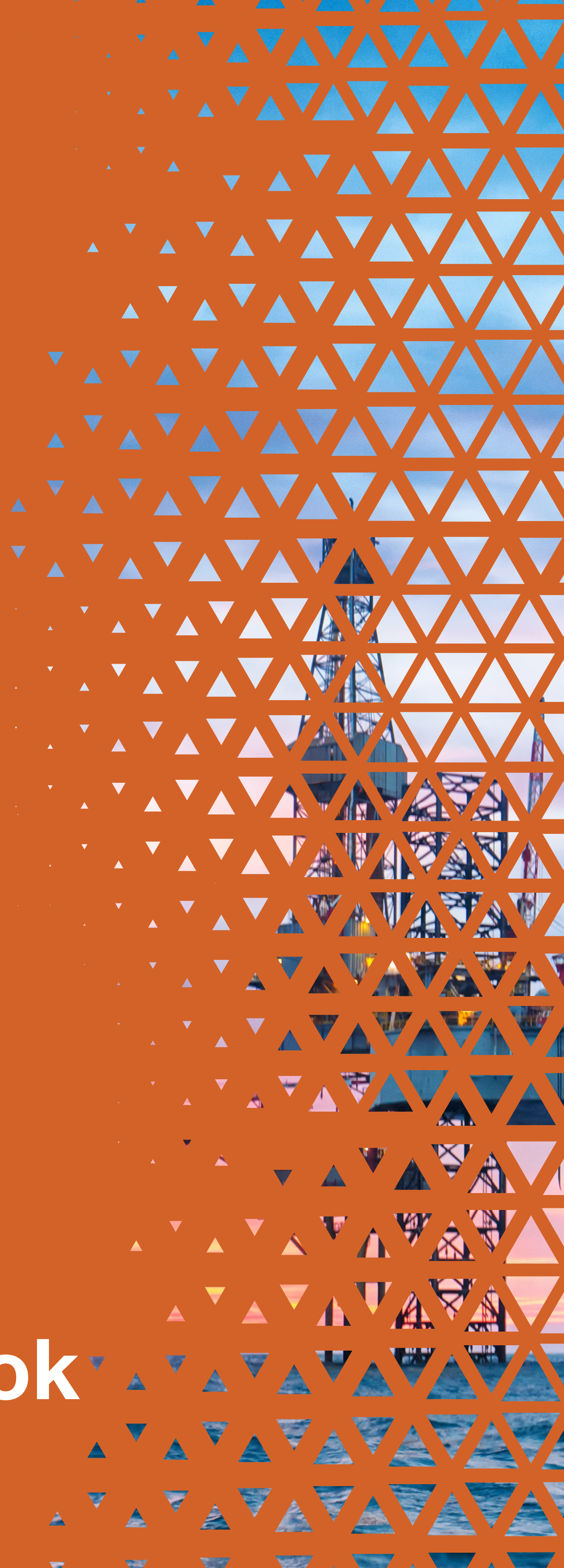
Source: GECF Secretariat based on data from the GECF GGM
Note: Others include bioenergy and hydrogen

generation present key growth opportunities for natural gas. Blue hydrogen, in particular, is poised for accelerated adoption due to tax incentives under the IRA. There is substantial potential for converting existing on-site grey hydrogen generation, especially in methanol, ammonia, and refining facilities, to blue hydrogen, further supporting demand. Additional growth in natural gas demand may also emerge from the export potential of blue hydrogen, which aligns with the National Clean Hydrogen Strategy and Roadmap.

Natural gas will play a pivotal role in the energy balances of all regions worldwide. Europe is projected to be the only region where demand for natural gas will significantly decline by 154 bcm by 2050. Demand for natural gas in North America is projected to remain stable, without sudden surges or drops in consumption. The Asia Pacific and Middle East regions will be the leading global growth centres in natural gas demand. Their overall increase in natural gas consumption is projected to reach 1000 bcm by 2050. The main growth drivers in these regions are population and economic growth, electrification, the coal-to-gas transition, and hydrogen production. In other world regions, an increase in natural gas demand will be observed, but the growth in absolute figures will be much lower. Key drivers for growth in these regions will be associated with infrastructure development, broader access to electricity, population growth, and the transition from biomass and coal to natural gas.

Chapter 5

Natural Gas Supply Outlook



Highlights

- The RCS projects global natural gas production to reach 5,317 bcm, with an average annual growth rate of 1%. Average annual growth is expected to decelerate from 1.6% within the current decade to 1% in the 2030s and eventually 0.6% in the 2040s.

- Non-associated gas from conventional reservoirs is projected to grow by 957 bcm, reaching 3,460 bcm by 2050, driven by key developments in the Middle East, Eurasia, and Africa.

- Production from new projects, including yet-to-find (YTF) resources, is anticipated to account for 81% of global natural gas production by 2050, underscoring their significant role in offsetting natural decline from existing fields and meeting growing natural gas demand.

- Onshore natural gas production is forecast to grow from 2,902 bcm in 2023 to 3,515 bcm by 2050, driven by expansions in Eurasia and the Middle East. Offshore gas production is expected to increase from 1,177 to 1,802 bcm over the same period, boosting its share of global output from 29% to 34% by midcentury, supported by new developments in Africa and the Middle East.

- Conventional gas production is forecast to reach 3,806 bcm by 2050, driven by Africa, Eurasia, and the Middle East, while unconventional sources are projected to contribute 1,511 bcm, largely from North America.

- By 2050, the Middle East is projected to lead in overall production growth, contributing an additional 461 bcm, followed by Eurasia with 362 bcm. Africa is set to record the fastest annual growth rate globally at 2.5%, adding nearly 250 bcm to its production over the outlook period.

- By 2050, the center of gravity for natural gas supply is expected to shift toward the Middle East, Eurasia, and Africa, collectively accounting for 54% of global production, up from 44% in 2023. This transformation reflects their growing role in meeting global energy needs, particularly after 2030.

- Unconventional gas production in North America is expected to peak at 1,205 bcm in the late 2030s, before declining to 1,126 bcm by 2050, driven by natural depletion of existing assets.

- Natural gas production from GECF member countries is projected to increase from 1,606 bcm in 2023 to 2,416 bcm by 2050, raising their share of global production from 39% in 2023 to 45% by 2050.

5.1 Global natural gas production overview

Global natural gas production reached 4,078 bcm in 2023, reflecting a modest 0.7% increase from 2022 and surpassing pre-pandemic levels. Growth accelerated in 2024, reaching 4,131 bcm, with a stronger expansion rate of 1.3%. However, this increase was uneven across regions, influenced by supply chain constraints, geopolitical developments, and varying investment levels in upstream projects.

North America remained the world's largest natural gas producer, contributing 1,275 bcm and accounting for 31% of global output in 2023. The region experienced a robust 4.7% growth, driven primarily by the United States, which expanded production by 47 bcm, supported by advancements in shale gas extraction and infrastructure expansion. Canada contributed an additional 6 bcm, while Mexico saw a decline, counterbalancing some of the region's growth. However, in 2024, North America's production stagnated due to declines in the United States and Mexico, offsetting the 4.8 bcm increase from Canada. This suggests that North America's production capacity may be plateauing, influenced by regulatory shifts, cost factors, and maturing shale fields.

The Middle East continued its steady expansion, with production reaching 694 bcm in 2023, representing 17% of global output. Growth stood at 2.7%, slightly above initial projections, led by Iran and Qatar, with additional contributions from Iraq, Oman, and the UAE. In 2024, the region's production grew by 3.1%, largely driven by Saudi Arabia, followed by continued expansion in the UAE, Iraq, and Oman. This trajectory underscores the Middle East's role as a key pillar of global natural gas supply, supported by vast reserves and ongoing investment in upstream development.

Africa's natural gas production increased to 252 bcm in 2023, accounting for 6% of global output. Algeria led regional growth, adding 8 bcm, while Mozambique and Nigeria contributed an additional 4 bcm and 2 bcm, respectively, reflecting the continent's expanding role in global energy markets. In 2024, production dynamics shifted, with North African output experiencing a temporary decline. However, strong gains from Nigeria and Mozambique helped balance regional supply, reinforcing Africa's long-term potential as a key natural gas supplier. Ongoing investments in LNG infrastructure and upstream developments across the continent are expected to enhance production stability and export capacity in the years ahead.

Asia Pacific saw a marginal increase of 0.4% in production in 2023, reaching 660 bcm and accounting for 16% of global output. China led regional growth, adding 14 bcm as part of its domestic energy security strategy, surpassing previous expectations with a 6% year-on-year increase. However, this was partially offset by a 4 bcm decline in Australia, linked to maintenance shutdowns and resource depletion. In 2024, regional production continued to grow, driven by China, followed by India and Thailand. Despite these increases, the region remains highly dependent on imported LNG, with production growth unlikely to keep pace with rising demand.

Eurasia experienced the most significant contraction in 2023, with production declining by 5.5% to 846 bcm, accounting for 21% of global output. Russia led this decline, facing production constraints due to reduced import by Europe, geopolitical imbalances, and shifting trade patterns. Uzbekistan also reported lower output due to market realignments. However, 2024 marked a substantial recovery, with Eurasia's production surging by 50 bcm to 891 bcm, driven largely by Russia, which expanded its production by 48 bcm as new export routes were developed and domestic consumption increased.

Europe's natural gas production declined sharply in 2023, falling by 9.3% to 198 bcm, accounting for just 5% of global supply. The drop was driven by Norway's declining output, the permanent shutdown of the Groningen field in the Netherlands, and resource depletion in the United Kingdom's North Sea operations. In 2024, production increased slightly to 202 bcm, with gains in Norway and Türkiye partially offsetting continued declines in the Netherlands and the United Kingdom. This ongoing downward trend highlights Europe's increasing dependence on natural gas imports, particularly from the Middle East, North America, and Africa.

Latin America's production fell by 1.2% to 152 bcm in 2023, accounting for 4% of global supply. Declines in Bolivia and Trinidad & Tobago outweighed stable production levels in Argentina and Brazil. In 2024, regional output rebounded by 2 bcm, led by Argentina and Brazil, reflecting renewed investment in upstream activities. Despite this recovery, Latin America's overall production remains constrained, with long-term growth highly dependent on infrastructure expansion and policy support.

While global natural gas production continued to expand, regional disparities remain evident. The regional production patterns indicate broader shifts in natural gas markets, where future supply growth will increasingly be influenced by reserves availability, investment attractiveness, and evolving energy policy choices. The competition between natural gas and alternative energy sources will continue to shape production trends and trade flows in the coming decades.

5.2 Global natural gas production outlook

Global natural gas production is projected to reach 5,317 bcm by 2050, reflecting a substantial increase of nearly 1,239 bcm or 31% compared to the base year, 2023 (Table 5.1). This growth aligns with the anticipated rise in global natural gas demand, as detailed in Chapter 4. It is expected to follow a similar average annual rate of nearly 1% during the forecast period. This expansion is set to decelerate over the coming decades, with the highest growth occurring in the near term at an annual rate of 1.6% through 2030, driven by relatively stronger demand. Gas production growth is forecast to moderate to 1% annually in the 2030s before slowing further to 0.6% in the 2040s.

Production growth is anticipated across most regions, driven by domestic demand and export opportunities, with Europe being the sole exception due to ongoing declines in domestic reserves and maturation of producing assets. North America is expected to remain the world's largest natural gas producer. Its output is projected to rise to 1,382 bcm by 2050, supported by unconventional resources, technological advancements, and growing LNG export capacity. Similarly, Eurasia is projected to remain a major contributor, with production reaching 1,208 bcm by mid-century, driven by expansions in Russia and other gas-rich countries, and efforts to enhance export routes and increase domestic consumption.

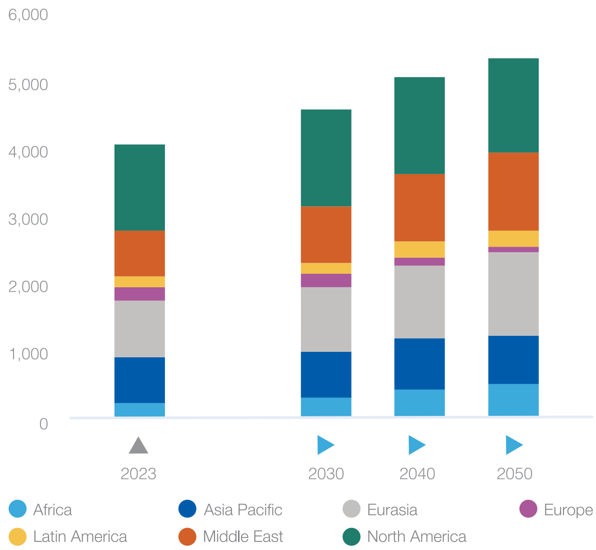
The Middle East is also projected to experience significant growth, with production rising to 1,155 bcm by 2050. This increase is underpinned by the region's abundant reserves, expanding industrial base, and efforts to develop blue hydrogen and other low-carbon gas-based solutions. The rise of the Middle East as a prominent natural gas supplier reflects its strategic investments in production capacity, infrastructure, and international partnerships aimed at strengthening its role in global markets (Figure 5.1).

Regional natural gas production projections from 2023 to 2050 show diverse trends, reflecting regional resource endowments, market dynamics, and policy environments. The Middle East is forecast to lead in absolute production growth. At the same time, Africa is poised for the strongest growth momentum, recording the highest annual growth rate and expanding its role in global natural gas markets.

Over the outlook to 2050, the Middle East is set to add approximately 461 bcm to its production, driven by robust reserves, infrastructure expansion, and the region's strategic focus on low-carbon gas solutions. Eurasia follows with an anticipated increase of 362 bcm, mainly supported by advancements in Russia's production and gas utilisation programs to Asian markets. Africa's natural gas production is projected to

Figure 5.1

Global natural gas production outlook by region, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Table 5.1

Global natural gas supply by region, 2023-2050

	Levels (bcm)				Change (bcm)	Growth (% p.a.)	Share (%)	
	2023	2030	2040	2050	2023-2050	2023-2050	2023	2050
Africa	252	312	431	502	250	2.5%	6%	9%
Asia Pacific	660	698	762	751	91	0.5%	16%	14%
Eurasia	846	940	1077	1208	362	1.3%	21%	23%
Europe	198	180	126	80	-119	-3.4%	5%	1.5%
Latin America	152	179	214	239	87	1.7%	4%	4.5%
Middle East	694	841	996	1,155	461	1.9%	17%	22%
North America	1,275	1,406	1,419	1,382	107	0.3%	31%	26%
Total	**4,078**	**4,557**	**5,026**	**5,317**	**1,239**	**1.0%**	**100%**	**99%**

Source: GECF Secretariat based on data from the GECF GGM

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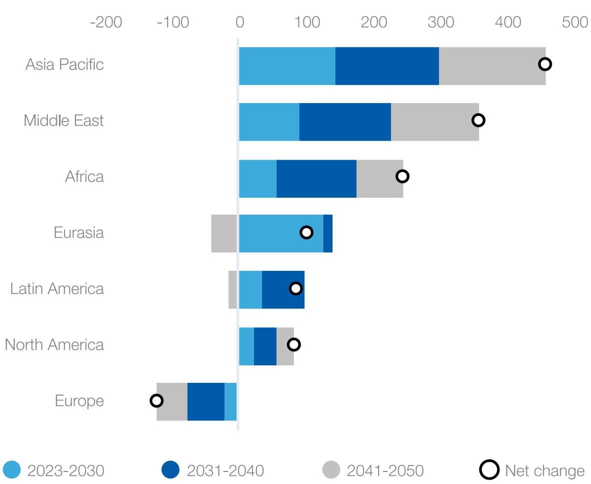
rise by 250 bcm, highlighting its growing prominence as a major supplier, underpinned by increasing investments in LNG and pipeline infrastructure. North America is expected to add a relatively modest 107 bcm over the outlook. Asia Pacific and Latin America are projected to contribute additional volumes of 91 bcm and 87 bcm, respectively, supported by domestic demand and infrastructure expansion. Conversely, Europe's natural gas production is forecast to decline significantly by 119 bcm over the outlook period due to resource depletion and policy-driven transitions away from fossil fuels (Figure 5.2).

The annual growth rates for natural gas production vary considerably across regions, underscoring differing stages of market maturity and development priorities. Africa leads with an impressive projected growth rate of 2.5% per annum, benefiting from new field developments and export opportunities. The Middle East follows with a growth rate of 1.9% per year, nearly twice the global average of 1%, as the region capitalises on its vast reserves and growing role in global gas trade. Latin America and Eurasia are also expected to outpace the global average, with growth rates of 1.7% and 1.3% annually, respectively, driven by industrialisation and infrastructure development.

In contrast, Asia Pacific and North America are forecast to see more subdued annual growth rates of 0.5% and 0.3% respectively, reflecting resource maturity, expected peak of unconventional production in North America and increased development costs in some Asia Pacific countries. Europe stands out as the only region projected to experience a significant decline in natural gas production, with an annual contraction of 3.4%, driven by resource depletion, the decommissioning of major fields, and aggressive decarbonisation policies.

Figure 5.2

Natural gas supply change outlook by region, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

The global distribution of natural gas production is expected to shift significantly by 2050, driven by regional disparities in resource availability, market demand, and energy policies. **The Middle East is forecast to experience the largest increase in its share of global gas production, rising from 17% in 2023 to 22% by 2050. Similarly, Africa is set to emerge as a key growth region, with its contribution increasing from 6 to 9%.** This expansion highlights Africa's efforts to tap into its significant untapped gas reserves. Eurasia is projected to see a modest increase in its market share, rising from 21 to 23% by 2050, with growth driven by Russia, Kazakhstan, and Turkmenistan. Latin America is projected to maintain a stable market share of 4% throughout the forecast period, driven primarily by developments in Argentina, Brazil, and Venezuela (See Box 5.1).

In contrast, other regions are expected to see declining shares of global production. While remaining the largest producer, North America is projected to see its share fall from 31 to 26% by 2050. Although production in the United States and Canada is expected to grow moderately, this growth will be outpaced by more rapid expansions in other regions. The Asia Pacific region is anticipated to see its share decline from 16% to 14%, as production plateaus in Australia and grows modestly in countries like China and Indonesia. Europe is forecast to experience the steepest decline, with its contribution shrinking from 5% in 2023 to just 1% by 2050, driven by resource depletion, field closures, and ambitious decarbonisation policies (Figure 5.3).

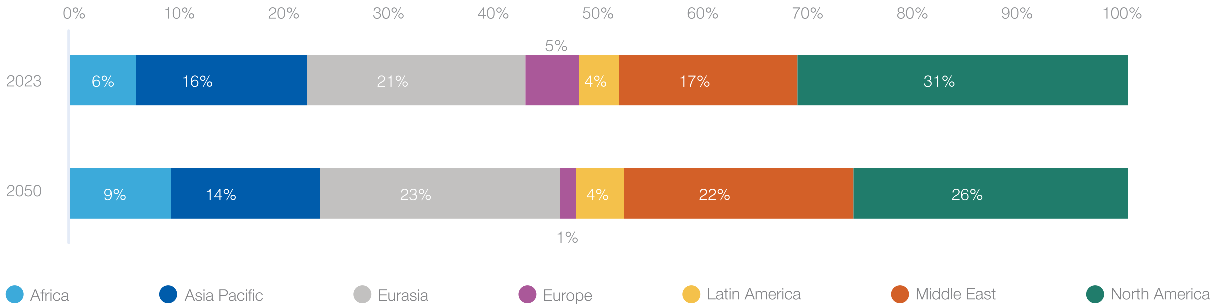
Global natural gas production is expected to undergo notable shifts in its sourcing dynamics through 2050, with non-associated gas (NAG) from conventional fields maintaining its primary supply source. Sufficient proven reserves, coupled with opportunities for significant reserve additions in emerging regions, will support long-term gas supply security. NAG production is projected to grow steadily, reaching 3,460 bcm by 2050, a rise of 957 bcm from 2023 levels, representing an average annual growth rate of 1.2%. This growth is set to be primarily driven by developments in resource-rich regions, including Iran, Mozambique, Qatar, and Russia.

Conventional NAG is set to remain the cornerstone of global natural gas supply, providing the foundation for long-term market stability. However, associated and tight oil-associated gas is anticipated to maintain consistent contributions to total production, reflecting the importance of oil and gas fields with co-produced natural gas.

Shale gas production is forecast to play an increasingly prominent role, driven primarily by North America, which has consistently led advancements in unconventional gas extraction technologies. By 2050, shale gas is expected to account for a larger share of the global natural gas supply, highlighting its role in meeting

Figure 5.3

Natural gas production contribution outlook by region, 2023 and 2050 (%)



Source: GECF Secretariat based on data from the GECF GGM

growing demand and maintaining energy security. Tight gas production is forecast to grow in countries like China and Argentina, supported by technological advancements and government incentives to reduce import dependencies.

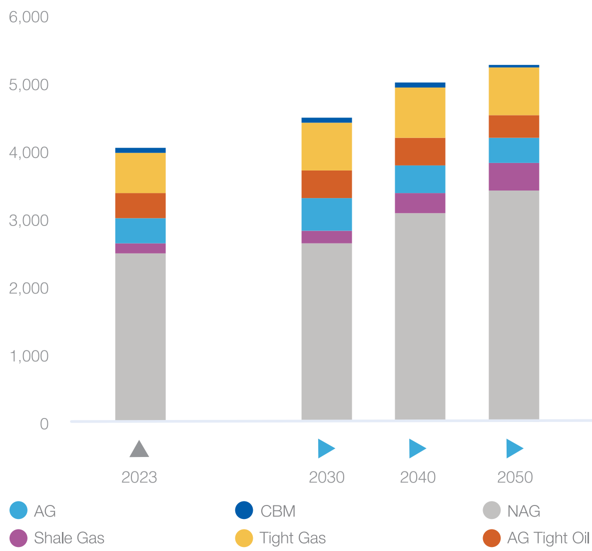
Coalbed methane (CBM) is expected to provide supplementary volumes, address niche market demands, and contribute to regional supply diversification. CBM, though geographically limited in scope, is projected to add incremental volumes in regions such as Australia and India, where its potential is being actively explored (Figure 5.4).

Existing conventional and unconventional gas fields that were operational before or during 2023 are expected to decline at varying rates, depending on reservoir characteristics, depletion stages, and regional factors. **Global natural gas production from existing conventional assets is projected to decline at an average annual rate of 4.1%, falling from 2,798 bcm in 2023. Unconventional fields, which typically have higher depletion rates, are expected to decline at a steeper rate of 11% annually, down from 1,280 bcm in 2023.** Regionally, decline patterns will vary based on reserve maturity and development stages. For conventional projects, Eurasia and the Middle East, which have large reservoirs and relatively recent developments, are projected to experience moderate decline rates of 3.9% and 1.6% per year, respectively. In contrast, Latin America and Africa are expected to see more pronounced declines in conventional fields, at 5% and 5.5% per year, respectively, due to the greater maturity and depletion levels of their existing producing assets.

Significant contributions are expected from new conventional and unconventional gas fields to counterbalance these declines and support future growth. By 2050, these fields are projected to add 1,984 bcm and 1,283 bcm to global production. Additionally, yet-to-find (YTF) resources are forecast to play an increasingly pivotal role, particularly after 2040, as exploration activities uncover new reserves. Conventional YTF resources are projected to contribute

Figure 5.4

Global natural gas production outlook by hydrocarbon type, 2023-2050 (bcm)



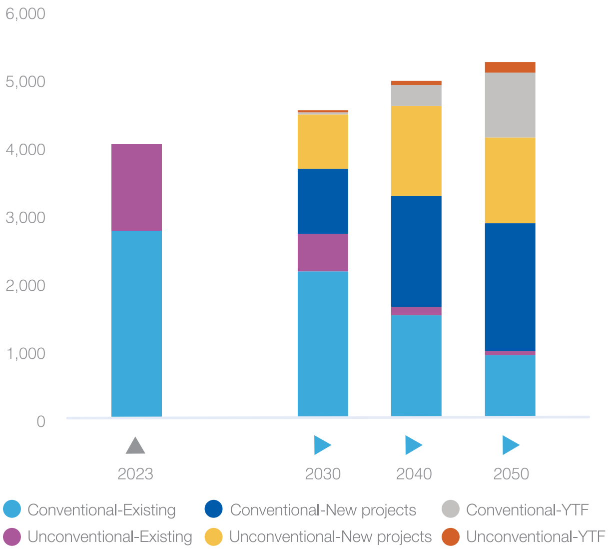
Source: GECF Secretariat based on data from the GECF GGM
Note: NAG: Non-associated gas, AG: Associated gas, CBM: Coalbed methane

approximately 958 bcm by 2050, while unconventional YTF resources are expected to provide an additional 165 bcm.

Over the outlook to 2050, the development of new projects, including YTF resources, is expected to play a critical role in offsetting natural declines from existing fields and meeting the projected growth in global natural gas demand. **Production from these new conventional and unconventional gas projects is anticipated to contribute 60% of global gas production by mid-century. Combined with YTF resources, these sources are forecast to account for 81% of global gas production by 2050** (Figure 5.5). This underscores the importance of sustained investment in natural gas exploration and production projects to ensure market stability and energy security, benefiting producers and consumers.

Figure 5.5

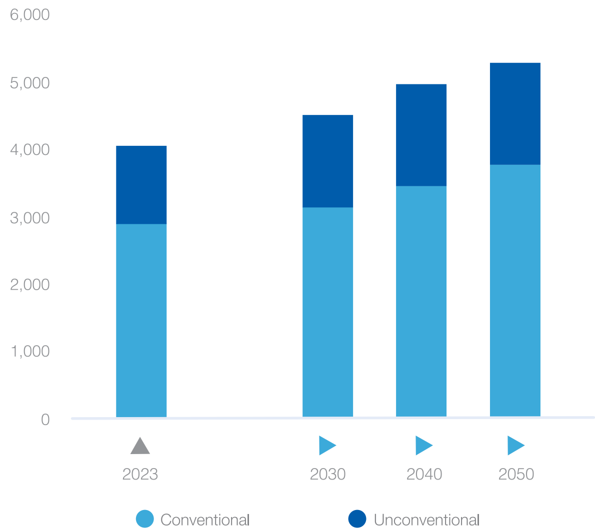
Global natural gas production outlook by project types, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 5.6

Global natural gas production outlook by field type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Natural gas production from conventional reservoirs is forecast to remain the cornerstone of global natural gas supply, driving production growth through 2050. Conventional gas production is expected to increase by 1,008 bcm, reaching 3,806 bcm by 2050, with an average annual growth rate of 1% over the outlook period (Figure 5.6).

The regions propelling this growth are Africa, Eurasia, and the Middle East. Africa is expected to emerge as a key contributor, with conventional gas production projected to grow from 252 bcm in 2023 to 482 bcm by 2050, marking an increase of 231 bcm as the continent capitalises on its vast untapped resources. Eurasia is projected to retain its position as the largest conventional gas producer, with natural gas production from conventional reservoirs rising from 846 bcm in 2023 to 1,176 bcm in 2050, an increase of 330 bcm. Similarly, the Middle East is forecast to experience the largest incremental growth, adding 397 bcm to reach 1,076 bcm from conventional reservoirs by 2050, reflecting the region's significant reserves and ambitious development plans.

Unconventional gas, which has evolved into a significant driver of global natural gas supply after huge growth over the past two decades. Production surged from 108 bcm in 2000 to 1,280 bcm in 2023, driven by technological and operational advancements, particularly in hydraulic fracturing and horizontal drilling throughout the 2010s. However, while unconventional gas remains integral to supply security, its growth trajectory is expected to decelerate significantly in the coming decades.

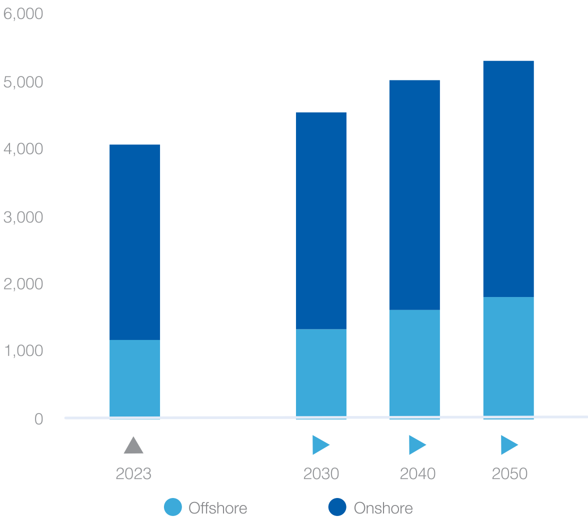
Unconventional gas production is projected to increase by 231 bcm, reaching 1,511 bcm by 2050, but its share of global gas production is anticipated to decline to 28%, down from 31% in 2023. Unconventional gas production is expected to experience a slowdown in growth to 0.6% over the outlook from 2023 and 2050, contrasting sharply with historical trends. This deceleration is primarily attributed to the rapid decline rates of existing unconventional assets, which are expected to decline by an average of 11% annually over the forecast period. While new developments are anticipated to contribute 1,283 bcm by 2050, these volumes will primarily offset declines from mature fields, resulting in slower net growth. Unconventional gas production is expected to grow modestly at 1% annually during the 2030s but contracting by 0.2% annually in the 2040s.

Regionally, North America is expected to maintain its dominance as the largest producer of unconventional gas. Production is forecast to rise from 1,108 bcm in 2023 to 1,126 bcm by 2050, reflecting the region's extensive resources and well-established infrastructure. Asia Pacific is set to emerge as the second-largest growth region, with production increasing from 132 bcm in 2023 to 195 bcm by 2050, driven largely by China's contribution, which is projected to reach 145 bcm of unconventional gas production by 2050. The Middle East is also poised for growth, with unconventional gas production expected to reach 80 bcm by 2050, supported by development activities in Oman, Saudi Arabia, and the UAE.

Global gas production by project location (onshore/offshore) are also expected to undergo notable shifts by 2050, driven by both onshore and offshore developments. Onshore natural gas production is projected to grow from 2,902 bcm in 2023 to 3,515 bcm

Figure 5.7

Global natural gas production outlook by field location, 2023 - 2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

by 2050, representing 0.7% average annual growth rate with Eurasia and the Middle East are the major drivers of this growth.

Eurasia's onshore gas production is forecast to increase significantly, rising from 781 bcm in 2023 to 1,103 bcm by 2050. Russia and Turkmenistan are expected to spearhead this growth, leveraging their vast reserves and ongoing infrastructure developments. The Middle East is also poised for substantial onshore production growth, with production increasing from 230 bcm in 2023 to 375 bcm by 2050. Iraq, Saudi Arabia, and the UAE are set to drive this expansion, underpinned by advancements in field development and policies aimed at maximising the region's abundant resources (Figure 5.7).

Additionally, offshore gas production is expected to experience faster growth than onshore production, increasing from 1,177 bcm in 2023 to 1,802 bcm by 2050, marking 1.5% annual growth. As a result, offshore production's contribution to total global gas output is forecast to rise from 29% to 34% by midcentury. Africa and the Middle East are anticipated to be the primary drivers of this growth, capitalising on significant offshore potential and large-scale investments in new projects.

In Africa, offshore natural gas production is forecast to increase from 88 bcm in 2023 to an impressive 353 bcm by 2050, representing one of the highest average growth rates globally. In Africa, offshore production, which accounted for 35% of total production in 2023, is projected to reach 70% of the region's gas production by 2050. Similarly, the Middle East's offshore gas production is projected to grow significantly, reaching 780 bcm by 2050, an increase of 316 bcm from 2023. This growth will drive the region's offshore contribution rise by only 2 percentage points, reflecting a balanced onshore and offshore growth in the Middle East's production outlook.

The number of gas-producing countries is set to increase throughout the outlook period as new entrants such as Cyprus, Mauritania, Namibia, and Senegal bring production online. These countries are leveraging newly discovered reserves to establish themselves as emerging players in the natural gas markets. Additionally, several smaller producers in 2023, including Mozambique, Tanzania, and Türkiye, are poised for significant production expansions, positioning themselves as major contributors to global natural gas supply.

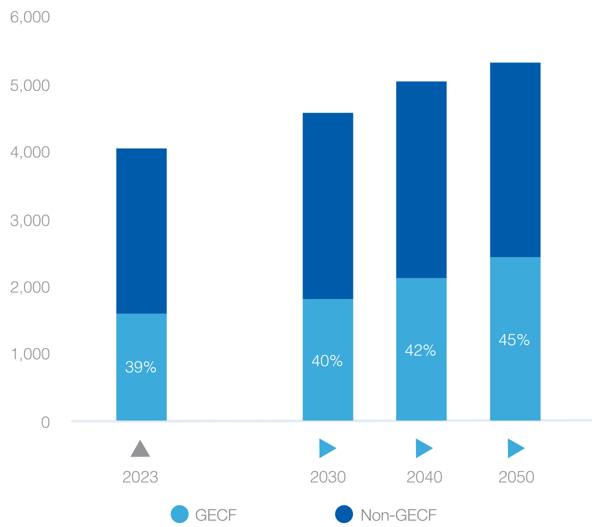
5.3 GECF share of global natural gas production

The share of GECF member countries in global natural gas production is projected to increase significantly by 2050, highlighting their growing role in meeting global energy demand. **Natural gas production from GECF member countries is expected to rise from 1,606 bcm in 2023 to 2,416 bcm in 2050, accounting for 45% of global production, up from 39% in 2023** (Figure 5.8). In contrast, the rest of the world is projected to produce 2,901 bcm by 2050. The average annual growth rate of natural gas production from GECF member countries is forecast at 1.5%, significantly outpacing the 0.6% growth rate for non-GECF countries over the same period.

This robust growth will primarily be driven by GECF member countries in Africa, Eurasia, and the Middle East, which are forecast to be the fastest-growing natural gas producers. These regions benefit from vast reserves, favorable production economics, and substantial investments in exploration, infrastructure,

Figure 5.8.

GECF member countries' contribution to global natural gas production, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

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and export capacities. For instance, countries like Qatar, Iran, Algeria, and Russia are leveraging their abundant gas resources and strategic geographical positions to increase output and enhance their presence in the natural gas markets.

The GECF member countries are poised to dominate conventional natural gas production growth, contributing 810 bcm to the total global conventional natural gas production increase by 2050. This accounts for an impressive 80% of the global growth in conventional gas production. Consequently, GECF's share of global conventional gas production is projected to rise from 57% in 2023 to 63% in 2050.

Box 5.1 Africa, Eurasia, and the Middle East will take centre stage in global gas production

The global natural gas production landscape is transforming from North American dominance to a more diversified and geographically balanced supply base. While North America remains the largest producer, supplying 31% of global gas, its growth trajectory is slowing, with an expected addition of 107 bcm over the forecast period. Despite this increase, North America's market share is projected to decline to 26% by mid-century as other regions accelerate production and establish themselves as the new pillars of global supply.

Africa, Eurasia, and the Middle East, which collectively accounted for 44% of global gas supply in 2023, are set to experience an unprecedented 1,072 bcm incremental supply increase over the outlook period. This growth will contribute to 87% of the total global supply expansion, consolidating these regions' positions as the dominant players in natural gas markets. By 2050, their combined market share is expected to exceed 54%, signalling a fundamental shift in global production dynamics. This transformation reflects rising investments in LNG infrastructure, the development of new gas fields, and strategic production expansions in resource-rich regions.

The Middle East capitalises on its low-cost production advantage, leveraging vast conventional reserves and expanding LNG export capacity to serve growing Asian demand. Africa is emerging as a new frontier in natural gas, with discoveries in Mozambique, Mauritania, Senegal, and Tanzania unlocking significant production potential. Despite geopolitical uncertainties, Eurasia remains a key global supplier, particularly with ongoing investments in pipeline infrastructure and LNG terminals to serve European and Asian markets. These shifts gradually relocate the international gas market's centre of gravity from North America to Africa, Eurasia, and the Middle East, reinforcing regional supply diversification and long-term market stability.

Regional production growth and decadal trends

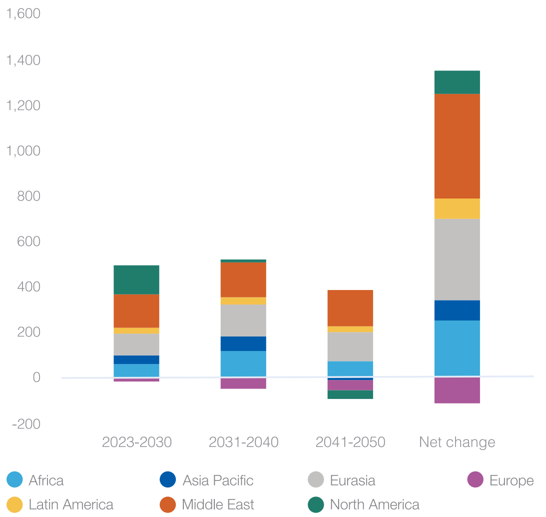
Figure 1 illustrates regional production increments per decade, which provides insights into the evolving supply structure through mid-century.

2023-2030: Accelerated growth across most regions

The period from 2023 to 2030 marks a robust growth phase, with natural gas production expanding across all regions except Europe. The Middle East leads global supply growth, adding 147 bcm, driven by capacity

Figure 1

Global natural gas supply change by region, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

expansions in Qatar, Saudi Arabia, and the UAE. North America follows with a 131 bcm increase, supported by continued shale gas output and LNG infrastructure expansion in the United States and Canada. Eurasia contributes 93 bcm, driven by Russian and Central Asian production. Africa begins to gain momentum with early-stage developments in its emerging gas basins.

2030-2040: A pivotal shift toward Africa

The decade from 2030 to 2040 marks a turning point in global gas dynamics, as Africa emerges as one of the fastest-growing production regions, adding approximately 119 bcm. This shift is driven by new producers such as Mozambique, Mauritania, Senegal, and Tanzania, which collectively contribute 85% of the region's growth. The Middle East and Eurasia sustain strong production acceleration, reinforcing their leading roles. North America, however, begins to slow down substantially, reflecting maturity in key unconventional plays in the United States despite gains from new unconventional projects. This period signals the end of rapid North American supply expansion as resource basins mature and new regulatory constraints emerge.

2040-2050: Structural rebalancing and supply realignment

The final decade of the Outlook (2040-2050) marks the onset of a structural rebalancing in global gas production. North America is projected to decline by 37 bcm, reflecting resource exhaustion in mature shale basins and a potential shift in investment priorities. Asia Pacific also contracts by 11 bcm as some gas fields enter the depletion phase. Meanwhile, the Middle East, Eurasia, and Africa maintain their supply momentum, ensuring continued market stability. By 2050, North America's global natural gas supply share will fall to 26%, finalising the transition toward a more regionally balanced global production landscape.

Implications for global gas infrastructure and trade

These structural shifts in supply dynamics necessitate significant new infrastructure investments, particularly in emerging production regions. To support rising output in Africa, Eurasia, and the Middle East, governments and industry players must expand LNG export terminals, develop new pipeline networks, and enhance gas processing capacity. The evolving supply landscape will also reshape global trade flows, requiring greater flexibility in infrastructure design, new shipping corridors, and long-term supply agreements to accommodate shifting market needs.

5.4 Regional natural gas production outlook

The regional outlook for natural gas production through 2050 highlights contrasting trends in growth and shifts in global market share among different regions. On one hand, some regions are poised for substantial production increases, while others are expected to experience a gradual decline due to resource depletion, policy shifts, or changing market dynamics. These opposing dynamics underscore the evolving landscape of global natural gas production. The remainder of this chapter delves into the production prospects of each region, providing a detailed analysis of the key drivers shaping their trajectories.

5.4.1 Africa

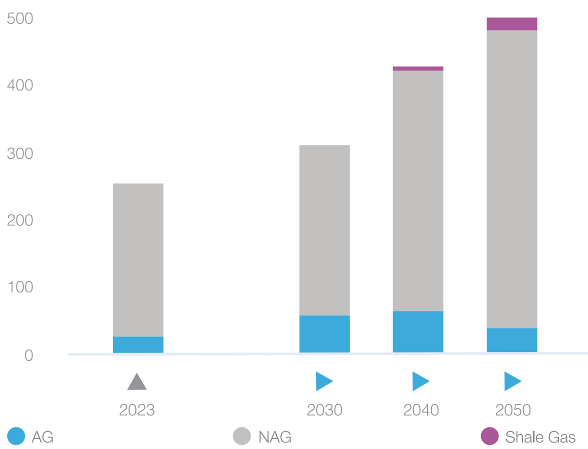
Africa's natural gas production rose modestly by 0.9% in 2023, reaching 252 bcm, driven primarily by robust output growth in Algeria, Mozambique and Nigeria. Looking ahead, **Africa is expected to exhibit the fastest average annual growth rate in natural gas production globally, at 2.5%, adding 250 bcm by 2050.** This is expected to result in total production reaching 502 bcm, marking an impressive 99% increase compared to 2023.

The continent's growth will be spearheaded by key countries with substantial natural gas reserves and expanding production capabilities. Nigeria, benefiting from its vast reserves, notably of associated gas, and policy reforms under the Petroleum Industry Act, is projected to reach 127 bcm by 2050. Mozambique, with its LNG megaprojects such as the Coral South FLNG and the Rovuma LNG projects, is expected to surpass 95 bcm. Emerging producers such as Mauritania and Senegal, leveraging recent gas discoveries and new infrastructure developments, are forecast to contribute 26 bcm and 20 bcm respectively by 2050.

The composition of Africa's gas production is set to evolve over the outlook period, with non-associated gas from gas and condensate fields continuing to dominate the production mix. In 2023, non-associated gas accounted for 228 bcm, representing 90% of the continent's total production (Figure 5.9). By 2050, production from these fields is projected to grow substantially, reaching 445 bcm with Algeria, Mozambique and Mauritania are the main drivers.

Figure 5.9

Africa's natural gas production outlook by hydrocarbon type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

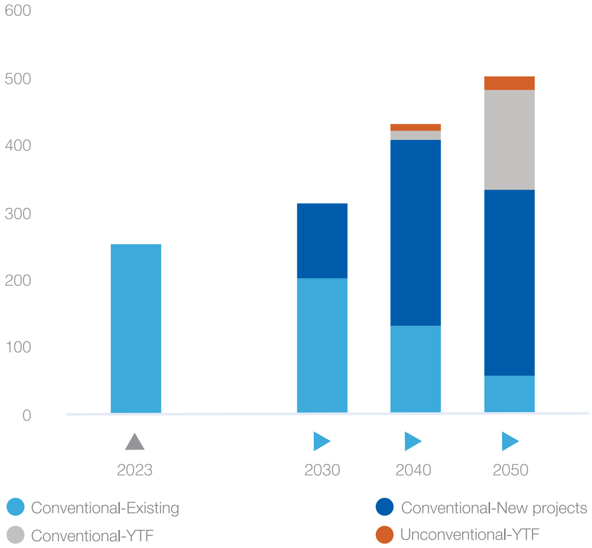
Associated gas production, however, is expected to follow a fluctuating trajectory. After peaking between 56 bcm and 61 bcm during the mid-2030s, output from associated gas fields is projected to decline to approximately 37 bcm by 2050. Nigeria is expected to lead the growth in associated gas production, driven by enhanced gas capture initiatives and the monetisation of gas previously flared during oil production.

Shale gas is anticipated to commence production in Africa's portfolio, projected to start production in mid 2030s, contributing around 19 bcm by 2050. Although still in its early stages, shale gas development could represent a long-term opportunity for countries with unconventional reserves, provided they address the associated technical and regulatory challenges.

New gas projects, particularly conventional assets, are forecast to add 277 bcm of natural gas production by 2050, with projects ranging from Mozambique's offshore developments to North Africa's producing basins. Future production growth will depend on exploration success, as yet-to-find resources, especially in Algeria, Egypt, and Nigeria, are needed to drive gas production growth after 2040. These resources are estimated to

Figure 5.10

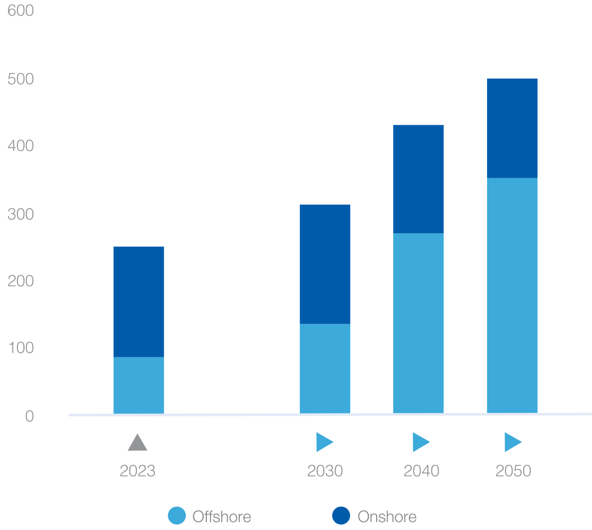
Africa's natural gas production outlook by project type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 5.11

Africa's natural gas production outlook by field location, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

provide 34% of the region's natural gas production by 2050, underscoring the critical importance of sustained exploration investment and regional cooperation (Figure 5.10).

The shift towards offshore resources is notable in Africa's gas production outlook. **Offshore production, which accounted for 35% of total production in 2023, is projected to reach 70% by 2050.** This increase in offshore production is driven by significant developments across several countries, including Mauritania, Mozambique, Nigeria, Senegal, and Tanzania. Several offshore projects are factored in the outlook, including BirAllah, Mozambique LNG, Tanzania LNG, and Yakaar Teranga LNG (Figure 5.11).

Africa's share of global gas production is expected to expand notably, from 6% in 2023 to 9% by 2050. Realising this potential will require continued exploration investment, infrastructure development, and regional cooperation, particularly in developing local gas markets and cross-border projects.

Algeria's natural gas sector is experiencing robust growth and transformation, with production rising 18 bcm from 2019 to 2023, primarily driven by the expansion of the Hassi R'Mel field. The country is actively pursuing strategies to maintain this momentum, aiming to increase production. These efforts include developing mature fields, expediting the exploitation of discoveries, and measures to mitigate natural decline over the long term.

The country fast-tracked the development of key projects that commenced production in 2023, including LD2 in Hassi R'Mel and Berkine South. Algeria's state-owned oil company, Sonatrach, made multiple hydrocarbon discoveries in 2023 across various basins, including Amguid Messaoud, Berkine, Illizi, and Oued Mya, further reinforcing the country's resource potential.

International oil and gas companies are increasingly significant in accelerating Algeria's gas production. ENI's acquisition of BP's operations is expected to expedite natural gas production, particularly from In Amenas and In Salah fields, which collectively hold approximately 850 bcm of recoverable gas resources. Moreover, Algeria's upstream sector is attracting attention from major players. In May 2024, ExxonMobil signed a tentative deal with Sonatrach to develop hydrocarbon resources in the Ahnet and Gourara basins. This follows TotalEnergies' recent memorandum of understanding for gas resource development in the Northeast Timimoun region. Recently, an agreement was signed with Chevron to assess the potentialities of the Algerian Offshore areas.

It is noteworthy that 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 beyond 2030, potentially maintaining or even increasing its production levels towards 2050.

Libya's gas production reached 13.5 bcm in 2023, an increase of 2 bcm from 2022. The production growth was driven mainly by increased gas production from the offshore West Libya Gas Project and the onshore Nasser project.

Libya has set an ambitious target to double its gas production before 2030. Recent developments suggest a renewed push to revitalise the sector. A significant step forward was awarding Block NC-07 to a consortium of companies. This deal and ongoing talks between IOCs and Libya's National Oil Corporation about potential development and exploration in the Ghadames Basin highlight the determination to advance long-stalled projects. Another promising initiative is the Bouri Gas Utilisation project, set to start operations in 2025. This project aims to capture flared natural gas, potentially boosting production while addressing environmental concerns.

Libya's natural gas production could reach 17 bcm by 2040, driven by growth from non-associated gas production. However, without new discoveries and exploration activities, production might plateau or slightly fall from the 2040 forecasted level to around 12 bcm by 2050. It is worth noting that these projections do not factor in potential YTF production, highlighting the importance of renewed exploration efforts.

Mauritania is emerging as a significant player in Africa's natural gas sector, with its offshore resources attracting substantial interest from international oil companies. The country's energy landscape is primarily shaped by the Greater Tortue Ahmeyim (GTA) project, a cross-border development shared with neighbouring Senegal. This project, operated by BP, has recently gained momentum with the arrival of the FPSO at the site and the start of gas production in January 2025, with LNG exports expected in 2025.

The success of the GTA project could catalyse further development and investment in the country's offshore resources. Beyond the GTA project, Mauritania's energy future also hinges on other significant discoveries, particularly the Bir Allah project. Over the long term, projections suggest a positive trajectory for Mauritania's gas production, which is expected to reach 26 bcm by 2050 from offshore locations.

Mozambique's natural gas sector is poised for substantial growth towards 2050, underpinned by its vast offshore resources in the Rovuma Basin and ongoing exploration efforts. Significant discoveries in Areas 1 and 4 of the Rovuma Basin initially highlighted the country's gas potential, uncovering estimated recoverable resources exceeding 2.8 tcm (100 tcf). These discoveries have led to developing three key LNG projects: Coral South FLNG, Mozambique LNG, and Rovuma LNG. The Coral South FLNG project, operated by Eni, commenced production in 2022 with a capacity of 3.4 Mtpa, marking Mozambique's entry into the LNG export market. Plans for a second FLNG unit, Coral North, with a 3.5 Mtpa capacity and potential start-up in 2028, further underline the country's ambition to expand its LNG capabilities.

Recent exploration activities have expanded beyond the prolific offshore areas to include onshore and shallow water regions, diversifying Mozambique's gas resource base. Sasol has been actively exploring and developing gas fields in southern Mozambique in its operated PPA, PSA, and PT5-C licenses. A notable recent discovery is the Bonito gas field in Area PT5-C, made in 2023.

The Mozambique government has demonstrated its commitment to attracting further investment and exploration through its 6th licensing round. Launched in 2022, this round offered 16 blocks for exploration, including five new offshore blocks in the Rovuma Basin and six onshore blocks in the Mozambique Basin. The round concluded in 2024 with the awarding of five offshore blocks, marking a significant step in Mozambique's efforts to sustain and potentially expand its gas resource base. This licensing activity is crucial for maintaining exploration momentum and potentially uncovering new gas reserves that could support production growth beyond 2040.

By 2030, Mozambique is projected to produce 30 bcm. This could grow to reach 95 bcm by 2050. Mozambique can effectively leverage its vast gas resources, continue successful exploration efforts, and capitalise on the outcomes of its licensing rounds; it has the potential to transform its economy and become a key player in the global energy markets.

Nigeria's natural gas sector is poised for significant growth and transformation through 2050, driven by its vast reserves and recent regulatory reforms. As of 2023, Nigeria holds Africa's largest natural gas reserves estimated at 5.9 tcm. This enormous resource base underpins the country's potential to become a major global gas player in the coming decades.

Nigeria's gas production is expected to grow substantially in the near term. Despite production in the range of 40 to 50 bcm over the past decade, the country is expected to witness large natural gas production increases in the medium and long term. This growth trajectory is supported by implementing the Petroleum Industry Act (PIA) of 2021, which introduces a more attractive fiscal regime and regulatory framework for the sector.

Infrastructure development will play a crucial role in unlocking Nigeria's gas potential. Major projects such as the Obiafu-Obrikom-Oben (OB3) and Ajaokuta-Kaduna-Kano (AKK) gas pipelines are set to improve nationwide gas distribution, spurring industrial growth and increasing domestic gas utilisation. These projects are expected to provide the necessary infrastructure for upstream companies to develop gas fields along their routes.

Nigeria is also exploring new territories with its first Floating Liquefied Natural Gas (FLNG) project by late 2026. This project represents a new avenue for monetising Nigeria's offshore gas resources and could pave the way for similar projects in the future, boosting the country's LNG export capabilities.

Nigeria's natural gas production potential to grow in the long term will depend on Nigeria's ability to effectively leverage its vast gas resources, fully implement the PIA's provisions, overcome infrastructure bottlenecks and attract investments.

Senegal is emerging as a significant player in West Africa's natural gas sector, with recent discoveries and ongoing developments positioning the country for substantial growth through 2050. The cornerstone of Senegal's gas future is the Greater Tortue Ahmeyim (GTA) project, a cross-border development shared with neighbouring Mauritania.

Looking beyond the GTA project, Senegal's gas sector holds further potential with the Yakaar-Teranga and other discoveries. These resources represent a significant opportunity for Senegal to expand its gas production in the medium to long term. However, the development of these fields faces medium-term uncertainty following BP's decision to exit these projects. Kosmos Energy, which retains ownership, is actively seeking partners to progress these developments, highlighting the challenges of financing crucial and capital-intensive projects in the evolving global energy landscape.

Exploration activities in Senegal are set to intensify, with the country's first major offshore licensing round in 2024. This round demonstrates the government's commitment to attracting further investment and potentially uncovering new gas resources. The success of this round could significantly impact Senegal's long-term gas production outlook, potentially adding new discoveries to the country's resource base and supporting production growth beyond 2030.

Looking towards 2050, Senegal's natural gas production is poised for significant growth. The GTA project's successful development and potential future phases could see Senegal's gas production reach 5 bcm by 2030. Over the long term, the Yakaar-Teranga project could further boost Senegal's gas production during 2030s and 2040s, with forecasted production at 20 bcm by 2050. The long-term production trajectory will depend on the outcomes of current exploration efforts and the success of future licensing rounds in uncovering additional resources together with securing investment.

5.4.2 Asia Pacific

The Asia Pacific region recorded a modest growth of 0.4% in natural gas production in 2023, reaching 660 bcm. This growth was primarily driven by China, which added 14 bcm and reached a production level of 227 bcm, representing a robust 6.6% increase. However, the region's overall performance was tempered by a 4 bcm decline in Australia's output, largely due to reduced production from the Northwest Shelf LNG and Gorgon LNG projects. Other major producers showed mixed results, with Indonesia posting a 1.9% increase to reach 58 bcm, while Malaysia maintained steady production levels at 79 bcm. Similarly, gas production grew in the region in 2024 driven mainly by China followed by India and Thailand.

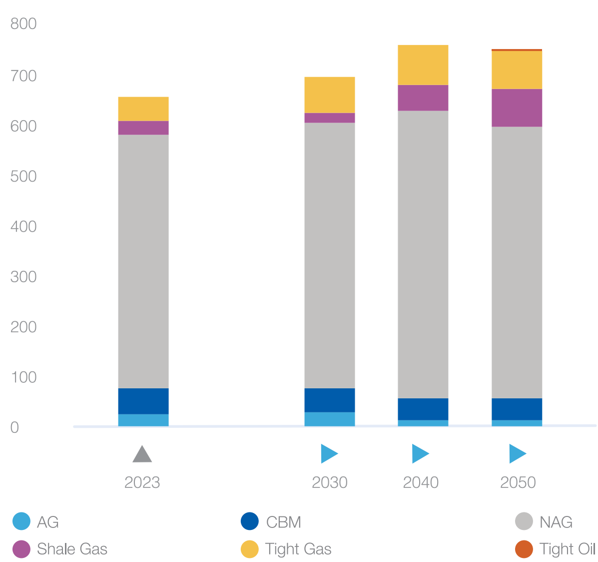
China's transformation in the natural gas sector, including ambitious policy reforms, investment incentives, and a strong focus on unconventional gas development, has been a key driver of the region's production dynamics. Over the past decade, China's unconventional gas production has tripled, increased from 29 bcm in 2013 to 87 bcm in 2023. The Ordos and Sichuan basins remain pivotal to this growth, supporting the country's strategic shift toward greater energy independence and cleaner energy sources.

Looking ahead, natural gas production in the Asia Pacific region is projected to experience moderate growth, reaching 751 bcm by 2050, an increase of 91 bcm from 2023 levels. The growth trajectory varies significantly across countries. China is forecast to lead the region, with production expected to climb to 350 bcm by 2050. The most substantial growth for China is anticipated between 2030 and 2040, with an annual growth rate of 3.1%. In contrast, Australia's production is expected to remain stable at around 140 bcm until 2040, after which it is projected to decline slightly to 128 bcm by 2050.

The production mix in the Asia Pacific region is set to be dominated by non-associated gas, which is forecast to grow from 509 bcm in 2023 to 542 bcm by 2050 (Figure 5.12). Associated gas production is expected to remain relatively stable, providing supplementary volumes. As conventional reserves mature, a notable shift towards unconventional gas production is anticipated in the latter half of the 2030s. This trend will be driven by

Figure 5.12

Asia Pacific's natural gas production outlook by hydrocarbon type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

increased investment in shale gas and CBM resources, particularly in China, which has consistently prioritised the development of these unconventional assets to meet its growing domestic demand.

Existing conventional and unconventional gas fields produced in 2023 are projected to experience an annual gas production decline of 7% and 8%, respectively, through the forecast period. By 2050, these mature fields are projected to contribute only 10% to the region's total gas production. The growth in gas production through 2040 will primarily come from newly developed conventional fields, while in the 2040s, yet-to-find resources are anticipated to play a key role in growing gas production in the Asia Pacific (Figure 5.13).

Onshore natural gas production is forecast to drive the region's growth. Onshore natural gas production is expected to grow from 343 bcm in 2023 to 433 bcm in 2050, making up 58% of the region's natural gas production. The projected growth in onshore gas production is expected primarily by China. In contrast, offshore gas production is expected to remain stagnant, reaching 318 bcm by 2050 (Figure 5.14), similar to the 2023 level. Consequently, Asia Pacific's offshore natural gas production share is projected to fall from 48% in 2023 to 42% in 2050. This stagnation in the overall production of offshore assets is primarily attributed to the maturation of key offshore assets in Australia, including Gorgon, Jansz-Io, Wheatstone, and others.

Despite this growth, the region's share of global natural gas production is projected to decrease slightly from 16% to 14% by 2050. Asia Pacific will remain the major net importer of natural gas, as gas demand is set to outpace production growth. As a result, continued natural gas exploration and development is important to maximise domestic production and reduce import dependency.

Natural gas production declined in **Australia** in 2023 by 4 bcm. The decline is primarily due to the reduction of gas production from offshore, which accounts for 70% of gas production in the country. The key projects behind the decrease in production are the Northwest Shelf LNG project and the Gorgon LNG project that experienced decreases of 3 bcm and 2 bcm, respectively. Australia has been experiencing a decline in natural gas reserves, with a 31% decrease since their peak in 2013 due to low levels of investment in the natural gas sector. In addition, the number of exploration wells has been on a decreasing trend since 2010 as reported by Rystad Energy.

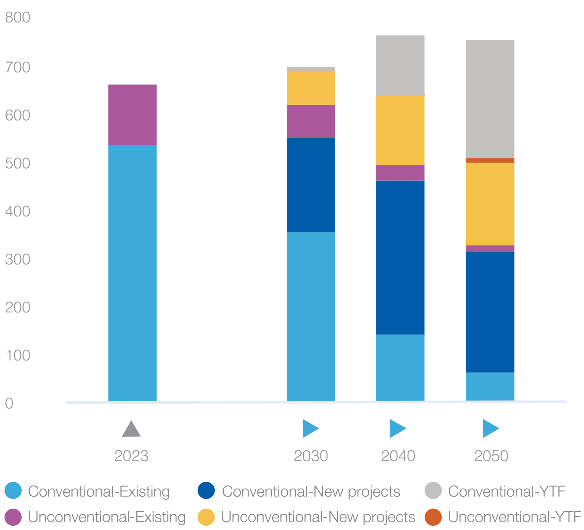
In the last edition of the GECF Global Gas Outlook, uncertainties surrounded the future of natural gas production in Australia. However, the announcement of the Future Gas Strategy in 2024 reinforces the role of natural gas in the country's energy sector. The strategy emphasises sustained production and exploration while aiming to balance emissions reduction targets with energy affordability.

The outlook expects natural gas production in Australia to be maintained around the 140 bcm level until 2040. This period will feature the start of new projects including Barossa, Browse, Ichthys, and Pluto Train-2. After 2040, production is expected to decline and by 2050, natural gas production is projected to reach 128 bcm.

China's upstream oil and gas sector has undergone significant transformations in recent years, driven by rising energy demand and the need for energy security. To enhance competitiveness and attract diverse

Figure 5.13

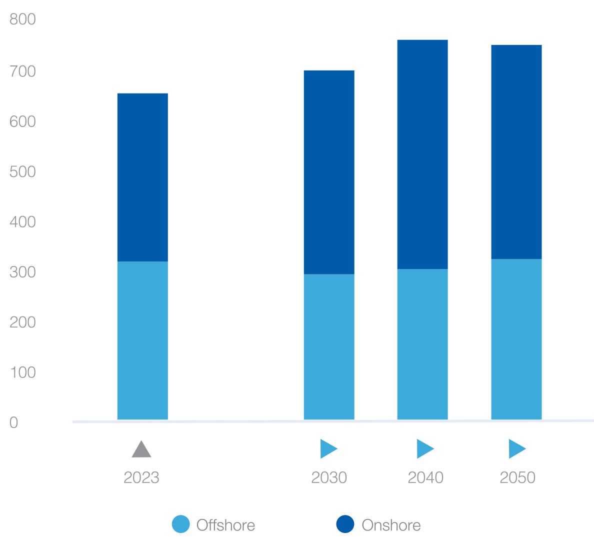
Asia Pacific's natural gas production outlook by project type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 5.14

Asia Pacific's natural gas production outlook by field location, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

investments, the government has introduced a series of policy reforms and incentives. Before 2017, efforts focused on subsidising unconventional assets, which helped boost production from unconventional projects and drive gas output growth. This trend is expected to continue in the coming years. China's unconventional gas production stood at 29 bcm in 2013 and tripled to 87 bcm by 2023.

From 2017 onwards, the country shifted towards structural reforms, opening the sector to private and foreign companies. A milestone was reached in 2019 when foreign companies were allowed to independently explore and produce oil and gas within China. The country managed to increase its production by 57 bcm in 4 years as production increased from 170 bcm in 2019 to 227 bcm in 2023. The driver behind the growth was unconventional gas production specifically from the Ordos and Sichuan basins followed by growth of natural gas production from conventional assets. In 2023, natural gas in China witnessed an increase of 14 bcm and reached 227 bcm, a growth rate of 6.6%. The growth was driven by multiple basins mainly the Ordos, Sichuan, and Tarim basins.

China's natural gas exploration efforts have yielded significant results in recent years. Over the past decade, China increased its gas reserves by 21% through discoveries distributed in several basins, including Sichuan, Qiongdongnan, Yuanjiang, and Ordos basins. In 2024, the exploration momentum continued with the Lingshui 36-1 discovery in the deepwater of the South China Sea and successful exploration resulted in a discovery in the Bohai Bay basin.

Natural gas production in China is expected to reach 350 bcm in 2050. The highest growth rate will be achieved during 2030s when production is expected to grow from 252 bcm in 2030 to 340 bcm in 2040 at an annual growth rate of 3.1%, which will drop to 0.3% during 2040s driven by expected declines from the countries major basins (Ordos, Sichuan, and Tarim). Unconventional gas production is forecast to lead the country's growth in gas production and is projected to reach 148 bcm by 2050, accounting for 42% of China's natural gas production.

Indonesia's natural gas production reached 57 bcm in 2023, growing 1.9% from 2022 but remaining below the 2019 level of 61 bcm, with offshore production still lagging pre-2019 figures. The Abadi LNG project is a major development on the horizon, and it is expected to add 13 bcm at peak production in 2030. This project notably incorporates the country's first cost-recoverable CCS component. Indonesia is positioning itself as a regional CCS hub through new regulations (MoEMR Regulation 2/2023), establishing the legal framework for CCS activities, including "CCS as a service".

The government has outlined ambitious targets through its Oil and Gas Strategic Plan (IOG 4.0), aiming to produce 12 bcf/d (124 bcm) by 2030. To achieve this, the Upstream Oil and Gas Regulatory Task Force (SKK Migas) plans to develop 133 oil and gas projects by 2029, including the Mako, Singa Laut, and Kuda Laut projects.

Exploration activities showed promising results in 2023, with new gas discoveries totalling 148 bcm, primarily in the Kutai and North Sumatra basins. This represents 48% of all gas discoveries in the past decade. These discoveries are vital given the significant decline in natural gas reserves, which, according to the Cedigaz reserves dataset, fell from 2.7 tcm in 2017 to 0.9 tcm in 2023. Thus, to promote oil and gas exploration, the government offered 60 oil and gas blocks across 14 regions in 2024. While conventional gas reserves have declined, Indonesia holds substantial CBM reserves, estimated at 12.8 tcm (453 tcf) of reserves. Development of these resources is starting with the Tanjung Enim project, which received environmental approval in 2023 as the country's first CBM development.

Natural gas production is projected to increase to 96 bcm by 2050. The achievement of this outlook relies on continued exploration success and resource development.

Malaysia's natural gas production rebounded from COVID-19 impacts to its 2019 levels and reached 79 bcm in 2023, supported by new developments, including the Pegaga project, which started in 2022 and Petronas FLNG2, which commenced gas production in 2021.

The country's gas production, which is 100% offshore, faces challenges as natural gas reserves have declined since 2015, dropping 25.7% at an annual rate of 3.6%. This decline points to the critical importance of new gas discoveries for sustaining future production growth. In response, Malaysia has intensified its upstream exploration strategy since 2020 through annual licensing rounds, offering 14 blocks in 2022, 10 blocks in 2023, and 5 blocks in 2024, with the latest round including both frontier areas and mature basins with discovered resources. By early 2024, licensing activity reached a significant milestone with all exploration blocks fully allocated in both the Sarawak basin, which contributed 55% of national gas production in 2023 and the Northwest Sabah basin.

Natural gas production is projected to decrease to 49 bcm by 2050, with yet-to-find resources accounting for 27 bcm of the total production. The realisation of this production outlook will be influenced by the success of ongoing exploration campaigns and future licensing rounds, particularly in the Sarawak and Northwest Sabah basins, where exploration activities are currently concentrated.

5.4.3 Eurasia

Eurasia experienced a challenging year in 2023, with natural gas production declining by 4.6% to 846 bcm.

The decrease was primarily driven by reduced gas production from Russia and Uzbekistan. However, in 2024, Eurasia experienced a tremendous growth of nearly 50 bcm to 891 with Russia grew its production by 48 bcm.

Eurasia is forecast to solidify its position as the second-largest natural gas-producing region globally by 2050, with production expected to rise to 1,208 bcm. This represents a significant addition of 362 bcm, equating to an annual growth rate of 1.3%. Over the outlook period, Eurasia's natural gas production is projected to be driven by substantial developments across multiple key producers (Figure 5.15).

Russia is poised to remain the dominant contributor within the region, with production forecast to reach 929 bcm by 2050. This growth is expected to be supported by new field developments, the expansion of LNG capacity, and infrastructure projects aimed at diversifying export routes and markets. Notably, Russia's strategic focus on Eastern Siberia and the Far East regions, coupled with its expanding pipeline network to Asia, is anticipated to play a critical role in achieving these production targets.

Turkmenistan is anticipated to stand out, with its natural gas production projected to double to 150 bcm by 2050. This growth is underpinned by the country's extensive gas reserves, the development of new fields, and increased pipeline export capacity, particularly to China and South Asia. If realised, the Turkmenistan–Afghanistan–Pakistan–India (TAPI) pipeline will further increase the country's production and export potential.

Azerbaijan is also expected to contribute to the region's growth, with production forecast to reach 44 bcm by 2050. This increase will be driven by the continued development of the Shah Deniz field and other offshore gas assets in the Caspian Sea. Azerbaijan's strategic location and its role in the Southern Gas Corridor are pivotal in supporting the diversification of gas supplies to Europe, particularly as the continent seeks alternatives to traditional sources.

