

2018 GLOBAL GAS OUTLOOK



GECF

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ABOUT THE GECF

The Gas Exporting Countries Forum (GECF or Forum) is an intergovernmental organisation established in May 2001 in Tehran, Islamic Republic of Iran. The GECF Statute was signed in 2008 in Moscow, Russia. The GECF became a fully-fledged organization in 2008 with its permanent Secretariat based in Doha, Qatar.

The GECF comprises twelve Members and seven Observer Members (hereafter referred to as the GECF Countries). 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). Azerbaijan, Iraq, Kazakhstan, the Netherlands, Norway, Oman and Peru have the status of Observer Members (hereafter referred to as Observers).

The GECF is a gathering of the world's leading gas producers, whose objective is to increase the level of coordination and to strengthen collaboration among Member Countries. The Forum provides a framework for the exchange of views, experiences, information and data, and for cooperation and collaboration amongst its Members in gas-related matters.

In accordance with the GECF Statute, the organization 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 the GECF Long-Term Strategy, adopted during the 18th GECF Ministerial Meeting, the priority objectives of the GECF are as follows:

1. To maximize gas value, namely to pursue opportunities that support the sustainable maximization of the added value of gas for Member Countries.
2. To develop the GECF view on gas market developments through short-, medium- and long-term market analysis and forecasting.
3. To promote cooperation, namely to develop effective ways and means of cooperation amongst GECF Member Countries in various areas of common interests.
4. To promote natural gas, namely to contribute to meeting future world energy needs, to ensure sustainable global development, and to respond to environmental concerns, particularly regarding climate change.
5. To reinforce the international positioning of the GECF as a globally recognized intergovernmental organization, which is a reference institution for gas market expertise and a benchmark for the positions of gas exporting countries.

The GECF Global Gas Outlook is among the main key initiatives and instruments identified in the GECF's Long-Term Strategy

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Foreword



This 2018 edition of the GECF Global Gas Outlook was prepared by the GECF Secretariat to share our views on the developments that have been taking place in energy markets and on the multiplicity of factors and players which are resulting in shifting strategies and a new architecture shaping the world.

The document has been developed based on the GECF Global Gas Model (October 2018 Update) and supports the GECF's Long-Term Strategy, adopted during the GECF Ministerial Meeting in October 2017. Our Outlook projects that global energy markets will continue to evolve in the coming decades, with energy demand driving these transformations.

Over the next twenty years, the global population will increase by 1.7 billion and household wealth will increase by 80%. With the number of households totalling 2.8 billion by 2040 (a 33% increase from 2017) and over 2 billion cars on the road (a 60% increase), energy accessibility will become a top priority for policymakers, especially in Asia and Africa.

Global energy demand is forecast to increase by 26% by 2040. Fossil fuels are expected to continue to play a dominant role in the global energy mix, meeting 76% of total energy demand. Natural gas will be the only hydrocarbon resource to increase its share in the global energy mix, from 22% today to 26% in 2040.

These estimates were recently echoed at the 2018 G20 Meeting of Energy Ministers, who reached a consensus on the critical importance of natural gas and its capacity to expand significantly over the coming decades, supporting transitions towards lower emission energy systems.

Coordinated approaches to global energy market developments will contribute towards meeting the world's future energy needs, ensuring global sustainable development and responding to environmental concerns, in order to achieve the UN's seventeen Sustainable Development Goals (SDGs) and the Paris Agreement targets.

The GECF fully supports the global commitments toward clean and environmentally friendly energy sources, with the aim of promoting economic development with a smaller carbon footprint.

Africa and Asia currently have the most limited access to energy and the largest fuel substitution potential. Biomass

and waste support 36% of energy consumption in the domestic sector in developing Asia and 80% in Africa, compared to less than 6% in developed countries.

The GECF calculations show that through proper investment in infrastructure, natural gas can meet the energy needs of these populations while improving air quality and achieving the targets outlined in SDG 7: access to affordable, reliable, sustainable and modern energy for all. If these commitments are to be achieved, the role of natural gas in a sustainable energy future cannot be ignored, given its credentials. Furthermore, natural gas complements other energy sources, such as renewables, that are considered sustainable. In the GECF, we believe that there is the need for an increased share of natural gas in the energy mix given it is an abundant, affordable, versatile, flexible and environmentally friendly fuel of choice.

Despite natural gas's advantages, it is facing some key challenges, especially those related to energy policy. Firstly, the role of natural gas in reducing greenhouse gas emissions is not clearly highlighted in countries' National Determined Contributions (NDCs) submitted to the United Nations Framework Convention on Climate Change. It is estimated that only around twenty countries refer to natural gas in their NDC proposals for greenhouse gas mitigation.

Secondly, we observe some policy constraints in Europe with continuing changes of market rules and design, as well as the dominance of national policies and priorities over those of the UN. Thirdly, the policy remains unclear regarding the future role of natural gas and coal, particularly in some Southeast Asian countries. Additionally, the GECF is expressing its deep concern about the extraterritorial application of laws and regulations and objects to unilateral economic sanctions in the gas sector, particularly against GECF Member Countries, that are not authorized by the relevant agencies of the United Nations. The success of natural gas's penetration in the energy mix will be driven by the continuous hard work of all stakeholders to lower costs of production to make it an affordable option, and to achieve technological breakthroughs that will also facilitate the efficient use of natural gas in power generation and in gas-based industries.

However, the campaign for greater penetration of natural gas in the energy mix cannot be undertaken only by the owners of such resources or the producing companies; it should involve all stakeholders including producers, buyers, consumers, governments, environmental groups, academia and social media groups that reach millions of people and can educate them on the benefits of natural gas as a rightful and legitimate leader in the energy transition towards more sustainable energy sources. In this regard, the GECF provides a credible platform for an all-inclusive dialogue, including data exchange and debate, in the field of energy and natural gas market development.

Representing more than two-thirds of the world's proven gas reserves and almost half of global natural gas production, the GECF is open to dialogue with all parties interested in promoting natural gas to ensure global sustainable development and increase energy access to the world's most vulnerable populations.

Yury P. Sentyurin
Secretary General



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Executive Summary

Population growth and urbanisation

Population growth from 7.5 billion in 2017 to 9.2 billion by 2040, based on 2017 Revision of UN World Population Prospects medium fertility scenario, is the main driver of future energy trends. Most population growth will take place in regions with the lowest energy access and almost no infrastructure, and thus with important potential for promoting natural gas demand in the future. As the push towards global urbanisation is strong, almost all of the 1.7 billion population increase is expected to add to the urban population, with rural populations staying flat.

As population growth in the next 23 years will be two-thirds of the 2001-2017 rate, and 500 billion fewer workers will join the labour force, labour productivity will need to increase at over 2.0% per year to sustain a GDP growth of 3.4%. Despite productivity advances, global growth will decelerate significantly by 2040, as many countries will not be able to accelerate their economic development using the "Asian economic miracle" model.

Economic prospects

Overall, the global economy is still expected to grow at 3.4% p.a. on average for 2018-2040. With developed countries on a stable growth trend of 1.9%, and developing countries poised to grow 4.3% p.a., the long-term global economic growth is expected to be broad-based and stable, while medium-term growth will follow cyclical patterns. This growth will be concentrated in the power-hungry developing Asian market, with China growing by 4.7% on average and India at an average of 5.9% over the outlook horizon.

The new trade policy of the US government is a downside risk for global growth, and it is already impacting the long-term expectations of investors. Increases in US interest rates and the cessation of quantitative easing could constrain growth in developing countries which have high levels of dollar denominated debt.

Given the number of recent policy initiatives in European countries, China, and India, as well as from global industry leaders, electric vehicles are expected to receive most policy support and investment at the expense of internal combustion engines powered by petroleum products. The natural gas vehicle fleet is expected to grow, especially in the medium-term, as the air quality policies in several developing countries are enacted. Natural gas demand will increase as electricity demand from the growing electric vehicle (EVs) fleet rises. Changes in how the mobility sector is powered, unlocked by technological improvements, will impact demand closer to 2040, although transport energy demand still peaks at 2035.

Energy price projections

Long-term oil prices will reflect the falling costs of extraction for new tight oil projects, which are expected to decrease to \$70/bbl. The natural gas market structure over outlook period is expected to stay geographically segmented, despite some integration post-2025 driven by the construction of new infrastructure. Short-term price differences between regional markets could be eliminated via LNG shipments, but this requires price differences of over \$5-6/mmBtu depending on transport costs, as well as supply and demand balances. In the longer-term, increased pressure from energy transition and power mix substitution along with a lack of new projects in the medium-term is expected to drive prices significantly higher across all regions.

The global consumption of coal is expected to hold steady at around the present level, as is the amount of coal-generating capacity, as the volumes and capacity phased out in North America and Europe (and China, after 2030) are expected to be replaced by new ones in India and Southeast Asia. Over the outlook period to 2040, thermal (steam) coal will remain a key energy carrier in the global power mix, and is an important component for unlocking electricity access in some power-hungry developing Asian countries.

Several global carbon trading systems already in place will materially change the competitiveness of natural gas vs. coal in the long-term, as the carbon price sector coverage is expanded.

Energy policy developments and emissions trends

The strong link that energy forms between the 2030 Sustainable Development Agenda and the Paris Agreement allocates responsibility to energy policies in aligning the two frameworks. Policies that support natural gas can achieve progress for both agendas.

Natural gas continues to be encouraged through supply-side measures promoting availability and accessibility to resources, and through demand-side measures including emissions standards, carbon pricing or mandated switching.

The Outlook sees the Paris Agreement target being missed by some margin, with coal and oil representing around 72% of emissions by 2040. Increased gas use can contribute to closing the gap between emissions and the 2°C target.

Energy and natural gas demand trends

Primary energy demand is projected to rise by 1% p.a., from 14144 Mtoe in 2017 to about 17829 Mtoe in 2040. This represents a slower pace than the historical average of 2% p.a. seen since 2000, thanks to increased energy efficiency measures.

Fossil fuels will dominate the global energy mix although their share will decrease from 81% to 76% over the forecast period. Non-fossil fuels are expected to develop at a rate of 2.1% p.a., while fossil fuels will grow by an average of 0.7% p.a.

The share of oil, the world's largest source of energy, will decline from 32% to 29% by 2040. Coal's share will fall much more significantly, from 27% to 21%, due to environmental concerns, with the Asia Pacific region accounting for the bulk of demand. Renewable energy consumption (excluding hydro and biomass) is forecast to soar by 6.7% p.a., to reach 6% of the total energy mix by 2040.

Natural gas will be the fastest growing fossil fuel, mainly thanks to policy drivers concerning air quality, and will displace other sources of energy in a range of sectors. Demand is expected to increase by 1.7% p.a., with gas's share of the energy mix rising from 22% to 26% by 2040.

Natural gas consumption will climb from 3709 bcm in 2017 to 5427 bcm in 2040. Asia Pacific, North America, the Middle East and Africa will lead this growth. Gas demand in Africa will grow most rapidly (3.1% p.a.) albeit from a very low base. North America and Asia Pacific will account for 52% of global gas consumption in 2040. The US will consume

82% (1173 bcm) and China 49% (701 bcm) of demand in their respective regions.

From a sector perspective, the power generation (2.2% p.a.) and industrial sectors (1.2% p.a.) will be the biggest contributors to incremental gas demand. The transport sector (4.2% p.a.) will emerge as a significant new area with an overall increase of 160%, reaching 357 bcm in 2040.

Natural gas supply

Overall growth in production of 1.7% p.a. is expected in the period to 2040, with total output expected to reach 5427 bcm by that date. Africa is expected to see the fastest growth, albeit from a low base, while North America will be the largest contributor by 2040 with an overall share of 28% of global gas output.

The US, Russia, China and Iran are the largest contributors to this expansion, accounting for 24.8%, 12.4%, 12.4%, and 10.5% respectively, of total change. The US, Russia and Iran will remain the largest individual gas producers, although Chinese gas production is expected to increase dramatically. One-fifth of supply growth will come from the Asia Pacific region, split between countries looking to provide solely for domestic demand, those who are established exporters and those who are looking to minimize imports.

North America, led by the US, already accounts for more than one-quarter of global gas production, and the region's output is set to grow by 2% p.a. to 2040. With Iran and Qatar leading the way, gas production in the Middle East is set to grow by 61% to 2040, with total volumes reaching 980 bcm.

Gas trade and investment

Out of 5427 bcm of global natural gas demand in 2040, 1616 bcm will be imported, of which 960 bcm will come from GECF Members. The LNG segment will be more dynamic, growing at 2.2% p.a. to reach 769 bcm, while pipeline trade will expand at a slower rate of 1.1% per annum to 847 bcm.

The natural gas export capacity increases that started in 2016 and which will continue until 2025 are expected to be the largest seen so far. With a rapid expansion of LNG capacity in the medium-term, the share of LNG exports will rise from their current 41.5% to 45.3% by 2030, and further to 47.6% by 2040.

By 2040, we expect the largest additional import demand for natural gas to come from Asia Pacific and Europe, with a total increase of over 300 bcm and 150 bcm respectively. As of now, 27 countries are net exporters of natural gas, but up to 35 countries could become net exporters by 2030 and hold that status through to 2040, with many African countries among them. To meet the growing demand for natural gas and avoid energy crises by 2040, there is a need to invest \$7.9 trillion in additional natural gas production capacity and gas trade infrastructure.



Introduction and Scope

This 2018 GECF Global Gas Outlook reflects the impartial views of the GECF Secretariat and is prepared in accordance with the resolutions adopted in the 18th GECF Ministerial Meeting. It aims to support the Long-term Priority Objectives of the GECF Long-Term Strategy.

The present document is based on proprietary assessments of the evolution of energy and gas market fundamentals through to 2040. This Outlook was developed within the framework of the Technical and Economic Council created within the Forum, to guide and monitor extensive research on global gas markets. The GECF Global Gas Outlook is unique, as it is the only energy outlook worldwide to focus solely on natural gas. It aims to be a global reference for insights into gas markets. The document also represents an impartial view on gas market evolution by highlighting the most likely developments in the medium- and long-term.

The GECF reference case scenario highlights the current situation and the evolution of gas market and energy trends to 2040, in terms of global energy demand (by region/sector/fuel) and global gas supply (conventional and unconventional), for GECF and non-GECF countries. It also reflects current energy policies and the potential introduction of new policies that are likely to materialize throughout the forecast period, in accordance with our assessment.

In addition, this document explores the subject of competition from alternative sources of energy (mainly coal and renewables), as well as technological developments and their eventual impact on the energy mix and gas market shares, with a focus on power generation as a strategic sector for gas demand growth. Energy efficiency, environmental policies and other regulations have been considered in the reference case scenario, in order to study their impact on gas penetration in key markets/sectors.

The GECF Secretariat believes that it is impossible to cover all future uncertainties with a single scenario; multiple scenarios are needed in order to have a broader mapping of the uncertainties shaping the development of gas markets. In this regard, the Secretariat will address future uncertainties and their possible impact on alternative scenarios through the annual publication of the GECF Global Gas Outlook. The outcomes of the GECF reference case scenario will serve as a basis to support the formulation of a consistent Long-Term Strategy for the Forum, and will allow it to achieve the agreed upon objectives included in the GECF Statute and summit declarations.

This document is divided into six main chapters. Chapters I and II introduce key global gas demand assumptions, including economic, energy price and policy assumptions, as well as environmental policy development. Chapter III highlights energy and gas demand trends, followed by supply the natural gas supply outlook in Chapter IV, which includes projections for upstream production, including those for unconventional resources. Chapter V is dedicated to global trade outcomes resulting from the equilibrium between supply and demand. It takes into consideration gas market constraints, in terms of supply infrastructure, international supply contracts and gas supply policies (e.g. the satisfaction of domestic gas demand as a priority for some countries). The final chapter features two alternative scenarios devised by the GECF Secretariat: the Carbon Mitigation Scenario (CMS) and the Technology Advancement Scenario (TAS).

The reference case scenario is quantified through the use of the GECF GGM, which is a unique energy model developed in-house at the GECF Secretariat, and which includes different sub-models with each one focused on one segment of

the gas value chain (production, pipelines, LNG, shipping, regasification, contracts and demand).

Our model is characterized by its uniquely high granularity, encompassing:

- ⊗ 113 country-level forecasts, with 60 regional aggregates and a global projection
- ⊗ Complete energy balance estimates, covering 29 sectors and 34 fuels annually, from 1990 to 2040
- ⊗ More than 4300 gas supply entities representing gas supply potential at the global scale, divided into:
 - ⊗ 740 existing and operational production facilities (including aggregates)
 - ⊗ 2120 new projects based on existing reserves
 - ⊗ 1300 yet-to-find (YTF) entities
 - ⊗ 160 unconventional resources (existing and YTF), generating the most comprehensive database available of global shale and tight gas, coalbed methane (CBM) and methane hydrates.

The infrastructure database contains:

- ⊗ 240 liquefaction plants
- ⊗ 400 regasification plants
- ⊗ more than 5000 gas pipeline and shipping routes

The gas contracts database contains:

- ⊗ Annual contracted and delivered volumes, including 600 contracts (country-to-country and non-dedicated), based on more than 1000 company-to-company contracts

Another important characteristic of our model is that it endogenously calculates gas demand curves and gas production profiles country by country based on corresponding assumptions and inputs.

All of the sub-models have been calibrated and based on 2017 as the last available year of historical data. Energy and natural gas demand forecasts are derived based on a set of primary and secondary assumptions fed with macro and energy price data, utilizing econometric modelling techniques using time-series back to 1990. Policy measures are taken into consideration at each stage of this process.

In terms of data sources and historical data, we mainly reference the United Nations (UN) for demographic data, the International Monetary Fund (IMF) for economic data, and the International Energy Agency (IEA) for energy and gas demand data. These are cross checked with other international and regional statistical sources, especially for the GECF Countries. For data on gas supply we use an in-house database updated by the GECF Countries and secondary sources, which also plays an important role in the GECF GGM calculations.

The starting year of our projections is 2018. Therefore, all data from 2018 to 2040 in the following analysis is considered to be a part of the GECF forecast, unless otherwise stated.

The core engine of the GECF GGM is the Global Gas Trade Model, which matches gas supply with gas demand for all the countries under consideration. The global gas trade projections in the GECF modelling exercise are derived from three fundamental inputs.

The first input is the gas demand curve for each country/region. Econometric time-series and stock models are based on Eviews 10 software that links with other modelling outputs and a global gas trade model to produce a comprehensive global energy outlook.

The second key input is the available/potential domestic gas supply in each country/region that will define either the call for imports in any specific region or its export capacity, depending on whether the country is an importer or an exporter.

The third, most technical, input is the configuration of the trade network, either in terms of pipelines or shipping routes. Virtually all potential shipping routes are considered, while for the pipeline routes we consider only the main trans-border pipelines between the different trading regions and hubs. Our modelled gas pipeline network is a simplification of the actual physical network, which cannot be reproduced with the same level of detail and granularity as the shipping routes.

These three elements together - demand, supply and infrastructure - shape the projections for global gas trade. The consistency of the trade is always ensured in terms of total traded volumes between each source of supply and corresponding source of demand.



1 Global Economic and Energy Price Prospects



Key findings

- As population growth in the next 23 years will be two-thirds of the 2001-2017 rate, and 500 billion fewer workers will join the labour force, labour productivity will need to increase at over 2.0% per year to sustain a GDP growth of 3.4%.
- Despite productivity advances, global growth will decelerate significantly by 2040, as many countries will not be able to accelerate their economic development using the “Asian economic miracle” model.
- Rapidly growing regions in Southeast Asia and India will remain the engines for the global economy up to the 2040s, despite significant deceleration to around 4.0% by 2040 for Southeast Asia and close to 4.9% for India in PPP terms.
- Chinese and Indian economies will experience difficulties shifting to knowledge-intensive GDP growth in the long-term, as China’s labour force shrinks and India’s stops growing.
- For the developed economies, growth prospects are balanced, as they are already both knowledge-intensive and driven by increasing labour productivity.
- Growth deceleration is expected in Eurasian economies under the compounded pressure of demographic, energy and geopolitical factors.
- Better prospects for growth are expected in Latin American economies, as the labour force grows and most proposed institutional and structural policies are implemented.
- Long-term oil prices will reflect the falling costs of extraction for new tight oil projects, which are expected to decrease to \$70/bbl.
- Asian natural gas prices will increase in the long-term, fuelled by increasing demand, a policy push for air quality and expanding infrastructure.
- European natural gas prices will experience strong price pressure in the long-term, as carbon mitigation policies and global gas market integration increase competition between European and Asian consumers.
- The launch of carbon trading schemes in many countries is expected to provide significant support to the competitiveness of natural gas versus coal in the long- term.

This section describes the key macroeconomic assumptions behind the 2018 Global Gas Outlook (GGO). Key assumptions include quantitative assumptions such as population and urbanisation trends, economic prospects, the outlook for the size and structure of the global car fleet as well as projections for natural gas, oil, and coal prices. Qualitative assumptions include technological development, the geopolitical situation and general economic policy. Energy and environment policy assumptions are covered in a separate chapter.

The assumptions of this Outlook are based on benchmark United Nations (UN) forecasts for population and urbanisation. The long-term macroeconomic, vehicle fleet and reference price projections have been developed in-house by the GECF Secretariat. Neither the qualitative or quantitative assumptions necessarily reflect the views of individual GECF Members.

Main energy demand drivers were strong in 2017 and 2018, although rising geopolitical risks have decreased security both for supply and demand in the short- and medium-term. After achieving its fastest growth in seven years in 2017, the global economy kept pumping on all cylinders this year. Growth is poised to hold the record for 2018-2019, as the global economy accelerates to 3.7%, the fastest seen since the post-Great Recession recovery in 2011. This growth is broad-based, as the strongest global trade recovery in eight years has helped to spread growth benefits among developing economies.

The financial risks both for developed and developing countries are at their lowest, and government debt levels are being brought to a sustainable level. Along with strong growth, there are some signs of overheating, but central banks have already started reacting by increasing interest rates in the US and by tapering the quantitative easing program in the Euro zone and Japan.

Although the global economy appears to be in good shape for growth, risks are heightening. For the first time in decades, these risks stem mainly from geopolitical trends. Tensions outlined in the 2017 GGO, have not subsided, but instead appear to be increasing both globally and in several key areas. Global trade and investment risks increased when the US began to introduce trade barriers on the largest scale since World War II. Geopolitical tensions in Southeast Asia and the Middle East also escalated in 2017-2018, increasing risks to the security of energy supply. In Europe, the "hard Brexit" for the UK remains a possibility as the EU and UK parliaments may fail to agree on the deal.

There are background macroeconomic risks for the growth outlook as well. In the medium-term, growth in emerging markets will be put under pressure from tighter monetary policy and deceleration in the US, the test of EU budget and banking supervision put up by the Italian government, as well as increasing concerns about the mountain of local debt in China. However, compared to the situation in the past, the policies and the economies themselves are much better poised to avoid these risks.

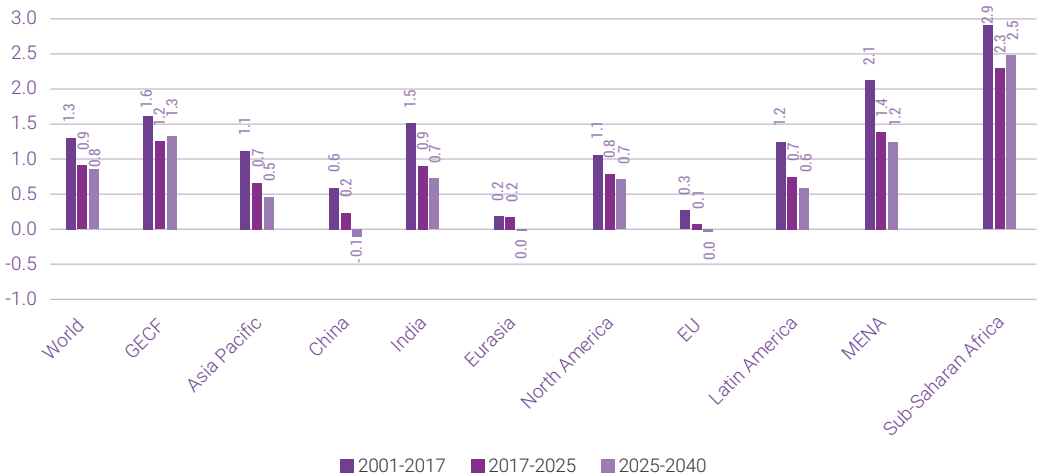
The longer-term trends for the Outlook period remain unchanged from the last edition, with an average annual growth rate for GDP of 3.4%. The most important difference this year is the size of electric vehicle fleets which have been revised upwards, as climate policy challenges (1) put increasing pressure on carbon emitters and batteries become more affordable. However, if the geopolitical situation escalates, this will also impact longer-term perspectives.

1.1 Population growth and urbanisation

Population growth is the main driver of future energy trends. This Outlook is based on the projections outlined in the UN World Population Prospects Revision 2017 (2), medium fertility scenario, which sees the global population rising from 7.5 billion in 2017 to 9.2 billion by 2040.

Most population growth will take place in regions with the lowest energy access and almost no infrastructure, which could provide important potential for promoting natural gas demand in the future. Of this 1.7 bn increase, Sub-Saharan Africa is expected to provide 0.7 bn, and another 0.5 bn will come from Asia Pacific, with India alone accounting for 260 million, almost the size of the current US population. Population growth will slow over the projection period (see Figure 1.1), moving from 1.3% p.a. growth between 2000 and 2017 to 0.9% p.a. from 2018 to 2040, in line with trends seen over the last three decades. The fastest growth will be experienced in Sub-Saharan Africa, with 2.4% p.a., followed by the Middle East and North Africa (MENA), with 1.3% p.a. As the GECF comprises ten Members from the Middle East and Africa, the combined population of GECF countries is expected to grow strongly at a rate of 1.3%, amounting to over 1 bn by 2040.

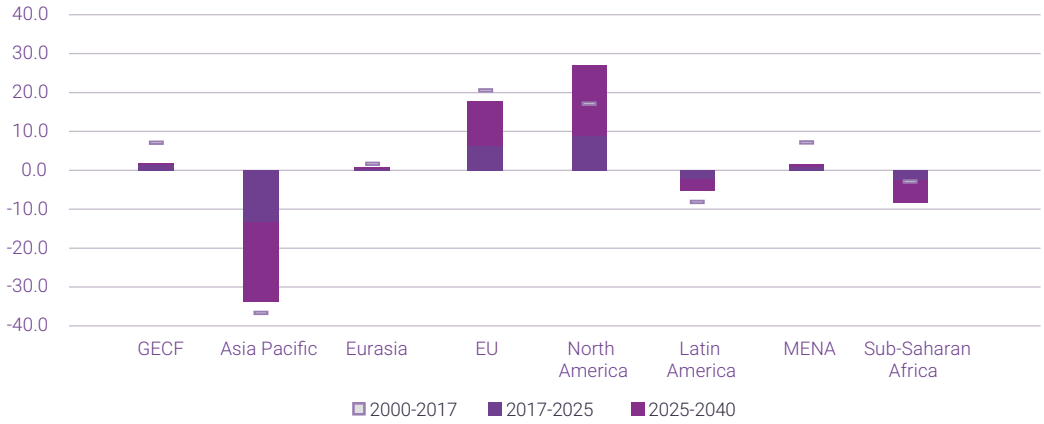
Figure 1.1. Population growth rates (%)



Source: UN World Population Prospects rev. 2017

Migration is expected to be the main driver of population growth in several regions over the projection period (see Figure 1.2). Overall, net migration flows will contribute significantly to population growth in North America (5% of 2040 population) and the EU (4% of 2040 population). While these figures underestimate the size of migration (not including intraregional migration, such as over the Mexico-US border), the main trend continues to be from developing to developed countries. As migration supports population growth in these regions, this trend means corresponding energy demand will decline less. In donor countries, the difference between migration outflows and the energy demand added by migrants is probably negligible.

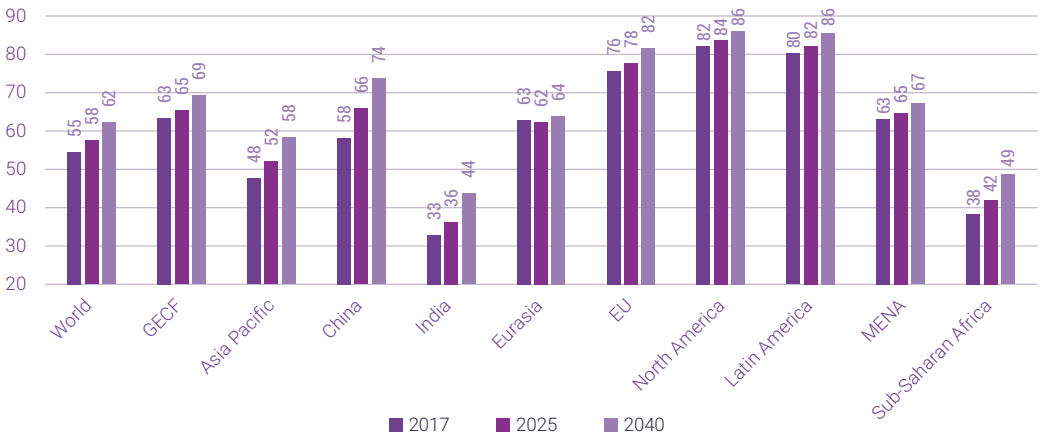
Figure 1.2. Migration flows 2017 vs. 2040 (million)



Source: UN World Population Prospects rev. 2017

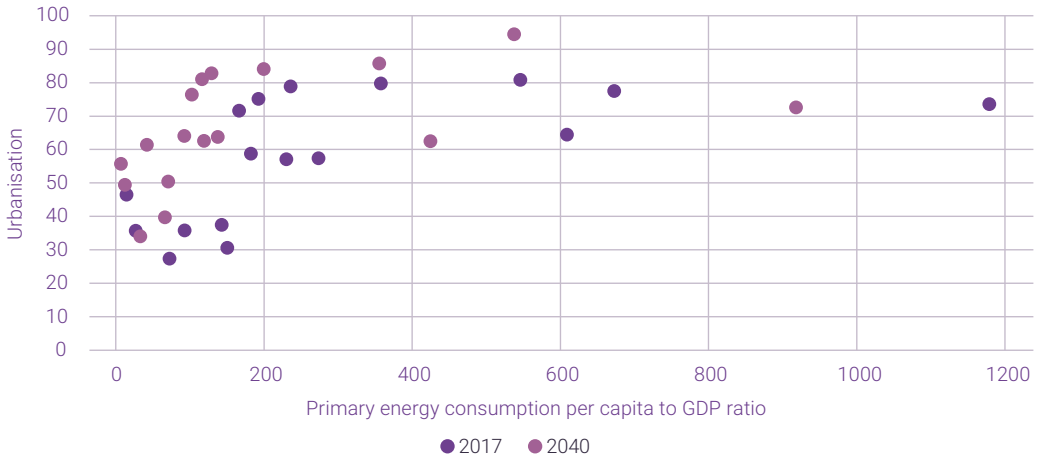
Urbanisation prospects used by this Outlook are based on UN World Urbanisation Prospects, Edition 2018 (3). As the push towards global urbanisation is strong (see Figure 1.3), almost all the 1.7 bn population increase is expected to add to the urban population, with rural populations staying flat. The rapid pace of urbanisation is expected to transform rural societies in Sub-Saharan Africa (39% urban population) and developing Asia (with China still at 58% and India at just 34% urban population). This will lead to an 8% increase in world urbanisation levels to 62% by 2040, although this barely reaches the current urbanisation level of the GECF countries.

Figure 1.3. Share of urban population (%)



Source: UN World Urbanization Prospects rev. 2018

Figure 1.4. Urbanisation (%) vs. primary energy consumption per capita to GDP ratio (toe per thousand population per thousand 2017\$)

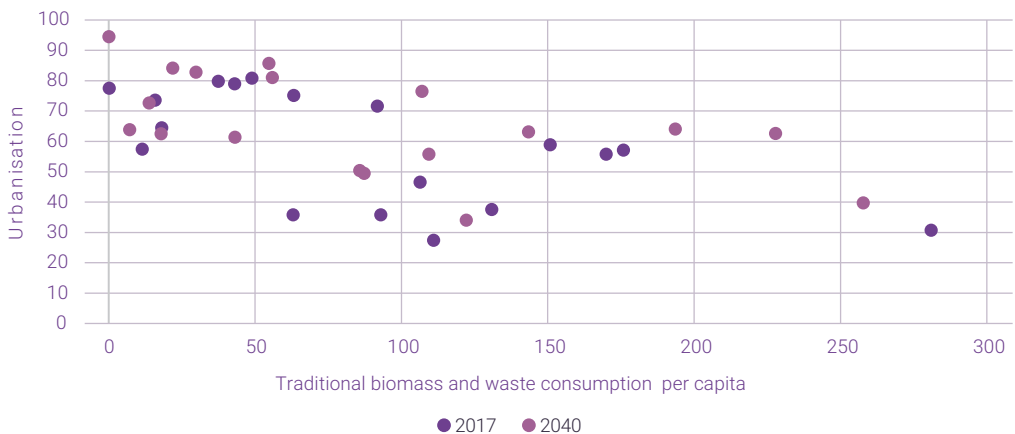


Source: UN World Urbanization Prospects rev. 2018 and GECF Secretariat based on data from the GECF GGM

Urban energy consumption patterns differ from rural ones, and this affects energy demand. Figure 1.4 illustrates the trends of increasing per capita consumption for countries with higher urbanisation levels.

In addition, access to gas, heating and power networks is much higher in cities, thus decreasing the need to use diesel or traditional biomass in the domestic sector. Figure 1.5 indicates that after a level of 65% urbanisation has been reached, the use of traditional biomass per capita decreases dramatically, with very low traditional biomass use after 80% urbanisation is reached.