In the region, onshore natural gas production dominates, accounting for 92% of the region's gas production in 2023. This dominance is set to continue throughout the outlook period, with onshore gas production projected to reach 1,103 bcm in 2050 (Figure 5.16). However, the role of offshore production is evolving differently across the region. Azerbaijan's production is almost entirely offshore, primarily through the Shah Deniz field, which accounts for 73% of the country's total gas production. On the other hand, Russia's offshore developments in the Kara Sea and Sakhalin are expected to drive the region's offshore production to 105 bcm by 2050 from the 65 bcm level in 2023, representing 8% of the region's total gas production.

New conventional gas projects in Eurasia are expected to be the primary driver of gas production growth, adding 199 bcm by 2030 and a substantial 590 bcm by 2050 (Figure 5.17). Russia is set to lead this growth through several strategic projects, including the Kovyktinskoye gas field in Eastern Siberia, the Utrenneye field on the Gydan Peninsula, which will supply the Arctic LNG-2 project, the Kharasaveyskoye field on the Yamal Peninsula and the Bovanenkovskoye field's Neocomian Jurassic layer development. Similarly, Turkmenistan's growth is anticipated to be driven by the phased development of the Galkynysh field. Additionally, Azerbaijan's growth is supported by ongoing exploration

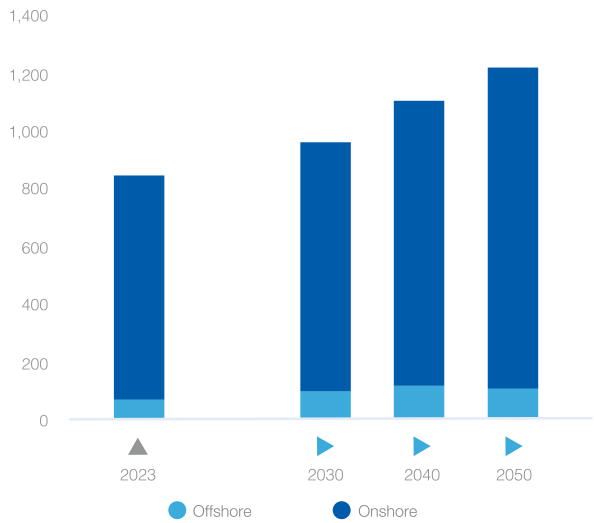
Figure 5.15

Eurasia's natural gas production outlook by hydrocarbon type, 2023-2050 (bcm)

Source: GECF Secretariat based on data from the GECF GGM

Figure 5.16

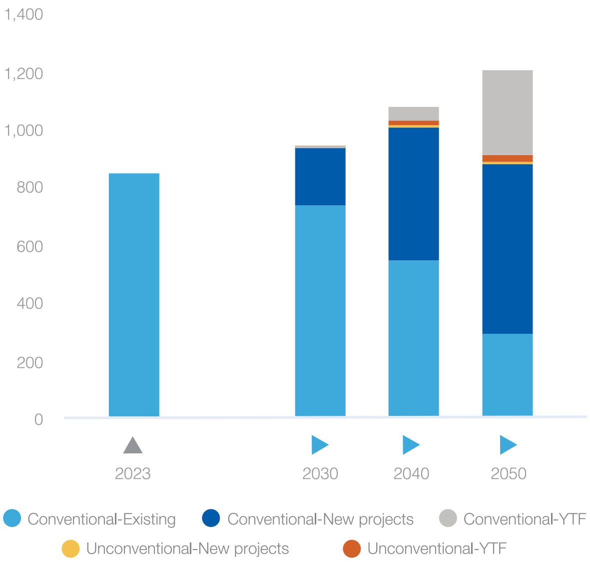
Eurasia's natural gas production outlook by field location, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 5.17

Eurasia's natural gas production outlook by project type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

and development activities in Shah Deniz. This robust project pipeline and resource base are expected to increase Eurasia's share of global gas production from 21% in 2023 to 23% by 2050.

Azerbaijan's natural gas sector experienced robust growth, with production reaching 36 bcm in 2023, a 4.4% increase from the previous year. This growth is primarily attributed to increased output from the Shah Deniz offshore gas condensate field, accounting for 73% of the country's total gas production.

The Shah Deniz field continues to be the cornerstone of Azerbaijan's gas sector. In 2024, the field's annual production capacity was raised by 1.5 bcm to 29 bcm, underscoring its significance in the country's gas production. Additionally, ongoing exploration activities in the Shah Deniz area, particularly targeting deeper reservoirs, suggest the potential for further future reserve addition and production increases. Furthermore, the Umid Babek project is projected to support gas production growth from 2030 onwards.

Over the long term, Azerbaijan's natural gas production is projected to maintain a growth trajectory and remain entirely from offshore assets. The outlook anticipates production to reach 44 bcm by 2040, with this level expected to be sustained through 2050.

Russia, the world's second-largest natural gas producer, is poised for significant long-term growth in its natural gas sector despite recent challenges. After experiencing a gas production decline in 2022 and 2023, natural gas production is set to grow, supported by the focus on Asian markets and increased domestic consumption with 2024 reflecting a 48 bcm growth in Russia's natural gas production.

In the medium term, Russia's natural gas production growth is set to be driven by several key projects across various regions. Developing the Utrenneye field on the Gydan Peninsula is a crucial milestone in supplying the Arctic LNG-2 project and strengthening Russia's LNG export capabilities. In parallel, the Kharasaveyskoye field on the Yamal Peninsula, expected to start by 2026, will significantly augment production capacity. In addition, Russia is focusing on expanding the Kovyktinskoye and Chayandinskoye gas fields to support supplying gas to the Asian market. Moreover, by the end of this decade, the development of the Neocomian Jurassic layer in the Bovanenkovskoye field is expected to contribute substantially to gas production growth. Furthermore, the outlook includes significant production from the Tambey project during the 2040s. These projects demonstrate Russia's comprehensive approach to expanding its gas production across various geographical areas, targeting both domestic consumption and diverse export markets.

By 2050, Russia is projected to reach a gas production level of 929 bcm, representing a substantial increase of 291 bcm from the 2023 level. The continued development of Eastern Siberian and Far Eastern gas fields, expansion of LNG capabilities for global market access, and pipeline infrastructure development to Asian markets support this long-term growth.

Turkmenistan, despite facing challenges in fully realising its export potential due to infrastructure constraints, is positioned for substantial growth in both gas production and exports over the coming decades. In 2023, the country's natural gas production reached 76 bcm, a 20% increase from 2019. This production is primarily sourced from the Amu-Dar'ya basin.

Going forward, production from the Galkynysh field, one of the world's largest gas fields, will drive gas production growth. Phase 2 of the field's development, with a capacity of 30 bcm, is expected to come online in mid-2020s. Phase 3 of the project is expected to commence production by the mid-2030s with peak gas production of 32 bcm. Additionally, the Bagtyarlyk field, Turkmenistan's second largest field, supplies an additional 13 bcm annually to China, with China National Petroleum Corporation holding a 50% interest. The long-term outlook for Turkmenistan's gas production is promising. By 2050, the country is projected to reach 150 bcm, doubling its current production.

5.4.4 Europe

European natural gas production dropped by 8% to 198 bcm in 2023, reversing the growth seen in 2022. This decline was due to a drop in gas production from Europe's major producers, including Norway, the Netherlands, and the United Kingdom. However, in 2024, Europe experienced a 4 bcm growth to 202 bcm driven primarily by growth from Norway and Türkiye while large declines were observed in the Netherlands and the United Kingdom. **The region's production**

outlook indicates continued decline through 2050, with gas production projected to decline at an annual rate of 3.4% to reach 80 bcm by 2050 (Figure 5.18).

The past decade revealed structural challenges in European gas production, declining by 90 bcm between 2013 and 2023. A major factor in this decline was the Netherlands' Groningen field, which produced 61 bcm in 2013 but was shut down in 2024. Regional production faces twin challenges of mature assets and reduced upstream investment. These factors are expected to reduce Europe's share of global gas production from 5% in 2023 to 1% by 2050, reflecting both resource depletion and evolving energy policy priorities.

Offshore natural gas production remains the predominant source of Europe's gas supply, currently accounting for 90% of production throughout the outlook period. Despite exploration efforts, such as Norway's offering of 92 new blocks in 2023 (78 in the Barents Sea and 14 in the Norwegian Sea), the outlook remains challenging. While holding an estimated two-thirds of Norway's undiscovered resources, the Barents Sea presents significant challenges due to high costs and substantial infrastructure requirements.

Some countries are making efforts to counter this decline. Romania's Neptun Deep project, a USD 4.4 billion offshore development, is set to commence production in 2027 with a potential peak production of 7.5 bcm, helping push Romania's total production to 14 bcm by 2030. Türkiye's ambitious development of the Sakarya field, with its second phase expected to reach 9 bcm, could help the country achieve 17 bcm by 2050. However, these new developments cannot offset the broader regional decline (Figure 5.19).

By 2050, the production landscape will be dramatically different. Norway's output is expected to fall to 42 bcm, the United Kingdom to 10 bcm, and Romania to 3 bcm. These declines, coupled with the Netherlands' complete phase-out of production, will result in Europe's total gas production falling to 80 bcm by 2050.

The **Netherlands** has recently experienced a dramatic decline in natural gas production. In 2023, the country's gas production fell to 11.5 bcm, representing a 33% reduction compared to 2022 and a staggering 65% decrease from 2019. A significant portion of this decline is attributed to the Groningen field, which saw a reduction of 3.5 bcm in 2023 as production ceased in October 2023. The field will be permanently closed based on the recently approved law by the Dutch Senate, which aims to address seismic risks in the region.

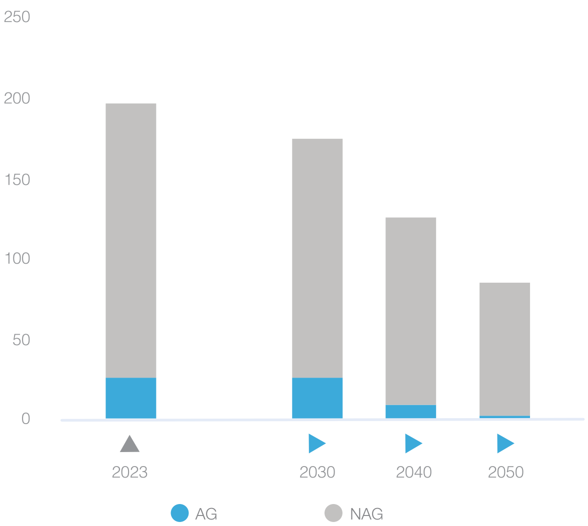
This sharp downward trend is part of a deliberate policy to phase out natural gas production in the Netherlands. The country is projected to stop production entirely soon, marking the end of its role as a major European gas producer.

Norway, as Europe's largest supplier of natural gas, experienced a decline in natural gas production in 2023. In 2022, natural gas production reached 132.5 bcm supported by delayed maintenance and reduction in gas re-injection in mature oil fields. However, in 2023, Norway produced 126 bcm, a 5.2% reduction. The decrease in gas production is due to the maintenance at the Troll field (in which production dropped 2.4 bcm) as well as the Kollsnes gas processing plant that handles more than 40% of Norway's total gas exports with capacity of 156 million standard cubic meters, equivalent to 57 bcm annually.

Looking towards 2030, Norway is expected to reach 98 bcm. The reduction in gas production is driven by the

Figure 5.18

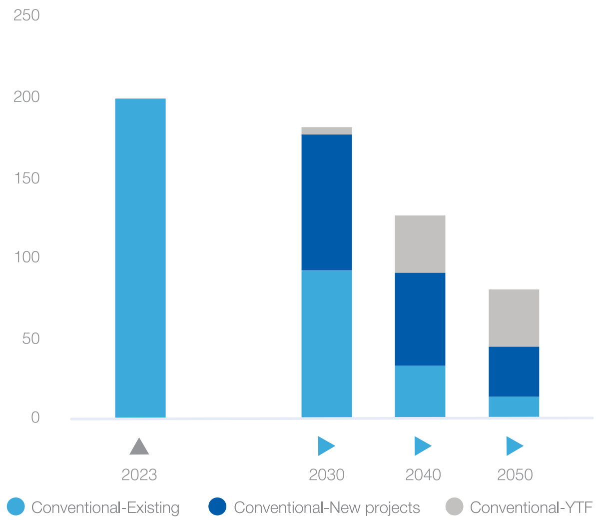
Europe's natural gas production outlook by hydrocarbon type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 5.19

Europe's natural gas production outlook by project type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

maturity of gas fields, which is expected to be countered by some new developments. The Troll Phase 3 Project, a USD 1.13 billion investment by Equinor and partners scheduled to bring its first wells online by the end of 2026, is expected to contribute an additional 7 bcm annually at its peak.

Exploration activities are ramping up significantly. In 2023, Norway offered 92 new blocks for oil and gas exploration, with 78 in the Barents Sea and 14 in the Norwegian Sea. Norway recently launched its latest APA (Awards in Predefined Areas) round. This focus on exploration aims to offset the depletion of existing fields and potentially discover new resources.

However, the medium to long-term outlook presents challenges. Many of Norway's existing fields are maturing, necessitating the development of new resources to maintain production levels. The Barents Sea, believed to contain about two-thirds of Norway's undiscovered oil and gas resources, presents significant exploration challenges due to high costs and substantial infrastructure requirements. Consequently, the outlook anticipates a decline in Norway's gas production to 42 bcm by 2050, assuming no major new discoveries.

Romania's natural gas production profile is entering a new phase of development. After experiencing a long-term decline from its peak production of 25 bcm in 1990, the country has recently shown signs of growth. In 2023, gas production reached 9.8 bcm and grew at 2%. Romania's gas production is expected to grow substantially, primarily driven by the development of the Neptun Deep project in the Black Sea. This offshore project is expected to start gas production in 2027 and has the potential to produce 7.5 bcm at its peak.

By 2030, Romania's total gas production is projected to reach 14 bcm, a significant increase from current levels. This growth will be supported by the Neptun Deep project, continued production from onshore fields operated by Romgaz, and potential contributions from other offshore discoveries like the Lira gas condensate field. However, the long-term outlook suggests a decline in production. By 2050, natural gas output is expected to decrease to approximately 3 bcm.

Türkiye is an emerging natural gas producer in Europe, with ambitious plans to boost domestic production over the coming decades to reduce energy import costs. In 2023, Türkiye's natural gas production reached 1.3 bcm compared to 0.4 bcm in 2022. A key driver of this growth was the Sakarya field in the Black Sea, discovered in August 2020. The field's first phase commenced production in 2023 with an expected peak production rate of 3.4 bcm. The country aims to ramp up production significantly from the Sakarya field. The second development phase is anticipated to start production by the second half of this decade with a potential to reach 9 bcm.

Türkiye's natural gas production is forecast to reach 17 bcm by 2050, supported by gas production from the Sakarya development and new discoveries in the South Akcakoca basin. Production from Sakarya is expected to continue through 2050, establishing a foundation for the country's domestic gas supply. The potential for additional production growth exists through exploration activities in the Black Sea, where the government seeks to attract partners for further development.

The **United Kingdom**'s natural gas sector experienced a continued decline in 2023, with production decreasing by 3.4% to 34 bcm. This decline is part of a long-term trend that has seen United Kingdom gas production steadily fall since its peak of 102 bcm in 2000, primarily due to the maturation of the region's active assets. By 2030, the outlook remains challenging as major producing fields are expected to see significant reductions in output. Fields such as Culzean, Cygnus, and Elgin, which are currently substantial contributors to United Kingdom gas production, accounting for 31% of the total gas production, are projected to experience considerable production decline by the decade's end. Similarly, the long-term perspective to 2050 expects a contraction in the United Kingdom's gas production. Given the declining reserves observed over the past two decades and the ongoing maturation of producing fields, forecasts suggest gas production could drop to 10 bcm by 2050. This projection underscores the critical need for major new discoveries to boost domestic production.

5.4.5 Latin America

Latin America experienced a modest decline of 1.2% in gas production in 2023, reaching 152 bcm. This decrease was mainly due to reduced production in Argentina, Bolivia and Trinidad and Tobago, while Brazil maintained stable gas production. Venezuela showed resilience, with production reaching 25 bcm in 2023, continuing its recovery trajectory from 18 bcm in 2020. In 2024, gas production in Latin America rebounded and increased by 2 bcm driven by Argentina and Brazil.

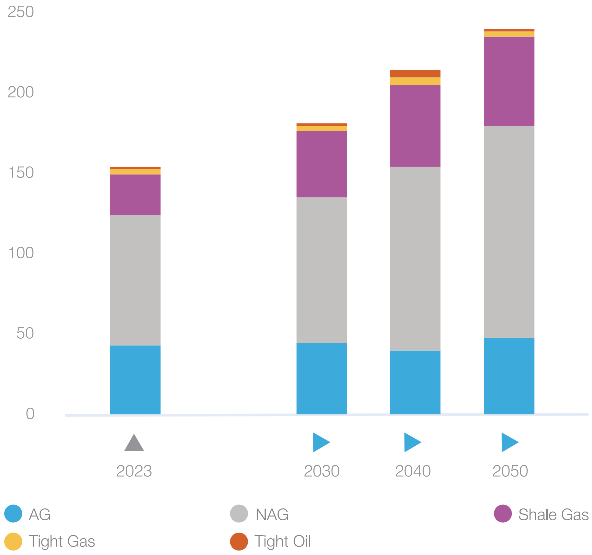
Natural gas production in Latin America is projected to expand by 87 bcm by 2050, growing at an annual rate of 1.7% from 2023 levels. This growth is expected to be uneven across the region. Argentina's production is forecast to rise to 83 bcm by 2050, supported by the development of Vaca Muerta, while Venezuelan production is projected to reach 46 bcm. Despite this increase, contribution of Latin America to global natural gas production is expected to hover around 4% over the forecast period.

The production mix in Latin America is forecast to evolve, with non-associated gas remaining the primary source, reaching 131 bcm by 2050. Additionally, shale gas production is expected to provide the second-largest contribution to growth, reaching 56 bcm by 2050, double the current level (Figure 5.20).

Conventional and unconventional gas production is

Figure 5.20

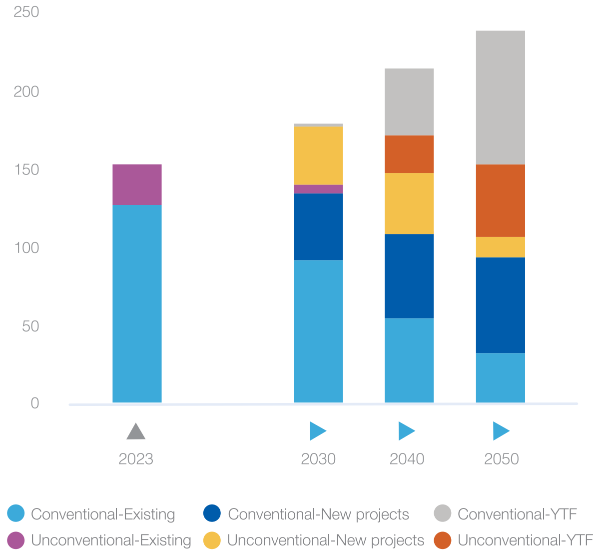
Latin America's natural gas production outlook by hydrocarbon type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 5.21

Latin America's natural gas production outlook by project type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

projected to grow in the region. The overall growth is expected to come from conventional gas projects, accounting for 75% of the region's gas production in 2050. In these projections, YTF resources are projected to lead the gas production growth over the last decade of the outlook period, specifically in Brazil, Peru, Trinidad and Tobago, and Venezuela (Figure 5.21).

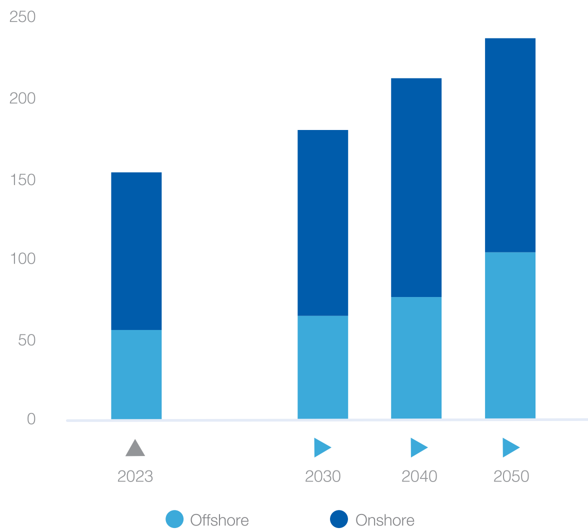
The share of offshore gas production in Latin America's total production is projected to increase from 37% in 2023 to 43% in 2050 (Figure 5.22). This expansion represents an additional 48 bcm of offshore gas production, marking a 53% rise over the forecast period. Key drivers of this growth are expected to include developments in Brazil, Trinidad and Tobago, and Venezuela.

Argentina's natural gas sector has undergone a profound transformation over the past decade, marking a significant shift in the country's energy landscape. This change is primarily characterised by focusing on gas production from unconventional reservoirs.

A decade ago, in 2013, unconventional gas production played a minor role in Argentina's gas production, accounting for 2.5 bcm, or 7% of the country's total gas production. However, in 2023, unconventional reservoirs dominated Argentina's gas production, accounting for 25 bcm out of a total production of 42 bcm, representing 60% of the country's gas production. The Vaca Muerta shale in the Neuquen basin is the country's main driver of unconventional gas production, accounting for 19.3 bcm in 2023, representing 77% of unconventional gas production and 46% of total gas production.

Figure 5.22

Latin America's natural gas production outlook by field location, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Argentina's natural gas production decreased by 1.2 bcm in 2023 due to a decline from mature conventional fields that offset gains from unconventional assets. Looking ahead, total gas production is projected to reach 75 bcm by 2040 and expand further to 83 bcm by 2050, primarily driven by development in Vaca Muerta. This production trajectory is based on the continued expansion of unconventional production activities and the expansion of gathering systems and pipeline capacity in the Vaca Muerta area.

Trinidad and Tobago is a significant Caribbean natural gas producer with 27 bcm output in 2023. The country has been actively working to stimulate its hydrocarbon sector through a series of licensing rounds. After a long gap since 2014, Trinidad and Tobago conducted its 2021 Deep/Ultra Deep-Water Round. The 2022 onshore and nearshore rounds followed this, and most recently, the 2023 Shallow Water Competitive Bid Round attracted bids from EOG Resources, Shell, and BP for several blocks. Furthermore, the government launched its deepwater bid round in January 2025, highlighting the strong direction towards promoting oil and gas exploration activity.

Trinidad and Tobago is projected to experience gas production growth in the second half of this decade supported by the start of Cypre, Manatee, and Mento assets in the Columbus basin. In addition, the ramp-up of gas production from Cassia C and Cassra will support the production growth. However, after 2030, the decline of major fields will begin to impact overall production levels, highlighting the importance of ongoing exploration activities to support natural gas production in the country after 2030.

Venezuela's natural gas sector has shown resilience and potential for growth in recent years. Despite experiencing a decline in production from its high in 2017, the industry has been on a recovery trajectory since 2020. Gas production increased from 18 bcm in 2020 to 25 bcm in 2023, primarily driven by key projects such as Pearl Phase 1, Mulata, and Carlito Norte.

Several key factors drive the projected expansion of Venezuela's natural gas sector. Regional cooperation is at the forefront, highlighted by the Venezuela-Trinidad and Tobago agreement to develop the Dragon field. This partnership aims to utilise Trinidad and Tobago's excess LNG and petrochemical capacity, potentially creating new production and export opportunities.

Venezuela also plans to capitalise on previously flared and vented gas from the north of Monagas and Anaco regions. This initiative could substantially increase production volumes while addressing environmental challenges.

Further reinforcing the country's natural gas prospects are YTF resources in the Trinidad and Maracaibo Basins. Exploration and production activities are planned for promising areas, including the Blanquilla field, Block 5, and the Barbacoa block.

5.4.6 Middle East

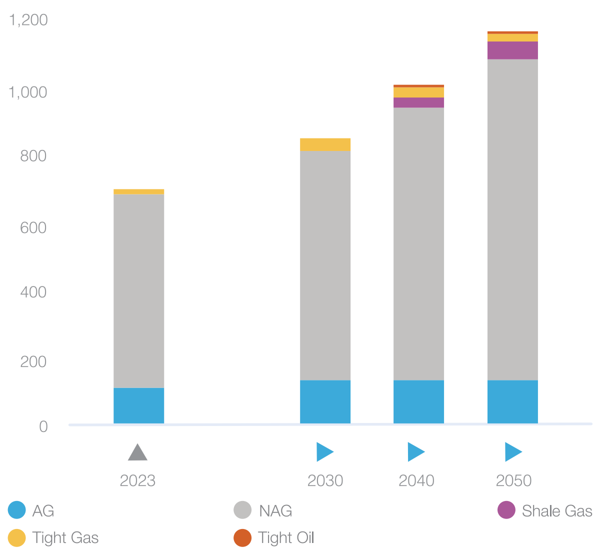
The **Middle East** is set for substantial growth, building on its vast resources and historical success in growing its gas production. From 2010 to 2023, the region witnessed a remarkable 51% increase in natural gas production, surging from 460 to 694 bcm. In 2023, gas production grew by 2.3%, accounting for 17% of global gas production. This growth was driven by Iran and Qatar, with significant contributions from Iraq and Oman. For instance, Qatar's production stood at 169 bcm in 2023, adding 4 bcm primarily from the Barzan project, while Iraq achieved a notable 14% growth to 19 bcm, driven by the Basrah gas project. In addition, Oman reached 39 bcm in 2023. Additionally, in 2024, the region continued growing at 3.1% driven largely by Saudi Arabia followed by the UAE, Iraq and Oman.

Gas production in the Middle East is set to continue growing, with projections indicating a further expansion to reach 1,155 bcm by 2050, elevating the Middle East's global share in natural gas production to 22%, up from 17% share in 2023 (Figure 5.23). The projections highlight the Middle East as the region with the most substantial gas production expansion over the outlook, accounting for 461 bcm at an annual growth rate of 1.9%, double the average global figure over the forecast period to 2050. Qatar's expansion will lead this extraordinary growth to 300 bcm, complemented by Saudi Arabia's increase to 160 bcm, UAE's growth to 93 bcm, and Iraq's expansion to over 60 bcm by 2050.

Substantial investments and strategic developments underpin the region's growth. In 2023, Qatar led the investment in the natural gas sector, accounting for 45% of the Middle East's upstream gas investment with USD 9.6 billion of the region's USD 21.3 billion investment. Similarly, Saudi Arabia has outlined ambitious plans for a 60% increase in gas production from 2021 levels by 2030, supported by an unprecedented lifecycle investment exceeding USD 100 billion in the Jafurah field alone. In addition, the UAE has significantly expanded its exploration efforts since 2019, awarding 15 exploration blocks across Abu Dhabi, Sharjah, and Ras al Khaimah. Meanwhile, Iraq's gas production is positioned

Figure 5.23

Middle East's natural gas production outlook by hydrocarbon type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

advantageously with some of the lowest production costs in the Middle East, with key projects such as Akkas, Khor Mor, and Mansuriyah scheduled to start gas production by 2030.

Several transformative projects will drive natural gas production growth in the Middle East. Qatar's North Field Expansion project, including Qatar Gas LNG T8-T11 and T12-T13, is a cornerstone development. Similarly, the UAE is advancing its Hail & Ghasha field, Dalma Gas, and Offshore Block 2 projects. Furthermore, Saudi Arabia's gas projects, including the Ghawar Haradh project and Hawiyah gas plant expansion, will significantly increase the region's growth. In addition, Oman continues to explore opportunities across six additional onshore blocks, while Iraq focuses on developing its Nahr bin Umar and Zubair assets.

While conventional resources remain the backbone of the Middle East's gas production, accounting for 93% of the region's gas production in 2050 (Figure 5.24), unconventional sources are gaining traction. **In 2023, unconventional gas reservoirs contributed a modest 15 bcm, comprising 2.2% of the Middle East's total gas production. However, this segment is poised for significant growth, with projections indicating an expansion to 80 bcm by 2050, constituting 7% of the region's total natural gas production.** The Middle East is witnessing an increasing interest in unconventional hydrocarbon development, with Oman currently leading the region in unconventional production. However, this landscape is set to change as Saudi Arabia ramps up its unconventional developments. The kingdom has recently begun tight gas production from its South Ghawar field and is poised to commence shale gas production from the Jafurah field by 2025. Similarly, the UAE started production from its Ruwais Diyab unconventional field in 2020.

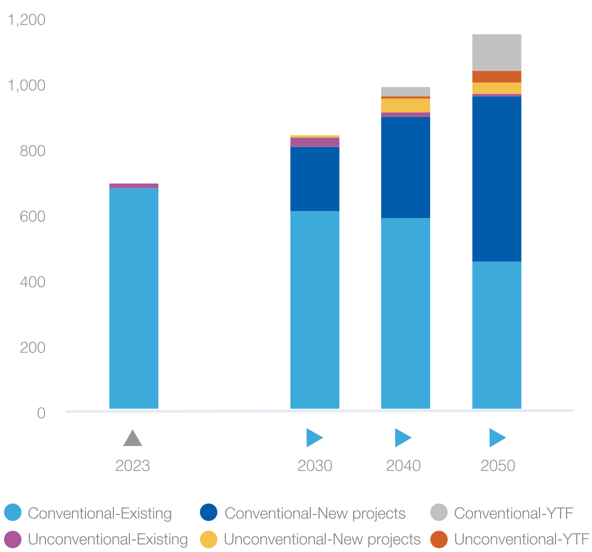
Over the outlook, gas production growth in the region by 460 bcm will depend on several factors. First, continued investment in major gas projects will be crucial. Second, successful exploration activities, particularly in newly awarded blocks across the UAE and Oman. Third, effective management of mature fields through sustainability projects, as demonstrated by Qatar's North Field initiatives. Additionally, developing robust infrastructure to support new production will be fundamental to achieving the region's production potential. Finally, developing unconventional resources, led by Saudi Arabia's Jafurah project and the UAE, will be essential for diversifying production sources.

By 2050, offshore production is projected to reach 780 bcm in the Middle East, maintaining its dominant position at approximately 68% of the region's total gas production (Figure 5.25). With its massive North Field expansion projects, Qatar will be the leading country behind this offshore gas production growth in the region. Similarly, the UAE is projected to significantly contribute to offshore growth by developing major projects such as the Hail & Ghasha field, Dalma Gas, and the promising discoveries in Offshore Block 2, where recent exploration success in the XF-002 well has opened new potential.

Iraq's natural gas production continues to expand, focusing particularly on flared gas capture and reserves development. In 2023, gas production reached 19 bcm, a 14% increase from 2022. This growth was primarily achieved by increased gas production from the Basrah gas project, with additional contributions from the Pearl project. The growth trajectory is expected to continue

Figure 5.24

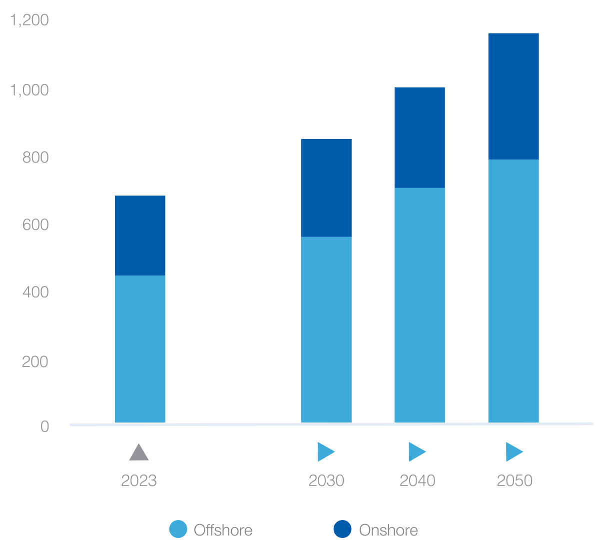
Middle East's natural gas production outlook by project type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 5.25

Middle East's natural gas production outlook by field location, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

in 2024, supported by production increases from the Qurna West and Rumaila developments within the Basrah project.

Iraqi gas production is projected to reach 30 bcm by 2030, supported by several new field developments. Key projects expected to begin production by the end of this decade include Akkas, Khor Mor, Mansuriyah, Nahr bin Umar, and Zubair. Analysis of Rystad Energy data shows these Iraqi gas developments have competitive breakeven costs, ranking among the lowest in the Middle East.

In addition to expected projects, the country focuses on natural gas exploration. The 6th Bid Round featured 14 blocks located mainly in unexplored areas with gas potential.

Saudi Arabia's exploration sector is poised for significant growth in the coming years. Its focus is on expanding gas from conventional and unconventional resources. Natural gas production in the country stood at 82 bcm in 2023 and experienced high growth in 2024. Early data for 2024 indicates dry gas production of 96 bcm, a 16% increase in gas production. This huge production growth is driven by the start of Ghawar Haradh project at the end of 2023 with estimated production of 11 bcm in 2024 and to some extent to the expansion of the Hawiyah gas plant.

The country has plans to focus on natural gas. In this regard, Aramco is planning to increase its gas production by 60% from the 2021 level (78 bcm) by 2030. Unconventional resources are receiving increased attention, with key focus areas including Northern Arabia, the South Ghawar area, and the Jafurah Basin east of Ghawar. This push into unconventional aligns with Saudi Arabia's broader strategy to diversify its hydrocarbon portfolio and secure long-term energy sustainability. Saudi Aramco is investing substantially in developing the Jafurah field, a major shale gas project that underscores the kingdom's commitment to expanding its natural gas resources. The company envisions a total lifecycle investment exceeding USD 100 billion for this project.

The development of Jafurah is progressing in multiple phases. In 2021, Aramco allocated approximately USD 10 billion for the initial phase, covering subsurface work, engineering, procurement, and construction (EPC). Recently, the company has significantly expanded its investment, awarding an additional USD 25 billion in contracts for Phase 2 development and the expansion of the gas system. Production is expected to start in 2025, and the field is expected to produce 20 bcm by 2030, driving the country's gas production to 124 bcm in 2030.

Over the long term, the outlook expects Saudi to reach 160 bcm by 2050, with associated gas projected to remain a key pillar of the country's production, accounting for 27% of its gas production by 2050.

In **Qatar**, natural gas production stood at 169 bcm in 2023, a growth of 4 bcm from the 2022 level, driven primarily by production growth from the Barzan project. Natural gas production in the country is mainly non-associated offshore gas production from the Rub Al Khali basin, and a small fraction of its production is associated with gas from the onshore Dukhan onshore project.

Post-2020 pandemic, Qatar has emerged as the primary force behind new project sanctions in the Middle East region. This surge in activity is largely driven by two key factors: Qatar's ambitious LNG expansion plans and its commitment to sustainability projects aimed at mitigating production decline in its flagship North Field. The North Field Expansion and Barzan projects will lead the country's gas production growth.

Qatar's share of the region's upstream investment is substantial. In 2023, Qatar accounted for 45% of the Middle East's upstream gas investment, USD 9.6 billion from the region's upstream investment in natural gas projects estimated at USD 21.3 billion. The Qatar Gas LNG T8-T11 project in the North Field, Qatar Gas LNG T12-T13 in the North Field South, the North Field Sustainability project, and the North Field Compression project drive the growth in investment and future production.

Over the long term, the outlook expects Qatar to reach 244 bcm in 2030 and grow to 300 bcm by 2050. The focus on expansion and sustainability reflects Qatar's strategic approach to energy development, balancing growth with responsible resource management.

Natural gas production in **Oman** has shown steady growth since 2020. Natural gas production reached 39 bcm in 2023 compared to 33 bcm in 2020. Gas production growth was driven primarily by Khazzan-Makarem, which accounted for 33% of the country's gas production in 2023, and the startup of the Marsa LNG project. Natural gas production in Oman is 100% from onshore projects, and Oman is among the drivers behind onshore gas production growth in the region.

Oman is among the first movers into unconventional gas production in the region. Unconventional gas production started in Khazzan Makarem in 2011 and grew gradually until it reached 33% of Oman's gas production in 2023.

In 2023, Oman made significant efforts to expand its hydrocarbon exploration. The country awarded three onshore exploration blocks covering over 20,000 square kilometres in the southern Rub al Khali Basin near Block 6. Building on this momentum, Oman has launched a direct award opportunity, offering six additional onshore blocks (43A, 43B, 66, 73, 75, and 76) for exploration.

The outlook is that Oman will sustain its natural gas production during the forecast period and reach 43 bcm by 2050. For this outlook to materialise, successful exploration is considered a key, as YTF resources are projected to account for 60% of total gas production in 2050.

In the **UAE**, natural gas production is expected to grow significantly, driven by intensified exploration, large resources, and diversified development in conventional and unconventional resources.

The UAE has significantly expanded its exploration activities since 2019, awarding 15 exploration blocks through competitive bid rounds across Abu Dhabi, Sharjah, and Ras al Khaimah. Additionally, two unconventional onshore blocks have been awarded, demonstrating the country's commitment to diversifying its hydrocarbon resources.

International oil companies have been actively exploring these newly awarded blocks, with some notable successes: a multi-reservoir oil discovery in Onshore Block 3 and a gas discovery in the XF-002 well in Offshore Block 2. These positive results are expected to drive continued exploration efforts in the coming years, with both international and state-owned operators maintaining high activity levels.

A significant unconventional-producing asset during the forecast period is the Ruwais Diyab unconventional field in the Rub Al Khali basin in Abu Dhabi, which started production in 2020. In addition, the country is taking solid steps and plans to increase unconventional project development, including tight and shale oil formations, to unlock an estimated 13 tcm (460 tcf) of unconventional resources.

The UAE is poised for significant gas production growth over the forecast period. By 2030, three major gas fields are currently under development, which are expected to boost the country's natural gas production by 2030 substantially. These projects are Hail & Ghasha field, Dalma Gas and the offshore Block 2 project. Together, these projects will drive natural gas production to 70 bcm by 2030.

5.4.7 North America

North America, currently the world's largest natural gas producer, contributed significantly to global growth in 2023, reaching 1,275 bcm at a growth of 4.1%. This growth was largely driven by the United States, which added 43 bcm, and Canada, which contributed an additional 6 bcm. This growth increased North America's share of global gas production to 31% in 2023. Conversely, North American natural gas production remained flat in 2024 as production gains of 4.8 bcm in Canada were counterbalanced by declines in the United States and Mexico.

North America is projected to remain the largest gas producer through the outlook, reaching 1,382 bcm in 2050 (Figure 5.26). The region is projected to add 107 bcm to its gas production by 2050, reflecting an average annual growth rate of 0.3%. **However, North America's contribution to global gas production is expected to decrease from 31% in 2023 to 26% in 2050.**

Natural gas production in the region is dominated by onshore unconventional gas production. In 2023, unconventional natural gas production in the region accounted for 87% of the total gas production, thanks to the shale revolution that transformed oil and gas production growth since 2010. This transformation is particularly evident in the United States, where unconventional production reached 958 bcm (90% of total production) in 2023, and Canada, which accounts for 81% of production.

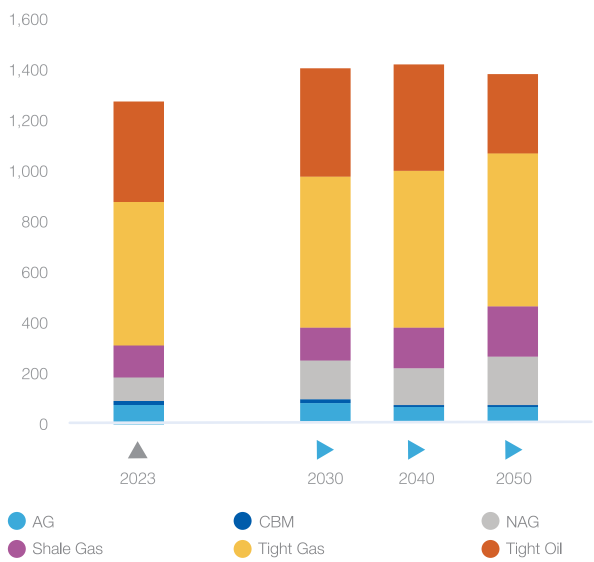
North American unconventional gas production has shown varying growth rates over distinct periods. Unconventional gas production in the region experienced a rapid growth rate during 2010-2015 at an annual growth rate of 14%. Despite low oil and gas prices in the second half of the 2010s, unconventional gas production grew 8% annually. Growth further slowed to 5% annually from 2020 to 2023, even as commodity prices strengthened, particularly during 2021-2022, indicating a possibility of flattening. Operational efficiency improvements have played a crucial role in sustaining unconventional production growth despite the volatility of oil and gas prices. According to Wood Mackenzie, in 2023, the United States achieved notable efficiency gains, with drilling and completion cost reductions of 5-10% across multiple basins.

The outlook for unconventional production through 2050 indicates continued moderation in growth rates. Production is forecast to reach 1,167 bcm by 2030, at 0.7% annually. This rate is projected to slow

Chapter 5

Figure 5.26

North America's natural gas production outlook by hydrocarbon type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

to 0.6% per year in the 2030s before shifting to a 1% annual decline in the 2040s. The change in the region's growth pattern of unconventional gas production is attributed to the natural maturation of existing unconventional gas projects. While new unconventional projects are expected to remain robust, their gas production growth will not be sufficient to offset declining production from mature assets, particularly during the 2040s (Figure 5.27).

The regional outlook masks divergent trends between the United States and Canada. While the United States production is expected to peak at 1,157 bcm by 2030 before declining to 1,095 bcm by 2050, Canada is projected to experience sustained growth, reaching 245 bcm by 2050.

Infrastructure development is fundamental to North America's natural gas production growth, particularly in connecting major supply basins to evolving demand centres. Pipeline expansion projects have been critical in unlocking production potential from key regions like the Appalachian and Permian basins.

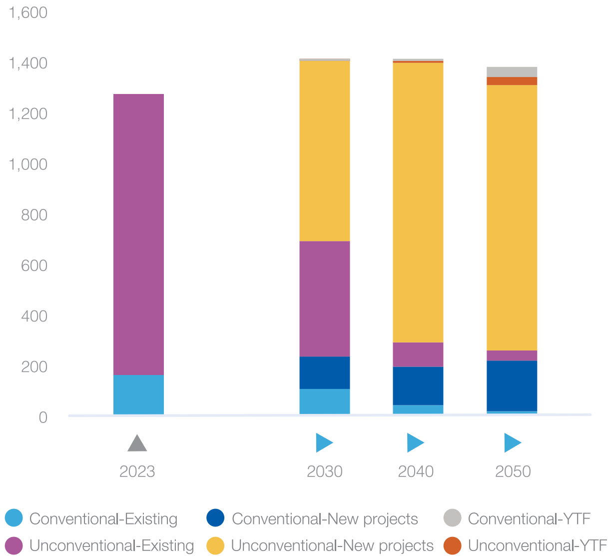
A strong dominance of onshore resources characterises North America's natural gas production profile. In 2023, offshore production contributed only 2.4% to the region's total gas production, primarily from the United States Gulf Deepwater and Gulf Coast Shelf basins. This production structure is expected to persist through 2050, with offshore production projected to reach 60 bcm, maintaining a modest 4% share of the region's total gas production. The continued dominance of the onshore output reflects North America's continental gas resources and the success of technologies that have unlocked vast shale and tight gas plays across the region.

Natural gas production in the **United States** reached 1,065 bcm in 2023, an increase of 43 bcm from 2022, representing a growth rate of 4.2%. This growth was driven by unconventional gas, which reached 958 bcm, representing a 5.6% increase. Meanwhile, conventional gas production declined by 6.9% to 108 bcm. On gas type, associated gas production was a strong driver of production growth. Associated gas added 17 bcm in 2023, representing around 40% of the growth in 2023. Associated gas production from the Permian basin was the main driver behind the growth, while Marcellus and Haynesville were the main drivers for non-associated gas growth.

Despite declining natural gas prices in 2023, the United States experienced production growth, driven primarily by significant improvements in operational and capital efficiencies. For instance, according to Wood Mackenzie, the United States experienced a substantial cost reduction in drilling and completion operations across multiple basins, with improvements ranging from 5% to 10%. Operational efficiency gains were particularly evident in drilling performance, with

Figure 5.27

North America's natural gas production outlook by project type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

rig productivity improving across almost all basins. For example, operators reported 20% more wells per rig in the Permian than in the 2020 level. These operational enhancements, combined with other efficiency improvements, resulted in a 13% increase in capital efficiency in 2023 compared to 2022.

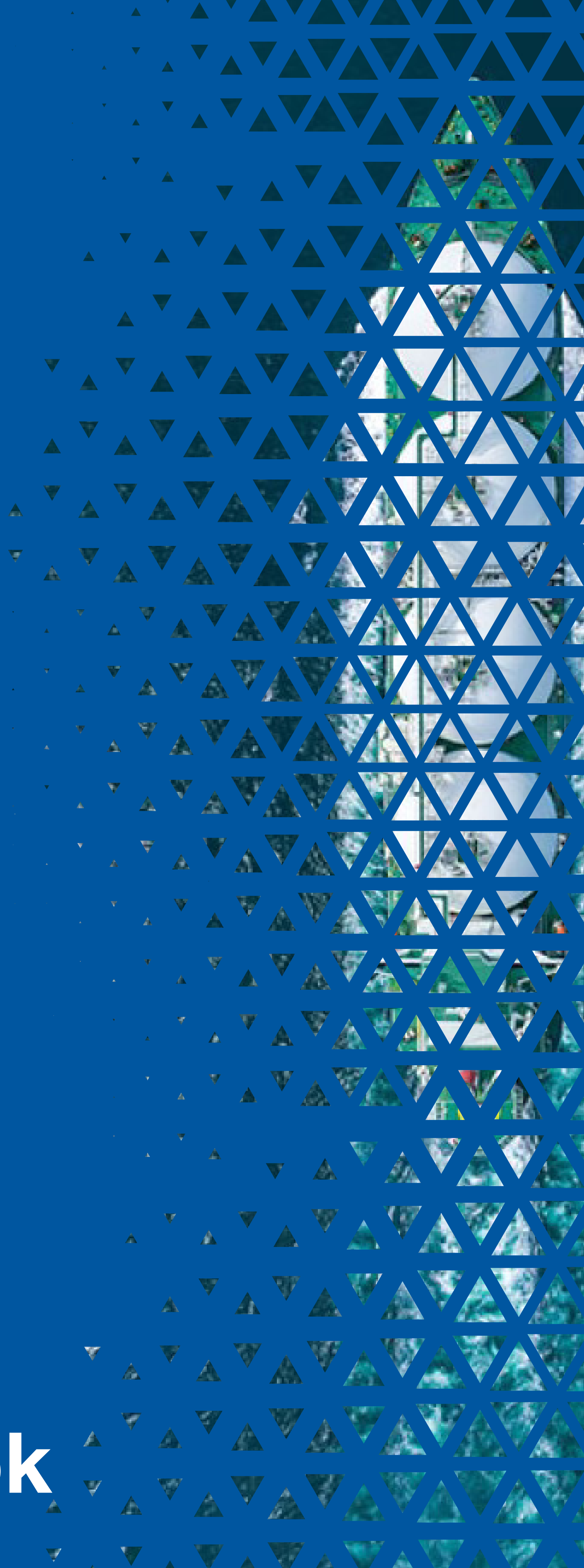
The United States' natural gas production is projected to follow a two-phase trajectory over the coming decades. In the medium term, production is expected to expand to 1,157 bcm by 2030, with the Permian Basin - which has demonstrated significant operational efficiency improvements - leading this growth. However, the long-term outlook suggests a gradual decline, with production expected to decrease to 1,095 bcm by 2050. This decline is primarily attributed to expected production reductions in major producing basins as they mature.

Canada's natural gas production has been growing and passed its previous high of 177 bcm in 2002 but with a shift in gas production asset types from conventional to unconventional assets. Post 2020, natural gas production increased steadily from 160 bcm to 185 bcm in 2023 at an annual growth rate of 4.9%, with 2023 experiencing a growth of 6 bcm. The main driver behind the growth is the unconventional Montney play, which added 6 bcm of gas production in 2023. Like the United States, unconventional gas production in Canada was the driver of the growth and makes up most of the gas production, 81%, contrary to the past (from 2000 to 2008) in which the country relied on conventional gas production that accounted for over 80% of the countries production. The decline in conventional gas production was driven by the general maturation of fields in the Western Canadian Sedimentary basin. Moreover, the shift towards unconventional gas production was supported by the development of hydraulic fracturing technology in 2010, which allowed the commercialisation of uneconomic unconventional gas.

Canada's natural gas production is set for remarkable growth over the coming decades. The outlook is that gas production will reach 245 bcm by 2050, representing a 33% increase from the 2023 level. The Montney Play is forecast to drive growth and is projected to contribute 160 bcm to Canada's gas production by 2050. In addition, the production ramp-up in Spirit River and Duvernay will add to the outlook for production growth after 2030.

Chapter 6

Natural Gas Trade Outlook



Highlights

- Global natural gas trade is projected to grow by 44% from 2023 to 2050, reaching 1,743 bcm, equivalent to one-third of global gas demand.
- LNG is set to dominate, doubling to 800 Mt and accounting for 63% of traded gas by mid-century. While pipeline trade is anticipated to decline initially, modest growth is expected as Eurasian exports pivot from Europe to the Asia Pacific, driven by rising demand in China.
- Eurasia and North America are poised to drive natural gas export growth, with North America expanding LNG capacity and Eurasia advancing both LNG and pipeline projects. Africa is set to become a key supplier, while the Middle East will sustain a steady export contribution.
- By 2050, GECF member countries are projected to supply approximately 869 bcm of natural gas exports, increasing their market share to around 50% from 40% in 2023. LNG exports from these countries are expected to reach about 445 Mt, accounting for 56% of global LNG exports.
- Asia Pacific is expected to dominate LNG imports, accounting for 76% of global volumes by 2050, with China, South Asia, and Southeast Asia driving the growth. The region is expected to contribute 88% of gross global LNG imports increase, adding 343 Mt, solidifying its role as the primary destination for LNG in the long run.
- By 2050, Europe's natural gas imports will decrease by 167 bcm to 263 bcm, driven by decarbonisation efforts, reducing its share from 37% in 2023 to 15% by mid-century. Despite this decline, it will remain the second-largest LNG importer, underscoring LNG's vital role in energy security and the global shift toward sustainability.
- Global LNG exports are projected to undergo significant changes from 2023 to 2050, with North America leading growth, expanding by about 133 Mt to secure 27% of the market. The Middle East will follow, increasing exports by approximately 99 Mt, driven by Qatar's capacity expansions.
- Eurasia's LNG exports are projected to quadruple, capturing a 16% market share by mid-century, driven mainly by Russia's new liquefaction projects. Africa is also set to experience substantial growth, adding around 78 Mt, supported by developments in Mozambique, Nigeria, Senegal and Mauritania.
- Global liquefaction capacity is projected to exceed 1,000 Mtpa by 2050, up from 462 Mtpa in 2023. North America and the Middle East are expected to contribute 34% and 23% of global liquefaction capacity additions respectively by mid-century.
- Regasification capacity is expected to reach 1,805 Mtpa by 2050, up from 1,117 Mtpa in 2023. Asia Pacific and Europe are set to capture 82% and 12% of global regasification increase respectively over the forecast period.

6.1 Natural gas market current developments and trends

The global LNG market experienced significant volatility and structural shifts in 2023 and 2024, shaped by supply constraints, evolving demand patterns, geopolitical disruptions, and regulatory developments. While 2023 marked a period of stagnation due to limited liquefaction capacity additions and operational challenges, 2024 saw a modest recovery in the LNG trade. However, market growth remained well below historical averages, constrained by project delays, regulatory barriers, and supply-side disruptions.

In 2023, LNG supply growth was minimal, with new liquefaction projects limited and several existing facilities facing feedgas shortages and performance issues: maintenance shutdowns, unplanned outages, and delays in commissioning restricted global LNG output. The United States maintained its position as the world's largest LNG exporter, surpassing Australia and Qatar, but infrastructure bottlenecks and extreme weather events hindered production growth. Regulatory challenges, including the President Biden administration's pause on non-FTA LNG export approvals, further dampened supply-side momentum in North America.

By 2024, LNG supply reached 411 Mt on a delivered basis, marking a modest 0.7% year-on-year increase. The limited growth was primarily supported by reduced planned maintenance and increased production from Southeast Asia, Nigeria, and Mozambique, which helped offset declines in several legacy LNG producers. New supply additions, primarily involving smaller floating units, remained scarce, with notable projects such as Marine XII FLNG in Congo and NFE Altamira in Mexico coming online. Arctic LNG 2 in Russia also began commissioning. The United States expanded its LNG export capacity with the first cargoes from Plaquemines LNG and Corpus Christi Train 3 in late December 2024. However, planned maintenance continued to weigh on global capacity, with major facilities in Australia, including Gorgon and Northwest Shelf, undergoing extensive maintenance, while the United States facilities, such as Sabine Pass and Cove Point, experienced shutdowns for infrastructure upgrades.

Regarding demand, Asia Pacific played a central role in shaping market dynamics. Asian LNG demand rebounded more strongly than expected, increasing by 7.4% in 2024 compared to 2023. China remained the world's largest LNG importer, with imports rising by 8% to 78 Mt, driven by an improving economy and increased spot purchases. Japan and South Korea saw higher LNG demand due to extended summer heatwaves and delays in nuclear restarts. At the same time, South and Southeast Asia also registered strong growth, with India and Thailand increasing LNG imports to meet peak cooling demand. South Asia's LNG imports surged 16% year-on-year, while Southeast Asia recorded 15% growth. Emerging LNG importers such as the Philippines and Viet Nam maintained steady LNG procurement, with the Philippines importing 1.2 Mtpa and Viet Nam 0.3 Mtpa.

In contrast, European LNG demand weakened significantly, declining by 19% year-on-year due to mild weather, strong renewable energy generation, and subdued gas-to-power demand. Non-power sector gas consumption increased marginally, supported by industrial growth, but overall demand remained suppressed. The availability of a strong Norwegian pipeline supply and continued Russian piped gas imports further limited Europe's LNG import requirements.

In South America, severe drought conditions in Brazil, marking one of the driest year in nearly a century, significantly impacted hydropower generation. This increased gas-fired electricity output and boosted regional LNG imports by 41.5%. Other South American markets, including Chile, Argentina, and Bolivia, experienced relatively stable LNG demand.

Market fundamentals remained tight, keeping LNG prices elevated despite some periods of softness. Average annual prices for TTF and Japan LNG DES were down 29% and 24%, respectively, compared to 2023. However, disruptions in the Middle East and the continued threat of supply uncertainty prevented prices from falling further. An abnormally hot summer in Asia pushed LNG prices to a premium over European benchmarks, while geopolitical risks and shipping disruptions reinforced bullish sentiment. In the early months of the year, ample gas storage and mild winter weather had driven European prices to a three-year low, but an early cold snap in the fourth quarter prompted rapid withdrawals from storage, causing prices to climb back into the USD 13-15/MMBtu range.

The LNG market also faced regulatory headwinds, particularly in North America, where the pause on non-FTA export approvals slowed project momentum. The total volume of new supply capacity sanctioned in 2024 was significantly lower than in previous years, with no major United States projects reaching a final investment decision (FID) compared to 38 Mtpa sanctioned in 2023 and 24 Mtpa in 2022. Meanwhile, several under-construction projects faced delays, including Golden Pass LNG, which was impacted by the bankruptcy of its lead contractor, and the second and third trains of Arctic LNG 2.

However, in January 2025, the newly elected United States administration lifted the halt on non-FTA LNG export approvals, reversing the policy implemented under the previous administration. This policy shift is expected to accelerate the approval process for pending United States LNG projects, unlocking stalled developments and reinforcing the United States' position as a key global LNG supplier. Projects such as Rio Grande LNG, Texas LNG, and Calcasieu Pass 2 (CP2) are now expected to move forward, pending financing and final regulatory steps. This move is likely to increase long-term LNG supply availability, enhance market liquidity, and strengthen United States export competitiveness, particularly in Asia and Europe.

Despite these challenges, some new LNG supply projects were sanctioned, including the 3.3 Mtpa Cedar LNG project in Canada, the 9.6 Mtpa Ruwais LNG facility in the UAE, and the 1 Mtpa Marsa LNG project in Oman. Additionally, emerging LNG import infrastructure developments gained traction, with China commissioning four new regasification terminals and expanding capacity at existing sites. In Europe, new regasification capacity additions totalled 19.4 Mtpa, reflecting continued efforts to enhance energy security, though overall import demand remained weak.

In the medium term, the LNG market is expected to transition from tight supply conditions to a potential oversupply scenario by 2030, driven by a wave of new liquefaction capacity currently under construction. Consequently, competition among suppliers is expected to intensify, placing downward pressure on prices and reshaping LNG trade dynamics. Buyers may regain leverage in contract negotiations, pushing for more flexible terms, lower prices, and destination-free cargo. At the same time, LNG producers will face mounting pressure to adapt to evolving policy frameworks, decarbonisation commitments, and the growing role of alternative energy sources. Investment decisions in the late 2020s will need to carefully balance long-term demand uncertainty with supply expansion strategies, ensuring that the industry remains resilient amid shifting energy transitions priorities, geopolitical risks, and evolving cost structures.

6.2 Natural gas trade outlook

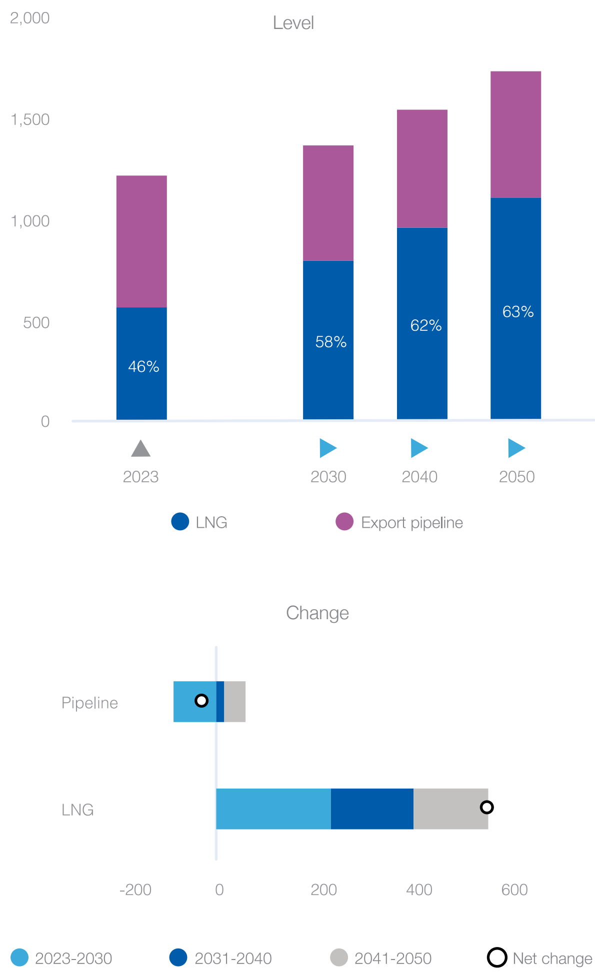
Between 2023 and 2050, global natural gas trade is projected to expand by 44%, increasing from 1,212 bcm to 1,743 bcm (Figure 6.1). By mid-century, traded gas will constitute approximately one-third of global gas demand, which is expected to reach 5,317 bcm. Meanwhile, the majority of natural gas production - around two-thirds - is anticipated to be consumed domestically within the regions of extraction, highlighting the continued importance of regional gas markets and infrastructure investments in meeting local energy needs.

LNG exports are poised to become the dominant global natural gas trade driver, with volumes projected to double and reach 800 Mt (1,104 bcm) by 2050, accounting for 63% of total traded gas volumes. This robust expansion of LNG trade from 2023 to 2050 is expected to enhance market flexibility and liquidity, strengthening the role of LNG in addressing the energy trilemma by improving affordability, reliability, and sustainability in the global energy system. As a result, regional natural gas markets will experience deeper integration and stronger interconnections, supported by LNG expansion and pipeline trade evolution.

The global LNG and pipeline imports increase from 2023 to 2050 is projected round 531 bcm, a trend largely driven by LNG growth. Despite declining pipeline trade volumes between 2023 and 2030, each subsequent period - 2030-2040 and 2040-2050 - exhibits a net positive trend in overall gas trade. The strongest growth in LNG volumes is anticipated in the 2023-2030 period, where LNG trade is forecast to expand by 232 bcm, underscoring the immediate role of LNG in meeting global energy demand (Figure 6.1).

Figure 6.1

Global natural gas trade* outlook by flow type, 2023-2050 (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*

In the near to medium term, however, global pipeline gas exports are expected to decline marginally by 12%, falling from 648 bcm in 2023 to 570 bcm by 2030. This decline is primarily attributed to the reduction in Russian pipeline gas exports as geopolitical and economic shifts reshape traditional trade flows. Nonetheless, the long-term outlook for pipeline trade is expected to stabilise and recover, with volumes reaching 640 bcm by 2050. This gradual rebound will be driven by infrastructure investments, new interregional supply agreements, and the evolving role of pipeline gas in complementing LNG in increasingly interconnected natural gas markets.

Global natural gas imports expansion is primarily driven by a widening imbalance between regional supply and demand, with Asia Pacific accounting for 94% of the increase over the forecast period. As domestic production struggles to keep pace with growing consumption, the region's reliance on both LNG and pipeline imports is expected to rise significantly. Between 2023 and 2050, Asia Pacific's natural gas imports are projected to increase by 557 bcm, bringing total imports to 988 bcm by mid-century (Figure 6.2).

A key transformation in the region's supply structure will accompany this import growth. Around 52% of Asia Pacific's LNG imports are sourced from within the region, ensuring relative supply security. However, by 2050, the RCS projections indicate a fundamental shift, with over 80% of LNG imports expected to originate from outside the region. This shift highlights the increasing importance of interregional trade as the Asia Pacific becomes more reliant on gas supplies from the Middle East, North America, and Africa to meet its energy demands.

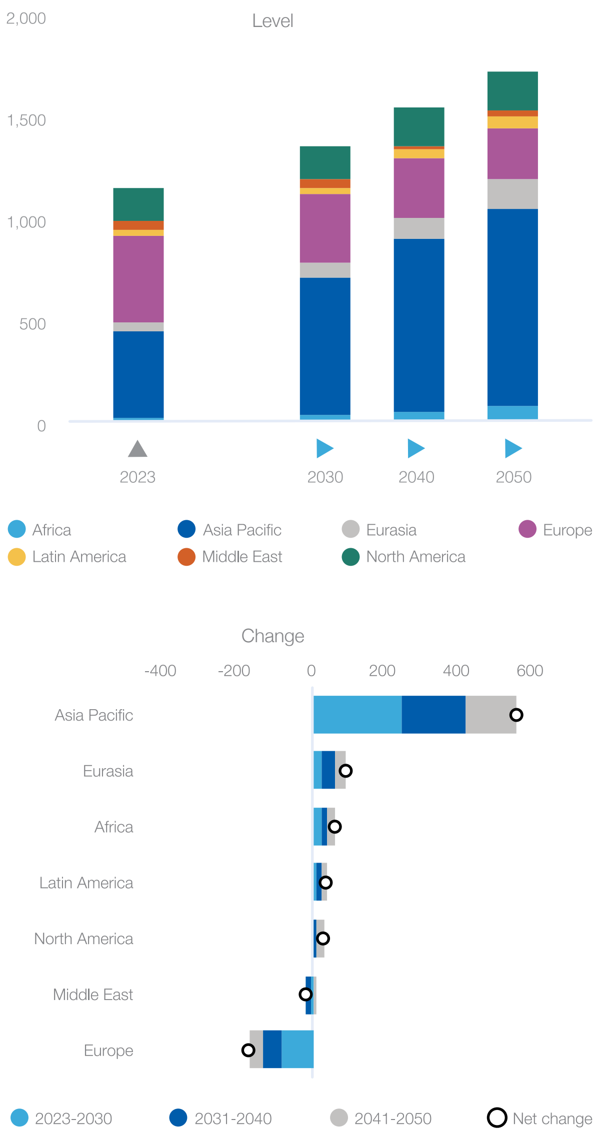
The evolution of natural gas demand within Asia Pacific reflects a regional divergence in consumption trends, reinforcing the growing shift of global gas trade toward developing Asia. China, Southeast Asia, and South Asia are expected to drive the majority of LNG demand growth, with China also emerging as a major destination for increased natural gas pipeline imports. Several structural factors, including rapid economic expansion, urbanisation, and the push for cleaner energy alternatives, will continue to drive natural gas import growth in the medium to long term, strengthening the region's position as the dominant force in global LNG trade.

Beyond Asia Pacific, Eurasia emerges as the second-largest contributor to global natural gas trade growth, more than doubling from 2023 to 2050. Unlike Asia Pacific, which is witnessing a surge in LNG imports, Eurasia's growth is both driven by pipeline and LNG trade.

Other regions, including Africa, Latin America, and North America, will also experience moderate increases in natural gas imports by mid-century, contributing 10%, 6%, and 5%, respectively, to the net global trade growth. While Africa and Latin America primarily rely on LNG

Figure 6.2

Global natural gas imports outlook by region, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

imports, North America's rising import volumes will be influenced by seasonal demand variations and regional market dynamics rather than structural dependence on foreign gas.

In contrast, Europe and the Middle East are set to experience a decline in natural gas imports by 2050. As illustrated in Figure 6.2, European natural gas imports are expected to decrease by approximately 167 bcm, following a consistent downward trajectory over the next three decades. This decline is driven by Europe's ongoing transition toward renewables, enhanced energy efficiency, and declining industrial gas consumption. Similarly, natural gas imports in the Middle East are projected to fall, with the most significant reductions occurring during the 2030s. This trend reflects the region's growing emphasis on domestic gas production, self-sufficiency, and expanding gas-based industrial projects prioritising local supply utilisation.

While global natural gas exports is projected to grow by 44% by 2050, this expansion will not be evenly distributed across regions. North America, which holds the largest market share in global natural gas trade, particularly LNG, is set to strengthen its position further. By 2050, North America is expected to account for 29% of global exports, up from 23% in 2023, solidifying its role as a key supplier to both Asia Pacific and Europe. This growth is primarily driven by continued expansion in LNG capacity, infrastructure investments, and favourable market conditions supporting long-term export contracts.

Eurasia is poised for the fastest export growth rate, exceeding 50% over the forecast period, with natural gas exports reaching 523 bcm by 2050. This increase will elevate Eurasia's share in global natural gas exports to nearly 30%, making it a leading contributor to global supply. Most of this growth is expected post-2030 as ongoing investments in gas infrastructure, new pipeline routes, and LNG terminals materialise. The expansion of Russian gas exports to China and other Asian markets and new supply developments in Central Asia will be key in driving this trend.

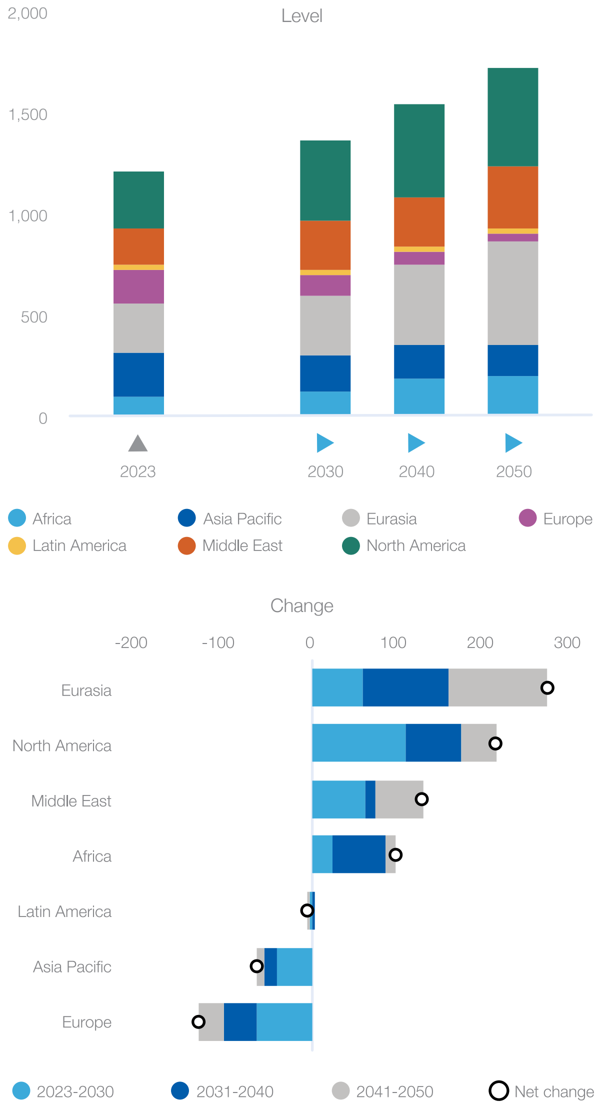
The Middle East remains a critical pillar of global natural gas exports, experiencing steady growth in its market share. By mid-century, the region's share in global gas exports is expected to reach 18%, marking an increase of nearly 3 percentage points from 2023 levels. This expansion will be driven by Qatar's continued LNG leadership, growing exports from the UAE and Oman, and new gas developments in Saudi Arabia to support both domestic industrial expansion and global exports.