Figure 1.5. Urbanisation (%) vs. traditional biomass and waste consumption per capita (toe)



Source: GECF Secretariat based on data from the GECF GGM

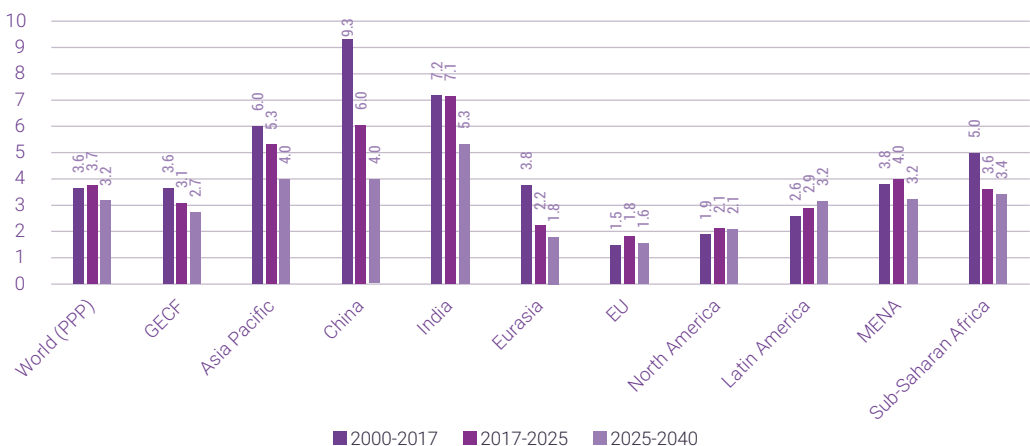
1.2 Economic projections

Overall, the global economy is still expected to grow at 3.4% on average for 2017-2040. This growth will be concentrated in the power-hungry developing Asian market, with China growing by 4.7% on average and India at an average of 5.9% over the Outlook horizon. With developed economies following a stable growth trend of 1.9%, and developing economies poised to grow by 4.3%, long-term global economic growth is expected to be broad-based and stable, while medium-term growth will follow cyclical patterns. For 2017-2025, the global economy is forecast to grow at a more modest pace of 2.8% as Eurasia, Southeast Asia and the Americas are expected to experience below average growth. For the current edition of the Outlook, there are several important developments in the global economy that have been taken into account.

First and foremost, the new trade policy of US government is a downside risk for global growth, and it is already impacting the long-term expectations of investors. The downside of this impact is unclear, as there is no indication from the US on how much trade tensions could escalate. This unpredictability itself is one of the main risk factors for the long-term. Secondly, the growth of the Indian economy is estimated to be less than previously forecast, as previous and current years have not seen any progress on structural reforms after the semi-successful tax reform last year. Thirdly, in Europe the risks of a “hard Brexit” rose significantly in 2018 as the UK government and the EU were together unable to develop any meaningful solutions to their current impasse at the time of writing. This is reflected in the outlook for the EU.

However, all things considered, these developments will not affect aggregate global growth, as the outlook for non-UK Europe remains strong, as it is for global trade which will help spread growth more evenly to developing countries, especially in Sub-Saharan Africa and Southeast Asia.

Figure 1.6. Projected GDP growth rates (%)



Source: GECF Secretariat based on data from the GECF GGM

The GECF economies are expected to grow strongly both in the medium-term (benefiting from a lasting rebound in the energy markets) and in the long-term based on strong labour force inflows, provided that enough investment is devoted to human capital (see Figure 1.6).

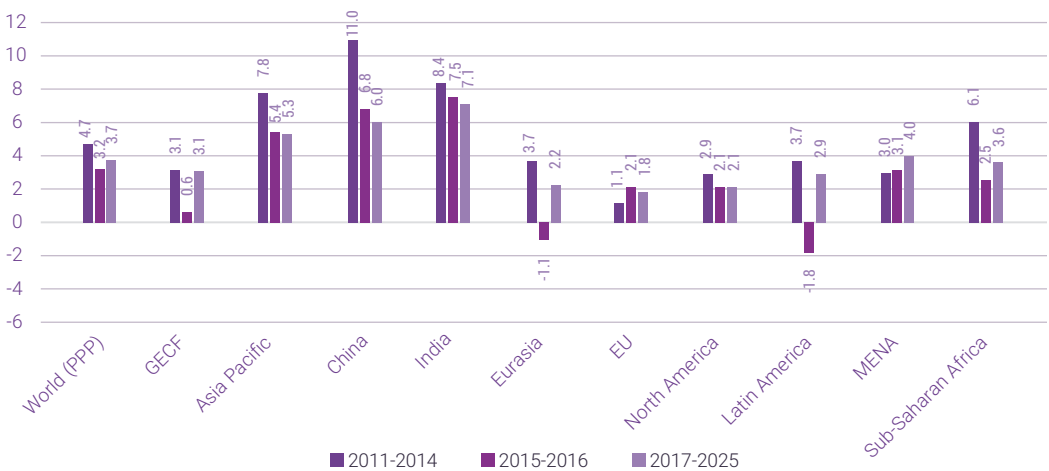
1.2.1 Short- and medium-term global economic prospects: 2017-2025

The near-term prospects for the global economy appear bright, as the increasing geopolitical risks are not expected to stifle global economic growth until after 2020. The medium-term outlook is more clouded, however, as the deceleration in growth in the US, Japan, China and India is expected to outweigh recovery in Eurasia and Latin American regions.

For a few notable exceptions (such as the US), the global macroeconomic risks are low in the medium-term, allowing for a higher and more stable global GDP growth rate (see Figure 1.7). Mounting geopolitical and structural challenges, however, could impact the outlook post-2020.

The risks of further sharp rises in US interest rates to curb inflation stoked by the Trump administration's late-cycle tax cuts and subsequent 'overheating' of the economy, could have dire consequences for developing countries with large dollar denominated debt. Additionally, the challenge between Italy, which is pursuing a budget in defiance of EU policy, and Brussels may destabilise the Eurozone banking system.

Figure 1.7. Short- and medium-term global economic prospects (%)



Source: GECF Secretariat based on data from the GECF GGM

1.2.2 Regional economic growth prospects for the medium-term

Developed economies

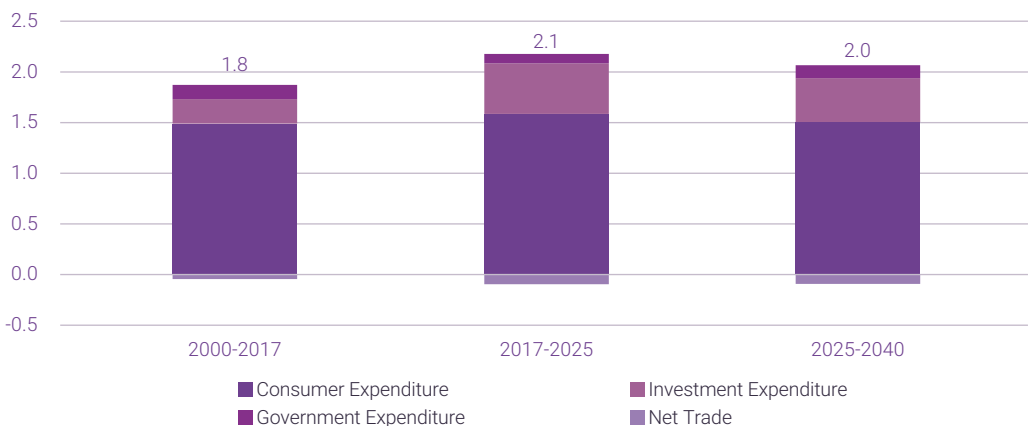
United States

The US economy logged strong performance in 2016-2018 and this will continue in the short-term, only to be replaced by deceleration in the medium-term as the tax reform and budget stimuli fade. Growth in 2017 was strong as a result of strong domestic demand and a balanced position on external trade. The global trade upswing, energy price recovery, tax reform and expectations of a business-friendly regulatory environment boosted investment in 2017. Investment in equipment grew to a three-year high and goods exports received a sizeable boost starting mid-2016.

Core inflation reached above 2.5% and is now back to a healthy level, assuming that monetary policy normalisation continues. While this will impact the credit market, no credit restrictions have been observed for the private sector. Recent stress tests indicate that banks are properly capitalized and that there is no significant non-performing loan build-up (non-performing assets accounted for 2.2% of assets in mid-2018, corresponding to a 10-year low). Furthermore, risks appear to be well-balanced by the moderate pace of interest rate increases. So far, the US Federal Reserve is on course to achieve its plan to have a mid-corridor rate of 2.25% in 2018, 3.10% in 2019 and 2.90% in 2020.

For the last ten years the labour market in the US has featured a low (sub-63%) labour force participation rate (LFPR), coupled with rising temporary employment and decreasing unemployment that averaged 4.3% in 2017. In 2018 the unemployment rate has already edged below 4%, indicating an overheated economy. However, the LFPR has stayed below 63%, close to a 10-year minimum, indicating significant but latent slack in the labour market. Recent signs indicate that more people could join the labour force as the economy reacts to the increase in labour demand.

Figure 1.8. Outlook for the GDP growth structure of the US (p.p. per annum)



Source: GECF Secretariat based on data from the GECF GGM

The budget policy in the US from 2013 to 2016 was contractionary after the 2012 tax increases and budget cuts in 2011 and 2013. On the heels of a budgetary impulse determined by the impact of tax reforms, extra growth in 2017-2018 amounting to 0.3 percentage points (p.p.) will likely fade by 2020 as the budget is tightened.

In the medium-term, the prospects for the US economy are lacklustre as at least three major factors will stall growth. Firstly, there is the trade tension which is shaping prospects for US exports. While public discussion is more centred on tariff increases for trade with China (8.4% of US exports in 2017), it is the tensions with European (18.4% of US exports) and NAFTA partner countries (34.0% of US exports) which might actually prove more harmful for trade and investment. While there has been a new US-Canada-Mexico deal announcement, it is still unclear when and whether the deal will be finalized, and whether it will comprise the same terms of trade as NAFTA.

Secondly, there is a risk of cyclical growth correction after the overheating. There have been quite a few signs that the US economy is starting to overheat. These include the lowest unemployment for a decade, rising core inflation, benign credit conditions and a boom in fixed investment. It is unclear if there is aggregate supply slack that can be scooped up by the growing demand. However, the cyclical indicators (as well as most forecasts) suggest that by around 2020, US growth will decelerate from its current 2.2% to 1.6-1.7% as inflation increases and tighter monetary policy cools growth down.

Thirdly, there is a risk posed by dollar appreciation and deceleration in emerging economies. For the last five years, as quantitative easing was tapered and monetary policy normalised, the US dollar strengthened by 20% in real terms, undercutting the price competitiveness of US exports. As interest rates rise, this trend will continue, attracting more goods but also capital from emerging markets. While this trend will amplify overheating in the US financial markets, it will impact US growth even more.

European Union

The European economy is growing at its strongest pace since the Great Recession, with a record 2.4% growth in 2017 alone, the fastest in a decade. This compares to -0.1% in 2009-2013, and 2.0% in 2014-2016. Growth from 2018 to 2020 is expected to remain at the same level, while a slight deceleration is expected after 2020. In terms of growth structure, exports and fixed investment accelerated in the EU from 2014, and consumption (both public and private) picked up a year later. The record growth in 2017 was caused by a strong pickup in net trade, with both accelerating exports (+2.3 p.p. of GDP growth) and slightly decelerating imports (-1.9 p.p. of GDP growth) contributing to the increase.

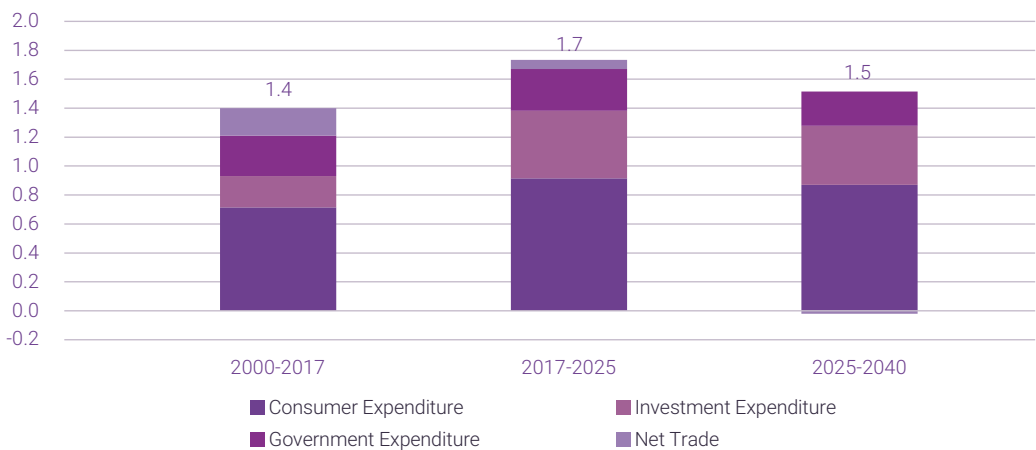
Inflation is at 1.6% and it appears to be back on track in 2017 after slowing down almost to zero in 2013-2016. The price outlook is moderate, with the inflation in 2018-2020 still predicted lower than the European Central Bank's (ECB) target of 2%, but gradually increasing in the medium-term.

Quantitative easing programs, specifically the Public Sector Purchase Programme or PSPP, of the ECB impacted credit and investment growth from the second half of 2016. Loans to non-financial sectors increased by 1.2% annually (data is only available for the euro area) in 2016-2017, compared to the lack of growth during the European debt crisis of 2010-2013 and its aftermath in 2014-2015. In response, the ECB has currently tapered the program from Eur 60 billion to Eur 30 billion per month, and has plans to halve that by the year's end.

The EU labour market has normalised as well. The unemployment rate was down to 7.6% in 2017, below the 8.0% observed in the 2000s. In the medium-term it is set to further decrease as a result of structural factors, such as better employment flexibility via deregulation, increasing labour mobility, better education and training quality, and macroeconomic factors: economic growth will sustain labour demand in the EU as a whole. Structural improvement means that even after the European economy slows down after 2020, the unemployment rate will be more resilient than before.

At a national level, Spain, Greece and Italy (the economies that were in the centre of the European debt crisis of 2010-2013) returned to growth in 2017. The “core” economies of France, Germany and the Netherlands also accelerated the pace of their growth despite political uncertainty (Germany and the Netherlands had prolonged government formation processes in 2017). Budget risks are very low for the short-term, but in the medium-term, the comprehensive integration of the “Budget Compact” with the Stability and Growth pact is already meeting internal political opposition. As an example, the recent standoff on the Stability and Growth Pact mechanisms between the European Commission and Italian government is increasing the risks for the euro area growth. This will be compounded by ECB rates that are set to increase after 2020, driving up the cost of government debt.

Figure 1.9. Outlook for the GDP growth structure of the EU (p.p. per annum)



Source: GECF Secretariat based on data from the GECF GGM

From a structural perspective, EU countries are expecting medium-term growth in the next decades. Over the last few years, progress in budget and banking supervision, labour market reforms, competition and privatization has been remarkable, as noted by the increases in the region's World Economic Forum (WEF) competitiveness rankings for the last three years. Out of the twelve pillars of competitiveness noted by the Forum, the EU countries on average logged a significant increase in their global ranking in four pillars during 2015-2018, specifically those related to institutions, macroeconomic environment, higher education and training, and financial market development. Real labour costs are down 2% compared to 2013 levels, and the decrease is widespread, covering 25 out of 27 countries. They are also down about 5% relative to the OECD average, making the EU an attractive destination for investment among developed countries.

Japan

In 2017 the Japanese economy grew at its highest rate for five years, as favourable external conditions boosted net trade along with aggressive monetary and budgetary stimuli, as well as recovery in residential investment. From 2018 to 2025, growth is expected to slow down to less than 1.0% p.a. on average, as the virtuous cycle of exports and business investment is expected to be undermined by an increase in VAT on household consumption.

Demographic factors, anaemic income growth and the planned VAT hike from 8% to 10% in October 2019 will dampen medium-term growth in household consumption. While consumption growth in 2018-2019 will stay moderate, reaction to the VAT hike is expected to take out over 1 p.p. from household consumption, thus a decline in household consumption after 2019 is expected. This could change if the VAT hike is suspended, but it is unlikely that a temporary suspension, even if it happened, would prevent a VAT hike beyond 2022.

While the boost to residential investment in 2017 will likely prove temporary, non-residential investment is back on track and is set to grow in the range of 2.5-3.0% in the medium-term. Following favourable global trade growth, the Japanese corporate sector is projected to boost investment growth.

In the medium-term, labour-saving investments will likely be prioritized, along with gradually increasing investment in research and development (R&D) projects. For 2018-2025, numerous investment projects in artificial intelligence (AI) and research into the Internet of Things (IoT) are expected to make a positive contribution to overall investment in private business equipment.

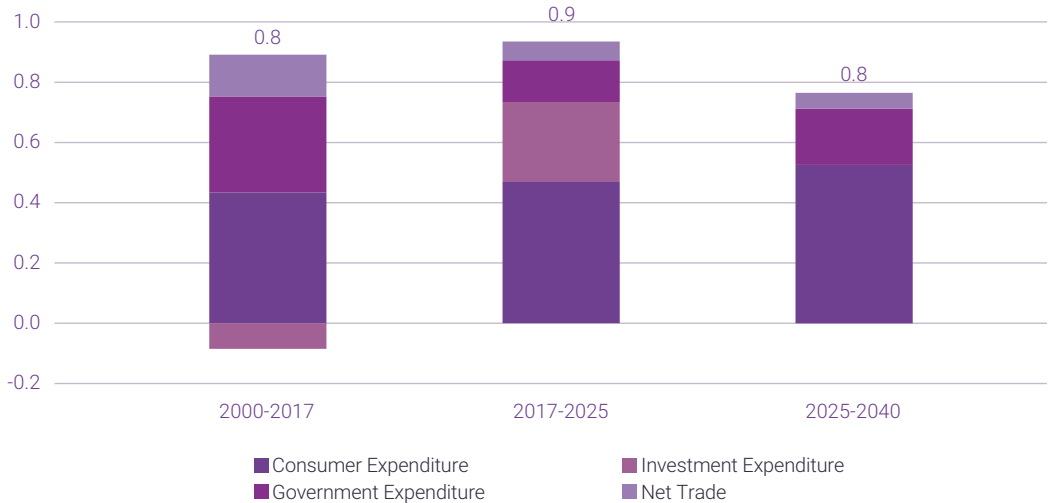
The “Abenomics” policy of 2012-2018 has been instrumental in both stimulating economic activity and putting an end to the well-known phenomenon of Japanese deflation. However, it had very limited success in bringing about real credit growth, budget or structural reforms.

The Bank of Japan is tapering its ambitious 100 trillion (tn) Japanese yen (JPY) asset purchase program from 2017, and will likely purchase only around 25 tn JPY assets in 2018. Private credit growth has not emerged, as the main focus was on government debt and not private debt (the Bank of Japan now owns about 40% of the government debt), and short- and medium-term interest rates have been kept negative.

Three challenges for the Japanese economy remain in the medium-term. Firstly, as far as demographics are concerned, from 2018 to 2025 the number of employees is projected to decrease by 2 million, or by 0.3% per year. The labour productivity trend will offset this decrease, but the resulting wage pressure will likely take a significant chunk out of corporate incomes, thus decreasing investment potential. Secondly, the budget policy will remain restrictive, and the government has not ruled out further VAT rate hikes to 15%. Thirdly, the external sector might be one of the first to feel the escalation of global trade and investment tensions, as Japan’s current account depends crucially on global corporate incomes flowing back to the country.

While struggling with those challenges, the Japanese economy will decelerate from the 1.2% growth observed in 2013-2017 to a more modest 0.9% pace, with depressed household consumption growth and more modest growth in fixed investment.

Figure 1.10. Outlook for the GDP growth structure of Japan (p.p. per annum)



Source: GECF Secretariat based on data from the GECF GGM

Developing and transition economies

Brazil

The economy of Brazil is on track to a slow recovery after the long recession of 2014-2016, with GDP growth of 1.0% in 2017 registering the first expansion since 2014. Private consumption has stabilized, while investment hit its nadir in 2018, and is now back on an upwards growth trend. On the one hand, ongoing budget consolidation will slow down the recovery, but on the other, a healthy financial sector will boost growth. In the short-term, the Brazilian economy is expected to grow 2.1% in 2018 and 3.9% in 2019.

The recession of 2014-2016 started after the World Cup, and was driven by soured construction credit and investment, as well as cyclical overheating. As construction volumes contracted sharply in the overheated economy from the second half of 2014, so did investment and household consumption. By 2016, the investment to GDP ratio was down to 15.3% (from 21.7% in 2013, the peak of World Cup construction). During 2014-2015, it followed an L-shaped dynamic with across-the-board contraction of most economic indicators.

The government enacted a countercyclical spending policy from 2015 that quickly led to an explosion of debt, whereby general government net debt increased from 32.5% in 2014 to 46.2% of GDP in 2017, with gross debt reaching 80% of GDP. As a measure to balance the budget, a new fiscal rule in December 2016 fixed the real level of government expenditures. However, at this level of government expenditure and persistently high interest rates, the debt to GDP ratio is poised to become unsustainable shortly after 2020. Thus, additional consolidation effort is needed to bring the debt to GDP ratio under control and avoid budget crises.

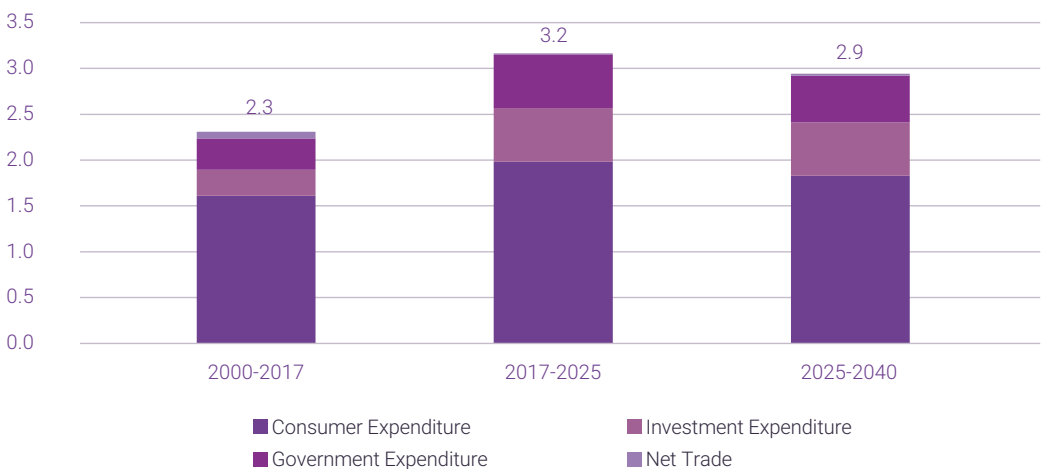
Net trade was rebalanced after the sharp correction seen in 2014-2016, when imports contracted by 7.5% p.a. on average, while exports advanced at 3.7% p.a. over the same period. Together with depreciation of the national currency of over 60% in 2015, the current account deficit was 0.5% of GDP in 2017, a 10-year minimum.

In the medium-term, the recovery will gain pace after 2020, led by investment, especially in infrastructure. The Brazilian financial sector has reaped the benefit of the highest interest rates among emerging markets, and with higher margins and interest rates, Brazilian banks do not need significant capital injections, meaning claims on the private sector were down 3.9% in 2016-2017 alone. With inflation and current account balances back under control, credit interest rate decreases after the central bank rate fell in August to 6.5% from a peak of 14.25% in September 2016 will likely stimulate investment growth.

The policy challenges to accelerate long-term growth remain for the medium-term. The labour market reform brought about some additional flexibility and stimuli to decrease employment in the informal economy, but there is still uncertainty concerning pension reforms and privatization perspectives, as well as macroprudential reform for the banking system. Improvements in efficiency of public infrastructure investment are also important, as demonstrated by the post-World Cup experience. There is also a strong institutional challenge to provide for public order and reduce crime rates.

After getting back on track after the 2014-2016 recession, the acceleration of GDP is expected to moderate after a short-term rebound. Brazilian GDP is expected to grow by 3.2% on average for 2017-2025 compared to the average change in 2013-17 of -0.7%.

Figure 1.11. Outlook for the GDP growth structure of Brazil (p.p. per annum)



Source: GECF Secretariat based on data from the GECF GGM

China

China's economy is undergoing a deep transformation as economic development along the lines of the labour-intensive "Asian economic miracle" is being replaced by a different kind of growth mechanism. To sustain economic and social stability while transforming the economy to one based on higher value-added sectors is a challenging task, and in the recent years some of the risks of this shift have materialised.

In 2017, the Chinese economy gained pace on the back of the recovery in global trade as GDP increased 6.9% after registering 6.7% in 2016. Net trade propped growth up, even as fixed investment growth slowed to 4.3% from 6.8% following the government's decision to taper the credit stimulus of 2013-2016 (banking assets grew by 8% compared to 16% in 2016). This credit tapering together with a decrease in new wage earners affected household consumption as well, with a decline in growth to 7.6% from 8.6% in the previous year. Net trade made a positive 0.6 p.p. GDP growth contribution for the first time in three years even as the yuan strengthened during the second half of the year. While net trade was the only driver of GDP growth acceleration in 2017, it is unlikely to sustain growth even in the short-term, given the recent mutual introduction of tariffs imposed by the US and China.

The government declared in October 2017 that the quality of economic and social development – namely, the elimination of pollution, reduction of poverty and financial stability – should supersede any GDP growth targets. The 5-year plan adopted in 2016 declared poverty and the elimination of pollution to be obligatory targets for 2020, while the establishment of an innovation-driven economy is the primary aim for economic development and policies. Thus, the Chinese economy has entered a new stage of structural transformation, which means that growth will be lower but more stable, and consumer demand, R&D investment and international income inflows will play a larger role. While those targets are very ambitious, it is worth mentioning that the size and scope of structural reforms implemented in 2013-2017 together with those planned for implementation in the medium-term, are of a similar scale to those of Deng Xiaoping's market socialism reforms started forty years ago.

In the corporate sector, there has been significant product and energy market liberalization, and an industry and science program called "Made in China 2025" has been introduced, which put export promotion, technological development and industrial policy into a single framework. There has also been the global expansion of Chinese businesses, backed by state money, into both developed and developing markets, targeting both consumers (as with Alibaba), technologies (Huawei and ZTE) and energy (CNPC). The integration into the global intellectual property rights system, both in terms of the registration of patents and protection on the domestic market, has also been considerable.

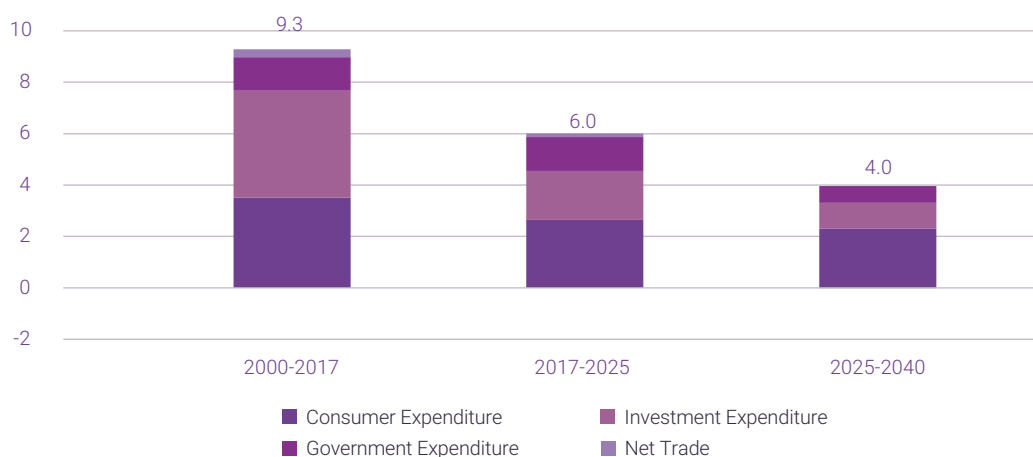
These processes are expected to continue, with most challenges stemming from restructuring the state-owned enterprise sector. For the capital markets and the external sector, it is expected that by 2025 China will have no capital controls in place (banking supervision will be implemented according to the Basel III macroprudential framework, while debt and capital markets will be open to international investors and comprehensively liberalized). There has already been significant progress on capital account regulation, financial oversight in banking and open markets, and monetary policy implementation. However, in the medium-term the challenge for the financial system will be to safely digest the issue of non-performing loans, further implement regulation to address shadow or unregulated banking issues, and ensure that the yuan can float without any damage to the non-financial sector.

Where the labour market and social stability are concerned, a universal pension system has already been introduced (although the benefits are regional), in addition to ongoing reforms of the healthcare, education and science systems, as well as the elimination of the “one family, one child” policy back in 2015. Ongoing measures for poverty elimination will also target the differences in geographic development as the north-eastern, central and western provinces still lag far behind the more prosperous east and south-east.

In the medium-term, the most important challenge for China is the economic development needed to secure its position in the global market with higher added value and R&D content. This needs to happen as cost competitiveness in lower added-value markets is decreasing even as wages are climbing. A second challenge is to secure its role in the global financial system. As China moves forward with the global integration of its financial markets, the risks of balance of payments crises are exacerbated by the opening up of financial accounts.

The medium-term growth rate of the Chinese economy will go down from 7.1% on average in 2013-2017 to 6.0% on average in 2017-2025, and by 2025 GDP growth will slow further to 5.5%. This deceleration will come about as investment contributions decline and household consumption becomes the main driver of GDP growth.

Figure 1.12. Outlook for the GDP growth structure of China (p.p. per annum)



Source: GECF Secretariat based on data from the GECF GGM

India

The Indian economy has been through several major economic reforms in the last few years, including the introduction of a goods and services tax (GST) and demonetization in 2017. Although planned and implemented reforms (like the bankruptcy code overhaul) have been designed to generate higher long-term GDP growth, in the medium-term they will likely stifle growth. In 2017, the Indian economy dipped to 6.7% growth after the acceleration which had been fostered by cheap energy in 2016-2017 stalled, following structural reforms which increased policy uncertainty and compounded the ongoing investment deceleration. Falling investment has been an important deceleration driver in the last five years, with the ratio of investment to GDP decreasing from 35.3% in 2003-2012 to 32.4% in 2013-2017. Excluding the effect of structural policies, it is expected to wind down further as the domestic savings rate goes down and external financing pressures mount.

Despite this, the fundamentals indicate that the economy will bounce back into a growth zone of 7.0% or more in the short-term (2018-2019), as consumption and investment growth are expected to be robust and a boost in global trade will provide additional export growth.

Price deceleration hit a 17-year low in 2017, with an inflation rate of 3.6%, but in the short-term inflation will likely accelerate to around 5%. However, inflation expectations remain anchored high, as a result of a significant share of food in the consumer basket and persistently high inflation in previous years. It is likely that this will lead to increased policy intervention by the Reserve Bank of India (RBI) to keep inflation within a declared 2-6% corridor in the medium-term. Also, rising oil prices will put medium-term pressure both on prices and the net trade.

Export growth in goods and services was anaemic, registering 3.3% per annum in 2013-2017 compared to an average of 12.7% per annum for 2001-2012. Import deceleration has been considerable and foreign income flows into India have been limited despite strong global integration into the services sector. There was some recovery in exports of goods and services during 2016-2017, and recovery in net trade is expected to boost growth in the medium-term. While the rupee depreciation in 2018 is expected to be limited as exports recover, the commitment of the RBI to increasing exchange rate flexibility will likely lead to a gradual depreciation in the rupee in the longer-term.

There are three important challenges in the medium-term. The first is to implement existing reforms and to launch new ones, including the challenge to the judicial system with a new nine-month bankruptcy code, the introduction of universal national health insurance, and improvement of tax collection. This needs to be done while keeping the social consensus and in a manner that does not severely impact growth, as happened with the demonetization reform.

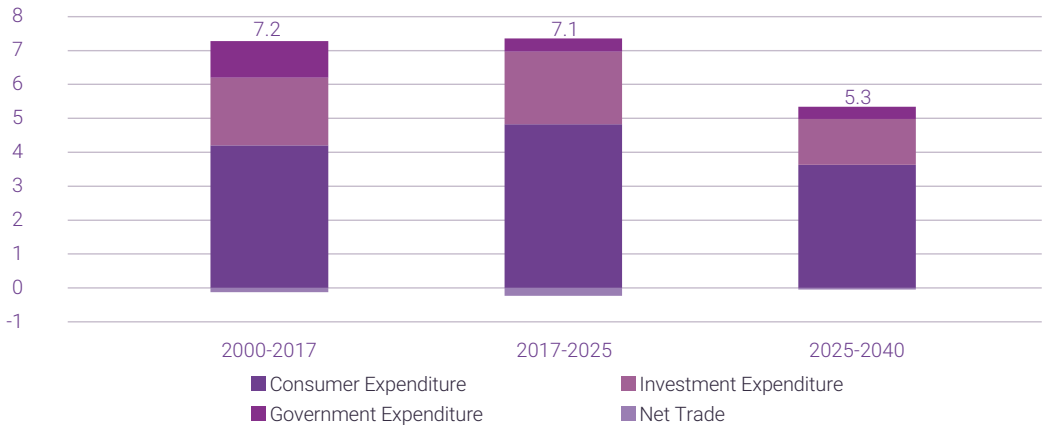
The second challenge is to deal with the issue of non-performing loans in the Indian banking system which currently stand at almost 15% of assets. The increase in bad debt was boosted by the new bank provisioning rules from the RBI which were enacted in the summer of 2017. Those rules, together with the bankruptcy code overhaul of 2016, are expected to clean up the banking system in the long-term. It should be noted that most of the bad loans (over 80%) are on the balance sheets of state banks and were accumulated as a result of state-directed lending. Thus, the planned clean-up will likely involve the write-off of bad debt, state capital injections, a new wave of investment into state-directed projects, and consequently a new boost to inflation. While this will accelerate growth in the medium-term, keeping inflation under control will be a challenge.