As an emerging natural gas export powerhouse, Africa is set to play an increasingly significant role in shaping global energy trade. Natural gas exports from Africa are projected to rise by nearly 100 bcm, increasing its share of global exports from 8% in 2023 to 11% by 2050 (Figure 6.3). This expansion is underpinned by substantial investments in new LNG projects in Mauritania, Mozambique, Nigeria, and Senegal, alongside enhanced gas infrastructure supporting interregional trade. Africa's growing role in global natural gas markets reflects its strategic importance as a diversified supply source, particularly for Europe and Asia, as energy security and supply diversification remain key global priorities.

In 2023, global natural gas consumption was approximately 4,018 bcm, with about 1,212 bcm exported via LNG and pipelines to meet demand. GECF member countries supplied around 481 bcm of this total, including 266 bcm as LNG, accounting for a 40%

Figure 6.3

Global natural gas exports outlook by region, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

share in the global gas trade that year. Looking ahead to 2050, projections indicate that global natural gas demand will reach approximately 5,317 bcm, with about 1,743 bcm expected to be exported through LNG and pipelines. **GECF member countries are anticipated to supply around 869 bcm of these exports, potentially increasing their market share to approximately 50%.**

Conversely, natural gas exports from Europe, Asia Pacific, and Latin America are expected to decline, reflecting shifting regional supply-demand balances and the maturing of key production fields. Asia Pacific, which currently accounts for 18% of global natural gas exports, is projected to see its share decline sharply to just 9% by 2050. This significant reduction is expected to occur

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primarily within the current decade, driven by rising domestic demand, declining production from ageing fields, and limited new large-scale gas developments. The growing dependency on imported LNG in the Asia Pacific -particularly in China, South Korea, Japan, and South and Southeast Asia - will further contribute to the region's shrinking role as a natural gas exporter.

Similarly, **Europe is set to undergo a dramatic decline in natural gas exports, with its share in global trade falling from 14% in 2023 to just 2% by 2050.** This steep reduction is attributed to the depletion of North Sea reserves, declining production in key exporting countries such as Norway and the Netherlands, and the continent's broader transition away from fossil fuels. As Europe pivots toward renewables, energy efficiency measures, and alternative low-carbon energy sources, its export capacity will diminish, reinforcing its position as a major import-dependent region rather than a net gas supplier.

In Latin America, the decline in natural gas exports is expected to be more gradual, with a modest reduction in its share of the global gas trade. While some countries, such as Argentina and Brazil, may see short-term export growth due to new gas developments, overall regional supply constraints, increased domestic consumption, and policy shifts favouring local energy security are expected to contribute to a slight decline in export capacity over the long term.

The evolving landscape of the LNG market reflects a delicate balance between long-term security and short-term flexibility. Over the past decade, the industry has transitioned from rigid, oil-linked long-term contracts to a more dynamic structure incorporating spot transactions and shorter-term agreements. This shift was particularly pronounced during the 2019-2020 supply glut when buyers capitalised on spot market opportunities. However, the energy crises of 2021-2023 underscored the importance of supply security, prompting a renewed interest in long-term contracts. As highlighted in Box 6.1, this trend is evident in recent contracting activity, with buyers - especially in Asia - securing LNG volumes under extended agreements to hedge against market volatility. At the same time, the role of traders and portfolio players continues to grow, ensuring that flexibility remains a defining feature of the LNG market.

Box 6.1 LNG contracts reconfiguration - balancing flexibility and security

In recent years, the global LNG market has evolved from one dominated by long-term, oil-indexed contracts with little flexibility to a more flexible merchant market with multiple indexations bases and a larger role for traders. The oversupply in 2019-2020 made spot purchases attractive, particularly for European buyers, who preferred purchasing on European hubs like TTF rather than committing to long-term contracts. However, reducing pipeline gas imports to Europe from 2021 to 2023 has led some buyers to favour long-term LNG contracts as a reliable and stable supply. This shift does not signal a decline in the merchant LNG market but reflects a natural adjustment from a spot-driven market during a supply glut to an emphasis on term contracts in a tighter market. Despite this, spot transactions will remain crucial in offering flexibility and optimising portfolios. Their share of total LNG trade is expected to rise again after 2025-2026 as the supply balance shifts.

On the one hand, long-term contracts have traditionally played a critical role in ensuring energy security. These agreements provide stability and predictability for suppliers and consumers by locking in supply volumes and prices over an extended period. This approach is especially valuable in mitigating risks associated with market volatility, ensuring uninterrupted energy flows, and supporting infrastructure investments.

On the other hand, a notable shift towards shorter-term contracts has been observed in recent years. This trend reflects an increasing preference for flexibility among market participants. Shorter-term agreements allow buyers and sellers to adapt quickly to changing market conditions, price fluctuations, and evolving policy landscapes. They also enable consumers to take advantage of spot market opportunities and integrate new sources of energy into their portfolios more dynamically.

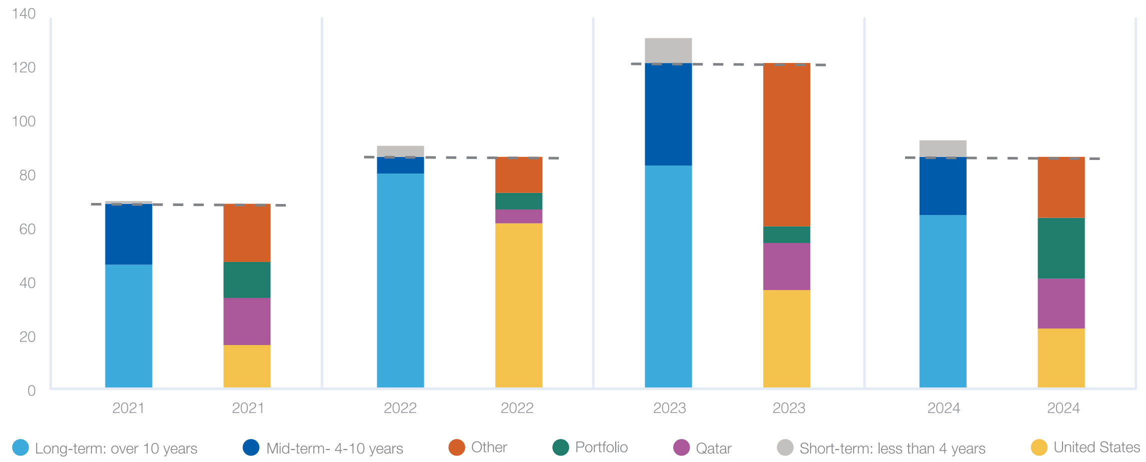
These contrasting approaches - prioritising long-term stability versus spot and short-term adaptability - highlight the complexity of managing energy security in an era of rapid change and uncertainty. Both strategies have merits and are likely to coexist, reflecting the diverse needs and priorities of stakeholders in the global energy landscape.

Longer-term security

In 2023, long- and mid-term LNG contracting reached its peak, with volumes rising to 121 Mtpa from 69 Mtpa in 2021 (Figure 1). This surge was largely driven by increased commitments from the United States, as well as from 'Other' suppliers, notably Trinidad and Tobago, Indonesia, Mexico, and Oman. This surge reflected strong demand for supply security amid market uncertainties. However, in 2024, contracted volumes declined to 85 Mtpa, signalling a growing preference for flexibility in LNG procurement. The United States played a leading role in shaping this trend, with its contracted volumes skyrocketing from 16.5 Mtpa in 2021 to 60.9 Mtpa in 2022, before tapering off in subsequent years. Meanwhile, portfolio supply, which had been minimal until 2024, is now expanding as buyers adopt more flexible sourcing strategies. This shift away from long-term commitments highlights an increasing reliance on short-

Figure 1

LNG contracts* by duration and by source, 2021-2024 (Mtpa)



Source: GECF Secretariat based on data from the GECF GGM, Wood Mackenzie
*Note: * LNG contracts include Sales and Purchase Agreements (SPAs), Heads of Agreements (HOAs), Secondary Contracts with Renewal Provisions, secondary contracts anticipating renewal, Memorandums of Understanding (MOUs).*

term and spot markets, balancing the need for security of supply with market adaptability.

The duration of LNG contracts has undergone a significant shift over the past decade, with the LNG market now experiencing a shift back toward longer-term contracts, with durations once again exceeding 16 years. In 2012-2013, most LNG contracts typically lasted between 16 and 20 years or even longer. However, between 2020 and 2021, there was a noticeable shift towards shorter contract terms ranging from 6 to 10 years. Examples of such contracts include those signed by QatarEnergy with portfolio traders like Vitol and Shell and major Chinese oil and gas companies such as Sinopec. However, following the energy crisis of 2021-2023, energy supply security has become a key priority for both governments and buyers, prompting a return to longer-term contracts in the LNG market. Energy security concerns and the energy crisis prompted some buyers to secure long-term contracts, particularly between the United States and China, as well as Qatar and the Asia Pacific region. Before the 2021-2022 energy crisis, the duration of Asian long-term LNG contracts shortened from 15-20 years to 10-15 years due to rising market uncertainty. However, supply security has become a key concern since then, driving a significant rise in long-term contracts lasting over 15 years.

Long-term LNG contracts remain the standard in Asia, particularly among established buyers with stable demand profiles. However, only China has committed to imports under contracts exceeding 20 years, set to begin in 2025/2026.

Chinese buyers have led the LNG contracting market in 2021-2023, as Chinese buyers have secured substantial volumes of LNG, particularly for volumes from new projects in the United States and Qatar. Between 2021 and 2023, China entered into approximately 67 Mtpa of LNG contracts, with 61 Mtpa of these being long-term agreements averaging 18 years in duration. By 2026, Chinese companies are projected to secure over 100 Mtpa of LNG supply through contracts.

In 2024, Chinese buyers slowed their LNG contracting, being well-supplied for the coming years and selective on terms and prices. In contrast, Indian buyers re-entered the long-term market, attracted by declining oil-linked slopes. While Indian companies can still secure contracts over 20 years, Japanese and Korean importers remain cautious about such long commitments.

QatarEnergy and ADNOC from the Middle East and United States LNG producers maintained strong momentum throughout 2023 and 2024. QatarEnergy continued to prefer long-term, large-scale contracts and has successfully secured agreements primarily with Asian buyers. Between 2020 and 2024, QatarEnergy signed long-term Sales and Purchase Agreements (SPAs) totaling 67 Mtpa. During this period, the only short-term contract (less than 10 years) was signed in 2021 between Vitol and Petrobangla for 1.25 Mtpa, with an eight-year duration. QatarEnergy has also signed equity-linked offtake agreements with Shell, TotalEnergies, ConocoPhillips, and Eni, with volumes to be supplied from Qatar's North Field LNG developments.

Shorter-term flexibility

With increasing liquidity in gas and LNG markets, buyers are turning to shorter-term commitments to meet their needs. This trend toward shorter contracts offers greater flexibility, allowing both buyers and sellers to adapt more swiftly to market volatility.

In 2023, global LNG trade exceeded 408 Mt, with spot and short-term imports rising to 35% of total trade from 19% in 2010.

Unlike Asia Pacific, nearly half of Europe's LNG trade is conducted through spot and short-term agreements, with many long-term volumes structured as flexible portfolio contracts allowing for diversion. The share of spot trade in Europe has grown significantly, increasing from 20% in 2010 to 46% in 2022.

European buyers favour LNG agreements with durations of less than 10 years, reflecting their commitment to transitioning from hydrocarbons to renewable energy. Contracts exceeding 15 years, especially those with DES terms, are less attractive, leading to limited interest from European players in signing new long-term deals with Middle Eastern suppliers for DES volumes.

Amid the recent energy crisis, European players have signed a series of long-term LNG contracts, though often for relatively small quantities. Notable examples include Centrica's agreement with Coterra Energy (Delfin LNG), EnBW and SEFE LNG's deals with Venture Global LNG, and contracts signed by PKN ORLEN and ENGIE with Sempra Infrastructure. Additionally, Galp Energia and ENGIE have entered into agreements with NextDecade. These FOB contracts with U.S.-based projects provide European buyers with significant flexibility, enabling them to divert LNG shipments to other markets, such as Asia or Latin America. Meanwhile, European buyers have also secured long-term contracts with Middle Eastern suppliers, including QatarEnergy, Oman LNG, and ADNOC, primarily on a DES basis. Since 2023, FOB oil-linked contracts have been traded at a slight premium, reflecting an increasing demand for flexible volumes.

In 2023, more than half of LNG volumes traded in the Americas were under spot or short-term agreements. Brazil emerged as the region's largest importer of spot and short-term LNG, driven by fluctuations in hydroelectric power generation, which significantly influenced gas-fired power production. The area is anticipated to rely heavily on spot and short-term deals to meet a considerable portion of its gas and LNG needs over the forecast period.

The LNG business model is experiencing a shift in the seller landscape. Integrated energy companies like Shell and TotalEnergies and major trading firms such as Gunvor and Vitol are increasingly prominent. These players can secure long-term LNG supplies while offering buyers greater flexibility through a range of contract durations for LNG.

Maintaining a diverse portfolio of contract durations allows gas exporters to adapt to shifting market dynamics and buyer preferences while managing economic and regulatory risks. Diversifying into multiple markets is crucial for LNG producers, as dependence on a single market with long-term contracts increases vulnerability to geopolitical risks.

Before the energy crisis, the Asian LNG market commanded higher prices. However, the European market now demands a premium, creating lucrative arbitrage opportunities for traders and aggregators. The ability to flexibly shift LNG cargoes between these markets is now paramount for long-term supply agreements. Major players are acquiring substantial United States LNG volumes, positioning themselves to capitalise on this dynamic. They initially plan to supply Europe and pivot towards Asia as European demand moderates and Asian demand rebounds.

Building LNG trading capabilities allows for greater involvement in the spot and short-term LNG markets, enabling sellers to manage and optimise their supplies more effectively. Prominent examples of this strategy on the seller side include QatarEnergy, ADNOC, and similar companies.

Conclusions

In today's dynamic LNG market, it is crucial for buyers and sellers to maintain a balanced approach to long-term and short-term contracts.

LNG exporters can maintain a competitive edge by structuring portfolios that include a mix of long-term, mid-term, and short-term contracts. This adaptability enables them to respond effectively to shifting market dynamics and evolving buyer preferences. Moreover, diversifying their buyer base across multiple markets reduces vulnerability to geopolitical risks, an essential consideration for LNG producers.

To further enhance their market positioning, LNG producers and sellers can explore developing LNG trading capabilities for active participation in spot and short-term markets. Examples such as Qatar Energy Trading, ADNOC Trading's LNG desk, and Oman's OQ Trading highlight the strategic advantages of this approach. These initiatives provide additional revenue streams and offer sellers the flexibility to optimise their LNG cargo sales, positioning them to capitalise on long-term stability and short-term opportunities.

- The LNG market is characterised by evolving buyer preferences and increasing demand for flexibility.
- Sellers can leverage this dynamic by diversifying their contract portfolio and actively participating in spot and short-term markets.
- Developing in-house trading capabilities is crucial for LNG exporters to optimise their LNG sales and effectively navigate the evolving market landscape.

6.2.1 Pipeline natural gas trade outlook

Global pipeline gas trade is projected to decline by 78 bcm between 2023 and 2030, primarily impacting Europe's gas market, which has been a dominant force in global pipeline imports. While a modest recovery in pipeline trade is expected in the long term, this will be largely offset by a shift in Eurasia's export flows, as gas previously destined for Europe is increasingly redirected to the Asia Pacific region, particularly China, via new pipeline routes from Russia and Turkmenistan.

Europe remains the largest market for pipeline gas trade, accounting for 44% of global pipeline gas imports in 2023. Five key suppliers - Norway, Russia, Algeria, Azerbaijan, and Libya - play a crucial role in meeting regional demand. However, Europe's import structure has undergone a rapid transformation, with pipeline imports from Russia falling drastically from 63 bcm in 2022 to just 27 bcm in 2023. Norway, already operating near its maximum production capacity, remained Europe's top supplier, followed by Algeria and Russia.

Europe's dominance in global pipeline gas trade is expected to decline significantly by 2050, with its share projected to fall from 44% in 2023 to just 18% by mid-century. European pipeline imports are forecast to drop by over 136 bcm to approximately 118 bcm during 2023-2050 as the region continues to prioritise renewables, energy efficiency, and also due to deindustrialisation as energy-intensive industries are at a disadvantage caused by the large energy price differential with the United States. Meanwhile, North America, Asia Pacific, and Eurasia are anticipated to see growing shares in global pipeline trade as regional trade flows continue to shift.

Europe's options for increasing pipeline gas imports in the short term remain limited. Norway's production was already near peak levels in 2022-2023, leaving little room for further supply expansion. Algeria could provide additional pipeline gas with new developments in the Berkine South basin. Azerbaijan could expand supply in the mid-term as the country further expands the Caspian Shah Deniz field and the Azeri-Chirag-Deepwater Gunashli (ACG).

While Europe's pipeline imports are shrinking, **Asia Pacific's share of global pipeline gas imports are expected to grow by 2.4 times, rising from 11% in 2023 to 24% by 2050.** This reflects an increase of around 88 bcm in annual pipeline imports, solidifying China's role as the dominant importer, with a projected 70% share of the region's total pipeline imports. China imported 23 bcm from Russia, and 33 bcm from Turkmenistan in 2023, and its total pipeline imports are expected to grow more than 2.6 times to 150 bcm by 2050.

The Power of Siberia 1 pipeline has played a key role in increasing Russian gas exports to China, with the full capacity of 38 bcm per annum expected to be reached by 2025. Russia's Far East pipeline (10 bcma) is set to boost supplies further. Furthermore, the planned Power of Siberia 2 pipeline (50 bcma) is expected to substantially expand Russian gas exports to China in the long term.

China is also actively diversifying its pipeline gas supply sources in Central Asia. Turkmenistan remains China's largest gas supplier via the Central Asia-China Gas Pipeline corridor (Lines A, B, and C), which has a combined capacity of 55 bcma. Plans for the Central Asia-China Gas Pipeline D (30 bcma) are set to significantly increase deliveries to western China, enhancing the country's energy security.

Eurasia is expected to play an increasingly dominant role in the global pipeline gas trade, with its share of global exports rising from 30% in 2023 to 55% by 2050. Simultaneously, Eurasia's import role is set to expand, making it the third-largest gross importer of pipeline gas by mid-century, with its share of imports tripling to 21%. Rising domestic energy demand in Uzbekistan and Kazakhstan, driven by industrial expansion and urbanisation, is expected to reduce their export volumes or necessitate higher imports. Uzbekistan's pipeline imports are projected to reach 57 bcm by 2050.

North America is expected to account for 31% share of gross pipeline gas exports in 2050, supported by expanding cross-border trade between the United States and Mexico. The United States pipeline gas exports to Mexico are projected to grow from 63 bcm in 2023 to nearly 110 bcm by 2050, a 75% increase, reinforcing the strong energy integration within North America.

The North American pipeline gas market experienced strong growth in 2023, closely linked to the expansion of the United States LNG exports. As the world's leading LNG exporter, the United States relies heavily on its extensive pipeline network to support both domestic demand and LNG exports. Investments in new and expanded liquefaction facilities in Canada, the United States, and Mexico will further strengthen the region's role in global gas trade. The continued development of cross-border infrastructure will solidify North America's position as a key supplier of both pipeline and LNG exports.

6.2.2 LNG imports outlook

Global LNG imports are projected to increase by 392 Mt, nearly doubling to 800 Mt by 2050. This growth reflects LNG's expanding role in global energy security and flexibility, particularly as regions shift to integrate more LNG infrastructure into their supply mix (Table 6.1).

Despite accounting for 64% of global LNG imports in 2023, Asia Pacific is set to further solidify its

Table 6.1

Global LNG imports outlook by region, 2023-2050

	Levels (Mt)				Change (Mt)	Growth (% p.a.)	Share (%)	
	2023	2030	2040	2050	2023-2050	2023-2050	2023	2050
Africa	0	13	21	32	32	-	0%	4%
Asia Pacific	262	405	510	605	343	3%	64%	76%
Eurasia	0	2	0	1	1	-	0%	0%
Europe	127	126	118	105	-22	-1%	31%	13%
Latin America	11	17	31	41	30	5%	3%	5%
Middle East	7	12	12	14	7	2%	2%	2%
North America	1	2	3	2	1	2%	0%	0%
Total	**408**	**577**	**695**	**800**	**392**	**2%**	**100%**	**100%**

Source: GECF Secretariat based on data from the GECF GGM

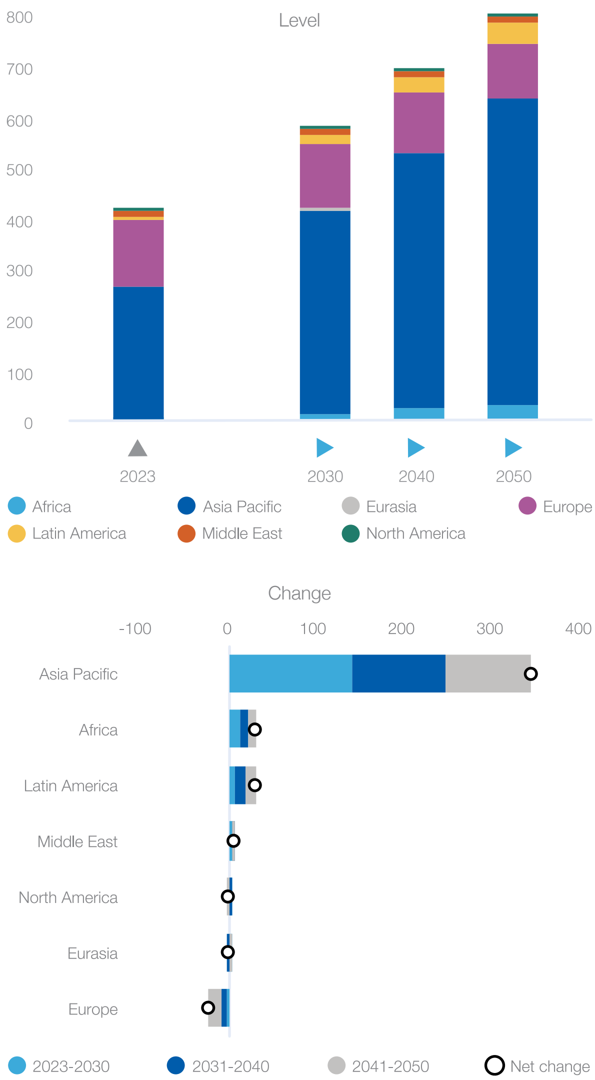
dominance in the LNG market, with its share rising to 76% by 2050. This sustained growth is driven by strong economic expansion, industrialisation, coal-to-gas switching, and energy security priorities in key importers such as China, India, Japan, South Korea, and emerging Southeast Asian markets. However, while LNG demand in the Asia Pacific is projected to increase significantly, the overall growth rate of natural gas imports in the region is expected to decelerate over the long term. This slowdown is reflected in the RCS projection, which indicates a moderation in LNG import growth over the next 27 years, largely due to greater energy efficiency, increased domestic gas production in some countries, and stronger competition from renewables.

Nevertheless, the Asia Pacific region is expected to remain the primary driver of global LNG trade, accounting for nearly 88% of the net increase in global LNG imports over the forecast period (Figure 6.4). This underscores Asia Pacific's central role in shaping future LNG demand patterns, with the region becoming the key destination for LNG cargoes, reinforcing its strategic importance for global exporters. The scale of this transformation will require substantial investments in LNG regasification capacity, infrastructure expansion, and long-term supply agreements, positioning Asia Pacific as the focal point of global LNG trade well into 2050.

In contrast, **Europe, which accounted for nearly 31% of global LNG imports in 2023, is projected to experience a sharp decline in its share of LNG trade by mid-century, maintaining only a 13% share in 2050.** This stagnation reflects the region's ongoing transition toward renewables, advancements in energy efficiency, and policies aimed at reducing dependence on fossil fuels. With natural gas production from mature fields in steady decline, LNG will continue to play a role in energy security and seasonal flexibility, but the overall trajectory points toward a gradual reduction in demand.

Figure 6.4

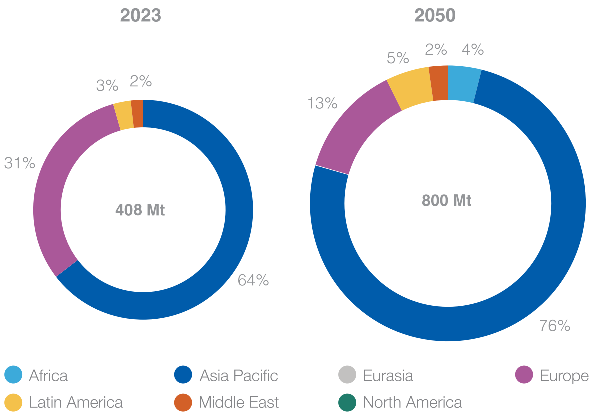
Global LNG imports outlook by region, 2023-2050 (Mt LNG)



Source: GECF Secretariat based on data from the GECF GGM

Figure 6.5

Global LNG imports market share outlook by region, 2023-2050 (%)



Source: GECF Secretariat based on data from the GECF GGM

As European countries intensify their decarbonisation efforts, including electrification and hydrogen adoption, the pace of LNG demand decline is expected to accelerate in the coming years.

Most regions outside Asia Pacific and Europe are not expected to contribute substantially to global LNG imports. However, Latin America stands out as an exception, with the region anticipating a steady increase in LNG demand over the coming decades.

By 2050, Latin America's share in global LNG imports will rise from 3% in 2023 to 5%, equivalent to an additional 30 Mt of LNG imports (Figure 6.5). This growing demand will be primarily met by supplies from the United States, reinforcing North America's role as a key LNG supplier to the region. Infrastructure expansion, increasing natural gas demand for power generation, and the need to complement intermittent renewables are expected to be the main drivers behind Latin America's rising LNG imports, positioning the region as an emerging LNG growth market within the evolving global energy landscape.

6.2.3 LNG exports outlook

LNG exports are projected to expand significantly over the next three decades. The number of LNG-exporting countries is expected to rise from the current 22 to 27 countries by 2050, leading to a more diversified supply landscape, with North America emerging as the dominant LNG-exporting region by mid-century.

With the largest contribution to global LNG exports by 2050, North America is set to surpass both Asia Pacific and the Middle East, establishing itself as the leading LNG-exporting region. By mid-century, North America's share in global LNG exports is projected to reach 27%, up from 21% in 2023 (Table 6.2). The region is expected to increase its LNG exports by around 134 Mt, accounting for one-third of the global supply increase over the forecast period (Figure 6.6). This expansion will be driven primarily by the United States, with Canada and Mexico contributing to the region's growing export capacity. The continued development of LNG infrastructure, increased liquefaction capacity, and long-term supply agreements with key importing regions will solidify North America's role as a critical player in global LNG trade.

The Middle East is set to follow closely behind North America, with its share of global LNG exports projected to reach 25% by 2050, compared to 24% in 2023. The region is expected to increase its LNG exports by approximately 106 Mt, accounting for 27% of the global LNG supply increase over the forecast period. A significant portion of this growth is expected within

Table 6.2

Global LNG exports outlook by region, 2023-2050

	Levels (Mt)				Change (Mt)	Growth (% p.a.)	Share (%)	
	2023	2030	2040	2050	2023-2050	2023-2050	2023	2050
Africa	40	60	107	118	78	4%	10%	15%
Asia Pacific	136	124	118	112	-24	-1%	33%	14%
Eurasia	31	57	80	125	94	-	8%	16%
Europe	7	8	9	10	3	2%	2%	1%
Latin America	13	13	14	15	2	1%	3%	2%
Middle East	96	151	163	202	106	3%	23%	25%
North America	85	164	204	218	133	3%	21%	27%
Total	**408**	**577**	**695**	**800**	**392**	**2%**	**100%**	**100%**

Source: GECF Secretariat based on data from the GECF GGM

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the current decade, supported by major investments in Oman, Qatar, and the UAE. Qatar, already a leading LNG exporter, is expanding its liquefaction capacity through the North Field East and North Field South projects, while the UAE and Oman are ramping up production to meet growing global demand. These investments will further strengthen the Middle East's position as a key LNG supplier, particularly to Asia Pacific and Europe, reinforcing its strategic importance in the evolving global LNG market.

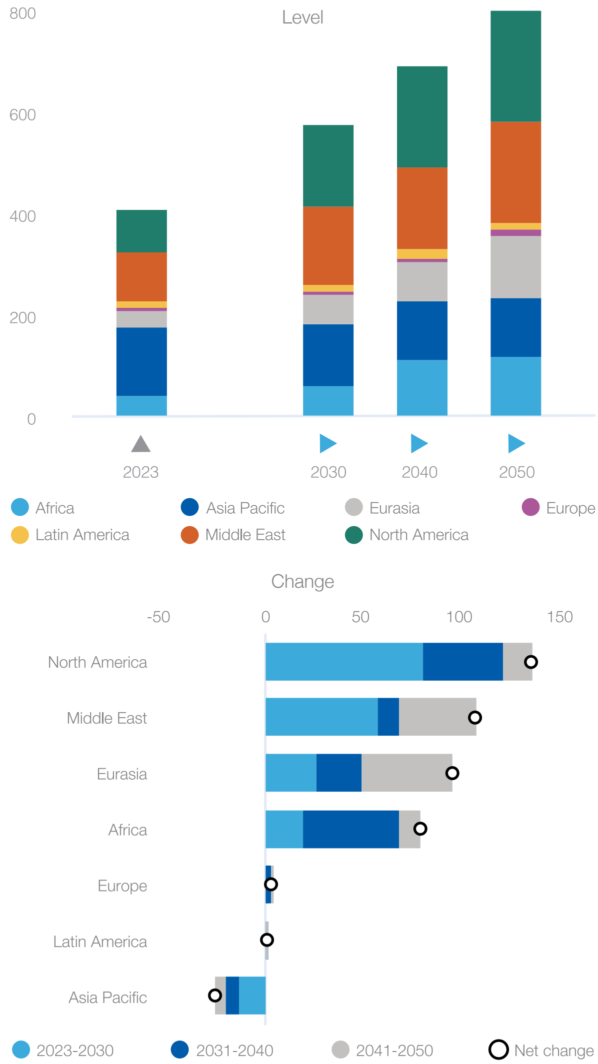
Eurasia and Africa are emerging as key growth regions in global LNG exports, with both regions expected to significantly expand their contributions to global supply over the forecast period. While capturing just 8% of the global LNG export market, Eurasia is projected to experience a rapid expansion, with its share doubling to 16% by 2050. Eurasia's LNG exports are set to increase by 94 Mt by mid-century, accounting for 24% of the total global LNG supply growth during the forecast period. As illustrated in Figure 6.6, a substantial portion of this growth is expected to materialise in the later decades, reflecting an accelerating trend as new liquefaction capacity comes online. This expansion is expected to be driven by Russia, which is actively developing LNG infrastructure to diversify its export routes and shift trade flows toward Asia, particularly China and India. Investments in Arctic LNG projects, the expansion of Yamal LNG, and the development of new liquefaction plants along Russia's eastern coast will be key factors in Eurasia's rising role as an LNG exporter.

Africa, particularly Sub-Saharan Africa, is also set to see a substantial increase in LNG exports, leveraging its vast untapped natural gas reserves. Currently accounting for 10% of global LNG exports, Africa's share is projected to rise to 15% by 2050, reflecting its growing role in supplying Asian and European markets. The region's LNG exports are expected to increase by 78 Mt by mid-century, contributing one-fifth of the total global LNG supply increase over the forecast period. Much of this growth is anticipated during the 2030s as investments in Angola, Mauritania, Mozambique, Nigeria, and Senegal drive new liquefaction capacity. Ongoing infrastructure development, improved investment climates, and growing partnerships with global energy companies will be crucial in unlocking Africa's full LNG export potential. Given the continent's proximity to European and Asian demand centres, Africa is well-positioned to play an increasingly strategic role in the global LNG trade, offering a diverse and flexible supply source in an evolving energy landscape.

In 2023, twelve of the twenty LNG suppliers were GECF member countries, collectively supplying 193 Mt of LNG and meeting 47% of global LNG demand. LNG trade is poised for significant growth among GECF member countries over the forecast period. This trend is driven by financial and technological advancements, making LNG more accessible to new consumers. As global natural

Figure 6.6

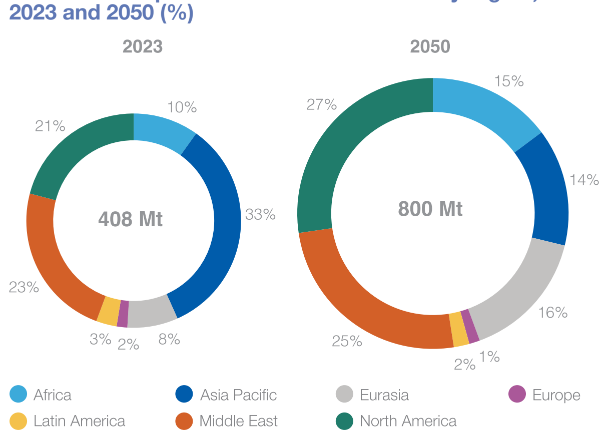
Global LNG exports outlook by region, 2023-2050 (Mt LNG)



Source: GECF Secretariat based on data from the GECF GGM

Figure 6.7

Global LNG exports market share outlook by region, 2023 and 2050 (%)



Source: GECF Secretariat based on data from the GECF GGM

gas demand increases, LNG is emerging as a strategic commodity, influencing the political and economic landscapes of gas-producing countries. **Projections indicate that LNG exports from GECF member countries will reach approximately 445 Mt by 2050, accounting for 56% of global LNG exports.**

A major structural shift in the global LNG export market is the projected decline in LNG supply from Asia Pacific, which has historically been one of the leading LNG-exporting regions. As the only region expected to experience a decrease in LNG exports, Asia Pacific's LNG exports are forecast to fall by 24 Mt by 2050, resulting in a significant loss of market share, from 33% in 2023 to just 14% by mid-century. This contraction will be driven by the depletion of mature gas fields, shifting domestic energy priorities, and rising domestic demand in key LNG-exporting countries such as Australia and Indonesia.

As a result, **Asia Pacific will increasingly rely on LNG imports from other regions, particularly the Middle East, North America, and Eurasia, to meet its growing energy needs.** This increased dependency on external suppliers will reinforce long-term LNG trade relationships and accelerate investment in import infrastructure and long-term contracts to ensure supply security for the region's industrial and power sectors.

In contrast, Europe and Latin America are not expected to play a significant role in LNG exports over the forecast period. Their share of global LNG exports is projected to remain stable by approximately 1% and 2% respectively by 2050 (Figure 6.7). Limited new liquefaction capacity, high domestic gas demand, and policy-driven shifts toward renewable energy will constrain Europe's ability to expand LNG exports. In contrast, Latin America's natural gas production will be primarily directed toward meeting regional consumption rather than large-scale 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 also expected to undergo significant reconfiguration. As outlined, Asia Pacific and Europe will remain the primary LNG-importing regions in the coming decades, with Asia Pacific's share rising as Europe's demand declines. This transformation will reshape LNG trade flows, altering traditional supply dependencies.

Table 6.3 presents regional LNG net imports from 2023 to 2050, highlighting significant shifts in trade dynamics. **The Asia Pacific region is set to continue to lead in LNG imports, with net imports increasing nearly fourfold from 126 Mt in 2023 to 495 Mt by 2050.** In contrast, Europe sees a slight decline in net imports, from 120 Mt in 2023 to 95 Mt in 2050. **Other regions, including Africa, Eurasia, the Middle East, and North America, continue to be net exporters, with North America and the Middle East experiencing the largest growth in net exports, at 133 Mt and 99 Mt, respectively.** Latin America is the only other region with positive net imports, increasing by 28Mt.

In 2023, as illustrated in Figure 6.8, nearly 52% of Asia Pacific's LNG imports were sourced within the region, reflecting the region's reliance on domestic LNG production, primarily from Australia and Indonesia. The Middle East accounted for nearly 29% of Asia Pacific's LNG supply, followed by North America (8%), Eurasia (6%) and Africa (4%). However, with the anticipated increase in LNG imports and the decline in regional LNG production, this sourcing pattern is set to shift significantly over the coming decades.

Asia Pacific's intraregional LNG sourcing is expected to decline sharply, dropping to just 18% by 2050. This decline will be compensated by a substantial rise in LNG imports from other regions, with the Middle East, North America, and Eurasia emerging as dominant suppliers. By 2050, the Middle East is projected to supply 29% of Asia Pacific's LNG imports followed by North America at 23%, Eurasia at 18% and Africa at 12% (Figure 6.9). These shifts underscore the increasing diversification of LNG supply sources in the Asia Pacific as the region turns to long-term contracts and expanded LNG infrastructure to secure reliable gas supplies in a rapidly evolving global market.

As the second-largest LNG import market, Europe

Table 6.3
Regional LNG net imports, 2023-2050 (Mt)

	2023	2030	2040	2050	Change, 2023-2050
Africa	-40	-47	-86	-87	**-47**
Asia Pacific	126	281	393	495	**369**
Eurasia	-31	-54	-80	-124	**-93**
Europe	120	118	109	95	**-25**
Latin America	-2	4	18	26	**28**
Middle East	-89	-140	-152	-188	**-99**
North America	-84	-162	-202	-217	**-133**

Source: GECF Secretariat based on data from the GECF GGM

Figure 6.8

LNG flows outlook by region, 2023 (Mt LNG)

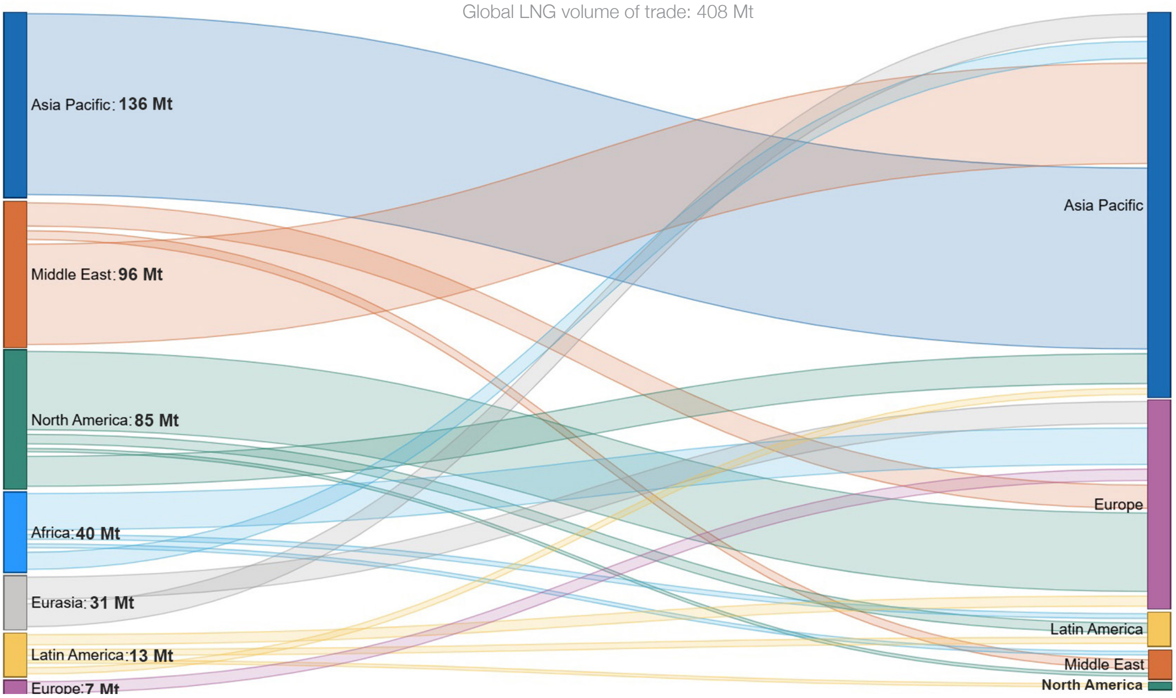
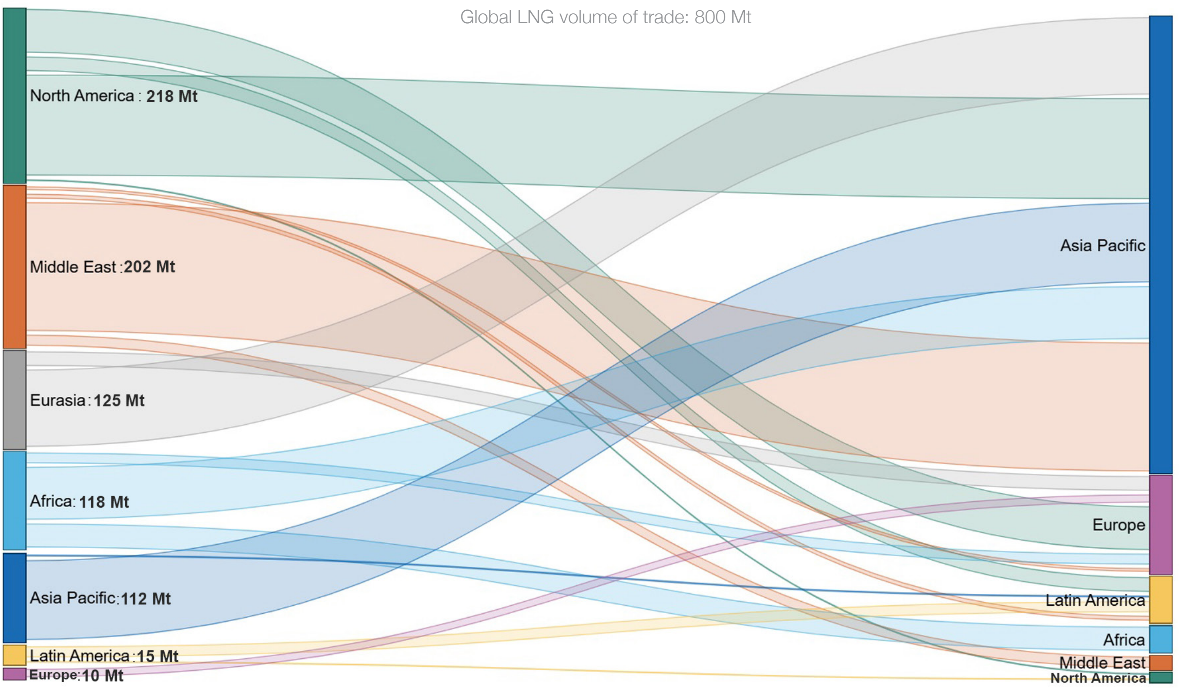


Figure 6.9

LNG flows outlook by region, 2050 (Mt LNG)



Source: GECF Secretariat based on data from the GECF GGM

sourced nearly 47% of its LNG demand from North America in 2023, making it the region's largest supplier. In 2023, Africa was the second-largest LNG supplier, accounting for 21% of Europe's LNG imports, while the Middle East and Eurasia contributed 13% and 12%, respectively. **By 2050, North America is expected to strengthen its dominance in the European LNG market, supplying 57% of the region's imports**. Eurasia and Africa are projected to provide 18% and 13%, respectively, while the Middle East will primarily direct most of its LNG exports to the Asia Pacific market.

In 2023, Africa did not import any LNG. However, by 2050, the region is expected to import approximately 32 Mt of LNG, with all supplies sourced from within Africa. This shift will be driven by the continent's rising natural gas demand, fueled by rapid population growth, urbanisation, and expanding economic activity.

In brief, the Asia Pacific is set to continue to be the main driver of LNG demand growth, gradually shifting away from intraregional imports in favor of supplies from North America, the Middle East, Eurasia, and Africa. Meanwhile, Europe is expected to deepen its reliance on transatlantic LNG imports from North America.

6.3 Natural gas trade balance outlook

The RCS projections indicate that while global natural gas demand and trade volumes are expected to grow significantly by mid-century, the fundamental structure of net importing and exporting regions will largely remain intact. However, substantial structural shifts are anticipated within each region, driven by changing supply dynamics, evolving energy policies, and shifting geopolitical influences.

The only major exception to this stability is **Latin America**, projected to transition from a net natural gas exporter to a net importer by 2050. This shift will be primarily driven by rising domestic demand, particularly for power generation, industrial applications, and household consumption. As regional production fails to keep pace with surging energy needs, Latin America is expected to increase its reliance on LNG imports, with North America emerging as its primary supplier.

By 2050, **Asia Pacific**'s net imports are projected to surge by approximately 619 bcm compared to 2023 (Table 6.4), reinforcing its dominant role as the primary driver of global LNG trade growth. With declining domestic production and increasing energy demand, Asia Pacific's reliance on interregional imports will deepen, leading to greater dependence on suppliers from North America, the Middle East, and Eurasia.

In contrast, **Europe** is projected to experience a decline in net natural gas imports, with volumes decreasing by 36 bcm by 2050. This decline reflects Europe's continued shift toward renewables, improved energy efficiency, and reduced industrial gas consumption. While natural gas will still play a role in balancing intermittent renewables and ensuring supply security, Europe's overall reliance on external gas supplies will diminish, signalling a structural shift in the region's energy landscape.

On the export side, **North America** is projected to experience the largest net export growth, with net exports reaching 300 bcm by 2050, an increase of 185 bcm from 2023 levels. This expansion will be driven primarily by the United States, followed by Canada and Mexico, reinforcing North America's role as a leading supplier to Asia Pacific and Europe. Growing LNG capacity, expanding liquefaction infrastructure, and deepening long-term supply agreements will support this upward trajectory.

Eurasia is expected to hold the largest net export volume by 2050, with net exports reaching 388 bcm, representing an increase of nearly 192 bcm from 2023. This growth will be driven by Russia's expanding LNG production and pipeline gas exports to Asia, particularly China. As Russia diversifies its energy partnerships away from Europe, its increasing LNG capacity and enhanced pipeline infrastructure will play a central role in meeting Asia's rising gas demand.

Table 6.4

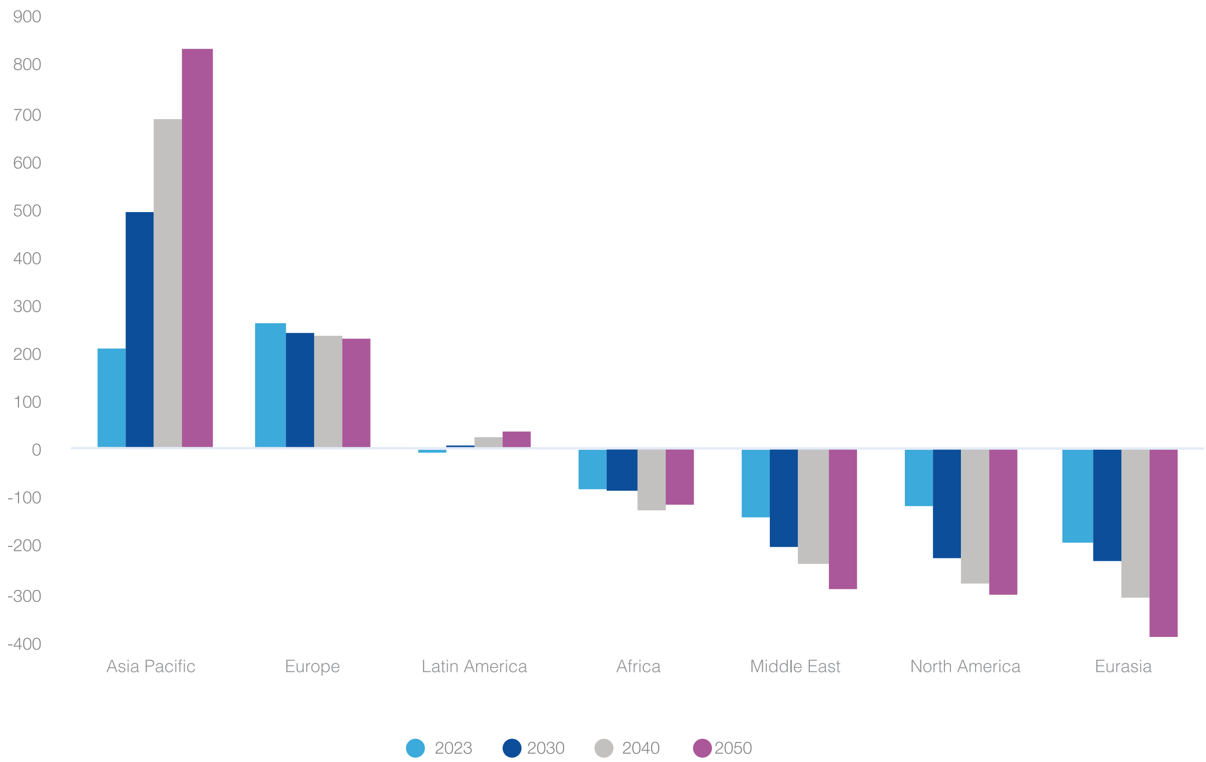
Regional natural gas balance (net imports) outlook, 2023-2050 (bcm)

	2023	2030	2040	2050	Change, 2023-2050
Africa	-82	-84	-127	-117	-35
Asia Pacific	211	494	687	830	619
Eurasia	-196	-230	-307	-388	-192
Europe	265	243	237	229	-36
Latin America	-2	5	24	36	38
Middle East	-139	-205	-235	-290	-151
North America	-115	-223	-279	-300	-185

Source: GECF Secretariat based on data from the GECF GGM

Figure 6.10

Regional natural gas balance (net imports) outlook, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

The **Middle East** follows closely, with net exports projected to rise by 151 bcm, reaching 290 bcm by 2050. This increase will be underpinned by Qatar's LNG expansion projects and growing contributions from the UAE and Oman, reinforcing the Middle East's long-term role as a key LNG supplier to Asia and Europe.

While **Africa**'s net gas exports are expected to grow significantly through 2040, rising domestic natural gas consumption is projected to moderate net exports by 2050. Natural gas is set to play a critical role in Africa's industrialisation and economic development, particularly in power generation, manufacturing, and petrochemical industries. As a result, Africa's net gas exports are expected to decline slightly after 2040, settling at 117 bcm by 2050. This shift highlights the increasing role of natural gas in supporting Africa's economic transformation, as more gas is retained for domestic use rather than exports.

As depicted in Figure 6.10, these regional shifts in net importing and exporting patterns illustrate the evolving structure of natural gas markets, where Asia Pacific's rising import demand is counterbalanced by increasing exports from North America, Eurasia, and the Middle East. At the same time, Europe and Latin America undergo structural changes in their energy supply strategies. The realignment of supply-demand balances and the diversification of energy partnerships will shape the long-term trajectory of global natural gas trade.

6.4 Natural gas trade infrastructure prospects

Investments in pipeline and LNG infrastructure are projected to grow steadily through 2050. Until 2030, spending will primarily target expanding liquefaction and regasification capacities, with growth expected to slow after 2040. Export pipeline development is forecast to continue until 2050, especially in Eurasia and the Asia Pacific region.

6.4.1 LNG liquefaction

By the end of 2023, the global liquefaction capacity reached 463 Mtpa, including the addition of 12 Mtpa of floating liquefaction units (FLNG). In 2023, Indonesia's 3.8 Mtpa Tangguh Train 3 commenced operations. In spring 2024, the Republic of the Congo (Brazzaville) entered the LNG export market for the first time by launching a 0.7 Mtpa FLNG project using the Tango FLNG barge. That same year, Mexico commenced operations at the 1.4 Mtpa Altamira Fast LNG facility.

In 2023, final investment decisions (FIDs) were

made for four liquefaction projects with a combined capacity of approximately 38 Mtpa. These include three projects in the United States: the 6.7 Mtpa Plaquemines LNG Phase II, the 13 Mtpa Port Arthur Trains 1 and 2, and the 17.5 Mtpa Rio Grande LNG Phase I, alongside a smaller-scale project in Gabon, the 0.7 Mtpa Cap Lopez LNG.

By 2023, more than 55 Mtpa of new LNG capacity had been approved, adding to over 200 Mtpa of LNG supply already under construction. This significant expansion comfortably positions the market to meet demand through 2030. However, the rapid increase in production capacity raises concerns about potential oversupply in the coming years, which could lead to further price declines.

Looking ahead, global LNG liquefaction capacity is projected to reach 1,004 Mtpa by 2050, exceeding the expected LNG supply of approximately 800 Mt. This expansion represents a net increase of nearly 541 Mtpa in liquefaction capacity over the forecast period, highlighting significant infrastructure investments and shifting supply dynamics in key producing regions.

As illustrated in Figure 6.11, **North America and the Middle East are expected to be the primary drivers of this capacity expansion, accounting for 34% and 23% of the global increase by 2050.** North America's expansion will be driven by large-scale LNG projects in the United States, Canada, and Mexico, reinforcing its position as a leading global LNG supplier. Meanwhile, Qatar's North Field expansion and growing contributions from the UAE and Oman will lead to a surge in the capacity of the Middle East.

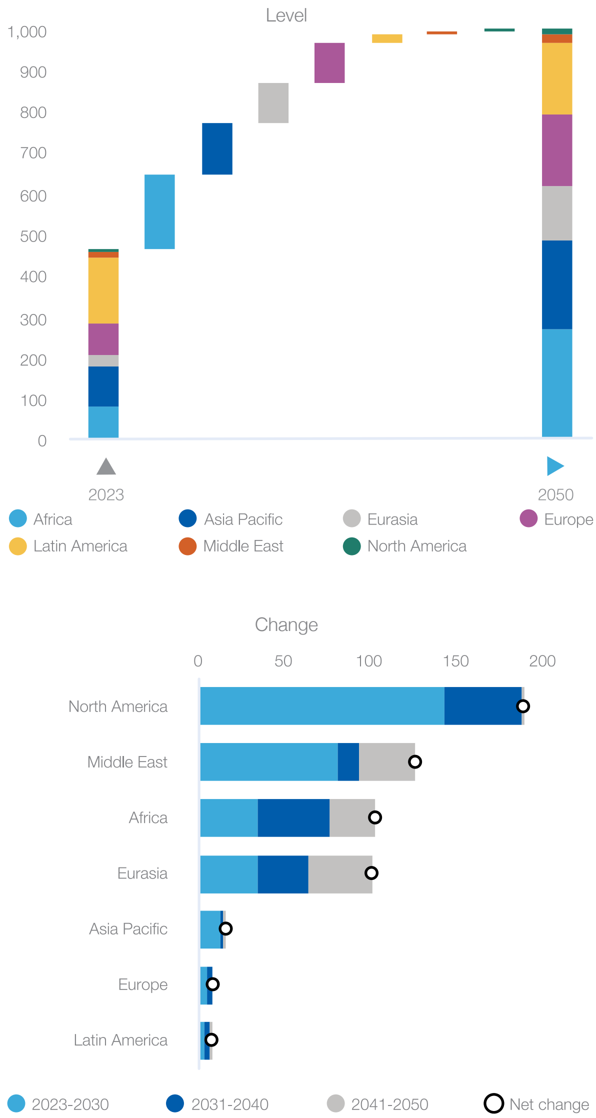
Eurasia and Africa are also set to make substantial contributions, contributing 18% and 19% respectively of the total liquefaction capacity growth. Russia's LNG export ambitions and the development of Arctic LNG projects will drive Eurasia's expansion, while new liquefaction projects in Mozambique, Nigeria, Senegal, and Mauritania will support Africa's rising capacity. These developments will enhance Africa's role as a long-term supplier to Europe and Asia, diversifying global LNG supply sources.

In contrast, Asia Pacific is expected to play a minor role in global liquefaction capacity expansion, contributing just 3% of the total increase by 2050. Despite overtaking the largest existing liquefaction capacity, feed gas constraints due to declining domestic production and maturing gas fields will limit further investments in new projects. As a result, the region is likely to increase its reliance on imported LNG rather than expanding its liquefaction infrastructure.

Over the forecast period, Latin America is projected to add approximately 7 Mtpa of liquefaction capacity, driven by small-scale proposed projects and regional supply diversification efforts. Meanwhile, Europe's liquefaction

Figure 6.11

Global LNG lequefaction capacity outlook by region, 2023-2050 (Mtpa)



Source: GECF Secretariat based on data from the GECF GGM

capacity is expected to remain unchanged, reflecting the region's policy-driven transition away from fossil fuels and its growing dependence on LNG imports rather than domestic production.

As of the end of 2023, GECF member countries had an existing LNG liquefaction capacity of 235 Mtpa, with an additional 119 Mtpa under construction. Collectively, these countries accounted for 51% of the world's total liquefaction capacity. There were also 131 Mtpa of proposed projects and approximately 61 Mtpa of speculative projects. **These developments are projected to increase the total LNG liquefaction capacity of current GECF members countries to**

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about 462 Mtpa by 2050, accounting for 54% of the anticipated global liquefaction capacity.

Between 2024 and 2030, approximately 306 Mtpa of liquefaction capacity is expected to come online, including facilities currently under construction, projects that have reached FID, and those in the commissioning phase as of the end of 2023. This pipeline of projects represents a highly probable capacity expansion, reinforcing global LNG supply growth over the next decade.

North America leads the expansion, accounting for 47% of the total under-construction capacity, with 111 Mtpa currently under construction and an additional 7 Mtpa in the commissioning phase. The Middle East is the second-largest contributor, with 58 Mtpa of liquefaction capacity under construction by 2030. Africa and Eurasia are also poised to expand their LNG production capacity, with Africa adding 29 Mtpa (12% of the total) and Eurasia contributing 33 Mtpa (14%) through projects currently under construction, expected by 2030. Asia Pacific is expected to add 7 Mtpa to the global liquefaction capacity, accounting for a relatively small share of overall growth.

Global LNG liquefaction capacity expansion from 2024 to 2050 follows a shifting regional pattern (6.17). North America leads early growth with 140 Mt by 2030, while the Middle East (79 Mt) contribute significantly. Expansion slows in 2031-2040, with Africa (42 Mt) and Eurasia (30 Mt) taking prominence as North America's growth declines (44 Mt). By 2041-2050, Eurasia (36 Mt), the Middle East (32 Mt), and Africa (27 Mt) drive new capacity. The outlook reflects a strong initial expansion in North America, followed by growing contributions from resource-rich regions in later decades.

This evolving LNG infrastructure development reflects changing market dynamics, investment strategies, and regional energy policies, shaping the global LNG trade trajectory over the next decade.

6.4.2 LNG regasification

By the end of 2023, global regasification capacity reached 1,117 Mtpa, with 17 new terminals commissioned, adding 69 Mtpa of new receiving capacity. This marks significant growth in the global regasification landscape over the past year.

Asia remained the dominant region for capacity expansion, particularly with major increases in China, which added four new terminals and one extension, and India, which opened a new terminal on its West Coast. Floating Storage Regasification Units (FSRUs) played a key role in opening new markets in Hong Kong, Viet Nam, and the Philippines, which now hosts two terminals.

In Europe, the focus was on enhancing capacity through new FSRU-based facilities, with Germany adding three terminals and France, Finland, Italy, and Türkiye each adding one. Additionally, Belgium expanded its facilities, and Spain activated an onshore terminal, further boosting its regasification capabilities.

Global regasification capacity is expected to reach 1,804 Mtpa by the end of the forecast period, driven by LNG import projections, with utilisation rates anticipated to remain around 45%. This marks an increase of 689 Mtpa, highlighting the ongoing expansion of LNG import infrastructure to meet rising demand.

With the rapid expansion of LNG imports, the Asia Pacific region is set to be the main driver of regasification capacity growth, contributing 82% of the total global increase over the forecast period. Most of this growth is expected between 2024 and 2030, adding 355 Mtpa (Figure 6.12). The surge in LNG demand across China, India, Southeast Asia, and emerging economies is prompting significant investments in regasification terminals, ensuring supply security and energy diversification

Europe ranks second in regasification capacity expansion, accounting for 12% of the global increase, or 80 Mtpa. This growth reflects ongoing efforts to diversify gas supply sources, with the majority expected to take place within the current decade. This increase is largely driven by efforts to enhance energy security and build strategic LNG infrastructure. Many European countries have accelerated the development of floating storage and regasification units (FSRUs) and onshore regasification terminals to safeguard against future supply disruptions.

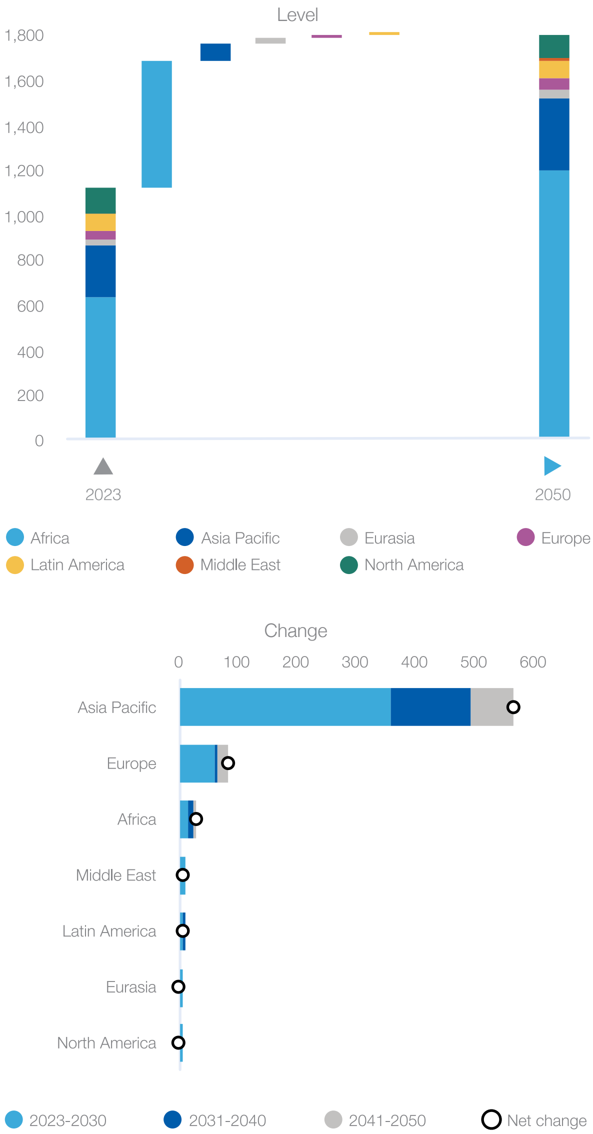
Africa, the Middle East, and Latin America are expected to make comparatively smaller contributions to global regasification expansion, as their natural gas strategies remain focused on domestic production and exports rather than large-scale LNG imports. Africa, the Middle East, and Latin America see moderate increases, with 30 Mtpa, 9 Mtpa, and 6 Mtpa, respectively. However, some investment is anticipated in key markets such as Brazil, South Africa, Bahrain and Kuwait, where LNG imports support growing energy demand.

Eurasia and North America are not projected to expand their regasification capacity throughout the forecast period. North America remains a key LNG exporter, minimizing the necessity for additional regasification infrastructure. Likewise, Eurasia, particularly Russia, focuses on LNG production and exports rather than increasing import capacity.

Regasification capacity projects under construction or in the commissioning phase by the end of 2023 are projected to add 298 Mtpa by 2030. This expansion is heavily concentrated in Asia Pacific, which is expected to account for 81% of the regasification projects under construction increase, reflecting the region's rising LNG demand and efforts to secure long-term supply sources.

Figure 6.12

Global LNG regasification capacity outlook by region, 2023-2050 (Mtpa)



Source: GECF Secretariat based on data from the GECF GGM

Europe ranks second, contributing 15% of the global regasification capacity addition under construction, driven by energy security concerns and diversification away from Russian pipeline gas. The majority of these projects are expected to become operational within the current decade as European countries accelerate investments in onshore terminals and floating storage and regasification units (FSRUs).

This outlook highlights the evolving global LNG landscape, with Asia Pacific and Europe leading regasification infrastructure expansion, while other regions adopt a more targeted approach based on localized demand and strategic priorities. The projections show that the majority of growth will take place before 2040, reflecting global energy transition trends and increasing natural gas demand in emerging economies.

6.5 Natural gas trade outlook by region

6.5.1 Africa

Africa's vast natural gas reserves and strategic geographic location offer a significant opportunity to export LNG to global markets. As LNG market dynamics shift due to geopolitical tensions and energy transitions, Africa is capitalising on its position to strengthen the stability and reliability of the global energy market.

In 2023, Africa's natural gas net exports totalled approximately 82 bcm, with nearly 40 Mtpa (equivalent to 55 bcm), or about 67%, exported as LNG. Africa did not import LNG in 2023. Most LNG exports came from GECF member countries, including Algeria, Angola, Egypt, Equatorial Guinea, Mozambique, and Nigeria, while pipeline exports were largely from Algeria.

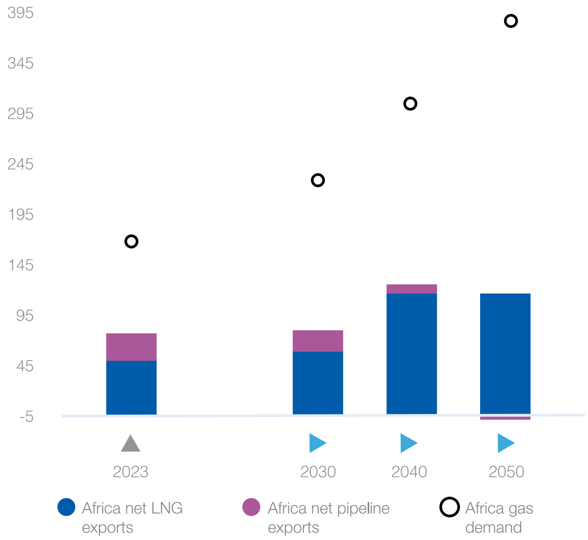
Africa's proximity to Europe and its abundant LNG supply provides a strategic advantage in meeting Europe's energy needs. The RePowerEU plan has further highlighted the critical role of African LNG in Europe. As a result, Africa has become a key player in Europe's efforts to diversify its natural gas sources. In 2023, Algeria supplied 11.7 Mtpa to Europe, while Nigeria became Europe's fifth-largest LNG supplier, delivering 6.9 Mtpa. Algeria and Nigeria ranked as Europe's fourth and fifth-largest LNG suppliers in 2023, respectively.