The third challenge is the extreme poverty which prevails in the country. With 21.2% of the population having income levels of less than \$1.9 a day (measured in 2011) and 14.5% of the population undernourished, over 250 million people probably do not impact domestic demand whatsoever. Therefore most measures aimed at poverty reduction will likely increase household consumption with a visible short-term effect on GDP. The elimination of geographical disparity is also expected to support the growth of the Indian economy. As of 2015, people in three states – Goa, Delhi and Sikkim – earned three times the average Indian income per capita, and those in another ten states received twice the average Indian income per capita.

While these challenges are being addressed, the medium-term growth rates of the Indian economy in 2018-2025 will remain steady at 7.1% on average, the same as seen in 2013-2017, and by 2025, GDP growth will slow down to 6.5%.

The success of structural reforms will determine longer-term growth rates, as with current trends India is poised to decelerate to well below 5.0% by 2040.

Figure 1.13. Outlook for the GDP growth structure of India (p.p. per annum)



Source: GECF Secretariat based on data from the GECF GGM

Russia

Thanks to a booming oil market in 2017, the Russian economy has emerged from the recession of 2015-2016 into a subdued growth path, with GDP increasing by 1.5% in 2017 (the highest rate since 2014) and set to grow by the same amount in 2018. The growth in 2017 was dampened by a restrictive fiscal and monetary policy, conducted with the objective of keeping the economy resilient to external shocks.

Overall, the Russian economy has slowly crawled out of the recession caused by the post-2014 oil price adjustment. However, the quarterly growth rate has been uneven and volatile, and strongly dependent on export markets. The recovery was helped by a historically low inflation rates of 3.6% in 2017, and inflation is projected to fall further to 2.8% in 2018. This price deceleration comes on the heels of a much sharper adjustment: with the average annual inflation rate for 2014-2017 amounting to 8.4%, household demand on average decreased by 1.8% p.a.

While an increase in public service wages by end-2017 supported household consumption in 2018, it is unlikely that over the medium-term households will support GDP growth as seen in 2011-2013. The VAT hike of 2 p.p., from 18% to 20%, which will come into effect in 2019, is expected to boost inflation and impact household spending.

The World Cup provided a temporary boost to consumption during the summer of 2018, but it does not appear to have had a long-lasting effect on the economy, and will not lead to a post-event recession. There was no World Cup-related overheating, unlike that seen after the 2010 World Cup in South Africa or the 2014 World Cup in Brazil. The Russian construction industry was in recession, with volumes decreasing throughout 2015-2017, thus World Cup construction turned out to be countercyclical and supported the industry instead of overheating it.

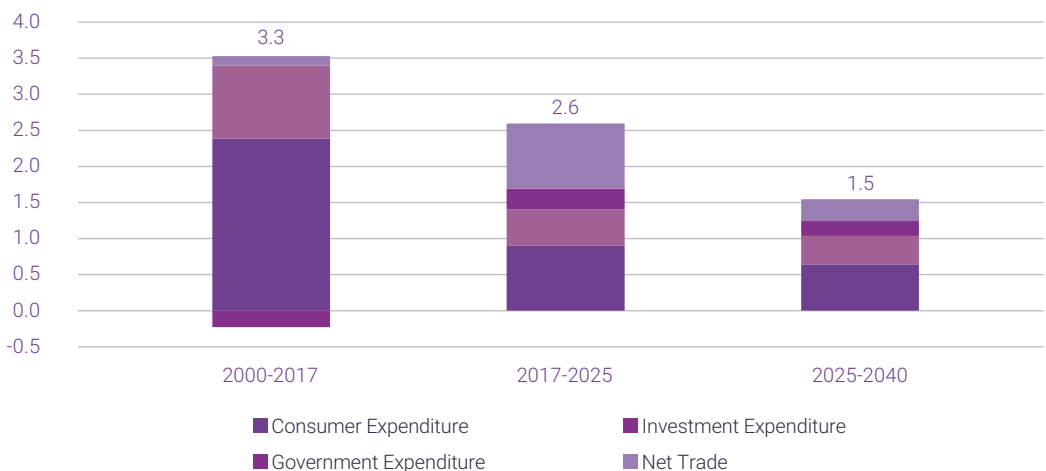
The government is expected to keep a tight lid on spending even though there are more oil and gas revenues pouring into the budget. Monetary policy will remain very tight in the medium-term, with real interest rates of over 3%, and this will keep the brakes on investment projects not supported by the government.

In the medium-term, the recovery of household expenditures after 2020 along with increased investment in infrastructure projects could make growth more dynamic, as investment becomes more attractive in a lower-inflation environment. There are several downside risks, however.

First, there is the risk of stronger sanctions that will require more restrictive policies and could stifle the recovery. Secondly, there are risks associated with the implementation of pension reform from 2019, and associated changes to companies and individuals behaviour – primarily, the extent to which the informal sector will absorb growth and jobs.

Provided that both of these risks are avoided, the Russian economy is projected to accelerate in the medium-term on average from 0.1% in 2013-2017 to 2.7% in 2018-2025, and to increase still further to 3.0% by 2025 as investment and export recovery lead the way even as the conservative economic policy stays in place.

Figure 1.14. Outlook for the GDP growth structure of Russia (p.p. per annum)



Source: GECF Secretariat based on data from the GECF GGM

1.2.3 Long-term global economic prospects and the main structural challenges for the global economy (2025-2040)

The global economy is about ten years into the transition period towards a new global architecture which encompasses geopolitics, technology and energy among its main features. The mechanisms of economic growth and the long-term prospects of individual economies have significantly changed during this period which started with a Great Recession in 2008. The transition is still in progress, and while the new global architecture of economic growth has not yet emerged, some features are already obvious.

Main structural features of the long-term economic scenario

No more “Asian Economic Miracles” in the future

The theory of economic development states that a country should start by building and exporting the most basic things (raw materials, agricultural products, textiles) and subsequently move up the value chain to heavy industry, machinery exports and finally to the export of innovation, finance and professional services in a knowledge-based economy.

These assumptions are built into most authoritative global competitiveness rankings compiled by such organizations as IMD Lausanne and the WEF or instance, the WEF ranking weights three groups of competitiveness indicators differently based on the level of GDP per capita. The prospects of long-term growth change once an economy moves up to the next group, and the policy challenges are also different.

It is important to note that most upcoming technological advances erode this order, making the transition between levels a bigger challenge. Twenty years from now, for example, it will be much harder to base this transition on the wealth accumulated from the export of cost-competitive labour or natural resources to the premium consumer markets.

Automation is already affecting the demand for unskilled, poorly-educated labour. New industrial projects which are moved from Asia to the developed countries already automate a large proportion of unskilled and low-skilled labour. This deprives developing countries from future labour export rent, and thus of future investment and development resources. Existing producers face human-robotics competition that further depresses producer margins and incomes in developing countries. The revolution in 3D-printing will also affect many producers in low-added value manufacturing sectors in developing countries.

Cleaner energy needs and carbon taxes will depress producer margins for coal and oil, decreasing export revenues for several developing nations, including Saudi Arabia, Iran, Iraq, Nigeria, Venezuela, Colombia, Indonesia and South Africa. They will also drive up costs and erode margins for energy-intensive products mostly produced in developing countries.

In the future, for those Asian and African countries which have not yet undergone an “economic miracle” or a windfall from petrodollars, it will be much harder to go down the same development path to achieve an “Asian economic miracle” of their own.

Geopolitics will cast a much longer shadow over economic development

In the new global architecture, economic development and foreign investment in several fast-growing regions will be affected by global and regional security shifts. While this Outlook assumes no global or major regional military conflict will take place in the foreseeable future, we assume geopolitics will influence economic development as global value chains get restructured in line with new geopolitical priorities. This will affect the global economy and energy along three main avenues.

First is the redistribution of global trade flows. There is a conflicting global trade policy agenda from the US, the EU, the UK and China, not to mention several new regional economic unions (like the Eurasian Economic Union, EEU) in the process of integration. There are several likely outcomes of this decade-long, multilateral process of revision of global trade and investment arrangements (many researchers date it from the Doha round of World Trade Organization talks in 2004).

Global trade growth will benefit developing economies less than before, as the value added will be eroded by stricter standards. The instruments are aplenty, including stricter intellectual property, environmental and ethical standards. A wider base for patent royalties, new green taxes and probably even Tobin taxes could also be used. Also, there will be stronger competition for the developed markets, including competition between human labour and robotic automation and increased South-South competition as ASEAN and selected Middle East and African countries emerge as new production hubs.

The governments of large developing economies are already taking steps to protect their domestic markets. This typically takes the form of non-tariff barriers and indirect subsidies to national 'champions', but also the buildup of R&D, innovation systems and human capital. Some of these programs, like 'Made in China 2025', imply building competing value chains at home or within the region, aimed at the global market. This is what is currently happening with the shipbuilding, aerospace and electric vehicles industries in China.

The second consideration is the way that investment and finance flows are being limited for political reasons, which poses the risk of global financial market fragmentation. There is the capacity to limit investment and technology transfer from developed to developing countries by imposing sanctions. These political sanctions are treated as national security measures and are not covered by any trade and investment regulation or international arbitration. This makes it a flexible tool to stifle investment flows and to potentially destabilize the financial system in any particular country. In the long-term, it is likely that sanctions instruments will be used for more countries, and will cover a wider range of sectors. It is also likely that countries (most likely, the EU and the UK) which are able to project financial power will impose sanctions and freeze the assets of certain entities as part of their geopolitical interaction.

The third issue is the increased risk of supply route disruptions, especially for energy supplies. Tensions are already mounting regarding Bab-el-Mandeb and the Hormuz straits, as well as South China Sea shipping routes. The risks for the East European gas corridor are also elevated.

Demographics means yet another growth transition

Over the next twenty three years, population growth will only achieve two-thirds of the rate seen in 2001-2017 rate. This

translates into a fall by a factor of two in the availability of new workers: there was a global inflow of 1 billion employees in 1994-2017, but only 560 million employees are expected to join the global workforce by 2040, most in regions with low productivity.

Labour productivity will have to increase by over 2.0% per year to compensate for this deceleration, amounting to a 62% increase over the period in question (twice the 34% achieved in 1994-2017). Such a growth in productivity has never been observed before.

The labour market in Japan is a case in point. The number of people aged between 15 and 64 in Japan is expected to decrease to 75.3 million by 2040, from 88.8 million in 2017, at a rate of 0.7% p.a. Thus, in the long-term, increasing labour productivity to counter the economic decline will be the most important policy challenge. Compared to 66 million people working in 2018, only 58 million are expected to be in work by 2040, a decrease of 0.5% p.a. In order to sustain economic growth against this backdrop, labour productivity is projected to increase 1.3% p.a. based not only on technological innovations such as robotics, AI and 3D printing, but also on social innovations such as institutional and structural policies, gender equality and flexible work schedules, and virtual offices.

This labour supply challenge will create considerable wage pressures which will need to be solved in a cost-competitive manner. Even after the recent tax code changes, the labour supply could be increased further if older groups and female workers are involved in the labour force.

GDP projections to 2040: main assumptions and results

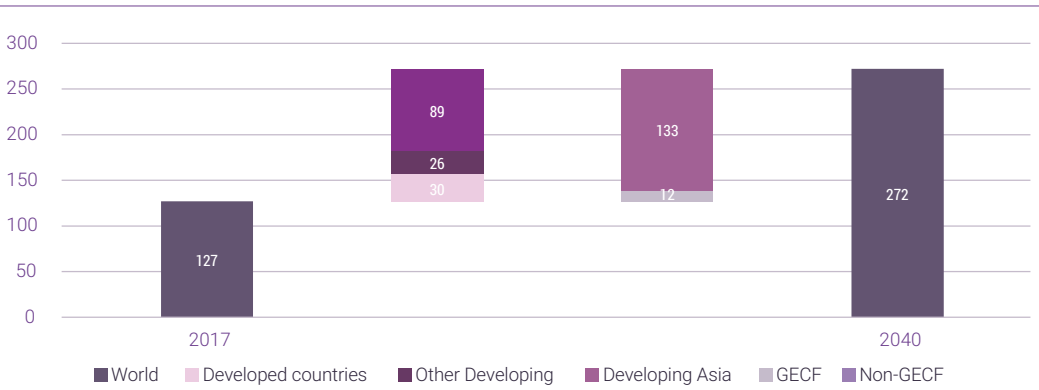
While all these challenges will remain in place for the long-term, GECF projections (see Figure 1.8) are built around a storyline that foresees a global shift in the geopolitical center of gravity towards Asian markets. The changing shares in global economy and trade, as well as geopolitical features, provide for this evolutionary shift in the institutional setting and structure of the global economy. Thus, the globalization process will continue despite all the challenges, and global institutions will either endure the recent changes or adapt to maintain the wider globalization needs. No global or major regional military conflicts are anticipated.

As far as general technological development is concerned, we do not expect any new game-changing innovations in energy-related areas. The main avenues for technology development are digitalization, the evolution of more flexible markets and a global transition to a wider base for knowledge-based growth.

Some energy efficiency developments are accounted for in the scenarios, while others, such as new manufacturing technologies like distributed 3D-printing, are not expected to impact GDP structures and energy consumption significantly outside of the transport and heavy goods vehicles segment. The game-changing impact of new technologies for the health industry is also expected to reverberate through the global economy well after 2040.

The world is expected to return to relatively strong economic growth in the long-term, anchored by strong labour productivity growth and assuming the avoidance of any major financial market bubbles. For 2025-2040, economic growth is projected to be relatively strong and centered on emerging markets where an expanding middle class becomes increasingly important.

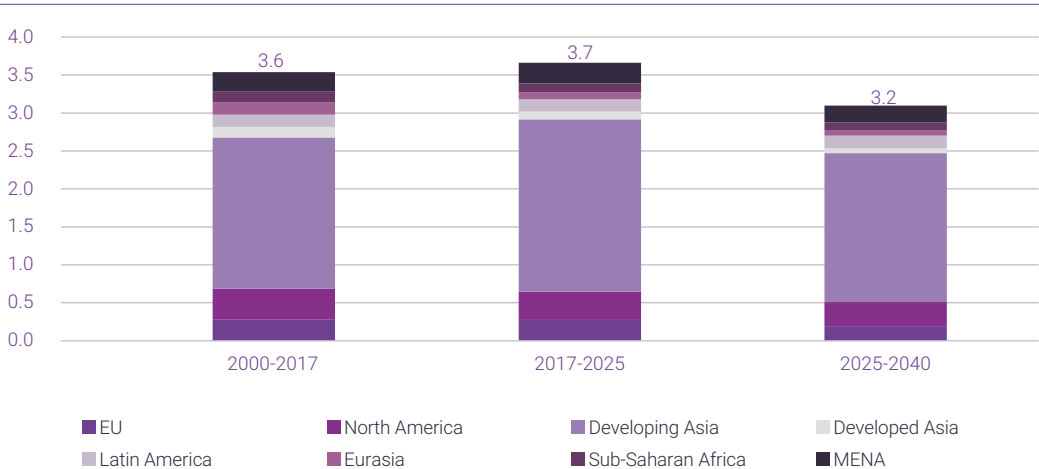
Figure 1.15. Projected GDP growth composition to 2040 (2017\$ trillion in PPP)



Source: GECF Secretariat based on data from the GECF GGM

Developing economies are already 25% larger than developed economies in terms of purchasing power parity GDP and will be 2.2 times larger by 2040, and thus make a much more significant contribution than they have done over the past 30 years. Global growth will see most contribution from developing economies as the productivity gap closes. Developing Asian economies will contribute over 2.0 p.p. to global growth, while the contribution of all the developed economies will be less than 1.0 p.p. The MENA region will contribute 0.3 p.p. as the whole, and Sub-Saharan Africa will contribute around 0.1 p.p.

Figure 1.16. Projected GDP growth composition to 2040 (p.p. per annum)



Source: GECF Secretariat based on data from the GECF GGM

1.3 Vehicle markets outlook

The transport sector accounted for a little over 7.8% of global natural gas consumption in 2017, with just 0.5% coming from the road transport segment. Nonetheless, road transport's energy consumption is large, accounting for 22.2% of global energy consumption, a share that is expected to decrease just slightly to 2040.

The present structure of the car fleet is bound to change with new technology advances and shifting policy priorities. A number of recent policy initiatives in European countries, China and India, as well as from global industry leaders, means that electric vehicles, mostly battery-electric vehicles and plug-in electric vehicles, are expected to receive most policy support and investment at the expense of internal combustion engines powered by petroleum products. There are two ways that natural gas demand could benefit from this process.

The first is through an increase in the natural gas vehicle (NGV) fleet, especially in the medium-term, as air quality policies in several developing countries are enacted. According to the World Health Organization (WHO) Global Urban Ambient Air Pollution Database, 91% of the global population lives in areas where air pollution exceeds WHO guideline limits.

A significant part of this pollution comes from transport emissions. According to the website of the Natural Gas Vehicle Association Europe (NGVA Europe), compressed natural gas transport emits 95% less PM-2.5, and 70% fewer nitrate oxides compared to the strict Euro IV vehicle fuel standards. This means ten times fewer polluting emissions as compared to the vehicle fuel standards (Euro III or less strict) used in most developing countries.

Both liquefied petroleum gas (LPG) and compressed natural gas (CNG) vehicles (as well as the rapidly developing sub-segment of liquefied natural gas [LNG] vehicles) are more affordable in cities once there is gas infrastructure in place. There is also potential for the government policy to increase usage of NGVs. So far, CNG vehicle markets will likely remain in the MENA and Latin America, with the only new market emerging in South Korea as a result of an announced program for replacing diesel vehicles with LPG, CNG and LNG vehicles. As the vehicle fleet in developing Asian countries grows by 570 million vehicles up to 2040, there is additional potential to increase the share of NGVs, especially in public transport and heavy goods vehicles sectors.

The second way in which gas demand could benefit is through an increase in demand in the power sector as a result of more electricity demand from the growing electric vehicles (EV) fleet. The global EV fleet is expected to rise by 300 million vehicles by 2040. Even though about 200 million of these new EVs are in developing Asia, where 55% of the power will still be generated from coal by 2040, there is a projected increase of over 1000 TWh for global electricity demand from the road transport sector. This will be an additional driver for natural gas demand in the power sector.

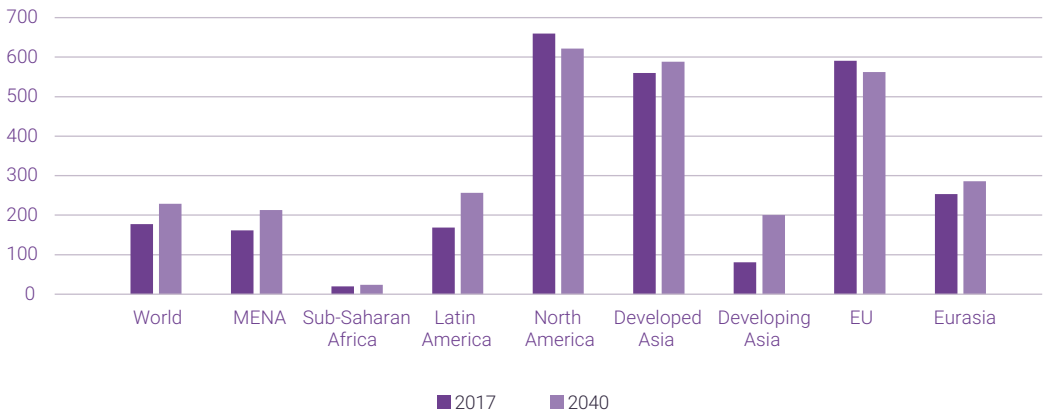
Vehicle fleet outlook

The global passenger car and light commercial vehicle (LCV) fleets are projected to grow by 770 million by 2040, at an annual rate of 2%. This forecast remains mostly unchanged from previous GGO editions. Out of these 770 million new vehicles, developing Asia fleets are to add 570 million vehicles to 2040, and Latin America fleets are to add another 67 million. This reflects the growing population and urbanisation levels, and to a greater extent, economic growth rates and the corresponding increase in household wealth.

Despite the increasing well-being in developing countries, in terms of the total car fleet they will only overtake the fleet size in developed countries in 2025. Motorization levels in developing Asia will double, as measured by cars per capita, but for developing countries cars per capita will still be three times less than that of developed countries by 2040.

As for North America and the EU, the projections assume changes in the mobility industry that will cause a slight decrease in motorization levels, as penetration of autonomous cars will enable the wider use of car sharing and ride-hailing as a substitute to car purchases.

Figure 1.17. Cars per '000 population



Source: GECF Secretariat based on data from the GECF GGM

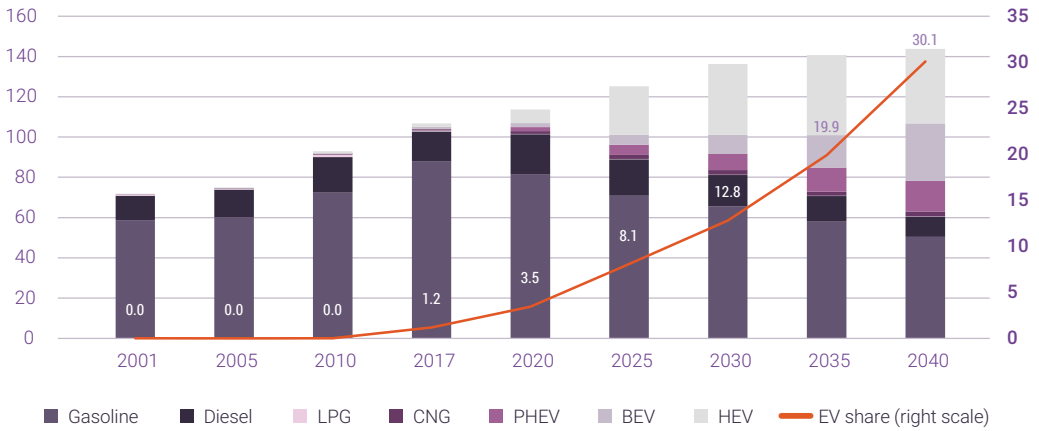
Fleet structure outlook

The passenger car and LCV fleet structure projections entail assumptions both for policy decisions and for the penetration of new powertrain technologies, especially in the battery-powered and plug-in hybrid EV (BEV and PHEV, respectively) sectors.

In 2016-2018, policy decisions to restrict the sales of new internal-combustion engine (ICE) vehicles have been announced at a national or large city level in 20 countries. The proposed deadlines are largely for the 2030-2035 period, and are expected to impact R&D investment and the bankability of new ICE powertrain projects. The global automotive industry has also announced several pledges to completely remove or significantly reduce ICE powertrains with new models.

These are some of the main drivers behind the decreasing share of sales of new vehicles powered by gasoline or diesel from 96% in 2017 to 42% by 2040. If gasoline and diesel hybrids are included in the sales figure, the share goes up to 67%, which still remains a significant decrease. There is potential for different alternative fuel vehicles to capture this sales share. Given the current policy priorities, in the Ref. Case this share is mostly captured by the EVs and hybrids (30% of sales by 2040), while the NGV sales share by 2040 without policy support is expected to increase just slightly.

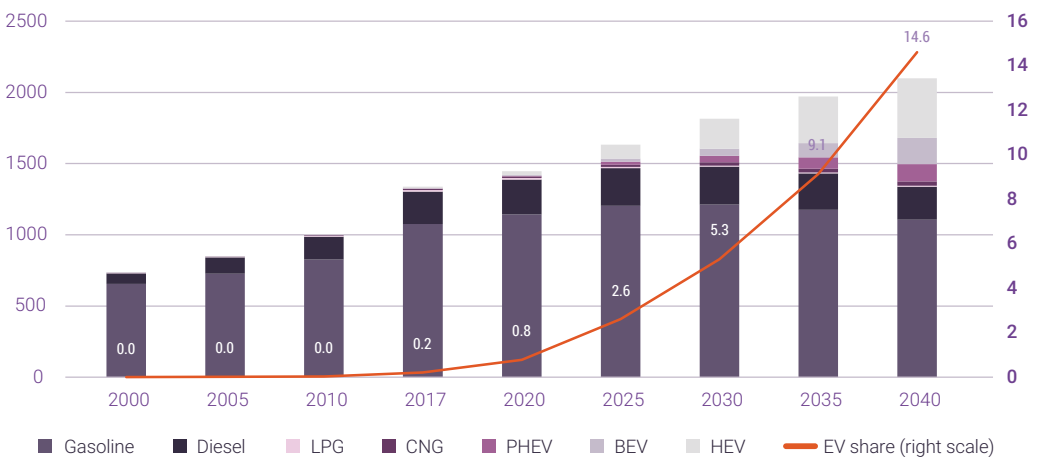
Figure 1.18. Global car sales structure (million)



Source: GECF Secretariat based on data from the GECF GGM

Changes in passenger cars and LCV sales structures will impact the corresponding fleet structure with an average lag of 5 to 10 years, depending on the vehicle service life in a given country. Based on the sales structure trends outlined above, we assume a decrease in the share of vehicle fleets powered by gasoline or diesel from 98% in 2017 to 64% by 2040. NGVs will account just for 1.6% of the car fleet (mostly CNG vehicles), compared to 14.6% for EVs and 19.8% for hybrids.

Figure 1.19. Global car fleet structure (million)



Source: GECF Secretariat based on data from the GECF GGM

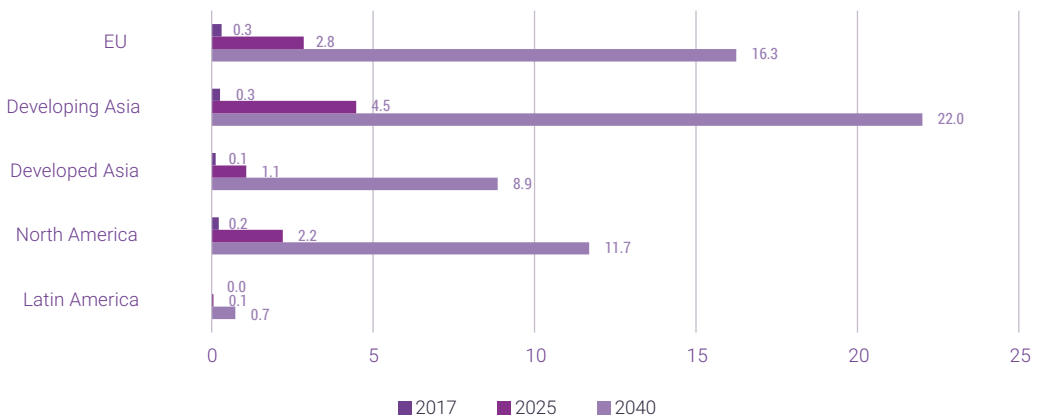
Electric vehicles prospects

There will be a projected 300 million electric passenger cars and LCV globally by 2040, compared to 2.8 million in 2017, corresponding to the annual growth rate of 123% for 2017-2040.

These figures represent a very significant change to the outlook for the share of electric vehicles, now that announced EV program support in India and China has been taken into account. The global fleet share of EVs is up to 14.6% from 9.2% a year ago, and the share of new sales could be as high as 13% in 2030 (unchanged from last year's estimate) and over 30% (compared to 21% last year) by 2040. This sales structure implies 300 million EVs by 2040 (plus 400 million hybrid vehicles) out of the 2.1 bn fleet, and is in line with projections from other energy forecasters such as the IEA.

Developing Asia will remain the primary market for new electric vehicles and hybrids, with China announcing plans to aggressively expand its public EV charging infrastructure, and targeting public transport and taxis. However, in terms of private passenger cars and LCVs, North America and Europe are expected to achieve the fastest transition due to stricter vehicle emission standards, higher fuel excise duties, and a significantly higher level of household wealth. The lower EV share in developed Asian countries corresponds to the diversification of the alternative fuel vehicle fleet, including support for NGVs in some countries.

Figure 1.20. EV fleet shares by region (%)



Source: GECF Secretariat based on data from the GECF GGM

It should be noted that currently most of the projected EV fleet growth is policy-based, as competitive economic and environmental advantages of EVs are unclear, especially in developing Asia. With policy support for most EV programs in Europe gone by 2020, it is unclear, however, if this projection will survive the affordability test in the coming years.

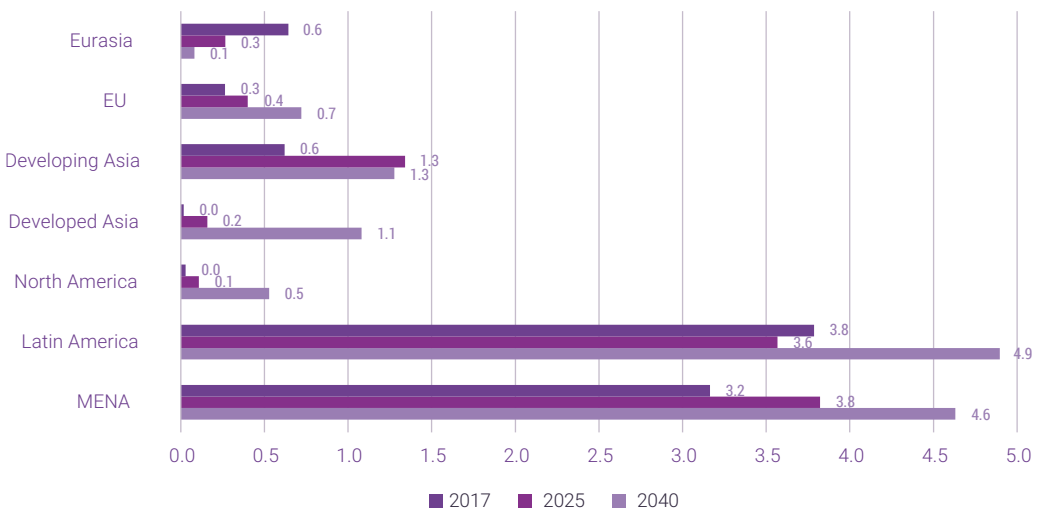
Natural gas vehicle prospects

Out of 1.3 bn passenger cars and LCVs in 2017, there were more than 19 million NGVs globally, representing less than 1.5% of the global car fleet. By 2040, the size of this segment is expected to almost doubled, numbering over 35 million

cars. However, this will still represent only about 1.6% of the global car fleet as very few countries will have enacted policy support programmes aimed at NGVs or no-preference programs for alternative fuel vehicles. Given the policy priorities, in the future NGVs are expected to lose ground to electric vehicles and hybrids, and account just for 1.4% of the car fleet, compared to 14.6% for EVs and 19.8% for the hybrids.

A stark example is the largest market, namely developing Asia, with over 570 million additional cars expected to go on the road by 2040. Out of those new cars, we project that 230 million will be hybrids, 200 million will be electric vehicles and only 9 million will be CNG cars. Given the technological readiness and environmental advantages of NGVs as compared to EVs in developing Asia (where 55% of electricity is coal-generated), this is disproportionately low. However, at the moment there are only EV policy support programmes in China and India, with both targets and budgets overshadowing any NGV support. On the other hand, there are best practices in Asia on how to use NGVs to achieve significant ecological benefits, such as the air quality policy in South Korea which includes a target of 75% CNG and LNG powertrains in public transport buses by 2022.

Figure 1.21. NGV fleet shares of total by region (%)



Source: GECF Secretariat based on data from the GECF GGM

Looking at the sub-segments, CNG vehicles will command the larger share of the NGV fleet. As of 2017, there were 9 million CNG vehicles globally and this number has been growing at over 7.0% p.a. over the last five years, twice as fast as the total car population. By 2040, this dynamic segment is expected to more than triple, numbering over 30 million cars. The prospects for the sub-segment of LNG vehicles in the early development stage are bright, and the fleet is growing fast, mainly in LNG trucks in China, where numbers increased to over 9000 in 2017. However, the penetration of the technology is so far limited to the heavy goods vehicles sector where they compete with diesel-powered vehicles, while passenger vehicle prototypes are still far from the market despite the potential of LNG to provide for higher ICE efficiency.

1.4 Energy and carbon price projections

1.4.1 Crude oil

Market developments in 2017-2018

Throughout 2017-2018, the oil market recovered to price levels seen in 2014, albeit in a more controlled manner. Several factors contributed to the increase in the oil price in 2018. Firstly, a supply reduction was exacerbated by falling production in Venezuela in the first half of the year. The decrease in Iranian oil supply to the market also largely contributed to the reduction in supply. Secondly, global economic growth drove an increase in oil demand which exceeded expectations. Thirdly, uncertainty over the exact impact of sanctions by the US on Iran announced in May, has already limited Iranian oil supply in the second half of the year. This has exacerbated the increased volatility from short-term supply disruptions in Libya, Nigeria and Iraq.

The developments in Venezuela raised the price to over \$80/bbl, which is expected to trigger a significant increase in US unconventional oil production in 2019-2020. On the demand side, there is a downside risk for 2019 posed by tensions in the US-China standoff on trade and security. The expected rise in US supply coupled with a half-year waiver on oil import restrictions from Iran will still impact the oil price in 2019, but should still keep prices high enough to support rising tight oil production for some time. Thus, in the near-term, oil output growth in the US will likely put increased pressure on the market and cause a new market correction, albeit at a more modest scale than in 2014.

Medium-term drivers and outlook

In the medium to long-term (2019-2025), the oil and gas industry appears to be ready to start another cycle of upstream expansion after holding back on investment and cutting costs during 2015-2017. With most indicators pointing at a balanced market with growing demand, there is a greater need for the industry to bring forward postponed new project plans to keep up with increasing production decline rates. In addition, governments are pushing plans for more oil and gas revenues, thus stimulating national oil companies to beef up their capital expenditures. As a result, in 2019-2025 we expect to see an increase in new upstream projects and exploration.