By 2050, Africa is projected to export approximately 193 bcm of natural gas through pipelines and LNG, with the majority - around 85%, or 163 bcm - expected to be exported as LNG. It is important to note that Africa's net natural gas exports will amount to only 117 bcm due to the anticipated growth of intra-regional gas trade in the long term. (Figure 6.13)

In 2023, Europe accounted for 64% of Africa's total LNG exports, making it the primary destination, followed by Asia Pacific with 28%, while exports to Latin America and the Middle East remained minimal. Over time, Africa's LNG trade is expected to shift significantly toward Asia Pacific, surging nearly sevenfold to 81 Mt by 2040 before experiencing a slight decline by 2050. Meanwhile, exports to Europe are projected to decrease sharply after 2023 and stabilise at 2040 levels onward. Intra-African LNG trade is set to expand substantially, rising from not importing in 2023 to 32 Mt by 2050, indicating growing regional integration. As a result, **Africa's LNG trade is anticipated to undergo a strategic shift, with a growing focus on intra-regional trade and a stronger alignment with Asia's rising gas demand.** (Figure 6.14)

Figure 6.13

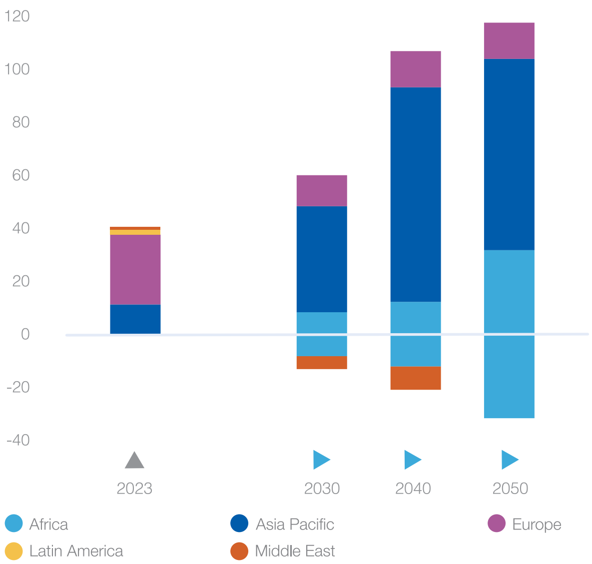
Africa natural gas demand and net exports outlook by flow type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 6.14

Africa LNG exports (+) by destination and imports (-) by origin outlook, 2023-2050 (Mt)

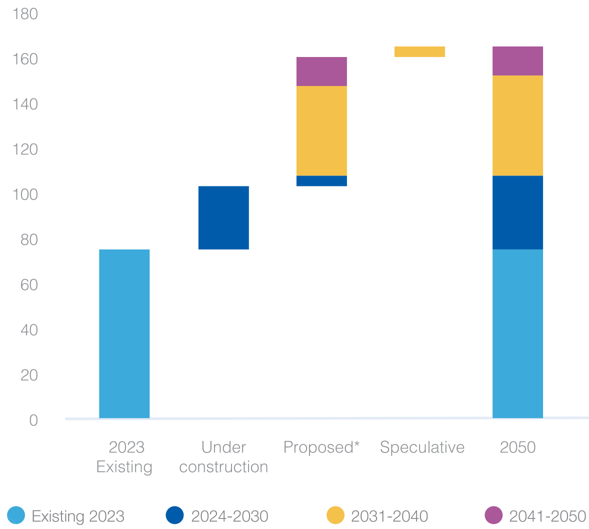


Source: GECF Secretariat based on data from the GECF GGM
Note: Regional LNG exports and imports include intraregional trade

Algeria and Nigeria are expected to remain key players in the LNG export market, with Mozambique emerging as a significant contributor in the coming decades. By 2050, Mozambique is projected to become the world's fifth-largest LNG exporter, contributing 49 Mt - over 40% of Africa's LNG exports. Nigeria is forecasted to be Africa's second-largest LNG supplier by 2050, with an output of approximately 22 Mt.

Figure 6.15

Africa LNG liquefaction capacity outlook, 2023-2050 (Mtpa)



Source: GECF Secretariat based on data from the GECF GGM
Note: Proposed capacities include in-FEED, pre-FEED and FEED completed projects, planned and announced projects (for further details, please, refer to Annex D. Definitions)*

Africa's LNG trade trajectory is set to be shaped by its ability to meet growing demand. LNG exports are expected to rise to 60 Mt by 2030, 107 Mt by 2040, and stabilise at 118 Mt by 2050.

As of 2024, Africa's total LNG liquefaction capacity reached 75 Mtpa, distributed across Algeria, Angola, Cameroon, Congo (Brazzaville), Egypt, Equatorial Guinea, Mozambique, and Nigeria. Algeria and Nigeria accounted for 63% of this capacity, with 25.3 Mtpa and 22.3 Mtpa, respectively. Mozambique commenced LNG exports in 2022 with the 3.4 Mtpa Coral Sul FLNG facility. In 2024, Congo (Brazzaville) joined the LNG exporters with its 0.6 Mtpa Tango floating LNG facility. By 2025, Congo (Brazzaville) is set to increase its capacity to 3 Mtpa by adding a second floating LNG facility with a capacity of 2.4 Mtpa. Furthermore, the Greater Tortue FLNG project in Senegal and Mauritania, with a capacity of 2.5 Mtpa, is expected to begin production in late 2024 or early 2025.

In 2023, Africa's LNG capacity utilisation rate was just 54%, largely constrained by upstream supply limitations.

The RCS projects substantial growth in Africa's LNG infrastructure, with capacity expected to grow by 2.4 times, surpassing approximately 176 Mtpa by 2050 (Figure 6.15). This expansion will be primarily driven by developments in Congo (Brazzaville), Mauritania, Mozambique, Nigeria, and Senegal, with further contributions from countries such as Tanzania.

The LNG industry in Sub-Saharan Africa exhibits significant diversity in scale and development timelines. **Projects with final investment decisions**

(FID) reached or under construction represent a combined liquefaction capacity of 29 Mtpa, all expected to become operational by 2030. This includes Mozambique's Mozambique LNG project with a total capacity of 12.88 Mtpa, Mauritania and Senegal's Greater Tortue FLNG with 2.5 Mtpa, and Nigeria's Nigeria LNG Train 7 alongside the UTM Floating LNG project, together accounting for 10.8 Mtpa. Additionally, liquefaction projects are under construction in Congo (Brazzaville), with a capacity of 2.4 Mtpa, and presumably in Gabon, with a capacity of 0.7 Mtpa. Mozambique has completed the front-end engineering design (FEED) for the 18 Mtpa Rovuma LNG 1 facility.

Across the African region, proposed LNG projects total approximately 56 Mtpa, with an additional 16 Mtpa classified as speculative liquefaction capacity.

LNG developers face country-specific challenges, including security issues, infrastructure limitations, bureaucratic obstacles, and financial hurdles. Timely execution and accelerated development will be crucial for Africa to unlock its full potential, especially as competition rises from stable, established export regions with transparent regulatory frameworks. In the short term, Africa could increase LNG exports by maximising the utilisation of existing facilities and utilising floating LNG (FLNG), assuming a reliable feed-gas supply is secured.

Despite limited infrastructure, represented by a few regional pipelines – such as the Algerian pipeline to Tunisia, the West African Gas Pipeline (WAGP) from Nigeria to Benin, Togo, and Ghana, and the Mozambique-South Africa Gas Pipeline – the outlook anticipates the development of additional intra-regional gas pipelines. This growth could enhance Africa's regional gas trade and connectivity, potentially transforming the energy landscape. Pipeline gas exports are expected to stabilise at 30 bcm by 2050, down from 40 bcm in 2023. Meanwhile, pipeline imports are projected to increase significantly, rising from 13 bcm in 2023 to 31 bcm by 2050.

Africa is projected to strengthen its role as a net exporter of natural gas, reaching 128 bcm by 2040. However, net exports are expected to slightly decline to around 118 bcm by 2050 as the continent increasingly utilises natural gas to support its economic growth and meet the needs of its rapidly expanding population.

Africa stands on the verge of a significant industrialisation surge, driven by a rapidly growing young population, abundant natural resources, and expanding domestic markets. The continent's population is projected to rise substantially, from approximately 1.5 billion today to nearly 2.5 billion by 2050. This demographic and economic growth will lead to a sharp increase in energy demand, with natural gas imports playing an important role. In 2023, Africa imported 13 bcm of natural gas via pipelines, primarily to Egypt, South Africa, and Tunisia. **By 2050, natural gas imports are expected to reach 75 bcm, with nearly 60% - 44 bcm (32 Mt) - coming in the form of LNG, primarily destined for South Africa.**

Algeria remains a key natural gas supplier to Southern Europe, providing about 65% of its pipeline exports and the remaining 35% as LNG. In 2023, Algeria exported 52 bcm of natural gas, including 34 bcm through pipelines. Its LNG exports totalled 13 Mt in 2023, with 90% or 11.7 Mt sent to Europe. The country operates LNG facilities with a combined capacity of 25.3 Mtpa, located at Arzew, Bethioua, and Skikda. Algeria is expected to remain a significant natural gas supplier to Europe through both pipelines and LNG exports until 2050, with both LNG and pipeline exports of about 30 bcm.

Angola's LNG exports totalled 3.2 Mt in 2023, with 84% directed to Europe, compared to 17% in 2021, when most shipments – 77% went to the Asia Pacific region, with India accounting for a third of the total. The Angola LNG plant has a capacity of 5.2 Mtpa and is supplied with associated gas from the Kizomba A and B and Saxi/Batuque fields. There are no immediate plans to expand liquefaction capacity in the near future, with long-term exports expected to be sustained at 4 Mtpa through 2050.

Egypt aims to establish itself as a regional natural gas hub, linking Africa, the Middle East, and Europe, supported by the discovery of the Zohr gas field. In 2023, the country exported 3.6 Mt of LNG, with over two-thirds directed to Europe. Egypt currently operates two LNG plants with a combined capacity of 12.2 Mtpa: the 7.2 Mtpa Idku facility (T1, T2) and the 5 Mtpa Damietta facility. Long-term LNG exports are expected to stabilise at 5-6 Mt annually. Additionally, the Arab Gas Pipeline, with a 10 bcma capacity, connects Northern Sinai to Jordan, Syria, and Lebanon. In 2023, Egypt exported less than 1 bcm of gas to Jordan via this pipeline.

Equatorial Guinea's gas production is predominantly directed towards LNG exports, with the 3.7 Mtpa EGLNG facility on Bioko Island commencing operations in 2007. In 2023, the facility exported 2.8 Mt of LNG, with over half of exports targeting the Asia Pacific region. Over the long term, Equatorial Guinea is anticipated to sustain its LNG exports at 3 Mt by 2050. Equatorial Guinea is poised to emerge as a key LNG hub in West Africa following a pivotal agreement between its government, Marathon Oil Corporation, and Chevron's Noble Energy E.G. Ltd to advance the Gas Mega Hub (GMH) project. The GMH will be located north of Bioko Island, strategically positioned near Cameroon and Nigeria. Furthermore, in 2023, a coalition of nations, including Equatorial Guinea, signed a memorandum of understanding (MOU) to collaborate on developing the 6,500-km Central African Pipeline System (CAPS).

Mauritania and Senegal are set to become LNG exporters with the launch of the 2.5 Mtpa Greater Tortue Phase 1 project in 2025. The bp-operated Greater

Tortue Ahmeyim (GTA) LNG project, located offshore Mauritania and Senegal, achieved its LNG production in January-February 2025. In 2020, Kosmos Energy secured a 20-year sale and purchase agreement (SPA) with BP to supply the full capacity of the project's first phase. Phase 2 will increase the capacity to 5 Mtpa, potentially expanding to 10 Mtpa. In addition to the 10 Mtpa GTA LNG hub, two other LNG hubs were initially considered to develop and monetise additional natural gas resources discovered in Mauritania and Senegal: Yakaar/Teranga in Senegal, with a capacity of 10 Mtpa, and Bir Allah in Mauritania, also with 10 Mtpa of LNG liquefaction capacity, both potentially coming online between 2030 and 2040. The combined capacity of the Mauritania/Senegal LNG complex could reach 30 Mtpa by 2050.

By the mid-2030s through 2050, **Mozambique** is poised to become Africa's largest LNG producer. In 2022, the country began LNG exports from the Coral Sul FLNG facility, marking the first use of a floating liquefaction facility in African deep waters. Mozambique has approximately 34 Mtpa of LNG capacity planned to come online between 2030 and 2040 from three major projects: (i) Coral Norte FLNG (3.5 Mtpa), (ii) Mozambique LNG (12.9 Mtpa), and (iii) Rovuma LNG (18 Mtpa). The Mozambique LNG project has secured long-term contracts for 90% of its production. However, security concerns have caused construction delays, with work slated to resume in 2025. The Rovuma LNG project also faces setbacks, with ExxonMobil's final investment decision (FID) expected in 2026 and operations projected to begin around 2030. Long-term projections indicate that Mozambique could reach 51 Mtpa liquefaction capacity by 2050, with around 49 Mt of LNG exports expected by then.

Nigeria has been exporting LNG from its Bonny Island facility since 1999, with exports totalling 13 Mt in 2023 from the 22.3 Mtpa Nigeria Liquefied Natural Gas (NLNG) plant. Projections suggest LNG exports could reach 22-23 Mt through 2030-2050. In 2019, NLNG reached an FID on Train 7, aimed at coming online in 2026, expanding capacity to 30 Mtpa by then. Also, the UTM Floating LNG project is expected to go online in 2026. The West African Gas Pipeline (WAGP) also facilitates gas deliveries from Nigeria to Benin, Togo, and Ghana over its 680-km route. Nigeria exported to Ghana 0.8 bcm in 2023 via the WAGP.

In 2023, **South Africa** imported 4.3 bcm of natural gas, exclusively via pipelines from neighbouring Mozambique. By 2050, the country aims to increase its natural gas imports to 21-23 bcm annually to meet rising demand driven by accelerated power generation, coal-to-gas switching, and its commitment to achieving net-zero emissions by 2050. Over 80% of these imports are expected to be in the form of LNG. Among key developments in this transition is the planned LNG regasification terminal at Richards Bay port, South Africa's largest coal export hub. This facility, set to begin operations in 2027, will initially have a capacity of 2.5 Mtpa, with plans to expand to 5 Mtpa. Additionally, an LNG import terminal in Matola, Mozambique, also scheduled for completion in 2027, could enable Mozambique to export gas-generated electricity to South Africa.

6.5.2 Asia Pacific

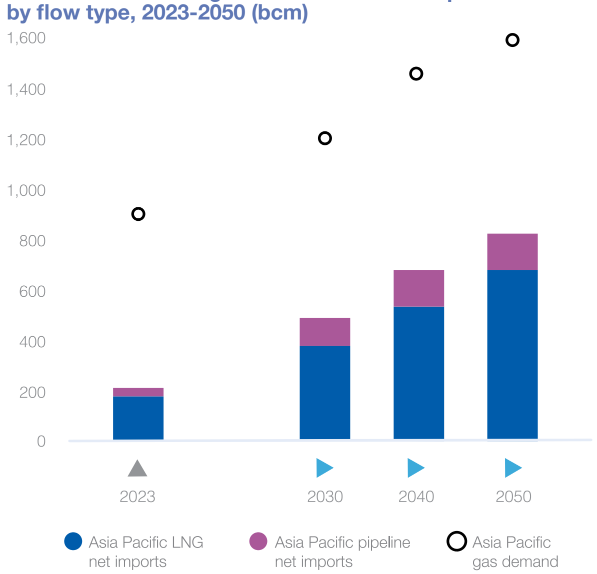
The Asia Pacific region's economy is rapidly expanding, with energy demand expected to rise by 30% by 2050. Natural gas is becoming increasingly important in the energy and climate strategies of many Asian countries, aiming to improve air quality, reduce GHG emissions, and enhance the reliability and affordability of energy supply. The region's primary growth drivers of natural gas demand are increased electrification and the shift from coal to gas.

In 2023, the Asia Pacific region recorded net natural gas imports totalling 211 bcm, with approximately 89% of this volume - equivalent to 179 bcm or 126 Mt - delivered as LNG, highlighting its reliance on LNG for natural gas supply (Figure 6.16). The region's overall gross LNG imports amounted to 262 Mt, including intra-regional shipments from countries such as Australia, Brunei, Indonesia, Malaysia, and Papua New Guinea.

The surge in LNG demand in Europe during the recent energy crisis pronouncedly impacted Asian markets in 2022. Europe emerged as a primary destination for premium LNG, driving global price increases that rendered Asian spot prices unaffordable for many countries. By 2023, the situation improved, particularly for price-sensitive developing Asian markets.

Figure 6.16

Asia Pacific natural gas demand and net imports outlook by flow type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Consequently, LNG imports rose significantly compared to 2022, with China increasing by 11%, India by 10%, Thailand by 33%, and Bangladesh by 17%. However, Japan, which imported 66 Mt of LNG - 10% less than the previous year - lost its position as the world's top LNG importer to China.

Demand for LNG in developing Asia is expected to recover further after 2026-2027, driven by increased LNG supply availability and further price moderation. China, Southeast Asia, and South Asia are projected to be the fastest-growing LNG markets, accounting for the majority of medium- to long-term growth in the region. In contrast, Northeast Asia's demand is expected to remain stable and decline after 2030.

The Asia Pacific region is set to remain the largest global centre for LNG demand and the primary destination for LNG imports. By 2050, it is expected to account for nearly 76% of global LNG imports. From 2023 to 2050, Asia Pacific is projected to account for around 88% of the incremental growth in LNG imports. **The region's LNG imports are projected to grow 2.3-fold, reaching approximately 510 Mtpa by 2040 and further increasing to 605 Mtpa by 2050.** China remains a key driver of growth throughout the 2020s, while Southeast and South Asia are expected to become some of the fastest-growing LNG markets globally after the 2030s.

In 2023, Asia Pacific sourced 52% of its LNG from within the region, followed by 29% from the Middle East, while North America accounted for 8%, Eurasia 7%, and Africa 4%. Over time, Asia Pacific's LNG imports are expected to diversify, with significant increases primarily from the Middle East, reaching 178 Mt by 2050. LNG imports from North America are projected to surge to 140 Mt by 2050, reinforcing its role as a key supplier. Meanwhile, Eurasia is expected to expand its exports to 106 Mt by 2050, and Africa's LNG supply to the region is set to grow nearly sevenfold to 81 Mt by 2040. In contrast, intra-regional LNG trade within Asia Pacific is expected to decline gradually from 136 Mt in 2023 to 110 Mt by 2050 (Figure 6.17). This evolving trade pattern highlights Asia Pacific's increasing reliance on external LNG sources, particularly from the Middle East, North America, Eurasia, and Africa, while intra-regional LNG trade sees a gradual decline.

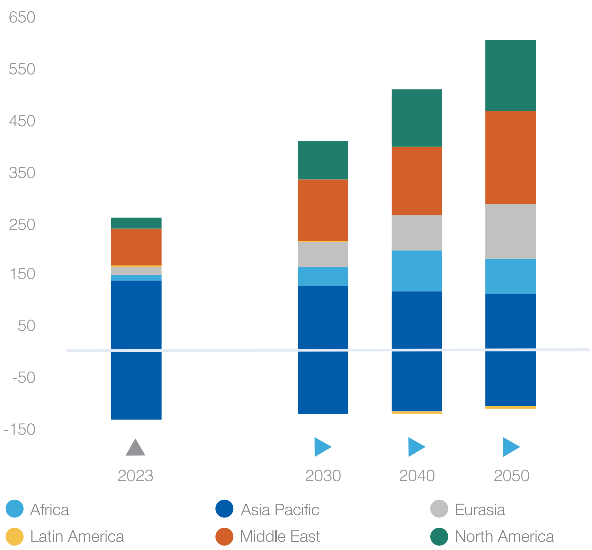
In 2023 end, the Asia Pacific region had an estimated regasification capacity of 632 Mtpa. Almost 80% of this capacity is concentrated in the established JKT group (Japan, South Korea, Chinese Taipei) and China. JKT accounted for 58%, while China held a 21% share. The remaining 20% was distributed across South and Southeast Asia. Japan led with 210 Mtpa of regasification capacity, followed by South Korea at 139 Mtpa, China at 135 Mtpa, and India at 51 Mtpa (Figure 6.18).

Additionally, **approximately 241 Mtpa of new regasification capacity was under construction in the region in 2023, with China (153 Mtpa) and India (38 Mtpa) leading the development. China represented about 64% of the projects underway, while India accounted for around 16%.**

By By 2050, the regasification capacity balance in the Asia Pacific region is projected to undergo significant changes. China is expected to account for

Figure 6.17

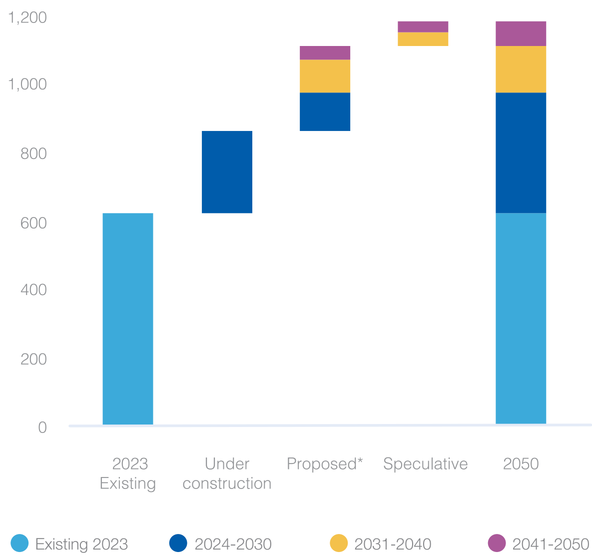
Asia Pacific LNG imports (+) by origin and LNG exports (-) by destination outlook, 2023-2050 (Mt)



Source: GECF Secretariat based on data from the GECF GGM
Note: Regional LNG exports and imports include intraregional trade

Figure 6.18

Asia Pacific LNG regasification capacity outlook, 2023-2050 (Mtpa)



Source: GECF Secretariat based on data from the GECF GGM

Chapter 6

30% of the total capacity, South and Southeast Asia for 36%, and JKT for the remaining 34%. These figures do not factor in the substantial decommissioning of existing capacities.

The region's proposed LNG import projects total 255 Mtpa, with China representing 26% or 66 Mtpa of the proposed capacity, India contributing 18%, and Southeast Asia contributing 37%. Together, China, India, and Southeast Asia account for just over 80% of the total proposed LNG import projects.

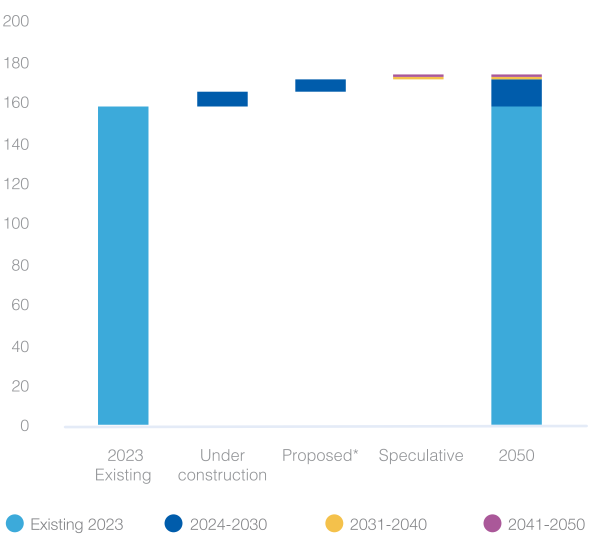
In 2023, five Asian Pacific countries collectively exported 136 Mt of LNG, with nearly all shipments going to other countries within the region. Australia was the second-largest LNG exporter globally, shipping 79 Mt, followed by Malaysia and Indonesia with 27 Mt and 16 Mt, respectively. During the same year, Papua New Guinea and Brunei exported 8.4 Mt and 4.6 Mt, respectively.

By 2050, LNG exports from the Asia Pacific region are expected to decrease by approximately one-third, dropping to around 112 Mt due to insufficient gas supply, declining production, lack of new investments, and the shutdown of liquefaction facilities. Despite this decline, Australia is projected to remain the leading LNG exporter in the region. However, its export volumes may be affected by new climate change policies and regulations, which are expected to render certain oil and gas upstream investments non-commercial.

In 2023, the region had approximately 158 Mtpa of liquefaction capacity (Figure 6.19), with Australia accounting for over half of this, at nearly 88 Mtpa. Malaysia and Indonesia held 32 Mtpa and 22 Mtpa of established export capacity, respectively. Australia (5 Mtpa), Indonesia (0.5 Mtpa), and Malaysia (2 Mtpa)

Figure 6.19

Asia Pacific LNG liquefaction capacity outlook, 2023-2050 (Mtpa)



Source: GECF Secretariat based on data from the GECF GGM

currently have a combined 7.5 Mtpa of liquefaction capacity under construction, with a further 9 Mtpa at various stages of proposed and speculative developments.

As a result, Australia is expected to remain one of the world's leading suppliers, with nearly 93 Mtpa of liquefaction projects, and the total liquefaction capacity in the region is projected to reach 173 Mtpa by 2050.

The three countries - **Japan, South Korea, and Chinese Taipei** - all among the top six LNG importers, have significant common ground in the strategic challenge of decarbonising their energy systems. In all three countries, efforts are underway to maintain LNG as a significant part of the energy mix for the longer term - whether through infrastructure investments or the renewal of long-term contracts - despite ambitious emissions reduction targets. Government reassessments of energy strategies, potentially involving the relaxation of medium- and long-term emissions targets, could further strengthen this expectation.

Nevertheless, the share of JKT LNG markets in Asia Pacific's total LNG imports is projected to decline from 50% in 2023 to 18% by 2050. This decline is primarily driven by accelerated energy transitions and decarbonisation efforts, which focus on increasing reliance on renewable energy, nuclear power, and energy efficiency improvements. Once leaders in LNG consumption, these countries are expected to fast-track their efforts towards cleaner energy sources to reduce carbon emissions and meet net-zero targets by 2050, reducing overall LNG demand.

Japan has long-term emissions reduction targets for 2050 and ambitious interim targets for 2030 that aim to reduce the role of LNG. LNG demand in Japan is already declining, along with overall energy demand. Japan relies entirely on imported LNG, remaining the second-largest LNG importer, having imported 66 Mt in 2023, accounting for 16% of the global LNG market. The country sourced LNG from sixteen countries, with Australia being the largest supplier (28 Mt), followed by Malaysia (10.4 Mt), Russia (6 Mt), and the United States (5.6 Mt). Japan operates 45 regasification terminals with a total capacity of 210 Mtpa. However, LNG imports are forecast to decrease by around 46% during the forecast period. Despite this decline, Japan is expected to remain the world's third-largest LNG importer, with an estimated demand of 36 Mt by 2050. Natural gas will still play a transitional role in Japan's energy mix, but the country's pro-nuclear policies and net-zero target will accelerate the decline in LNG demand.

Like Japan, **South Korea**'s energy supply heavily relies on imported hydrocarbon fuels. In contrast to Japan, South Korea's primary energy supply has experienced steady growth. Over the past decade, the largest growth in energy supply has been in LNG. Between 2012 and 2023, LNG imports increased by around one-third. In

2023, South Korea was the world's third-largest LNG importer. South Korea's LNG imports are expected to remain stable through 2050, with a slight decline from 45 Mt in 2023 to 44 Mt by 2050. The leading suppliers of LNG are expected to be Qatar, Australia, Russia, and the United States. South Korea's regasification capacity is currently 139 Mtpa, with an additional 14 Mtpa under construction and expected to be operational by 2030.

By 2025, **Chinese Taipei** aims to source 50% of its electricity from LNG, a significant shift in its energy mix. This transition is part of the government's strategy to reduce reliance on coal and nuclear power while increasing natural gas and renewable energy use. Chinese Taipei is investing in LNG infrastructure and enhancing its gas import capabilities to achieve this target. Still, this shift also highlights the importance of securing a stable natural gas supply, especially as the country faces challenges diversifying its energy sources while ensuring energy security and meeting environmental goals. To accommodate the above, Chinese Taipei currently operates two LNG receiving terminals: CPC's Yung-An LNG terminal, which has a capacity of 10.5 Mtpa and the Taichung LNG terminal, which has a capacity of 6 Mtpa. Chinese Taipei plans to expand its LNG infrastructure by adding two more terminals currently under construction. Taichung's third LNG terminal has a capacity of 3 Mtpa, and the Taoyuan LNG terminal has a capacity of 4.5 Mtpa. In 2023, Chinese Taipei ranked as the sixth-largest importer of LNG globally, surpassing Spain. Its LNG imports reached 20 Mt, primarily sourced from Australia and Qatar, collectively supplying over two-thirds of its LNG needs. Projections indicate a significant 30% growth in Chinese Taipei 's LNG imports between 2023 and 2050, with the anticipated volume reaching 26 Mt.

China set its dual carbon goals of peaking carbon emissions by 2030 and achieving carbon neutrality by 2060 in 2020. Natural gas has a long-term role in China's energy transition, shifting toward a cleaner, more diversified energy mix. China's natural gas demand ranks as the world's third-largest gas market, with only the United States and Russia consuming more.

China's gas imports are anticipated to be a critical factor in driving natural gas consumption growth and bridging the supply-demand gap. Over the long term, China is projected to remain among the world's largest natural gas importers. Ensuring supply security will likely rely on strategies such as diversifying import sources, expanding flow types, and securing long-term contracts.

China's natural gas (gross) imports are projected to increase from 145 bcm in 2023 to 314 bcm by 2050, with LNG imports rising from approximately 71 Mt in 2023 to 120 Mt by 2050. China's LNG imports grew by 12% in 2023, reflecting the economic recovery and normalising spot gas prices. The country is expected to be a key destination for new pipeline and LNG projects over the current and subsequent decades.

Supply security and reliability concerns drive China's emphasis on natural gas strategies. To address these concerns, China has focused on diversifying its LNG supply and ensuring stability through long-term contracts (LTCs). In 2023, the share of LNG volumes under contract was exceptionally high at 96%, and this trend is anticipated to remain strong in 2030 at 89%, the highest among Asia-Pacific sub-regions. In comparison, Northeast Asia is expected to have 65%, South Asia 46%, and Southeast Asia 26%.

Chinese buyers have secured substantial volumes of LNG. Between 2021 and 2023, China entered into approximately 67 Mtpa of LNG contracts, with 61 Mtpa being long-term agreements averaging 18 years. By 2026, Chinese companies are projected to secure over 100 Mtpa of LNG supply through contracts. During the same period, China signed around 25 Mtpa of LNG contracts, specifically with the United States, the majority of which are also long-term agreements. Initially, in 2020-2021, they focused on oil-linked volumes from Qatar. However, from mid-2021 to 2023, their strategy shifted to targeting hub-linked deals with the United States.

Simultaneously, China has dramatically increased its pipeline imports, reaching 66 bcm in 2023. Turkmenistan and Russia were the dominant suppliers, providing 33 bcm and 23 bcm, respectively, accounting for 85% of China's pipeline imports. China's pipelines import capacity currently stands at 105 bcma, with several ongoing projects expected to expand this to 195 bcma by 2050. Notable projects include the Far Eastern pipeline extension from Russia, adding 10 bcma; the Power of Siberia 2 pipeline from Russia, projected to deliver 50 bcma; and the Line D expansion from Turkmenistan, adding 30 bcma. By 2050, pipeline imports are expected to rise to 150 bcm, primarily from Russia and Turkmenistan.

Thus, China's growing reliance on pipeline and LNG imports reflects its strategic diversification of natural gas supply, which strongly focuses on securing stable, long-term energy resources while adapting to market fluctuations.

South and Southeast Asia are projected to become the largest LNG demand bloc in the Asia Pacific, with their share of Asia Pacific regional imports rising from 23% in 2023 to 61% by 2050. Rapid population growth, urbanisation, and industrialisation, particularly in countries like India and Indonesia, are supporting increasing energy demand, including for LNG in power generation and industry. These regions are also witnessing a shift from net LNG exporters to net importers due to declining domestic production. Countries like Malaysia and Indonesia, traditionally significant LNG exporters, are expected to become net importers in the long term. The Philippines and Viet

Nam, which began LNG imports in 2023, are also set to gradually increase their imports, although rising global prices and macroeconomic challenges may slow this growth.

In **South Asia**, LNG demand growth is expected to stall temporarily due to the high sensitivity to spot LNG prices. However, strong demand recovery is forecast post-2026 as LNG prices soften. To achieve net-zero emissions by 2070, India is striving to increase its natural gas share in the energy mix. Although India's target of 15% gas in the energy mix by 2030 may be challenging, the country's LNG imports are projected to rise significantly, from 22 Mt in 2023 to 130 Mt by 2050. This growth will require substantial investments in LNG infrastructure, including regasification capacity, which is expected to increase from 51 Mtpa in the beginning of 2024 to 135 Mtpa by 2050. Pakistan and Bangladesh are expected to see long-term LNG demand growth in the power sector, driven by urbanisation, stricter air quality regulations, and industrialisation.

Australia, a major global LNG exporter, has seen significant investment in LNG infrastructure since 2009, expanding its liquefaction capacity to 88 Mtpa by 2023. Although Australia remains the third-largest LNG exporter, the decline in upstream production is expected to reduce its LNG export capacity over the long term. Australia is projected to maintain a strong export position, with liquefaction capacity expected to reach 93 Mtpa by 2050. However, a sustained reduction in production could lead to a decline in LNG exports in the future. LNG exports are anticipated to account for 62 Mt by 2050.

6.5.3 Eurasia

In 2023, Eurasia's gross gas exports amounted to around 239 bcm, with Russia accounting for approximately 142 bcm. Around 82% or 196 bcm of Eurasia's natural gas exports were delivered via pipelines.

Russia was the largest exporter of piped gas, sending around 99 bcm, of which roughly 50 bcm went to Europe and 23 bcm to China. Other countries, including Azerbaijan, Kazakhstan, Turkmenistan, and Uzbekistan, collectively exported about 97 bcm via pipelines, mainly through Central Asia. The Central Asia-China pipeline corridor, with the capacity of 55 bcm annually, has the potential to expand to 85 bcma by constructing Line D, which would run from Turkmenistan through Uzbekistan, Tajikistan, and Kyrgyzstan, ultimately reaching China.

In 2023, Russia's gas exports declined by 17%, falling to 142 bcm compared to 170 bcm in 2022. While pipeline exports to Europe saw further reductions, LNG exports remained steady, securing Russia's position as the world's fourth-largest LNG exporter after Qatar, Australia, and the United States. Russia's LNG exports totalled 31.4 Mtpa, nearly unchanged from 32 Mtpa in 2022, accounting for approximately 8% of the global LNG market. Of this, 14.4 Mt of LNG was exported to Europe (14.2 Mtpa in 2022), representing 46% of Russia's total LNG exports. Consequently, Russia contributed 12% to Europe's total LNG imports.

By 2050, Eurasia's net LNG exports are projected to reach 125 Mt, equivalent to approximately 172 bcm of natural gas, accounting for 44% of the region's total gas net exports. Meanwhile, pipeline exports are expected to surpass 200 bcm, bringing Eurasia's total net gas exports to 389 bcm, which represents 47% of total region's gas demand (Figure 6.20).

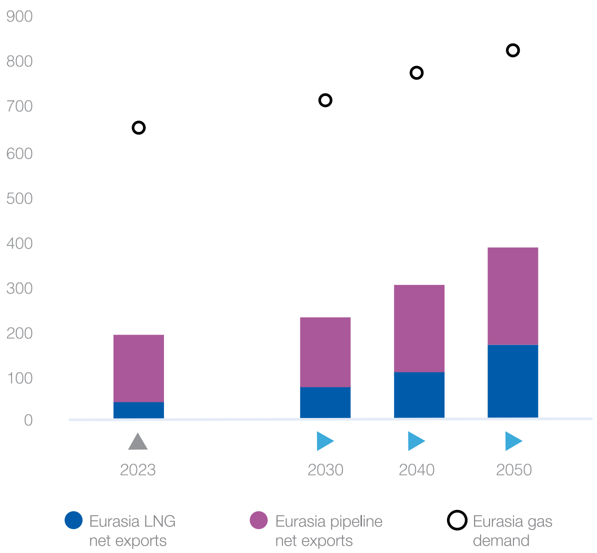
Russia has been working to expand its export infrastructure, focusing on boosting gas sales to the Asia Pacific region. The country has prioritised increasing LNG exports, placing significant strategic emphasis on the Asia Pacific markets, especially China.

By 2050, Eurasia's LNG exports are projected to grow significantly, quadrupling from 31 Mt in 2023 to 125 Mt. The export destination trends indicate a strong shift toward Asia Pacific, which will receive 85% of Eurasia's LNG exports by 2050, up from 52% in 2023. This reflects Asia's increasing gas demand and its role as the dominant market for Eurasian LNG. Conversely, Europe's share of Eurasia's LNG exports is expected to decline from 48% in 2023 to just 15% by 2050, indicating a shift in trade patterns and potentially reduced reliance on Eurasian gas amid diversification efforts in European markets (Figure 6.21).

Russia began supplying natural gas to Asia in 2009 and delivered approximately 46 bcm to the region in 2023 through LNG and the Power of Siberia pipeline. This contrasts sharply with its European market, where annual exports typically range between 160 and 200

Figure 6.20

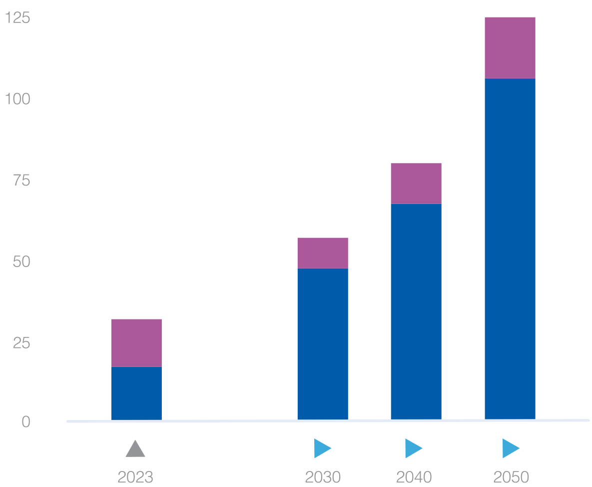
Eurasia natural gas demand and net exports outlook by flow type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 6.21

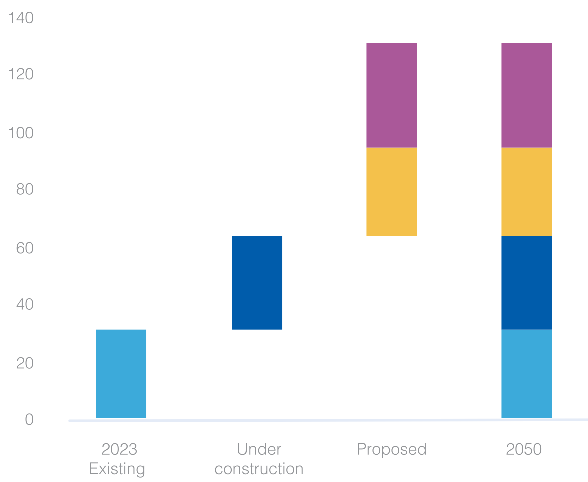
Eurasia LNG exports outlook by destination, 2023-2050 (Mt)



Source: GECF Secretariat based on data from the GECF GGM

Figure 6.22

Eurasia liquefaction capacity outlook, 2023-2050 (Mtpa)



Source: GECF Secretariat based on data from the GECF GGM

bcm. In 2023, Russia emerged as China's largest gas supplier, delivering 33.4 bcm, including 22.7 bcm via the Power of Siberia pipeline, which commenced operations in late 2019. In comparison, Turkmenistan and Australia supplied similar volumes of natural gas to China in 2023, exporting 33.2 bcm and 32.1 bcm, respectively.

The current infrastructure for gas supply to the Asia Pacific region includes the Power of Siberia pipeline, which connects the Yakutia and Irkutsk production centres to China with a capacity of 38 bcma. Ongoing and planned pipelines aimed at expanding supply to China include (i) the Far Eastern pipeline, designed to link Russia's Far East to northeast China, with a proposed capacity of 10 bcma, and (ii) Power of Siberia 2, which aims to deliver gas from western Russia to China via Mongolia with a proposed capacity of 50 bcma. The Power of Siberia 2 pipeline, slated to begin operations in the early 2030s, could significantly increase Russian gas supplies to China, potentially matching the volumes previously supplied to the European Union.

Russia's natural gas exports are expected to increase from 142 bcm in 2023 to 185 bcm by 2030, 260 bcm by 2040, and approximately 352 bcm by 2050. Major natural gas developments in regions such as the Yamal Peninsula, the Arctic, East Siberia, and the Far East are expected to significantly boost Russia's production by 2050.

Russia aims to maintain its position as a key player in the global LNG market by advancing major projects such as Arctic LNG 2 (20 Mtpa) and Ust-Luga LNG (13 Mtpa), both of which have received FIDs and are under construction (Figure 6.22). These projects are expected to add a combined 33 Mtpa capacity, effectively doubling Russia's current LNG liquefaction capacity of 31 Mtpa by 2030 or the early 2030s. If all proposed LNG projects are realised, Russia's LNG liquefaction capacity could reach approximately 130 Mtpa by 2050. By then, Russia is projected to surpass Australia as the world's third-largest LNG supplier. LNG exports are expected to grow from 31.4 Mt in 2023 to around 80 Mt by 2040 and 125 Mt by 2050.

Azerbaijan has been a key natural gas exporter since the launch of the Shah Deniz field in 2007, with exports steadily increasing, reaching 24 bcm in 2023. Of this, 12 bcm were sold to Europe, 9.5 bcm to Türkiye, and 2.5 bcm to Georgia. In 2023, Azerbaijan began supplying gas to Hungary and Serbia, and in the second half of 2024, it started delivering gas to Croatia. Azerbaijan aims to export approximately 16 bcm of gas to Europe by 2027, a target that was initially set at 20 bcm. Azerbaijan focuses on optimising domestic efficiency, expanding renewable energy, and exploring alternative energy sources and export routes to further increase its gas exports. With the support of neighbouring countries like Turkmenistan, Azerbaijan could enhance its exports to Europe, but this would require substantial investment to expand the Trans-Anatolian (TANAP) and Trans-Adriatic (TAP) pipeline capacities, targeting 32 bcma for TANAP and 20 bcma for TAP. Over the forecast period from 2023 to 2050, Azerbaijan's natural gas exports are projected to reach 30 bcm by 2040 and remain at that level through 2050.

In 2023, **Turkmenistan** exported 48 bcm of natural gas via pipeline. Turkmenistan is expected to significantly boost its gas exports, reaching 105 bcm by 2040 and 125 bcm by 2050, with China remaining the primary destination. The 1,830 km-long Central Asia-China pipeline corridor (Lines A, B, C), which runs from eastern Turkmenistan to north-western China via Uzbekistan and Kazakhstan, currently has an operating capacity of 55 bcma. There is potential to expand this capacity to 85 bcma with the development of Line D. However, construction has been delayed due to ongoing negotiations between China and Turkmenistan over the gas sales agreement (GSA) for Line D. Work on the pipeline has been suspended since 2017. Turkmenistan's gas costs about 30% more than gas supplied via Russia's Power of Siberia pipeline. Additionally, Central Asia has further gas supply potential. The proposed Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline, spanning 1,814 km, could carry up to 33 bcma and is planned to supply 14 bcm per annum to India, 14 bcma to Pakistan, and 5 bcma to Afghanistan over 30 years.

6.5.4 Europe

The European gas market is undergoing a profound transformation as it seeks to balance multiple objectives, including risk reduction, climate goals, methane emissions mitigation, and transportation security.

In the near term, European natural gas demand is projected to remain strong, driven by easing gas prices and an improving macroeconomic outlook. However, demand is expected to decline post-2030 as renewable energy sources become more prominent. Achieving the EU's 2030 climate goals - such as REPowerEU and Fit-for-55 - will require stricter climate policy enforcement and rising carbon prices. These factors are expected to significantly reduce gas consumption, particularly in the power, heating, and industrial sectors.

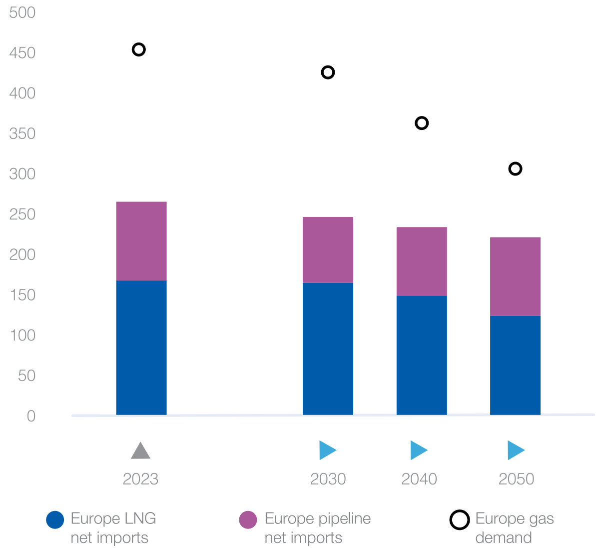
Nevertheless, **by 2050, Europe is expected to remain the world's second-largest natural gas importer, after the Asia Pacific region.** LNG is anticipated to play a crucial role in Europe's strategy to diversify gas sources and expand infrastructure, ensuring a stable and secure energy supply through the mid-2030s. Beyond that, pipeline imports are anticipated to recover partially, providing long-term support for Europe's energy security. Norway is expected to remain a reliable supplier in the near term; however, its pipeline gas exports are projected to decline sharply, falling from 108 bcm in 2023 to approximately 50 bcm by 2040, due to substantial decreases in production from mature, established fields.

Declining domestic production, along with reduced pipeline imports from Norway and Algeria, ensures that LNG imports will continue to play a resilient role in Europe, even as overall gas demand decreases.

In 2023, Europe imported net of 167 bcm (120 Mt) of LNG, a level expected to remain stable through 2030 (Figure 6.23). After 2030, net LNG imports to Europe are projected to decrease by 9% to reach 109 Mt by 2040

Figure 6.23

Europe natural gas demand and net imports outlook by flow type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

and by an additional 13% by 2050, reaching 95 Mt. By 2050, Europe is expected to net import approximately 100 bcm of natural gas through pipelines, with Türkiye accounting for over half of this volume.

By 2050, Europe's LNG imports are projected to decline to 105 Mt, down from 127 Mt in 2023, reflecting a potential shift toward alternative energy sources. North America remains the dominant supplier, providing 57% of Europe's LNG imports by mid-century, although its share decreases from 67% in 2030. Eurasia's share grows significantly, rising from 12% in 2023 to 18% in 2050 as well as African continent maintains a stable role, contributing 13% by 2050 (Figure 6.24).

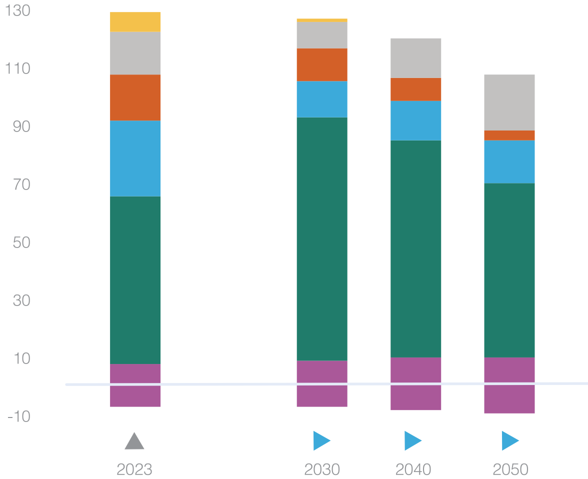
By 2050, net gas imports in Europe are projected to fall to 229 bcm, down from almost 265 bcm in 2023. Despite this decline, Europe is expected to still account for around 21% of global gas net imports. France, Germany, Italy, Spain, Türkiye, and the United Kingdom will likely remain Europe's primary natural gas markets in the foreseeable future. Germany is spearheading the surge in European LNG imports, driven by substantial expansions in regasification capacity, underpinned by new long-term supply agreements and a projected increase in gas-to-power demand in the medium term.

The EU's strategy prioritises LNG, with the bloc actively working to expand its regasification capacity and address current infrastructure limitations.

Global regasification capacity expansions accelerated in 2023, with Europe leading the way, adding 30 Mtpa of new capacity. In 2023, seven European regasification

Figure 6.24

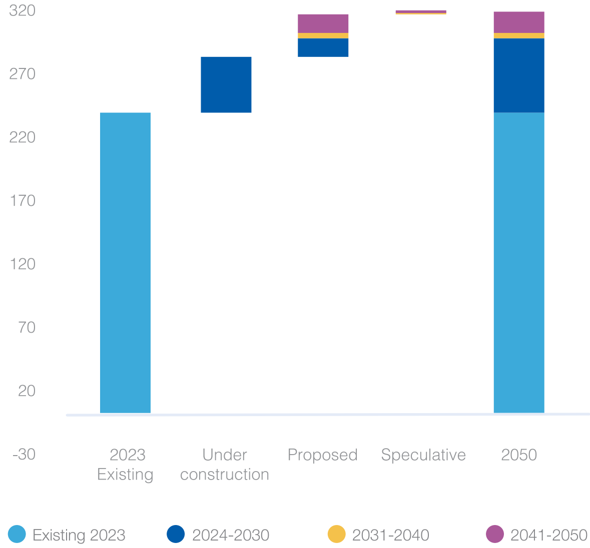
Europe LNG imports (+) by origin and export (-) by destination outlook, 2023-2050 (Mt)



Source: GECF Secretariat based on data from the GECF GGM
Note: Regional LNG exports and imports include intraregional trade

Figure 6.25

Europe LNG regasification capacity outlook, 2023-2050 (Mtpa)



Source: GECF Secretariat based on data from the GECF GGM

projects were launched, including two in Germany and five in Finland, Türkiye, Italy, Spain, and France. Europe favours floating terminals due to their flexibility and lower fixed investment requirements. Of the seven projects commissioned in 2023, six were FSRU-based, contributing a combined capacity of 24 Mtpa.

By 2023 end, Europe's total LNG regasification capacity had reached 238 Mtpa (Figure 6.25), driven by accelerated efforts from European governments to deploy floating storage regasification units (FSRUs) and expand capacity. **Currently, 45 Mtpa of regasification capacity is under construction and scheduled to come online between 2024 and 2030, with FSRUs accounting for 20 Mtpa of this capacity.**

Looking ahead, Europe could increase its regasification capacity by an additional 35 Mtpa by 2030 through proposed projects beyond the existing and under-construction capacity. This expansion will mainly stem from infrastructure upgrades and new developments, with significant additions planned in Germany, Greece, and Italy.

In **Germany**, natural gas will continue to play a crucial role in electricity generation during the energy transition, especially as the country phases out nuclear power and coal. In 2023, Germany imported 75 bcm of natural gas and 68 bcm via pipelines, accounting for 91% of its gas imports. In 2023, Germany imported only 7 bcm or 5.1 Mt as LNG. Germany has been expanding its LNG capacity to enhance energy diversity and address vulnerabilities in its energy supply. In 2023, the country began importing LNG, initially through floating storage and regasification units (FSRUs), with plans to replace some FSRUs with onshore terminals by the late 2020s. By 2030, Germany aims to reach a peak LNG import capacity of 38 Mtpa, with three FSRUs already operational and four more under construction, expected to be completed between 2024 and 2027. Over the forecast period, Germany's gas imports are projected to peak before 2030, then decline to 61 bcm by 2030 and further decrease to 15 bcm by 2050. In contrast, the country's LNG net imports are expected to rise from 5 Mt in 2023 to 21-22 Mt between 2030 and 2040 before decreasing to 11 Mt by 2050, which aligns with the country's gas demand decline.

Norway, the world's fourth-largest natural gas exporter and Europe's leading supplier, exports nearly all of the gas produced from its offshore fields, as it relies heavily on hydropower for domestic energy needs. In 2023, Norway exported around 114 bcm of natural gas, with 108 bcm (95%) transported via pipelines. The country is connected to continental Europe by five pipelines and to the United Kingdom by two, offering a combined export capacity of approximately 138 bcm. Norwegian piped gas is valued for its flexibility and competitive pricing, making it a reliable supply source for Europe in short to medium term. However, Norway's LNG exports were limited in 2023, accounting for just 5% of total exports, primarily to European markets. Due to declining production, Norway's gas exports are expected to decrease to 92 bcm by 2030, drop to 53 bcm by 2040, and ultimately decline to 25 bcm by 2050.

Türkiye is positioning itself as a key player in the global energy market, serving as a transit hub between major suppliers in the Middle East, Russia, and Europe. The country imports nearly all of its natural gas and has significant pipeline connections, particularly with Russia. In 2023, Türkiye imported 50 bcm of gas, with pipelines supplying 72% of the total, including 20.5 bcm from Russia, 10.3 bcm from Azerbaijan, and 5.4 bcm from Iran. Additionally, Türkiye imported 10 Mt of LNG, with 4.3 Mt coming from Algeria. The country's infrastructure includes five LNG regasification terminals, with a combined capacity of 38 Mtpa, and no further expansion is expected. By 2050, Türkiye's net gas imports are projected to reach 69 bcm, with LNG imports anticipated to reach 13 Mt.

In the **United Kingdom**, the complete phase-out of coal power in 2024 is anticipated to enhance the role of natural gas in stabilising the energy system as the proportion of intermittent renewable energy sources increases. In 2023, net natural gas imports to the United Kingdom totalled 26 bcm, with 20 bcm (or 14.5 Mt), making up nearly 77% of total imports. All of the United Kingdom's pipeline gas imports in 2023 came from Norway. The United Kingdom has Europe's second-largest LNG regasification capacity, after Spain, and uses its interconnectors to export gas to Belgium and the Netherlands. The United Kingdom's total import capacity is 168 bcma, with nine pipelines and three LNG terminals, which have a capacity of 36 Mtpa. By 2050, the United Kingdom is projected to net import around 36 bcm of natural gas, with LNG imports constituting the majority. Its pipeline exports to Europe are expected to be around 5 bcm by 2050, while LNG imports are forecast to reach 22 Mt by then.

6.5.5 Latin America

In Latin America, the demand for natural gas will be driven by the shift away from coal, the replacement of oil in power generation, and the role of natural gas in addressing the intermittency issues posed by increasing renewable energy sources.

This will help facilitate the energy transitions while supporting hydroelectric capacity. The main factors fueling natural gas demand are expected to be the expansion of power generation, industrial growth, and, to a lesser extent, the rise of gas use in road transportation.

Given the challenges in launching new gas projects across the region, supply is expected to fall short of meeting growing demand, prompting the need for increased imports in the coming decades. Countries in the central part of the continent may encounter greater difficulties in integrating natural gas.

In 2023, the region imported around 25 bcm of gas, with 15 bcm (11 Mt) coming in as LNG. During the same period, it exported approximately 27 bcm of gas, of which 17 bcm (12 Mt) was LNG. All regional pipeline trade was primarily sourced from Bolivia, while Bolivia exported 8 bcm to Argentina and Brazil in 2023.

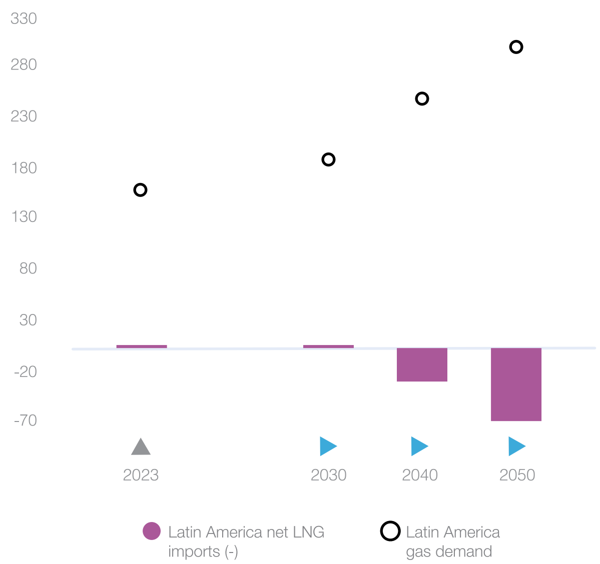
Forecasts indicate a significant rise in net natural gas imports to 36 bcm by 2050 (Figure 6.26), signalling a major shift as the region moves from being a marginal net exporter - exporting about 2 bcm in 2023 - to becoming a net importer by the early 2030s. LNG is expected to play a dominant role in shaping the natural gas trade across Latin America. While pipeline trade will continue to originate from Bolivia, its volume is anticipated to decline gradually. Additionally, Argentina is likely to shift from being a pipeline importer to an exporter of more pipeline gas after the mid-2030s or possibly earlier.

By 2050, Latin America's LNG imports are projected to reach 41 Mt, growing from 11 Mt in 2023, highlighting the region's growing reliance on LNG. North America remains the dominant supplier, increasing its exports to Latin America from 6 Mt in 2023 to 22 Mt in 2050, reflecting deepening regional trade integration. On the export side, Latin America's LNG exports rise to 14 Mt, balanced primarily by regional trade, as shipments to Europe and Asia Pacific phase out entirely. This shift underscores **Latin America's increasing role as both an LNG importer and regional supplier, while its global LNG trade diminishes** (Figure 6.27).

A key shift in Latin America centres around Argentina's potential to become a gas supplier to neighbouring countries. In 2023, gas exports to Chile from Argentina were mainly delivered via the GasAndes pipeline, with smaller volumes reaching Uruguay. There are also plans to develop LNG facilities in Argentina, which could open up export opportunities to other regions. The rapid growth of shale production in Argentina's Vaca Muerta, which holds the world's second-largest shale gas

Figure 6.26

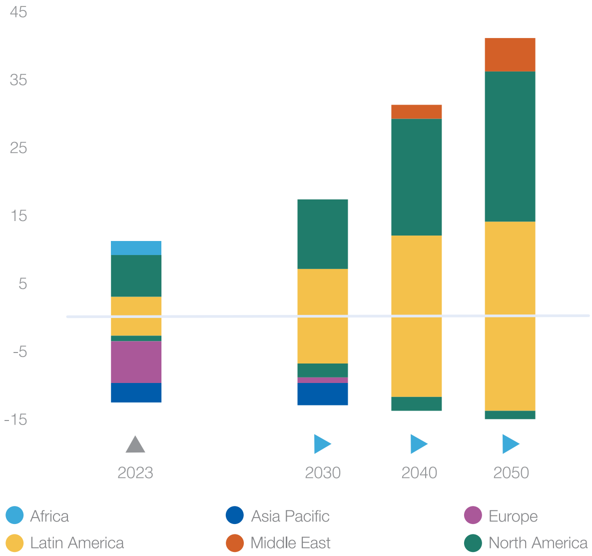
Latin America natural gas demand and net LNG imports outlook, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 6.27

Latin America LNG imports (+) by origin and exports (-) by destination outlook, 2023-2050 (Mt)



Source: GECF Secretariat based on data from the GECF GGM
Note: Regional LNG exports and imports include intraregional trade

reserves after the United States, is set to transform the region's energy landscape significantly. The development of extensive pipeline infrastructure, such as the Nestor Kirchner Gas Pipeline might support the operation of up to 25 Mtpa LNG export terminal in Bahia Blanca, slated to begin operations around 2030.

Trinidad and Tobago and Peru are the region's only LNG exporters, having delivered 7.7 Mt and 3.7 Mt of LNG in 2023, respectively. Over the long term, Latin America is expected to marginally increase its LNG exports, reaching approximately 15 Mt by 2050, driven mainly by Argentina and Trinidad and Tobago.

A significant rise in LNG imports is anticipated within the region. From 11 Mt in 2023, imports are projected to reach approximately 41 Mt by 2050. Chile was the largest LNG importer in Latin America in 2023, with LNG accounting for the majority of its gas imports. Other countries such as Argentina, Brazil, the Dominican Republic, and Puerto Rico also imported LNG, with Colombia, El Salvador, Jamaica, and Panama being smaller importers. By 2050, Brazil is expected to emerge as the region's leading LNG importer, accounting for 21 Mt or more than 50% of the region's total LNG imports.

The influx of United States LNG into Latin America presents opportunities and challenges. Importers stand to benefit from access to affordable United States LNG, expanding their energy sources. At the same time, exporters face increased competition for market share both domestically and internationally due to the competitively priced United States LNG.

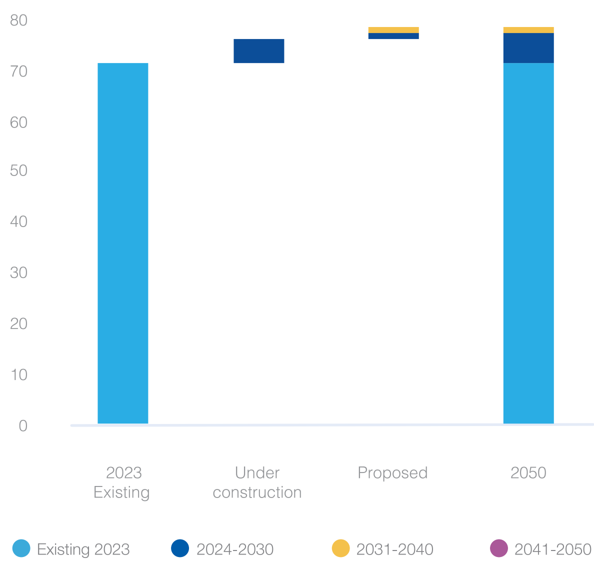
Currently, Latin America has approximately 71 Mtpa of LNG regasification capacity, with an additional 5 Mtpa under construction and a further 2 Mtpa potentially proposed for development in countries such as Aruba, Brazil, Colombia, the Dominican Republic, Ecuador and others over the forecast period (Figure 6.28).

Through dedicated export pipelines, Bolivia plays a significant role in supplying natural gas to its neighbours, Brazil and Argentina. The natural gas sector is crucial to Bolivia's economy, with sales to these two countries accounting for over 100% of total gas sales. Bolivia exports gas through three key pipelines: (i) GIJA to Argentina, with a capacity of 10.2 bcma; (ii) Gasbol with 11.5 bcma capacity; and (iii) Gasyrg to Brazil. Bolivia is exploring opportunities to diversify its export markets, with plans to connect to the Gasoducto Sur Peruano in Peru and the Port of Montevideo in Uruguay, giving the landlocked country access to ports on both sides of South America.

Brazil is expected to see a significant rise in natural gas import demand in the coming years while developing LNG import options to supplement declining pipeline imports from Bolivia. In 2023, Brazil's gas imports dropped dramatically to 6.6 bcm, a nearly 60% decrease from 2021, as the country recovered from a severe drought and reduced reliance on hydropower. If needed, Brazil's primary flexibility in scaling up LNG imports lies in accessing LNG exports from the United States. By 2050, Brazil is projected to remain a net importer of natural gas, with imports reaching up to 30 bcma, primarily as LNG (around 21 Mt), and with 40 Mtpa of LNG regasification capacity in place. The

Figure 6.28

Latin America LNG regasification capacity outlook, 2023-2050 (Mtpa)



Source: GECF Secretariat based on data from the GECF GGM

country currently operates nine LNG import terminals with a combined capacity of 40 Mtpa, all in the form of FSRU. Brazil imported only 0.7 Mt of LNG in 2023. It also imported 5.4 bcm via pipeline from Bolivia in 2023 and is set to increase gas imports from the Vaca Muerta field.

Argentina, a key market for Bolivian gas exports, is poised to transition into a net exporter of natural gas in the medium and long term, fueled by the increased production from the Vaca Muerta shale deposit and the development of the Nestór Kirchner gas pipeline system. In 2023, Argentina remained a net importer of natural gas, importing 2.5 bcm of pipeline gas from Bolivia and 2.5 bcm (1.8 Mt) of LNG, mainly from the United States. By 2040, Argentina is projected to become a net exporter, with its net exports potentially reaching up to 10 bcm annually by 2050. The country is expanding its gas pipeline network, with the first phase of the Nestor Kirchner pipeline launched in July 2023, linking the Vaca Muerta field to Buenos Aires. The second phase, set to be completed by 2025, will connect Vaca Muerta to Santa Fe, increasing capacity to 16 bcma. Argentina has also agreed to construct an LNG facility at Vaca Muerta (Bahia Blanca), which, when completed, will be capable of exporting up to 25 Mtpa of LNG.

Trinidad and Tobago is Latin America's leading LNG exporter, with 7.7 Mt of LNG exported in 2023. Over 80% of these exports were to Latin America and Europe, with the remainder going to the Asia Pacific region. The country's LNG exports are projected to stabilise at 8 Mt during 2030 - 2040. However, there is a potential for a volume decline beyond this timeframe. Future growth is anticipated from the Dragon field's joint development with Venezuela, utilising Trinidad and Tobago's liquefaction infrastructure. Additional exploration and new gas fields are also under consideration, which may alter these forecasts.

Peru was the second-largest LNG exporter in South America in 2023, exporting 3.7 Mt of LNG via the Peru LNG (T1) facility, which has a capacity of 4.5 Mtpa. Projections suggest that Peru's LNG exports will stabilise at 4 Mt from 2030 to 2040 and decline afterwards through 2050.

Venezuela, which currently does not export natural gas, holds significant potential in the sector. Venezuela may begin exporting natural gas to Trinidad and Tobago, potentially supplying the country's primary Atlantic LNG plant. Venezuela has also been importing gas from Colombia, with efforts underway to revive the pipeline project between the two countries, offering a feasible export avenue for Venezuela.

6.5.6 Middle East

In recent years, the Middle East has seen a notable increase in natural gas demand, driven by population growth and the subsidisation of gas prices. These subsidies were designed to promote economic development, support energy-intensive industries, and share the benefits with the local population.

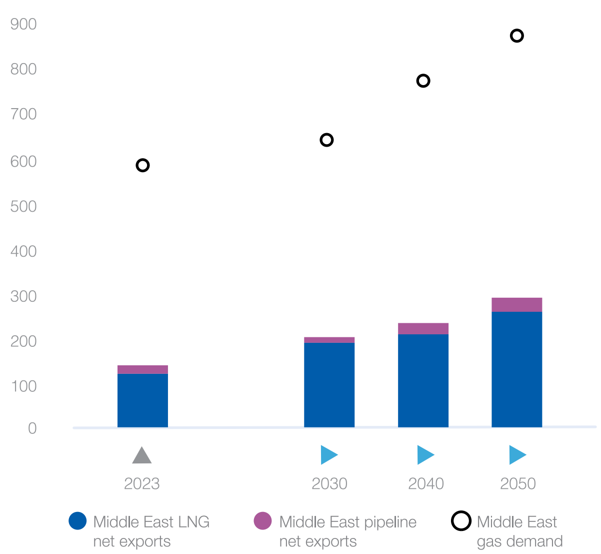
At the same time, the region's vast natural gas reserves have created opportunities for expanded trade. While LNG exports to Asia and Europe have been the main focus, regional gas trade - both within the Middle East and beyond - has also involved smaller volumes transported through export pipelines. These include pipelines connecting Qatar to the UAE and Oman, Iran to Iraq and Türkiye, Armenia and Azerbaijan, and Israel to Jordan and Egypt.

The key driver of the Middle East's natural gas exports is expected to be the growth in LNG supplies, with Qatar at the forefront. Qatar's position as a leading global LNG exporter is set to strengthen further, with 2024 marking the continued expansion of its liquefaction capacities. Qatar aims to nearly double its LNG production capacity, increasing output by approximately 85% from the current 77 Mtpa to 142 Mtpa by 2030. This ambitious growth, led by the North Field Expansion project, will be implemented in three phases - through the North Field East (NFE), South (NFS), and West (NFW) expansion projects - and could contribute to a global oversupply later in the decade. This significant expansion will underpin Qatar's continued and sustainable economic growth, aligning with the Qatar National Vision 2030.

In 2023, the Middle East's net gas exports reached 139 bcm (Figure 6.29). Projections suggest a substantial increase, with total net exports expected to rise to 289 bcm by 2050. In 2023, the region contributed 96 Mt to global LNG exports, accounting for 23% of the worldwide total. Qatar was the top global LNG exporter,

Figure 6.29

Middle East natural gas demand and net exports outlook by flow type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

shipping 78 Mt, followed by Oman and the UAE, which exported 12 Mt and 5 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 2023, the Middle East imported 7 Mt of LNG, with Kuwait being the dominant importer, accounting for 6.1 Mt. The UAE also imported 0.7 Mt of LNG. Since 2020, Jordan's gas market has shifted towards regional pipeline gas, with LNG now serving a supplementary role in meeting the country's gas needs.