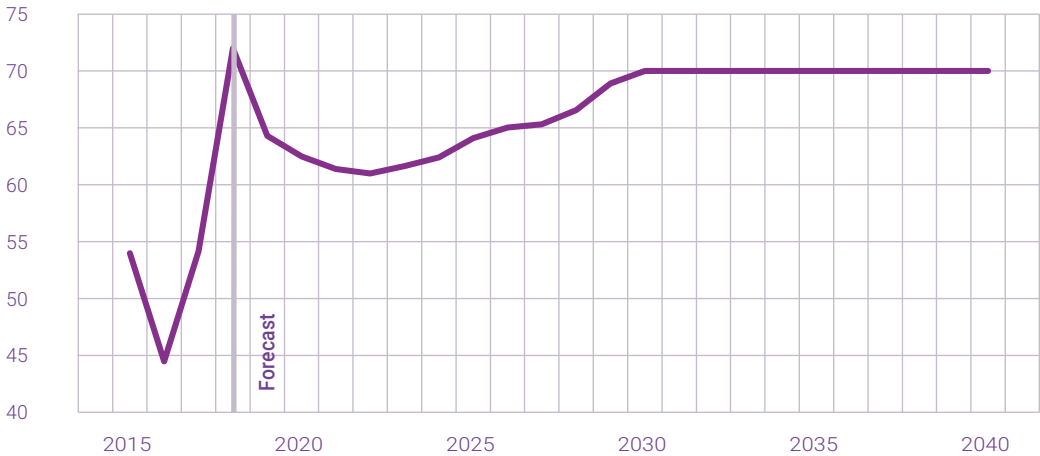
After the oil price shock of 2014, however, there has been increased attention on the cost-competitiveness of new projects. In previous cycles, during an expansion phase, inefficiencies and wasteful practices mounted which rendered many projects less competitive. Now as the industry emerges from a period of increased scrutiny resulting from low oil prices, this risk is lessened, but the scrutiny itself will likely hold back investment growth.

Over the medium-term, North American output will keep rising as producers will be supported by the financial hedge obtained at prices well above breakeven levels, as well as by accumulated efficiency improvements which will drive the marginal costs of tight oil down. Along with slower investment expansion, this will lead to a continued oil price recovery up to 2030. We expect OPEC and non-OPEC countries to drop the element of supply restraint by 2019, to avoid losing the market share to US producers.

Long-term drivers and outlook

For the longer term (2025-2040), we assume the same structure of the oil market as today, with the price tracking marginal costs. Changes in how the mobility sector is powered as it is transformed by technological improvements will impact demand closer to 2040, though transport energy demand still peaks in 2035.

Figure 1.22. Brent oil price (2017 US dollars per barrel)



Source: GECF Secretariat based on data from the GECF GGM

We have revised our oil price projections based on the market developments of 2017, observing the growth in US tight oil even at \$60/bbl levels. In the long-term, prices will reflect efficiency savings, as well as pressure from the mobility revolution, and are forecast to be around \$10/bbl lower than in the previous edition of the Outlook.

Structurally, in the long-term OPEC is still assumed to be the swing producer, as the outlook for US tight oil has been revised up by an average of 1.5 mb/d in 2018-2020 and an average of 1.6 mb/d in 2021-2040, despite the forecast price decrease. It should be noted that the costs of extraction projects are still falling globally: the marginal cost for US tight oil decreased to \$50-60/bbl, while in 2015, the majority of the projects were in \$70-80/bbl range.

1.4.2 Natural Gas

We project that the structure of the natural gas market over the outlook period will remain largely geographically segmented, although integration processes will pick up from post-2025. Short-term price differences between regional markets will be increasingly eliminated via LNG shipments, although this requires a price differential of over \$5-6/mmBtu depending on transport costs, as well as supply and demand balance. The integrated market regions with the most natural gas turnover or liquidity will still be the American and European markets, as well as the Asian and Latin American markets.

Market developments in 2017-2018

Oil and quasi-oil indexation (hybrid) pricing mechanisms served over 50% of imported volumes of natural gas on the global markets in 2017, according to an IGU survey (4). The effort to create hubs in various regional markets, including Europe, has so far not accumulated enough momentum for it to account for a majority of gas exports to these regions, even though with more regulatory pressure hub-indexed pricing is expected to expand further.

In Asian markets, however, there is no integrated trading network and no single regulator, making a physical hub creation less feasible for the outlook period. While there is an increasing turnover of financial products based on a "JKM (Japan Korea marker) swaps" benchmark, market participants and experts cite little reliability of this price reference for physical settlement trades, as it is based mainly on daily bid-ask price differences. In the longer-term, China and Singapore LNG quotes will be more suitable to use as a benchmark as those countries are striving to develop a gas trade infrastructure.

Medium-term drivers and outlook

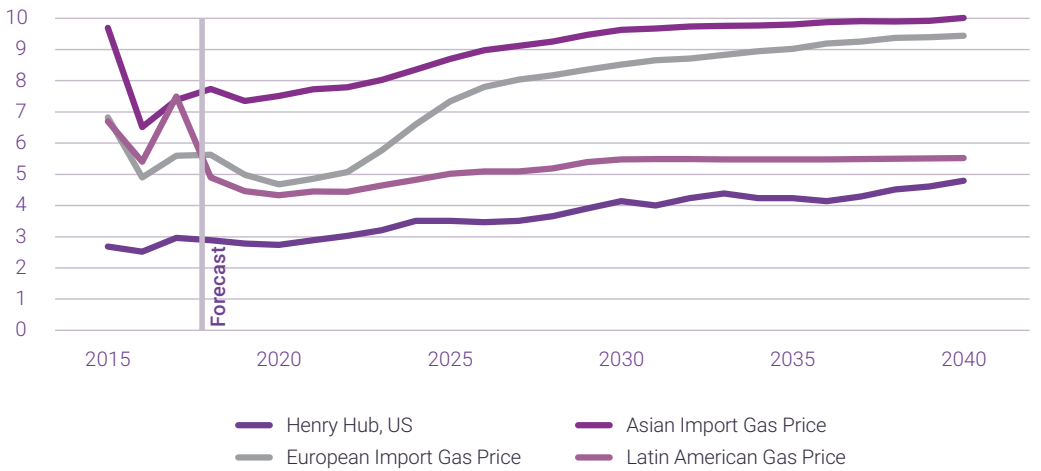
While all volumes traded within the US go through a gas-to-gas competition mechanism and are tied to the Henry Hub quotation, volumes exported to Asian and Latin American markets are largely oil-indexed (at least 84.1% and 70%, respectively, plus any hybrid pricing volumes). This difference in market structures is expected to persist for the outlook period. A majority of volumes (estimated at over two thirds) imported to the European market are currently priced using a hybrid oil and benchmark gas indexation mechanism (these are mostly classified as gas-to-gas competition by the IGU), and unless more regulation is enforced, this is expected to persist.

Notwithstanding the pricing structures described above, price will define the role of natural gas in the energy mix as a result of competition between fossil and non-fossil energy sources across the transformation, industry, domestic, transport and feedstock sectors in regional markets. These dimensions of competition determine the lower and upper bounds for natural gas prices. While the LNG market remains under pressure from projects started when the oil price was twice as high, there have been announcements that mean a significant number of those projects will be postponed indefinitely or cancelled. This backs up our projection that the natural gas market is expected to rebalance within two or three years, with the 2020-2025 period seeing a slow but steady upward price trend for all regional markets.

Long-term drivers and outlook

For the longer-term, increased capital cost of production (see Chapter 6), gas demand pressure from energy transition and power mix substitution, as well as the lack of new transportation projects coming after 2030 are expected to drive prices up. The important exception will be Latin America, where the growth in indigenous natural gas production and short distance for US LNG shipments will keep prices at a slight premium to Henry Hub. For the European market, the price is expected to edge up significantly following the new avenues for gas-to-gas competition with both LNG and pipeline supplies to Asia, as well as an increase in the carbon price and planned coal and nuclear capacity phase-outs.

Figure 1.23. Natural gas prices (2017 US dollars per mmBtu)



Source: GECF Secretariat based on data from the GECF GGM

1.4.3 Thermal coal

The global consumption of coal is expected to hold steady at the present level of below 3.8 billion mtoe (6.3 mt of coal equivalent), with the volumes phased out in North America and Europe (and China, after 2030) being replaced by growth in India and Southeast Asia. Global coal-generating capacity is also expected to stay at around 2.1 TW by 2040 as compared to 2.0 TW in 2017.

Over the outlook period to 2040, thermal (steam) coal will remain a key energy carrier in the global power mix, and is an important component for unlocking electricity access in some power-hungry developing Asian countries.

Both developed and developing countries will continue to put into place policies discouraging, limiting or phasing out coal combustion without carbon capture and storage (CCS), citing the need for carbon mitigation, as well as for cleaner air and long-term protection for public health. We expect these policies to reduce the competitiveness of coal as a source for power generation compared to renewables and natural gas, and demand to be reduced through increased efficiency of global coal-powered generating capacity. Prices, however, will mostly be unaffected, as the policy impact is expected to be very gradual and there is ample time for suppliers to phase out coal production facilities.

Market developments in 2017-2018

Recent years have seen a trend of coal price increases, underpinned by rising Asian demand and supply restrictions, notably for the premium low-ash grades from Australia and Indonesia. On average, prices have topped \$100/t by the mid-year and are now spiking, reminiscent of the previous high price record in 2011.

Price levels are expected to remain elevated in the near-term, and this has already provoked government intervention in domestic energy markets in China and India. While some additional supply capacity will be put online in the next two years, only a demand slowdown connected to the US and EU coal phase-outs could materially impact the market. However, in the near term, this would be outweighed by rising Asian demand.

Medium-term drivers and outlook

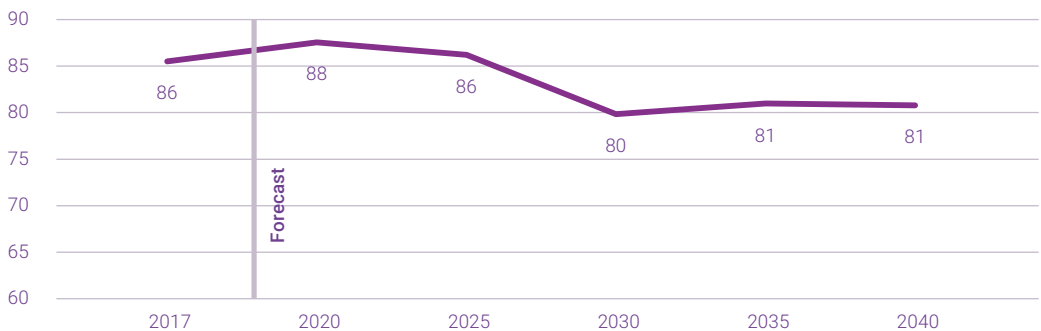
In the medium-term, the primary market is expected to be driven by limitations and phase-outs of coal-generating capacities in China, the US and a number of European countries. By 2025, the US and EU countries are expected to use 25% or 200 mt less coal than in 2017, while coal capacity in China will be capped from 2021, and this will counterbalance Indian demand growth. However, new investment will allow supply to adapt both geographically and technologically, and is expected to balance the market at around \$85/t by 2025.

Long-term drivers and outlook

The long-term outlook for thermal coal prices is shaped by the competitiveness of coal vis-à-vis the consumption alternatives, under the influence of:

- ③ Strong electricity demand growth in developing Asia
- ③ Increasing carbon prices and proactive air quality policies
- ③ The capital requirement and marginal cost of non-coal power capacities.

Figure 1.24. Thermal coal price* (2017 US dollars per tonne)



*Average of Richards Bay, ARA and Newcastle prices.

Source: GECF Secretariat based on data from the GECF GGM

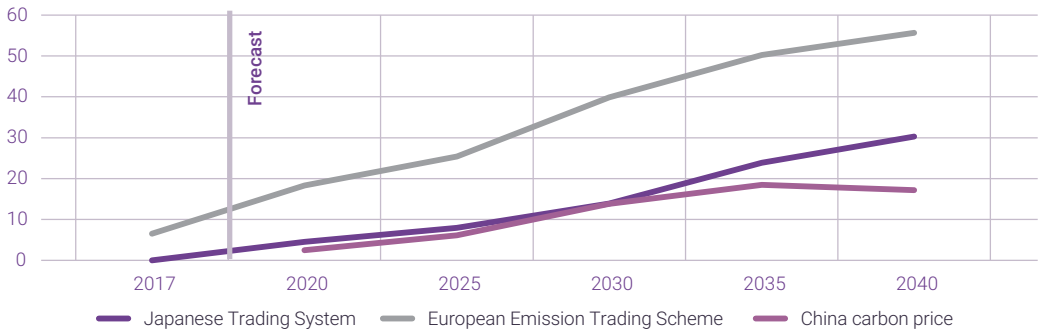
We expect that in the long-term prices will be driven by a reduction in inefficient coal capacity and decreasing pressure from consumption alternatives, especially from natural gas and renewables. This pressure will drive global prices down to around \$80/t on average.

1.4.4 Carbon

This Outlook's projections for the Ref. Case assumes that by 2020, several global carbon trading systems will be functioning on a regular basis, but will not yet be integrated into a global carbon trading system. This includes the EU ETS stage IV, the Japanese Trading System (JTS), the Australian and New Zealand Trading System, expansion of Chinese national cap-and-trade system, and several state-level and local trading systems in the US starting up at CO₂ price levels that could materially impact fuel source competitiveness in the medium and especially long-term. According to World Bank estimates (5) there are about 60 city-level or broader carbon pricing initiatives in action or at the implementation stage, covering about 11 GtCO₂ in total, compared to 8 GtCO₂ as of 2017. At a subnational level,

these initiatives are being enacted mostly in US, Canadian, and Chinese cities. In 2017-2018, the governments of Chile and Colombia, as well as several additional US states, reached decisions to enact carbon taxes. The EU ETS so far remains the only national-level or higher initiative.

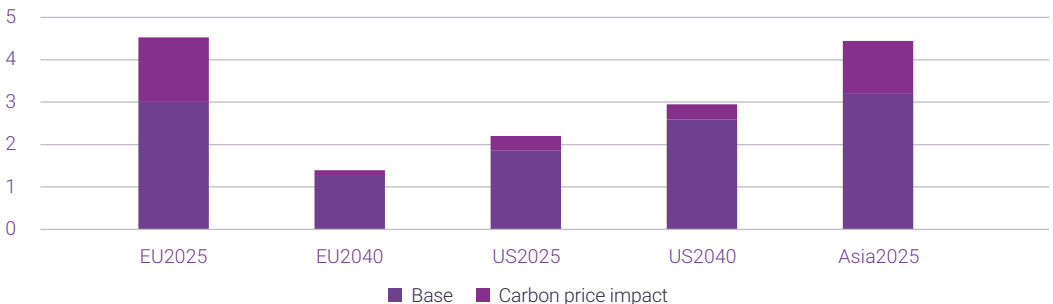
Figure 1.25. Carbon ETS reference price forecasts (2017 US dollars per tonne CO₂)



Source: GECF Secretariat based on data from the GECF GGM

While EU ETS carbon prices during 2018 have already reached \$17/tCO₂, some rebalancing is expected as premature carbon price spikes will impact on economic activity. In the long-term, as the carbon price sector coverage is expanded and the system reaches its next stage, the CO₂ price is forecast to reach \$55/t and \$30/t for the ETS and JTS respectively. The Chinese national carbon price is projected to be less restrictive, as emphasis so far is being made on the expanding the sectoral coverage of the cap-and-trade system. As per the emission targets, carbon prices and carbon taxes are expected to materially change the competitiveness of natural gas versus coal in the long-term. The carbon market is expected to support the competitiveness of natural gas, keeping the coal-gas price ratio within the affordability range.

Figure 1.26. Natural gas to coal price ratio and the carbon price impact



Source: GECF Secretariat based on data from the GECF GGM



Energy Policy Developments and Emissions Trends



Key findings

The strong link that energy forms between the 2030 Sustainable Development Agenda and the Paris Agreement allocates responsibility to energy policies in supporting alignment of the two frameworks. Policies that support natural gas can achieve progress for both agendas.

Market-based mechanisms, such as auctioning and tradable certificates, are increasingly contributing to renewables and energy efficiency. However direct government intervention and subsidies will continue to play a key role, especially in emerging markets.

Integration is the main challenge for renewable energies and gas is expected to improve their integration and power system flexibility.

Natural gas continues to be encouraged through supply side measures promoting availability and accessibility to resources, and through demand side measures, including emissions standards, carbon pricing or mandated switching.

Coal policy is expected to continue limiting coal's environmental impacts, either through mandated phase-out or through energy efficiency and emissions standards. Several countries, mainly in the Asia Pacific region, will continue to rely heavily on coal to meet growing energy demand.

Countries with developed nuclear power systems will extend the lifetime of several existing projects to support energy independence and carbon mitigation commitments, but this will not counterbalance the long-term downward trend, since no large nuclear program will be adopted to replace the old fleet.

Carbon pricing is assumed to progress in several countries, but large pricing disparities will persist, reflecting countries' conditions and climate commitments. Carbon markets are not expected to be globally integrated over the forecast period.

CO₂ emissions are expected to continue to grow, albeit at a reduced rate of 0.6% p.a. Emissions from non-OECD economies will more than offset declines in the OECD as economic growth and urbanisation encourage greater energy use.

The Outlook sees the Paris Agreement target being missed by some margin and that coal and oil will represent around 72% of 2040 emissions. Increased gas use can contribute in closing the gap between emissions and the 2°C target.

There is large uncertainty on methane emissions data from gas-related activities. Recent studies reported emissions ranging from 0.2% to 10% of the methane produced. Despite these uncertainties, the gas industry is taking this issue seriously through concrete actions and initiatives.

2.1 The role of energy policies in achieving sustainable development

The adoption of the United Nations 2030 Agenda for Sustainable Development in September 2015 marked the commitment of more than 190 countries to implement policy measures and initiatives that aimed to meet the UN Sustainable Development Goals (SDGs). This Agenda encompasses 17 SDGs and 169 associated targets, which bring together the economic, social and environmental dimensions of sustainable development. It represents a universal commitment toward the pursuit of global development through the eradication of poverty and hunger, in all their forms. The 2030 Agenda also aims to address social and economic inequality, while ensuring that human development occurs within the confines of Earth's biophysical boundaries.

Nearly three months after the 2030 Agenda was agreed upon by the UN General Assembly, the Paris Agreement was adopted, underpinned by countries' Intended Nationally Determined Contributions (INDCs)¹. While the SDGs reflect the holistic nature of sustainable development, the Paris Agreement specifically addresses greenhouse gas (GHG) emissions. Both initiatives represent universal visions, but they also allow countries to identify domestic measures and policies that best suit their needs. This approach enables nations to prioritize targets, ambitions and implementation plans in line with their individual development trajectories and mitigation costs.

Actions proposed under the 2030 Agenda and the INDCs are voluntary, necessitating the need to integrate the two frameworks coherently through well designed policies. The first part of the policy chapter will examine the role that energy policies play in reconciling these very ambitious global initiatives. It takes a look at how energy forms a link between the 2030 Agenda and the Paris Agreement, demonstrating how natural gas, as the most reliable, affordable and cleanest burning fossil fuel, can concurrently support international climate ambitions and achieve progress toward the SDGs.

2.1.1 Energy at the crossroads of the 2030 Sustainable Development Agenda and the Paris Agreement

The efficient implementation of the 2030 Agenda and Paris Agreement requires an understanding of the existing links and interdependencies between them and the discovery of ways that can consistently support both the SDGs and climate change mitigation and adaptation actions.

The SDGs recognize the important role that combating climate change plays in achieving sustainable development. Climate change is not only reflected in SDG 13 (climate action), but is explicitly referenced in other goals and targets. For example, SDG 2 (zero hunger) draws links between sustainable food production systems and the capacity to adapt to climate change. This is correlated with SDG 1 (no poverty), which recognizes the need to increase the resilience of vulnerable populations to climate-related extreme events. SDG 11 (sustainable cities and communities) also conveys the significant contribution that urbanisation plays in mitigating climate change and other environmental impacts, such as air quality.

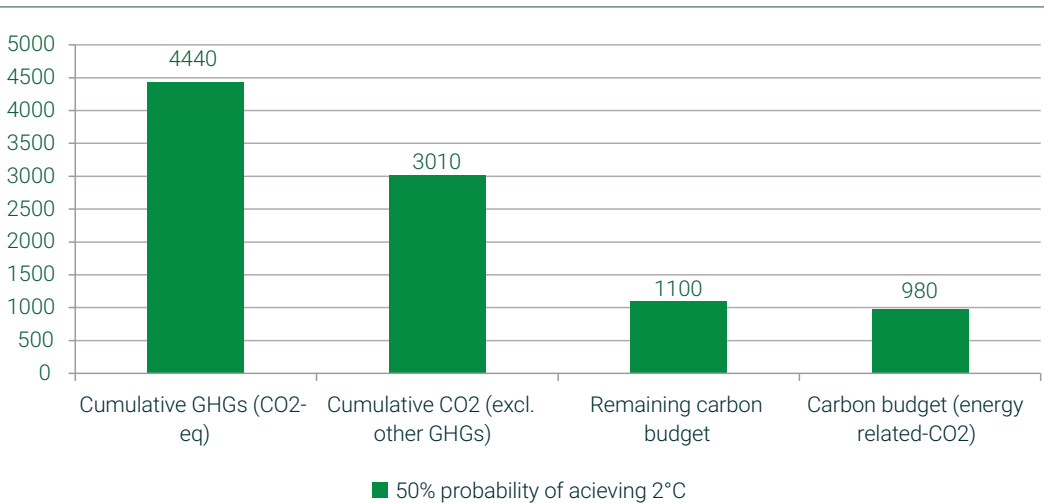
There are many overlaps amongst the 17 SDGs, and between the SDGs and Paris Agreement where SDGs and targets

¹ In the following paragraphs, INDCs include both countries that ratified the Paris Agreement, transforming their INDCs into NDCs, and those that have not yet ratified it.

are highlighted in several INDCs' proposed actions (1). However, the most critical point of intersection between the SDGs and the Paris Agreement is energy [see Box 2.1]. More energy-related actions outlined in countries' INDCs relate to SDG 7 (affordable and clean energy) than to other goals, but energy should not be restricted to only one SD goal. Energy underpins all the economic, social and environmental aspects inherent to sustainable development, and actions specific to the energy sector play a dominant role in supporting country-level commitments under the Paris Agreement.

It is worth mentioning that the very ambitious objectives set out in the Paris Agreement require a dramatic transformation in the energy sector, whose GHG emissions represent nearly 75% of the global total. The IPCC (AR5 report) estimates that, in order to achieve the 2°C target outlined in the Paris Agreement with a probability of 50%, cumulative atmospheric GHG emissions cannot exceed 4400 GtCO₂-eq throughout the rest of the century.

Figure 2.1. Carbon stock calculations for the energy sector, considering historical emissions and Paris Agreement 2°C target (GtCO₂)



Source: Estimations based on data from IPCC (AR5) report and GECF Secretariat based on data from the GECF GGM

Figure 2.1 demonstrates that, if other GHGs are excluded from consideration, the remaining share of CO₂ emissions is equivalent to 3010 GtCO₂. When historical CO₂ emissions are subtracted, a carbon allowance of approximately 1100 GtCO₂ remains if the Paris targets are to be achieved. This carbon budget shrinks even further if only energy-related emissions are considered, totalling 980 GtCO₂ between 2016 and 2100. This carbon allowance will be reached in less than three decades if current levels of energy-related CO₂ emissions (33 GtCO₂ per annum) are maintained. Consequently, the energy sector needs to achieve marked reductions to comply with the ambitious 2°C Paris Agreement target.

The special IPCC Report on global warming (IPCC SR15), which was published in October 2018, shows that more critical values need to be met for the remaining CO₂ budget in order to achieve a lower temperature increase target of 1.5°C, which is the temperature required, according to the report, to limit the global warming effect significantly. The

Box 2.1: Energy-sustainability links

The GECF has identified six main criteria for energy-sustainability links that represent the channels by which energy could or could not contribute to achieving SDGs. The table below highlights some of the examples supporting the links between energy and SDGs through the identified criteria.

Analysing the relationship between energy and the SDGs shows that undertaking energy-related actions to meet one SDG can significantly affect another SDG, often in a negative way. For instance: the use of motorization and fertilizers can increase the productivity of agriculture and contribute to reducing hunger and poverty, but in the same time, it will drive an increase in energy demand and GHG emissions. Furthermore, increasing the share of carbon free alternatives, such as renewables, would reduce the environmental impact but might lead to an increase in the cost of energy and therefore reduce its affordability. This overlapping demonstrates the overriding complexity behind defining the appropriate energy options that fit different SDGs, and this complexity has been further increased with the adoption of a very ambitious climate change agenda within the framework of the Paris Agreement that has put more pressure on traditional energy options and technologies.

Table 2.1. Links between energy and the SDGs

Criteria	Examples of the energy – SDGs link for the specific criteria
Ensuring access to modern energy	Greatly contributes to the alleviation of poverty (SDG 1) through electrification; improves food security and agricultural productivity (SDG 2) through motorization; supports inclusive and sustained growth through job creation and economic productivity (SDG 8); improves indoor air quality and associated health risks through access to modern cooking infrastructure (SDG 3); contributes to gender equality (SDG 5), as women and girls are often responsible for household management and may spend hours each day collecting biomass and fuel.
Improving availability, reliability and security of supply	Encourages the use and monetization of domestic resources for local development (SDG 8); supports industrialization and infrastructural improvements for the benefit of local populations (SDG 9); sustains energy-intensive utilities (e.g. water treatment, desalination and wastewater treatment) (SDG 6).
Enhancing affordability and competitiveness	Supports economic growth and social welfare (SDGs 1 and 8); promotes competitive economies and industrialization (SDGs 8 and 9); reduces inequality through affordable and universal energy access (SDG 10).
Reducing carbon intensity	Mitigates the impacts of climate change through GHG reductions; reduces the frequency and magnitude of climate-related hazards (e.g. droughts, floods, sea level rise) (SDG 13); mediates the negative impacts associated with climate change on terrestrial ecosystems (e.g. desertification, biodiversity loss, habitat degradation) (SDG 15).
Mitigating pollution from energy-related activities and processes	Improves access to clean air, soil and water (SDGs 3, 15, 6 and 14); improves living conditions, overall health and well-being and economic activities that may be impaired by degraded human and ecosystem health (e.g. fisheries and agricultural systems) (SDGs 1, 2, 3, and 8).
Increasing cooperation between energy stakeholders	Supports economic opportunities, energy infrastructure, technology transfer, and innovation (SDGs 8, 9, and 17). Improves institutional capacities, reinforces capacity building, and promotes international cooperation (SDGs 16 and 17).

SR15 report estimates the remaining CO₂ budget from the end of 2017 to 2100, with a 50% probability of occurrence, at 580 GtCO₂ (the estimate uses the same methodology as the previous AR5 report, which is based on global mean surface air temperatures). This remaining CO₂ budget increases to around 770 GtCO₂ when using a methodology based on the global mean surface temperature (GMST) observed for the decade 2006–2015. This puts further pressure on the energy sector to achieve some progress, while at the same time meeting sustainability requirements.

The strong link that energy forms between the 2030 Agenda and the Paris Agreement allocates responsibility to energy policies in supporting the alignment of the two frameworks. Energy policies establish priorities for the energy sector, affect preferences for particular energy resources, and define production, distribution, and consumption patterns. As such, energy policies can support progress towards achieving the SDGs and carbon mitigating actions outlined in countries' INDCs. Balanced and coherent energy policies are therefore key to advancing both agendas. Despite efforts to integrate and align the SDGs with the Paris Agreement, important trade-offs exist between the two. These trade-offs add significant complexity to the planning and selection of policy responses.

2.1.2 Promoting natural gas: a solution for a more balanced policy approach

Natural gas can be a balanced and viable solution that achieves progress toward climate objectives and the SDGs. The technical, economic, social and environmental advantages of natural gas enable it to contribute efficiently to the achievement of the SDGs through several channels (see Section 2.1.1). Natural gas contributes to reducing carbon intensity and the pollution effects which result from energy related activities; it supports access to modern energy; it improves the availability and reliability of supply; and it provides competitive and affordable energy. Natural gas can also be a vector for increased cooperation and the transfer of technologies between countries. Thanks to all these benefits, policies and measures which support natural gas can drive the implementation of both climate and sustainable development agendas. The following paragraphs provide some analysis and evidence on the role of natural gas in mitigating CO₂ emissions and in progressing towards sustainable development, through the previously cited channels affecting SDGs.

Natural gas and carbon mitigation

Greater penetration of natural gas, especially when substituting for coal, has contributed significantly to mitigating CO₂ emissions. Figure 2.2 depicts the change in the share of natural gas and of carbon intensities in selected countries between 2012 and 2017. It can be noted that in many countries, especially in key energy consuming countries like China, the US and the UK, an increase in the share of natural gas in the primary energy mix between 2012 and 2017 has been associated with decreasing carbon intensity.

Between 2012 and 2017, China increased the share of natural gas in its primary energy mix from 4.4% to nearly 6% and decreased the share of coal from 67% to nearly 62%. Despite the fact that coal to gas switching was not the only factor affecting carbon intensity, it did contribute significantly to its decrease from 3.22 tCO₂/toe in 2012 to around 3.04 tCO₂/toe in 2017. The subsequent increase in coal demand in 2017 compared to 2016 contributed to a net slowdown of the trend in carbon intensity decline which had reached 3.05 tCO₂/toe in 2016. (Carbon intensity decreased by just 0.01 tCO₂/toe tCO₂ in 2017, mainly supported by the progress of renewables.)

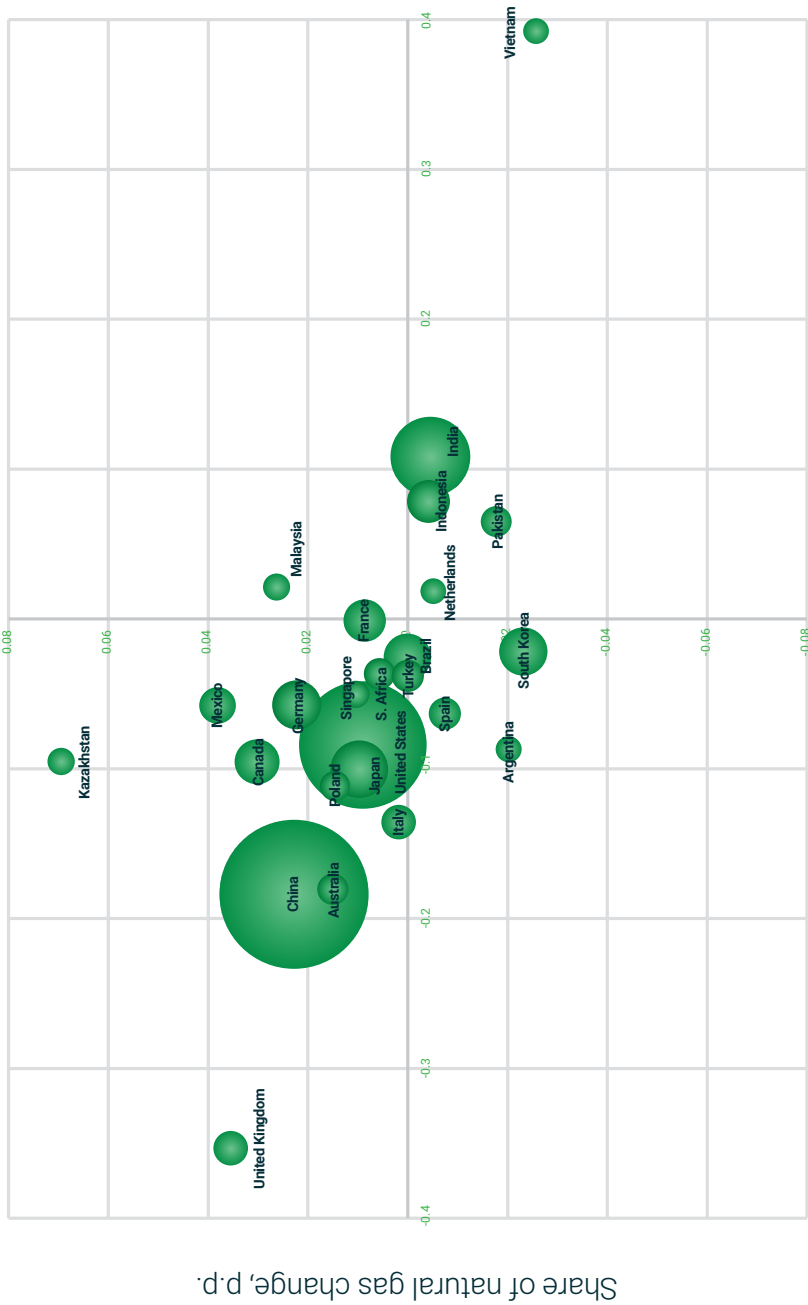
The US and UK are also relevant examples of where the shift to natural gas in the power sector and, to a lesser extent, in the industrial sector has significantly contributed to emissions reductions between 2012 and 2017, estimated at 3.5% for the US and 18.2% for the UK.

The opposite is true in countries like India, Vietnam, Pakistan and Indonesia, which have reduced the share of natural gas in their primary energy mixes between 2012 and 2017, to the benefit of coal, especially in the power sector. This penetration of coal, driven by the lower coal costs and often by a decreasing availability of domestic gas, contributed to an observed increase in the countries' carbon intensities.

Malaysia has observed an increase in the share of natural gas and a relative stagnation of coal share. This has contributed to a slight increase in its carbon intensity, by around 0.02 tCO₂/toe. The figure could be improved if natural gas were to achieve more penetration at the expense of coal; but the country has initiated a plan to build new coal-fired power plants that might negatively affect its carbon intensity.

There are, however, other situations whereby a decrease in the share of natural gas in a country's primary energy mix can be associated with decreasing carbon intensity. This can be seen in Argentina and South Korea and can be attributed to a rise in nuclear power generation capability. A similar trend in Spain and Turkey can be attributed to a recovery in hydroelectric power generation.

Figure 2.2. Change of natural gas shares and carbon intensities between 2012 and 2017



Carbon intensity change, tCO₂/toe

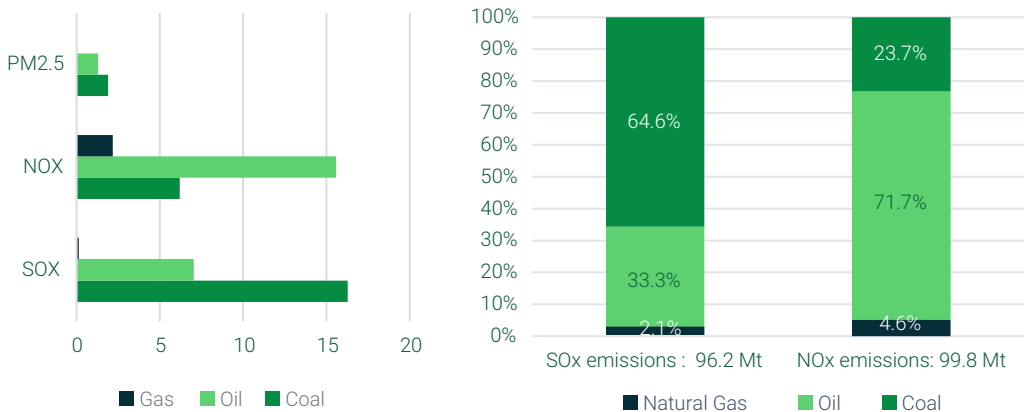
Note: The size of the bubbles represents the country's share in global primary energy consumption.
Source: GECF Secretariat based on data from the GECF GGM

Natural gas and pollution

In addition to its role in reducing carbon emissions, natural gas has undeniable benefits in reducing emissions of hazardous pollutants that are responsible for air quality degradation, such as nitrogen oxides (NOx), sulphur oxides (SOx, particularly sulphur dioxide, SO2), and particulate matters (PM2.5). Based on the respective emissions factor, natural gas emits 65% less NOx than coal and 85% less than oil. Regarding SO2, gas emits 99% less than coal and 98% less than oil. Gas also emits almost no fine particulate matters (see Figure 2.3 below).

In 2017, coal was responsible for nearly two-thirds of global SO2 emissions, estimated at around 94 million tonnes; oil represented more than 70% of global NOx emissions, estimated at around 100 million tonnes. Natural gas was responsible for much lower shares of overall global emissions of hazardous air pollutants, contributing less than 5% of NOx and 2.1% of SO2 (2).

Figure 2.3. SOx, NOx, and PM2.5 emission factors for gas, oil and coal (kg/toe), and global SOx and NOx emission shares by fuel in 2017 (%)



Source: GECF Secretariat based on data from the GECF GGM

Availability and reliability of gas supply

Natural gas is an available and reliable source of energy. The abundance of natural gas, with proved reserves estimated at more than 193 trillion cubic meters, means that the world has plenty of gas to meet its energy requirements for several decades. There is also a large untapped potential if we consider under-explored but promising areas such as Africa and the Arctic, and the development of unconventional gas resources significantly extends this potential.

The gas industry has made large efforts to make the exploration and development of gas resources more efficient, and it has been able to reduce both the costs and the environmental impact of gas-related activities significantly. The GECF countries have made a lot progress in this regard and they continue to undertake large investments in order to reinforce their gas production capacities despite challenging market conditions.

The availability and reliability of natural gas are also reflected in the ability of gas systems to ensure a continuous supply over the short-, medium-, and long-term. This ability has improved significantly with the increasing flexibility of gas supply chains, driven particularly by the expansion of LNG capacities. LNG supplements pipeline networks in order to provide diversified supply routes, and the recent emergence of floating and small scale LNG facilities has contributed towards improving the availability of natural gas and its expansion into new and emerging markets.

Moreover, the development of storage capacities, both in the form of underground reservoirs for long-term storage and pipeline line-pack and LNG for shorter-term storage, is another indicator of the increasing flexibility of gas supply chains. Countries such as China are striving to improve their storage capacity significantly in order to better manage seasonal demand and supply imbalances. China has released a plan to double its gas storage capacity from 7.4 bcm in 2016 to around 14.8 bcm by 2020.

Despite all these advantages, ensuring sustained availability and security of gas supply over the long-term needs large investments and this is strongly affected by security of gas demand. The gas industry remains capital-intensive and requires security of demand and visibility on revenues in order to ensure economic viability and secure funding. Security of demand can be improved through transparent policy actions in consumer markets, which recognize the important role of natural gas in achieving sustainable development.

Gas affordability and competitiveness

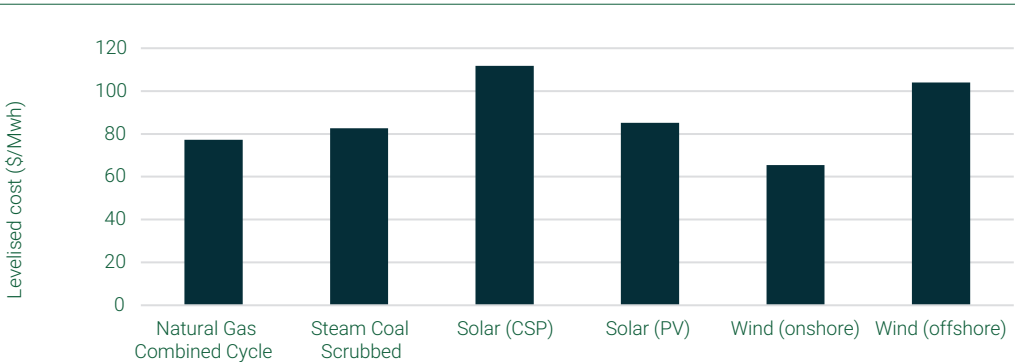
Natural gas remains an affordable and competitive energy source in many markets and for various usages, especially when compared to other energy alternatives such as oil products, electricity or even renewables. The integration of environmental externalities through the pricing of pollution and carbon emissions can further reinforce natural gas's competitive advantage, particularly over coal.

There are many drivers that support the affordability and competitiveness of natural gas including: its abundance and wide availability; an expanded gas infrastructure and networks in different markets; the energy efficiency of the gas based technologies (e.g. CCGT); possible synergies with other processes such as the combined production of power and heat; and low carbon penalties and pollution costs. Furthermore, it is much less costly to transport the same amount of energy in the form of natural gas than in the form of electricity, and this adds a further advantage to natural gas over electricity.

In power generation, one key indicator of the competitiveness of natural gas is the long-term levelised cost of producing power by using CCGTs. Based on an estimation of these costs in OECD Europe in 2017, CCGT remains competitive compared to solar, offshore wind and nuclear, with a cost estimated at around \$78/MWh. When the higher carbon prices which are forecasted in this Outlook, are taken into consideration, the cost of CCGT is even more competitive than coal-fired power plants in OECD Europe

In the case of onshore wind, the estimated levelised cost (\$66/MWh) is lower than CCGT. However, this cost estimation does not incorporate the hidden costs of integrating wind into power systems, which include the costs of strengthening electricity networks and the costs of back up generation to allow for the variability of renewables.

Figure 2.4. Average levelised costs by type of power plants in OECD Europe (\$/MWh)



Source: GECF Secretariat based on data from the GECF GGM

It is worth noting that the previous average levelised costs (Figure 2.4) aim to give an overall picture in OECD Europe, but there are some differences at countries' level. For instance, countries in southern Europe, such as Spain and Italy, have lower than average solar PV costs (estimated at around \$70/MWh for Spain and \$75/MWh for Italy) which is mainly due to larger exposition to sunlight in these countries. These costs also need to be addressed carefully since they do not take into account the other costs that deal with solar intermittency.

Natural gas and access to energy

Natural gas can provide significant access to modern, affordable and reliable energy. This access can take different forms including the supply of affordable gas-fired electricity, the expansion of gas networks to supply new areas and the development of small-scale LNG projects which make gas accessible in small and niche markets. Furthermore, the development of gas activities in countries with poor access to energy, particularly in sub-Saharan Africa, can provide revenues for these countries and enable them to develop infrastructure which will support improved access to that energy.

It is estimated that around 1.1 billion people worldwide have no access to electricity, most of them located in sub-Saharan Africa and South East Asia. Developing gas-fired power plants can strongly improve access to affordable and reliable electricity in these regions. In sub-Saharan Africa, electricity generated from natural gas expanded from 4% in 2000 to more than 10% in 2016. This figure is expected to more than double by 2040 according to the GECF Outlook. Several countries with relatively low access to electricity such as Mozambique, Tanzania and Angola are encouraging the use of gas in power generation as a lever to improve access and reduce energy poverty. Improving the domestic usage of gas, especially in power generation, is often planned as part of an extended gas/LNG export plan that enables countries to both increase their revenues and support energy access.

The expansion and integration of gas networks has the potential to increase the grid coverage in various regions, and to support access to clean energy for different domestic uses such as heating and cooking. Different countries have initiated programs of gas network extensions in order to reach new and isolated areas, such as in Algeria which has improved the penetration of gas such that 55% of Algerian households had access to gas by 2016. Russia has also been able to improve access to natural gas from 53% in 2005 to 67% in 2016 through the extension of its networks. The country further plans to reinforce its domestic gas network and ensure access to gas in new areas in eastern Siberia. Additionally, the development of gas networks and their integration is improving access to newly discovered or existing gas reserves in Sub-Saharan Africa.

2.2 Recent policy developments

The second part of the policy chapter provides an overview of the major policy developments that have occurred since the publication of the last Outlook, and which could have an important effect on the future for gas and energy in general. It is focused on those key markets which have a noticeable impact on gas prospects.

United States

Since the publication of the 2017 GGO, the US has pursued its 'America First' agenda through policy actions that demonstrate a willingness to use presidential power in an unprecedented manner. The actions taken by the current administration have made 2018 a tumultuous year for American domestic energy and environmental policies, as well as policies concerning the country's trade and geopolitical aspirations.

The Executive Order (EO) on 'Promoting Energy Independence and Economic Growth' supports the exploration and production of domestic energy resources by rescinding or modifying existing regulations. While there are uncertainties surrounding the implementation and potential impacts of this policy's directives, numerous actions have been taken since its passage that underscore the administration's aim to bolster 'energy dominance' through deregulation and increased production.

The passage of the 'America-First Offshore Energy Strategy' has opened nearly all offshore waters to oil and gas development, and numerous policies have been implemented to support the ailing domestic coal industry, including a replacement for the 2015 Clean Power Plan and the Grid Resiliency Pricing Rule.

For the first time in American history, the Department of the Interior (DOI) scaled back previously designated national parks by over two million acres. Both the parks subject to reductions are rich in oil, coal and uranium. The sites will remain open to mining claims until legal challenges have been resolved. At the time of writing, at least twenty mining claims had been made in previously protected areas. These actions come after the lifting of a coal leasing moratorium on federal lands, underscoring the administration's pledged commitments to reviving the coal and manufacturing industries.

During 2018, tariffs were also implemented on steel, aluminium, solar panels and numerous other goods from a wide range of trading partners. Furthermore, the past year has witnessed marked regulatory rollbacks on key environmental policies, which the subsequent sections will discuss in greater detail.

The complexity of the American legal system makes evaluating the long-term effects of these policies highly uncertain, not least because their implementation hinges on pending court cases. A characteristic feature of the American political system is that federal actions and proclamations are often challenged by State and local governments, private and non-state actors, environmental groups, non-governmental organizations (NGOs) and the general citizenry. While many actions taken by the Trump administration are certainly symbolic, they may have only a limited effect on long-term policy development.

European Union

During the last year the European Union took further steps towards implementing the ambitious Clean Energy for All package, which incorporates directives dealing with energy efficiency, energy performance in buildings, electricity market design, and guidance on governance. This package is also designed to advance the implementation of the Energy Union strategy, which pursues the objective of improving security of supply, affordability, and sustainability by encouraging a more integrated approach for cooperation between the EU Member States.

EU Member States have reached consensus on the implementation of the European Commission's (EC) clean energy package rules, and have agreed on more stringent targets compared to the initial proposal, for renewable penetration and energy efficiency by 2030 (3)(4).

Energy efficiency targets have been strengthened, with the objective of reducing primary energy demand by 32.5% by 2030, relative to the reference case scenario. (Initially, the proposed target was 30%). The EU has adopted a set of measures to support this target, including: i) the extension of annual energy saving obligations beyond 2020, ii) the consideration of an annual saving target of 1.5% of national energy sales with cumulative effect for the period 2021-2030; iii) the acceleration of smart metering for electricity and gas. Energy efficiency measures are also being reinforced by a revised Energy Performance of Buildings Directive (EPBD). This directive aims to accelerate the renovation of existing buildings and to reinforce energy performance standards for new ones. The EU also aims to achieve zero-emission buildings by 2050 (5).

The share of renewables in gross final energy demand will be subject to a revised binding target of 32% by 2030, up from 27%. The EU is also considering an upward revision clause in its renewables directive of this renewables target by 2023, signalling its ambitions to consolidate leadership in renewables development. The EU has also, however, enacted a set of measures including the reform of renewables support schemes favouring market instruments and the enhancement of electricity design which will improve the flexibility of power systems as well as their ability to balance the intermittency of renewables.

Another important development in Europe is related to the adoption of policy measures in several countries that aim to limit the role of coal and its environmental impact. Several EU countries, including Portugal, the Netherlands, Austria and France, recently decided to accelerate the phasing out of their coal-fired plants (6), particularly within the framework of the "Powering Past Coal Alliance" (7). For France, the President announced the retirement of coal power assets by 2021, bringing forward its previous 2023 target. Germany's new government agreed a coalition treaty to fix a date for the phase-out of coal, and established a commission to agree on a possible date for ending coal usage. In October 2017, Berlin was the first city to decide on ending coal heat and power by 2030. In addition, the EU adopted the

EU ETS phase IV reforms for the period post 2020, that creates mechanisms aimed to balance the supply and demand of emission allowances and to reinforce the role of these markets in reducing emissions (8).

China

China's policy continues to support the transition to a cleaner and more environmentally friendly energy system, especially through the implementation of its 13th Five-Year Plan, which mainly promotes renewables, energy efficiency and coal-to-gas switching.

For renewables, recent statistics indicate that China outpaced its solar PV capacity target (i.e. 105 GW by 2020) three years ahead of schedule and has also made significant progress toward its wind capacity target (i.e. 210 GW by 2020). For the latter, the country has increased its ambitions in terms of offshore wind development in order to tap a larger share of existing potential.

China's government incentivizes renewables capacity development through various support instruments, including priority access regimes and subsidies, mainly in the form of feed-in tariffs. However, the government has recently considered a significant reduction to these tariffs, especially for solar PV, in order to reduce government spending, to factor in renewable cost reductions, and to reduce the observed mismatch between capacity development and the ability of networks to reduce curtailments and waste (9). In addition to subsidy payment constraints, this mismatch contributed to a government decision to temporarily halt the development of large scale solar PV projects and impose a 10 GW cap on distributed solar PVs in June 2018.

It worth noting that one of the key recent policy orientations in China relates to improving the effectiveness of renewable support schemes and fostering better integration of renewable capacities in power systems. China has adopted a set of measures to tackle these issues, which include: i) issuing guiding principles to increase flexible capacities (e.g. gas fired capacities) and support efficient dispatching; ii) forcing power distribution companies to use renewable energy and support integrating actions; and iii) establishing an alert system to avert the risk of high curtailment and over-capacity to enhance the planning process (10). Furthermore, China is strongly promoting renewable capacities in areas where it can reduce their curtailment, for example near to high-consumption zones.

The Chinese government initiated energy market reforms with the aim of improving the competitive environment and setting domestic energy prices that incentivize investments in gas supply and infrastructure. They recently adopted a new pricing methodology for wholesale residential gas that aims to provide better signals for investors. The government has also reduced restrictions for foreign investment, especially to support domestic unconventional production (11).

China's coal policy has been focused towards strict limitations on the usage of coal in order to reduce its environmental impact, as well as on the large existing over-capacities of coal-fired plants. These policy restrictions were slackened slightly after shortages in gas supply last winter, and also after a temporary electricity shortage in the summer driven by increasing residential and industrial electricity demand. Specifically, the government allowed northern industrial regions to use coal for winter heating and it permitted the restart of coal-fired plant construction in some Chinese provinces such as Shaanxi, Hubei, Jiangxi and Anhui (12).

India

India is pursuing an ambitious policy aimed at shifting its energy system towards more efficiency and sustainability by encouraging the deployment of renewables and natural gas, and by promoting energy efficiency, particularly in the power generation and industrial sectors. The government has ambitions to meet the country's huge energy needs, driven by a growing population and economy, while simultaneously alleviating energy poverty and preserving the environment. Renewables continue to be a key priority in India and the government has intensified the auctioning of renewable projects to increase capacity in line with stated targets (175 GW by 2022 for solar, wind, biomass and small-scale hydropower). Recent solar and onshore wind auctions were driven by cost reductions and the relatively low prices attracted significant interest from renewable developers. India is planning further auctioning rounds to achieve a higher penetration of renewables in its energy mix. In April 2018, the country invited a first offshore wind auction, and has also announced a new policy to incentivize the development of hybrid wind and solar projects that could better integrate renewables into power systems.

In its draft National Energy Policy document (NEP) released in June 2017 (13), the Indian government stressed the role of natural gas in improving the Indian economy and reducing air pollution. The document recalled the ambition to increase the share of natural gas used in the country, and to reinforce measures that support this progress in different demand sectors. The government aims in particular to advance energy market and price reforms in order to support more competitiveness and to encourage investments in the development of the gas infrastructure and domestic supply. The reforms will focus on reducing the regulated price distortions exacerbated by subsidies, as well as tackling the lack of harmonization between Indian states. Last year, the Indian government introduced a new tax regime for goods and services (GST) which aimed to harmonize tax rates, including those on energy products, in different Indian states (14).

Measures have also been undertaken to encourage investments in domestic supply under the Hydrocarbon Exploration & Licensing Policy (HELP), which was designed to attract more investment interest. India also applied market-based mechanisms for domestically produced gas as a lever to incentivize investment in domestic supply.

In addition, the NEP document demonstrates the country's support for domestic coal production and the increase of its quality. In line with this policy, Coal India, a state-controlled mining company, announced plans to significantly boost domestic production. India has achieved important steps in promoting clean coal technologies, particularly through mandatory regulation and reinforced emission standards. However, the recent reduction of coal taxes (Coal Cess) plays in favour of coal demand and associated emissions.

Japan

In July 2018 Japan approved its 5th Strategic Energy Plan, which supports energy security, economic efficiency, environment and safety. The government has kept the 2030 power generation mix target that was set in 2015 (nuclear 22–24%; renewables 22–24%; gas 27%; coal 26%). The plan confirms the key role that nuclear power will continue to play in the country's energy mix and outlines the trajectory by which the share of fossil fuels will be reduced, from 90% in 2016 to around 76% in 2030 (15)(16).

Through these targets the Japanese government hopes to enhance energy self-sufficiency to 24% by 2030, up from 8% in 2016. In addition to restarting nuclear power plants and promoting renewable energies, Japan aims to increase

energy self-sufficiency by directly participating in the development of hydrocarbon resources abroad, as well as through resource diplomacy with countries that supply the country with energy, including GECF Members, such as Qatar and the UAE.

Renewables and energy efficiency are also key features of the Strategic Energy Plan. The government wants to ramp up the tendering of renewable projects, promote other solar technologies, improve the flexibility of power systems in order to integrate renewables, and incentivize innovation, especially for storage technologies.

Japan has also taken important steps to liberalize its gas market by introducing full competition in its gas retail business in 2017. The government expects that boosting competition and attracting investors in gas infrastructure will mitigate the bottlenecks and existing disconnections between regional gas networks. The next stage of gas reforms will reinforce open access to infrastructure and LNG supply, in order to diversify a market that is currently dominated by a few large suppliers (e.g. Tokyo Gas, Osaka Gas, and Toho Gas).

South Korea

The recently elected president, Moon Jae-In, and his administration have put environmental protection and nuclear safety as key strategic energy priorities in the country. In this context, the administration aims to reduce the role of coal and nuclear, while supporting cleaner and safer options including LNG, renewables and energy efficiency improvement.

In December 2017, the government launched the 8th Long-Term Electric Plan which supports the reduction of the share of coal and nuclear in the country, although this support is not as ambitious as that pledged by President Moon (17)(18). For instance, the plan considers the conversion of only two out of nine planned coal plants to natural gas, instead of the four initially announced by the President. However, the Korean government has declared it will introduce coal taxation and reinforce pollutants standards as a way of reducing the environmental impact of coal combustion. For nuclear, despite a projected decline in capacity due to the decommissioning of old nuclear capacities, the government plans to build two new reactors by 2022 after these plants gained public support in a poll last October.

The 8th Long-Term Electric Plan anticipates LNG and renewables playing a key role in the future energy mix, and the recently announced initiatives to introduce fiscal incentives (e.g. a reduction of LNG and renewable equipment import taxes) will encourage this development. South Korea also plans to reinforce its renewable support schemes, mainly through feed-in tariffs and funding as well as renewable obligations, particularly for the heating sector.

Other Asian Countries

The recent policy developments in many Asian countries show increasing interest in promoting natural gas, especially in the power generation sector. This interest is mainly driven by government willingness to reduce pollution and carbon emissions as well as to substitute gas for oil in the power, industry and transportation sectors. Countries like Pakistan, Bangladesh and Vietnam have taken steps towards setting incentivizing gas policies to attract investors to develop gas-fired power plants, import infrastructure and upstream activities. This has led to the sanctioning of various projects including gas-to-power plants as well as LNG terminals.

Policy makers in the region still consider coal to have a key role to play in securing affordable energy supply in the

context of growing energy needs. Many coal-based projects are planned that will support coal demand in the region (e.g. Indonesia, Malaysia and Vietnam want to diversify their supply within the context of increasing gas imports). However, recent energy plans produced by different Asian governments highlight in many cases a downward revision of additional coal capacities compared to previous plans, as well as more support to renewable energy and energy efficiency to rationalize demand growth. Indonesia has reduced the huge planned additional coal capacity in its 10 year electricity development plan for the period 2016-2026 by 17% compared to the previous plan, and the recently released plan for the period 2017-2027 confirms the need to retire old and inefficient coal capacities by 2025. Moreover, Vietnam reduced its coal planned capacities by around 30% in a plan adopted in March 2016, compared to its previous program elaborated in 2010 (19).

In addition to these developments, Asian countries are continuing to make efforts in order to enhance energy cooperation and the integration of their energy systems, especially via the framework of the Association of South East Asian Nations (ASEAN). The ASEAN ministers of energy have endorsed a plan of action for energy cooperation over the 2016-2025 period that sets out several areas of cooperation including: the development of an ASEAN integrated power grid; the development of integrated gas systems through pipelines and LNG trade; support for clean coal technologies; and the promotion of energy efficiency and renewables. For the latter, ASEAN has set 2025 targets to achieve 23% of renewables penetration in the energy mix and to decrease energy intensity by 30% compared to 2005 levels.

Latin American countries

The push towards the use of more renewable energy and natural gas has been one of the main features of recent policy actions and announcements in key Latin American countries. The dominance of hydropower in the region and its sensitivity to weather conditions make renewables, including biomass, and natural gas good partners to hydro in order to achieve a reliable energy supply.

The key policy instruments used to promote gas and renewables are primarily related to advancing energy market reforms and promoting market mechanisms, such as the auctioning of capacity for renewables. Brazil, Argentina and Mexico have adopted plans to scale up the amount of renewable capacity to be auctioned, through different bidding rounds, in order to advance their ambitious renewable targets. This renewable policy orientation has been boosted by the positive results and low prices achieved in recent rounds. For instance, in its last 2017 auction, Mexico secured record low prices (less than 20\$/MWh) for wind and solar power. Argentina has already undertaken three successful auction rounds that awarded more than 3.8 GW of renewable capacity projects by the end of 2017. Brazil is also using auctions to help achieve the goal it set out in its most recent 10-year energy expansion plan which sets a target for renewables to reach 48% of primary energy consumption by 2026.

Regarding natural gas, several measures and initiatives undertaken recently in major markets reveal an ambition to enhance the role of natural gas, particularly by advancing reforms and improving the efficiency of gas markets. Brazil has initiated a gas market liberalization process and the country has taken some steps to open up the distribution sector to private companies, advancing third-party access for gas pipelines and LNG terminals as well reducing the monopoly role of the national company Petrobras. Brazil has also announced a gas initiative that supports gas in power generation as a substitute to oil-fired power and as a viable option to compensate for fluctuations in hydro power.

Argentina has also taken policy measures that aim to encourage investment in its upstream gas sector, including offshore exploration and unconventional resources. For the latter, the country recently adopted a program that considers specific price incentives and measures aimed at accelerating the development of the promising Vaca-Muerta basin.

Mexico has achieved advanced liberalization of its gas sector and set various measures to facilitate third-party access to its natural gas assets. The last licencing round attracted a number of foreign companies driven by the oil price increase. However, the newly elected president vowed to change the policy and to review energy contracts signed under the previous regime amid criticisms over the liberalization of the energy sector. This will entail some uncertainty over future energy policy development in the country. It is worth noting that one of the key priorities announced by the new president is to reduce gas dependency and support domestic production.

2.3 Energy policy assumptions

This Section defines the main policy assumptions considered in the Outlook, taking into account key policy drivers and developments, and the challenges faced by different countries in achieving these targets and policy ambitions. The assumptions are structured by policy domains including renewables, non-renewables, energy efficiency, and climate-oriented measures. They are highlighted on global scale and by key consuming markets. The aim is to capture the common and impactful global policy trends and assumptions occurring in various policy domains, and to show policy orientations that support these global trends at a market level.

2.3.1 Renewable policies

Assumptions for renewable policies on a global scale

More than 170 countries have set renewables targets that drive their policy effort (20). These countries deploy different renewable support schemes either in the form of direct government intervention through subsidies and funding supports, or in the form of market-based mechanisms that might include renewable auctions, feed-in premiums or renewable trading certificates. In addition to renewable specific schemes, countries also apply transversal policy measures such as carbon pricing or emissions standards that can incentivize renewables and other clean options such as switching to natural gas.

Concerning renewable support schemes, the role of market-based mechanisms in the portfolio of measures considered by countries has been increasing, specifically in countries that have achieved large renewables progress. These countries are aiming to shift their renewable policy approach to achieve cost efficiency and to allow better integration of intermittent renewables.

Market-based mechanisms can be a response to a reduction in the cost of subsidies and a way to incorporate market fundamentals in investment decisions, mainly by transferring the risk to project developers. However, higher risk and lower revenues for investors might lead to a significant slowdown in the installation of additional renewable capacities. In this regard, the implementation and design of these market-based instruments needs to take account of country specifics, the maturity of the market and of the renewable technologies to be promoted (21)(22). Auctioning of capacities has recently emerged as a popular market-based policy instrument, since it lowers the price of renewable

capacity due to competition between bidders. However, it can also increase the risk of not achieving appropriate returns for investors (23).

This Outlook assumes that renewable support schemes will be a combination of instruments including subsidies as well as market-based instruments. Subsidies are assumed to continue to play a key role, especially in emerging markets, and also for some renewable options and technologies such as distributed renewable energy systems.

The integration of renewables is the main challenge for their progress, especially in markets hoping to achieve a high level of penetration. To deal with this challenge, the Outlook expects increased implementation of policy measures aimed at improving the flexibility of power systems and their capacity to accommodate a large share of intermittent renewables. Gas-fired power plants are expected to play a significant role in improving renewable integration.

Despite increasing policy attention being given to the deployment of renewables in other sectors such as heating and transportation, the Outlook is cautious regarding renewables progress in these sectors; this view is mainly supported by competition from other energy alternatives such as oil and natural gas.

Renewable policy drivers and assumptions in key markets

In the US, the only national renewable energy targets set by the government were enshrined in the 2013 Climate Action Plan, which aimed to double renewable electricity generation by 2020. The Trump administration ordered the policy to be rescinded immediately, which was made official with the passage of the Executive Order on Energy Independence.

At the federal level, corporate tax credits for renewable technologies have been reinstated by the Budget Act of 2018, offering (among other incentives) a scaled 30% rebate for solar and wind technologies, as well as fuel cells. Tax credits for renewable energy installations and energy efficiency improvements in residential and commercial buildings have also been reinstated under the ENERGY STAR programme.

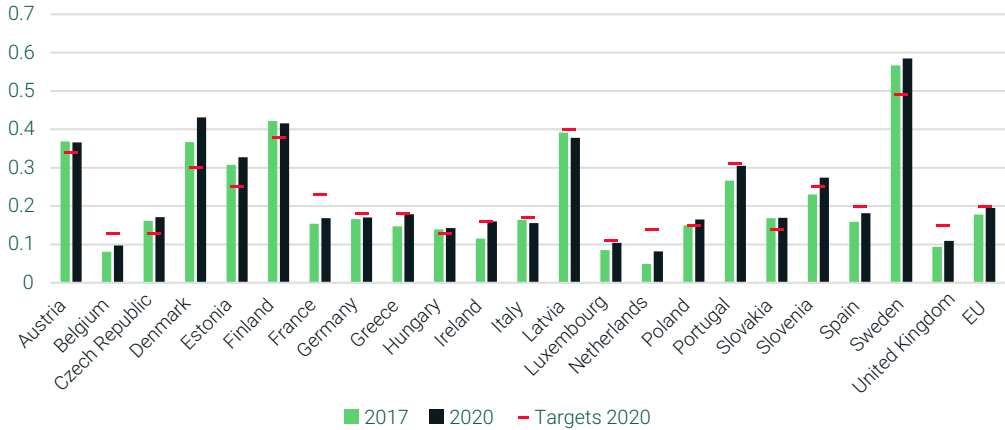
However, the majority of efforts regarding renewable energy policies and measures have been spearheaded by sub-national governments, industry, utilities, and businesses. Twenty-nine states and Washington D.C. have set mandatory Renewable Portfolio Standards (RPS) and eight states have voluntary renewable energy targets. While RPS have been responsible for approximately 50% of the growth in renewable generating capacities since 2000, their role and scale have diminished over time. These policies are systematically revised and vary widely by region and in terms of design, enforcement mechanisms, and scope.

In addition to state mandates, cities and businesses have also committed to renewable energy targets. Six US cities are already powered by 100% renewable electricity and 78 more have pledged their commitment. An influential and diverse group of American businesses, including the five largest publicly-traded companies in the world—Apple, Amazon, Google, Microsoft and Facebook—have also announced 100% renewable electricity targets. These trends demonstrate an important paradigm shift, where corporate demand is making increasingly important contributions to renewable power projects and investments.

This Outlook assumes that communities, state and local governments, and the private sector will continue to play an

influential role in renewable energy generation through to 2040, notwithstanding federal policy mandates.

Figure 2.5. EU Member States renewable shares, and targets according to National Renewable Energy Action Plans



Source: GECF Secretariat based on data from GECF GGM

For the EU, the Outlook assumes that the adoption of more ambitious targets in the new EU renewable energy directive will encourage EU countries to implement measures aimed at accelerating the development of renewables, and to deal with their different challenges, mainly the cost of subsidies and renewables' integration. However, differences are expected in terms of policy effort and outcomes depending on countries situations and constraints (24)(25).

The Outlook assumes that Member States in northern Europe, and several countries in the eastern part of the EU, especially those that have large hydro potential such as Romania, Austria and Bulgaria will over-achieve their 2020 targets (i.e. targets set in the National Renewable Energy Action Plans). However, other countries such as Germany, Netherlands, France and the UK are expected to miss their 2020 targets. The UK and France, in particular, are assumed to be deploying more effort in order to catch up with other countries.

The collective effort of EU Member States is expected to allow the EU to get close to its 2020 renewables target (20%), and to achieve a renewables share of around 25% by 2030, thereby missing the ambitious stated target for this horizon (32%).

As indicated in the EU Renewable Energy Directive and EU guidelines on State Aid (26) EU countries will focus on cost efficiency and market approaches when designing their policy support instruments. As a result, market-oriented renewable schemes, including the auctioning of capacities, feed-in premiums as well as renewable certificate trading, will all see progress. Despite this progress, government intervention, either in the form of direct subsidies or fiscal and financial incentives, will still play a role to keep renewable momentum going, especially for the less mature renewable technologies.

In addition, electricity market reforms and capacity mechanisms are assumed to improve the ability of liberalized electricity markets to accommodate intermittent renewables and to reduce the distortions observed in these markets. Natural gas is also expected to be supported as an efficient flexible option which encourages this renewable integration.

For China, the Outlook takes into account the recent government decisions to reduce subsidies for solar PV and onshore wind projects and to cap the development of solar PV projects. This decision is expected to slow down solar PV capacity development significantly, as well as onshore wind compared to recent trends. However, despite this slowdown, renewable capacities will continue to grow over the long term driven by cost reductions and by the auctioning of new capacities. Auctions will be an important driver of renewable capacity additions reflecting a policy shift from direct subsidies to market-oriented support schemes. Conversely, the Outlook assumes that China will be able to reduce the large observed renewables curtailment, mainly by improving the flexibility of its power system. Gas-fired power plants play a key role in improving this flexibility.

Furthermore, the Outlook considers that China will make some progress with solar CSP including power storage development which is an option that allows the management of variability in solar power production. The country has a target of reaching 5 GW of CSP by 2020 and aims to surpass 27 GW capacity by 2030 (27), but it is expected that Chinese CSP will only reach around 10 GW by 2030 due mainly to cost issues.

For India, the government has recently announced that the country can achieve its 175 GW renewable capacity target before 2022, through strengthened policy support, intensified auctioning of projects and mobilization of funding (28). The government expects that the International Solar Alliance will play a key role in supporting the implementation of solar projects that will drive renewable growth in the country.