By 2050, LNG exports from the Middle East are projected to reach 202 Mt, driven largely by expansion efforts in Qatar. It is expected for the Middle East to significantly increase LNG net exports to 188 Mt by mid-century. Long-term LNG imports are expected to grow to 14 Mt by 2050, with Kuwait accounting for around 50% of this growth.

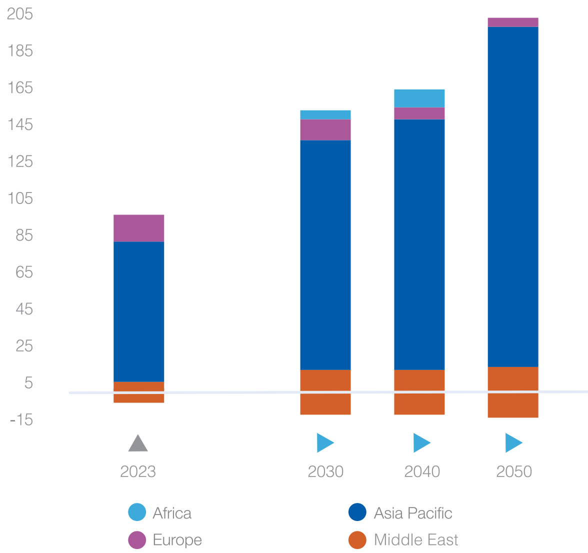
Asia Pacific will remain the primary destination for Middle Eastern LNG. By 2050, the Asia Pacific region is expected to receive over 178 Mt, representing around 90% of the region's total LNG exports (Figure 6.30). Exports to Europe will decline significantly by mid-century reflecting Europe's shift towards alternative energy sources. Africa's role as a destination will diminish following a rise by 2030. The Middle East remains 100% self-sufficient in LNG imports, underscoring its dominant supply position. This trend highlights the growing Asia-centric nature of Middle Eastern LNG exports and a declining reliance on European markets.

The Middle East currently has 95 Mtpa of liquefaction capacity (Figure 6.31), with Qatar accounting for 77 Mtpa, Oman for 12 Mtpa, and the UAE for 6 Mtpa. From 2023 to 2050, the region might consider adding up to around 124 Mtpa of new LNG liquefaction capacity, with Qatar spearheading the expansion. Utilisation of this increased capacity is expected to stay around 92% by 2050. Additionally, Oman is considering adding 1 Mtpa of liquefaction capacity, and Iraq and Iran may develop LNG facilities in the 2030s and 2040s, respectively. The UAE's planned new additional liquefaction facility, originally scheduled for Fujairah, has been relocated to Ruwais (Abu Dhabi) with a capacity of 9.6 Mtpa. Qatar's NFE and NFS expansion projects, currently under construction, will add 48 Mtpa, and the NFW expansion project to add another 16 Mtpa. By the end of 2023, NFW is considered an announced project and its development is underway.

The Dolphin gas pipeline, the largest in the Middle East, connects Qatar's North Field to the UAE and Oman. With a capacity of 33 bcma, it currently operates at around 62% of its capacity. In 2023, it delivered 18.8 bcm to the UAE and 1.5 bcm to Oman under long-term contracts expiring in 2032. Iran also has two pipelines

Figure 6.30

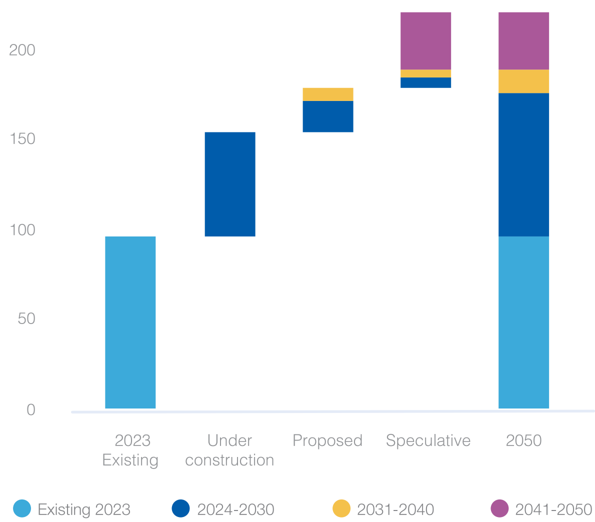
Middle East LNG exports (+) by destination and imports (-) by origin outlook, 2023-2050 (Mt)



Source: GECF Secretariat based on data from the GECF GGM
Note: Regional LNG exports and imports include intraregional trade

Figure 6.31

Middle East LNG liquefaction capacity outlook, 2023-2050 (Mtpa)



Source: GECF Secretariat based on data from the GECF GGM

supplying natural gas to Iraq, serving the Baghdad and Basra regions.

Qatar's LNG exports are expected to grow by 2.2 times, reaching 170 Mt by 2050, up from 78 Mt, while pipeline exports are projected to decrease from 20 bcm to smaller volumes by 2040. The UAE, which exports and imports LNG and pipeline gas, exported 7 bcm (5 Mt) of LNG in 2023 and primarily imported gas from Qatar

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via the Dolphin pipeline, amounting to 18.8 bcm. LNG exports are handled through the Das Island liquefaction plant in Abu Dhabi, which has a capacity of 5.6 Mtpa. By 2050, the UAE is expected to remain a net exporter of LNG, with its LNG exports growing and reaching 13 Mt.

Oman's natural gas trade will continue to consist predominantly of LNG exports. In 2023, Oman exported 12 Mt of LNG, with over 90% of the exports directed to the Asia Pacific region. Oman's LNG exports are expected to remain steady at 10 Mt by 2030, gradually declining to 8 Mt by 2040 and further decreasing by 2050. The country operates a single LNG liquefaction facility at Qalhat, with three units and a combined capacity of 10.4 Mtpa. In early 2024, the country, in partnership with TotalEnergies, reached a final investment decision (FID) to develop the 1 Mtpa Marsa (Sohar) LNG bunkering project, which is scheduled to commence operations in 2028. This project is set to establish Marsa LNG as the Middle East's first LNG bunkering hub, positioning LNG as an alternative marine fuel to help reduce emissions in the shipping industry.

Iran has substantial gas export potential. In 2023, Iran exported 20 bcm of gas, with the majority exported to Iraq (9.2 bcm), then Türkiye, with smaller quantities sent to Armenia. While plans for additional pipelines connecting Iran to Oman, Pakistan, Turkmenistan, and India have been proposed, progress has been limited. Over the long term, through 2050, Iran aims to maintain its natural gas exports at a steady level of 16 bcm. While the country's natural gas production is expected to increase, this growth will likely be matched by a rise in domestic consumption. Also, the Turkmen government recently announced plans to construct a new gas pipeline to Iran and increase annual shipments to 40 bcma. In the summer of 2024, Turkmenistan signed a swap agreement with Iran to supply 10 bcm of natural gas annually. Under this arrangement, Iran will deliver equivalent volumes of gas to Iraq on behalf of Turkmenistan, facilitating the flow of energy resources between the two regions.

Iraq has significant gas export potential but remains a net importer, receiving 9.2 bcm of gas from Iran in 2023. Iraq has finalised a five-year agreement with Iran to import 50 mcm/day of natural gas in spring 2024. Iraq relies on Iranian gas for its power generation sector. Although Iraq's gas export potential is currently limited by pipeline constraints and the lack of LNG infrastructure, it may consider starting LNG exports post-2030 and ramping up its LNG exports to reach 11-13 bcm through 2040-2050.

Despite its dominant role in the global oil market, **Saudi Arabia** currently uses all of its gas production domestically and has no immediate plans or strategies to export LNG or pipeline gas. However, in the long term, the country seeks to position itself as a major player in the LNG market through strategic investments and partnerships. In 2023, Saudi Aramco acquired a minority stake in MidOcean Energy from EIG Global Energy Partners for $500 million, marking its first international LNG investment. By December 2024, Aramco had increased its stake to 49%. In mid-2024, Aramco entered non-binding agreements with NextDecade for a 20-year LNG offtake from the Rio Grande LNG project and Sempra for 5 Mtpa of LNG from the Port Arthur LNG Phase 2 expansion. The agreement with Sempra also includes a potential 25% equity stake in the Phase 2 project.

6.5.7 North America

Currently, North America is the largest global consumer of natural gas. North America's natural gas demand is projected to grow marginally over the 2030s, supported by its sustained use in the power sector. This growth is anticipated to be driven by the retirement of coal-fired power plants and increased electricity demand from data centres, fuelled by advancements in artificial intelligence (AI). CCUS could also support maintaining gas demand.

In the long run, while the region's natural gas demand is expected to decrease marginally by 77 bcm in 2050 compared to 2023 levels, the region's net natural gas exports are projected to increase 2.6 times over the same period.

In 2023, North America's total (gross) natural gas exports, including intra- and inter-regional trade, totalled around 285 bcm. Of this, approximately 40% or 85 Mt was exported as LNG, all of which came from the United States and was primarily directed toward European consumer markets.

Net exports are anticipated to rise from 115 bcm in 2023 to around 300 bcm by 2050, with LNG exports accounting for nearly all of this growth (Figure 6.32). Global demand for North American LNG exports remains robust, driven by increased LNG demand in Europe, especially by the 2030s.

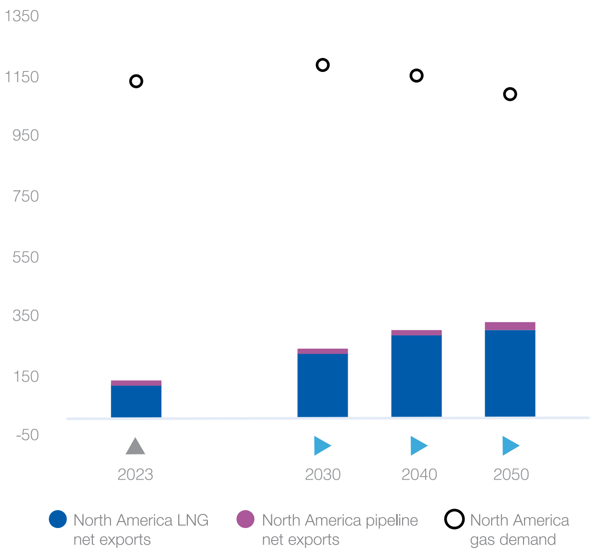
By 2050, North America's LNG exports will reach 219 Mt, with Asia Pacific absorbing 63% of these volumes, marking a significant shift in trade flows towards the region. Exports to Europe will decline to 28% by mid-century, indicating reduced European dependency on North American LNG, possibly due to diversification strategies and evolved domestic energy mix. Latin America's share will remain modest at 9%. **Overall, North America will reinforce its role as a major LNG supplier, particularly to Asia Pacific, as global trade patterns adjust to long-term energy transitions and regional demand shifts** (Figure 6.33).

Globally, the sustained momentum in LNG contracting is underpinned by buyers' growing focus on gas supply security and reliability. The ever-increasing North American LNG production and depletion of low-cost supply may pose a potential downside risk, manifesting in higher prices or diminished LNG export capacity from the region in the medium to long term.

From 2023 to 2050, North America is projected to play a crucial role in driving the global growth of LNG supply. Exports are expected to surge significantly, outpacing the growth rates of other regions. North America's LNG exports could rise to 164 Mt by 2030 and further increase to 219 Mt by 2050.

Figure 6.32

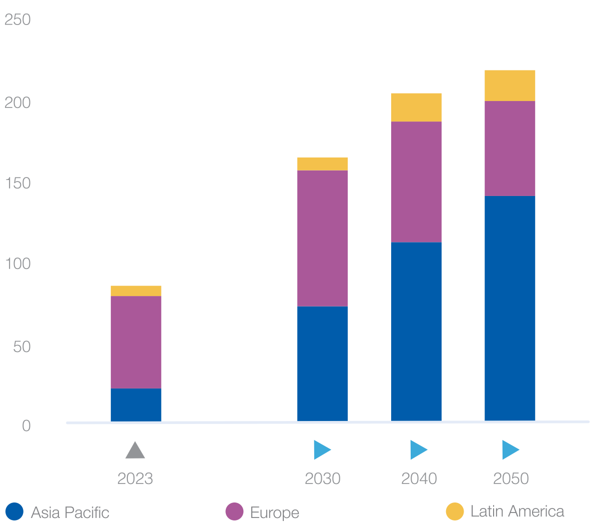
North America natural gas demand and net exports outlook by flow type, 2023-2050 (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Figure 6.33

North America LNG exports outlook by destination, 2023-2050 (Mt)



Source: GECF Secretariat based on data from the GECF GGM

The outlook for LNG exports remains strong, fuelled by a robust portfolio of pre-FID projects, mainly in the United States. In 2023 and 2024, LNG contracting activity shifted toward longer contract durations and a growing preference for larger-volume agreements. Recent United States regulatory delays for non-FTA LNG projects have slowed United States LNG development, while Mexican and Canadian projects continue to advance. United States LNG FIDs are expected to resume in 2025.

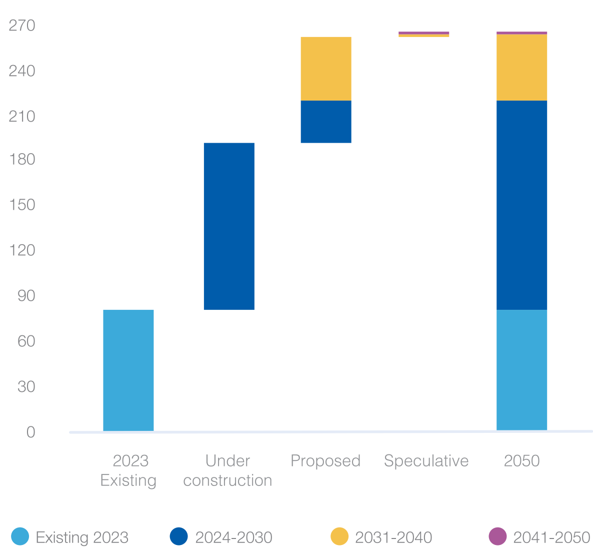
The ongoing construction of LNG export facilities in the United States and other regions is expected to add over 200 Mtpa to global supply by the decade's end. Post-2028, United States LNG exports are most likely to rebound from the recent 'pause' in project approvals as President Trump lifted the moratorium in January 2025.

By 2023 end, North America's LNG liquefaction capacity, totalling 82 Mtpa (Figure 6.34), was entirely concentrated in the United States. There are currently around 111 Mtpa of LNG liquefaction capacity under construction in the North America, 85 Mtpa in the United States, 19.4 Mtpa in Canada and 7.5 Mtpa in Mexico. **By 2050, North America is expected to account for around 27% of the global LNG production capacity, reaching nearly 268 Mtpa, with the United States contributing the majority (216 Mtpa), followed by Canada and, to a lesser extent, Mexico.** As a result, the United States is set to lead the expansion of global LNG liquefaction capacity and maintain its position as the world's largest LNG supplier from 2023 to 2050.

Canada, a net exporter of natural gas, is expected to see its net exports grow from 58 bcm in 2023 to 98 bcm by 2050, largely due to a rise in LNG exports, particularly

Figure 6.34

North America LNG liquefaction capacity outlook, 2023-2050 (Mtpa)



Source: GECF Secretariat based on data from the GECF GGM

to the Asia Pacific region. By 2050, Canada is projected to account for over 15% of North America's LNG exports, up from zero at present. The Canadian natural gas market is tightly linked to the United States via an extensive pipeline network, primarily exporting gas to the United States, especially to the Midwest region, where significant gas-fired power generation exists. Canada's natural gas exports to the United States will remain stable at around 70 bcm by 2050.

Over the past decade, several LNG export projects have been proposed in Canada's West Coast and eastern regions, securing export licenses. However, as of 2024, only three projects are actively under construction - LNG Canada (T1, T2), Cedar FLNG and Woodfibre LNG (T1, T2). LNG Canada's first phase, designed to produce 14 Mtpa, is set to begin shipments in 2025. There are plans for a second phase, potentially doubling its capacity to 28 Mtpa by 2035. Other projects, Woodfibre LNG with 2.1 Mtpa and Cedar LNG with 3.3 Mtpa, both having taken FIDs in 2022 and 2024, respectively, are planned to come online in 2027-2028. Proposed LNG liquefaction projects, including Ksi Lisims LNG and LNG Canada Phase 2 with Trains 3 and 4, are advancing through various development stages. These projects could bring Canada's total LNG export capacity to nearly 34 Mtpa by 2050.

In 2023, **Mexico** imported 63 bcm of natural gas from the United States via pipelines. By 2050, these imports are expected to rise to 109 bcm, driven by declining domestic production and rising demand in the power sector and LNG exports. Mexico is tapping into LNG export potential on its Pacific coast, capitalising on low-cost natural gas resources in the United States and its strategic location to access the growing Asia Pacific market. As a result, Mexico is poised to become a significant LNG exporter, with its exports forecast to be around 17 Mtpa by 2050.

Mexico's LNG infrastructure includes the pioneering floating LNG (FLNG) hub near Altamira, Tamaulipas, which will host up to three 1.4-Mtpa FLNG units by 2027. The first unit became operational in 2024 and delivered its first LNG to Europe in October 2024. Energia Costa Azul (ECA) LNG Phase 1, converting an existing import terminal to an export facility, will begin operations in 2025. Another major project, Saguaro Energia's LNG facility in Sonora, will have a capacity of 9.4 Mtpa, with Phase 1 set for commercial operations in 2030.

In 2023, the **United States** net-exported over 121 bcm of natural gas, with 118 bcm (85 Mtpa) shipped as LNG and the remainder transported via pipelines to Mexico and Canada. By 2050, United States net exports are expected to reach 308 bcm, with LNG exports accounting for 251 bcm (182 Mtpa), constituting over 70% of total United States natural gas exports.

Key United States LNG projects currently under construction include five mega projects: Corpus Christi Stage 3 (10.4 Mtpa), Golden Pass (18 Mtpa), Plaquemines (20 Mtpa), Port Arthur (13.5 Mtpa), and Rio Grande (17.6 Mtpa). These projects are set to add 80 Mtpa of capacity between 2024 and 2028. As of February 2025, the Calcasieu Pass LNG project (5.7 Mtpa) remains in commissioning but is classified as "under construction" in projections. This brings total United States liquefaction capacity under construction to 86 Mtpa, with potential expansion to 216 Mtpa by 2050.

In the United States, most LNG contracts extend beyond 2030, with about 75% of contracts on a free-on-board (FOB) basis, providing flexibility for redirection and reselling. Of the 93 Mtpa in contracts expected between 2024 and 2027, 32% are committed to Asian buyers and 26% to European buyers, highlighting the shift towards flexible, end-user contracts.

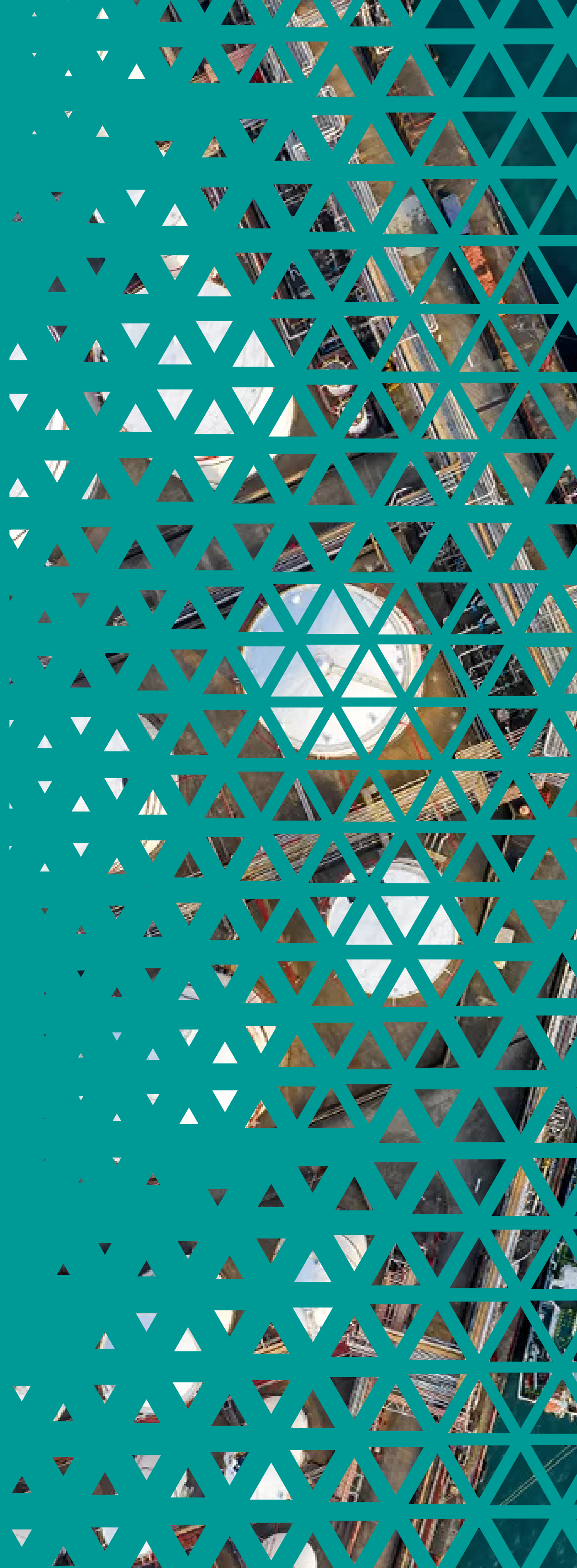
The United States industry is grappling with rising costs, particularly due to escalating EPC (Engineering, Procurement, and Construction) expenses. Many projects have encountered higher-than-expected costs, and the bankruptcy of several EPC firms has disrupted timelines for initiatives like Golden Pass, limiting contractor availability and causing delays and uncertainty. This is especially critical as the United States is currently experiencing a slowdown in the approval of new LNG projects.

Additionally, gas production costs in the United States are under increasing pressure due to inflation and the depletion of the most accessible and productive reserves. Another factor impacting the industry's outlook is the introduction of methane emissions fees, which will begin in 2024 at USD 900 per metric ton and rise to USD 1,200 per ton by 2026. LNG producers, along with other stakeholders in the supply chain, will either need to bear these costs or invest in technology to reduce methane emissions. This move mirrors the European Union's efforts to restrict methane emissions from hydrocarbon imports.

Chapter 6

Chapter 7

Natural Gas Investment Outlook



Highlights

- In 2023, global upstream oil and gas investment reached USD 577 billion. Upstream natural gas development accounted for an estimated USD 165 billion, or 29%, up from USD 142 billion in 2022.
- Natural gas cumulative investment is projected to reach USD 11.1 trillion by 2050, with 94% of this spending or USD 10.4 trillion allocated to upstream developments.
- By 2050, North America and Asia Pacific will lead global upstream investments, accounting for 28% (USD 2.9 trillion) and 23% (USD 2.4 trillion) of total spending, respectively. This growth is driven by unconventional resource development. North America's reliance on non-associated unconventional resources demands continuous drilling and high capital investment to offset rapid decline rates, raising the production costs.
- The Middle East, accounting for 14% of global upstream investment requirement, is set to provide one-fifth of cumulative gas production over the forecast period, benefiting from lower decline rates and unit development costs.
- Eurasia will dominate capital spending on conventional yet-to-find (YTF) resources by mid-century, accounting for nearly 29% of required investment, driven by its extensive untapped reserves.
- The long-term marginal cost of natural gas supply is expected to rise as the industry turns to more difficult to find and produce resources. This reflects the growing reliance on new long-cycle conventional greenfield projects and discovered YTF resources to sustain production.
- Of the USD 704 billion projected for gas midstream investments projected by 2050, LNG developers are expected to alloacted arround USD 435 billion toward liquefaction projects, while USD 214 billion is forecast for regasification facilities.
- From 2023 to 2050, midstream investments will begin with intense early spending in Asia Pacific, North America, and Europe, gradually shifting toward export-driven projects in Africa and Eurasia.
- The Asia Pacific region is projected to lead in spending on natural gas export infrastructure from 2023 to 2050, with nearly USD 200 billion, representing 28% of overall global midstream investment requirements. Additionally, the region will also dominate global regasification investments, with expenditures reaching USD 152 billion accounting for 71% of total regasification spending.

The global natural gas capital investment landscape is set to transform significantly, with cumulative investments projected to approach USD 11.1 trillion by 2050. This substantial capital allocation highlights the critical role of natural gas in the global energy mix as a reliable enabler of energy security and a key driver of just, orderly, and equitable energy transitions. Investments across both upstream and midstream sectors will be essential to meeting rising demand, offsetting the natural decline of existing fields, and expanding infrastructure for LNG trade and domestic distribution.

The year 2023 marked a pivotal turning point for natural gas investments, characterised by a notable rebound driven by geopolitical shifts, heightened energy security concerns, and the increasing need for cleaner energy solutions. This investment upturn followed 2022's reversal of a decade-long trend of chronic underinvestment in the sector. Upstream investments in 2023 focused on exploration, field development, and maintaining output from mature fields, while midstream investments prioritised LNG infrastructure expansions, including liquefaction and regasification facilities, to address surging global demand. Regions such as North America, the Middle East, and Asia Pacific led these efforts, leveraging resource development and technological advancements to enhance operational efficiency and reduce emissions.

Looking ahead to 2050, global natural gas investments are expected to maintain a robust upward trajectory. Approximately 94% of cumulative spending is projected to be allocated to upstream activities, with the remaining 6% directed toward midstream infrastructure. Upstream investments will be directed in priority developing conventional and unconventional resources, with substantial funding for greenfield projects to unlock untapped reserves and brownfield optimisations to extend the productive life of existing fields. Midstream investments will focus on LNG infrastructure expansions, with leading liquefaction facilities in Qatar, Australia, and the United States playing pivotal roles. Europe and Asia will emphasise regasification capacity to diversify gas imports and strengthen energy security.

Several key trends are shaping the investment outlook for natural gas, reflecting its evolving role in the global energy mix. The heightened focus on energy security, driven by geopolitical uncertainties, underscores natural gas as a reliable and flexible energy source. At the same time, decarbonisation initiatives, including the adoption of CCUS technologies, are increasingly shaping investment priorities as stakeholders aim to align with global climate goals. Advances in extraction and processing technologies drive operational efficiency while integrating digital innovations, particularly AI, which are set to transform the sector further. AI's applications, such as predictive maintenance, reservoir optimisation, and real-time data analytics, reduce production costs and improve project viability. Additionally, the substantial demand growth projected in emerging markets, particularly in Asia Pacific and Africa, redirects investment flows toward regions with significant untapped resources and growing energy needs.

This chapter will provide a detailed analysis of capital spending requirements for upstream and midstream natural gas investments. It will examine recent developments and long-term investment needs in the natural gas sector, focusing on upstream and midstream segments. It will also explore how these investments align with global energy security and sustainability objectives.

7.1 Upstream natural gas investment trends

In 2023, global upstream oil and gas investment reached approximately USD 577 billion, representing an 11% increase from the USD 520 billion spent in 2022. This growth marks a sustained recovery in capital spending following nearly a decade of underinvestment. Notably, upstream natural gas development, including exploration, development, and production, accounted for an estimated USD 165 billion, an increase from USD 142 billion in 2022 (Figure 7.1).

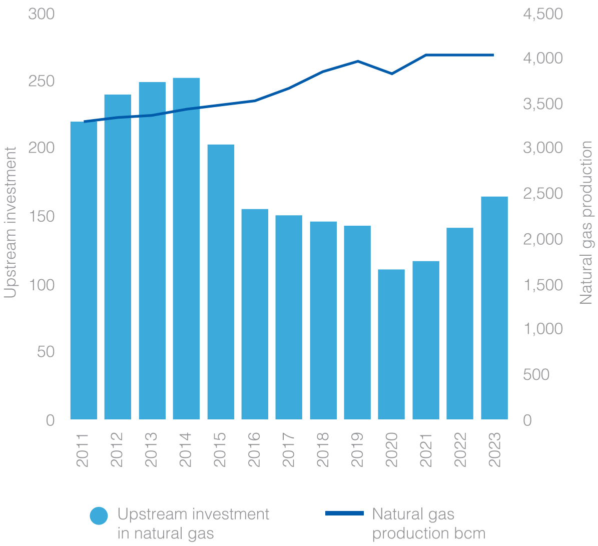
The resurgence in investment was driven by geopolitical disruptions, underscoring the critical importance of energy security. Elevated commodity prices and record corporate profits also incentivised companies to prioritise natural gas projects, especially those supporting LNG exports to Europe and Asia. Companies have predominantly funded these investments through operational cash flows, a significant shift from previous years when external financing played a more prominent role. This financial independence has allowed for more targeted capital allocation, focusing on high-demand regions and strategic projects aligned with long-term growth and decarbonisation objectives.

Key trends in natural gas investment in 2023 include a strong focus on LNG infrastructure, with FIDs on major projects in North America, Qatar, and Africa. For example, the United States led LNG infrastructure investments, with over USD 35 billion committed to expanding liquefaction capacity along the Gulf Coast. Qatar's North Field Expansion also remained a flagship project, with estimated investments exceeding USD 30 billion. In Africa, Mauritania, Mozambique, and Senegal LNG developments have progressed aimed at capitalising on growing demand in Asia and Europe.

Onshore and offshore natural gas field developments also saw renewed capital inflows, particularly in regions with cost-competitive production. North America invested heavily in shale gas development, allocating approximately USD 50 billion to upstream projects, driven by technological advancements and high demand

Figure 7.1

Upstream CAPEX (USD billion) and natural gas production (bcm)



Source: GECF Secretariat based on data from the GECF GGM

for LNG exports. Meanwhile, deepwater gas projects in Brazil and offshore Africa received increased attention, with capital directed toward fields offering low breakeven costs and scalable production.

Operating and capital costs in the upstream sector have experienced significant volatility over the past two years, driven by supply chain disruptions and global inflation. Essential components such as pressure pumps, drilling fluids, and pipeline steel faced shortages, resulting in project delays and cost escalations. In 2022, these disruptions caused operating and capital expenditures to rise by approximately 10–15%, compounded by an additional 15% increase due to inflation across exploration, extraction, transportation, and refining activities. By 2023, capital expenditure per unit of production averaged USD 12.5/MMBtu, up from USD 11.2/MMBtu in 2022, as reported by Rystad Energy (2024). This increase reflects the cumulative effects of inflationary pressures and supply chain constraints. For example, steel prices surged by 50%, significantly impacting the costs of tubular commodities, while well development expenses climbed by 25–30% as service costs rose. Deepwater projects followed a similar pattern, with capital expenditures increasing by 15–20% due to the logistical complexities and higher costs associated with specialised offshore equipment and rigs. These rising costs underscore the challenges the upstream sector faces as it balances financial pressures with the need for continued investment to meet growing energy demands.

Despite these challenges, companies have increasingly turned to technology-driven efficiency improvements to mitigate cost pressures. Investments in automation, digitalisation, and advanced data analytics have become critical to enhancing operational uptime and optimising resource allocation. Predictive maintenance systems and remote monitoring tools have allowed operators to reduce unplanned downtime, while machine learning algorithms have improved drilling accuracy and resource recovery rates. These innovations have offset rising expenses and enabled sustained production growth even in a high-cost environment.

Decarbonisation considerations have also emerged as a central theme in shaping upstream investment strategies during this period. Increasingly stringent environmental regulations and growing investor expectations for decarbonisation have driven oil and gas companies to allocate significant capital toward emissions reduction technologies. CCUS projects, along with methane abatement initiatives, have received heightened attention as part of broader efforts to align operations with global climate objectives. In 2023, major oil and gas companies allocated an estimated 15–20% of their capital expenditures to low-carbon initiatives, reflecting both regulatory pressures and the strategic necessity of reducing Scope 1 and Scope 2 emissions. These investments have introduced additional cost burdens but are seen as critical to maintaining the sector's social license to operate in a rapidly decarbonising world. However, this may change with the onset of a new administration in the United States.

Mergers and acquisitions (M&A) activity has also played a transformative role in reshaping the upstream investment landscape during 2022 to2023. Total upstream gas deals surged to USD 115 billion in 2022, up from USD 80 billion in 2021. Although M&A activity moderated slightly to USD 110 billion in 2023, it remained robust, focusing on strategic acquisitions aimed at increasing production capacity, optimising operations, and maximising value from mature gas fields. North America accounted for the largest share of gas M&A, with approximately USD 45 billion in transactions centred on shale gas and LNG infrastructure. Notable deals included BP's acquisition of United States LNG assets and Chesapeake Energy's strategic mergers to consolidate its portfolio. In Europe, M&A activity concentrated on North Sea assets, driven by regulatory pressures and the need to ensure regional supply resilience. Meanwhile, Asia-Pacific and the Middle East saw significant activity in LNG terminals and production facilities to secure long-term gas supplies for growing demand centres.

The financial strength of oil and gas companies in 2023 provided significant flexibility in capital deployment. Record profits, strengthened by elevated oil and gas prices, enabled firms to prioritise shareholder returns while maintaining substantial cash reserves. According to S&P Global, companies now face strategic decisions about allocating these reserves, balancing reinvestment in traditional upstream projects with expanding low-carbon portfolios. This strategic dilemma reflects broader industry challenges as firms navigate immediate energy security needs alongside long-term sustainability goals.

Numerous oil and gas companies are navigating increasing investor pressures to allocate cash flows toward decarbonisation and diversification initiatives, such as CCUS, hydrogen production, and renewable energy ventures, while maintaining robust shareholder returns. This pressure reflects a growing consensus among investors that the industry must align with global sustainability goals while ensuring continued profitability. Recognising the cyclical nature of the oil and gas industry, companies have exercised caution in committing to large-scale projects based solely on high prices, as profits remain subject to unpredictable market dynamics. This cautious approach is reflected in the growing preference for small-to-medium-scale projects, which typically require USD 200 million to USD 1 billion. These projects offer shorter payback periods, often less than five years, and carry reduced risks of becoming stranded assets as energy transition policies accelerate.

As shown in Figure 7.2, the global natural gas supply has increasingly depended on short-cycle and brownfield production, representing a significant share of new upstream activity in 2023. However, the share of greenfield projects saw a relative increase in 2023 compared to 2022, reflecting renewed efforts to develop untapped resources and expand production capacity. This trend has helped address immediate supply needs and masked the long-term effects of underinvestment in large-scale conventional gas projects. The shift toward short-cycle production has contributed to an increase in the global natural decline rate to approximately 6%, up from 4% in the mid-2010s, reflecting a growing reliance on rapidly depleting resources.

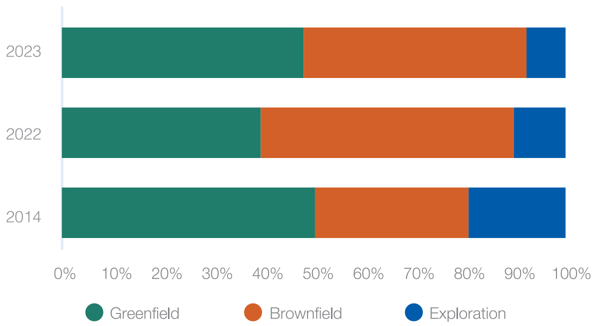
Globally, the responsiveness of natural gas production to price increases has been constrained by a combination of fiscal discipline, rising costs, and a focus on shareholder returns. For instance, while European and Asian spot LNG prices remained elevated in 2023, the pace of production growth from key suppliers, including regions with significant conventional reserves, lagged behind historical expectations. In regions such as North America, natural gas production growth slowed despite robust demand and relatively high prices, reflecting a broader trend of cautious capital allocation. Similarly, the Middle East and Africa, though holding vast reserves, faced challenges in ramping up production due to logistical bottlenecks and delayed project timelines.

Without sufficient reinvestment in long-cycle projects such as offshore gas fields, major onshore developments, or LNG feedstock infrastructure, the risk of a significant global supply shortfall becomes increasingly likely. This would exacerbate market volatility and pose a substantial threat to the stability of international energy security, particularly as demand for natural gas continues to grow in regions like Asia and Europe. Enhancing capital investment in conventional and unconventional resources remains critical to ensure long-term market balance.

In 2023, the industry's recalibration of strategies highlighted its ongoing balancing act: addressing immediate energy security demands while laying the groundwork for the long-term challenges of a decarbonising global economy. This period saw companies leveraging advanced technologies, including AI-driven exploration tools, digital twins, and predictive analytics, to enhance operational efficiency and optimise decision-making across complex supply chains. These innovations enabled firms to maximise returns from short-cycle and long-cycle projects, reducing lead times and improving asset utilisation. Additionally, targeted capital allocation strategies reflected a nuanced approach to balancing short-term profitability with investments in low-carbon technologies, such as CCUS and renewable gas solutions. As the industry navigates this pivotal phase, the dual emphasis on near-term supply resilience and long-term sustainability signals a profound transformation in global energy systems, reshaping the sector's role in delivering reliable, affordable, and cleaner energy.

Figure 7.2

Natural gas upstream CAPEX by type, 2014, 2022 and 2023 (%)



Source: GECF Secretariat based on data from the GECF GGM

7.1.1 Upstream natural gas investment requirement

The outlook for upstream gas investments represents a critical juncture, with substantial increases projected to meet rising global demand, ensure energy security, and counterbalance natural declines from existing fields. **Over the 2023–2050 outlook period, cumulative investment in the upstream sector is estimated at USD 10.4 trillion, averaging approximately USD 385 billion per year (base year = 2023)**. This projection reflects an upward revision from earlier forecasts, such as the 8th edition of the Global Gas Outlook (GGO), largely due to higher production costs and a growing reliance on higher-cost assets, including unconventional and yet-to-find (YTF) resources, to satisfy future demand.

As shown in Figure 7.3, the long-term supply cost curve for natural gas is expected to shift upward, particularly at the higher-cost end, as the industry increasingly depends on capital-intensive resources. This trend underscores the urgent need for expanded gas production from new long-cycle conventional greenfield projects, as well as from discovered and YTF resources. These resource types are critical for meeting future demand but are associated with higher production costs due to remote locations, complex extraction processes, and advanced technological requirements. The gradual depletion of mature, low-cost fields further compounds this challenge, forcing operators to pivot toward more expensive resources.

The required pace of capital spending is expected to accelerate over the forecast period, even as natural gas supply growth slows toward the latter stages. This decoupling of investment and supply growth reflects a structural shift in the upstream sector, driven by the transition from easily accessible reserves to more technically challenging and capital-intensive projects. For example, developing deepwater fields or YTF resources often involves extended lead times, higher break-even costs, and increased susceptibility to inflationary pressures in materials and services. Furthermore, the growing integration of decarbonisation technologies, such as CCUS, into upstream projects adds another layer of complexity. While these technologies align with global climate goals, they elevate per-unit investment requirements, intensifying the pressure on capital efficiency.

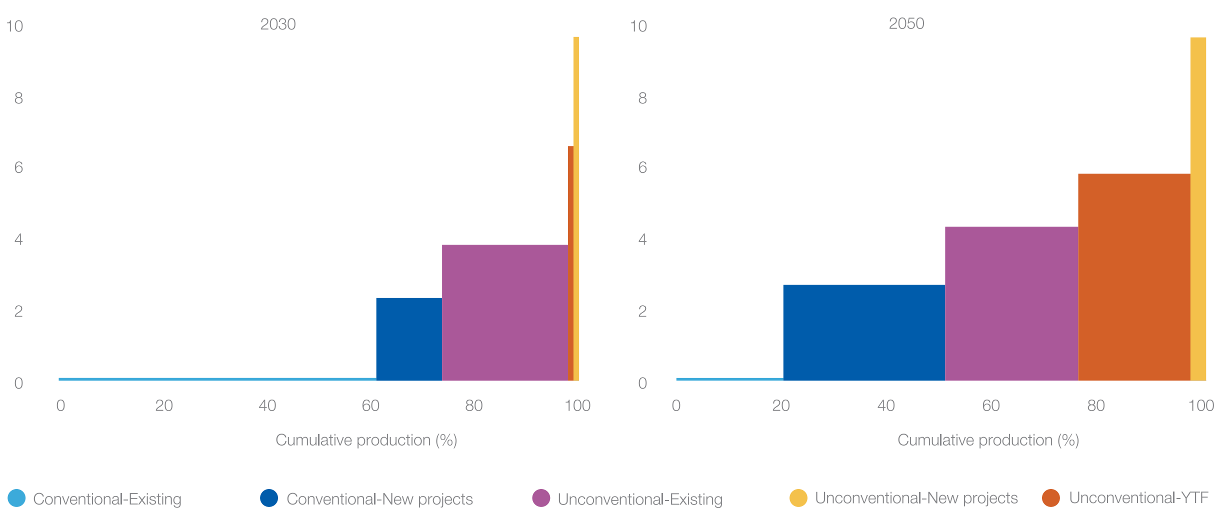
As a result, **operational capital efficiency, the volume of natural gas produced per unit of capital invested, is projected to decline steadily over the outlook period.** This trend underscores technological innovation's increasing importance in managing costs and optimising resource recovery. Advances in digital technologies, particularly AI, hold significant promise in mitigating these challenges by enabling predictive analytics, real-time monitoring, and enhanced operational optimisation. Similarly, enhanced recovery techniques, such as CO_2 injection, alongside digitalisation strategies like predictive maintenance and real-time data analytics, are expected to play pivotal roles in controlling costs and maintaining production levels. These innovations will be especially critical as the industry grapples with the complexities of developing unconventional and costlier conventional resources (see Box 7.1). Nevertheless, despite these advancements, the overall trend reflects a steady increase in operational capital intensity, highlighting the broader challenges and evolving dynamics within the upstream natural gas sector.

Our projections further indicate that unconventional new projects are expected to account for a larger share (33%) of total investment requirements during the outlook period than conventional new projects (25%). However, the share of conventional YTF resources (31%) significantly outweighs that of unconventional YTF assets (9%), demonstrating the continued importance of exploring and developing conventional resources, particularly in untapped regions. Approximately 2% of total investment requirements are attributed to already sanctioned projects, underscoring the need for sustained capital commitments to bring these developments to fruition and ensure a stable supply base.

From a regional perspective, projected investments in upstream natural gas are expected to exhibit significant variation over the 2024–2050 outlook period. North America and Asia Pacific are forecast to lead upstream investments, accounting for approximately 28%

Figure 7.3

CAPEX per unit production by project type, 2030 and 2050 (real USD/MMBtu, base year = 2023)



Source: GECF Secretariat based on data from the GECF GGM

and 23% of total global upstream capital spending, respectively. These regions' dominance reflects their ongoing focus on developing unconventional resources, expanding LNG infrastructure, and maintaining existing production levels. Following closely are Eurasia, the Middle East, Africa, Latin America, and Europe, each contributing to the global investment landscape as they capitalise on their unique resource bases and market dynamics.

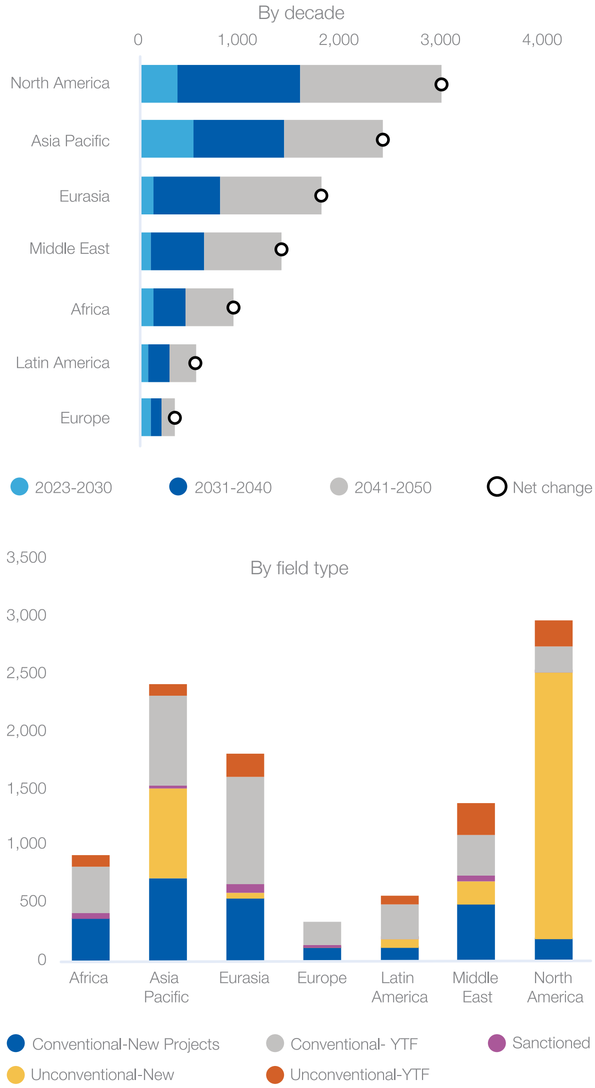
As illustrated in Figure 7.4, capital expenditure is expected to accelerate across all regions, accompanied by rising capital intensity driven by the transition to technically challenging projects, the integration of decarbonisation technologies, and increasing inflationary pressures in materials and services. However, **operational capital intensity remains relatively lower in the Middle East, Eurasia, and Africa than in other regions throughout the outlook period.** This disparity can be attributed to several factors, including the abundance of low-cost, conventional reserves, favourable geological conditions, and ongoing investments in infrastructure in these regions.

The lower operational capital intensity in these regions is expected to enhance their attractiveness as investment destinations for natural gas production, particularly in a global environment where capital efficiency is increasingly critical. The Middle East, for instance, benefits from vast, easily accessible reserves and economies of scale. Africa is emerging as a hub for new gas developments, supported by significant discoveries in Mozambique, Senegal, and Mauritania. Similarly, Eurasia's resource-rich basins and established infrastructure provide a competitive edge for long-term production growth.

Our projections reveal that North America, and the Asia Pacific will dominate investments in unconventional new projects, accounting for 68% and 23% respectively of the required capital over the forecast period. This reflects North America's continued leadership in shale gas production and the Asia Pacific's growing focus on unconventional resources to meet rising regional demand. Conversely, Eurasia is poised to take the lead in capital spending on conventional YTF resources, contributing nearly 29% of the total required investment in this category. This prominence is driven by Eurasia's vast untapped reserves and its strategic importance as a major supplier to global markets.

The Asia Pacific and Africa are projected to follow, accounting for 24% and 13% of conventional YTF capital spending, respectively. In the Asia Pacific, the emphasis will likely remain on offshore exploration and development to support expanding LNG export capacity and domestic consumption. Meanwhile, Africa's significant YTF potential lies in its emerging deepwater and onshore basins, where investments are increasingly geared toward addressing domestic energy access and export opportunities.

Figure 7.4
Regional CAPEX requirement, 2023-2050 (real USD billion, base year = 2023)



Source: GECF Secretariat based on data from the GECF GGM

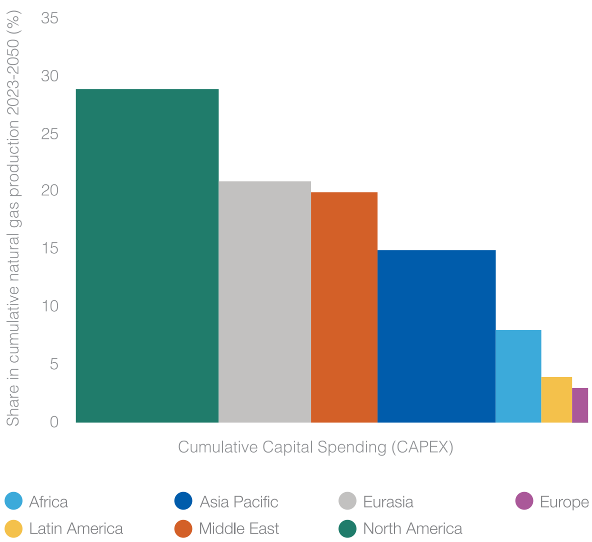
The significant differences in resource base quality, production costs, and technological capabilities across regions lead to variations in how capital expenditure translates into natural gas production growth. Figure 7.5. highlights these disparities, demonstrating the divergent efficiency of regions in converting investment into production over the 2023–2050 outlook period.

With 28% of the required global upstream investment, North America is projected to deliver the most substantial contribution to cumulative natural gas production, accounting for 29% of the global cumulative increase. This reflects the region's heavy reliance on unconventional resources, particularly shale gas, which demands continuous drilling and capital-intensive operations to offset rapid decline rates. Moreover, North America's focus on short-cycle projects prioritises flexibility in responding to market dynamics, which results in lower relative capital efficiency than regions with more extensive conventional reserves.

Eurasia is the second-largest contributor, requiring 17% of global cumulative upstream capital expenditure while contributing approximately 21% of cumulative production. This strong performance is underpinned by large-scale conventional reserves in Russia and Central Asia, supported by significant investments in sustaining output from mature fields and developing untapped resources in remote and challenging areas such as Siberia and the Caspian

Figure 7.5

Regional distribution of cumulative natural gas production vs. cumulative CAPEX, 2023-2050 (%)



Source: GECF Secretariat based on data from the GECF GGM

Basin. However, the region faces higher average production costs than the Middle East due to its extreme climate, geographic remoteness, and logistical complexities, which temper its overall capital efficiency.

The Middle East is the third-largest contributor, delivering one-fifth of global cumulative production while requiring just 14% of total capital investment. This exceptional efficiency stems from the region's abundant, low-cost resources, particularly in Qatar, Saudi Arabia, and Iran, where vast conventional reserves necessitate relatively modest capital outlays for development. Established infrastructure, economies of scale, and high reservoir productivity further enhance the Middle East's ability to achieve significant production growth with minimal investment.

In contrast, Europe is projected to experience a decline in natural gas production despite accounting for 3% of global upstream capital investment. This reflects the maturity of European gas fields, stringent environmental regulations, and high operational costs constraining the region's ability to sustain or expand production. Consequently, European investments are increasingly redirected toward decarbonisation initiatives and securing LNG imports to address domestic energy demand.

These regional variations underscore the critical role of resource quality, production costs, and regional policy environments in shaping the efficiency of upstream investments. **Regions with abundant, low-cost conventional reserves, such as the Middle East and Eurasia, continue to deliver high capital efficiency, whereas regions reliant on unconventional resources, like North America, face diminishing returns on incremental production. Meanwhile, Europe's declining output highlights the growing importance of diversification strategies, including LNG imports and renewable energy investments, to secure its energy future.**

Box 7.1 The transformative role of AI in the natural gas industry: cutting costs, boosting output, and enhancing efficiency

The upstream gas sector, an indispensable pillar of the global energy industry, faces mounting challenges due to market volatility and intensifying competition. Global natural gas prices are expected to remain under pressure in the medium term, driven by an anticipated oversupply in LNG markets, shifting geopolitical balances, and evolving energy policies. According to GECF Global Gas Outlook forecasts, LNG liquefaction capacity is set to increase by over 238 Mtpa between 2024 and 2030, leading to downward pressure on prices and narrowing profit margins for gas producers. Additionally, capital-intensive exploration and production operations continue to strain profitability, with average upstream development costs ranging from USD 5-15 per MMBtu (Rystad Energy, 2024), necessitating stringent cost-cutting measures and efficiency improvements. Oil and gas companies must develop resilient strategies to sustain competitiveness, optimise resource extraction, and navigate unpredictable economic cycles. Integrating AI emerges as a crucial solution to mitigate financial risks, enhance operational efficiency, and ensure profitability in this evolving landscape.

AI, combined with data analytics, the Industrial Internet of Things (IIoT), and digital twin technology, is revolutionising upstream operations by improving decision-making and automating complex processes. Predictive analytics powered by AI can forecast market trends, optimise production schedules, and develop robust hedging strategies to counter price fluctuations.

Machine learning models analyse vast datasets, including historical drilling performance, global supply-demand imbalances, and geopolitical shifts, enabling operators to refine production strategies dynamically. Industry-wide AI adoption has led to an estimated 10-30% reduction in upstream capital expenditures and a 2-10% increase in production output (McKinsey, 2024), reinforcing its role as a profitability driver for oil and gas firms. AI also plays a pivotal role in accelerating decision-making, with AI-driven simulations reducing reservoir modelling time from weeks to minutes and improving asset evaluation and investment decisions (SLB Digital Report, 2024).

AI delivers substantial gains in specific upstream gas activities. AI-driven geological assessments facilitate the rapid mapping of reservoir rock properties and real-time analysis of well logs, reducing data processing time by up to 100 times (TotalEnergies, 2024). In drilling operations, AI-driven automation optimises wellbore placement and adjusts drilling parameters in real-time, increasing efficiency by 25% and cutting equipment downtime by 40% for leading operators (ExxonMobil, 2024). AI-powered seismic data processing and interpretation, as well as reservoir modelling, are transforming exploration and development, enabling ExxonMobil, Shell, and ADNOC to enhance exploration success rates while improving field petroleum recovery and reducing operational costs. AI-driven autonomous drilling systems have been deployed to optimise penetration rates and torque management (BP, 2024). Furthermore, predictive maintenance algorithms prevent equipment failures and reduce unplanned downtime.

Digital twin technology and AI-enhanced intelligent operations are reshaping production optimisation and risk management. Companies like Shell and ADNOC have successfully integrated digital twins into their operations, enabling real-time production monitoring and efficiency improvements. AI-powered supply chain solutions are optimising inventory management, logistics, and pipeline integrity monitoring, ensuring uninterrupted operations while cutting transportation costs. AI-driven workforce automation also addresses labour shortages by reducing reliance on large maintenance teams and expediting workforce upskilling, lowering operational expenditures. Across the industry, AI adoption has resulted in an estimated 6-20% reduction in operational costs (Rystad Energy, 2024), reinforcing its role as a key enabler of cost efficiency.

Looking ahead, AI is expected to further reshape upstream gas operations, with projections estimating up to a 25% AI-enabled reduction in total upstream expenses by 2050 (McKinsey, 2025). However, despite its vast potential, the full-scale adoption of AI faces significant hurdles. The integration of AI into legacy oil and gas infrastructure requires substantial investment, which can be a deterrent for companies already grappling with budget constraints. Additionally, concerns surrounding data security, lack of AI expertise, and resistance to technological change present major adoption challenges. Companies will gain by prioritising workforce training, enhancing cybersecurity frameworks, and developing robust AI implementation roadmaps to capitalise on AI's potential fully.

7.1.2 Regional upstream gas investment

7.1.2.1 Africa

Driven by energy transition policies, technological advancements, and increasing global gas consumption, natural gas investment in Africa is projected to grow significantly through 2050, with cumulative investments estimated at USD 934 billion. This level of investment is critical to achieving the continent's estimated 502 bcm gas supply by 2050, underscoring Africa's pivotal role in global energy markets. Africa's projected upstream investment expansion reflects its dual focus on enhancing local energy security and meeting the growing global demand for LNG. Key regions, including East, North, and West Africa, are expected to absorb 80% of these investments, led by countries such as Algeria, Egypt, Mozambique, and Nigeria.

Algeria, a prominent natural gas supplier to Europe, is set to make significant upstream investments over the coming decades, focusing on developing new reserves and optimising existing fields. Key initiatives include recovery enhancement and infrastructure upgrades at the Hassi R'Mel field in the Oued Mya Basin and efforts to sustain output from the Touat, Reggane, and Timimoun basins. This also includes shale gas. Algeria's strategy is driven by its ambitions to expand natural gas exports, ensure domestic energy security, and incorporate carbon capture and low-emission technologies into its operations. Algeria's recent hydrocarbons law offering favourable conditions, advanced pipeline and LNG infrastructure, large resources notably unconventional and strategic geographical position strengthen its appeal to investors.

Egypt's upstream natural gas investments are set to accelerate, and significant offshore developments in the Nile Cone Formation support them. Landmark projects such as Zohr and the Nile Delta Project lead the way, driving growth in both greenfield and brownfield developments. Egypt's favourable production-sharing agreements, advanced LNG infrastructure, and strategic geographical position strengthen its appeal to investors. These factors position Egypt to meet rising natural gas demand in Europe and the Mediterranean, while meeting its growing gas demand.

Nigeria is poised to attract substantial upstream investments through 2050, with an estimated reserve base of 5.9 tcm. Major projects targeting the Akata and coastal plain formations, such as Bonga, Agbami, Bonga North, Zabazaba, and Nnwa-Doro, are central to this growth. Investments are driven by rapid population growth, urbanisation, and the country's focus on reducing gas flaring. Recent policy reforms, including the Petroleum Industry Act (PIA), have improved fiscal terms and strengthened investor confidence. The Decade of Gas initiative also underscores natural gas's role as a destination fuel for Nigeria's development.

Angola is emerging as a key player in Africa's natural gas market, with plans to develop critical fields such as Katambi-1 and the Northern Gas Complex. Investment drivers include rising LNG demand from Asia and Europe, the need to address power and industrial energy requirements, and efforts to curb gas flaring. By leveraging its strategic location and established LNG infrastructure, Angola aims to enhance its position as a significant LNG exporter while addressing environmental and economic priorities.

Mozambique is set to establish itself as a major global LNG player, with flagship projects such as Coral South FLNG, Coral North, and onshore Area 1 developments driving its expansion. Rising projected LNG production highlights Mozambique's growing importance in the global gas markets. It is expected to become the 5th largest LNG exporter by 2050. The gas sector will play a pivotal role in boosting Mozambique's economic growth, infrastructure development, and job creation, cementing its position as a key LNG supplier.

Tanzania is projected to attract upstream investments focusing on the substantial offshore reserves in the northern extension of the Rovuma Basin. The Tanzanian government has introduced supportive upstream policies and engaged actively with international investors to enhance project viability. Natural gas also plays a central role in Tanzania's energy transition strategy, providing a cleaner complement to renewables and aligning with global decarbonisation objectives.

South Africa is charting a path for growth in its natural gas sector, seeking to diversify its energy mix and reduce reliance on coal. Investments are expected to target offshore discoveries such as Brulpadda and Luiperd, contingent on favourable regulatory and market conditions. This trajectory is driven by South Africa's coal-to-gas transition strategy, and the need for a reliable energy source to fuel industrial economic growth. Advances in extraction technologies, including hydraulic fracturing and deepwater drilling, are anticipated to reduce costs and the environmental footprint, making upstream gas projects more viable and attractive to investors.

7.1.2.2 Asia Pacific

Aided by supportive policies such as fiscal reforms in Indonesia and an increasing focus on clean energy, the Asia Pacific gas sector is poised for significant growth by 2050. This growth is driven by surging regional demand, particularly from China, India, and Japan, as well as the region's abundant reserves in both mature markets (e.g., Australia, Indonesia, and Malaysia) and emerging markets (e.g., Myanmar and the Philippines). Gas production in Asia Pacific is projected to rise steadily, reaching 751 bcm by 2050. Achieving this production will require cumulative investments of approximately USD 2.4 trillion, with around 80% of this investment concentrated in China, Australia, Indonesia, and India. These investments will focus on developing unconventional gas fields in China, deepwater resources in Indonesia, and infrastructure projects to enhance production in mature fields, such as Baros and Scarborough in Australia.

Australia's upstream gas investment outlook through 2050 highlights its growing prominence as a major LNG supplier, supported by rising global demand, particularly from Asia. Investments in Australia are projected to be directed toward maintaining and expanding LNG infrastructure. Major projects include Ichthys and Gorgon, alongside exploring new reserves in the Browse, Bonaparte, and Cooper-Eromanga Basins. The energy transition positions Australia as a key provider of lower-carbon energy alternatives, reinforced by supportive government policies and technological advancements in LNG processing and carbon capture. Australia's robust LNG infrastructure and strategic geographic position ensure its competitiveness in meeting Asia's growing energy needs.

Indonesia's upstream investment outlook for gas by 2050 is equally promising, focusing on both traditional and new developments. Key projects include the Abadi Project in the Masela Block and the expansion of the Tangguh Fields, which is expected to increase Indonesia's gas add capacity significantly. In addition to upstream developments, Indonesia prioritises infrastructure enhancements, including LNG import terminals and gas processing facilities, to support its dual goals of meeting domestic demand and expanding export markets. These investments align with Indonesia's broader strategy to diversify energy sources and leverage its significant natural gas reserves, positioning it as a regional energy hub.

Malaysia's upstream gas investment outlook through 2050 reflects its commitment to meeting Southeast Asian energy needs while aligning with sustainability goals. Investments are projected to focus significantly on brownfield developments. Key projects in the Brunei and Central Luconia Basins, including fields such as Geronggong-Jagus East, Lang Lebah, and Cengkih-1. Additional investments will target greenfield developments in the Pertang, Kenarong, Noring, and Bedong Fields, as well as the Sarakwa Offshore Basin. Malaysia's strategic investments aim to balance its role as a regional gas supplier with its energy transition objectives, integrating enhanced recovery techniques and sustainable practices into its operations.

The future of **Myanmar**'s gas investment through 2050 depends heavily on regional demand, political stability, and regulatory support. Upstream gas investments are expected to be contingent on favourable policy and market conditions. Key drivers include Southeast Asia's energy needs and Myanmar's economic reliance on gas exports. Investment opportunities lie in untapped reserves, mature field developments, and the integration of emission-reduction technologies such as CCUS. However, challenges such as geopolitical instability, regulatory unpredictability, and competition from renewables pose significant risks to investment feasibility. Gas price volatility further complicates large-scale, capital-intensive projects. Despite these hurdles, Myanmar has strong potential as a regional supplier if it aligns its development strategy with energy transition goals and attracts international investment to unlock its resource potential.

7.1.2.3 Eurasia

By 2050, gas investments in Eurasia will focus on ensuring energy security, adapting to geopolitical shifts, and advancing carbon neutrality goals. With estimated investments totalling USD 1.8 trillion, the region's efforts will support mature fields, explore untapped reserves, and expand export infrastructure, particularly toward Asia. Key greenfield projects include gas feed to Russia's Power of Siberia 2 pipeline and Turkmenistan's Yashlar Field. In addition, significant investments will be directed toward brownfield developments such as Murgab and Galkynysh in Turkmenistan. Alongside exploration and development, recovery enhancement techniques and carbon capture technologies will receive growing attention, reflecting the sector's alignment with global sustainability objectives.

As one of the world's largest natural gas producers, **Russia** is expected to remain a cornerstone of the Eurasian gas sector by 2050. The expected substantial investment will focus on greenfield developments, including the South Kara Sea Offshore Field and Power of Siberia 2. Brownfield developments, such as the Northwest Siberian Offshore Field, will also play a vital role. The Russian gas industry, however, faces mounting pressure to adopt sustainable practices, particularly in reducing methane emissions and environmental impacts. To address these challenges, investments in CCUS technologies and methane reduction initiatives are anticipated to increase, aligning the industry with evolving regulatory demands and environmental objectives.

Azerbaijan's gas investment outlook through 2050 is centred on boosting production for European markets, driven by the continent's demand for energy diversification. Investments are primarily directed toward greenfield exploration in the Caspian Sea and sustaining output from mature fields like Shah Deniz through enhanced recovery methods. The Southern Gas Corridor, a strategic pipeline network supplying Europe, is also a key focus. The majority of investment is anticipated to be allocated to the third development phase of the Shah Deniz Field. Furthermore, brownfield projects such as the Lower Kura Shelf Gas Field are expected to contribute significantly to Azerbaijan's gas investment by 2050.

Kazakhstan is expected to see significant upstream gas increase by 2050, with its significant untapped reserves and strategic location in Central Asia. The country's gas sector strategy focuses on balancing domestic energy needs with increasing export capacity, particularly to China and Europe. Key projects include the development of the Kashagan Gas Field, part of the North Caspian Sea Production Sharing Agreement. Additionally, brownfield developments in the Karachaganak Field require considerable investment, focusing on recovery enhancement and infrastructure modernisation. Kazakhstan's proximity to the Central Asia-China Gas Pipeline and its involvement in expanding regional pipeline networks position it as a vital transit hub for Eurasian gas exports. Furthermore, investments in decarbonisation initiatives, including methane abatement and CCUS, are set to align Kazakhstan's gas sector with global climate goals, enhancing its competitiveness in international markets.

Turkmenistan, with the fourth natural gas reserves in the world, is projected to invest in greenfield projects, such as the Yashlar Field and other reserves in the Amu Darya Basin, to enhance production for domestic use and export. Brownfield developments in the Murgab and Galkynysh fields will also attract significant investment, focusing on recovery optimisation and infrastructure upgrades. Turkmenistan's strategic position in Central Asia makes it a pivotal supplier to Asian markets, particularly China, via the Central Asia-China Gas Pipeline. Turkmenistan is increasingly aligning with global sustainability goals by adopting methane reduction technologies and exploring CCUS integration to improve environmental performance and attract international investment.

7.1.2.4 Europe

By 2050, Europe's upstream gas investment will focus on three key priorities: energy security, decarbonisation, and hydrogen integration. As natural gas continues to play a transitional role, investments will increasingly target lower-emission solutions, with countries like Germany and the Netherlands spearheading hydrogen initiatives and carbon capture technologies. In Northern and Western Europe, key producers such as the United Kingdom and Norway will prioritise asset optimisation and advanced recovery techniques. At the same time, Eastern and Southern Europe will emphasise LNG import capacity and pipeline expansions to secure energy supplies. Over 2023–2050, Europe's total gas production is expected to contract, with annual production declining to 80 bcm. Supporting this reduced output will require cumulative investments of USD 342 billion, with Norway, the United Kingdom, and the Netherlands accounting for around 80% of total gas investments, collectively leading the region's energy transition efforts.

Norway, Europe's largest gas producer, is set to remain a critical supplier through 2050, driven by ongoing projects in the North Sea and new developments in the Barents and Norwegian Seas. Significant greenfield exploration efforts in these regions, alongside enhancements at brownfield sites like Snøhvit Future and Ormen Lange, will help sustain output while meeting stringent environmental standards. Norway's upstream strategy focuses on ensuring European energy security and advancing net-zero ambitions through investments in CCUS technologies and digitalisation initiatives. However, the country's approach will be influenced by growing competition from renewables and regulatory pressures aimed at reducing methane emissions and environmental impacts.

Romania is set to become a key contributor to Europe's upstream gas sector by leveraging its strategic location and resource potential in the Black Sea region. By 2050, investments are expected to focus on both offshore and onshore developments. Offshore projects like the Neptun Deep Gas Field will unlock deepwater reserves through international partnerships, while onshore developments, including the Carpathian Basin Fields, will prioritise brownfield optimisations and infrastructure upgrades. Romania's proximity to major European markets and integration into regional pipeline networks, such as the BRUA Gas Corridor, position it as a vital transit hub. These strategic investments align with Romania's goals to enhance domestic energy security and support Europe's energy diversification efforts.

By 2050, **Türkiye**'s upstream gas investment is forecasted to increase significantly, reflecting its strategic focus on achieving energy independence and reducing reliance on imports. Key investments will target the Black Sea's Sakarya Gas Field, which represents a cornerstone of Türkiye's efforts to enhance domestic production and position itself as a regional gas transit hub. Additional investments will support greenfield developments in the Black Sea, onshore production enhancements, and pipeline infrastructure expansions to connect domestic supplies with both regional and international markets. Government incentives and partnerships with foreign investors facilitate technological advancements and operational efficiency, positioning Türkiye to balance energy security, geopolitical ambitions, and environmental goals. By leveraging its domestic resources and transit capabilities, Türkiye aims to maintain natural gas as a transitional fuel while diversifying its energy landscape.

The **United Kingdom** is expected to experience a gas production contraction leading up to 2050, despite ongoing investments in brownfield extensions and small-scale developments such as the Central Graben and Viking Graben Gas Fields. These efforts reflect the United Kingdom's focus on maximising resource recovery from mature fields while aligning with its decarbonisation goals. The country's supportive regulatory environment and commitment to CCUS technologies reinforce its strategy to remain a reliable contributor to Europe's gas supply during the energy transition.