The Outlook assumes that India's policy will contribute to accelerating renewables development, especially through capacity auctioning that has helped to achieve low prices. However, some key challenges will prevent India from reaching its ambitious renewables target, including funding constraints and competition from cheap coal, a lack of compliance with renewable obligations at provincial levels, a non-stable fiscal policy with the reduction of renewable subsidies funded from coal taxation, and an increase in the tax on imported solar panels. Furthermore, the ability to integrate renewables will be a key concern due to grid bottlenecks and the lack of flexibility of power systems, and this challenge will affect the deployment of intermittent renewables in the country. The Outlook assumes that India will reach around 75 GW of solar PV out of the targeted 100 GW by 2022. Wind capacities are expected to account for around 47 GW by 2020.

Japan and South Korea exhibit strong policy ambitions to scale up the share of renewables in order to support their energy security and deal with environmental concerns. Their recent plans consider a portfolio of measures such as auctioning of projects, subsidies, financial and fiscal incentives and also strengthened renewable portfolio standards in the case of South Korea.

The Outlook factors in the 5th Strategic Energy Plan for Japan which considers renewables as a major power source and assumes that the country will be able to achieve its target (i.e. 24% of power generated from renewables, solar and

Table 2.2. Targets and main renewable policy drivers and assumptions in key markets

	Renewables targets	Main renewable policy drivers and assumptions
US	No national target State level targets (e.g. California = 60% by 2030 and 100% by 2045)	<ul style="list-style-type: none"> - Implementation of federal tax credits for renewables - Introduction of tax on the import of solar panels - Increasing role of communities, state and local governments, and the private sector in supporting renewables
EU	Renewable share in gross energy consumption: 20% (2020) and 32% (2030). Upward revision of the 2030 target	<ul style="list-style-type: none"> - Strengthened measures to support more ambitious targets in the new EU renewables directive; but disparities between countries - Increasing use of market-oriented renewable schemes, including auctioning, feed-in premiums as well as renewable certificate trading - Electricity market reforms improve ability to integrate renewables. - Natural gas will play an important role in supporting renewable deployment - EU expected to achieve 25% renewable share by 2030 (missing its 32% target)
China	Share of non-fossil fuels in the energy mix: 15% (2020) and 20% (2030). (2020) 13th FYP power capacity targets: Solar PV 105 GW; Solar CSP 5 GW - Wind 210 GW)	<ul style="list-style-type: none"> - China expected to over achieve its 13th Five-Year Plan targets for Solar and Wind driven by past years' progress - Slowdown of renewables progress compared to recent trends, driven by recent decisions to reduce subsidies and to cap solar projects - Cost decrease and auctioning of new capacities support continued growth over the long-term - Implementation of measures to improve power system flexibility and management of renewables curtailment - Gas will play a key role in providing flexibility for intermittent renewables
India	Share of non-fossil fuels in power generation: 40% of installed capacity by 2030 (2022 power capacity targets: Solar PV: 100 GW; Wind: 60 GW; Bioenergy : 10 GW; Small Hydro: 5 GW)	<ul style="list-style-type: none"> - Cost decreases and auctioning of new capacity will support large renewables progress. - Funding issues, persisting power grid bottlenecks; competition from coal and non-stable fiscal policy will hamper the country in meeting its targets.
Southeast Asia	ASEAN = 23% (2025); Indonesia = 23% (2025), 31% (2030); Malaysia = 22-24% (2030)	<ul style="list-style-type: none"> - Feed-in tariffs, fiscal and financial incentives as main support of renewables progress. - Need of affordable energy sources to meet the huge requirements of baseload power will challenge the achievement of national targets and ASEAN target
Latin America	Mexico: Share of non-fossil fuels: 35% by 2024, 40% by 2035 - Argentina: 20% share of electricity consumption by 2025 - Brazil: Share of renewables in the energy mix: 48% by 2026; share of non-hydro renewables in the power 23% by 2030	<ul style="list-style-type: none"> - Auctioning will be a key driver in supporting the development of renewable capacities - Reinforcing networks to integrate renewables will be a major challenge in the region

hydro in particular). However, for South Korea, despite strong expected progress, the stated target of 20% renewables excluding large hydro in the power mix appears very ambitious. The country has to deal, in particular, with the high cost of developing renewables compared to other alternatives, which might affect the competitiveness of its export-oriented

industry.

Regarding the other Asian countries, the Outlook assumes that the implementation of renewable support schemes, in particular feed-in tariffs as well as fiscal and financial incentives, will drive the progress of renewables in addition to cost decreases. Cooperation between Asian countries in the framework of ASEAN also contributes to renewable development, especially for solar PV. However, many challenges hinder the achievement of the announced targets at a country level and at the ASEAN regional level. Among these challenges are the need for affordable energy sources, such as coal and gas, to meet the huge requirements of baseload power capacities in the region. The region also needs to scale up investments in grid connections in order to integrate intermittent renewables (29).

For Latin American countries, the Outlook assumes significant progress, especially in wind, solar PV and bio-energy driven by the huge potential of countries as well as by strengthened policy support, specifically with the intensification of auctioning (30). Like other emerging countries with growing electricity demand, the need to ramp up power capacities and to reinforce networks in order to integrate intermittent renewables constitute major challenges for renewable progress in the region.

2.3.2 Non-renewable policies

NATURAL GAS

Assumptions for gas policies on a global scale

Policies play a key role in supporting or constraining the progress of natural gas in countries' energy mixes. There is evidence that the adoption of measures favourable to natural gas could accelerate the penetration of this source of energy and achieve many economic, technical, social and environmental advantages. One case in point is China. The country adopted several measures to support the development of gas infrastructure and trade, and to encourage the penetration of gas at the expense of polluting and carbon intensive fuels, mainly coal; these measures resulted in an increase in the share of natural gas from 2.8% in 2007 to around 6.7% in 2017.

There are, however, some policy challenges for natural gas. They can be related to poorly designed policies as seen in countries like India (31), or to the reluctance of policymakers to support natural gas as a sustainable fuel as it can be seen in some European countries. This policy reluctance is particularly driven by the perception of policymakers that natural gas can lead to insecurity of supply and, as a fossil fuel, that it is not compatible with a vision of an energy future based solely on carbon-free alternatives (renewables in particular). These perceptions need to be mitigated through a constructive dialogue. So far, a major part of feasible forecasts and scenarios consider hydrocarbons to remain an important constituent of the future global energy mix, in order to meet growing energy demand, especially for non-OECD countries. Natural gas as the cleanest fossil fuel therefore has a key role to play. Moreover, the abundance and diversity of supply routes can make natural gas a reliable and secure source of energy.

In this Outlook, it is assumed that natural gas continues to be encouraged through different measures that promote domestic production, the development of gas infrastructure, integration of networks, and the development of imports, particularly through LNG. Among the key measures that are expected to be adopted in this regard are: market reforms that aim to improve competition and attract gas investments in the upstream and midstream sectors; the facilitation of permits and administrative processes for gas project developments; and cooperation between countries to improve the availability and accessibility to natural gas and to enhance gas trade.

The Outlook also assumes the adoption of environmental policies that encourage the consumption of natural gas through strengthened emissions standards, pricing of carbon, or mandated fuel switching to natural gas from coal and oil. Gas is particularly promoted in power generation as a flexible option to balance the variable electricity that results from a large penetration of intermittent renewables.

The transportation and heating sectors will see strong policy attention to improve the penetration of natural gas. For transportation, one of the key policies is the support to infrastructure development in bunkering and gas refuelling stations, in order to cope with strengthened emission standards. Specifically, the development of bunkering is encouraged by expected implementation of the new International Maritime Organization (IMO) standards after 2020 (32).

Gas policy drivers and assumptions in key markets

In the US, the 'America-First Offshore Energy Strategy' encourages oil and gas development on the Outer Continental Shelf (OCS). In January 2018 the US revised a 5-year (2019-2024) leasing plan for the OCS, opening nearly all offshore waters to oil and gas development. The Secretarial Order addressing the matter cited the billions of barrels of oil and over 100 trillion cubic feet of gas from undiscovered technically recoverable oil and gas resources which had been foregone as a result of the previous administration's ban on drilling leases.

The decision was met with swift opposition from coastal states. Just days after the announcement, the DOI amended its original statement by exempting one state from consideration, due to its heavy reliance on coastal tourism. A group of 227 state legislators from 17 other coastal states then also petitioned to be removed from the programme.

Preceding significant and lengthy legal challenges, the previous year also saw the rescission of a ban on hydraulic fracturing on federal and tribal lands. The state of California and a coalition of environmental groups have sued the US Bureau of Land Management (BLM) over the decision. A court ruling denied a motion to dismiss the case for lack of jurisdiction, and a more recent bid to transfer the environmental litigation to outside of California was denied. The implementation of this policy is therefore uncertain - as are its potential effects on US natural gas reserves.

Nonetheless, this Outlook assumes that the shale revolution in the US will retain its momentum, regardless of pending legal challenges in the aforementioned policy cases. This Outlook also assumes that US gas exports will be aided by the Department of Energy's decision to streamline reviews. The final ruling, published in July, ensures that any complete application that seeks to export natural gas (including LNG) will be authorised, as long as the application proposes exports under a specified volume and does not require an environmental impact statement or an environmental assessment.

The EU's gas policy is mainly articulated around building an internal and competitive gas market through the implementation of the Third Energy Package and promoting gas security of supply through diversification and increased cooperation between Member States. The liberalization of European gas markets has been a long and challenging process, and contributed to increased risks for gas suppliers, mainly because it brought uncertainties over the final configuration of the EU gas market, on the implementation and enforcement of EU rules and mechanisms in different Member States as well as on gas revenues. The stability of gas revenues, which has been ensured by the traditional gas transaction model (i.e. long-term indexed contracts), is considered as an important driver for funding and developing capital-intensive gas supply projects. Although the EU does consider some derogations to the liberalization rules and proposes funding for gas projects of common interests, important challenges remain, especially for gas pipelines, due to financing issues and economic uncertainties as well as geopolitical constraints.

This Outlook assumes a level of EU policy support to some key gas infrastructure projects, especially those outlined in the European Union list of projects of common interest (33). However, the Outlook adopts a cautious view on the timing of their implementation due to various economic and geopolitical concerns.

LNG is assumed to play a non-negligible role in the EU, consistent with the strategy adopted by European countries to diversify sources and secure large supplies of natural gas (34). Moreover, this Outlook expects UK regulation to be supportive to the development of natural gas, shale gas in particular, which will contribute in slowing down the decline of UK domestic gas production. The UK policy to encourage domestic production is particularly underpinned by the Dutch gas supply concerns which has led to the rapid decline of European production and a loss of flexibility which this supply provided in the past (35).

In addition to measures affecting gas supply, the Outlook assumes that natural gas consumption will benefit from a policy push towards clean sources of energy, especially with the implementation of reinforced emission standards. Natural gas will also be promoted as a flexible option to support renewable electricity.

For China, although the recent policy push has led to a significant increase in gas demand, there are still some challenges that need to be overcome in order to meet the country's announced target (8-10% share of gas by 2020 and 15% by 2030). Among these challenges are the need to scale up domestic production, build extended infrastructure and storage facilities to manage seasonality and implement pricing and market reforms.

The rigidity of the gas market structure in China, difficulties in implementing market reforms at a provincial level and the dominance of regulated gas domestic prices prevents investments and weighs on government budgets. The recent decision of the National Development and Reforms Commission (NDRC) to amend gas prices in the residential sector (36) is an important step forward aimed at relaxing this budget constraint and improving price responsiveness to market fundamentals.

In the Outlook, China is expected to advance the reforms of its gas sector, which will allow it to increase the role of market mechanisms in domestic gas transactions. Reinforced cooperation with international actors is expected to support investment in the Chinese gas supply chain and the upstream gas industry. On the demand side, Chinese

policy is expected to continue supporting the progress of gas in different sectors to reduce pollution, mainly in heating, industry, power generation and transportation. Gas will also play a role in complementing the expected penetration of renewables in the country. China is expected to achieve a gas share of 8% in 2020 and 15% by 2040.

Despite an ambitious gas target, India has struggled to increase the role of gas. The fuel faces several barriers including affordability issues, competition from cheap coal, a lack of infrastructure and the stagnation of domestic production due to lack of investment (31). There are also challenges due to the organization of the energy sector and difficulties in implementing harmonized policy measures and reforms at a state level (13)(37)(38).

In its draft NEP policy, the Indian government announced its intention to address different barriers to natural gas, by advancing price and market reforms. Some steps have been taken with recent domestic price adjustments and the launching of new exploration and development policies. However, the gas sector in India remains very sensitive to price evolution and competition from coal in some sectors such as power generation.

This Outlook assumes that Indian policy measures will contribute to increasing availability and accessibility to natural gas, and will drive its growth, especially in sectors where gas is in competition with oil, such as transport and industry. For the power sector, measures that support increased usage of gas-fired plants are expected to be implemented, but gas will continue to observe difficulties due to competition from coal, and the uptake of renewables. Despite some expected progress by gas, the Outlook assumes that its share in the energy mix will remain far below the ambitious stated target. The sensitivity of gas to price evolution and its competitiveness against cheap coal will remain key determinants for gas penetration over the long-term.

The recent policy developments in many Asian countries show increased interest in promoting natural gas, especially in the power generation sector. This interest is mainly driven by the willingness of governments to reduce pollution and carbon emissions, as well as to substitute gas for oil in the power, industry and transportation sectors. Countries like Pakistan, Bangladesh and Vietnam have taken steps in setting up incentivizing gas policies to encourage investors to develop gas-fired power plants, import infrastructure and upstream activities. This has led to the sanctioning of various projects including gas to power plants as well as LNG terminals.

For other Asian countries, it is expected that natural gas will benefit from policy support in order to reduce carbon and other pollutants' emissions, and to substitute for oil, especially in the power and industrial sectors. Policy incentives for domestic production and LNG imports, as well as cooperation, especially through ASEAN framework, will drive the progress of natural gas, although competition from coal will mitigate its potential.

COAL

Assumptions for coal policies on a global scale

As the most carbon intensive and polluting fuel, coal is largely targeted by policies as a means of improving air quality and reducing CO₂ emissions. In this regard, several countries have announced plans to phase out or limit the role of coal in their energy mixes. The launching of a new initiative, "Powering Past Coal Alliance", supports these commitments with more than 25 countries which account for around 7% of global carbon emissions, deciding to move away from coal

by 2030. Other actors are also playing a role in this dynamic such as cities, institutions, banks, environmental agencies and business entities which have pledged to undertake actions against coal.

Despite these observed trends, other countries, especially in Asia and Eastern Europe, continue to rely on coal as an abundant, cheap and often domestically produced alternative. These countries have, though, deployed extended efforts to adopt cleaner and more efficient coal technologies. These clean technologies can be used in different phases of coal exploitation, including the pre-combustion phase (e.g. coal washing); combustion phase (e.g. efficient coal burning with the use of ultra-supercritical coal power plants); and post-combustion phase (e.g. desulphurization of flue gas).

In this context, the global coal policy orientation assumed in the Outlook is to limit the environmental impact resulting from coal-related emissions. This will occur either through the phasing out of coal or by adopting measures, particularly in emerging countries, which improve energy efficiency and support pollutants emissions' reduction from coal-based technologies.

Coal policy drivers and assumptions in key markets

The 2015 Clean Power Plan (CPP) was the first national policy in US history to set limits on carbon emissions from the power sector. The plan largely targeted coal-fired power plants, promising to reduce CO₂ emissions by 32%, SO₂ emissions by 90%, and NO_x emissions by 72% by 2030, relative to 2005 levels. The CPP was hailed by many as a significant step towards meeting international climate commitments under the Paris Agreement.

The current administration has been extremely vocal about reviving the failing coal industry and, as noted in last year's GGO, the EO on Energy Independence ordered a review of the policy. In August of this year, the US Environmental Protection Agency (EPA) announced a potential replacement: the Affordable Clean Energy (ACE) rule.

There were also ongoing litigation challenges to policy updates during 2018, including: delayed compliance deadlines for a policy targeting effluent limits from coal-fired plants, weakening of a coal ash rule that regulates disposal, reconsideration of mercury and air toxins standards for coal-fired plants, the repeal of a stream protection rule aimed at protecting drinking water sources from mountain-top mining operations, and a proposed grid Resiliency Pricing Rule (which will be discussed in greater detail in the subsequent section on nuclear energy policies).

Despite the administration's efforts to extend a lifeline to the ailing coal industry, this Outlook assumes that coal-fired generation in the US will continue to shrink due to the flexibility and cost-competitiveness of natural gas and renewable resources. In line with historical trends, which saw the retirement of 358 coal plants between 2012 and 2017, this Outlook assumes that the drive generated by increased environmental concerns and basic market forces will play a more significant role than policy interventions.

For the EU, the Outlook assumes the phasing out of coal in power generation as already announced by several European countries. There appears to be a stronger desire to implement the phasing out this year, compared to what was assumed by the Outlook last year, supported by the EU's plan to accelerate its carbon mitigation measures in the context of the implementation of the Paris Agreement. (It is worth noting that 15 out of the 20 countries which are part of the Powering Global Alliance of Coal are located in the EU). Even in Germany, one of the largest coal consumers, this

Outlook assumes more efforts will be made to reduce coal usage, to reflect the recent policy shift after the election of a new government in the country. This shift is also expected in the context of Germany missing its 2020 GHG emissions reduction target (39).

Furthermore, the implementation of reinforced emissions standards in the context of Industrial Emissions Directive (40) and EU ETS Phase IV reforms are expected to affect coal use in the region significantly. Although coal use will diminish overall in the EU, it will retain a non-negligible share in some eastern countries, such as Poland, as a means of securing affordable energy supply.

In China, despite an observed loosening of policy restrictions on coal in 2018 (see Section 2.1), the government is assumed to be continuing to implement measures on limiting the consumption of coal, and accelerating the use of clean technologies as outlined in the 13th Five-Year energy plan, thus realising China's policy ambition to reduce its environmental footprint. China is expected to achieve its objective for coal to reach less than 58% of the primary mix by 2020. The country is also promoting clean coal technologies, especially in the power sector where the energy efficiency of the coal power plants' fleet is expected to improve significantly (41).

For India, although the recent reduction in the coal tax is expected to drive growth in the usage of coal over the short- to medium-term; the Outlook expects that this growth will be mitigated over the long-term by the implementation of policy measures which support efficiency in coal usage. Nevertheless, India is assumed to continue to rely on coal as an important source of energy, especially in the power sector.

For Japan, the recent strategic plan highlights that the country will still rely on coal over the long-term. There is a plan to add 36 coal-fired power plants in the next decade, but this plan might face some challenges including public opposition and the decision of large banks to stop financing coal projects. Despite these challenges, the Outlook assumes that the targeted 26% coal share in power mix will be achieved by 2030, in line with the government's priorities to diversify its energy sources and secure its supply. However, strong efforts are expected to be deployed in order to reduce the environmental impact of coal through the development of highly efficient technologies such as Ultra Supercritical Coal plants and Integrated Gasification Combined Cycles.

For Korea, this Outlook assumes that coal policy, particularly coal taxation and emissions standards, will contribute to mitigating the growth of coal demand, especially in the power sector. The share of coal is assumed to be reduced over the long-term, but coal will still play a role in the country's energy mix. The Outlook assumes increased penetration of clean technologies in South Korea.

For other Asian countries, this Outlook assumes that coal will remain a strategic option that contributes to meeting growing energy needs and security of supply. However, extended efforts to support gas, renewables and energy efficiency, especially in the context of ASEAN cooperation, is expected to mitigate coal demand growth compared to previous projections and plans elaborated by different ASEAN governments. The Outlook assumes a larger dissemination of efficient and clean coal technologies to deal with air quality and carbon emissions which are key concerns in this region.

NUCLEAR

Assumptions for nuclear policies on a global scale

Government intervention remains a key determinant of nuclear's contribution in a country's energy mix. Indeed, the government plays a central role in setting the regulatory conditions for nuclear project development and exploitation, framing the safety requirements, establishing the required political support, bearing the market risks and supporting the financing of costly nuclear projects. To figure out this key involvement of the government, it is worth mentioning that the bulk of nuclear projects sanctioned recently or where FID decisions been taken, have benefited from large political and funding supports and from other mechanisms that aim to mitigate revenue uncertainties, such as regulated electricity prices and power purchase agreements with state owned entities. Cooperation with traditional nuclear countries has also played a key role in driving the recent development of nuclear projects.

Despite the apparent resistance of the nuclear industry to the wave of opposition that followed the Fukushima catastrophe and the reluctance of many governments to significantly reduce the role of nuclear in their future energy mix, there are still large policy uncertainties and challenges affecting nuclear future at a global level.

In mature nuclear markets, one of the key challenges for policymakers is to deal with an old fleet and therefore with increased security risks (it is estimated that 60% of nuclear power plants are more than 30 years old). In many of these countries, there is still policy decision doubt over whether to proceed with large-scale nuclear phase out, to extend the plants' lifetime or to build new nuclear plants. These decisions have been complicated by factors such as the resistance of the local population, energy independence concerns and the government's fear of abandoning nuclear expertise and losing skilled employment opportunities.

For emerging nuclear markets, the main challenges are related to technology transfer, the complexity of projects and high development costs, financing issues, geopolitical concerns, resistance from the local population and constraints on fuel supply and skilled labours.

This Outlook assumes that nuclear policy will focus on supporting safety requirements and controls of nuclear power plants and operations along the nuclear fuel cycle, and that this will contribute to the increasing cost of nuclear power generation. The Outlook assumes that many projects in developed nuclear countries would benefit from lifetime extension, driven by the concerns about energy independence and carbon mitigation, but that this will not counterbalance the long-term decreasing trends of nuclear power in these countries, since no large nuclear program will be adopted to replace the old nuclear plants.

The Outlook assumes there will be policy support for nuclear in emerging and developing countries which have announced nuclear programs, driven by the willingness to diversify supply and meet the growing needs of baseload power generation. However the various challenges faced by these countries will result in slow progress towards the announced targets and ambitions. Furthermore, it is assumed that progress in renewables and natural gas will affect the prospects of nuclear and offer a less complex and more viable solution to meet both electricity needs and sustainability requirements.

Nuclear policy drivers and assumptions in key markets

The most notable change to American nuclear policy involved the 'Grid Resiliency Pricing Rule,' which sought direct subsidies for nuclear and coal-fired plants in three wholesale electricity markets. The proposed rule preceded a 2017 grid study that concluded electricity grids significantly benefit from the flexibility provided by natural gas plants. The study suggested that nuclear and coal generators were being unfairly disadvantaged and that their retirement impacted the resiliency and reliability of national power grids.

The rule drew significant criticism from a large number of stakeholders, including utilities and industry groups. The Federal Energy Regulatory Commission (FERC) unanimously rejected the proposed pricing rule. FERC determined that coal and nuclear retirements did not jeopardize grid resilience and that the rule was "aimed at subsidizing certain uncompetitive electric generation technologies."

The unanimous rejection of this policy underscores the assumption that, despite the current administration's efforts to support ailing coal and nuclear plants, cost-effective and flexible fuel sources, such as natural gas and renewables, will continue to challenge their standing in the national energy mix.

EU nuclear policy is governed by the EURATOM treaty and is mainly concerned with the cooperation between Member States in ensuring nuclear safety and security along the nuclear supply chain. However, the nuclear policy orientations and the role of nuclear in energy mix are largely determined by the European Member States' priorities and challenges.

One common factor for a majority of these Member States is the old age of the nuclear fleet and the strong opposition to nuclear that emerged after the Fukushima catastrophe. However, it is possible to note different policy approaches in the region. Germany confirmed its decision to phase out nuclear by 2022. Belgium also announced its intention to decommission nuclear by 2025, while the French parliament decided to reduce the share of nuclear to 50% by 2025. However, the French government announced recently that this objective would be postponed due to several challenges faced by the country, mainly security of supply and employment concerns in the nuclear industry. Switzerland and Spain considered the possibility of extending the lifetime of their nuclear facilities providing that they meet safety requirements. Conversely, some eastern European countries, including Slovakia, Romania and Poland, are encouraging the construction of new nuclear plants, as a way of diversifying their energy supply and reducing carbon emissions.

The UK has agreed the installation of new nuclear power plants with the approval of the Hinkley Point C project, and a proposal to construct a new power station in North Wales. The government has confirmed its support for nuclear projects and strives to reinforce cooperation with international nuclear companies and governments in order to overcome various challenges faced by its nuclear industry, particularly access to skills and services that could be costlier after Brexit (42).

The Outlook assumes that security of supply concerns and carbon mitigation will delay the decommissioning of some projects, especially in countries like France and Spain, but that west European countries will not initiate large replacement programmes, and the share of nuclear in the energy mix will see a steep decline after 2025. In the UK, the construction of new nuclear power plants will increase nuclear power use over the medium term, but this share

is expected to decline after 2035 with the decommissioning of aged power plants. The very high cost of the Hinkley Point C project shows that nuclear development in the UK is a costly option and this constitutes a real barrier for the development of a nuclear program which would enable the replacement of aged power plants.

China and India have initiated an ambitious nuclear program driven by the announced targets to reach 58 GW of nuclear generation by 2020 according the 13th Five Year Plan, and to achieve 63 GW by 2032 according to India's INDC proposal. The Indian target will entail a huge development of nuclear capacity from the current 7 GW total. The two countries consider cooperation with experienced nuclear countries and foreign investments as key levers to progress with their nuclear programs. China, for instance, has adopted new rules which allow private and foreign investors to be more involved in nuclear projects.

India's NEP highlights the government's intention to step up efforts to accelerate nuclear capacity development. However, several challenges are affecting progress, including primarily funding issues, and also the complexity of projects as well as the availability of nuclear fuel, uranium in particular. The government is trying to overcome these challenges by supporting foreign and private investors, intensifying exploration to increase domestic uranium availability and promoting technologies that consume less fuel such as Fast Breeder Reactors and thorium based reactors.

The Outlook assumes that China will achieve significant progress towards its target and will reach it by around 2022. However, for India, the Outlook assumes that the country will realize only around 16 GW of nuclear capacity over the forecasting period, based on projects under construction and currently approved. These projects are essentially based on Pressurized Heavy Water technology, which is a more mature technology and which has a large potential for deployment in India.

In Japan, the recent 5th strategic energy plan confirmed the government's intention to restart nuclear power plants closed after Fukushima, and to reach a target of 20-22% nuclear share by 2030. This target is, however, ambitious since it means that all the country's nuclear power stations which are currently under examination according to the new regulatory requirements will receive permission for exploitation and that many of them will be allowed to extend their lifetimes. The key challenges for Japan are public opposition and legal procedures that are slowing the restarting process significantly, and constraining the extension of nuclear units' lifetime (43). The Outlook assumes that Japan will not achieve its nuclear target, and nuclear capacity will see a strong decline after 2030 driven by the decommissioning of old plants. However, the country will pursue its efforts to mitigate the impact of reduced nuclear dependence by promoting renewables and energy efficiency.

In South Korea, the recently released 8th Long Term Electric Plan projects a decrease of nuclear's share from 30% in 2017 to 24% in 2030, and this projection take into account the decommissioning of nuclear capacities and the construction of two new nuclear plants. South Korea's announcement that it plans to significantly reduce the role of nuclear is challenged by energy independence concerns as well as by the ambition of the country to cut emissions (17) (43). The Outlook assumes that nuclear in South Korea will still play a role over the long-term despite a notable decrease, and would reach a share of around 21% by 2040. Furthermore, the Outlook expects South Korea to keep a footprint in the nuclear industry and that the country will continue to position itself as an exporter of nuclear technology

and expertise.

Despite the complexity and challenges faced by nuclear projects, the Outlook assumes the continued expansion of nuclear in countries such as Russia, Argentina and Brazil, as well as its development in some other new nuclear countries like the UAE and Turkey. These two countries are expected to reach around 15 GW of nuclear capacity by 2040.

2.3.3 Energy efficiency policies

Assumptions for energy efficiency policies on a global scale

Deploying energy efficient opportunities continues to attract the interest of policymakers because of the large energy saving potential it can achieve in different sectors and countries. However, despite this potential, the adoption of energy efficient options faces various barriers including: high upfront costs; financing issues; high risk exposure of energy efficiency projects and difficulties of estimating their benefits; lack of information about energy efficient opportunities; and lack of incentives due to lack of energy pricing signals (44)(45). In this context, governments strive to implement policy measures that allow them to address these barriers and challenges.

In the last edition of the Outlook, the energy efficiency measures were categorized as: i) regulation and mandatory energy efficiency standards; ii) fiscal and financial supports; iii) information and labelling; iv) market-based instruments including auctioning and white certificates; and v) price signals that can be reflected in subsidy reduction, or in energy price differentiation, often enabled by the deployment of smart technologies (e.g. smart meters). There are also policies that support structural changes in economies such as a shift to more service-based economies, the promotion of fewer heavy products or of a circular economy.

Recent policy trends highlight an increasing number of mandatory energy standards being imposed by different countries, with a vision to strengthen them gradually in order to achieve energy savings and reduce the environmental impact. According to the IEA, these standards covered 34% of global energy use in 2017 up from 14% in 2005 (46). These mandatory standards target sectors including buildings, industry and transportation, and are usually associated with fiscal incentives, financial supports and price signals in order to improve their effectiveness in promoting energy efficient opportunities. There is also an emerging trend of market-based instruments, such as white certificates and auctioning, to support energy efficiency, primarily in developed countries (47).

In this Outlook, policy measures including standards, funding supports, price signals and the promotion of smart technologies are expected to support the energy efficiency progress in different sectors. The Outlook assumes that policy measures will focus on energy consumption in buildings and industry, including the consumption of electrical appliances and equipment as well as cooling and heating services. For heating, the penetration of gas-based boilers, as well as the combined production of heat and power are assumed to be supported as a cost efficient way to improve air quality and reduce carbon emissions.

Energy efficiency policies will also support the energy performance of power plants, and the reduction of waste in power networks, particularly in emerging and developing countries. Gas power plants are expected to play an important role in energy efficiency improvements.

Energy efficiency policy drivers and assumptions in key markets

The US Budget Act of 2018 reinstated tax credits and deductions for energy efficiency improvements in residential and commercial buildings under the ENERGY STAR programme. The US also has a Building Energy Codes Program in place, which offers state assistance and access to a network of regional energy efficiency organizations that can help with application and compliance. The 'Better Plants' initiative is a multi-sectoral program that promotes energy efficiency by helping industry, companies, municipal buildings and the commercial sector to reduce energy intensity by 25% over a 10 year period. While the program is voluntary, it fosters training, accreditation and innovation, and provides funding mechanisms worth \$8.6 billion.

Parallel to these ongoing initiatives, the current administration has revised energy efficiency standards for more than 70 categories of consumer and industrial products. A lawsuit brought by environmental groups resulted in a ruling that ordered the government to publish efficiency standards that had been completed by the previous administration.

Finally, despite highly publicised efforts to implement budget cuts for the Office of Energy Efficiency and Renewable Energy, the congressional budget has increased funding to a total of \$2.38 billion. This funding support, coupled with numerous public and private initiatives and basic consumer preferences, allows this Outlook to conclude that energy efficiency measures in the US will remain important drivers of future energy demand. However, the potential of energy saving in the country will be affected by relatively lower average energy prices compared to other advanced economies. For the EU, the Outlook considers that the updated Energy Efficiency Directive, with more stringent targets, will incentivize European Member States to reinforce their efficiency measures, despite disparities between countries. Based on the last efficiency progress report of the European Commission (48), the Outlook assumes that countries such as Austria, Germany, the UK, Netherlands and Scandinavian countries will achieve important progress towards their energy efficiency targets and energy saving requirements by 2020 (as set in their National Energy Efficiency Action Plans). Other countries are expected to catch up and to significantly progress beyond 2020 including France and some countries in Eastern Europe such as Romania and Poland.

The implementation of energy saving obligations schemes as outlined in the Energy Efficiency Directive, Article 7, is supposed to be a key driver of the energy efficiency policies in Europe. Other supportive measures are assumed to be applied in the region including energy performance standards, financial supports and fiscal incentives, as well as support for the large-scale deployment of smart meters. The latter are expected to encourage energy saving behaviours by providing information to consumers and applying price signals incentives.

The building sector will continue to attract a large degree of policy focus, supported by the adoption of an eco-design directive and retrofitting programs, as well as encouragement of the use of more efficient appliances and heating equipment. For the latter, energy efficient solutions, such as heat pumps, gas based district heating and cogeneration are assumed to be increasingly adopted in the EU.

In China, the support of energy efficiency has emerged as a key priority, and is highlighted in different plans and policy documents. In its Energy Production and Consumption Revolution Strategy for 2030, the country underscored its ambition to adopt strengthened energy efficiency measures and market reforms that promote energy saving

behaviours and accelerate the deployment of energy performance options, technology innovation and the digitalization of energy networks (49). China also envisions the achievement of a deep transformation of its industrial structure by focusing on less energy-intensive industries. The 13th Five-Year Plan translates this strategy highlighting targets to achieve a 15% energy intensity reduction by 2020 compared to 2015, and to cap energy consumption to 5 tce. The plan outlines a set of measures including: reinforced standards in buildings, industry and transportation; the facilitation of the development of energy management systems in different business sectors; the implementation of the 'top 10000 energy consumers program'; and the promotion of low carbon power plants in the electricity dispatching process.

The Outlook assumes that China will continue with energy reforms which allow it to set price signals (e.g. for electricity) which will discourage the waste of energy. The country will implement energy performance and emissions standards and other regulations in different sectors that are expected to increase the penetration of energy performant technologies, such as gas-based options in heating services and transportation. Combined Heat and Power (CHP) will benefit from these regulations. In power generation, natural gas will play a key role, especially with the promotion of low carbon power plants in the power dispatching process. However, coal-based power generation still remains an important contributor and will see an improvement in its energy efficiency with the dissemination of ultra-supercritical power plants. Furthermore, the promotion of less energy-intensive industries and the resorption of industrial over-capacity will underpin the reduction in energy intensity in the country.

For India, the NEP identified some key policy challenges for the deployment of energy efficient opportunities. Among these challenges are: lack of coordination between different sectoral programs and energy efficiency programs; poor implementation of efficiency policy instruments, particularly at the Indian state level; and lack of effective price signals and funding constraints.