7.1.2.5 Latin America

By 2050, Latin America's gas upstream investments, estimated at USD 574 billion, will focus on achieving a projected production of 239 bcm. These investments are strategically aimed at balancing domestic energy needs, fostering export growth, and advancing sustainability goals. Key players such as Brazil, Argentina, and Peru are leading the region's efforts with substantial commitments to greenfield developments, including Argentina's Vaca Muerta Shale and Brazil's offshore fields in the Santos and Campos Basins, which collectively account for USD 120 billion of the continent's cumulative upstream investments. Additionally, significant investments in brownfield enhancements across mature fields will strengthen production efficiency and extend field lifespans.

Argentina's upstream gas investments are set to focus on expanding the Vaca Muerta Shale Basin, one of the world's largest shale gas reserves. Significant attention will also be directed toward brownfield enhancements in mature fields to ensure sustained production and resource optimisation. These investments aim to enhance domestic energy security, reduce import dependency, and meet the growing LNG demand in Asia and Europe. By advancing these developments, Argentina is poised to establish itself as a competitive gas supplier in the global transitional energy landscape.

By 2050, **Brazil**'s upstream investments are expected to focus heavily on offshore pre-salt exploration, with significant attention also directed toward brownfield enhancements in mature fields to optimise recovery and improve efficiency. These investments align with Brazil's goals to strengthen energy security, reduce reliance on gas imports, and capitalise on rising global LNG demand, particularly from Asia. By advancing these developments, Brazil can solidify its status as a competitive gas supplier in the global energy transition.

Peru's upstream gas investment outlook highlights its growing role as a regional supplier and contributor to LNG markets. Investments will prioritise greenfield projects in the Camisea Basin, focusing on untapped reserves to expand domestic production and support export initiatives. Additionally, brownfield developments will optimise existing fields to maintain output levels.

Peru's natural gas strategy is aligned with its goals of enhancing energy access for domestic industries, reducing carbon emissions, and expanding LNG exports, particularly to Asia and North America. While specific cumulative investment figures for Peru are under development, its strategic focus on LNG infrastructure and regional market integration underscores its importance in Latin America's upstream gas sector.

Venezuela holds one of the world's largest proven natural gas reserves, yet its upstream sector remains underdeveloped due to limited infrastructure and investment constraints. Recent partnerships, such as BP and Trinidad & Tobago's NGC securing a 20-year license for the Cocuina-Manakin offshore gas field, highlight progress in offshore development, but further foreign direct investment (FDI) is required to expand production capacity. Fields like Dragon and Perla, alongside domestic gas projects, could drive short-term growth, while LNG infrastructure expansion by 2040 may facilitate access to European and Asian markets. By 2050, Venezuela has the potential to become a leading regional LNG supplier, contingent on increased investment in offshore deepwater exploration and large-scale gas processing facilities.

Trinidad and Tobago's natural gas upstream investment outlook to 2050 is shaped by strategic policies, major field developments, and efforts to counteract production declines. The government's commitment to maximising resource recovery is evident in Shell's 2024 final investment decision on the Manatee gas field, which holds 76.5 bcm of reserves and is expected to produce over 17 bcm at peak output, boosting LNG and petrochemical production. However, challenges persist due to declining output from mature fields, prompting the government to launch offshore and onshore bid rounds and explore cross-border gas projects. With global LNG demand projected to rise by over 50% by 2040, Trinidad and Tobago have a crucial opportunity to solidify its position as a key LNG exporter. Continued upstream investments, policy incentives, and new field developments will be essential to maintaining production levels and sustaining its role in the global gas market.

7.1.2.6 Middle East

With approximately 40% of global proven natural gas reserves, the Middle East is poised for remarkable growth in natural gas production, necessitating significant investments in conventional and unconventional gas resources to meet future demand. By 2050, an estimated USD 1.4 trillion will be required to achieve the projected natural gas production of 1,155 bcm with Qatar, Iran, and the UAE, as the primary supplier. The majority of upstream investments will target conventional gas reservoirs. At the same time, unconventional assets are anticipated to require 17% of total investment in the region, particularly in countries like the UAE, Saudi Arabia, and Oman.

Qatar's strategy focuses on expanding its LNG capacity, with gas production projected to reach 300 bcm by 2050. This significant growth requires massive investments toward the North Field Expansion Project, the world's largest natural gas reserve. These efforts aim to solidify Qatar's position as a leading LNG exporter to Asia and Europe, strengthen its energy security, and align with global energy transition goals. Qatar's stable investment environment, strengthened by long-term contracts and established market access, further supports its growth as a reliable supplier in global energy markets.

Saudi Arabia's gas upstream strategy aligns with Vision 2030, emphasising domestic energy needs, industrial growth, and environmental goals. By 2050, upstream gas investments are forecast to be allocated to developing the Jafurah Shale Gas Field, one of the world's largest unconventional gas reserves. In addition, further investment will focus on enhancing recovery from conventional fields. Saudi Arabia aims to leverage natural gas as a cleaner fuel to reduce oil dependency, support industrial diversification, and achieve sustainability objectives, including aligning with global decarbonisation efforts.

By 2050, the **UAE**'s cumulative gas upstream investments are projected to centre on achieving energy self-sufficiency, supporting economic growth, and advancing sustainability. Key initiatives include greenfield projects like Hail, Ghasha, and Dalma, brownfield enhancements targeting mature fields, and CCUS and methane reduction technologies to meet net-zero 2050 targets. The UAE's strategic investments align with its role as a low-carbon leader in gas production, enhancing energy security and paving the way for potential LNG exports.

Iraq's upstream gas investments are set to focus on capturing flared gas, enhancing field recovery, and supporting domestic electricity generation. Key projects, including the Ratawi Gas Hub and the Basra Gas Company, will drive production growth while reducing gas flaring. Significant investments will target new greenfield developments to unlock untapped reserves alongside brownfield optimisations and infrastructure upgrades. These efforts aim to leverage Iraq's abundant reserves to meet rising domestic energy demands, reduce reliance on imports, and align with environmental goals through flaring reduction and emissions management technologies.

Oman's upstream gas investments are forecast to focus on conventional and unconventional developments. Key projects include the Khazzan and Ghazeer Fields, representing a cornerstone of Oman's production capacity. Additional investments will target smaller greenfield developments and the optimisation of brownfield sites, enhancing recovery and operational efficiency. Oman's strategy emphasises balancing domestic energy needs with export ambitions, particularly to Asia, while integrating decarbonisation technologies like CCUS to align with global sustainability goals. Oman's commitment to fostering an investor-friendly regulatory environment further supports its upstream growth and international partnerships.

7.1.2.7 North America

By 2050, North America will maintain its position as the world's largest natural gas-producing region, with total annual production forecasted to reach 1,382 bcm. Achieving this production level will require an estimated cumulative upstream investment of USD 2.9 trillion, with 90% of this investment directed toward unconventional resources. Unconventional basins such as the United States Tight Dry Gas, Canada's Western Canadian Sedimentary Basin (WCSB) Shale, and Mexico's Sabinas Eagle Ford Shale Dry Gas will absorb the lion's share of this investment, reflecting the region's dominant reliance on advanced shale and tight gas extraction technologies. The upward trajectory of North American gas production is driven by several factors, including the energy transition and the role of natural gas as a transitional fuel, the strengthening United States-Mexico gas partnership supported by expanded cross-border infrastructure, and technological advancements in shale extraction, which continue to reinforce North America's competitive advantage in the global natural gas markets. These elements position North America as a critical natural gas supplier, particularly for LNG exports to Asia and Europe.

The **United States** is forecast to lead North America's natural gas upstream investments. This dominance reflects the United States's vast shale resources and continued leadership in advanced extraction technologies. Unconventional production will remain the cornerstone of the United States's upstream strategy, with key basins such as the Permian, Appalachian (Marcellus and Utica), and Haynesville absorbing the bulk of these investments. Together, these basins will account for over 80% of United States natural gas production, supported by consistent investments in enhanced recovery techniques, digitalisation, and advanced well-completion methods. The Permian Basin is expected to remain a key driver of gas production, benefitting from its dual role as a central oil and gas-producing region. Investments in associated gas capture, pipeline infrastructure, and flaring reduction technologies will enhance its contribution to the overall gas supply. Meanwhile, the Appalachian Basin, home to the Marcellus and Utica shales, will solidify its position as the largest gas-producing region in the United States, with its proximity to key LNG export terminals and Northeastern consumption hubs providing logistical advantages. The Haynesville Shale will also play a critical role, particularly in supplying feedstock for Gulf Coast LNG facilities.

Canada's upstream gas investment is projected toward shale and tight gas development in the Western Canadian Sedimentary Basin (WCSB). This reflects Canada's focus on maximising the potential of its unconventional resources while maintaining its position as a reliable natural gas supplier to domestic and international markets. Additionally, Canada's commitment to reducing emissions and integrating CCUS technologies into its upstream operations aligns with its broader energy transition objectives. These advancements are expected to enhance Canada's global competitiveness in supplying low-carbon natural gas.

Mexico's natural gas production is projected to focus on the Sabinas Eagle Ford Shale Gas Basin, representing the bulk of Mexico's total required investment. Mexico's role as a strategic partner for the United States' natural gas exports through expanded cross-border infrastructure is a key driver of its investment growth. Mexico's focus on developing domestic unconventional resources aligns with its goals of improving energy security, reducing reliance on imports, and enhancing its role in North America's integrated energy landscape. Investments in pipeline infrastructure and LNG terminals are expected to strengthen further Mexico's contribution to regional and global natural gas markets.

7.2 Midstream natural gas investment trends

Current investment levels in global midstream gas projects appear sufficient to meet anticipated gas demand through the 2030s, assuming sustained technological advancements and geopolitical stability. However, beyond the early-to-mid 2030s, the sector faces a growing risk of underinvestment in natural gas supply, which could threaten global energy security. Supply uncertainties may emerge without adequate and timely investments, increasing market volatility and raising the likelihood of price spikes. The extreme natural gas price fluctuations observed between 2020 and 2022 are a stark reminder of the consequences of supply-demand imbalances, underscoring the need for a well-planned investment approach that ensures long-term market stability. Additionally, inadequate midstream infrastructure investment could exacerbate these risks, limiting the ability to transport and distribute gas efficiently, further constraining supply and driving up natural gas prices.

The long-term investment trajectory in the global natural gas sector is shaped by two fundamental drivers: energy security and the evolving energy transitions. To maintain a stable and cost-effective natural gas supply, substantial investments flow into midstream infrastructure, particularly export pipelines, liquefaction, and regasification facilities. These projects, however, involve long development timelines and substantial upfront capital commitments, making them highly sensitive to policy shifts and market uncertainties. As energy transition policies accelerate and regulatory frameworks evolve, projects that appear viable today may face diminishing returns in the future. This uncertainty complicates infrastructure investment decisions, requiring companies to adopt a more flexible and forward-looking approach to capital allocation.

For midstream companies, anticipating and adapting to these shifting market conditions is critical. Strategic foresight allows them to allocate resources efficiently - infrastructure, capital, or time - to the most pressing priorities. This approach delivers long-term value to stakeholders and ensures resilience in an evolving energy landscape. The challenge lies in balancing short-term energy security needs with long-term decarbonisation goals, aligning investments with market realities and global sustainability objectives.

While the upstream sector will continue to attract significant capital due to its resource-intensive nature, midstream investment is increasingly centred on liquefaction capacity expansion. LNG infrastructure, encompassing both liquefaction and regasification, remains a key focus area, given the increasing role of LNG in global energy transitions. As natural gas is positioned as a cleaner and more flexible alternative to other fossil fuels, strategic expansion of midstream capabilities is essential to meeting rising global demand and addressing regional supply imbalances. By proactively investing in LNG infrastructure, the natural gas sector can reinforce its role in immediate energy security and long-term sustainability, ensuring its continued relevance in the evolving global energy landscape.

7.2.1 Recent developments and global outlook

Investment in the midstream segment of the LNG market remained a focal point in 2024 despite regulatory and geopolitical challenges. Liquefaction capacities saw notable developments across multiple regions, with several new projects being sanctioned while others faced delays. A total of 15 Mtpa of new LNG supply capacity was approved in 2024, with significant projects emerging in Canada, the Middle East, and Asia. In Canada, the Cedar LNG project, a 3.3 Mtpa floating LNG development by Haisla Nation and Pembina, was sanctioned, providing strategic access to Asian markets. ADNOC took a final investment decision (FID) on the 9.6 Mtpa Ruwais LNG facility in the UAE, securing long-term agreements with buyers in Europe and Asia for over 8 Mtpa production. In Oman, TotalEnergies sanctioned the Marsa LNG project, a 1 Mtpa bunkering facility, while in Asia, Genting Berhad signed a USD 1 billion contract to construct a floating LNG plant.

Despite continued confidence in LNG investments, regulatory challenges in the United States had previously slowed new developments. The President Biden Administration's pause on non-FTA approvals, imposed in January 2024, had stalled multiple United States LNG projects targeting an FID decision in 2024, leading to a sharp decline in sanctioned capacity compared to previous years. However, the new United States Administration removed the pause in January 2025, paving the way for renewed project momentum. The only exception to the slowdown was the newly commissioned NFE Altamira FLNG, which received approval to export up to 1.4 Mtpa of LNG for five years. In addition to regulatory hurdles, several under-construction projects faced delays. The Golden Pass LNG project in the United States, with a planned capacity of 18 Mtpa, was significantly delayed due to the bankruptcy of its lead contractor, Zachry Holdings. In West Africa, BP and Kosmos have delayed the start of gas production at Tortue FLNG Phase 1 from Q3 2024 to early 2025, with initial LNG exports now anticipated in early 2025.

Regasification infrastructure expanded significantly, with global regasification capacity increasing by 53 Mtpa in 2024. Europe remained a key driver of this growth, commissioning 19.4 Mtpa of new regasification capacity as part of its broader energy security strategy. Notable projects included expansions in France, Poland, and the United Kingdom, with Poland confirming its second FSRU import project scheduled for deployment in 2027. China also played a critical role in expanding global LNG import capacity, commissioning four new import terminals that added 14 Mtpa and expanding existing facilities to increase capacity by another 5.5 Mtpa. Brazil commissioned nearly 16 Mtpa of new regasification capacity in South America through three new FSRU projects. LNG infrastructure developments also advanced in the Middle East and South Asia, with Egypt and Jordan enhancing their LNG import capabilities. At the same time, Singapore announced a 25-year FSRU charter agreement to establish its first LNG import terminal by the end of the decade.

Looking ahead, LNG markets are set to continue evolving, with Asia expected to remain the primary driver of global LNG demand through 2050. While European LNG imports have temporarily increased due to energy security concerns, Asia's long-term structural demand growth will dominate the market. The shift from coal to natural gas across developing Asian economies is accelerating, particularly beyond the 2030s, as governments seek cleaner energy solutions and industrial sectors expand. China is projected to lead this demand growth, supported by strong South and Southeast Asian contributions. As traditional LNG producers such as Indonesia and Malaysia approach production plateaus, Southeast Asia is expected to become a net LNG importer. Emerging markets like the Philippines and Viet Nam are set to become key players, reflecting a broader regional shift toward greater LNG reliance.

The period spanning the 2010s to the 2020s is often

called the 'golden era' for midstream investments (Figure 7.6), particularly in LNG infrastructure. During this time, capital midstream capital expenditures reached historic levels, supporting the expansion of liquefaction and regasification capacity to strengthen the rapid increase in global LNG trade. However, investment priorities are shifting as the market matures and energy transition policies gain momentum. Uncertainties surrounding long-term energy policies and decarbonisation goals are expected to contribute to a significant slowdown in midstream capital expenditures beyond 2030, altering the investment landscape for LNG infrastructure.

Despite these projected declines, the midstream natural gas sector will continue to present substantial investment opportunities. **Between 2023 and 2050, cumulative midstream investments needed to support global natural gas demand are expected to total approximately USD 704 billion** (Figure 7.7), underscoring the critical role of infrastructure in ensuring energy security and trade efficiency.

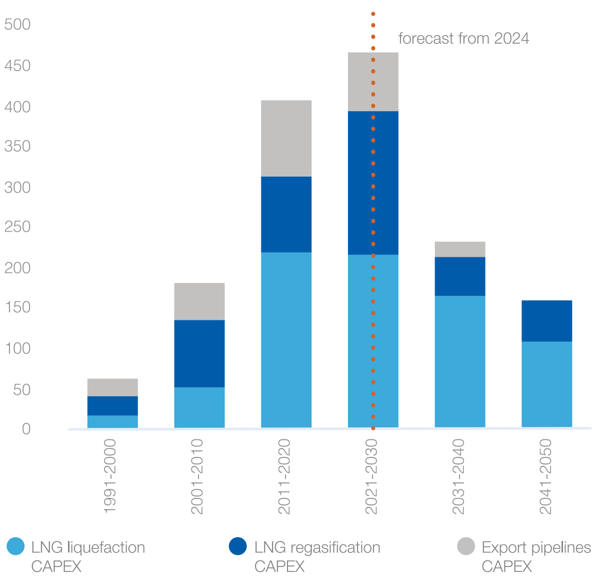
Midstream investments from 2023 to 2050 tell a dynamic story of regional priorities, economic drivers, and the gradual transition of global energy markets. The journey begins with rapid, front-loaded spending during the first decade, followed by a decline in the middle period as infrastructure stabilises, and concludes with a focused recovery in specific regions toward the end of the timeline.

Asia Pacific leads global midstream capital expenditure, accounting for 28% equivalent or the total USD 200 billion, reinforcing its status as the largest gas-consuming region. The investment story unfolds with USD 110 billion (35% of cumulative global capital expenditure) allocated between 2023 and 2030, driven by strong demand growth in major economies such as China and India. However, investment declines to USD 57 billion in 2031-2040 and further to USD 33 billion in 2041-2050, reflecting a gradual slowdown in infrastructure expansion as the market matures.

Eurasia ranks as the second-largest regional player, accounting for 19% of cumulative capital expenditure, totaling USD 135 billion, with a distinct trend of increasing investment over time. While early spending remains relatively moderate in 2023-2030, investments

Figure 7.6

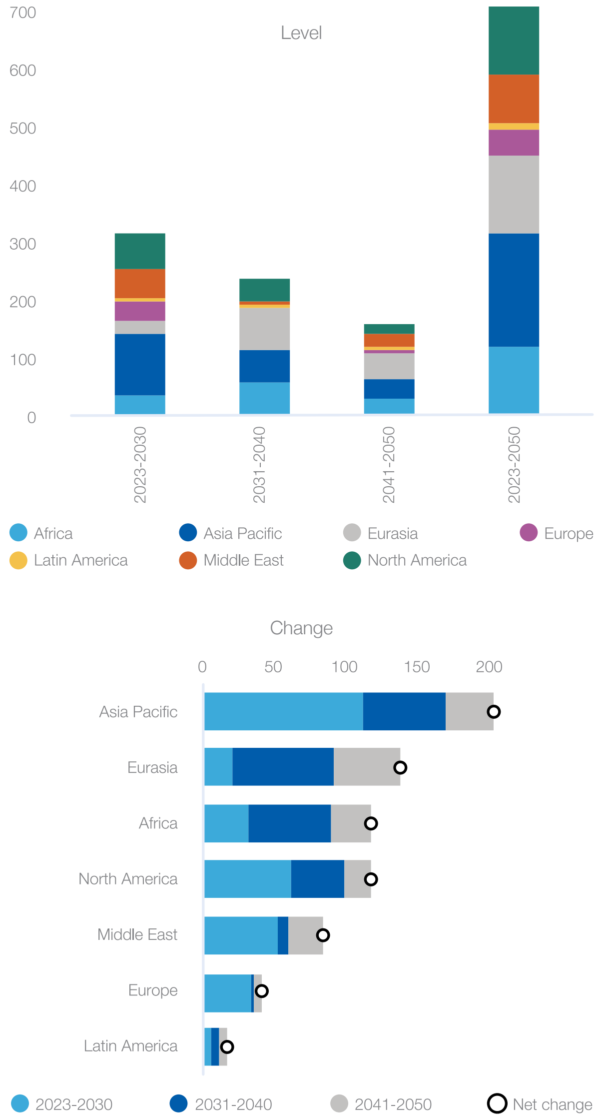
Historical and future global outlook of midstream investment (real USD billion, base year = 2023)



Source: GECF Secretariat based on data from the GECF GGM

Figure 7.7

Global gas midstream CAPEX outlook by region, 2023-2050 (real USD billion, base year = 2023)



Source: GECF Secretariat based on data from the GECF GGM

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increase approximately 3.5 times to USD 70 billion in 2031-2040 before stabilising in 2041-2050. This steady upward trajectory highlights the region's strategic emphasis on expanding its export infrastructure, reinforcing Eurasia's long-term position as a key supplier of LNG and pipeline gas to global markets.

North America, with 17% of cumulative global capital expenditure, plays a significant role, driven almost entirely by liquefaction infrastructure. The region's story peaks early, with USD 61 billion invested during 2023-2030 to expand its LNG export capacity. As its industry matures, spending gradually declines to 15% in 2031-2040 and 12% in 2041-2050 of global midstream investment, reflecting a stable yet declining need for further development. This trend highlights North America's early leadership in global LNG markets and its gradual shift toward maintaining existing infrastructure.

Africa's midstream investment narrative highlights its rising role as an export hub. Accounting for 16% of cumulative global capital expenditure, totalling USD 115 billion, the region is set for a significant surge in 2031-2040, driven by projects in countries such as Mozambique and Nigeria. This represents a pivotal point as Africa establishes itself as a major player in the global LNG supply chain. While spending slows in 2041-2050, it reflects a shift toward sustaining operations and supporting long-term demand.

The **Middle East**, contributing 12% of cumulative global capital expenditure (USD 82 billion), tells a story of concentrated investments in liquefaction capacity. Early efforts dominate the region's narrative, with 16% of cumulative global capital expenditure spent during 2023-2030. However, subsequent investments fall sharply in 2031-2040 and 2041-2050. This modest spending trajectory suggests a region already well-equipped with infrastructure, focused on optimising its existing capabilities rather than expanding further.

Europe's investment narrative revolves around its urgent energy security priorities. Contributing 6% of cumulative global capital expenditure (USD 39 billion), Europe's spending is heavily front-loaded, with USD 33 billion allocated during 2023-2030 to diversify its energy supply. After this initial push, investments are anticipated to plummet over the next two decades, reflecting Europe's transition toward renewables and a more diversified energy mix.

Latin America plays a minor role, contributing only 2% of cumulative global capital expenditure. Its investments are modest and consistent, driven by small-scale projects aimed at meeting regional energy needs. The region's limited natural gas infrastructure expansion reflects its smaller role in global midstream development.

The narrative of midstream investments from 2023 to 2050 reveals a clear pattern: early and intense investment in regions like Asia Pacific, North America, Middle East and Europe is followed by a gradual transition to export-driven projects in Africa and Eurasia. The Middle East maintains a steady role in liquefaction, while Europe shifts away from natural gas toward renewables.

The global LNG industry is expected to see significant investment in liquefaction projects - accounting for approximately 62% of total midstream investment growth - between 2023 and 2050. Regions with abundant natural gas reserves are focusing on expanding LNG export capacity to meet rising demand. The required investment for liquefaction projects is projected to reach nearly USD 435 billion over the long term (Figure 7.8), reflecting regional priorities, resource availability, and evolving market dynamics.

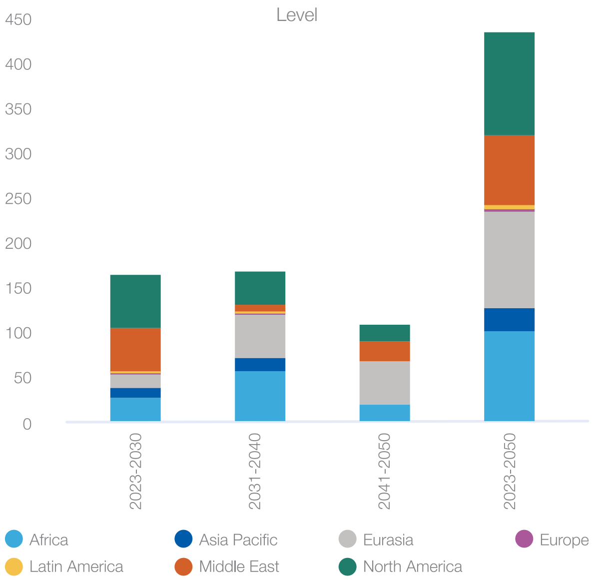
North America is poised to dominate global liquefaction investments, capturing 27% of total liquefaction investments by 2050. The United States, supported by competitive feed gas pricing and well-established infrastructure, will spearhead this expansion. Liquefaction projects in the region are strategically positioned to meet rising demand from Europe and Asia, backed by long-term contracts, increased contract flexibility, and a growing role for portfolio players. The region's reliance on hub-based pricing models further enhances its competitive advantage. Major projects, such as Golden Pass LNG and the expansion of Plaquemines LNG, are set to reinforce the United States's role as a leading exporter. Meanwhile, Canada's liquefaction projects, though fewer in number, are strategically designed to serve the Asia Pacific market, ensuring North America remains a key player in global LNG trade.

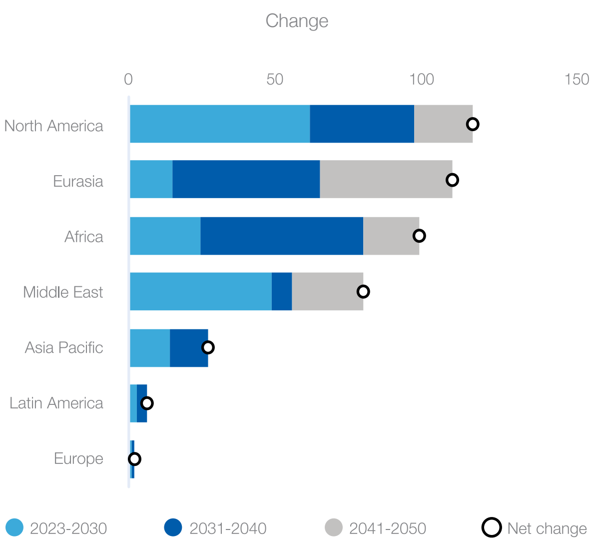
Eurasia is expected to secure 25% of global liquefaction investments, reflecting its strategic focus on monetising vast untapped natural gas resources. Russia will be the primary driver of these investments, aiming to enhance export capacity, particularly towards Asia, amid evolving geopolitical dynamics. Projects like Arctic LNG 2 are progressing, underscoring Russia's strategic commitment to LNG exports, particularly targeting Asian markets via the Northern Sea Route. However, logistical, technical, and sanction-related challenges continue to pose risks to the timely execution and expansion of Russian LNG infrastructure.

Africa is gaining prominence in the LNG sector, projected to account for 23% of global liquefaction investments by 2050. Countries rich in natural gas, such as Mozambique, Nigeria, Mauritania, and Senegal are leveraging their vast reserves to establish themselves as critical LNG suppliers. Mozambique's Rovuma LNG and Coral South FLNG projects, alongside Nigeria's ongoing liquefaction expansions, are set to transform the continent's role in global LNG markets. Additionally, the Greater Tortue Ahmeyim project in Mauritania and Senegal highlights West Africa's growing LNG footprint.

Figure 7.8

Global LNG liquefaction Capex outlook by region, 2023-2050 (real USD billion, base year = 2023)





Source: GECF Secretariat based on data from the GECF GGM

Gabon's entry into the LNG market further signals Africa's diversification in natural gas supply, attracting foreign investment and fostering regional economic development. These investments not only address global supply needs but also unlock new economic opportunities across the continent.

The **Middle East** is projected to hold an 18% share of global liquefaction investments, with Qatar leading the charge through its North Field Expansion (NFE and NFS). These projects will significantly boost Qatar's LNG output, solidifying its position as a cost-competitive, high-volume supplier to Asia and Europe. Beyond Qatar, Oman and the UAE are also expanding their LNG infrastructure to capitalize on growing demand and strengthen their integration into global supply chains. Despite a smaller overall share compared to other regions, the Middle East's strategic advantages - low production costs and proximity to key markets - ensure its continued influence in global LNG trade.

Despite the overall momentum in liquefaction investments, **Asia Pacific** presents a more constrained outlook for new large-scale projects. The region is expected to account for just 6% of global liquefaction investments by 2050, reflecting the region's shift from being a net LNG exporter to a net importer. The region's easily accessible LNG reserves, particularly off the coasts of Australia and Papua New Guinea (PNG), have already been largely developed, leaving fewer opportunities for additional greenfield projects. Australia, a dominant force in LNG exports, is focusing primarily on brownfield expansions and operational efficiency improvements rather than major new capacity additions. In Papua New Guinea, while expansion efforts continue, the most commercially viable reserves have already been tapped, reinforcing Asia's increasing reliance on imported LNG.

Between 2023 and 2030, liquefaction investments are projected to total USD 163 billion, representing a critical phase in the global LNG development cycle. This period is expected to see the highest capital expenditure levels as project developers seek to secure long-term contracts, capture emerging demand opportunities, and position themselves competitively in the evolving energy landscape. Timely execution of these investments is crucial to preventing future supply shortages, mitigating price volatility, and ensuring long-term market stability. Any delays or inefficiencies in project execution during this window could have cascading effects on global supply chains, impacting not only profitability but also energy security in key demand centres. As the LNG market becomes increasingly competitive, developers will need to navigate shifting policy frameworks, evolving trade dynamics, and technological advancements to ensure that their liquefaction projects remain economically viable and strategically positioned for long-term success.

Between 2023 and 2040, global liquefaction investments will account for 75% of total liquefaction spending, driven by expansion efforts in Africa, Eurasia, Middle East, and North America, which capitalise on their resource wealth and cost advantages. In the final decade, from 2041 to 2050, investment will decline to just 25% of total liquefaction spending for the entire period as major infrastructure projects are completed and decarbonisation policies reshape the market. The focus will shift from expansion to optimising efficiency, sustainability, and adapting to evolving energy dynamics.

The timeline and distribution of LNG liquefaction investments underscore the strategic priorities of resource-rich regions. North America and Eurasia lead the charge, while Africa's rapid rise signals a reshaping of the global energy landscape. The Middle East continues to leverage its competitive cost structure, and Asia Pacific's limited role reflects its focus on imports rather than production. The long-term viability of these investments will depend on balancing rising LNG demand with global decarbonisation goals, ensuring LNG's pivotal role in the energy transitions.

Technological advancements and cost reductions are expected to play a crucial role in enhancing the profitability and efficiency of liquefaction investments worldwide. Improvements in liquefaction processes, the integration of CCUS, and modular plant designs are enabling developers to optimise capital expenditures while minimising environmental footprints. Additionally, the rise of FLNG technology is offering more flexible and cost-effective solutions for gas monetisation, particularly in regions where onshore infrastructure is limited or prohibitively expensive.

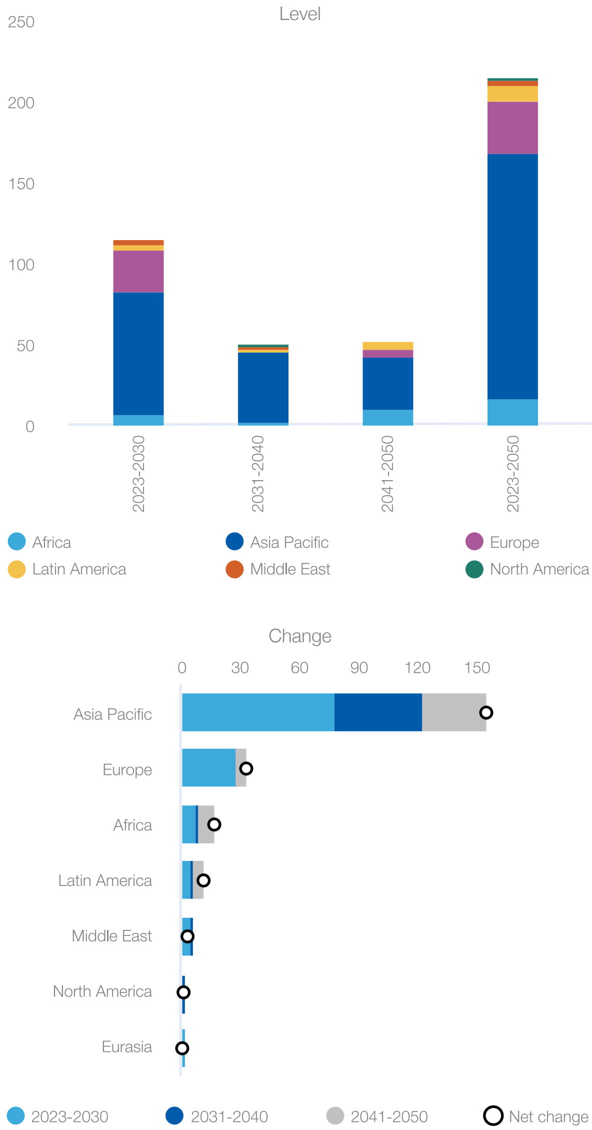
Approximately USD 214 billion (Figure 7.9) is anticipated to be directed toward expanding regasification facilities to ensure sufficient capacity for rising LNG imports. These investments underscore the essential role of midstream infrastructure in facilitating global natural gas trade and addressing regional supply-demand imbalances.

Asia Pacific is set to dominate the global regasification investment landscape, accounting for 71% of total spending, or USD 152 billion between 2023 and 2050. This reflects the region's status as the primary LNG import hub, driven by strong demand growth in major economies such as China, India, and Southeast Asia. Urbanisation, industrialisation, and a transition to cleaner energy sources underpin this sustained anticipated demand for LNG. Investments in regasification in Asia Pacific remain consistent across all timeframes, even beyond 2040, signalling its long-term reliance on LNG imports. The region's strategy also focuses on expanding infrastructure to secure supply stability through diversified sourcing. Notably, Asia Pacific is the only region with significant regasification investment post-2040, contributing USD 32 billion during this period, highlighting its resilience in LNG demand even as global growth slows.

Europe is expected to follow as the second-largest contributor, representing 15% of global regasification investments with USD 32 billion. The majority of Europe's regasification projects are concentrated between 2023 and 2030. Europe's need to diversify its energy supplies is reflected in investments totalling USD 27 billion during this initial period. However, as the continent progresses in its energy transition - marked by increased adoption of renewables and hydrogen technologies - LNG demand stabilises. Post-2030, investment activity tapers off

Figure 7.9

Global LNG regasification CAPEX outlook by region, 2023-2050 (real USD billion, base year = 2023)



Source: GECF Secretariat based on data from the GECF GGM

significantly, mainly to maintain flexibility in energy supply.

In **Africa**, regasification investments are expected to total USD 16 billion, equivalent to 7% of the global share. Economic growth, electrification, and increasing domestic energy demand drive LNG adoption in regions such as North and West Africa, where LNG serves as a complement to pipeline gas. Interestingly, Africa sees its most significant investment surge post-2040, with USD 9 billion allocated during this period. This reflects a growing reliance on LNG as domestic gas production may not fully meet rising energy needs in the future.

Latin America is anticipated to account for 5% of global regasification investments. The region's investment trajectory is characterized by steady growth, driven by industrial expansion, urbanisation, and the need to integrate natural gas with renewable energy sources. Overall trend suggests a gradual shift toward greater reliance on LNG imports as domestic production matures.

In the **Middle East**, investments are expected at the modest USD 3.3 billion, making up 2% of the global total. As a gas-rich region, the Middle East's regasification projects are limited to niche markets or specific import needs in countries like the UAE and Kuwait, which require seasonal LNG imports to meet peak demand. Investment activity is concentrated before 2030 and declines significantly afterward, as most energy needs are met through domestic production or regional pipelines.

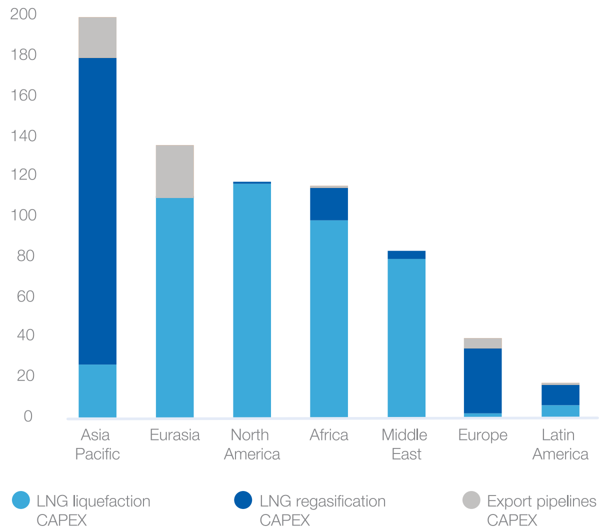
Across all regions, 76% of global regasification investments occur in the first 18 years (2023 - 2040), as emerging Asia and Europe focus on immediate capacity expansion to meet growing demand and diversify energy supplies. The period from 2023 to 2030 marks the peak of global LNG regasification investments, with 53% of the total spending concentrated in these years. This surge is primarily driven by rapid growth in Asia Pacific and Europe's urgent efforts to diversify energy supplies. However, the following decade, 2031 to 2040, sees a significant slowdown, with investments declining to 22% of the total ragasification. This reflects a stabilisation in many regions as they achieve adequate regasification capacity, alongside the growing influence of the global energy transition. By 2041 to 2050, investments recover modestly, driven largely by Africa and the Asia Pacific. These regions continue to invest in LNG infrastructure to meet their increasing energy demand, highlighting their ongoing reliance on natural gas in the longer term.

The regional disparities in regasification investments underscore the uneven adoption of LNG globally. Asia Pacific solidifies its role as the world's leading LNG importer, while Europe's investments focus on short-term diversification. Meanwhile, Africa and Latin America exhibit more gradual and long-term growth. These trends highlight the evolving role of LNG as a transitional energy source, with its importance varying significantly by region and timeframe.

In contrast to LNG liquefaction and regasification capital spending trends, investment in pipelines is expected to decline gradually, decreasing from 11% of total gas midstream investment in the current decade (2023-2030) to virtually zero by 2041-2050. This decline is attributed to the sufficient capacity of existing pipelines and lower capital costs driven by technological advancements. Completed major pipeline projects, such as TurkStream, Power of Siberia 1, the South Caucasus Pipeline, TANAP, and various North

Figure 7.10

Cumulative midstream gas CAPEX requirement by region, 2023-2050 (real USD billion, base year = 2023)



Source: GECF Secretariat based on data from the GECF GGM

American upgrades have significantly reduced the need for additional pipeline infrastructure.

Eurasia remains at the forefront of global pipeline investments, accounting for a substantial 48% share. This dominance is primarily driven by its strategic pipeline development initiatives aimed at strengthening inter-regional gas trade. The region is undergoing a major shift, realigning its export markets from Europe to Asia, particularly to meet China's growing energy demand. This transition underscores Eurasia's ambition to capitalise on Asia's increasing reliance on natural gas as a critical component of its energy mix. **Asia Pacific ranks second with a 38% share, driven by the need to expand pipeline infrastructure to facilitate the growing flow of natural gas from Eurasia.** The region's pipeline investments reflect its long-term vision of enhancing energy connectivity and ensuring adequate supply to meet its rapidly rising energy demand. In contrast, Africa, and Latin America each account for less than 5% of global pipeline investments. These regions have prioritised liquefaction and regasification projects over pipeline development, reflecting their focus on monetising natural gas through LNG exports or supporting domestic energy needs rather than developing extensive cross-border pipeline infrastructure.

A notable feature of these global investments is their front-loaded nature. The majority of expenditures are concentrated between 2023 and 2030, as countries and regions prioritise near-term expansion of pipeline infrastructure. This investment surge reflects the urgency of addressing immediate energy security concerns, enabling market diversification, and creating a foundation for long-term gas trade. After 2030, investments are

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expected to taper off as key infrastructure projects reach completion, with subsequent spending primarily focusing on maintenance and incremental upgrades.

7.2.2 Midstream gas investment by region

As illustrated in Figure 7.10, global midstream gas infrastructure investment exhibits significant regional disparities shaped by diverse market dynamics, regulatory frameworks, and energy security priorities. While Asia Pacific is expected to lead global midstream investment, other regions exhibit distinct capital allocation patterns, reflecting their unique roles in the natural gas value chain.

With an estimated USD 200 billion in cumulative capital spending, **Asia Pacific** is poised to be the largest recipient of midstream investment, accounting for 28% of total global capital requirements in this segment. The region's growing dependence on imported gas is reflected in the allocation of around 76% of its investment to LNG regasification facilities. Asia Pacific is set to dominate global regasification capital spending, accounting for 71% of total regasification investment required by 2050, reinforcing its role as a key driver of LNG demand. Despite a downward trend in midstream capital expenditure, pipeline infrastructure development remains crucial through 2030 to accommodate surging natural gas demand, ensuring long-term supply security and market stability.

Following Asia Pacific, **Eurasia** emerges as the second-largest contributor to midstream investment, accounting for 19% of total global capital spending in this segment. Unlike Asia Pacific, liquefaction dominates midstream investments in Eurasia, with 81% of total spending on liquefaction projects. However, much like Asia Pacific, where investment is front-loaded, Eurasia's liquefaction investment is expected to accelerate post-2030. Additionally, the region is projected to remain the largest investor in natural gas pipelines, representing just under half of the total global capital expenditure required for pipeline infrastructure. This highlights Eurasia's strategic role in international gas trade, ensuring connectivity between key production hubs and consumer markets, thereby strengthening long-term energy security and supply diversification.

As a leading LNG exporter, **North America** is projected to account for 17% of global midstream capital spending between 2023 and 2050, making it the largest regional investor in liquefaction. Nearly all midstream investment in the region is expected to be allocated to liquefaction infrastructure, comprising over one-fourth of total global liquefaction investment. However, unlike Eurasia, where investments increase over time, North America's liquefaction capital spending is expected to be heavily front-loaded, with most investments occurring before 2030. Post-2030, investment in liquefaction is projected to decline sharply, reflecting a maturing LNG export infrastructure and shifting investment priorities driven by energy transition policies and evolving global market dynamics.

Africa follows closely behind North America, contributing 16% of global midstream capital investment over the outlook period. With 85% of this spending directed toward liquefaction infrastructure, Africa is focusing on expanding its LNG export capacity to capitalise on growing global demand. The majority of these investments are expected within the next decade, underscoring the region's efforts to establish itself as a key LNG supplier. At the same time, Africa's midstream investment is not solely focused on exports -14% of total midstream spending in the region is expected to be allocated to regasification projects, particularly in South Africa, reflecting efforts to enhance domestic gas accessibility and energy diversification.

The **Middle East** is projected to account for 12% of global midstream investment, with liquefaction projects making up over 95% of this expenditure. Much like North America, the bulk of investment is expected to take place within the current decade, with a gradual decline in spending in the subsequent years. However, the Middle East's long-term role in global gas trade is further reinforced by its significant investments in pipeline infrastructure, particularly in cross-border natural gas transportation.

In **Europe**, midstream investment dynamics are distinct from those in Asia, Eurasia, and North America. While Europe is projected to contribute just 6% of global midstream capital spending between 2023 and 2050, its investment profile is front-loaded, with nearly 84% of total spending concentrated within the current decade. This reflects Europe's urgent efforts to enhance energy security following recent geopolitical disruptions. However, post-2030, investment levels are expected to decline sharply, reflecting a maturing natural gas infrastructure and shifting energy priorities toward decarbonisation.

Latin America is expected to contribute the smallest share to global midstream investment, accounting for just 2% of total cumulative capital spending over the forecast period. Unlike Africa and the Middle East, where liquefaction dominates spending, Latin America's midstream investment is primarily concentrated in regasification infrastructure, which is projected to make up 63% of total investment. This underscores the region's growing dependence on imported LNG to support domestic energy demand, particularly as countries seek to balance economic growth with energy security challenges.

7.2.2.1 Africa

Africa is poised to become a critical player in the global natural gas market, with cumulative midstream investments projected to exceed USD 115 billion by 2050. These investments are driven by the continent's abundant natural gas reserves, increasing domestic energy needs, and the strategic importance of LNG exports to global markets, particularly Europe and Asia. Africa's midstream infrastructure development is centred around liquefaction projects, regasification facilities, and the expansion of pipeline networks, enabling the continent to capitalise on its vast natural resources and growing demand for cleaner energy solutions.

Pipeline infrastructure is another area of midstream investment in Africa, although progress has been slower than liquefaction and regasification. The proposed Trans-Saharan Gas Pipeline (TSGP) aims to transport natural gas from Nigeria to Algeria, connecting with Europe through existing networks. While this project holds significant potential, geopolitical and financial challenges have delayed its progress.

Egypt is set to strengthen its role as a key LNG exporter, capitalising on its strategic location to serve both European and Asian markets. With the Idku and Damietta LNG plants providing a combined capacity of over 12 Mtpa, the country is enhancing its midstream infrastructure to support long-term LNG supply commitments. Future investments are focused on expanding offshore gas developments, improving regional pipeline connectivity, and securing additional gas resources from neighbouring producers. These initiatives position Egypt as a regional energy hub, ensuring a stable LNG export outlook while adapting to evolving global demand trends.

Nigeria is expanding its LNG capacity and midstream infrastructure to strengthen its role in global energy markets. The USD 4.3 billion Nigeria LNG Train 7 Project will increase LNG production to 30 Mtpa, enhancing export potential. Simultaneously, the Ajaokuta-Kaduna-Kano (AKK) Pipeline, spanning 614 km, will boost domestic gas distribution for power generation and industrial use. These investments position Nigeria as a key player in Africa's LNG expansion while supporting both export growth and domestic energy security.

Mauritania and Senegal are emerging as significant LNG producers in West Africa, primarily through the development of the Greater Tortue Ahmeyim (GTA) LNG Project, led by BP and Kosmos Energy and located on the maritime boundary between the two nations. Phase 1 of the project is designed to produce approximately 2.5 Mtpa of LNG, with first production already commenced in early 2025. The initial phase involves an investment of around USD 4.8 billion, with plans for subsequent expansions that could eventually increase output to 10 Mtpa. The GTA project underscores the strategic importance of collaborative regional efforts to maximise resource utilisation and attract foreign investment.

Mozambique is advancing its position as a major LNG exporter with key projects underway. Coral Sul FLNG (3.4 Mtpa) began production in 2022, marking Africa's first deepwater floating LNG facility. The Mozambique LNG Project (12.9 Mtpa, USD 20 billion) and Rovuma LNG Project (15.2 Mtpa, USD 30 billion) are expected to drive the country's export growth by the early 2030s. Despite delays, these projects could add over 30 Mtpa of LNG capacity, solidifying Mozambique as a key global supplier.

Tanzania is advancing its midstream capabilities, particularly through the development of the Tanzania LNG Project, an onshore initiative with an estimated investment of USD 42 billion. This project aims to tap into the country's substantial offshore gas reserves, estimated at around 57 trillion cubic feet. International energy companies, including Shell, Equinor, and ExxonMobil, are partnering with the Tanzanian government to drive these developments, which are critical for meeting global LNG demand, particularly in Asia.

Across Africa, regasification projects are critical to meeting domestic energy needs and enabling industrial growth. Countries such as **South Africa** is investing in LNG import terminals to diversify their energy sources and reduce dependence on coal and oil. For example, South Africa's plans for the Richards Bay LNG Terminal highlights the continent's growing focus on energy security and sustainability.

7.2.2.2 Asia Pacific

The Asia Pacific region is set to witness substantial growth in midstream natural gas investments, projected to exceed USD 200 billion by 2050. This investment is driven by the region's rapidly increasing energy demand, urbanisation, industrial expansion, and a strategic shift toward LNG to reduce dependence on coal and oil. Key countries such as Australia, China, India, Indonesia and Southeast Asia are at the forefront of this transformation, focusing on liquefaction, regasification, and pipeline infrastructure to enhance energy security and meet domestic and export demands.

In addition to liquefaction and regasification, the Asia Pacific region invests in pipeline infrastructure to facilitate domestic and regional gas transport. Pipelines connecting offshore gas fields to mainland terminals are critical to these investments, particularly in countries like Indonesia and Malaysia, where offshore reserves are substantial. Regional pipeline projects that aim to connect Southeast Asia's markets are also being explored, although geopolitical and financial challenges remain barriers to implementation.

Australia continues to dominate LNG production in the region, with its extensive liquefaction infrastructure and high export capacity. As one of the world's largest LNG exporters, Australia is investing in maintaining and expanding its existing facilities, such as Ichthys LNG and

Gorgon LNG, which are integral to its export strategy. Projects targeting new reserves in the Browse and Bonaparte Basin are also under development, ensuring Australia remains competitive in meeting global LNG demand. These investments are particularly significant as Australia seeks to reinforce its position as a major supplier to Asia, where LNG demand is projected to grow steadily through 2050.

China is expected to remain the largest LNG importer globally, with its regasification capacity expanding rapidly to meet surging domestic demand. Investments are focused on building new terminals and upgrading existing infrastructure to handle increased imports. China's transition to cleaner energy sources has accelerated its reliance on natural gas, and by 2050, the country is expected to account for a significant share of global LNG imports. State-owned enterprises and private companies are leading this expansion with partnerships and agreements with major LNG exporters such as Qatar and the United States.

Indonesia is emerging as a significant player in the LNG market, with its Abadi LNG Project in the Masela Block serving as a flagship development. This project, valued at USD 20 billion, is expected to enhance Indonesia's LNG export capacity and support its domestic energy transition. Additional investments target pipeline infrastructure to connect offshore reserves to processing facilities, facilitating domestic use and export. Indonesia's growing population and industrial needs are also driving the development of regasification terminals to address regional demand.

Southeast Asian countries, including Viet Nam, Thailand, and the Philippines, are intensifying their efforts to develop LNG infrastructure as part of their energy diversification strategies. These countries invest in new regasification terminals and small-scale LNG projects to support power generation and industrial use. Viet Nam, for example, is advancing projects such as the Thi Vai LNG Terminal, which will help the country transition away from coal-fired power plants. Similarly, Thailand's Map Ta Phut Terminal is undergoing capacity expansions to handle increased LNG imports, reflecting the region's commitment to reducing greenhouse gas emissions and enhancing energy security.

7.2.2.3 Eurasia

Eurasia's midstream natural gas infrastructure is on the cusp of significant transformation, driven by strategic pipeline developments and expanded LNG capacity in Russia. **Cumulative midstream investments in the region are projected to total nearly USD 135 billion by 2050, with approximately 81% of this capital directed toward LNG liquefaction infrastructure.** These investments reflect the region's strategic pivot toward diversifying export markets and enhancing energy security amid shifting global energy dynamics.

The Power of Siberia 2 pipeline, capable of transporting 50 bcma of natural gas from West Siberian fields to China, represents a cornerstone of Russia's long-term export strategy. Expected to become operational after 2030, the pipeline could significantly boost Russian gas exports to Asia, potentially matching the volumes traditionally supplied to Europe. This diversification aligns with Russia's broader objective to reduce dependence on Western markets and strengthen ties with the rapidly growing economies of South and East Asia.

In addition to Power of Siberia 2, the Central Asia-China pipeline corridor is another critical infrastructure development in the region. Currently operating at a near-maximum capacity of 55 bcma, the corridor could expand to 85 bcma with the construction of Line D. This extension would transport natural gas from Turkmenistan through Uzbekistan, Tajikistan, and Kyrgyzstan to China, enhancing regional connectivity and meeting China's surging energy demand. Similarly, the TAPI pipeline remains a potential game-changer, with the capacity to deliver 5 bcma of gas to Afghanistan, 14 bcma to Pakistan, and additional volumes to India. However, geopolitical and financial challenges have hindered its progress.

Russia continued strengthening its position in global gas markets by expanding its LNG export capacity and deepening ties with Asian and Southern markets. LNG exports to Europe remained robust, while deliveries to China and other Asian markets progressed steadily. Major projects, including Arctic LNG 2, advanced albeit with delays. Gazprom focused on optimising domestic pricing strategies and diversifying its export portfolio to align with shifting global demand. Additionally, Russia marked a key milestone in its LNG infrastructure development by launching its first domestically built ice-class LNG carrier, reinforcing its long-term commitment to global energy trade.

7.2.2.4 Europe

Europe is expected to invest approximately USD 39 billion in midstream natural gas infrastructure by 2050, with most of the expenditure occurring before 2030. These investments reflect Europe's urgent need to diversify its energy sources and enhance energy security amid ongoing energy transitions. The region's midstream strategy focuses on expanding regasification capacity, optimising LNG infrastructure, and integrating hydrogen-ready systems to align with its long-term decarbonisation goals under the Fit for 55 strategy, which aims to cut greenhouse gas emissions by 55% by 2030.

Over the past decade, the EU has significantly expanded its LNG infrastructure, achieving a total import capacity of 160-170 bcm through more than 20 large-scale operational terminals. However, the distribution of this capacity remains uneven, with nearly half concentrated in Spain, which faces limited interconnections with other parts of Europe. This geographic disparity has led to bottlenecks in gas distribution and highlighted the need for enhanced cross-border pipeline networks to ensure energy security across all member states.

In response to the energy crisis 2022, Europe has accelerated its LNG regasification capacity development, particularly through the rapid deployment of FSRUs. These units provide a flexible and fast-track solution to increase LNG import capacity. By 2025, Europe is expected to add between 60 Mtpa and 80 Mtpa of regasification capacity through new projects and the expansion of existing terminals. Germany, Italy, and Greece are at the forefront of these efforts.

Beyond regasification, Europe is investing in improving its cross-border pipeline network to address bottlenecks and ensure the seamless distribution of natural gas across member states. Projects such as the Baltic Pipe, connecting Norway to Poland via Denmark, and the expansion of reverse flow capacity in existing pipelines are critical to enhancing gas transit within the EU. These investments aim to integrate the European gas market, ensuring that all member states have access to liquid gas supplies.

Europe's short-term focus on LNG infrastructure is expected to wane after 2030 as the region accelerates its transition toward renewable energy. Post-2030, midstream investments will shift toward optimising existing LNG terminals, integrating hydrogen-ready technologies, and repurposing gas pipelines to transport hydrogen. These changes align with Europe's ambitious climate goals and commitment to achieving net-zero emissions by 2050.

Eastern Europe and the Baltic states also make targeted investments to enhance energy security. Countries like Poland and Lithuania have expanded their LNG import infrastructure. Poland's Świnoujście LNG Terminal, with plans to increase capacity to 8.3 bcm annually, and Lithuania's Klaipėda FSRU, with a capacity of 4 bcm annually, are vital to diversifying the region's energy sources.

Germany has emerged as a leader in LNG infrastructure expansion, with plans to develop 47 Mtpa of regasification capacity by 2027, including 20 Mtpa from FSRUs. This equates to approximately 65 bcm annually, positioning Germany as a critical hub for LNG imports in Central Europe. Major projects include the Wilhelmshaven and Brunsbüttel terminals, which are expected to enhance Germany's energy security and reduce its reliance on Russian gas.

Italy is also pivotal, with plans to add 7 Mtpa of regasification capacity by 2027, primarily through FSRUs. These projects aim to meet growing domestic demand and strengthen Italy's position as a regional energy transit hub, facilitating the flow of natural gas to Southern and Central Europe.

Greece is expanding its LNG infrastructure to become a gateway for gas imports into the Balkans and Southeastern Europe. By 2027, Greece is expected to achieve 7.3 Mtpa of regasification capacity, including both onshore terminals and FSRUs, equivalent to 10.1 bcm annually. Key projects like the Alexandroupolis FSRU will enhance Greece's ability to supply natural gas to neighbouring countries, such as Bulgaria, North Macedonia, and Serbia.

The **Netherlands** and **Belgium** also play significant roles in Europe's LNG infrastructure. The Netherlands' Gate Terminal, with a capacity of 12 bcm annually, and Belgium's Zeebrugge Terminal, with 9 bcm, are integral to meeting regional demand. Both countries are exploring capacity expansions and hydrogen integration to align with the EU's decarbonisation targets.

7.2.2.5 Latin America

Latin America's midstream natural gas investment landscape is poised for growth, with cumulative investments projected to surpass USD 16 billion by 2050. These investments are driven by the region's increasing reliance on LNG imports to supplement domestic energy needs, expanding regasification capacity, and the potential for some countries to enhance LNG export capabilities. Brazil, Argentina, and Caribbean countries such as the Dominican Republic and Trinidad and Tobago are leading the way, reflecting a mix of import-driven demand and opportunities to monetise regional natural gas resources.

Argentina is emerging as a notable player in Latin America's natural gas market, leveraging its vast unconventional reserves in the Vaca Muerta Shale Play to support LNG exports. The country's plans to build liquefaction facilities are a key driver of midstream investments, aiming to monetise its significant gas reserves and reduce dependency on domestic pipeline networks. The Vaca Muerta is among the world's largest shale gas reserves, and Argentina's midstream strategy involves connecting these reserves to liquefaction terminals for export to global markets. The first phase of liquefaction capacity expansion could reach 10 Mtpa, with additional phases planned by 2050. This development is expected to attract foreign investment and strengthen Argentina's position as a regional energy hub.

Brazil is the centrepiece of Latin America's midstream gas sector, with its LNG infrastructure playing a critical role in addressing the country's seasonal energy demand fluctuations. Brazil has the largest regasification capacity in the region, supported by FSRUs that provide flexibility in meeting power generation needs during periods of low hydropower output. The country has 50 Mtpa of regasification capacity and is planning additional expansions, including constructing new FSRUs to cater to industrial and residential energy demands. With an energy matrix that heavily depends on hydropower, LNG imports have become a reliable buffer during dry seasons, stabilising the electricity grid and ensuring supply continuity. By 2050, Brazil's regasification investments are expected to account for a substantial share of regional spending.

The Caribbean region increasingly relies on LNG imports to transition from fuel oil and coal to power generation. **Trinidad and Tobago** remains the region's largest LNG exporter, operating the Atlantic LNG Facility with a total capacity of 15 Mtpa. However, declining gas reserves have prompted discussions on optimising existing infrastructure and extending the productive life of mature fields. Meanwhile, Jamaica and the Dominican Republic are expanding their regasification capacity to meet growing energy needs, supported by favourable government policies and private sector involvement.

Chile is another significant player in Latin America's LNG sector, with a well-developed import infrastructure. The country operates two major regasification terminals - Quintero and Mejillones - which collectively supply natural gas to power plants, industrial users, and residential consumers. Chile's reliance on LNG imports stems from its limited domestic natural gas production, making these terminals critical to energy security. Future investments are expected to enhance capacity and integrate LNG into Chile's energy transition strategy, particularly as the country works to reduce its carbon footprint.

Colombia has also entered the LNG import market with the Cartagena LNG Terminal, which supports its growing power generation needs. As Colombia looks to transition its energy sector, LNG plays a crucial role in bridging the gap between traditional fossil fuels and renewable energy. Plans for additional terminals, including one in Buenaventura on the Pacific Coast, highlight the country's commitment to expanding midstream infrastructure.

Throughout Latin America, factors such as geopolitical dynamics, uncertainties in domestic gas production, and access to abundant United States LNG imports are shaping midstream investment priorities. While the region's export pipeline infrastructure remains underdeveloped, growing domestic gas networks are expanding to improve access and support industrial growth.

7.2.2.6 Middle East

The Middle East is poised to solidify its role as a global leader in natural gas production and export, with midstream investments projected to reach approximately USD 82 billion by 2050. These investments are primarily directed toward expanding LNG liquefaction capacity and modernising infrastructure to meet growing global demand, particularly from Asia and Europe. The region's vast reserves, strategic geographic position, and established energy markets make it a global natural gas value chain cornerstone. Qatar, the UAE, Oman, and Saudi Arabia are leading midstream investment efforts, while countries like Iran and Iraq are also exploring opportunities to enhance their gas infrastructure.

Qatar remains the dominant player in the Middle East's midstream gas sector. With the North Field East (NFE) and North Field South (NFS) expansion projects, Qatar is set to significantly increase its LNG export capacity by 65 Mtpa, bringing the total to 142 Mtpa by the early 2030s. The NFE project, valued at approximately USD 29 billion, is expected to commence operations by 2026, while the NFS project, estimated at over USD 14 billion, will follow shortly thereafter. These projects are supported by partnerships with leading global energy companies such as ExxonMobil, Shell, TotalEnergies, and Eni, ensuring robust financing and access to advanced technology. Qatar's long-term contracts and reliable export infrastructure further enhance its role as a stable LNG supplier to Asian and European markets.

The **UAE** invests heavily in midstream infrastructure to achieve energy self-sufficiency and expand its role as a regional energy hub. The Hail, Ghasha, and Dalma Projects, part of the USD 40 billion Ghasha Concession, aim to develop sour gas resources and increase domestic production. These projects are complemented by investments in LNG liquefaction and regasification facilities, enabling the UAE to cater to both domestic and export markets. The UAE is also advancing its sustainability agenda by integrating CCUS technologies into its gas projects to reduce emissions and align with its Net Zero 2050 strategy.

Oman is also playing a significant role in the Middle East's midstream expansion, focusing on enhancing its LNG liquefaction capacity. The Oman LNG Facility, with a current capacity of 10.4 Mtpa, is undergoing upgrades to boost efficiency and output. Additionally, new projects are being explored to tap into Oman's substantial gas reserves, including those in the Khazzan and Ghazeer Fields. Oman's strategic location on key maritime trade routes positions it as a vital LNG supplier to Asia, where demand continues to grow. Investments in Oman's pipeline infrastructure also facilitate gas transport to domestic markets and export terminals, supporting local energy needs and international trade.

Saudi Arabia's midstream gas investments align with its Vision 2030 strategy, emphasising energy diversification and industrial growth. The development of the Jafurah Shale Gas Field, with an estimated investment of USD 170 billion, is central to Saudi Arabia's efforts to reduce reliance on oil and leverage natural gas as a cleaner energy source. While most of Saudi Arabia's gas infrastructure investments are focused on upstream and domestic distribution, the country is also exploring opportunities to expand its LNG export capabilities to meet growing global demand.

7.2.2.7 North America

North America is set to dominate the global natural gas market, with midstream investments projected to reach nearly USD 116 billion by 2050. These investments are primarily directed toward expanding LNG liquefaction capacity and strengthening infrastructure to facilitate the region's growing role as a major LNG exporter. The United States, Canada, and Mexico are leading this transformation, leveraging their abundant natural gas reserves, strategic geographic positions, and advanced technological capabilities.

The **United States** is at the forefront of North America's midstream investment efforts, driven by its robust LNG export market and expanding domestic production. With plans to add 120 Mtpa of new LNG capacity by 2030, the United States is poised to solidify its position as the world's largest LNG exporter. Recent projects, such as Golden Pass LNG and Plaquemines LNG, are expected to add approximately 45 Mtpa of capacity started in 2024. Pre-Final Investment Decision (pre-FID) developments account for a substantial portion of future investments, reflecting the strong momentum driven by energy security concerns and high global demand. Key facilities like Sabine Pass, Freeport LNG, and Corpus Christi LNG continue to expand, offering flexible and reliable supply to global markets.

The United States - EU energy partnership has further strengthened LNG development. Under this collaboration, the United States has committed to supplying an additional 50 bcma of LNG to Europe by 2030, addressing the continent's need to diversify energy sources. Long-term foundational agreements signed with Asian buyers also enhance investment confidence as United States developers secure contracts with energy-hungry economies in China, India and Japan.

Technological advancements are pivotal in enhancing the efficiency and environmental performance of United States LNG facilities. Innovations in liquefaction processes, CCUS, and methane abatement are being integrated into new and existing projects to align with global decarbonisation goals. The United States is also exploring small-scale LNG projects to meet regional and niche market demands, particularly in Latin America and the Caribbean.

Canada's midstream gas investments are projected to be directed toward liquefaction projects and infrastructure upgrades in the Western Canadian Sedimentary Basin (WCSB). The WCSB accounts for the vast majority of Canada's natural gas production, with tight and shale gas development forming the backbone of its supply. Liquefaction projects like Woodfibre LNG and Kitimat LNG are critical for Canada's efforts to tap into global LNG markets, particularly in Asia, where demand is expected to grow steadily through 2050. Canada's proximity to the Asia Pacific markets positions it as a competitive supplier in the global LNG market.

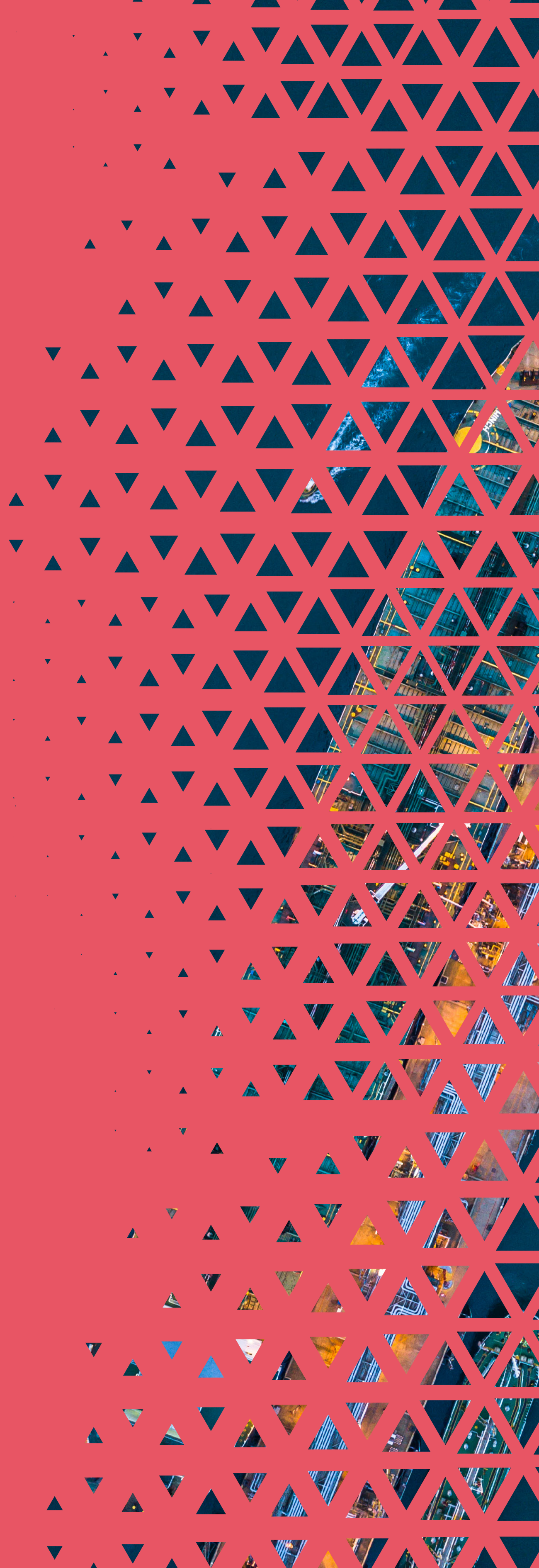
Canada is also focusing on integrating CCUS technologies and renewables into its midstream infrastructure to reduce emissions and enhance the environmental credentials of its LNG exports. Investments in regasification and domestic pipeline networks are facilitating the distribution of natural gas within Canada and strengthening connections with export terminals on the West Coast. These developments are expected to attract international partnerships and investments, ensuring Canada remains a key player in the global natural gas market.

Mexico is strategically positioned to serve both North and Latin American markets. While traditionally reliant on pipeline imports from the United States to meet domestic energy needs, Mexico increasingly focuses on developing LNG export infrastructure to capitalise on rising global demand. The Costa Azul LNG Facility in Baja, California, is a flagship project designed to export LNG to Asian markets, leveraging Mexico's access to abundant, low-cost United States natural gas. The project is expected to handle up to 12 Mtpa of LNG, strengthening Mexico's role in the global supply chain.

Mexico is also investing in regasification infrastructure to address regional energy needs, particularly in areas underserved by pipeline networks. New LNG import terminals, such as those planned for the Yucatan Peninsula, aim to enhance energy security and support industrial growth. Additionally, the country's cross-border infrastructure with the United States facilitates the seamless transport of natural gas, enabling Mexico to act as a transit hub for North American energy exports.

Chapter 8

Sustainable Energy Scenario



Highlights

- The Sustainable Energy Scenario (SES) provides a comprehensive framework that underscores natural gas's critical role in meeting global energy demand while simultaneously ensuring the progress of the UN Sustainable Development Goals, including universal access to affordable and modern energy, and facilitating a reduction of the energy system environmental footprint. It highlights how natural gas, combined with emerging decarbonisation technologies such as CCUS, can significantly reduce emissions while ensuring energy security and affordability.

- Global primary energy demand in the SES is projected to experience a 22% increase from 2023 level, rising by 140 EJ to reach 775 EJ by 2050, compared to an 18% increase in the RCS.

- Natural gas demand in the SES is expected to witness a substantial expansion of 1,979 bcm, reaching 5,997 bcm by 2050. This reflects a 49% growth, significantly surpassing the 32% increase in the RCS, as the dominant energy source.

- By mid-century, natural gas is projected to surpass both oil and coal, establishing itself as the leading fuel in the global energy system. Its share in the global energy mix is expected to reach 28% by 2050, 2 percentage points higher than in the RCS.

- The Asia Pacific region is anticipated to be the primary driver of natural gas demand growth, largely due to a major transition drive from coal to natural gas in power generation. Over the forecast period, natural gas demand in this region is set to increase by 967 bcm, reaching 1838 bcm by 2050, compared to 1,581 bcm in the RCS.

- Africa emerges as the largest contributor to global natural gas supply contribution under the SES by mid-centruy compared to the RCS. Over the forecast period, natural gas production in the region is projected to increase by more than 500 bcm, reaching 756 bcm by 2050, a significant rise compared to 502 bcm in the RCS.

- The global natural gas trade volume is forecast to expand by 817 bcm, reaching 2,030 bcm by 2050, compared to 1,743 bcm in the RCS. LNG is expected to account for 67% of total natural gas trade in the SES by 2050, up from 63% in the RCS, reinforcing its role as the dominant mode of global gas supply expansion.

- Cumulative capital investment required for natural gas upstream and midstream over the period 2023 to 2050 is projected to reach USD 12.1 trillion, exceeding the RCS level by USD 1.0 trillion. Upstream investment accounts for 93% of this total, amounting to USD 11.1 trillion, reflecting the intensified focus on exploration and production activities to meet the growing demand.

- Global energy-related emissions are projected to decline from 40.6 $GtCO_2e$ in 2023 to 26.9 $GtCO_2e$ by 2050, marking a 34% absolute reduction, significantly outpacing the 23% decrease observed in the RCS.

- The SES anticipates exponential growth in CCUS deployment, with its contribution to emissions reductions increasing from 41 $MtCO_2e$ in 2023 to 7.2 $GtCO_2e$ by 2050, representing a 5.2 $GtCO_2e$ increase compared to the RCS. Natural gas-based CCUS is expected to have the most substantial impact, delivering 3.6 $GtCO_2e$ in emissions reductions by 2050, 2.9 $GtCO_2e$ higher than in the RCS, accounting for 57% of the total additional CCUS-driven emissions savings between the two scenarios.

8.1 Introduction to the Sustainable Energy Scenario (SES)

Energy is the fundamental force driving economic development, social progress, and environmental protection. A modern, well-functioning energy system is indispensable for industrial growth, digital connectivity, infrastructure development, and higher living standards. Yet, despite remarkable advancements in energy technologies and the expansion of modern energy access, billions of people remain excluded from the benefits of a reliable and efficient energy supply. Approximately 4.7 billion people—nearly 60% of the world's population—live below the empowerment line, lacking the income needed to afford essential goods and services for a decent standard of living. **An overwhelming 2.1 billion people, nearly one-third of the global population, still depend on traditional biomass fuels, such as wood and charcoal, for basic needs like cooking and heating. At the same time, 770 million people remain without access to electricity, severely limiting their opportunities for education, healthcare, and economic participation.**

Addressing energy poverty requires accelerating economic growth and ensuring the expansion of energy systems in an inclusive and affordable manner. This necessity becomes even more urgent given the projected population growth of 1.8 billion people by 2050, primarily in low-income countries that already struggle with energy shortages.

The transition to a low-carbon energy system is neither linear nor uniform across regions. While the imperative to reduce emissions is clear, the pathways to achieving this objective remain uncertain, constrained by the maturity of available technologies, the scale of required investments, and the geopolitical and economic risks associated with disruptive energy transitions. The energy sector must navigate a set of intricate trade-offs that extend beyond the simple dichotomy of fossil fuels versus renewables. In reality, the global energy transitions will be shaped by region-specific conditions, including the availability of natural resources, economic and demographic trends, infrastructure readiness, and financial and technological capabilities. Energy systems are inherently complex, and no single energy source or technology can provide a universal solution to balancing emissions reductions with economic growth and energy security. The reality is that energy transitions must be understood as a dynamic and evolving process that requires the integration of multiple energy sources and technological solutions.

The projected gap between global energy supply and demand over the coming decades presents an immediate challenge that cannot be addressed solely through the expansion of renewable energy. Despite rapid growth, renewable energy technologies have not yet achieved the level of maturity, cost-efficiency, and infrastructure readiness necessary to replace conventional energy sources at scale fully. The power sector has seen significant progress in the deployment of wind and solar, yet challenges related to intermittency, grid reliability, and storage remain unresolved. Access to critical minerals is also an important constraint. Additionally, the industrial, transportation, and chemical sectors continue to rely on hydrocarbons due to the lack of viable alternatives at competitive costs. In this context, natural gas is a critical enabling fuel, ensuring energy security and facilitating just, orderly and equitable energy transitions.

Given these uncertainties and the complexities associated with decarbonisation, the need for an alternative energy scenario becomes evident. Existing energy outlooks often either overestimate the speed at which low-carbon solutions can replace traditional energy sources or underestimate the enduring role of hydrocarbons in meeting future energy needs. The reality lies in a more balanced and adaptive approach that accounts for regional disparities, economic feasibility, and technological progress. In response to these challenges, this chapter introduces the SES as an alternative pathway that seeks to balance emissions reductions with economic development and energy security.

8.2 SES Assumptions

As a counterfactual analysis, the SES envisions a transformative shift in the global energy landscape, driven by three key pillars: economic empowerment and energy system expansion, an optimised energy mix transition, and large-scale decarbonisation technology deployment. Unlike the RCS, where energy poverty persists by mid-century, the SES assumes that all countries achieve economic empowerment on average national level, ensuring higher energy access and consumption, particularly in Africa, developing Asia, and parts of the Middle East. This expansion results in a larger global economy and a higher overall energy demand, reinforcing the need for a secure, scalable, and efficient energy system.

To meet this growing demand while ensuring stability, the SES prioritises natural gas as a key enabler of energy transitions, accelerating unabated coal's phase-down and incorporating intermittency's full costs in renewable energy deployment. The assumption reflects natural gas as a flexible partner to renewables, a key feedstock for hydrogen production, and a cleaner fuel for transport and industrial sectors. Additionally, a structural shift in global transport is assumed, with LNG-fueled heavy-duty vehicles and ships expanding rapidly, displacing diesel and fuel oil. In parallel, exponential growth in AI and digital infrastructure increases electricity demand, reinforcing the role of gas-fired generation in securing reliable power supply for data centres. Moreover, the SES assumes an accelerated transition from traditional biomass toward LPG and natural gas for clean cooking, particularly in Africa, along with the widespread adoption of heat pumps in Europe and North America to decarbonise heating and cooling.

Given the larger scale of the energy system in the SES, decarbonisation technologies such as CCUS and hydrogen play a central role in ensuring emissions reductions without compromising economic and energy security. The scenario assumes a substantial capture rate of energy-related emissions in the industrial sector by 2050, widespread adoption of blue hydrogen, and efficiency improvements across all sectors. These integrated assumptions define a more inclusive, technologically advanced energy system that balances economic growth, environmental sustainability, and energy security.

The following sections provide a detailed analysis of each assumption. A summary of SES assumptions compared to the RCS is presented in Table 8.1.

8.2.1 Per capita GDP assumptions

A central objective of the SES is to achieve universal economic empowerment at the average national level by 2050, emphasising eradicating energy poverty. Economic empowerment extends beyond income growth to encompass universal access to essential services such as healthcare, education, affordable necessities, and the development of sustainable communities. Achieving these goals requires a shift from merely alleviating extreme poverty, as defined by the World Bank, to establishing a more comprehensive benchmark that ensures long-term resilience against economic vulnerability. Traditional poverty lines focus on subsistence-level survival, but sustained economic development demands a higher threshold that enables individuals and communities to secure a decent quality of life while building the foundation for continued progress.

In this context, economic empowerment is defined as achieving a minimum standard of living that guarantees access to essential services, including adequate nutrition, education, healthcare, housing, clean water, sanitation, and modern energy. This threshold signifies an improvement in material well-being and serves as a protective buffer against economic shocks that could otherwise push individuals back into poverty. Research by the McKinsey Global Institute (2023) estimates that this baseline equates to USD 12 per person per day in purchasing power parity (PPP) terms for 2017, which, when adjusted for inflation, corresponds to USD 5,250 per person per year in PPP terms for 2023 (see Box 8.1). Establishing this benchmark as a universal threshold at the average national level ensures that economic progress translates into tangible and sustainable improvements in well-being rather than temporary income gains that remain vulnerable to financial instability and external shocks.

The SES framework assumes that countries currently below the average national empowerment line, as defined in 2023, will achieve economic empowerment by 2050, reaching at least USD 5,250 per person per year in PPP terms (2023 base year). This transition is driven by sustained long-term economic growth rates that exceed those in the RCS by approximately 0.4 percentage points annually. While this incremental difference may seem marginal annually, its cumulative effect is projected to result in an additional USD 21 trillion in global GDP by 2050. A significant share of this growth is expected to occur in Sub-Saharan Africa and the developing Asia Pacific, the two regions facing the most severe challenges related to energy poverty and access to modern energy services. Africa is anticipated to account for nearly 70% of the GDP increment between the SES and RCS scenarios, with its average annual GDP growth rate rising to 5.4% in the SES, one percentage point higher than in the RCS. Meanwhile, developing countries in the Asia Pacific region are expected to capture 27% of the real GDP increase in the SES relative to the RCS, leading to an average annual growth rate of 3.5%, compared to 3.3% in the RCS.

Note that, in this context, the empowerment level is applied to the average national GDP per capita per year in PPP terms (2023 base year) and does not account for income distribution within countries. As a result, even if a country's average GDP per capita surpasses the empowerment threshold, it does not necessarily mean that all individuals in the country have reached this income level.

8.2.2 Residential and commercial sector assumptions

Under the SES, there are four key underlying assumptions for the residential and commercial sector:

a. A substantial decline in traditional biomass use, particularly in Sub-Saharan Africa, is a central assumption. This is based on an evaluation of policy commitments at both regional and national levels aimed at tackling the clean cooking deficit. Traditional biomass accounts for more than 80% of Sub-Saharan Africa's residential segment energy mix, but under the SES, it is projected to decline to 25% by 2050, compared to 50% in the RCS. This shift is primarily driven by increased investments in clean cooking solutions, LPG distribution, and electrification programs to improve energy access and reduce reliance on inefficient fuel sources.

b. A significant increase in natural gas and electricity grid expansion is assumed, particularly in Sub-Saharan Africa. Rising domestic gas production, ongoing infrastructure development, and

Table 8.1

Comparing global assumptions in SES and RCS

	RCS	SES
Macroeconomy	Global annual growth rate: **2.5%** Africa growth rate: **4.4%** Asia Pacific growth rate: **3.3%**	Global annual growth rate: **2.9%** Africa growth rate: **5.4%** Asia Pacific growth rate: **3.5%**
The residential and commercial sector	The share of **traditional biomass** in Sub-Saharan Africa's residential energy mix will decline to **50%**	The share of **traditional biomass** in Sub-Saharan Africa's residential segment energy mix will decline to **25%**
		Significant increase in natural gas and electricity grid expansion in Sub-Saharan Africa
	AI-driven energy consumption is not included	**AI-driven energy consumption** is projected to contribute approximately **30% to the non-substitutable electricity** demand growth in the **commercial segment** by 2050
	The coefficient of performance **(COP)** for **heat pumps: 2.5**	The coefficient of performance **(COP)** for **heat pumps: 3.0**
Transport sector	Limited LNG trucks are included	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**
	Limited LNG-fueled vessels are included	The growth in the number of LNG-fueled vessels: 2023-2030: **15%** 2031-2040: **10%** 2041-2050: **5%**
Industrial sector	No direct CCUS applied in the industrial sector	CCUS implemented by 2050: **75%** of energy-related emissions
Power sector	**Average CCGT efficiency** by 2050: **47%** New gas-fired capacity: CCGT and Steam turbine with CCUS after 2040	**Average CCGT efficiency** by 2050: **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 by 2050	CCUS applied in hydrogen production: 80% for all countries by 2050
Natural gas trade	Global liquefaction capacity utilisation: **80%** total global liquefaction capacity in 2050: **1,004 Mtpa**	Global liquefaction capacity utilisation: **85%** total global liquefaction capacity in 2050: **1,180 Mtpa**
	Global regasification capacity utilisation: **45%** Total global liquefaction capacity in 2050: **1,805 Mtpa**	Global regasification capacity utilisation: **50%** Total global liquefaction capacity in 2050: **2,000 Mtpa**

Source: GECF Secretariat based on data from the GECF GGM

Box 8.1 The role of economic empowerment in just, orderly and equitable energy transitions

The global energy transitions are often framed primarily as a climate imperative, with policies and investments overwhelmingly focused on reducing carbon emissions and accelerating the adoption of renewable energy. However, this approach frequently overlooks an equally critical challenge, economic empowerment. As countries work toward a low-carbon future, achieving just, orderly, and equitable energy transitions requires balancing environmental protection with economic prosperity and social progress. A transition that fails to integrate economic empowerment risks exacerbating global inequalities, hindering economic development, and creating deep social and political instabilities, particularly in developing regions.

Economic empowerment: Concept and measurement

Economic empowerment refers to the ability of individuals and communities to improve their living standards, participate in productive economic activities, and build financial resilience. The McKinsey Global Institute (MGI) quantifies economic empowerment using a composite index that includes income growth, financial inclusion, access to education, labour market participation, and essential infrastructure.

MGI defines the empowerment threshold at approximately USD 12 per day in purchasing power parity (PPP) terms (2017 base year), ensuring that individuals can afford essential needs such as food, healthcare, education, housing, and transportation while maintaining financial stability. Adjusted for inflation, this translates to an annual empowerment threshold of approximately USD 5,250 per person (PPP 2023 terms). Those earning between USD 2.15 (extreme poverty line based on the World Bank measurement) and USD 12 per day (PPP terms) are not classified as extremely poor but remain economically insecure, lacking the financial resilience to withstand economic shocks or make meaningful investments in their human capital.

Unlike standard poverty measurements, MGI's methodology captures multidimensional factors influencing economic empowerment, including access to reliable infrastructure, modern education systems, healthcare, digital connectivity, and financial services. It recognises that income alone does not guarantee economic security—access to these enablers is critical for sustaining economic well-being. True empowerment ensures individuals and communities are not merely surviving but thriving, capable of contributing to economic growth and benefiting from long-term development opportunities.

The scale of the economic empowerment gap and its energy link

Despite progress in reducing extreme poverty over the past two decades, 4.7 billion people worldwide remain below the economic empowerment threshold, underscoring the scale of global economic vulnerability (Figure 1). The distribution is highly regionalised:

Sub-Saharan Africa and South Asia together account for nearly 50% of the global population below the empowerment line, reflecting severe infrastructure deficits, weak financial systems, and constrained economic opportunities.

Latin America and Southeast Asia exhibit intermediate levels of vulnerability. Economic growth has lifted many out of extreme poverty but has yet to secure broad-based economic empowerment. Many remain economically fragile, with incomes insufficient to support long-term financial resilience.

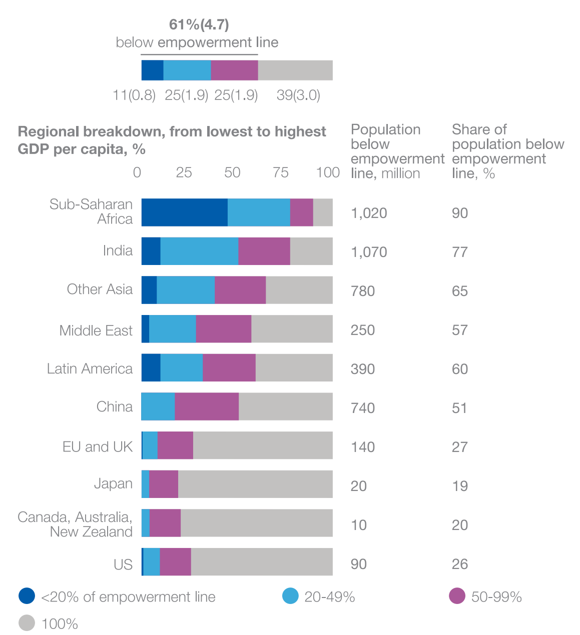
Even in high-income economies such as the United States and Europe, rising housing, healthcare, and education costs have placed significant portions of the population at risk of financial insecurity, despite high overall per capita incomes on a national level.

A major but under-discussed driver of economic empowerment is access to modern energy. Energy enables industrialisation, job creation, and financial inclusion, serving as a prerequisite for economic progress. The United Nations Sustainable Development Goal (SDG) 7 highlights the need for universal access to affordable, reliable, sustainable, and modern energy, recognising its fundamental role in reducing economic inequality and fostering inclusive growth. However, significant energy poverty persists:

- 770 million people worldwide still lack access to

Figure 1

Share of population, by spending level as percentage of empowerment line (Based on 2020 population)



Source: McKinsey Global Institute 2023 electricity, severely limiting their ability to participate in modern economies.

- 2.1 billion people rely on traditional biomass for cooking, exposing them to severe health, economic, and environmental consequences.

The interplay between energy, economic empowerment, and SDG 7

Access to reliable and affordable energy is a prerequisite for economic growth and a direct driver of industrialisation, job creation, and financial inclusion. Countries that have successfully expanded energy access, such as China and India, have witnessed substantial reductions in poverty and accelerated economic growth. Conversely, persistent energy poverty in Sub-Saharan Africa has slowed progress toward economic inclusion, leaving millions trapped in subsistence-level livelihoods.

Achieving SDG 7 requires integrated policies that link energy access to economic empowerment. Without electricity, businesses remain small-scale and inefficient, digital connectivity is limited, and education and healthcare services suffer. The interconnection between energy access and economic empowerment is evident across multiple SDGs:

- SDG 4 (Quality Education): Schools without electricity struggle to provide digital and practical learning resources, limiting educational attainment.
- SDG 8 (Decent Work and Economic Growth): Industrial expansion and job creation require stable and affordable energy.
- SDG 9 (Industry, Innovation, and Infrastructure): Reliable electricity and clean cooking fuel are essential for building resilient and competitive economies.

According to McKinsey Global Institute (2023), bridging the global empowerment gap by 2030 would require an additional USD 37 trillion in cumulative spending power, equivalent to 40% of the affected population's current consumption levels. Developing regions face the most significant hurdles, with empowerment gaps amounting to 45% of GDP annually in Sub-Saharan Africa and 13% in India. In contrast, high-income economies exhibit gaps closer to 1% of GDP.

The economic empowerment challenge cannot be separated from the energy transitions. Natural gas, LPG, and electrification remain essential tools in the fight against economic marginalisation, bridging the gap between poverty alleviation and long-term economic resilience. Sustainable economic empowerment strategies must integrate energy expansion with policies that foster industrialisation, entrepreneurship, and equitable financial access. Ensuring that SDG 7 is achieved alongside broader economic development objectives is critical to securing a more inclusive and stable global future.

targeted policy measures incentivising gas-based electrification and energy access support this assumption.

c. The commercial sector is assumed to experience a notable increase in electricity demand beyond the RCS projection, largely driven by the rapid expansion of data centres and AI applications. AI-driven energy consumption is projected to contribute approximately 30% to this segment's non-substitutable electricity demand growth by 2050. However, this scenario does not explicitly consider the reinforcing cycle between AI adoption and economic expansion, implying that actual demand could exceed current projections if AI-driven productivity gains further accelerate commercial activity.

d. In Europe and North America, the adoption of advanced dual-purpose heat pumps for heating and cooling in the residential and commercial sectors is assumed to accelerate significantly. The coefficient of performance (COP) is projected to rise from 2.5 in the RCS to 3.0 under the SES, reflecting substantial improvements in technology and greater policy incentives supporting electrification in heating applications. This transition aligns with broader energy efficiency targets and decarbonisation strategies in these regions.

8.2.3 Industrial sector assumptions

Under the SES, large-scale CCUS is assumed to play a pivotal role in industrial decarbonisation, particularly in high-emission sectors such as iron and steel, mining, and chemicals. The scenario envisions a steady and sustained increase in CCUS deployment, aiming to capture 75% of energy-related emissions from the industrial sector by 2050. A key implication of this assumption is the progressive substitution of grey hydrogen with blue hydrogen as a primary industrial feedstock, driven by enhanced policy incentives, infrastructure investments, and cost reductions in carbon capture technologies. This transition is expected to significantly mitigate industrial emissions while ensuring continued energy security and operational efficiency across these critical sectors.

8.2.4 Transport sector assumptions

Under the SES, there are two underlying assumptions for the improved adoption of natural gas in this sector:

a. The global fleet of LNG-fueled trucks is assumed to expand significantly, with an annual growth rate of 10% through 2030, before moderating to 8% per year by 2040 and stabilising at 5% annually by 2050. Stricter emissions regulations drive this rapid expansion, the growing cost competitiveness of LNG relative to diesel, and rising investments in LNG refuelling infrastructure to support long-haul freight transport. LNG truck efficiency is estimated at 25-30 kg of LNG per 100 km, with an average annual mileage of 100,000-120,000 km per vehicle. This transition is expected to lead to a displacement of diesel oil in the transport sector, particularly in the heavy-duty vehicle (HDV) segment, where LNG offers a viable alternative to diesel in long-haul applications. China and India are expected to dominate LNG truck deployment, accounting for the majority of global sales, driven by aggressive policy support, financial incentives, and expanding LNG highway corridors. These markets benefit from government-backed fleet conversion programmes, carbon reduction initiatives, and LNG infrastructure expansion.

b. LNG adoption in shipping and bunkering is assumed to gain momentum. The number of LNG-fueled vessels in shipping and bunkering is assumed to grow at an annual rate of 15% through 2030, driven by IMO decarbonisation targets, expanding LNG bunkering infrastructure, and cost advantages over conventional marine fuels. Growth is expected to moderate to 10% annually between 2030 and 2040 as LNG adoption becomes more widespread, retrofitting increases, and alternative low-carbon fuels such as hydrogen and ammonia begin scaling. By 2040-2050, LNG-fueled fleet expansion is projected to slow further to 5% annually as next-generation fuels become more competitive. However, LNG will remain a dominant fuel for long-haul shipping and energy-intensive segments. By 2050, LNG-fueled vessels are anticipated to account for 45-50% of the global commercial fleet.

8.2.5 Power sector assumptions

Under the SES, there are four (4) primary underlying assumptions for the power sector:

a. The thermal efficiency of Combined Cycle Gas Turbine (CCGT) power plants is assumed to increase gradually from 47% in 2023 to 56-58% by 2050, driven by advancements in turbine technology, improved heat recovery systems, and the integration of digital optimisation tools such as AI-driven predictive maintenance. While the latest H-class and J-class turbines already achieve over 64% efficiency under optimal conditions, the global fleet-wide average efficiency will improve more gradually due to the continued operation of older, lower-efficiency plants and regional variations in technological adoption.

b. It is assumed that all new gas-fired power capacity additions over the forecast period will be CCGT plants, progressively replacing retiring simple-cycle and steam turbine gas plants. Many OECD countries (North America, Europe, Japan, and South Korea) are expected to adopt state-of-the-art CCGTs with above 58% efficiency, while developing regions (India, Southeast Asia, the Middle East, Africa, and Latin America) may continue to rely on mid-efficiency gas plants with 50-55% efficiency due to cost constraints and infrastructure limitations. As a result, global gas-fired power capacity is projected to increase by 1,335 GW by 2050, compared with 1,153 GW in the RCS. CCUS is assumed to be implemented on all newly installed CCGT power plants from 2030 onward.

c. It is assumed that global coal-fired power plant capacity will decline by approximately 1,791 GW over the forecast period, driven primarily by the accelerated retirement of large scrubbed and unscrubbed steam turbine plants in OECD economies, China, and India, alongside the gradual transition toward cleaner energy sources. However, while large-scale retirements will dominate, a limited number of small, high-efficiency scrubbed steam turbine power plants equipped with CCUS technologies are expected to be deployed, leading to a modest increase in this segment over the forecast period. The scale and pace of coal plant closures will vary significantly by region. OECD countries (Europe, Japan, North America, and South Korea) are expected to phase out 80-90% of their existing coal fleet by 2050, aligning with climate commitments and carbon pricing mechanisms. China and India, while reducing their reliance on coal, will pursue a more measured transition, maintaining strategic coal capacity for energy security and grid stability, though with widespread adoption of high-efficiency, low-emission (HELE) technologies and mandatory CCUS deployment. Additionally, some emerging economies in Southeast Asia and Africa will continue to use domestic coal resources, albeit under increasing regulatory and policy pressures, to integrate advanced carbon capture solutions and alternative low-carbon technologies. In the RCS scenario, coal-fired capacity is projected to decline by 1,377 GW, reflecting a more gradual transition than in the SES, where full CCUS deployment on all remaining coal plants is assumed to mitigate emissions.

d. In the SES, the Levelised Cost of Electricity (LCOE) for variable renewable energy (VRE), including solar and wind, is assumed to account for intermittency-related costs, reflecting the additional investments needed to ensure grid reliability and system flexibility. This adjustment incorporates the cost of backup capacity, such as battery storage and gas-fired peaking plants, estimated to require 20-30% of total installed VRE capacity, adding USD 10-30/MWh to renewable LCOE depending on grid conditions. Additionally, transmission and distribution (T&D) expansion costs—necessary for integrating large-scale renewables—are expected to contribute USD 5-15/MWh due to grid reinforcement and expansion requirements. Curtailment and system balancing costs, arising as VRE penetration surpasses 50% in key markets like Europe, China, and the United States, introduce further inefficiencies, adding USD 5-10/MWh. As a result, the effective LCOE for renewables is adjusted upward by USD 20-50/MWh, depending on regional conditions, ensuring a more realistic cost comparison with dispatchable power sources such as natural gas and nuclear while maintaining energy system reliability.

8.2.6 Rapid low-carbon hydrogen adoption assumptions

In the SES, the large-scale deployment of CCUS in hydrogen production drives a gradual but strong substitution of grey hydrogen with blue hydrogen, capturing up to 80% of sectoral emissions by 2050. This transition is primarily cost-driven and policy-supported, with a rising global carbon price rendering grey hydrogen increasingly uneconomical. Simultaneously, technological advancements and economies of scale lower the cost of blue hydrogen to USD 1.0–1.5/kg H_2 by 2040, maintaining a 30–50% cost advantage over green hydrogen, which remains constrained by high electrolyser costs and renewable energy intermittency.

8.2.7 Increased midstream infrastructure capacity assumptions

Under SES, there are two key underlying assumptions for liquefaction and regasification capacities:

a. It is assumed that global liquefaction capacity utilisation will average 85%, reflecting operational efficiencies and downtime considerations. As a result, total global liquefaction capacity is projected to reach approximately 1,180 Mtpa by 2050, compared to 1,004 Mtpa in the RCS. Nearly 70% of this incremental capacity expansion is expected to occur in the Middle East and Africa, driven by rising LNG export ambitions, abundant, low-cost natural gas reserves, and strategic positioning to supply key demand centres in Europe and Asia.

b. It is assumed that global regasification facilities will operate at an average capacity factor of 50% throughout the forecast period, resulting in a total regasification capacity of approximately 2,000 Mtpa by 2050 under the SES, compared to 1,805 Mtpa in the RCS. This expansion is primarily driven by rising LNG demand and infrastructure investments, particularly in Asia Pacific, which accounts for over 90% of the incremental regasification capacity between the two scenarios.

8.3 SES Results

This section presents the results of the SES and compares them with the RCS to analyse the impact of accelerated energy transitions on global energy dynamics. The assessment covers primary energy demand, natural gas demand and supply, trade flows, sector investments, and energy-related emissions, providing insights into how structural shifts in the energy mix, policy-driven market transformations, and technological advancements shape the future trajectory of the natural gas sector.

8.3.1 Primary energy demand

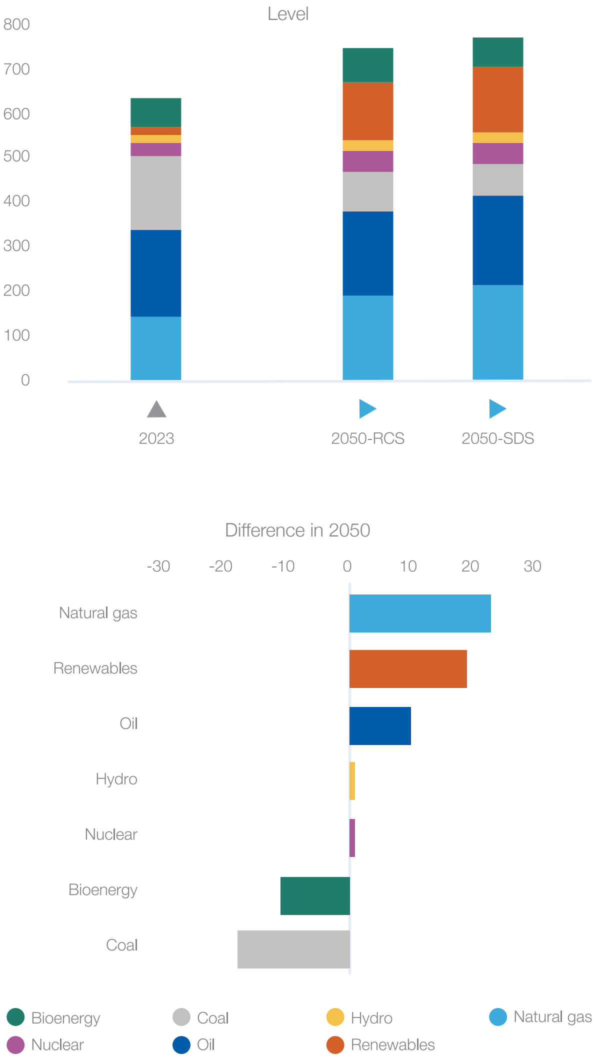
In the SES, **primary energy demand is projected to increase by 140 EJ, reaching 775 EJ by 2050, a 22% rise from 2023 levels, compared to an 18% increase in the RCS** (Figure 8.1). A significant part of this growth is attributed to developing economies currently experiencing energy poverty, whose expanding energy access drives higher consumption. As a result, primary energy consumption per capita in the SES remains stable at 79 GJ/person, exceeding levels in the RCS, where per capita consumption declines due to population growth, outpacing energy demand expansion. Africa is expected to experience the largest per capita energy consumption increase compared to the RCS, exceeding 34 GJ/person by 2050, up from 26 GJ/person in the RCS. Energy consumption per capita is more equitably distributed across regions in the SES, reflecting improved access to modern energy in lower-income countries.

Despite higher primary energy consumption, the SES follows a trajectory similar to the RCS in terms of global energy efficiency, with energy intensity declining at an average annual rate of 2.4% between 2023 and 2050. By the end of the forecast period, energy intensity is projected to reach 1.8 MJ per USD (PPP, base year = 2023), mirroring trends in the RCS. This alignment in energy intensity between the SES and RCS is primarily due to proportional growth in both primary energy demand and GDP, suggesting that efficiency gains are largely offset by increased economic activity and energy consumption across both scenarios. However, greater energy access in developing countries in the SES contributes to a more balanced and inclusive global energy landscape, fostering long-term economic resilience and social progress.

In the analysis of energy efficiency improvements in lower-income countries struggling with limited access to modern energy, both direct and indirect rebound effects must be carefully considered, as they can partially offset the expected energy savings achieved through efficiency gains. In regions with significant energy deficits,

Figure 8.1

Global primary energy demand by fuel type in RCS and SES (EJ)



Source: GECF Secretariat based on data from the GECF GGM

efficiency-driven cost reductions often lead to expanded energy access, resulting in higher energy consumption as individuals and communities take advantage of newly available resources to improve their quality of life.

A clear example of this phenomenon is evident in the transition to clean cooking solutions in Africa. Households that previously relied on traditional biomass for cooking, an inefficient and time-consuming method, may adopt cleaner and more efficient LPG or electric stoves. While this shift reduces emissions and enhances cooking efficiency, it also enables families to cook more frequently, potentially increasing their overall energy consumption. For instance, a household that once prepared only one meal per day due to fuel scarcity or the time-intensive nature of collecting firewood may now have the ability to cook multiple meals daily, leading to a rise in total energy demand. Additionally, modern cooking appliances can encourage households to diversify their diets by preparing a wider range of foods that require longer cooking times, further contributing to increased energy use.

Beyond cooking, the indirect rebound effect becomes even more pronounced as improved energy efficiency facilitates broader socioeconomic transformation. In communities that previously lacked reliable electricity access, the introduction of energy-efficient appliances often triggers a surge in overall electricity demand. For example, once connected to electricity, households initially use it for basic needs, such as charging radios and mobile phones, but over time, their consumption patterns evolve. As living standards improve, they begin to use energy for refrigeration to store perishable food, lighting for extended study and work hours, and entertainment appliances like televisions, all of which further increase electricity demand.

At the community level, energy efficiency improvements in small businesses and agricultural activities can also create secondary demand growth. For instance, the adoption of energy-efficient irrigation pumps allows farmers to expand crop cultivation, leading to increased demand for additional water pumping, storage, and processing equipment. Similarly, the availability of affordable and efficient lighting enables small businesses to extend operating hours, boosting economic activity but also raising overall energy consumption.

These examples illustrate that in regions with historically low energy access, efficiency improvements do not merely lead to one-time energy savings but often unlock latent demand for energy-dependent services. While this contributes to economic growth, poverty reduction, and improved well-being, it also challenges long-term energy planning by requiring a scalable and resilient energy supply to meet growing consumption. Recognising the indirect rebound effect is therefore crucial in designing sustainable energy policies that balance efficiency gains with equitable energy access and long-term supply security.

8.3.1.1 Global energy mix

As the global energy system expands in the SES, fossil fuels demand is projected to decrease by 21 EJ, reaching 486 EJ by 2050, which is 15 EJ higher than in the RCS (Table 8.2). Consequently, **the share of fossil fuels in the global energy mix remains nearly unchanged at 64% by midcentury, down from approximately 80% in 2023. While this underscores the continued reliance on hydrocarbons to meet growing energy needs, it also signals a structural shift in their composition, primarily due to coal-to-gas substitution.** The SES highlights the pivotal role of emerging technologies and retrofitting solutions, ensuring that fossil fuels remain an integral component

Table 8.2

Global primary energy demand outlook by fuel type in RCS and SES, 2023-2050 (EJ)

	Base	RCS			SES		
	2023	2030	2040	2050	2030	2040	2050
Natural gas	145	163	180	191	173	195	214
Oil	192	202	201	192	204	205	202
Coal	170	142	111	88	137	100	70
Nuclear	30	33	40	47	34	41	48
Hydro	15	18	20	23	19	21	24
Renewables	22	49	88	131	54	97	150
Bioenergy	61	68	76	77	63	69	67
World	635	675	716	750	684	728	775

Source: GECF Secretariat based on data from the GECF GGM

of just, orderly, and equitable energy transitions. Unlike the RCS, where fossil fuel demand remains more constrained, the SES sees stronger growth in Africa and the Middle East, where natural gas and oil play a crucial role due to their affordability, reliability, and compatibility with existing energy infrastructure. These factors make natural gas and oil indispensable in supporting economic growth, industrialisation, and energy security across these regions.

In 2023, **natural gas** was the world's third-largest energy source. However, under the SES, it is projected to surpass both oil and coal to become the dominant fuel by mid-century. **Over the forecast period, natural gas demand in the SES is expected to increase by 69 EJ, reaching 214 EJ by 2050, which is 23 EJ higher than in the RCS. This represents a 49% increase in the SES, significantly exceeding the 32% growth projected in the RCS.** Additionally, natural gas's share in the global energy mix is expected to rise to 28% by 2050 in the SES, nearly 2 percentage points higher than in the RCS. The divergence in demand between the SES and RCS is primarily driven by growth in power generation and the domestic sector, particularly in Africa and the Asia Pacific region. In the Asia Pacific power sector, natural gas is expected to replace coal, supported by the increasing role of renewables. The growing share of intermittent renewable energy sources in the power mix underscores the complementary role of natural gas, which will be crucial for peak shaving, ensuring grid stability and supply reliability in an increasingly electrified energy system. Furthermore, the SES assumes a faster transition from traditional biomass to cleaner fuels such as LPG and Pipeline Natural Gas (PNG), further contributing to higher natural gas demand compared to RCS.

While natural gas is set to become the leading fuel in the global energy mix, renewables are projected to experience the most significant growth in the SES. With 128 EJ, equivalent to 91% of the net increase in global energy demand, **renewable** energy consumption is expected to reach 150 EJ by 2050, surpassing the 131 EJ projected in the RCS. As a result, the renewables' share in the global energy mix is forecast to reach 19% by 2050 in the SES, compared to 17% in the RCS. This growth is primarily driven by developed economies, particularly Europe and North America, where the power and residential sectors increasingly rely on solar and wind energy. In these regions, the SES envisions a highly electrified energy system, with renewables playing a central role in power generation. Additionally, the rapid adoption of heat pumps, driven by cost competitiveness, efficiency gains, and strong policy support, is expected to further reinforce the transition toward low-carbon energy solutions.

Unlike the RCS, which projects a prolonged plateau in oil demand, the SES anticipates sustained, albeit decelerating, growth in **oil** consumption. As the third-largest contributor to incremental primary energy demand, oil demand in the SES is projected to increase by 10 EJ, reaching 202 EJ by 2050, which is 10 EJ higher than in the RCS. This growth results in oil maintaining a 26% share of the global energy mix by mid-century, similar to the contribution projected in the RCS, highlighting oil's continued relevance in the evolving energy landscape. The primary driver behind higher oil demand in the SES is the expansion of vehicle ownership in low-income countries, particularly in Africa, where rising incomes and improving transportation infrastructure contribute to increased fuel consumption compared to RCS.

Among all energy sources, **coal** is projected to experience the most significant decline in the SES compared to the RCS. Coal consumption is expected to fall by 100 EJ, reaching 70 EJ by 2050, which is 18

EJ lower than in the RCS. This substantial reduction lowers coal's share in the global energy mix to just 9%, 3 percentage points below the RCS, underscoring the accelerated transition away from coal in the SES. The primary factor behind this decline is the faster coal-to-gas switching in the SES, particularly in Asia, where natural gas is increasingly displacing coal as a baseload fuel. However, the SES assumes that many existing coal-fired power plants will undergo refurbishment, particularly in India and China, where large and small scrubbed steam coal plants will replace older, unscrubbed units. These modernised plants, equipped with advanced scrubbers, improve efficiency and sulfur emissions capture, reducing environmental impact. Additionally, the SES prioritises retrofitting coal plants with CCUS technologies and integrating co-firing systems with hydrogen and ammonia. This approach extends the operational lifespan of coal plants while significantly lowering their carbon footprint, offering a pragmatic pathway for emissions reductions without compromising energy security.

Alongside coal, **bioenergy** demand is also projected to be lower in the SES compared to the RCS, though to a lesser extent. While the SES projects a moderate 6 EJ increase in bioenergy demand, reaching 67 EJ by 2050, the RCS anticipates a stronger growth of 16 EJ, bringing total bioenergy demand to 77 EJ. Consequently, bioenergy's share in the global energy mix slightly declines to 9% in the SES, whereas it remains steady at 10% in the RCS. However, this aggregate bioenergy demand masks opposing trends between traditional and modern biomass. While traditional biomass consumption is projected to decline by half to 13 EJ in the SES by 2050, it remains higher at 18 EJ in the RCS. Conversely, modern biomass demand is projected to grow, reaching 54 EJ in the SES, though 5 EJ lower than in the RCS. The divergence in traditional biomass demand is largely due to Africa's accelerated transition toward cleaner cooking solutions, such as LPG and PNG, which reduces biomass reliance while improving health and energy efficiency.

Hydropower demand is expected to rise by 9 EJ over the forecast period, reaching 24 EJ by 2050 in the SES and 1 EJ higher than in the RCS. This growth is primarily driven by hydropower expansion in Eastern Africa, where large-scale projects will enhance energy access and grid stability. Meanwhile, **nuclear energy** demand shows 18 EJ demand increase, reaching 48 EJ by 2050 in the SES, up from 47 EJ in the RCS. This trend reflects ongoing global investments in nuclear energy as a low-carbon, baseload power source.

8.3.1.2 Energy demand by region

The increase in primary energy demand in the SES compared to the RCS is unevenly distributed across regions, reflecting varied economic growth trajectories, energy transition pathways, and sectoral dynamics. In developing economies, where higher per capita GDP growth and energy poverty reduction are key priorities, energy demand experiences a significant rise, driven by expanding energy access, industrialisation, and economic development.

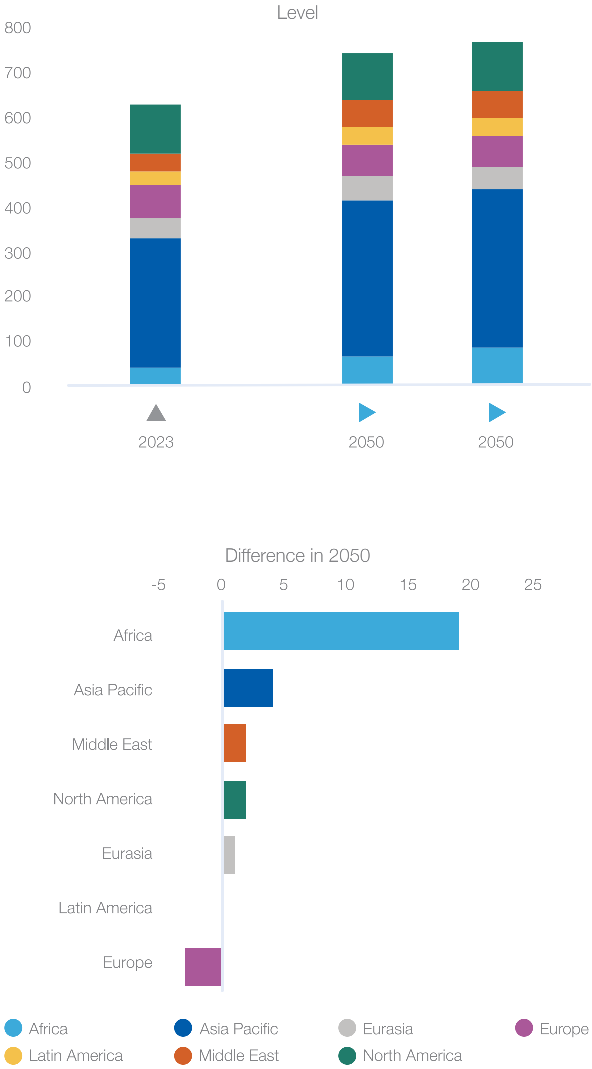
In developed countries, energy demand growth remains positive, but its composition is evolving, shaped by efficiency improvements, widespread adoption of renewable technologies, and the electrification of end-use sectors. While the accelerated deployment of heat pumps in the residential sector of Europe and North America reduces reliance on conventional energy sources and enhances overall efficiency, these efficiency gains are counterbalanced by rising electricity demand, particularly from the expansion of data centres and AI-driven digital infrastructure. As a result, energy demand in developed economies is expected to grow at a more moderate pace, with shifts in sectoral consumption patterns rather than an outright decline compared to the RCS.

As illustrated in Figure 8.2, **Africa emerges as the leading region in energy demand growth, accounting for 76% of the global net increase in primary energy consumption compared to the RCS.** Over the forecast period, Africa's energy demand is projected to grow by 48 EJ, representing a 130% increase, reaching 85 EJ by 2050 in the SES, which is 19 EJ higher than in the RCS. As a result, Africa's share of global primary energy consumption is expected to surpass Europe's and rise to 11% in the SES, up from 6% in 2023, reflecting a 2 percentage point increase compared to the RCS by mid-century. This divergence between the SES and RCS is primarily driven by growth across multiple sectors, with transport, power generation, the residential sector, the energy sector, and industry contributing to the higher energy demand in the SES relative to the RCS. These trends highlight Africa's accelerating economic development, urbanisation, and industrialisation, expected to fuel substantial energy consumption growth over the coming decades.

Asia Pacific follows Africa in energy demand growth, albeit on a smaller scale, contributing 16% of the global net increase in primary energy demand in the SES compared to the RCS. Over the forecast period, primary energy demand in the region is projected to rise by 60 EJ, reaching 355 EJ by 2050 in the SES, compared to 351 EJ in the RCS. Consequently, Asia Pacific's share of global primary energy consumption is expected to stabilise at 46% by 2050 in the SES, down from 47% in the RCS. Despite a significant decline in primary energy consumption in power generation relative to the RCS, mainly due to accelerated coal-to-gas switching and increased renewable energy deployment, this reduction is offset by strong demand growth in other sectors. The domestic sector, hydrogen generation, transport, and industry are projected to drive substantial increases in energy consumption, reinforcing

Figure 8.2

Global primary energy demand by region in RCS and SES (EJ)



Source: GECF Secretariat based on data from the GECF GGM

Asia Pacific's central role in the global energy landscape under the SES.

The Middle East ranks as the third-largest contributor to primary energy consumption growth in the SES compared to the RCS. By 2050, the region's primary energy consumption is projected to reach 59 EJ, reflecting a 20 EJ increase over the forecast period in the SES, which is 2 EJ higher than in the RCS. Given the relatively small difference between the two scenarios, the Middle East's share of global energy consumption is expected to reach 8% by 2050 in the SES, aligning with the RCS and rising from 6% in 2023. The primary drivers of energy demand growth in the SES, relative to the RCS, are power generation and the domestic sector, while industry and transport play a comparatively smaller role. These trends highlight the region's expanding energy needs, particularly driven by rising electricity demand, urbanisation, and population growth, reinforcing the Middle East's strategic role in the global energy landscape.

Driven by the rising demand for electricity in the commercial segment, particularly to support AI and digital infrastructure, **North America**'s energy demand is expected to increase in the medium term (up to 2030) in the SES compared to the RCS. However, this growth momentum is projected to continue in the long term, with primary energy demand in the SES reaching 111 EJ by 2050, up from 109 EJ in the RCS. As a result, North America's share of global primary energy consumption is expected to decline to 14% in the SES by 2050, compared to 15% in the RCS. Although accelerated renewable adoption, particularly the widespread use of heat pumps in the residential sector, exerts downward pressure on demand, this decline is fully offset by rising electricity consumption in the commercial sector, driven by the expansion of data centers and AI-related power needs. Consequently, the commercial sector and power generation emerge as the primary drivers of energy demand growth, while the residential sector and increasing heat pump adoption serve as counterbalancing forces, moderating overall energy consumption.

Eurasia follows closely in its contribution to primary energy consumption growth in the SES compared to the RCS. Over the forecast period, energy demand in the region is projected to grow by 9 EJ, reaching 54 EJ by 2050 in the SES, compared to 53 EJ in the RCS (Figure 8.2). Eurasia's share of global primary energy consumption remains unchanged relative to the RCS, standing at 7% by 2050, which is consistent with the 2023 level. The main drivers of increased energy demand in the SES compared to the RCS are power generation and the industrial sector, while the energy sector also contributes, though to a lesser extent. These trends reflect moderate energy growth, largely driven by domestic economic activity and evolving energy infrastructure in the region.

Europe is the only region where primary energy consumption in the SES is lower than in the RCS. Over the forecast period, primary energy demand in Europe is projected to decline more sharply by 7 EJ in the SES, reaching 69 EJ by 2050, compared to 72 EJ in the RCS. As a result, Europe's share of global primary energy consumption is expected to decline to 9% in the SES by 2050, down from 12% in 2023, and slightly lower than the 10% projected in the RCS. The primary driver of this decline is the accelerated adoption of renewables, particularly high-efficiency technologies such as advanced heat pumps, which significantly reduce overall energy consumption in the residential and commercial sectors. While this shift has increased electricity demand, the overall impact on primary energy consumption remains negative, reflecting efficiency improvements and the region's strong push toward decarbonisation.

Primary energy consumption in **Latin America** is projected to follow the same trajectory as the RCS, leading to an increase of 13 EJ over the forecast period, reaching 42 EJ by 2050. The region's share of global energy consumption is expected to remain stable at 5% in the SES by 2050, consistent with 2023 levels but 1 percentage point lower than in the RCS.

8.3.2 Natural gas demand by sector

The sectoral contribution to natural gas demand growth in the SES relative to the RCS is highly uneven. Power generation, the domestic sector, and the industrial sector emerge as the primary drivers of natural gas demand in the SES, compared to the RCS. In the hydrogen generation sector, the rising demand for natural gas in blue hydrogen production offsets the decline in natural gas use for grey hydrogen, a shift driven by the assumed rapid expansion of CCUS in hydrogen production. Table 8.3. presents the natural gas demand projections in the SES compared to the RCS.

As illustrated in Figure 8.3, **the power sector emerges as the primary driver of natural gas demand growth, accounting for 43% of the net increase compared to the RCS.** Demand in this sector is projected to rise by 857 bcm, reaching 2,248 bcm by 2050 in the SES, up from 1,866 bcm in the RCS. Consequently, the power sector's share of global natural gas demand rises to 378% by 2050 in the RCS, slightly higher than 35% in the RCS. The key drivers of this increase are rising per capita energy consumption in lower-income countries, rapid adoption of heat pumps, and the growing electricity demand of data centres and AI-driven infrastructure. While the impact of increased electrification on natural gas consumption varies by region, much of this additional power demand originates in Africa and developing Asia Pacific countries, where natural gas is expected to play a pivotal role in expanding energy access and supporting economic growth. Additionally, natural gas is anticipated to replace coal in Asia Pacific power generation, ensuring system stability and flexibility as renewable energy capacity expands.

The **domestic sector** contributes 14% of the natural gas demand increase in the SES compared to the RCS. Over the forecast period, demand in this sector is projected to grow by 136 bcm, reaching 962 bcm by 2050 in the SES, nearly 100 bcm higher than in the RCS. While the domestic sector accounted for 21% of global natural gas consumption in 2023, their share is expected to decline to 16% in the SES by 2050 due to a weaker growth rate of 18% compared to the overall volumetric global natural gas demand increase of 49%. The primary driver of growth in these sectors is the aggressive transition from traditional biomass to LPG and pipeline natural gas in African households, aimed at expanding access to clean cooking fuels. This shift is expected to improve both public health and energy efficiency by reducing dependence on inefficient biomass-based cooking methods. In contrast, in developed economies, particularly Europe and North America, heat pump adoption significantly reduces direct natural gas consumption for residential heating. However, this shift also increases electricity demand, reinforcing natural gas's role in ensuring grid stability amid rising renewable penetration.

The **industrial sector** ranks as the third-largest contributor to natural gas demand growth in the SES

Table 8.3

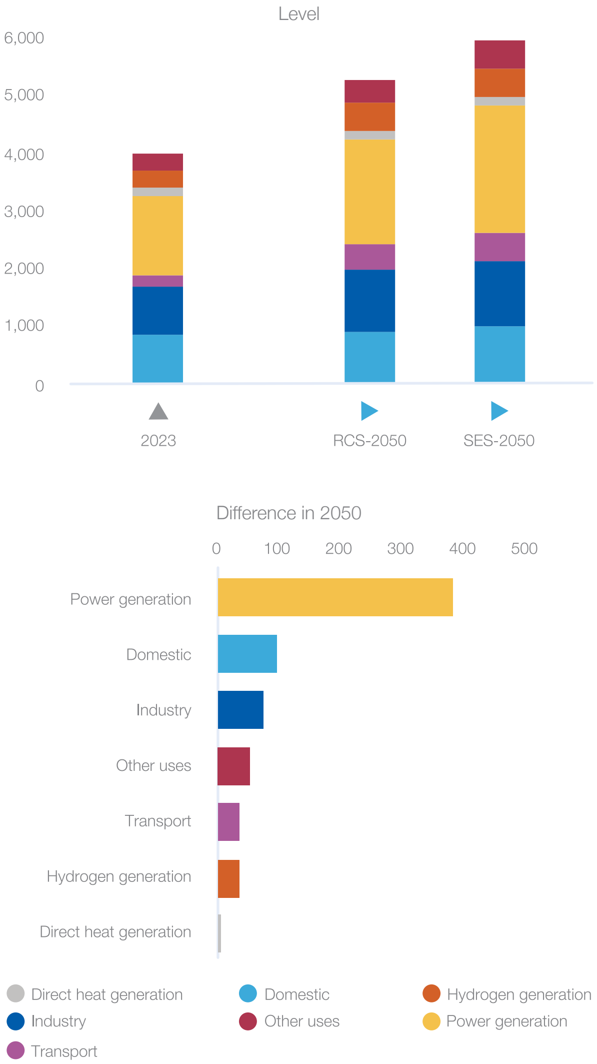
Global natural gas demand outlook by sector in RCS and SES (bcm)

	Base	RCS			SES		
	2023	2030	2040	2050	2030	2040	2050
Domestic	826	885	889	866	895	923	962
Industry	857	960	1,054	1,095	980	1,096	1,168
Transport	165	218	343	430	261	393	465
Power generation	1,391	1,606	1,758	1,866	1,772	2,078	2,248
Direct heat generation	190	189	172	150	190	173	156
Hydrogen generation	259	305	385	480	310	403	515
Other uses	330	394	424	430	403	432	483
Total	**4,018**	**4,557**	**5,025**	**5,317**	**4,811**	**5,498**	**5,997**

Source: GECF Secretariat based on data from the GECF GGM
Note: 1) Industry includes natural gas directly used as fuel and feedstock, as well as input for refineries.
2) Transport encompasses road transport, marine bunkers, rail transport, and pipeline operations.
3) Other uses cover natural gas consumption for the energy industry's own use, along with distribution losses.
4) Domestic sector includes residential, commercial and agriculture sectors.

Figure 8.3

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



Source: GECF Secretariat based on data from the GECF GGM

compared to the RCS. Over the forecast period, natural gas demand in this sector is projected to increase by 311 bcm, reaching 1,168 bcm by midcentury in the SES, up from 1,095 bcm in the RCS. The industrial sector's share of global natural gas consumption is expected to decline to 19% by 2050 in the SES, which remains lower than 21% projected in the RCS. Rising industrialisation in low-income countries is expected to drive greater demand for natural gas, both as a fuel input and feedstock, contributing to the sector's growing consumption. Additionally, the assumed large-scale deployment of CCUS in the industrial sector is another key factor supporting increased natural gas demand in the SES.

The **transport sector** is another key growth area, with natural gas demand projected to increase by 300 bcm, reaching 465 bcm by 2050 in the SES, which is 35 bcm higher than in the RCS. This accounts for 8% of the total difference in natural gas consumption between the two scenarios. The sector's share of global natural gas demand is expected to rise to 8% by 2050, up from 4% in 2023, aligning with RCS projections. The growing adoption of LNG in the marine sector and heavy-duty trucking is the primary driver of this increase. LNG-fueled ships and heavy trucks gain traction as cost-effective, lower-emission alternatives. In particular, natural gas is expected to be critical in decarbonising hard-to-electrify transport applications, reinforcing its strategic role in long-term energy transition efforts.

Natural gas demand for **other uses**, including own use in liquefaction, regasification, pipeline compressors, and distribution losses, accounts for 8% of the total increase in natural gas demand in the SES compared to the RCS. Over the forecast period, demand in this category is projected to rise by 153 bcm, reaching 483 bcm by 2050 in the SES, compared to 430 bcm in the RCS. Despite this growth, the sector's share of global natural gas consumption remains stable at 8% by 2050, mirroring the RCS. The primary driver of this increase is the expansion of LNG supply, along with proportional growth in distribution losses, which naturally accompany the scaling up of global gas consumption, trade and infrastructure expansion.

Hydrogen generation is also one of the drivers of natural gas demand growth, contributing 5% of the total increase in the SES compared to the RCS. By 2050, natural gas demand for hydrogen production is projected to reach 515 bcm, a significant rise from negligible levels in 2023 and exceeding the RCS projection of 480 bcm. As a result, the share of hydrogen in global natural gas demand is expected to increase to 9% in the SES, similar to the RCS. This growth coincides with a sharp decline in grey hydrogen consumption, reflecting large-scale CCUS deployment at hydrogen production facilities. The transition from grey to blue hydrogen reflects a wider shift toward carbon capture solutions that align with decarbonisation efforts and hydrogen's role as a key energy carrier in a low-carbon economy. The majority of this demand growth is expected in Asia Pacific and the Middle East, where hydrogen plays a central role in industrial decarbonisation strategies, particularly in hard-to-abate sectors. North America follows, albeit with a smaller contribution, as the region expands its hydrogen infrastructure and integrates it into existing natural gas value chains.

The **direct heat generation** sector's contribution to natural gas demand growth in the SES compared to the RCS is marginal. Over the forecast period, demand for natural gas in direct heat generation is projected to decline by 34 bcm, reaching 156 bcm by 2050 in the SES, compared to 150 bcm in the RCS. Consequently, the sector's share of global natural gas demand is expected to decline to 3% by 2050 in the SES, down from 5% in 2023. Notably, most of this increase is projected in Asia Pacific, where urban expansion, industrial growth, and district heating expansion continue to drive demand.

8.3.3 Natural gas demand by region

The regional contribution to natural gas demand growth in the SES compared to the RCS varies significantly, reflecting divergent economic trajectories, energy transition pathways, and development priorities. While developing regions, particularly Africa and Asia Pacific, emerge as the primary drivers of this increase, the contribution from developed economies remains relatively minor, with Europe expected to experience a slight decline. This divergence underscores the critical role of natural gas in supporting regions where energy consumption per capita is projected to rise substantially, driven by earlier-stage economic development, rapid industrialisation, and the pressing need to enhance energy access for socioeconomic empowerment. In contrast, developed countries, having reached maturity in energy consumption, are expected to experience either a gradual decline or a prolonged plateau in demand as they accelerate energy efficiency measures and the adoption of alternative low-carbon technologies.

This regional disparity highlights the dual role of natural gas in the evolving global energy landscape. In developing economies, natural gas is a critical enabler of economic growth, electrification, and industrial expansion, providing a reliable and scalable energy source to bridge the gap between energy poverty and sustainable development. Simultaneously, in developed regions, natural gas remains essential to energy security and system flexibility, particularly as a balancing fuel in power grids with high shares of intermittent renewables. These distinct priorities, capabilities, and circumstances reinforce the adaptability of natural gas in addressing diverse energy needs across regions, ensuring just, orderly, and equitable energy transitions that accommodate the realities of both emerging and advanced economies. Table 8.4. compares regional natural gas demand forecasts in the SES and the RCS.

Asia Pacific is projected to be the most significant contributor to natural gas demand net growth in the SES compared to the RCS, with consumption rising by 967 bcm over the forecast period to reach 1,838 bcm by 2050 in the SES, up from 1,581 bcm in the RCS. This additional 257 bcm accounts for 38% of the net global natural gas demand increase in the SES relative to the RCS by mid-century. As a result, the region's share of global natural gas demand rises to 31% in the SES by 2050, up from 30% in the RCS (Figure 8.4). At the same time, the role of natural gas in Asia Pacific's energy mix is expected to expand significantly, reaching 18% by 2050 in the SES, up from 11% in 2023, and slightly surpassing the 16% projected in the RCS. This shift underscores natural gas as a pivotal energy source in the region, complementing renewables and ensuring energy security in an evolving energy landscape. Power generation emerges as the primary driver of natural gas demand growth, accounting for 40% of total natural gas consumption in 2050, up from 38% in the RCS. Consequently, the share of natural gas in the region's power generation mix is expected to increase to 16% in the SES by 2050, compared to 13% in the RCS, both significantly higher than the 9% share in 2023. This trend highlights the increasing reliance on natural gas as a flexible and reliable energy source, particularly in balancing the integration of renewables into the grid, ensuring stability, and meeting the region's surging electricity demand.

Table 8.4

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

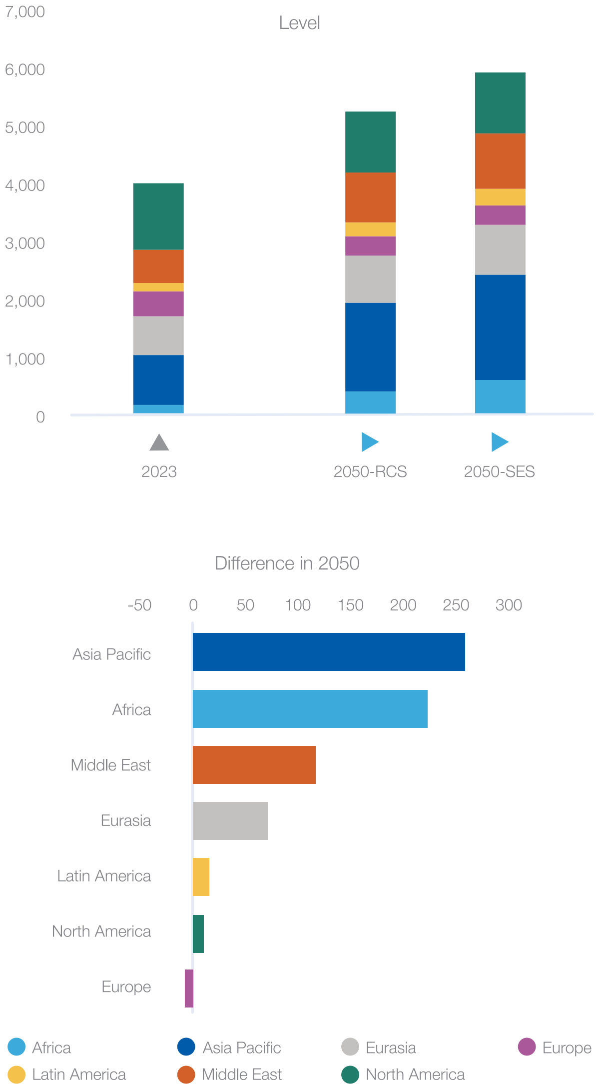
	Base	RCS			SES		
	2023	2030	2040	2050	2030	2040	2050
Africa	170	229	303	385	271	446	607
Asia Pacific	871	1,192	1,448	1,581	1,296	1,613	1,838
Eurasia	650	710	770	820	722	806	889
Europe	463	424	364	309	442	390	300
Latin America	150	185	238	275	186	246	290
Middle East	554	636	761	865	649	818	981
North America	1,160	1,183	1,140	1,083	1,244	1,180	1,092
Total	**4,018**	**4,557**	**5,025**	**5,317**	**4,811**	**5,498**	**5,997**

Source: GECF Secretariat based on data from the GECF GGM

Chapter 8

Figure 8.4

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



Source: GECF Secretariat based on data from the GECF GGM

Africa closely follows Asia Pacific in driving natural gas demand growth, accounting for 33% of the net increase in the SES compared to the RCS. Over the forecast period, natural gas demand in Africa is projected to rise by 437 bcm, reaching 607 bcm by 2050 in the SES, nearly 222 bcm higher than in the RCS. As a result, the share of natural gas in Africa's energy mix is expected to expand to 27% in the SES by 2050, compared to 21% in the RCS, both significantly higher than the 16% recorded in 2023. The domestic sector is projected to be the primary drivers of natural gas demand growth in the SES compared to the RCS, collectively accounting for 15% of total regional gas consumption by 2050, up from 8% in the RCS. This reflects the accelerated transition from traditional biomass to cleaner fuels such as LPG and PNG, particularly in addressing Africa's persistent clean cooking deficit. In addition, power generation is expected to remain the dominant sector for natural gas consumption, with its share in total electricity generation rising to 56% by 2050 in the SES, compared to 51% in the RCS, both significantly higher than 39% in 2023. This highlights the increasing role of natural gas in Africa's electrification efforts, providing a reliable and scalable energy source to support economic development, grid stability, and the integration of renewables across the continent.

Natural gas demand in the **Middle East** ranks third in contribution to the net increase in global natural gas consumption in the SES compared to the RCS. Over the forecast period, natural gas demand in the region is expected to rise by 427 bcm, reaching 981 bcm by 2050 in the SES, compared to 865 bcm in the RCS. As a result, the Middle East's share in global natural gas consumption is projected to increase to 16% in the SES by 2050, up from 14% in 2030, following a trajectory similar to the RCS. The role of natural gas in the Middle East's energy mix is anticipated to expand, reaching 57% in the SES by 2050, compared to 55% in the RCS, both significantly higher than the 23% estimated in 2023. This highlights the increasing reliance on natural gas as a cornerstone of the region's energy system, driven by its abundant reserves, cost competitiveness, and compatibility with existing infrastructure. Power generation remains the primary driver of natural gas demand, with its share in total electricity generation projected to rise to 79% in the SES by 2050, up from 73% in the RCS and higher than 70% in 2023. Furthermore, power generation is expected to account for 42% of total natural gas consumption in the Middle East by 2050 in the SES, surpassing the 37% projected in the RCS. This underscores natural gas as the dominant fuel for electricity generation in the region, ensuring energy security and grid stability while supporting industrial growth and economic diversification efforts.

With nearly 10% of the net increase in global natural gas demand in the SES compared to the RCS, **Eurasia** is set to experience a significant rise in natural gas consumption. By 2050, demand in the region is projected to increase by 239 bcm, reaching 889 bcm in the SES, which is 69 bcm higher than in the RCS. As a result, Eurasia is expected to account for 15% of global natural gas demand by 2050 in the SES, same as 15% in the RCS during the period. Additionally, natural gas is projected to solidify its role in Eurasia's energy mix, with its share rising to 59% by mid-century in the SES, mirroring the RCS projection and significantly exceeding the 51% recorded in 2023. This trend reflects the continued prioritisation of natural gas in the region's energy strategy, supported by its abundant domestic resources and established infrastructure. Power generation and the domestic sector are anticipated to be the primary drivers of natural gas demand growth in Eurasia. The share of natural gas in total power generation fuel input is projected to increase to 56% in the SES by 2050, compared to 48% in the RCS, reinforcing its critical role in ensuring energy security, grid stability, and cleaner power generation across the region.

As the largest natural gas-consuming region globally, **North America** is expected to contribute to the net increase in natural gas demand in the SES compared to the RCS, albeit marginally. Natural gas demand in the region is projected to peak in the coming decades before gradually declining to 1,092 bcm in the SES by 2050, reflecting a 68 bcm decline over the forecast period. However, this remains 9 bcm higher than in the RCS, accounting for 2% of the total net increase in global natural gas demand in the SES compared to the RCS by 2050. As a result, North America's share of global natural gas consumption is expected to decline to 18% by 2050 in the SES, compared to 20% in the RCS, both of which are significantly lower than the 29% recorded in 2023. This marks a major shift, as North America is projected to be overtaken by Asia Pacific as the world's largest natural gas-consuming region by mid-century. Despite the expected decline in absolute demand, natural gas is projected to maintain a stable role in North America's energy mix, with its share holding steady at 36% by 2050 in the SES, mirroring the RCS and slightly exceeding the 35% estimated in 2023. However, the widespread deployment of renewables and improvements in energy efficiency are expected to diminish natural gas's contribution to power generation, which is projected to fall to 31% by 2050 in the SES, down from 40% in 2030, reflecting a structural shift toward cleaner energy sources in the region.