Several measures have been proposed to address these challenges such as: enhancing multi-sectoral coordination of the initiatives developed under the National Energy Efficiency Mission framework; creation of State Nodal Agencies (SNAs) that support cooperation in the implementation of energy efficiency programs; and advancing the development of energy price signals, especially through market reforms. The government has also announced other key policy tools aimed at supporting energy efficiency. These include: reinforcement of the PAT market-based energy efficiency mechanism which is targeted to cover 80% of industrial energy consumption; implementation of energy efficiency standards for appliances, buildings and transportation sectors; implementation of programs allowing the dissemination of energy performant appliances and clean cooking options; scaling up financing support to energy efficiency projects; and supporting the emergence of energy service companies.

In this Outlook, it is assumed that India's energy efficiency measures will be effective, particularly in the residential, industrial and power sectors. However, large energy saving potential remains untapped due to persistent implementation challenges such as financing issues, low energy prices and the reliance on coal based technologies. The expected penetration of appliances in residential sectors and the rise of manufacturing industry will also mitigate the energy intensity reduction of the Indian economy.

Japan is expected to be at the forefront of deploying energy efficiency measures, especially in the industry and buildings sectors. Smart technologies will play an important role in controlling and incentivizing energy saving behaviours. The

Table 2.3. Targets and main energy efficiency policy drivers and assumptions in key markets

	Efficiency targets	Main efficiency policy drivers and assumptions
US	State level targets (e.g. California will achieve a cumulative doubling of energy efficiency savings by 2030)	<ul style="list-style-type: none"> - Implementation of federal efficiency measures (e.g. fiscal incentives; minimum energy efficiency standards) - Strengthened efficiency measures are implemented in the states with high efficiency ambitions - Relatively low energy prices globally affect the energy saving potential - Gas competitiveness supports penetration of efficient gas-based options
EU	Efficiency improvements compared to 'business as usual' scenario: 20% by 2020 and 32% by 2030.	<ul style="list-style-type: none"> - Strengthened EE measures driven by more ambitious EU target; but disparities between Member States. - Implementation of energy saving obligations schemes as a key driver of MS policies - Building sector's efficiency will be supported by eco-design directive and retrofiting programs. - Extended use of energy efficient heating solutions, such as heat pumps, gas based district heating - EU will not achieve its global 2030 target (despite important energy saving achieved by MS)
China	Improve energy intensity by 15% by 2020 relative to 2015 levels Cap energy consumption to 5 tce	<ul style="list-style-type: none"> - Implementation of efficiency measures (e.g. mandated decommissioning of old equipment) - Energy reforms progress will allow to set price signals (e.g. for electricity) encouraging rationalization of energy consumption - Promotion of less intensive industries and resorption of industrial over-capacities will support significantly energy intensity reduction - Progress in the heating sector, driven by penetration of gas - Policy support to efficient coal-fired power generation support more efficient use of in this sector - Energy intensity target expected to be achieved and coal demand to be capped at 5 tce
India	Avoid a power capacity addition by nearly 20GW and achieve fuel savings of around 23 Mtpce per year (at full implementation stage of the NMEEE)	<ul style="list-style-type: none"> - Implementation of EE measures (e.g. Extension of Perform, Achieve and Trade program; energy efficiency standards; building codes; energy pricing; enhanced coordination between sectors) - Large efficiency potential remains untapped due to financing issues; still low domestic energy prices and the reliance on coal-based technologies.
Japan	Save 50 million kilolitres (around 42 Mtoe by 2030 compared to business as usual)	<ul style="list-style-type: none"> - Strengthened energy performance standards, particularly in the building sector - Enhanced support in the development of energy efficient technologies and processes in the industry - Smart technologies are expected to play a key role
Korea	13% of energy demand reduction compared to 2015	<ul style="list-style-type: none"> - Implementation of EE measures, especially through voluntary agreements, efficiency standards and fiscal incentives - More efforts required to achieve progress with the target, mainly in industry, heating and power sectors
South east Asia	ASEAN = reduce energy intensity by 20% (2020) and 30% (2025) Indonesia: reduce energy intensity by 1% annually to 2025 and achieve savings (compared to business as usual) Malaysia : achieve 52 TWh cumulative energy savings for 2014-2024 (compared to BAU) Thailand: reduce energy intensity by 30% by 2036 relative to 2010 levels	<ul style="list-style-type: none"> - Implementation of EE measures (mainly energy standards; building codes and energy price subsidies' reduction) - Cooperation in the context of ASEAN to support the development of EE opportunities - Energy efficiency progress remains challenged by funding concerns; hard to monitor compliance and enforce standards (e.g. building codes) and to increase energy prices

Outlook assumes a continued decrease in the energy intensity of GDP in the country, and forecasts a fall of around 30% by 2030 compared to 2012, making the country closer to achieving its target (i.e. 50 million kilolitres of energy saving, which is equivalent to around a one third energy intensity reduction by 2030 compared to 2013).

South Korea is also expected to deploy energy efficiency measures, especially through voluntary agreements, efficiency standards and fiscal incentives. However, the country needs to utilize more efforts, especially in the industrial, power and heating sectors, in order to achieve progress towards its efficiency target (e.g. 13% of energy demand reduction compared to 2015).

The Outlook assumes that other countries with growing energy demand in Southeast Asia, Latin America and the MENA region will deploy energy efficiency measures to reduce the pace of growth of energy demand as well as the required investments to support this demand. One of the key measures is related to reinforcing energy performance standards and reducing the subsidies of energy prices. There are, however, some challenges related to funding energy efficiency programs, monitoring and enforcing standards, and designing energy prices that are not detrimental to human wellbeing and economic growth.

2.3.4 Climate policies

Assumptions for climate policies on a global scale

Climate policies have emerged as an important driver of future energy developments, especially after the adoption and ratification of the Paris Agreement. Almost all the countries emitting GHGs in the world submitted their INDCs to the UNFCCC and committed to undertake GHG mitigation initiatives, though several challenges affect the level of implementation of these initiatives and their outcomes. Among the key challenges are: i) the level of political support allocated to climate change, especially after the announced withdrawal of the US from the Paris Agreement; ii) funding constraints and the economic viability of climate friendly projects; iii) the cost of policy support (e.g. the high cost of subsidies contributed recently to the Chinese government's decision to reduce them) and; iv) economic and strategic priorities that can undermine climate friendly options and can lead, for instance, to keeping coal as a cheap and affordable energy source

Climate policies and initiatives are mainly driven by the emission reduction targets pledged by different countries in the context of their INDCs, and these climate initiatives interact strongly with other measures and plans adopted in different domains including renewables and non-renewables as well as energy efficiency (as highlighted in previous sections). Climate policies are also underpinned by some specific measures targeting GHGs mitigation such as carbon pricing and carbon and methane emissions standards.

One of the key uncertainties surrounding climate policies is related to the evolution of GHGs mitigation targets and ambitions which are outlined in countries' INDCs, and which are still not in line with the Paris Agreement 2°C objective. The Agreement stipulates that countries should raise their ambitions and revise their INDCs' commitments upwards in order to keep pace with its 2°C temperature increase target, or even with a lower 1.5°C target as highlighted in the 2018 IPCC Special Report (SR15). More than twenty countries, especially in Europe, issued a declaration in June 2018 aimed at enhancing their climate ambitions. However, this revision has so far faced some reluctance, with several countries maintaining that their climate change efforts and engagements should not harm their social and economic

development

The Outlook assumes that the current INDCs' GHG mitigation targets will continue to drive climate efforts for a large number of countries. Policies and measures adopted in these countries are then not consistent with even reaching the 2°C target, and much effort will be needed to keep pace with this very ambitious objective.

Carbon pricing, either in the form of carbon markets or carbon taxes, is expected to make some progress in different countries, but large disparities will continue in the level of carbon price references and taxes applied in different countries, reflecting varying conditions and climate ambitions. Moreover, several challenges will persist and affect the functioning of carbon markets including market design issues, overlaps with other mitigation policies (e.g. support for renewables can affect demand for carbon emission allowances and then depress prices), as well as business competitiveness. In the latter instance, the UK has frozen its carbon prices after experiencing competitiveness issues in its economy (50). The Outlook assumes that carbon markets will not develop into an integrated emission trading system over the forecast period.

In addition, the Outlook assumes no significant progress for CCS projects and technology, which would mean an important reduction of CO₂ emissions over the forecast period. Technical difficulties and high investment costs remain important barriers for CCS development.

Policy drivers and assumptions in key markets

The withdrawal of the US from the Paris Agreement sent a clear signal to the international community about the current administration's position on climate commitments. As mentioned in the 2017 edition of the GGO, several coalitions have been launched in response to the withdrawal. "We Are Still In" has expanded to include 3,500 organizations and ten states, representing 169 million people and an estimated \$9.46 trillion in GDP. The US Climate Alliance has also demonstrated that state governments are committed to ambitious climate action, pledging to reduce GHG emissions by 26-28% from 2005 levels by 2025 in sixteen states and Puerto Rico.

While there is concerted action from sub-national governments, US businesses and industry leaders, 2018 witnessed marked regulatory rollbacks on key environmental policies. The Waste Prevention Rule, which aimed to reduce the waste of natural gas from oil and gas operations on public and tribal lands, was officially suspended in December 2017. A Revision Rule was proposed earlier this year, returning to pre-2016 standards that were drafted in the 1970s. Two states and eighteen environmental groups have challenged the Revision Rule, which is scheduled to take effect on 27 November 2018.

Policies that mitigate adverse health and environmental impacts from interstate air pollution have also been challenged, most notably by a proposal to implement new corporate average fuel economy standards (CAFE) and GHG emissions standards for cars and light trucks. At the time of writing, the public comment period for these proposals is ongoing. The responsible agencies are recommending a freeze of 2020 standards through to 2026, and a standardization of fuel economy and CO₂ emissions standards across all fifty states. The later amendment could have detrimental environmental consequences, as it would prevent California from using its authority to set its own standards, which more than a dozen states adhere to. Nineteen states and Washington D.C. intend to sue over the proposal.

The aforementioned regulatory rollbacks constitute only a fraction of those planned or implemented by the current US administration. This Outlook assumes that, the administration's lenient stance on pollution and global warming will be, to some extent, mitigated by efforts made at sub-national and business society levels, as well as by some market fundamentals such as the competitiveness of gas-fired power plants compared to coal.

The EU committed to reduce its GHG emissions by at least 40% in 2030 compared to 1990 levels, and has developed a climate and energy policy which incorporates different targets and measures that support renewables deployment and energy efficiency, as well as limiting the usage of carbon intensive fuels, particularly coal. The EU's ambition is to take the lead in dealing with climate change, and to work on a new climate strategy that considers higher emission targets compared to the current ones. However, the implementation of strengthened mitigation and more ambitious targets remains very challenging, especially for Member States that are still dependent on coal. Furthermore, costly policy measures, difficulties over decarbonisation other than in the power sector and competitiveness concerns will make even the current stated emission targets difficult to achieve for the EU.

The two key climate-related policy instruments which aim to support carbon mitigation in the EU are the Emission Trading System (EU ETS) and the Effort Sharing Decision that targets sectors which are not included in the EU ETS. The EU approved a revision of its ETS system in February 2018 which introduced a set of measures aimed at balancing the demand and supply of emission allowances, and reinforcing its role in the decarbonisation process. Despite these reforms, the EU ETS faces some key challenges including: i) Brexit and its potential effect on the functioning and liquidity of the EU carbon market; ii) the issue of allocation of carbon allowances, especially for energy intensive industries (these industries receives free allocations to avoid emissions migration outside Europe, which can lead to carbon leakage and; iii) the overlaps between emission trading systems and aggressive regulatory measures (e.g. phasing out coal, pushing for renewables) that might affect the efficiency of the market in achieving decarbonisation compared to other measures (51).

The Outlook assumes that market reforms will reduce the excess of emission allowances and supports increasing trends in carbon prices. The Outlook also assumes that the UK carbon market will remain connected to the EU ETS system post-Brexit, and that the UK government will continue to apply a carbon price floor that adds a carbon price support (CPS) on the top of EU ETS reference price. Despite the recent freeze of the CPS due to business competitiveness issues, the UK carbon price floor is expected to raise over the long-term driven by strengthened UK climate policy.

In 2018, the EU also adopted an updated version of the Effort Sharing Regulation that concerns the non-ETS sector (i.e. transport, buildings, etc.) and sets binding emissions reduction targets for all Member States, with the objective of reducing total EU emissions by 30% compared to 2005 levels. The regulation includes flexibility to adjust for fluctuations in emissions levels depending on economic and weather conditions. These flexibilities include mainly: i) a banking and borrowing system (i.e. a Member State can bank emission allocations in years where emissions are low and use them later in years of higher emissions); ii) selling and buying emission allocations between Member countries, and iii) the potential use of emission allocations from the EU ETS system.⁶³ The implementation of this regulation encourages Member States to reinforce the deployment of carbon mitigation options, especially those related to improving energy efficiency in the building sector, that are also supported by the implementation of the Energy Efficiency Directive and

Eco Design Directive.

China has set two major targets in the framework of its climate policy: achieving peak CO₂ emissions before 2030, and reducing the carbon intensity of GDP by 60-65% compared to 2005 levels. The 13th Chinese medium-term plan pays large attention to climate mitigation and adaptation, and has introduced an intermediate target to reduce emissions by 18% by 2020. The government is also encouraging the endorsement of these targets at provincial and city levels. To support these targets, China is considering various initiatives including the deployment of renewables, reducing reliance on coal and promoting energy efficiency, especially through the promotion of less carbon intensive industries and services in its economy.

Furthermore, one of the key levers used by China to deal with climate change is the development of a national carbon trading scheme. This scheme was launched in December 2017, integrating eight pilot carbon markets already initiated at provincial and city levels. Several challenges affect the development and functioning of this national market, however, such as: differences between pilot carbon markets in terms of scope, coverage and design; complexity of harmonizing the legal framework and designing applicable rules at national level; the need to develop reliable data, monitoring, reporting and verification systems; and the need to support trading activities in order to improve carbon markets' liquidity. Another important aspect that need to be addressed in the design of the carbon market is related to the large regional disparities in terms of economic development, and the need to support growth in these regions (52). The government is trying to tackle these challenges by considering a phased approach, which will include system development and simulation phases before starting implementation and expansion of the market. China also relies on international carbon market experiences and cooperation, particularly with the EU, in its challenge to design an effective carbon market (53).

In this Outlook, the Chinese national carbon market is expected to start with low prices at the initial stages of its development before growing significantly after 2025. This growth is driven mainly by the improved efficiency in market functioning and balancing the supply and demand of emission allowances, but prices are expected to stagnate over the long-term due to less pressure on demand for carbon allowances driven by sluggish demand for coal. Chinese carbon prices are forecast to remain much lower than those in the European market reflecting less stringent rules in terms of emissions allowance caps and trajectories. China also relies on other policy measures to control its carbon emissions that overlap with carbon markets.

In its submitted INDC, India has set objectives to reduce the emissions intensity of its GDP by 33-35% in 2030 compared to 2005 levels, and to achieve 40% of non-fossil fuel powered installed capacities. Building on these objectives, the recent National Energy Policy's main policy orientations aim to achieve a transition towards a more sustainable economic development model, with the promotion of renewables, energy efficiency and natural gas (see previous sections). However, the government has stressed the need to mobilize finance from developed countries in order to support its carbon mitigation and adaptation efforts (54).

One of the key challenges in dealing with climate issues is related to the continued reliance on coal as an affordable source of energy. The government has tried very hard to reduce the environmental impact of coal and has introduced a coal tax to support this effort. But a recent downward revision of this tax could undermine its efficacy.

The Outlook assumes that the implementation of climate mitigation initiatives will allow India to meet its INDC objectives, which are very ambitious when set against the Indian potential. Scaling up financing resources through cooperation with developed countries, and strengthening the penetration of gas and renewables against coal could significantly slow the growth of coal-related emissions.

Japan and Korea also pay important attention to climate change mitigation in their released policies and plans. Japan has pledged to reduce emissions by 26% compared to 2013, while South Korea is considering a reduction of 37% compared to business as usual (equivalent to an 18% reduction compared to 2010). The two countries are supporting these targets mainly through the promotion of energy efficiency and renewables. There are key uncertainties, however, related to the future contribution of nuclear and coal in the context of this carbon mitigation effort. Japan and South Korea are both considering using international carbon credit mechanisms to support carbon mitigation at a global level.

Regarding carbon pricing, Japan introduced a carbon tax in 2010 and is implementing local Emission Trading System schemes in the cities of Kyoto and Saitama. Nationally, the key GHG related mitigation measure is the Japan Credit System (J-CDM) that allows the government to certify credits for GHG emission reductions realized by Japanese firms. The Outlook assumes that Japan will establish a national carbon market after 2020, building on its experience with local ETS systems and the J-CDM. Nevertheless, the price of carbon resulting from this initiative will remain relatively low.

For South Korea, a cap and trade emissions system was launched in 2015, and entered its second phase in 2018. In this phase, the emission allowances cap has been reduced and auctioning has been introduced as a method of allowances allocation in addition to free allocation. Despite the expected progress of carbon markets' functioning, the price references resulting from the Japanese and South Korean markets are projected to be relatively low since the governments are keen to support price levels that do not penalize their export-oriented industries. The Outlook assumes that Japan and South Korea will achieve progress in terms of GHG emissions reduction, supported by energy efficiency and renewables; however, this progress is not enough to meet the stated targets, since coal is expected to continue driving emissions in these two countries.

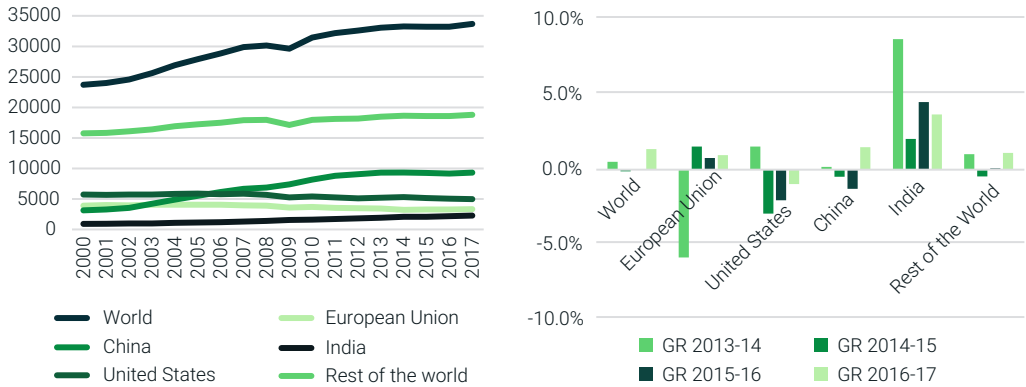
2.4 Energy-related greenhouse gas emission developments and trends

2.4.1 Energy-related CO₂ emissions

Recent evolution of CO₂ emissions

Global energy-related CO₂ emissions experienced rapid growth during the 2000s, driven by economic development and energy consumption in emerging economies, particularly China and India. The economic recession in 2007 significantly affected global emissions and contributed to their decline in several markets, including Europe and the US. Despite the relative recovery of the global economy, CO₂ emissions have undergone a significant slowdown and have stabilised since 2014. This slowdown reflects a strong reduction in the carbon intensity of the world's economies. As can be noted in Figure 2.6, the key CO₂ emitting markets (except India) recorded low or even negative emission growth rates during the 2014-2016 period. India, however, has seen a continued emission increase supported by the growth of its coal-dependent economy.

Figure 2.6. CO2 emissions (MtCO2) and annual growth rate (%)



Source: GECF Secretariat based on data from GECF GGM

In 2017, the stable global trajectory that had been observed over the past three years was disrupted, with CO2 emissions rising by 1.4% above 2016 levels and reaching a record of around 33.7 GtCO2. As indicated in Figure 2.11, the EU, China and India which together accounted for more than 45% of global emissions in 2016, increased their emissions in 2017 by 1.1%, 1.5% and 3.7% respectively. These growth rates added nearly 260 MtCO2 to 2016 emissions, out of the 456 MtCO2 incremental growth seen globally.

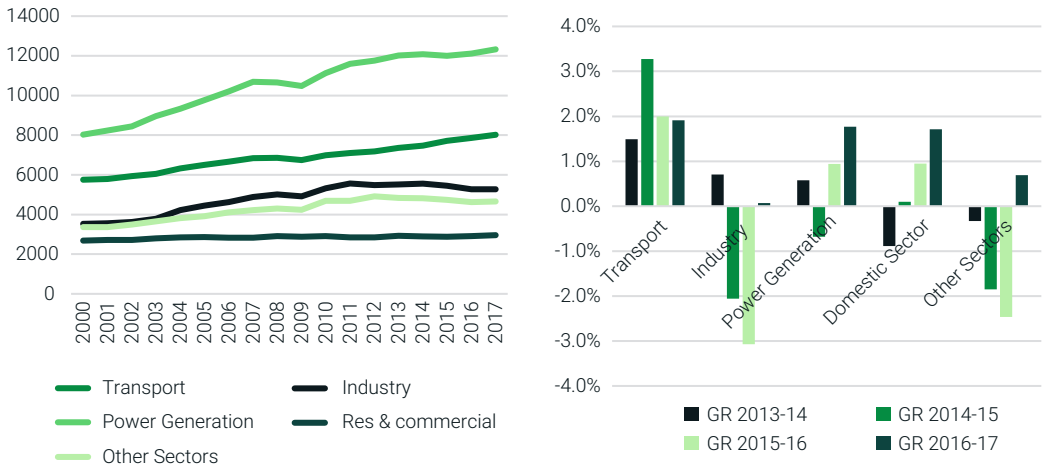
At a sectoral level, Figure 2.7 highlights the significant contribution made to the recent slow-down in global emissions by power generation and industry, in addition to other sectors such as district heating and coke ovens, especially during the 2014-2016 period. This is mainly due to energy efficiency improvements in these sectors and the slowdown of industrial activities in some countries (e.g. energy intensive activities in China), as well as the global trend for fuel substitution leading to less demand for coal, and more for gas and renewables, particularly in the power sector and industry.

Nevertheless, the power and industrial sectors' emissions increased in 2017, driven mainly by the growth of industrial activities and higher coal demand in many markets such as China and other emerging/developing countries. In China, the rise of coal consumption in 2017 reversed the declining trajectory observed since 2014, which had been driven by an aggressive policy to reduce pollution and to absorb the over-capacity in some coal-consuming activities such as power generation and the steel industry.

The domestic sector, which includes the residential and commercial sectors, is a small contributor to global CO2 emissions (around 10% in 2017) because of the dominance of electricity and natural gas in its energy consumption mix. In 2015, domestic sector emissions increased after a small reduction in 2014, a growth which was mainly due to an increase in the consumption of oil-based products (LPG in particular) prompted by the decline of oil prices. Conversely,

there has been a continued growth of emissions from the transportation sector which recorded average growth of 2% between 2010 and 2017. The decline in oil prices in 2014 supported the consumption of oil in this sector as well as its CO₂ emissions.

Figure 2.7. Evolution of CO₂ emissions by sector (MtCO₂), and annual growth rate since 2014 (%)



Source: GECF Secretariat based on data from GECF GGM

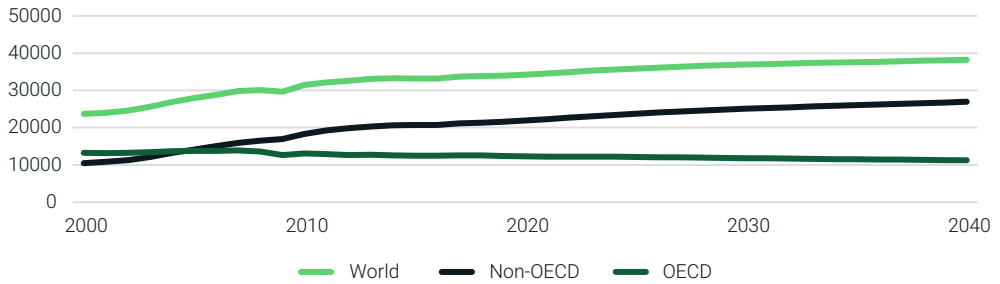
Forecasts and drivers

In this Outlook, global energy-related CO₂ emissions are forecast to exhibit increasing trends over the long term, despite an expected strong deceleration compared to the historical trajectory. The Outlook estimates an average annual growth rate at 0.6% between 2017 and 2040, bringing the overall level of emissions to around 38.2 GtCO₂ in 2040.

This growth rate hides different emissions prospects between regions, especially between OECD and non-OECD economies. The latter are expected to continue to drive emissions growth which will counteract the projected emissions decline in OECD economies to some extent. However, although non-OECD emissions are projected to grow, rates are forecast to slow down considerably reflecting efforts to curb emissions and to progress with the Paris Agreement's CO₂ mitigation commitments.

Despite several implementation challenges of the Paris Agreement, the momentum triggered by its adoption, as well as the international effort deployed to mitigate carbon and urban pollution, will contribute to a deceleration of CO₂ emissions at a global level. This effort is driving the decoupling between emissions, primary energy consumption and GDP.

Figure 2.8. Energy-related CO2 emissions (MtCO2)

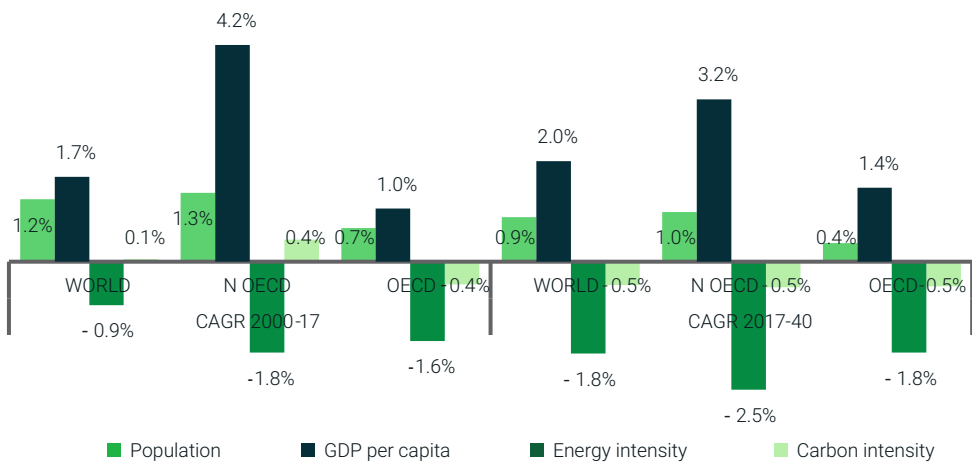


Source: GECF Secretariat based on data from GECF GGM

The Kaya decomposition gives an indication of the global drivers of future CO2 emissions and enables some key differences between OECD and non-OECD economies to be identified. The Kaya identity deconstructs CO2 emissions into four drivers: population, GDP per capita, energy consumption per unit of GDP (i.e. energy intensity) and CO2 emissions by unit of energy i.e. the carbon content of the energy mix or carbon intensity.

According to this decomposition (see Figure 2.9), population growth and, more specifically, the growth in revenue per capita are expected to be major drivers of increasing CO2 emissions globally. The revenue per capita is even projected to accelerate, compared to historical trends. Nevertheless, this increase is mitigated by a strong reduction in energy intensity and, to a lesser extent, a reduction in the carbon content of the energy mix. The latter has been stable historically and is forecast to decline by around 0.4% per annum over the long term, due to the penetration of less carbon intensive fuels.

Figure 2.9. Average annual growth rates of the CO2 emission drivers (Kaya decomposition) (%)



Source: GECF Secretariat based on data from GECF GGM

Key drivers of the trends at a global level are the non-OECD economies which will see important increases in population and revenues per capita, leading to carbon emissions growth despite the mitigating effect of declining energy intensity and carbon content. The situation for the OECD economies is different since the forecast decline in energy and carbon intensity will drive an expected reduction of emissions in the region and will surpass the impact of any growth in population or GDP per capita.

It is worth noting that the energy intensity of GDP is expected to fall faster for non-OECD economies, because they have a larger potential to improve energy efficiency, and to increase the contribution of the less energy-intensive sectors and industries in their GDPs. However, the carbon content of the energy mix is expected to decline more slowly in the non-OECD economies because of the greater reliance on coal and oil in several developing and emerging economies compared to OECD countries.

Regional trends

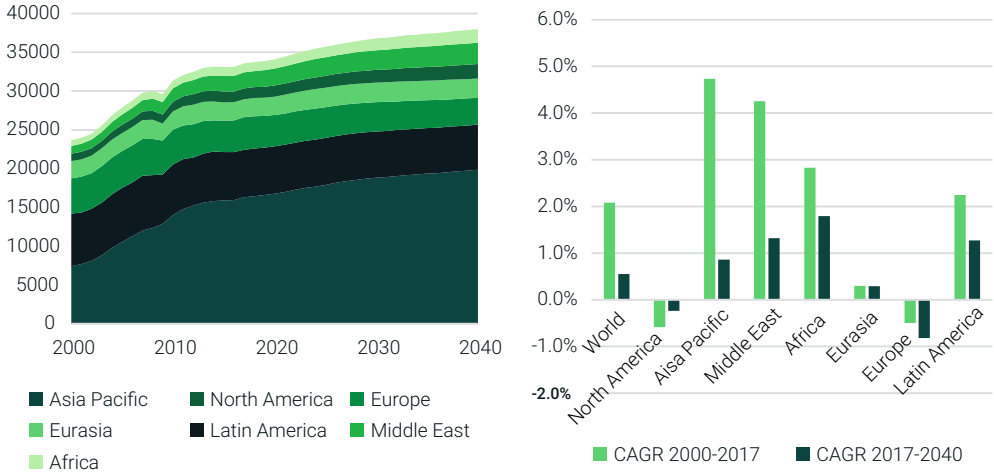
The Outlook forecasts that the Asia Pacific region will take the lead in terms of CO₂ emissions, accounting for around 53% of global emissions in 2040. This region will continue to see positive growth over the long term (CAGR 2017-2040: 1.1%) despite a net slowdown compared to historical trends. The GECF anticipates that the Middle East and Africa will experience the highest emission growth rates during the forecast period, which will increase the share of these two regions in global emissions from 9% in 2017 to closer to 12% in 2040. Conversely, Europe is projected to observe the highest emissions decline averaging around 0.7% between 2017 and 2040, followed by North America with a 0.2% average annual decrease over the same period. These forecasts reflect the fact that Europe, and particularly the European Union, will continue to be at the forefront of carbon mitigation efforts, with the implementation of strong climate and environmental policies. For North America, the decline of emissions is particularly expected in the US, driven by initiatives undertaken at a non-federal level (e.g. by states and businesses). Market fundamentals will also play a role in this region since they favour the penetration of abundant and affordable natural gas rather than more carbon intensive fuels.

CO₂ emissions forecasts in the biggest carbon-emitting markets

The US, EU, China and India are expected to remain the largest CO₂ emitters in the world, though their share of global emissions will decrease slightly from the current 60% to around 58% by 2040. As highlighted in Figure 2.11, China and India's increased contribution to CO₂ emissions will compensate the decreasing role of the US and the EU. India will see the highest rate of growth of emissions by a significant margin, with an average increase of 3.4% between 2017 and 2040, driven by the expansion of its population and economy as well as by its continued reliance on coal.

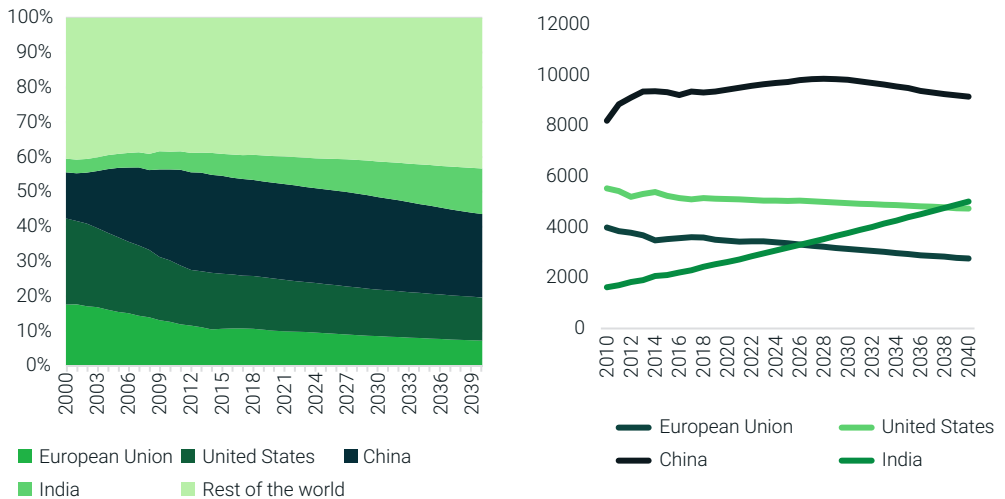
Nevertheless, India is attempting to mitigate its carbon emissions, mainly through improving energy efficiency and increasing the penetration of renewables and natural gas. The country has a target to reduce the GHG emissions intensity of its GDP by 33-35% by 2030, compared to 2005 levels. The Outlook forecasts that India will be able to achieve its target based on the deployed efforts and policies, and will in fact achieve a greater than 38% reduction of its GHG emissions intensity by 2030. The energy-related CO₂ emissions of India are estimated at around 3.8 GtCO₂ by 2030, which is less than the emission levels target set by the government (estimated at 4.0-4.1 GtCO₂ based on the estimation of GDP forecasts and of the contribution of the energy sector in global GHGs).