Latin America is expected to make the smallest contribution to the net increase in natural gas demand in the SES compared to the RCS, accounting for just 1% of the total net change. Over the forecast period, natural gas demand in the region is projected to rise by 140 bcm, reaching 290 bcm by 2050 in the SES, which is 15 bcm higher than in the RCS. As a result, Latin America's share of global natural gas demand is expected to rise slightly to 5% by 2050, a level consistent with the RCS and one percentage point higher than in 2023. The role of natural gas in Latin America's energy mix is also set to expand, with its share increasing to 24% by 2050 in the SES, compared to 23% in the RCS, both of which are notably higher than 18% estimated in 2023. The primary driver of natural gas demand growth in the SES is the power generation sector, which is expected to increase its share of the fuel mix for power generation to 25% by 2050, surpassing the 23% projected in the RCS, and both figures marking a significant rise from 20% in 2023. By 2050, natural gas consumption in power generation is expected to account for 37% of Latin America's total natural gas demand in the SES, mirroring the RCS and significantly exceeding the 28% recorded in 2023. This reflects the region's ongoing transition toward greater reliance on natural gas in electricity generation, supported by infrastructure expansion, affordability considerations, and the gradual shift away from more carbon-intensive fuels.

Europe is the only region expected to register a net decline in natural gas demand in the SES compared to the RCS, albeit at a moderate scale. By mid-century, natural gas demand in the region is projected to fall to 300 bcm in the SES, slightly lower than the 309 bcm projected in the RCS. As a result, Europe's share of global natural gas demand is expected to decline to 5% in the SES, down from 6% in the RCS, with both scenarios reflecting a significant reduction from the 11% recorded in 2023. This downward trajectory is mirrored in natural gas's contribution to Europe's energy mix, which is expected to decline to 14% by 2050 in both scenarios, compared to 21% in 2023, underscoring the region's accelerated shift away from fossil fuels. The primary driver of this decline is the domestic sector, where natural gas demand as a share of total gas consumption is projected to fall to 17% in the SES by 2050, compared to 20% in the RCS, with both figures marking a steep decline from the 39% estimated in 2030. A key factor behind this contraction is the widespread adoption of high-efficiency heat pumps in the residential sector, which are rapidly replacing conventional gas-fired heating systems. This shift reflects strong support for electrification, stricter energy efficiency regulations, and advancements in renewable energy integration, all of which contribute to the continued decline in natural gas demand in Europe over the long term.

8.3.4 Global hydrogen demand and generation

Over the forecast period, the global hydrogen outlook in the SES reflects a dynamic landscape of growth opportunities and persistent challenges. Beneficial growth has been driven by robust policy support, technological advancements, and increasing recognition of hydrogen's potential to enhance energy access and support climate change mitigation. However, significant hurdles remain, including delays in FIDs for hydrogen projects and the ongoing challenge of achieving cost parity with conventional energy sources. Hydrogen's role in decarbonising hard-to-abate sectors and providing sustainable energy solutions is a central theme in the SES. However, practical constraints, such as safety concerns and technical limitations, have necessitated adjustments in hydrogen applications, particularly in energy-intensive and long-haul transportation scenarios. These challenges highlight the importance of targeted innovation and infrastructure development to unlock hydrogen's full potential.

Despite these barriers, the outlook for hydrogen remains promising, particularly as an industrial feedstock and in applications powered by low-carbon sources like green and blue hydrogen. As outlined in the section below, the SES anticipates considerable traction in hydrogen adoption as policies and market mechanisms evolve to support its integration into energy systems.

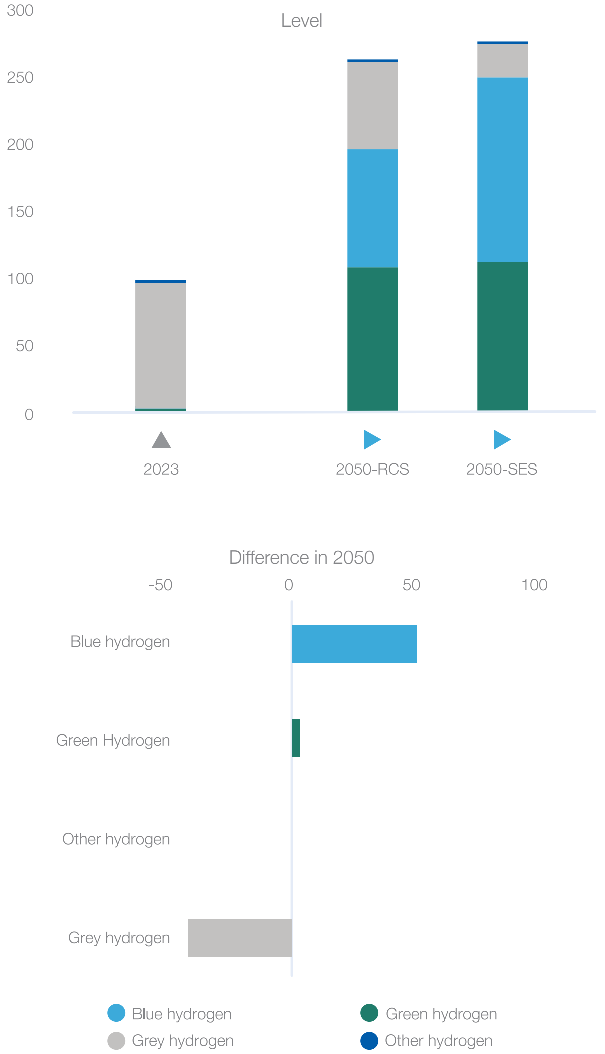
Under the prevailing assumptions of increased energy access and diversification of energy options, the SES projects significant growth in global hydrogen demand. **Hydrogen consumption is expected to rise from 97 MtH_2 in 2023 to nearly 274 MtH_2 by 2050, marking a 14 MtH_2 increase compared to the RCS.** This growth would elevate hydrogen's share in the global final energy consumption mix to 4.2% by 2050, up from 1.8% in 2023, mirroring the RCS trajectory (Figure 8.5). The SES outlook underscores hydrogen's pivotal role in diversifying and decarbonising the global energy system, particularly in hard-to-abate sectors such as industry, transport, and power generation.

However, hydrogen's demand growth varies significantly across regions, shaped by differences in technological adoption, policy support, and economic conditions. Asia Pacific is projected to account for the bulk of the increase in hydrogen demand in the SES relative to the RCS, reflecting the region's strategic focus on hydrogen as a cornerstone of decarbonisation and industrial transformation. Over the forecast period, hydrogen demand in Asia Pacific is projected to increase by 95 MtH_2, reaching 139 MtH_2 by 2050 in the SES, compared to 128 MtH_2 in the RCS. This represents a substantial 81% share of the total global increase in hydrogen demand in the SES, underscoring Asia Pacific's dominant role in shaping the global hydrogen economy. As a result, Asia Pacific's share of global hydrogen demand is expected to exceed half of the global market by 2050, slightly higher than in 2023 and closely aligned with the RCS trajectory. This trend is driven by strong industrial demand, a policy push for cleaner energy solutions, and continued investments in hydrogen infrastructure, reinforcing Asia Pacific's position as the world's leading hydrogen consumer by mid-century.

Beyond Asia Pacific, Africa, the Middle East, and North Africa are also expected to drive incremental hydrogen demand in the SES compared to the RCS, reflecting emerging hydrogen markets and rising investments in low-carbon hydrogen production. In contrast, hydrogen demand in other regions is projected to follow a trajectory similar to the RCS, with minimal deviations. Examining total hydrogen production to meet the growing demand in the SES masks significant shifts in the production technology mix. SES projections indicate a substantial increase in blue hydrogen production alongside a rise in green hydrogen, though on a smaller scale. In contrast, grey hydrogen production is expected to decline sharply by midcentury, reflecting the accelerated adoption of carbon capture technologies and the global policy shift toward low-carbon hydrogen pathways in the SES.

Figure 8.5

Global hydrogen generation by technology in RCS and SES (MtH_2)



Source: GECF Secretariat based on data from the GECF GGM

Despite its currently negligible production levels, blue hydrogen—primarily derived from natural gas—is set for remarkable growth in the SES, driven by cost competitiveness and advancements in Steam Methane Reforming (SMR) with CCUS. **Over the forecast period, blue hydrogen production is projected to increase by 137 MtH_2, surpassing green hydrogen to become the dominant production pathway in the SES.** As a result, the share of blue hydrogen in the global hydrogen mix is expected to rise to nearly half of total production in this scenario, significantly exceeding the 33% share projected in the RCS. This substantial expansion highlights blue hydrogen's critical role as a cost-effective solution for decarbonising energy-intensive industries such as refining, ammonia production, and steelmaking, leveraging proven SMR technology with enhanced

CCUS efficiency. The bulk of this growth is expected in Asia Pacific, Africa, and the Middle East, where abundant natural gas resources, favourable economics, and emerging hydrogen policies support large-scale adoption.

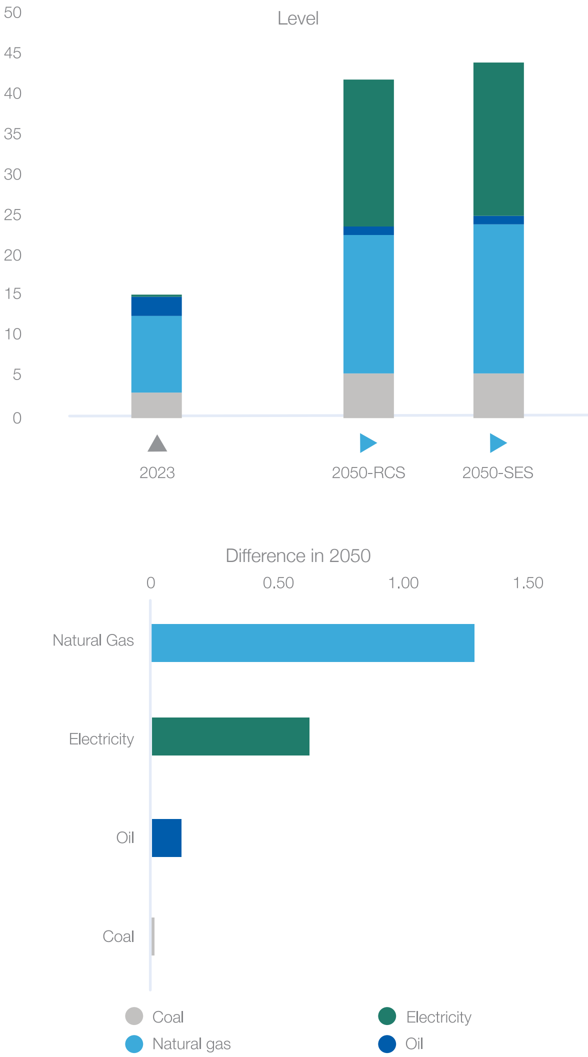
Green hydrogen, produced through renewable-powered electrolysis, is also expected to see substantial growth in the SES. From a modest 2 MtH_2 in 2023, production is projected to increase by 111 MtH_2 over the forecast period, reaching 113 MtH_2 by 2050, slightly exceeding the 108 MtH_2 projected in the RCS. As a result, green hydrogen's share in the global hydrogen mix is expected to rise to 41% in the SES by 2050, slightly trailing the 42% share projected in the RCS. However, the bulk of incremental hydrogen production in the SES compared to the RCS is concentrated in blue hydrogen, reflecting its cost advantage, established production pathways, and accelerated deployment of CCUS technologies. The limited divergence in green hydrogen output between the SES and RCS highlights persistent barriers to scaling green hydrogen production, including high capital costs, competition for renewable electricity, and infrastructure constraints. These challenges continue to hinder the large-scale deployment of green hydrogen, reinforcing the SES preference for blue hydrogen as the more economically viable near-term alternative.

While grey hydrogen dominates global hydrogen production, the SES projects a substantial decline, with output falling by 73 MtH_2 to 22 MtH_2 by 2050—42 MtH_2 lower than in the RCS. As a result, grey hydrogen's share in the global hydrogen mix is expected to drop to just 8% in the SES by 2050, down from 25% in the RCS. The primary driver of this decline is the widespread substitution of grey hydrogen with blue hydrogen, facilitated by the large-scale adoption of CCUS technologies in the SES. Stringent decarbonisation policies, carbon pricing mechanisms, and growing investor preference for low-carbon hydrogen alternatives further accelerate this transition, reinforcing the shift from unabated grey hydrogen toward cleaner production pathways.

According to SES projections, the fuel input for hydrogen production is expected to increase by 28.7 EJ over the forecast period, reaching 44 EJ by 2050, compared to 42.1 EJ in the RCS. As illustrated in Figure 8.6, natural gas is set to play the dominant role in fueling hydrogen production, accounting for 63% of the increase in the SES compared to the RCS. Electricity used for green hydrogen production is projected to comprise 31% of the rise, meaning that natural gas and electricity contribute 94% of the total growth in fuel input for hydrogen generation in the SES relative to the RCS. It is important to note that while natural gas demand increases significantly due to the ramp-up of blue hydrogen production, this growth is partially offset by the decline in grey hydrogen output, as carbon

Figure 8.6

Global fuel input mix for hydrogen generation in RCS and SES (EJ)



Source: GECF Secretariat based on data from the GECF GGM

capture adoption reduces reliance on unabated fossil-based hydrogen production in the SES. This shift underscores the structural transition toward low-carbon hydrogen pathways, balancing increased blue hydrogen production with the phaseout of grey hydrogen.

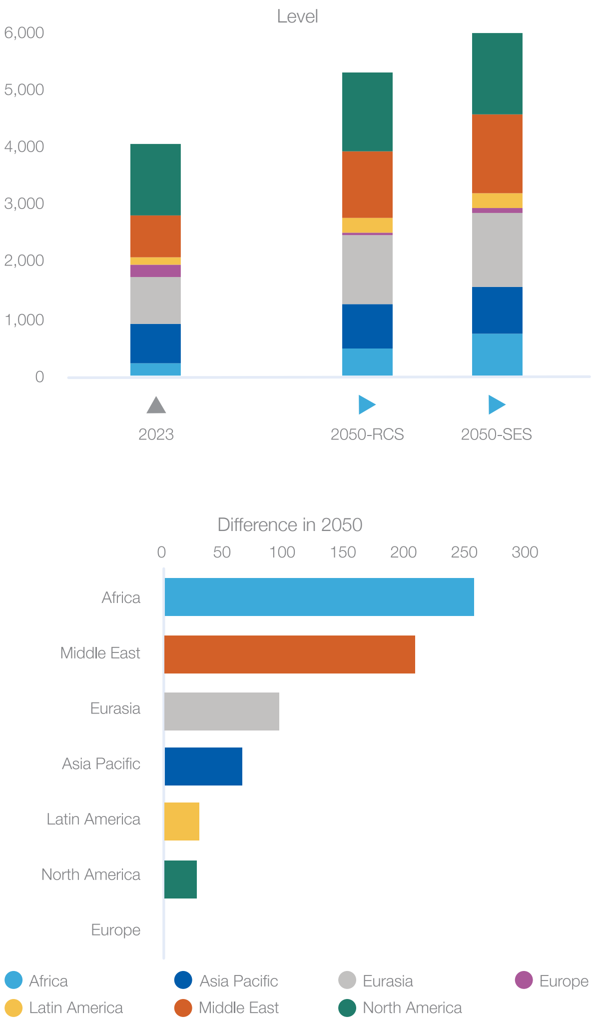
8.3.5 Natural gas supply

In response to the projected natural gas demand growth in the SES, natural gas supply must also expand over the forecast period to ensure market balance. However, as illustrated in Figure 8.7, the regional distribution of this supply increase is highly uneven, reflecting differences in natural gas resource availability, infrastructure development, and investment attractiveness.

Africa emerges as the largest contributor to the

Figure 8.7

Global natural gas supply outlook by region in RCS and SES (bcm)



Source: GECF Secretariat based on data from the GECF GGM

increase in the natural gas supply in the SES compared to the RCS. Over the forecast period, natural gas production in Africa is projected to rise by nearly 504 bcm, reaching 756 bcm by 2050 in the SES, compared to 502 bcm in the RCS. This substantial increase accounts for 37% of the total supply growth in the SES relative to the RCS, underscoring Africa's growing role in global gas markets. As a result, Africa's share in global natural gas supply is expected to rise to 13% by 2050 in the SES, up from 9% in the RCS, both significantly higher than 6% recorded in 2023. This projected supply surge in Africa reflects ongoing exploration and development efforts, particularly in Sub-Saharan Africa and the Eastern Mediterranean, and increased infrastructure investments to monetise gas resources for domestic and export markets. However, the extent to which Africa can realise this potential depends on regulatory frameworks, investment flows, liquefaction, and pipeline infrastructure expansion.

The **Middle East** ranks as the second-largest contributor to the natural gas supply increase in the SES compared to the RCS. Over the forecast period, natural gas production in the region is projected to rise by 669 bcm, reaching 1,363 bcm by 2050 in the SES, compared to 1,155 bcm in the RCS. This increase accounts for 31% of the total supply growth in the SES relative to the RCS, reinforcing the region's pivotal role in global gas markets. As a result, the Middle East's share in global natural gas supply is expected to rise to 23% by 2050 in the SES, slightly higher than the 22% projected in the RCS over the same period. This sustained growth is driven by the continued expansion of major gas projects, particularly in Qatar, Saudi Arabia, the UAE, and Iran, where investments in enhanced recovery techniques, unconventional gas developments, and LNG export infrastructure are set to strengthen the region's position as a key natural gas supplier. However, the pace of this expansion will depend on evolving market conditions, geopolitical developments, and policy frameworks supporting domestic gas utilisation and export strategies.

As one of the world's leading natural gas-producing regions, Eurasia is set to contribute 14% of the total natural gas supply increase in the SES compared to the RCS by 2050. Over the forecast period, natural gas production in **Eurasia** is projected to grow by 458 bcm, reaching 1,304 bcm in the SES, 96 bcm higher than in the RCS. As a result, Eurasia's share in global natural gas supply is expected to rise to 22% in the SES by 2050, slightly lower than 23% projected in the RCS, though exceeding its 21% share in 2023. This growth is primarily driven by Russia and Turkmenistan, where expanded pipeline infrastructure, LNG export capacity, and ongoing resource development are expected to support long-term supply resilience. However, geopolitical uncertainties, evolving trade dynamics, and investment conditions will play a crucial role in determining the actual scale of this expansion.

Asia Pacific follows closely in its contribution to the increase in the natural gas supply in the SES compared to the RCS. By 2050, natural gas supply in the region is projected to reach 816 bcm in the SES, marking an increase of 156 bcm compared to 2023, significantly exceeding the 91 bcm rise projected in the RCS. As a result, Asia Pacific's share of global natural gas supply is expected to reach 14% in the SES by 2050, aligning with the RCS projection but remaining well below its 16% share in 2023. This trend reflects the anticipated decline in domestic production from maturing fields in key producers such as Australia, Malaysia, and Indonesia, partially offset by new gas developments and enhanced LNG infrastructure investments. Despite the region's continued role in natural gas production, the growing dependence on imports, particularly LNG, underscores Asia Pacific's increasing reliance on interregional gas trade to meet future energy needs.

Collectively, Africa, the Middle East, Eurasia, and the Asia-Pacific are projected to account for 92% of the total increase in natural gas supply in the SES compared to the RCS by 2050. The remaining 8% of supply growth is expected to come from Latin America and North America, with each contributing 4%. While these regions play a smaller role in overall supply expansion, Latin America is set to experience moderate growth, driven by offshore developments and unconventional gas projects. In contrast, North America's contribution remains limited, as production stabilizes following years of rapid expansion. Meanwhile, Europe is not expected to contribute to the total expansion of natural gas supply in the SES compared to the RCS. This geographic shift in global natural gas production underscores the growing role of developing regions, while mature markets increasingly rely on imports or alternative energy sources.

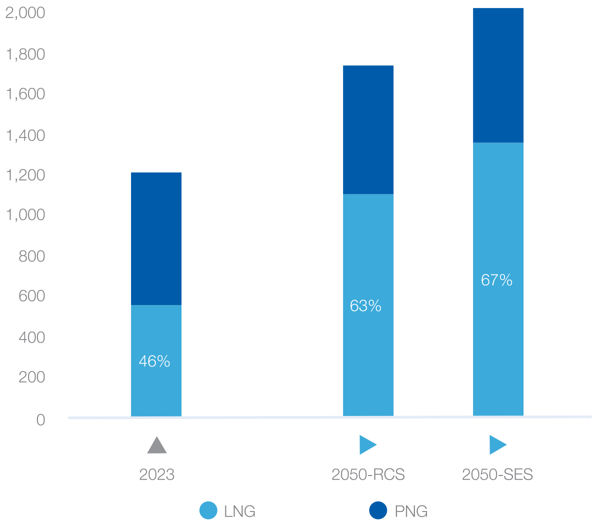
8.3.6 Natural gas trade

The implications of natural gas demand and supply balance on trade in the SES are significant, as the scenario envisions a substantial expansion in global natural gas trade. **Over the forecast period, natural gas trade volume is projected to increase by 817 bcm, reaching 2,030 bcm by 2050, compared to 1,743 bcm in the RCS.** This growth underscores the rising interconnectivity of natural gas markets and the increasing reliance on cross-border energy flows to meet demand. A key trend in the SES is the dominant role of LNG in driving trade expansion, with 91% of the projected trade growth attributed to LNG. **LNG supply is forecast to increase by 802 bcm by mid-century, reaching 1,365 bcm in the SES, compared to 1,104 bcm in the RCS.** This surge reflects growing LNG demand in key importing regions, including Asia Pacific, Africa, and Europe, as well as the continued expansion of liquefaction capacity in major exporting regions such as North America, the Middle East, and Eurasia. **As illustrated in Figure 8.8, LNG's share in total natural gas trade is expected to rise to 67% in the SES by 2050, up from 63% in the RCS**, reinforcing LNG's role as the primary vehicle for global gas supply expansion. This shift highlights the increasing flexibility, accessibility, and security of LNG supply, enabling markets to diversify their energy imports.

In the SES, **LNG imports are projected to rise by 585 Mt over the forecast period, reaching 993 Mt by 2050, up from 800 Mt in the RCS.** Asia Pacific is expected to dominate this growth, accounting for 92% of the net increase in LNG imports. **LNG imports in the region are forecast to surge by 520 Mt, reaching 786 Mt by 2050 in the SES**, which is 182 Mt higher than in the

Figure 8.8

Global natural gas trade outlook by flow type in RCS and SES (bcm)



Source: GECF Secretariat based on data from the GECF GGM

RCS over the same period. As a result, Asia Pacific's share of global LNG imports is expected to rise to 79% in the SES by 2050, up from 76% in the RCS, both significantly higher than the 64% recorded in 2023 (Figure 8.9). This reflects the region's increasing reliance on LNG to meet its growing energy demand amid declining domestic gas production.

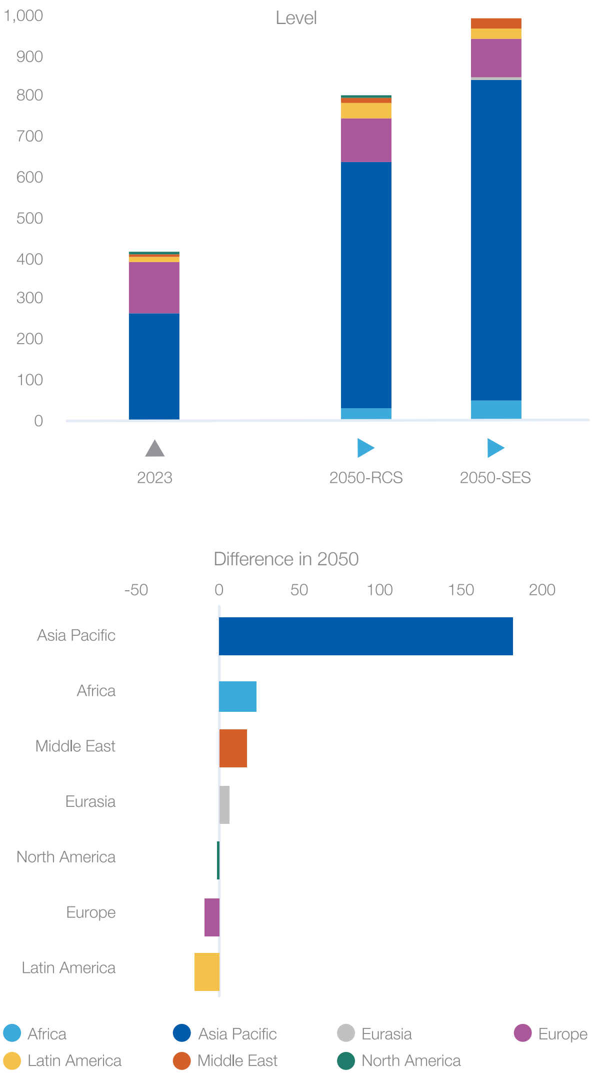
Africa follows as the second-largest contributor to the net increase in LNG imports in the SES compared to the RCS. The region's LNG imports are projected to rise by 53 Mt from a negligible level in 2023, exceeding the RCS projection by 21 Mt. As a result, Africa's share of global LNG imports is expected to reach 5% in the SES by 2050, one percentage point higher than in the RCS. This increase reflects the continent's increased natural gas demand, expanding gas infrastructure and the transition toward cleaner energy sources.

The contribution of other regions to the LNG import growth in the SES compared to the RCS remains minimal, as most developed markets either stabilise or reduce their reliance on LNG due to efficiency gains, increased renewable adoption, or slowing energy demand growth.

In the SES scenario, as illustrated in Figure 8.10, **the Middle East emerges as the leading contributor to the net increase in LNG exports compared to the RCS by 2050. LNG exports from the region are projected to rise by 192 Mt over the forecast period, reaching 288 Mt by 2050 in the SES, compared to 202 Mt in the RCS.** As a result, the Middle East's share of global LNG exports is expected to rise to 29% by 2050 in the SES, higher than 25% in the RCS, reinforcing its key

Figure 8.9

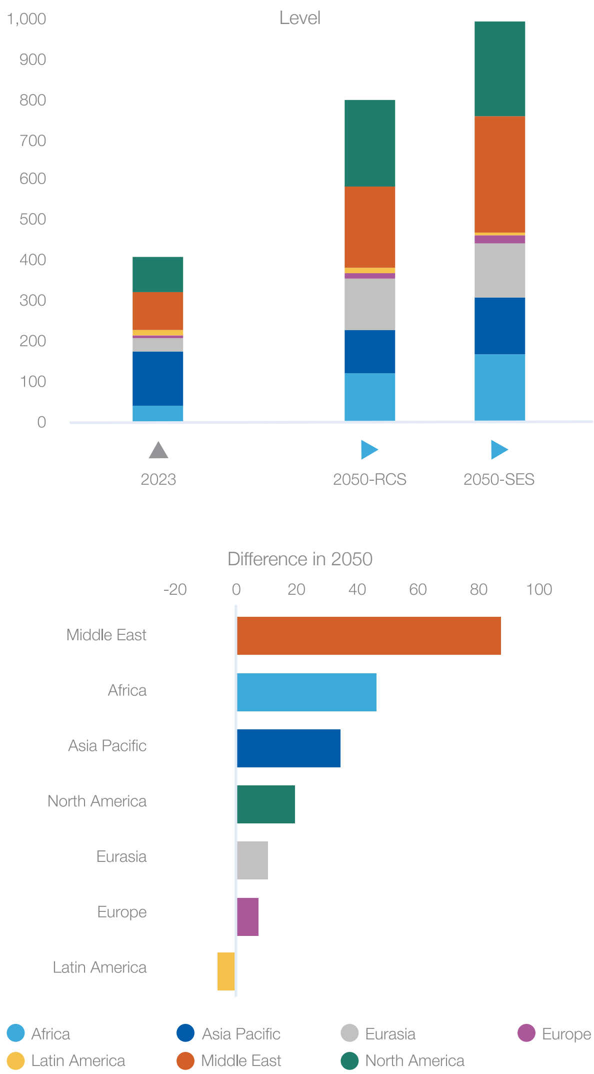
Global LNG import outlook by region in RCS and SES (Mt)



Source: GECF Secretariat based on data from the GECF GGM

Figure 8.10

Global LNG export outlook by region in RCS and SES(Mt)



Source: GECF Secretariat based on data from the GECF GGM

position in the global LNG export market under the SES scenario. This contrasts with the RCS, where North America holds the leading position in LNG exports.

Africa ranks as the second-largest contributor to the net increase in LNG exports in the SES compared to the RCS by 2050, accounting for 24% of the total increase. LNG exports from Africa are projected to rise by 124 Mt over the forecast period, reaching 164 Mt by 2050 in the SES, compared to 118 Mt in the RCS. Consequently, Africa's share of global LNG exports is expected to increase to 16% in the SES by 2050, slightly higher than 15% in the RCS, both significantly exceeding the 10% recorded in 2023. This growth reflects Africa's expanding LNG infrastructure, increased upstream development, and growing investments in gas monetisation strategies to meet rising international demand.

With a 17% contribution to the net increase in LNG exports in the SES compared to the RCS by 2050, Asia Pacific is also poised to be one of the key drivers of global LNG exports under the SES scenario. Unlike in the RCS, where LNG exports decline, Asia Pacific's LNG exports are projected to increase by 24 Mt in the SES, reaching 146 Mt by 2050, which is 34 Mt higher than the RCS. As a result of this upward trend, the share of Asia Pacific in global LNG exports is expected to rise to 15% by 2050 in the SES, slightly higher than 14% in the RCS, though both remain significantly lower than the 33% recorded in 2023. This reflects a structural shift in the region's LNG export capacity, as mature producers such as Australia experience declining output while emerging players in Southeast Asia make incremental contributions to the global market.

Collectively, the Middle East, Africa, and Asia Pacific are projected to account for 85% of the total increase in LNG exports in the SES compared to the RCS by 2050, underscoring their growing dominance in the global LNG supply chain. The remaining 15% of the increase is expected to come from North America and Eurasia, contributing 10% and 5%, respectively, with Europe playing a minor role in the overall export expansion. Meanwhile, Latin America is anticipated to experience a decline in LNG exports by 2050 under the SES compared to the RCS, reflecting shifting regional supply dynamics, limited new liquefaction investments, and increasing domestic gas consumption.

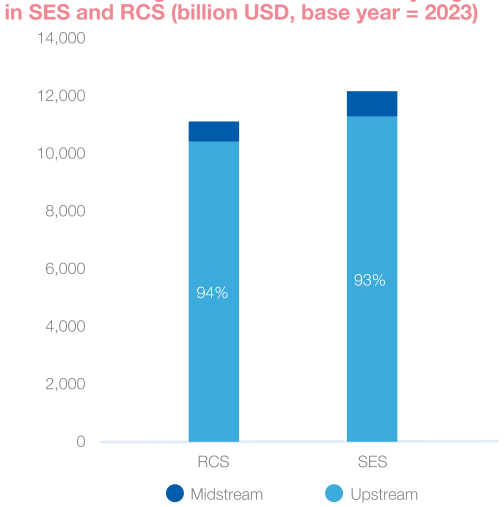
8.3.7 Natural gas investment

The cumulative capital investment required for natural gas from 2023 to 2050 in the SES is projected to reach USD 12.1 trillion, exceeding the RCS by approximately USD 1.0 trillion (Figure 8.11). This higher investment requirement in the SES is primarily driven by greater reliance on yet-to-find resources and the development of higher-cost greenfield projects. Additionally, the increased supply of LNG, a more capital-intensive segment, contributes to higher midstream investment growth in the SES compared to the RCS.

Upstream natural gas investment in the SES is projected to reach USD 11.1 trillion, representing 93% of total natural gas capital expenditure, an increase of USD 850 billion compared to the RCS. Meanwhile, cumulative investment in the midstream segment over the forecast period is estimated at USD 857 billion, accounting for 7% of total capital requirements and exceeding the RCS level by USD 159 billion. Within this segment, liquefaction and regasification investments are expected to contribute 63% and 31%, respectively, over the forecast period under the SES.

Figure 8.11

Global natural gas investment outlook by segment in SES and RCS (billion USD, base year = 2023)



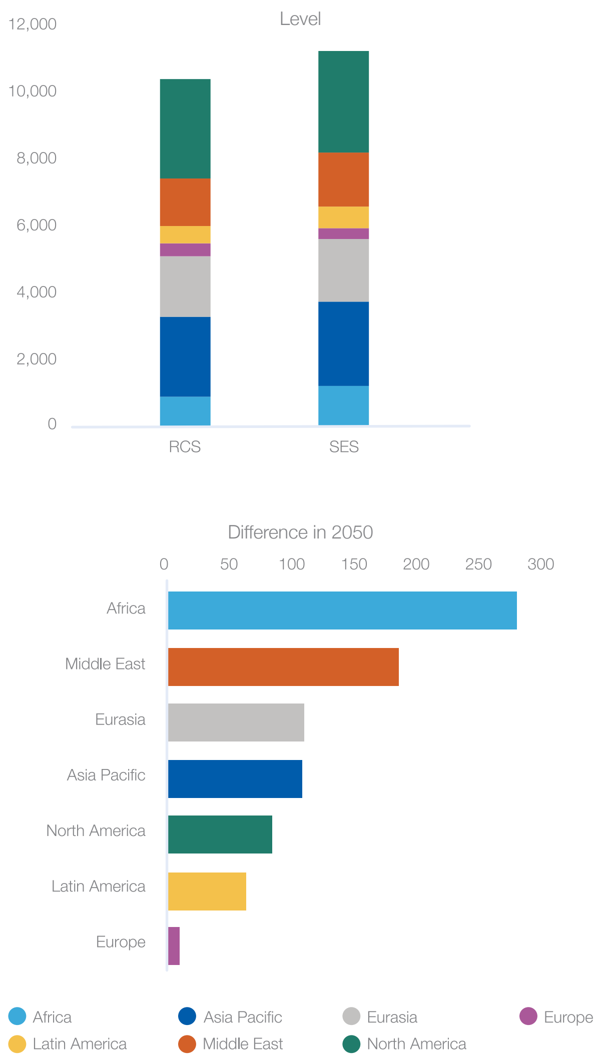
Source: GECF Secretariat based on data from the GECF GGM

The SES projects that Africa will account for one-third of the total increase in required upstream investment compared to the RCS, amounting to USD 282 billion (Figure 8.12). The Middle East follows closely, contributing 22% of the increase (equivalent to USD 186 billion) while Eurasia ranks third, representing 13% of the additional investment, or USD 111 billion.

Together with Asia Pacific, these regions collectively account for 81% of the required increase in upstream capital expenditure in the SES relative to the RCS. The remaining 19% is expected to be distributed among North America, Latin America, and Europe, with respective contributions of 10% (USD 85 billion), 8% (USD 68 billion), and 1% (USD 9 billion) to the overall investment increase.

Figure 8.12

Global upstream investment outlook by region in SES and RCS (billion USD, base year = 2023)



Source: GECF Secretariat based on data from the GECF GGM

8.3.8 Energy-related emissions outlook

Despite a larger global energy system and higher projected fossil fuel consumption in the SES, **cumulative energy-related emissions over 2023–2050 are expected to be nearly 5% lower than in the RCS.** This decline is primarily driven by structural shifts in the energy mix, including the increased substitution of coal with natural gas, rapid adoption of heat pumps, increased deployment of renewables and large-scale implementation of decarbonisation technologies such as CCUS and hydrogen-based solutions.

By 2050, global energy-related emissions are forecast to drop from 40.6 $GtCO_2e$ in 2023 to 26.9 $GtCO_2e$, marking a 34% absolute reduction, significantly outpacing the 23% decrease observed in the RCS. Over the entire forecast period, cumulative energy-related emissions in the SES are projected at 919 $GtCO_2e$, reflecting a reduction of 49 $GtCO_2e$ compared to the RCS, underscoring an overall 5% emissions savings (Figure 8.13).

A substantial portion of this emissions reduction stems from the accelerated deployment and scaling up of CCUS technologies across regions, particularly in hard-to-abate sectors such as heavy industry and power generation. The SES also benefits from enhanced energy efficiency measures in specific sectors, increased electrification of end-use sectors, and the expansion of hydrogen as an alternative energy carrier, reinforcing its trajectory toward a lower-carbon and more sustainable energy future.

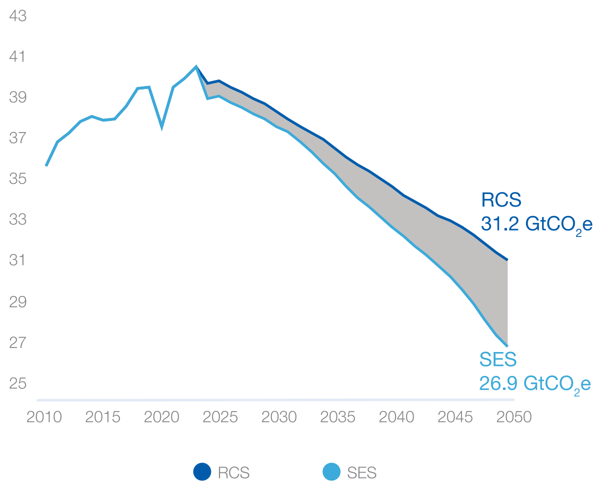
The distribution of energy-related emissions reduction under the SES is uneven across regions, reflecting differences in decarbonisation efforts, technological adoption, and energy demand growth trajectories. As illustrated in Figure 8.14, Asia Pacific is projected to account for the largest share of global emissions savings in the SES compared to the RCS. Over the forecast period, emissions in Asia Pacific are expected to be nearly 53 $GtCO_2e$ lower under the SES than in the RCS. This significant reduction is driven by the rapid deployment of CCUS technologies, large-scale renewable energy expansion, and accelerated electrification across key sectors. Additionally, the region's ongoing transition from coal and increased reliance on cleaner energy sources, including natural gas and hydrogen, further contribute to this decline.

However, despite these substantial emissions reductions, Asia Pacific is expected to remain the leading contributor to global cumulative energy-related emissions. The region's share of global emissions under the SES is projected at 46% by 2050, down only slightly from 50% in the RCS. This underscores Asia Pacific's continued dominance in global emissions, even as it makes notable strides in decarbonisation.

Beyond Asia Pacific, Eurasia, Latin America, and

Figure 8.13

Global energy-related emission outlook in SES and RCS ($GtCO_2e$)



Source: GECF Secretariat based on data from the GECF GGM

Europe also achieve notable but comparatively smaller reductions in cumulative emissions under the SES. However, their emissions savings remain significantly lower than those of Asia Pacific, reflecting differences in economic structures, industrial footprints, and the pace of energy transitions.

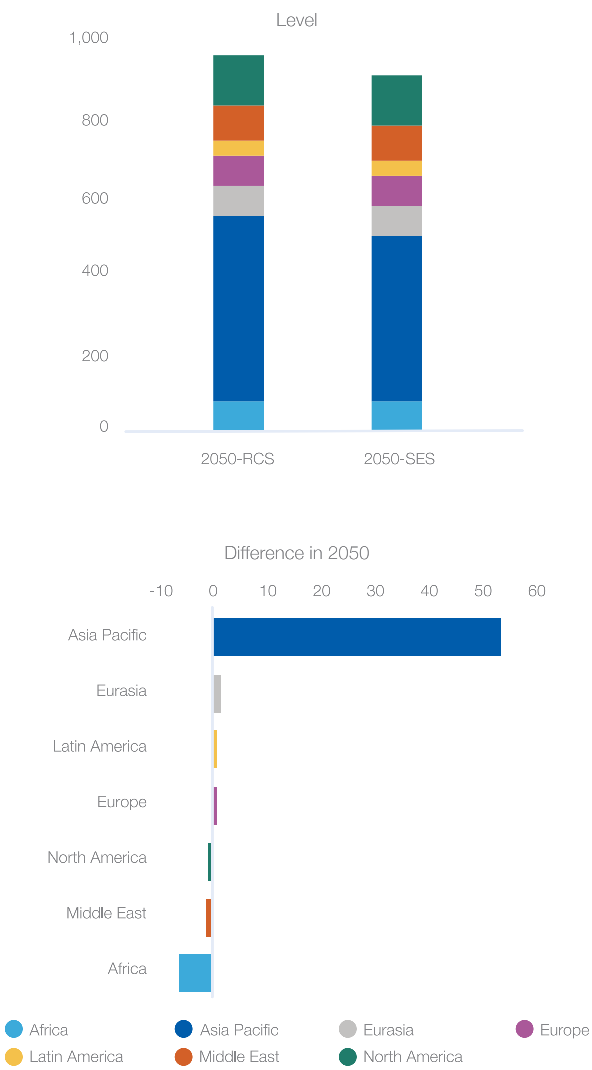
In stark contrast, Africa is the major region where cumulative energy-related emissions are projected to increase under the SES compared to the RCS, with a rise of approximately 6.4 $GtCO_2e$ over the forecast period. This increase is primarily driven by strong economic growth, surging energy demand, and a slower pace of renewable energy adoption alongside decarbonisation in certain sectors. While Africa is expected to expand its share of cleaner energy sources, its continued reliance on fossil fuels to support economic development and industrialisation increases net emissions.

However, it is important to note that even with this projected rise in emissions, Africa remains a minor contributor to global cumulative energy-related emissions. By 2050, Africa, home to nearly 20% of the global population, is anticipated to account for just 8% of cumulative energy-related emissions over the forecast period. Furthermore, energy-related emissions per capita in Africa are expected to decline to 2.75 tonnes of CO_2 per person by 2050, the lowest level among all regions. This remains significantly below the global average of 4.75 tonnes of CO_2 per capita, underscoring the continent's disproportionately low emissions footprint despite its growing population and economic expansion.

Similarly, the Middle East and North America follow Africa in registering modest increases in cumulative emissions under the SES relative to the RCS. These

Figure 8.14

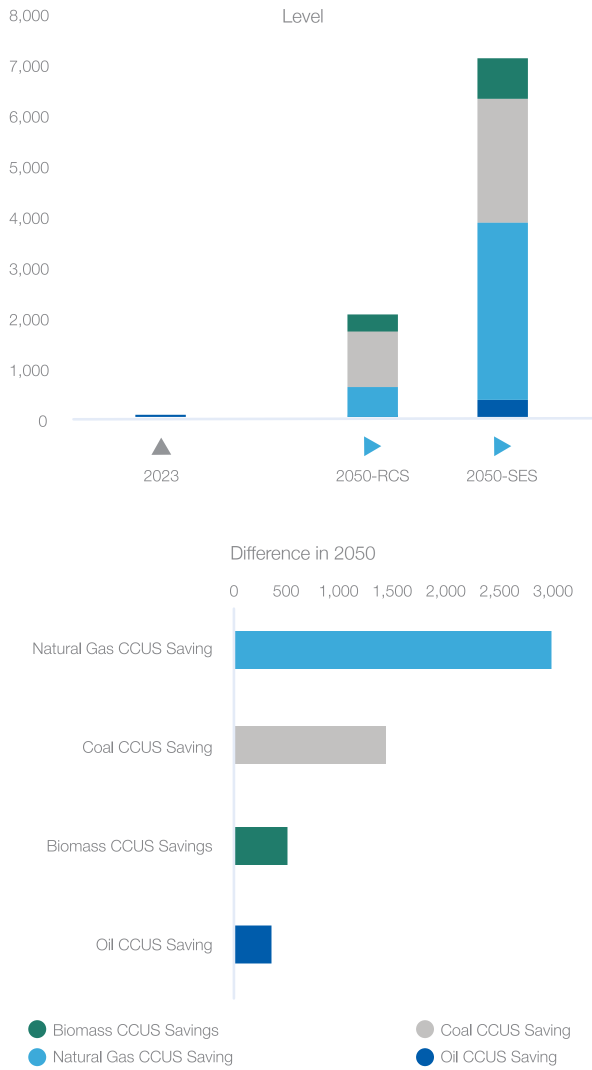
Global cumulative energy-related emissions outlook by region in RCS and SES ($GtCO_2e$)



Source: GECF Secretariat based on data from the GECF GGM

Figure 8.15

Global CCUS savings outlook by fuel type in RCS and SES ($MtCO_2e$)



Source: GECF Secretariat based on data from the GECF GGM

trends reflect regional variations in energy transition pathways, the pace of technology deployment, and sector-specific emissions dynamics, particularly in energy-intensive industries and hydrocarbon production.

The large-scale deployment of CCUS, as envisioned in the SES scenario's accelerated adoption pathway, emerges as a critical lever for reducing energy-related emissions. By enabling the capture and permanent storage of CO_2 emissions from energy combustion and industrial activities, **CCUS plays a pivotal role in mitigating climate impact while supporting the continued use of hydrocarbons in a lower-carbon energy system. Under the SES, the contribution of CCUS to emissions reductions is expected to grow exponentially, from 41 $MtCO_2e$ in 2023 to 7.2 $GtCO_2e$ by 2050, marking a 5.2 $GtCO_2e$ increase compared to the RCS.**

Among the various applications, natural gas-based CCUS is projected to have the most substantial impact, delivering over 3.6 $GtCO_2e$ in emissions reductions by 2050 in the SES, 2.9 $GtCO_2e$ higher than in the RCS. This accounts for a dominant 57% share of the total additional CCUS-driven emissions savings between the two scenarios, underscoring the growing role of natural gas as a cleaner energy source when coupled with carbon capture technologies.

Coal-based CCUS follows as the second-largest contributor, capturing 2.5 $GtCO_2e$ by 2050 in the SES, which is 1.4 $GtCO_2e$ higher than in the RCS. This represents 27% of the total increase in CCUS savings, reflecting targeted efforts to decarbonise coal use in regions where it remains a significant part of the energy mix.

Moreover, biomass and oil-based CCUS also make notable contributions. Biomass CCUS, often linked to negative emissions technologies such as bioenergy with carbon capture and storage (BECCS), is expected to account for 10% of the additional CCUS-driven emissions savings, while oil CCUS contributes 6% (Figure 8.15).

Asia Pacific, particularly countries with a heavy reliance on coal, are expected to play a central role in CCUS-driven emissions reductions under the SES, accounting for nearly 63% of total CCUS savings by 2050. Notably, 49% of these savings are projected to come from coal-based CCUS in the region, reflecting the continued importance of decarbonising coal-fired power and industrial processes. Meanwhile, natural gas CCUS is expected to contribute 33% of total CCUS savings in Asia Pacific by mid-century.

In contrast, in all other regions covered by the SES, natural gas CCUS represents the dominant share of total captured emissions by 2050. For example, in the Middle East, nearly all of the 649 $MtCO_2e$ CCUS savings projected under the SES are linked to natural gas applications. Similarly, in Africa, natural gas CCUS is expected to account for over 76% of the 402 $MtCO_2e$ total CCUS savings in the region by 2050. In North America, this share rises to 84%, contributing to 398 $MtCO_2e$ of captured emissions by mid-century.

Across all regions, the power sector, industrial sector, and hydrogen production are the primary areas where CCUS deployment is projected to deliver substantial emissions reductions. These sectors are expected to drive the majority of captured emissions under the SES, reinforcing the role of CCUS as a key enabler of a lower-carbon energy system.

It is important to note that the SES does not currently factor in potential emissions reductions from nature-based solutions, carbon sinks, or emerging carbon removal technologies such as Direct Air Capture (DAC). Considering these additional decarbonisation pathways, one could argue that the SES remains broadly aligned with the Paris Agreement's 2-degree Celsius target with 50% probability, provided these technologies are rapidly scaled up and integrated into the global emissions reduction framework.

Chapter 8

Annex A

Abbreviations

ACG	Azeri Chirag Deepwater Gunashli
AfCFTA	African Continental Free Trade Area
AfDB	African Development Bank
AG	Associated Gas
AGWP	Average Global Warming Potential
AI	Artificial Intelligence
AKK	Ajaokuta Kaduna Kano
AR	Assessment Report
ASEAN	Association of Southeast Asian Nations
ATR	Auto-thermal Reforming
BECCS	Bio-Energy with Carbon Capture and Storage
BRICS	Brazil, Russia, India, China, South Africa
CAPEX	Capital Expenditure
CAPS	Central African Pipeline System
CBAM	Carbon Border Adjustment Mechanism
CBDRRC	Common but Differentiated Responsibilities and Respective Capabilities
CBM	Coal Bed Methane
CCGT	Combined Cycle Gas Turbine
CCUS	Carbon Capture, Utilisation, and Storage
CELAC	Community of Latin American and Caribbean States
CGD	City Gas Distribution
CGM	City Gas Market
CGTP	Combined Global Temperature Potential
CHP	Combined Heat and Power
CIS	Commonwealth of Independent States
CMA	Capacity Market Agreement
CNG	Compressed Natural Gas
COP	Conference of the Parties
CSDDD	Corporate Sustainability Due Diligence Directive
DAC	Direct Air Capture
DES	Delivered Ex-Ship
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
ESG	Environmental, Social, and Governance
EU	European Union
EU ETS	European Union Emissions Trading System
EVs	Electric Vehicles
FCEVs	Fuel Cell Electric Vehicles
FDI	Foreign Direct Investment
FEED	Front-End Engineering Design
FID	Final Investment Decision
FLNG	Floating Liquefied Natural Gas
FOB	Free on Board
FSRU	Floating Storage Regasification Unit
FTA	Free Trade Agreement
G77	Group of 77
GCC	Gulf Cooperation Council
GFMR	Global Flaring and Methane Reduction
GGA	Global Goal on Adaptation
GGM	Global Gas Model
GGO	Global Gas Outlook

GHG	Greenhouse Gas
GIPP	Gwagwalada Independent Power Plant
GSA	Gas Sales Agreement
GST	Global Stocktake
GTA	Greater Tortue Ahmeyim
GTP	Global Temperature Potential
GWP	Global Warming Potential
HDV	Heavy-Duty Vehicle
HELE	High-Efficiency, Low-Emissions
HFO	Heavy Fuel Oil
HGV	Heavy Goods Vehicle
HOAs	Heads of Agreement
IIJA	Infrastructure Investment and Jobs Act
IIoT	Industrial Internet of Things
IMO	International Maritime Organization
IOC	International Oil Company
IOG4	Oil and Gas strategic Plan
IoT	Internet of Things
IPCC	Intergovernmental Panel on Climate Change
IRA	Inflation Reduction Act
JKT	Japan Korea Taiwan (Chinese Taipei)
LCOE	Levelized Cost of Electricity
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LTC	Long-Term Contract
M&A	Mergers and Acquisitions
MDBs	Multilateral Development Banks
MOU	Memorandum of Understanding
NAG	Non-Associated Gas
NCQG	New Collective Quantified Goal
NDC	Nationally Determined Contributions
NFE	North
NFE	North Field East
NFS	North Field South
NFW	North Field West
NGVs	Natural Gas Vehicles
NZIA	Net Zero Industry Act
OB3	Obiafu-Obrikom-Oben
OPEC	Organization of the Petroleum Exporting Countries
OPEC+	OPEC Plus
PIA	Petroleum Industry Act
PNG	Papua New Guinea
PPA	Power Purchase Agreement
PPP	Purchasing Power Parity
PSA	Production Sharing Agreement
PSH	Pumped Storage Hydropower
PT5-C	Power Transmission 5C
PV	Photovoltaic
RCEP	Regional Comprehensive Economic Partnership

RCS	Reference Case Scenario
RNGH	Renewable and Natural Gases and Hydrogen
SAF	Sustainable Aviation Fuel
SDG	Sustainable Development Goals
SES	Sustainable Energy Scenario
SMR	Steam Methane Reforming
SMRs	Small Modular Reactor
SPA	Sale and Purchase Agreement
T&D	Transmission and Distribution
TANAP	Trans-Anatolian Natural Gas Pipeline
TAP	Trans-Adriatic Pipeline
TAPI	Turkmenistan-Afghanistan-Pakistan-India Pipeline
TTF	Title Transfer Facility
UAE	United Arab Emirates
UNDESA	United Nations Department of Economic and Social Affairs
UNFCCC	United Nations Framework Convention on Climate Change
VRE	Variable Renewable Energy
WAGP	West African Gas Pipeline
WCSB	Western Canada Sedimentary Basin
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.*

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	103
Mega	M	106
Giga	G	109
Tera	T	1012
Peta	P	1015
Exa	E	1018

Annex D

Definitions

Ammonia (NH_3)

Ammonia is a hydrogen-based energy carrier and a key industrial chemical used primarily in fertilisers, chemicals, and industrial processes. In the context of energy, ammonia is gaining attention as a low-carbon fuel and hydrogen carrier, particularly for sectors that are difficult to decarbonise, such as shipping and power generation.

Announced LNG Project

An announced LNG project is an LNG project that has been publicly declared by its sponsors or developers as intended for future development. At this early stage, the project signals an intention to invest in LNG production but may still be in the conceptual or preliminary planning phase, with detailed engineering, final financing, or regulatory approvals yet to be completed.

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

Aviation refers to the transport of passengers and cargo by aircraft, including both domestic and international flights. It is a significant energy consumer, primarily dependent on jet fuel (aviation kerosene) and aviation gasoline for propulsion.

Biofuels

Biofuels are fuels derived from biomass, including plants, agricultural residues, 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 solid biomass, biogas, liquid biofuels, and waste-derived fuels from municipal solid waste and industrial waste. These sources are renewable when sourced sustainably and are extensively utilised for electricity production, heating, and transportation fuels.

Bunkers

Bunkers refer to fuels provided for ships and aircraft on international voyages, including marine bunkers for global shipping and aviation bunkers for international air travel. Marine bunker fuels include heavy fuel oil, marine gas oil. Is also include biofuels, ammonia and liquefied natural gas (LNG), reflecting the shipping industry's transition towards cleaner fuel options under international regulations. Aviation bunkers include jet fuel and sustainable aviation fuel.

Carbon Capture, Utilisation, and Storage (CCUS)

CCUS encompasses a range of technologies and processes designed to capture carbon dioxide (CO_2) emissions from sources such as power plants and industrial facilities, transport the captured CO_2 to a storage location, and store it in deep geological formations to prevent its release into the atmosphere. The utilisation aspect involves using captured CO_2 in applications such as enhanced oil recovery or as a feedstock for producing synthetic fuels and chemicals.

Coal

Coal is a fossil fuel primarily made up of carbon, formed from the remains of ancient plant matter. It is one of the most commonly used energy sources for generating electricity and supporting industrial processes. 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 encompasses non-industrial, non-residential services such as retail, finance, education, healthcare, and public administration. It plays a significant role in energy consumption, particularly for heating, cooling, and lighting in buildings like offices and retail spaces.

Condensate

Condensate refers to light liquid hydrocarbons extracted from natural gas during production, usually when the gas is cooled, or the pressure is reduced. Composed mainly of propane, butane, and other light oils, condensate is often used as feedstock for refined products or blended into gasoline. Typically produced in natural gas fields, it is processed and transported with natural gas or oil and is regarded as a valuable energy resource due to its versatility in industrial applications.

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.

Crude Oil

Crude oil is unprocessed petroleum extracted from underground reservoirs through drilling. It is a mixture of hydrocarbons found in liquid form within rock formations and can be refined into products such as gasoline, diesel, jet fuel, and petrochemicals. Once extracted, it is transported to refineries for processing.

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

DES is 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 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 system refers to a network of small-scale energy sources, located near the point of use, as opposed to centralised power plants. Such system typically generates electricity or heat from either renewable or conventional sources and is often integrated into local grids or used in off-grid setting.

Domestic Sector

The domestic sector encompasses the residential, commercial, and agricultural sectors, covering energy use for heating, cooling, lighting, cooking, refrigeration, and appliance operation.

Dry Gas

Dry gas refers to natural gas that has been processed to eliminate water vapour, hydrocarbon liquids (such as condensates, ethane, propane, and butane), and other impurities. It mainly consists of methane (CH_4) and is used as fuel in residential, commercial, and industrial settings, as well as for electricity generation.

Electric Vehicle (EV)

An electric vehicle is a vehicle powered either fully or partially by electricity. EVs are propelled by electric motors that run on electricity stored in rechargeable batteries or, in some cases, generated by fuel cells. These vehicles can be charged via plug-in stations or other power sources.

Electricity Generation

Electricity generation is the process of producing electrical power from a variety of energy sources. This can be done through methods like burning fossil fuels and nuclear fission or utilising renewable energy sources such as solar, wind, hydro, or geothermal. It involves converting energy from these sources into electrical power, which is then transmitted through grids to consumers for residential, commercial, and industrial use.

Electrolysis

Electrolysis is a process that uses electricity to split water (H_2O) into hydrogen (H_2) and oxygen (O_2). It is a key technology for producing low-carbon hydrogen when powered by renewable energy, offering a clean energy solution for sectors like transportation, chemicals, and energy storage.

Energy Sector

The energy sector refers to the part of the economy involved in the production, transformation, distribution, and consumption of energy. This encompasses activities such as the extraction of fossil fuels (coal, oil, natural gas), electricity generation (from fossil, nuclear, or renewable sources), and the distribution of energy to consumers through infrastructure like pipelines, grids, and storage systems.

Energy-Related Emissions

Energy-related emissions refer to greenhouse gases (mainly carbon dioxide, methane, and nitrous oxide) produced during the production, transformation, and consumption of energy. These emissions arise from the extraction, processing, and burning of fossil fuels, as well as from energy-related industrial activities and electricity consumption.

Enhanced Oil Recovery (EOR)

Enhanced oil recovery is a set of techniques used 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 (FiT) is a policy that supports renewable energy development by guaranteeing a fixed payment to electricity producers for the power they generate and supply to the grid, typically at above-market rates. This helps make renewable projects financially viable by providing stable, long-term revenue.

Feedstock

Feedstock refers to raw materials used in industrial processes to produce energy or products. In energy production, it includes materials like biomass, coal, natural gas, or oil, which are converted into fuels, chemicals, or electricity. Feedstock is vital in industries such as refining, bioenergy, and petrochemicals.

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

FOB 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 energy sources derived from the remains of ancient plants and animals that have been subjected to intense heat and pressure over millions of years. This process transforms the organic material into hydrocarbons, which are the primary components of fossil fuels such as coal, oil, natural gas, and peat. These fuels are a significant source of energy worldwide and are primarily used in electricity generation, heating, and transportation.

Geothermal

Geothermal energy is sourced from the Earth's natural heat, which can be accessed either near the surface or from deep underground reservoirs of heated rock and water. This energy is utilised for both heating purposes and the generation of clean electricity.

Hard-to-Abate Industries

Hard-to-abate industries are sectors or industries where significant reductions in carbon emissions are particularly challenging due to technological limitations, high costs, or other practical barriers. These sectors, which include steel, cement, chemicals, aviation, shipping, and trucking, are known for their high emissions and encounter considerable challenges in implementing low-carbon technologies.

Heads of Agreement (HoA) in LNG

HoA is 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

Heat plants are the facilities that produce thermal energy 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

Heavy-duty vehicles are large vehicles used for transporting goods and passengers. They include trucks with a gross vehicle weight (GVW) of 3.5 tonnes or more, ranging from medium-duty (3.5–15 tonnes) to heavy-duty (15+ tonnes), and buses designed for passenger transport, typically seating 30 to 70 people, excluding minibuses with fewer than 25 seats.

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

Hydropower is energy generated from the movement of water, typically harnessed through turbines in dams or river systems, to produce electricity. It is one of the most established and cost-effective renewable energy technologies.

In-FEED LNG Project

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.

Intermittency

Intermittency refers to the fluctuations in energy generation from renewable sources, such as solar and wind, which are influenced by weather conditions and the time of day. These variations can create challenges for maintaining grid reliability and stability.

International Aviation Bunkers

International aviation bunkers refer to the supply of aviation fuel to aircraft operating on international flights.

International Marine Bunkers

International marine bunkers refer to the fuel supplied to ships of all flags involved in international navigation, including travel at sea, along inland lakes and waterways, and coastal areas.

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

Maritime pertains to activities and industries related to the sea, particularly navigation, shipping, and marine environments. It is centred on the shipping sector, which involves transporting goods and passengers by sea, and is a major consumer of energy.

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

Methanol is a versatile fuel used for direct combustion, blending with other fuels, and as a feedstock for fuel additives. It powers fuel cell electric vehicles and can be converted into gasoline or diesel components like methyl tert-butyl ether (MTBE) and fatty acid methyl esters (FAME).

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)

NDC's are 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.

Natural Gas

Natural gas is a fossil fuel mainly composed of methane (CH_4) and other hydrocarbons. It is extracted from underground reserves and is used for heating, generating electricity, and as a raw material in chemical industries. It encompasses both non-associated gases, sourced solely from gas fields, and associated gases, produced concurrently with crude oil. Additionally, it includes methane extracted from coal mines, known as coalbed methane (CBM). This definition does not cover natural gas liquids, gases manufactured from municipal or industrial waste, or quantities of vented or flared gas. The energy content of natural gas is typically measured at 50.02 MJ/kg, based on its lower heating value.

Natural Gas Liquids (NGLs)

Natural Gas Liquids (NGLs) are hydrocarbons, including ethane, propane, butane, isopentane, and heavier alkanes, extracted from natural gas through processes like absorption or condensation at gas processing facilities. NGLs have various uses, such as serving as feedstocks for petrochemical production (e.g., plastics and synthetic rubber), fuels for heating and cooking (e.g., propane and butane), and transportation fuels, where some are blended into gasoline or used in compressed or liquefied forms to power vehicles.

Natural Gas Production

Natural gas production involves extracting natural gas, mainly composed of methane, from underground reservoirs. This process includes drilling wells into geological formations to access both conventional deposits, where gas is stored in large pockets, and unconventional sources like shale formations, which require techniques such as hydraulic fracturing to release the gas. Once extracted, the gas is processed to remove impurities before being distributed for various uses, including heating, electricity generation, and as a feedstock in chemical industries.

Natural Gas Production Capacity

Natural gas production capacity refers to the maximum volume of natural gas that can be extracted from reserves over a set period, usually measured annually. This capacity is shaped by factors such as technological progress, investment, regulatory policies, and the development of extraction infrastructure.

Natural Gas Proven Reserves

Proven reserves of natural gas are quantities that, based on geological and engineering analyses, can be estimated with a high degree of confidence to be commercially recoverable from known reservoirs under current technological, economic, and operational 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

Non-energy use refers to the use of energy products as raw materials in manufacturing processes, rather than for combustion or power generation. These products are primarily used as feedstocks in industries such as petrochemicals, where they are converted into items like plastics, fertilisers, and other chemicals.

Nuclear

Nuclear energy is produced by releasing energy from the atomic nucleus through processes like fission, where atomic nuclei are split, or fusion, where they are combined. This energy is captured and used in nuclear power plants to generate electricity.

Oil

Oil, or petroleum, is a naturally occurring liquid found beneath the Earth's surface, predominantly composed of hydrocarbons. It is extracted through drilling and serves as a vital energy source and raw material across multiple industries. Oil is utilised in various applications, including the production of transportation fuels, heating, electricity generation, and as a feedstock for the petrochemical industry.

Oil Products

Oil products, or petroleum products, are derived from the refining of crude oil through distillation and processing. These products include fuels such as gasoline, diesel, kerosene, and heavy fuels, which are used in energy production, transportation, heating, and various industrial processes. Additionally, they serve as feedstocks in petrochemical manufacturing.

Oil Sands

Oil sands are a naturally occurring mixture of sand, clay, water, which contains a dense and viscous form of petroleum known as bitumen. Oil sands are mined and processed to extract 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

Petrochemical feedstocks are raw materials, mainly derived from oil and natural gas, used to produce petrochemicals. These include naphtha, ethane, propane, and butane, which are processed into key chemicals like ethylene, propylene, and benzene. These chemicals are essential for producing a wide range of products, such as plastics, fertilisers, clothing, and medical equipment.

Planned LNG Project

Planned LNG project is 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

Probable reserves refer to quantities of oil or gas that geological and engineering analyses suggest have a greater than 50% chance of being technically and economically recoverable under current conditions. These estimates are based on available geological and engineering data, indicating the likely presence of hydrocarbons, but without sufficient drilling or production data to classify them as proven reserves.

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

Proven reserves are quantities of crude oil, natural gas, and natural gas liquids that geological and engineering analyses indicate with reasonable certainty can be recovered from known reservoirs under existing economic and operating conditions. These reserves are based on comprehensive geologic and engineering data, offering a high degree of confidence in their recoverability.

Refinery Feedstocks

Refinery feedstocks are raw materials derived from crude oil, natural gas, or other hydrocarbons that are processed in refineries to produce a range of refined products. These feedstocks include materials such as straight-run fuel oil, vacuum gas oil, and fractions like pyrolysis gasoline and C4 fractions. The feedstocks are further refined to create products like gasoline, diesel, jet fuel, and petrochemicals used in various industries.

Renewables

Energy sources that are continuously replenished by natural processes include solar, wind, hydropower, biofuels, geothermal and tidal energy. These technologies generate energy with little to no greenhouse gas emissions and are key to sustainable energy strategies.

Reserves

Reserves refer to the estimated quantities of resources that are expected to be economically recoverable from known oil and gas fields using existing technologies. This term includes various classifications, such as proven, probable, and possible reserves, depending on the level of certainty regarding their recovery and economic viability.

Residential Sector

The residential sector encompasses the portion of the economy where energy is used by households for functions like heating, cooling, lighting, and operating appliances. It covers all types of energy consumed in homes, including electricity, natural gas, heating oil, and other fuels.

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

Shale gas is a type of unconventional natural gas located in shale formations, which are fine-grained sedimentary rocks with low permeability. Its extraction usually requires hydraulic fracturing, or "fracking," a process that increases the flow of gas from the rock into the wellbore.

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)

Solar Photovoltaic technology transforms sunlight into electricity by using solar cells, which are electronic devices typically made from semiconductor materials. These cells absorb sunlight and produce an electric current. 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

Tight gas refers to natural gas is produced from reservoirs with very 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 Consumption (TFC)

Total final consumption refers to the energy used by end-users, including households, businesses, and industries, for purposes such as heating, cooling, lighting, running appliances, and powering vehicles and machinery. It also encompasses the non-energy uses of energy products, such as fossil fuels employed in chemical production.

Total Primary Energy Demand (TPED)

Total primary energy demand refers to the total amount of energy required to meet the needs of end users within a country. It includes energy used for power generation, as well as energy consumed across various sectors such as transportation, industry, and residential use. TPED also accounts for the energy required for other activities within the energy sector, excluding the energy used to generate electricity and heat.

Transport Sector

The transport sector includes all transportation modes - road, rail, air, and maritime - used for moving passengers and goods. It is a significant consumer of energy, primarily relying on petroleum products, with growing use of biofuels and electricity.

Unconventional Gas Production

Unconventional gas production refers to the extraction of natural gas from reservoirs that necessitate advanced techniques due to their distinct geological properties. These include shale formations, tight gas deposits, and coalbed methane. To improve gas flow from these low-permeability sources, methods like hydraulic fracturing (fracking) and horizontal drilling are commonly used.

Unconventional Resources

Unconventional resources are energy reserves that require advanced extraction technologies because their unique geological features make them challenging to access using traditional methods. These resources include shale gas, tight oil, oil sands, oil shale, coalbed methane, and methane hydrates.

Under Construction LNG Project

An under-construction LNG project is one that has progressed past the planning and FID stages and is now actively undergoing physical construction. At this stage, all major approvals, financing, and detailed engineering work (including FEED) have been completed, and the project is in the process of building the necessary facilities to eventually produce, liquefy, and export LNG. In this phase, the project's execution is typically managed through an EPC (Engineering, Procurement, and Construction) contract. Under construction, LNG project refers to the capacity that is currently under construction or going through commissioning.

Wind

Wind energy refers to the process of capturing the kinetic energy of moving air and converting it into electricity through the use of wind turbines. The movement of wind causes the rotor blades of the turbine to spin, which drives a generator to produce electrical energy. Wind farms, both onshore and offshore, are vital in supporting the transition to sustainable energy systems.

Yet-to-Find (YTF)

Yet-to-Find reserves refer to estimated quantities of oil and gas believed to exist in undiscovered fields. These estimates, based on geological and geophysical data, represent potential resources that have not yet been identified or developed. YTF reserves play a crucial role in energy resource assessments, offering insights into the future potential of oil and gas supplies.

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