Figure 2.10. CO2 emissions by regions in the outlook (MtCO2), and annual growth rate (%)



Source: GECF Secretariat based on data from GECF GGM

Figure 2.11. CO2 emission shares (%), and emission forecasts for the biggest carbon-emitting markets (MtCO2)



Source: GECF Secretariat based on data from GECF GGM

India is therefore expected to achieve its emissions target but the target is not seen as very ambitious compared to the large potential for mitigation which exists in the Indian economy. Indeed, the country would do better if the government addressed the various barriers which currently constrain the development of a gas-based economy and the improvement of energy efficiency, particularly in the power and industry sectors

In China, energy related CO₂ emissions are forecast to peak between 2025 and 2030, and then to decrease gradually, reaching 9.15 GtCO₂ by 2040. The Outlook projects a decrease in the CO₂ emissions intensity of China's GDP by around 68% in 2030 compared to 2005, meaning that the country will over-achieve its NDC stated target (i.e. a CO₂ emissions intensity reduction by 60-65% in 2030 compared to 2005). In terms of absolute energy-related emissions, China is expected to see higher emissions than last year's forecast, mainly due to better GDP prospects and also taking into account less optimistic development for renewables and a smaller forecast reduction in coal demand, due to the recent policies adopted in the country (see Section 2.2).

The Outlook projects a strong decline in energy CO₂ emissions from the EU, driven by concerted efforts to reduce coal usage, increase renewables and improve energy efficiency. Emission levels are expected to fall to 3.1 GtCO₂ by 2030 and 2.7 GtCO₂ by 2040. These forecasts are more ambitious than last Outlook edition to reflect recent policy orientations and higher carbon prices, but they are still not sufficient to reach the EU 2030 GHGs emissions target (e.g. 40% reduction compared to 1990). The energy-related CO₂ emissions level that is compatible with this target is estimated at 2.7 GtCO₂, which means the EU target is expected to be reached ten years late. Disparities between country-level policies and reliance on coal in certain EU countries will contribute to delaying the achievement of the EU's ambitious target.

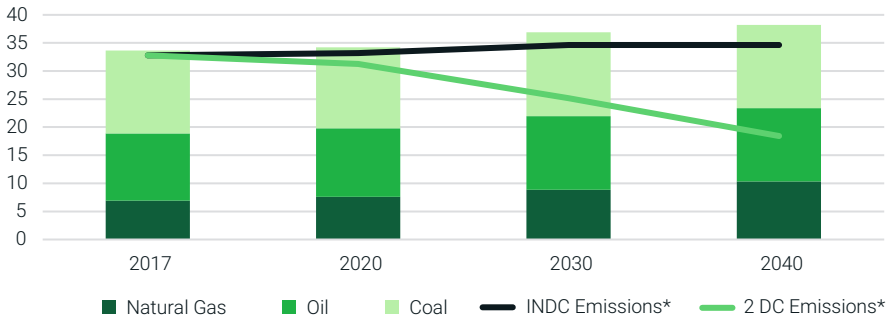
Trends by fuel

The Outlook projects that the major part of energy-related CO₂ emissions in 2040 will result from burning coal which will represent 39% of global emissions, followed by oil with 34%. Natural gas will have the least impact on emissions despite the expected growth in its consumption between 2017 and 2040 (see Figure 2.12).

The important role of carbon intensive fuels, particularly coal, contributes to the forecasted mismatch between CO₂ emissions in the reference case and in the Intended Nationally Determined Contributions (INDC) and 2 DC scenarios. The INDC scenario reflects an emissions trajectory which is compatible with countries' pledges in their INDCs, while the 2DC scenario considers the emissions reduction required to meet the temperature increase target set by the Paris Agreement.

The emissions gap compared to reference case is estimated at around 3.6 GtCO₂ for the INDC scenario and at more than 19 GtCO₂ in the 2 DC scenario by 2040, and this reveals the great effort required to achieve the Paris Agreement objectives. Natural gas, as a less carbon intensive fossil fuel, can play a key role in reducing this gap. As depicted in Figure 2.18, natural gas can achieve more penetration in the energy mix, particularly against coal, and this will enable further mitigation of carbon emissions.

Figure 2.12. CO2 emissions in the GECF reference case, NDCs and 2 DC scenario (GtCO2)



Source: GECF Secretariat based on data from GECF GGM

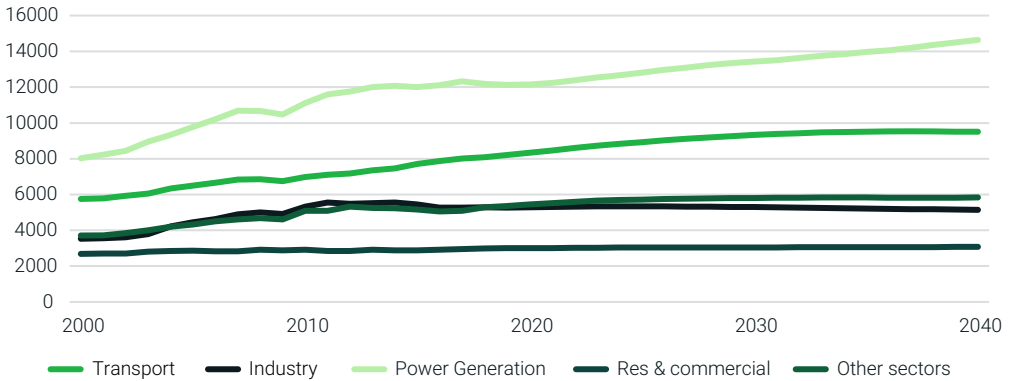
Note: INDC Emissions: CO2 emissions estimation based on aggregated INDCs targets (UNFCCC, 2016) - 2 DC Emission: based on IEA 450 scenario (WEO, 2016)

Trends by sector

The Outlook forecasts that power generation and transport will be the main drivers of CO2 emissions over the long term; these sectors are expected to grow annually by around 0.8% and 0.7% respectively over the 2017-2040 period. Power generation will continue to boost emissions to support the huge needs of baseload generation, particularly in emerging and developing Asian economies, where coal will continue to play a key role. Emissions from coal-fired power plants are forecast to grow globally by around 11% between 2017 and 2040, and by 38% in Asia Pacific region over the same time period.

The transport sector's emissions are projected to slowdown and stabilize after 2035, due to a strong improvement in vehicles' energy performance, as well as the penetration of hybrid, electric and gas-based vehicles. Specifically, the share of electric vehicles is expected to reach around 14.6% by 2040, up from a 1.2% share in 2017. Other sectors including refineries will increase their CO2 emissions but these emissions are expected to stabilize after 2030. The expected slowdown in demand for oil products will significantly affect refining activity and will contribute to the stabilization of emissions in this sector.

The industrial sector will see a stagnation of its emissions and a slight decrease after 2030. These trends are driven by the strong decrease in industrial energy intensity and the reduction of coal and oil shares to the benefit of natural gas in the industrial energy mix. The energy intensity of the industrial sector (expressed in energy consumed by industrial GDP) is forecast to decrease by more than 40% between 2017 and 2040. Over the same period, coal demand in industry will decline by 18% while gas demand is projected to increase by more than 32%. Improvements in energy efficiency, especially for electrical usage and the penetration of natural gas over coal and oil products, particularly in non-OECD economies will also mitigate emissions by residential and commercial sectors at a global level. These emissions are forecast to increase slightly by around 4% between 2017 and 2040.

Figure 2.13. CO₂ emissions by sector (MtCO₂)

Source: GECF Secretariat based on data from GECF GGM

2.4.2 Methane emissions

The role of methane in global warming

Methane (CH₄) has emerged as an important issue in the context of increased commitments and global efforts to reduce greenhouse gas emissions (GHG). Methane is, indeed, a potent GHG with a high global warming potential (GWP); but this potential is still a matter of debate, and questions continue to be raised about its importance compared to other GHGs, especially CO₂.

The GWP defines the radiative forcing impact of a specific GHG in comparison to CO₂, and then determines the relative contribution of this gas to climate change. There are different estimations of methane's GWP depending on the timeframe over which the cumulative radiative forcing effect is considered. For instance, if the estimation is based on a 20 years' timeframe, the global warming potential of methane (GWP₂₀) is 80 times more than CO₂. This potential drops to around 28 if the calculation is based on a 100 years' timeframe (GWP₁₀₀).

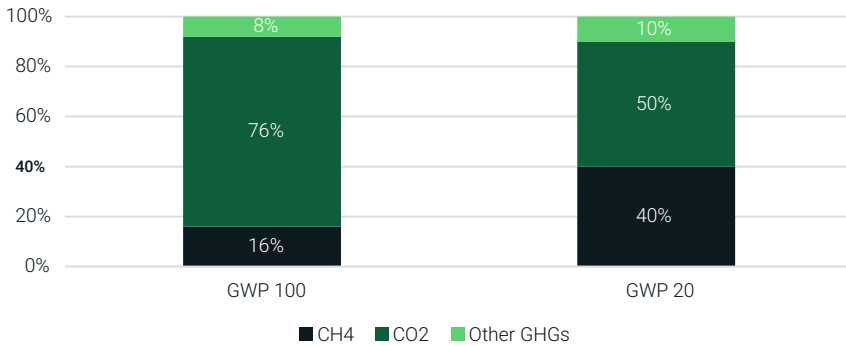
The timeframe assumed for methane GWP estimation can significantly change its contribution to global GHGs emissions (expressed in CO₂-equivalent). As depicted in Figure 2.14, the share of methane in global GHG emissions can increase from 16% to around 40%, when using GWP₂₀ instead of GWP₁₀₀.

Action against global warming, which is a long term issue, needs to consider appropriate efforts and initiatives that are able to address efficiently the effects of both methane and CO₂ over a long term timeframe. These two gases together represent more than 90% of GHGs emissions in the atmosphere.

Methane is a short-lived GHG and disappears from the atmosphere after approximately 12 years (compared to around 100 years for CO₂). If GWP₂₀ is considered in evaluating the contribution of methane to global warming, it

will exaggerate its effect and might give priority to short term initiatives that support methane mitigation over that of CO₂. Consequently, the use of GWP100 could be more appropriate in guiding policy actions and initiatives which would adopt a more balanced approach in combating the long term effect of global warming.

Figure 2.14. Methane and CO₂ shares in GHGs emissions depending on GWP calculation method



Source: IGU 2018

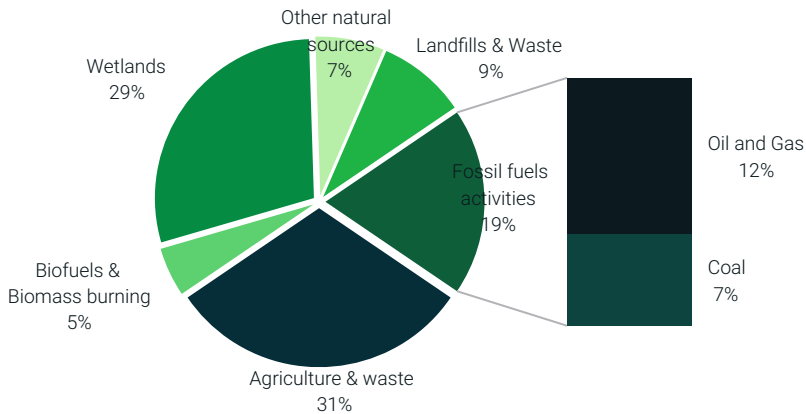
Methane emissions and natural gas activities

Recent data available from the Global Carbon Project (GCP) estimates that total CH₄ emissions from all sources averaged between 540 and 568 mt from 2003 to 2012. Anthropogenic sources accounted for approximately 60% of this figure, with agriculture being the largest contributor. Various studies reported that the rise in atmospheric CH₄ levels observed over the past ten years is not the result of increased gas production, but is most likely the result of increased agricultural activities (55) (56).

Fossil fuel emissions (including oil and gas, and coal) account for 19% of global methane emissions. Coal mining accounts for more than one third of the CH₄ emissions related to fossil fuel activities. This underscores the need to reduce the contribution of coal in the energy mix, in order to diminish both the emissions of CO₂ in the coal combustion phase and of methane along the coal supply chain.

There is significant uncertainty about the direct input of the natural gas supply chain to total fossil fuel-related CH₄ emissions, which is exemplified in Figure 2.15 by aggregating oil and gas into a single contributing sector. This uncertainty is reflected in the fact that a wide divergence in measurements exist between countries, and according to the methodology employed (bottom-up versus top-down).

Figure 2.15. Total average methane emissions by source, 2003-2012



Source: Saunois et al., 2016a (methane budget assessed by bottom-up approaches)

The challenge of measuring methane emitted from gas-related activities is also reflected in the huge number of potential sources of emissions worldwide. These might include intentional leakage and venting due for instance to the unavailability of processing facilities, and unintentional or ‘fugitive’ methane as well as methane emitted from incomplete combustion.

Balcombe et al., 2017 (57) reported that CH₄ emissions range from 0.2% to 10% of produced CH₄, a finding based on 250 published estimates, mainly in the US, of total supply chain emissions. One key conclusion of this study is that a non-negligible percentage of the emissions is created by “super-emitters”, which are a small number of facilities or equipment that create extremely high emissions. Acting on this small number of facilities is of paramount importance to reduce emissions significantly and efficiently.

It is worth mentioning that a large number of studies on methane are based on data from the US. There is, therefore, an important need to improve data availability, transparency and harmonization, especially outside the US, if emissions estimates are to be made more reliable and accurate. Despite these challenges and realities, the gas industry needs to seriously address the issue of methane emissions and step-up efforts in assessing leakage and promoting best practices in dealing with methane leaks.

Nevertheless, the oil and gas industry is deploying efforts to address emissions of methane and also of CO₂, especially CO₂ resulting from flaring activities. In addition to the environmental and sustainability concerns, the methane mitigation effort of the oil and gas companies is driven by: i) economic reasons to capture more value by saving natural gas; ii) safety reasons to avoid accidents due to methane leaks; and iii) the need to comply with methane emissions regulatory restrictions (e.g. Russia has adopted standards to reduce methane emissions).

The gas industry has adopted many initiatives and concrete actions to deal with the methane issue. For example, major oil and gas companies have recently committed to reducing methane emissions from their gas assets. They have signed a “guiding principles” document, which includes improvements in the accuracy of data and collection methods and increased transparency and reporting standards. Major companies have also pledged \$1.3 billion, through the Oil and Gas Climate Initiative, in order to scale up the development of climate-friendly technologies and solutions, including ones to reduce methane leakage and which therefore should be the focus of future investment.

In the US, the EPA recently released a plan to roll back methane emissions standards for upstream activities which had been proposed by the Obama administration. However, this plan is facing significant opposition from environmental groups and state level jurisdictions, making its implementation uncertain. Moreover, major US oil and gas companies consider the reduction of methane emissions as a strategic lever, and this can be seen by the recent involvement of three companies (Chevron, ExxonMobil and Occidental Petroleum) to the Oil and Gas Climate Initiative.



3

Energy Demand Outlook

Key findings

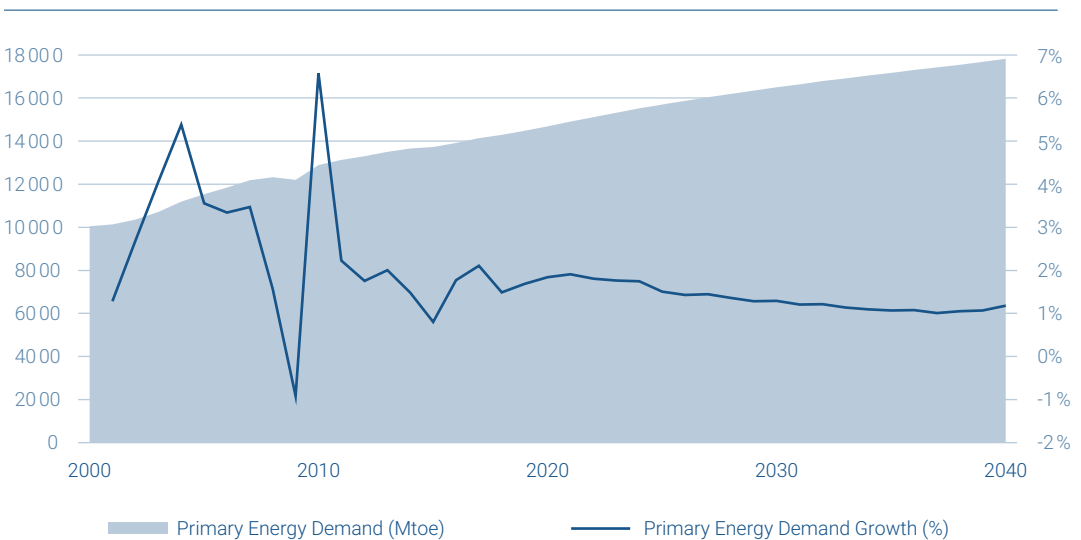
- Primary energy demand is projected to rise by 1% p.a., from 14144 Mtoe in 2017 to about 17829 Mtoe in 2040. This represents a slower pace than the historical average of 2% p.a. seen since 2000 thanks to increased energy efficiency measures.
- Fossil fuels will dominate the global energy mix with their share decreasing from 81% to 76% over the forecast period. Non-fossil fuels are expected to develop at a rate of 2.1% p.a., while fossil fuels will grow by an average of 0.7% p.a.
- The share of oil, the world's largest source of energy, will decline from 32% to 29% by 2040. Coal's share will fall much more significantly, from 27% to 21%, due to environmental concerns, with the Asia Pacific region accounting for the bulk of demand. Renewable energy consumption (excluding hydro and biomass) is forecast to soar by 6.7% p.a. and to reach 6% of the total energy mix by 2040.
- Natural gas will be the fastest growing fossil fuel, mainly thanks to policy drivers concerning air quality, and will displace other sources of energy in a range of sectors. Demand is expected to increase by 1.7% p.a., with gas's share of the energy mix rising from 22% to 26% by 2040.
- Natural gas consumption will climb from 3709 bcm in 2017 to 5427 bcm in 2040. Asia Pacific, North America, the Middle East and Africa will lead this growth. Gas demand in Africa will grow most rapidly (3.1% p.a.) but from a very low base.
- North America and Asia Pacific will account for 52% of global gas consumption in 2040. The United States will consume 82% (1173 bcm) and China 49% (701 bcm) of demand in their respective regions.
- From a sector perspective, the power generation (2.2% p.a.) and industrial sectors (1.2% p.a.) will be the biggest contributors to incremental gas demand. The transport sector (4.2% p.a.) will emerge as a significant new area with an overall increase of 160%, reaching 357 bcm in 2040.
- In the power sector, the advantages of gas over coal and oil will continue to drive fuel-switching. In addition, the increasing role of renewables will promote gas generation as a flexible back-up. Growth in electricity demand from 25613 TWh in 2017 to 42253 TWh in 2040 will also provide a boost for gas as a fuel input.
- In 2040, about 55% of electricity generation will come from fossil fuels and gas will represent 26% of the generation mix. Gas demand from the power sector is expected to grow by 67% to 2219 bcm in 2040.
- Under the assumption that the global urban population will reach about 5.7 billion by 2040, gas demand in the domestic sector will increase by 0.9% p.a. to about 924 bcm.

3.1. Primary energy demand trends: historical (2000-2017) and forecast (2017-2040)

Global primary energy demand, as measured by Total Primary Energy Supply (TPES), grew by 2.0% per annum between 2000 and 2017, climbing from 10049 Mtoe in 2000 to about 14144 Mtoe in 2017. Last year, global primary energy demand increased by approximately 1.7% compared to 2016, as demand growth accelerated in China (+2.1%), India (+3.0%), South Korea (+3.0%), Japan (+1.0%), Germany (+0.2%), Iran (+4.3%) and Brazil (+1.8%). Conversely, primary energy demand growth in the US and Russia, decreased by 0.2% and 0.4%, respectively.

The GECF estimates that due to energy efficiency measures, global energy demand will grow by 1.0% per annum over the forecast period, a slower pace compared to the 1.1% indicated in the 2017 GGO, and demand will increase to approximately 17829 Mtoe in 2040. This corresponds to an overall increase of 26%.

Figure 3.1. Trends in global energy demand (Mtoe, %)

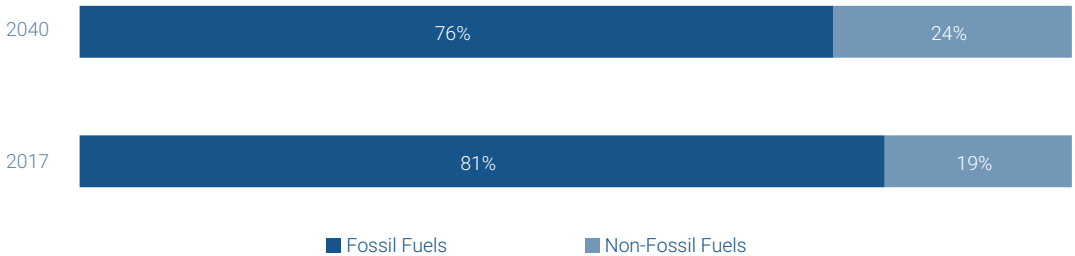


Source: GECF Secretariat based on data from the GECF GGM

Most of this growth is expected to come from key economies, where demand is driven by robust population and economic growth. In particular, Vietnam (145%), India (105%), Nigeria (97%), Egypt (96%), Indonesia (76%), Turkey (65%), Saudi Arabia (55%), Iran (50%), Pakistan (47%), Brazil (43%), Mexico (28%), and China (29%) will exhibit a surge in energy demand from 2017 through to 2040.

It is worth mentioning that due to energy efficiency measures, primary energy demand is expected to decline significantly in some countries, notably Japan (13%), Germany (21%), France (16%), the UK (8%), Italy (7%) and Spain (12%).

Figure 3.2. Global energy demand in 2017 and 2040 by fuel source (%)



Source: GECF Secretariat based on data from the GECF GGM

Fossil fuels accounted for 81% (approximately 11475 Mtoe) of global primary energy demand in 2017, with non-fossil fuels contributing 19% (approximately 2669 Mtoe). Despite the GECF forecasts that non-fossil fuels will grow at an annual average growth rate of 2.1%, faster than fossil fuels which have a forecast growth rate of 0.7% average per year, conventional fossil fuels will still dominate the global energy mix and will account for around 76% or almost 13546 Mtoe of the total world energy demand over the projection period.

Natural gas consumers are currently benefiting from a low-price environment, as well as ample reserves and supplies and fewer emissions than other fossil fuels. In 2017 global gas demand is estimated to have grown by 2.5% year-on-year, slightly more than the 2.4% average annual growth rate seen from 2000 to 2017. Hence, demand for gas grew at a much faster rate than overall primary energy demand, increasing the share of gas in the global energy mix to a record 22% or 3161 Mtoe in 2017.

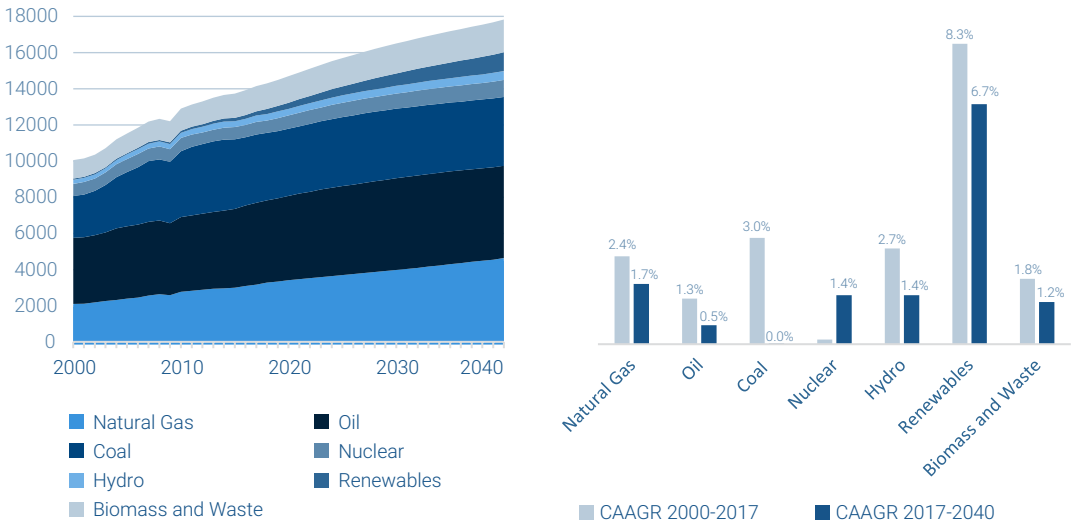
In line with last year's publication, the GECF expects that demand for all fuel sources will increase by 2040. Coal is the only exception, with demand dwindling as coal becomes increasingly replaced by natural gas and renewable energies.

As a result of environmental concerns and policy shifts toward low-carbon energy sources, natural gas is expected to not only become the world's fastest-growing fossil fuel, but also the fastest-growing source of energy, after renewables, increasing by an average of 1.7% annually over the projection period. As seen in Figures 3.3 and 3.4, the share of natural gas in the global energy mix is projected to rise to 26% or about 4633 Mtoe of total primary energy demand.

Oil contributed 32% or 4527 Mtoe to global primary energy demand in 2017 - more than any other fuel - and will remain the world's largest source of energy in 2040. However, its share is forecast to fall marginally to 29%, with an average growth rate of 0.5% per year. Oil is projected to contribute 5109 Mtoe to global primary energy demand in 2040, driven by the transport and petrochemical sectors.

Of total energy consumed in 2017, 27% or 3788 Mtoe came from coal. As previously mentioned, coal's decline is primarily attributed to increasing environmental concerns. By 2040 coal consumption will remain flat, and its share will drop sharply to 21% or about 3805 Mtoe of the global energy mix. Asian economies remain the largest consumers of coal, particularly India, where coal-fired power generation will continue to be a driving force of demand.

Figure 3.3. Global primary energy demand trends by fuel type (Mtoe), and associated CAAGR (%)



Source: GECF Secretariat based on data from the GECF GGM

Renewable energies (geothermal, wind, solar and, to a lesser extent hydrogen) are projected to be the fastest-growing energy sources in the long-term. Demand for renewables is expected to increase by an annual average growth rate of 6.7%, from 2% or almost 237 Mtoe in 2017, to 6% or almost 1047 Mtoe of total primary energy demand in 2040. The wind and solar sectors are forecast to experience dramatic growth in coming years, and the US and China will remain the largest markets. The main driver behind this growth is likely to be cost reductions for both onshore and offshore wind and solar energies.

After renewables and natural gas, nuclear will see the third largest percentage increase in consumption. From 2017 to 2040, total primary energy consumption for nuclear energy is expected to increase by an annual average growth rate of 1.4%. In 2017, nuclear power represented nearly 5% or 692 Mtoe of the global energy mix. Its share, however, will remain relatively stagnant at 2017 levels, with a projected 943 Mtoe consumed in 2040. Clearly, policy changes driven by the Fukushima Daiichi nuclear disaster in March 2011 have not only slowed the development of nuclear energy around the world but have resulted in many countries deciding to review their nuclear energy policies. The halt of nuclear power after the accident gave a major boost to the use of natural gas as an alternative energy source.

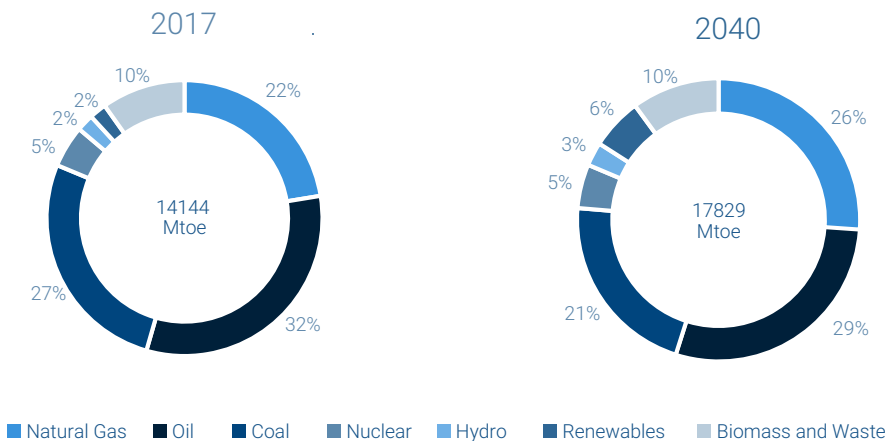
Hydropower accounted for just 2% or 352 Mtoe of global primary energy consumption in 2017, with demand expected to increase slightly by an average of 1.4% per annum to 3%, or around 480 Mtoe in 2040. Hydroelectric plants accounted for 16% of global electricity generated in 2017, and the sector is expected to account for 13.2% of consumption by 2040. Due to environmental concerns and climate change, the actual amount of electricity which will be generated by hydropower will be much less than its potential.

Currently, China is the world's largest producer of hydroelectricity, with much of the remaining hydro potential existing in the developing economies of Africa and Asia. Although small-scale hydro power plants, as well as new hydro technologies such as wave, tidal and osmotic power, have great prospects, they are still under development. The high construction and installation costs associated with hydro-electric facilities also pose a barrier to their deployment.

Biomass (including wood burning) and waste contributed 10% or 1387 Mtoe to the global energy mix in 2017. Consumption will increase by an annual average growth rate of 1.2%, to approximately 1813 Mtoe in 2040. The share of biomass and waste in the global energy mix is projected to remain stable (at 10%) over the outlook period, due to firewood and charcoal burning for off-grid lighting and cooking purposes, mainly in Africa and Asia.

At the same time, future prospects of electricity generation from biomass and waste materials may face certain constraints, connected with technical issues, the availability of land and high fuel prices (particularly, advanced generation biofuels) in comparison with other sources of energy. In 2017 there was approximately 138 GW of biomass power plant capacity throughout the world.

Figure 3.4 Global primary energy demand in 2017 and 2040 by fuel type (%)



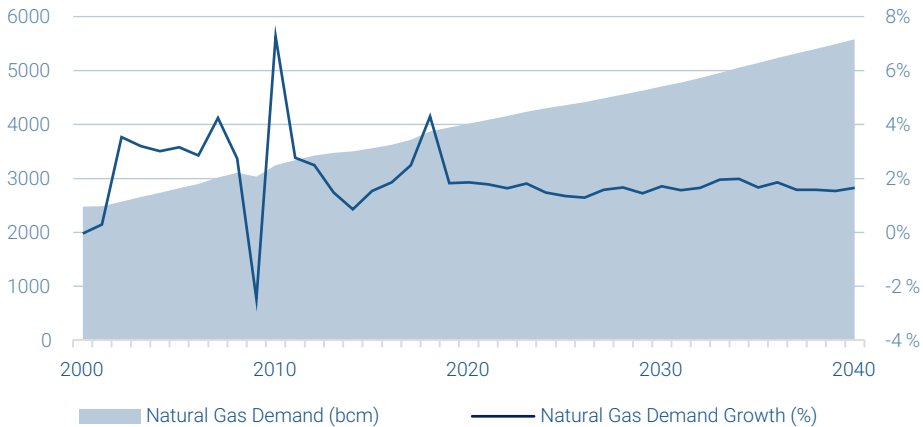
Source: GECF Secretariat based on data from the GECF GGM

3.2. Natural gas demand trends: historical (2000-2017) and forecast (2017-2040)

Global overview

Between 2000 and 2017 global demand for natural gas grew by 2.4% annually, from 2474 bcm to 3709 bcm, driven by consumption in the power generation sector. This year's edition of the GGO is very similar to last year's forecast, in terms of global trends in gas demand and sectoral contributions.

Figure 3.5. Trends in global natural gas demand (bcm, %)

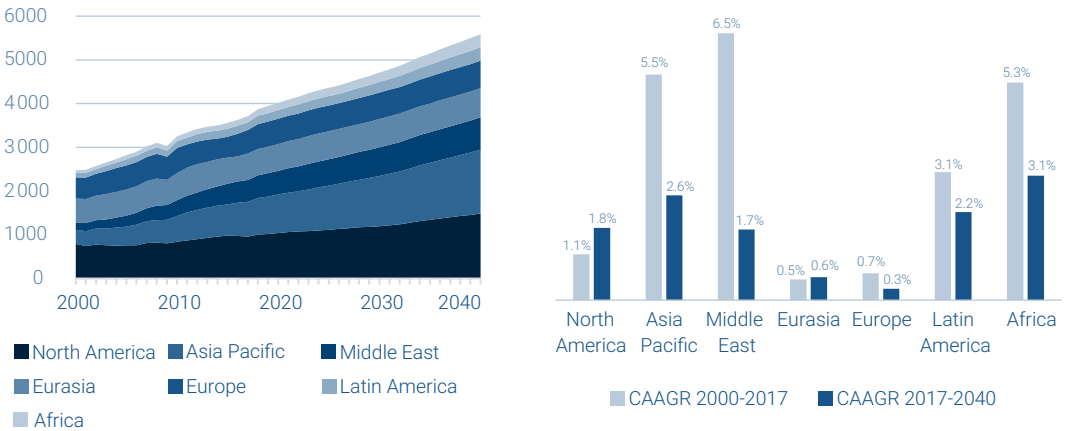


Source: GECF Secretariat based on data from the GECF GGM

The GECF forecasts that global natural gas demand will rise at an annual average growth rate of 1.7%, representing an overall increase of 46%, and climbing to about 5427 bcm in 2040. The key changes to the projections are:

- ⊙ Strong policy efforts to improve air quality through coal-to-gas switching in key regions.
- ⊙ The acceleration of natural gas use in the power generation sector worldwide.
- ⊙ Policies include the phasing out of coal-fired electricity, and in some countries, nuclear-fired power generation, which will lead to greater reliance on gas-fired power plants.
- ⊙ On the assumption that the urban population reaches about 5.7 billion by 2040, the potential for the use of gas in domestic and residential sectors is high.
- ⊙ Stronger demand in the industrial sector as a result of economic and population growth will lead to an increased use of gas for exports of manufactured and industrial products.
- ⊙ In the transport sector, LNG is expected to become an important alternative to heavy fuel oil in the marineshipping sector in the long-term, which will enable ships to meet increasingly stringent international regulations on emissions.
- ⊙ North America is currently the largest consumer of natural gas, accounting for 26% of global demand. The region will continue to drive global gas consumption. This fact is primarily attributable to shale gas development in the US. Exploitation of abundant unconventional reserves has lowered prices and made natural gas an attractive alternative fuel for the power sector.

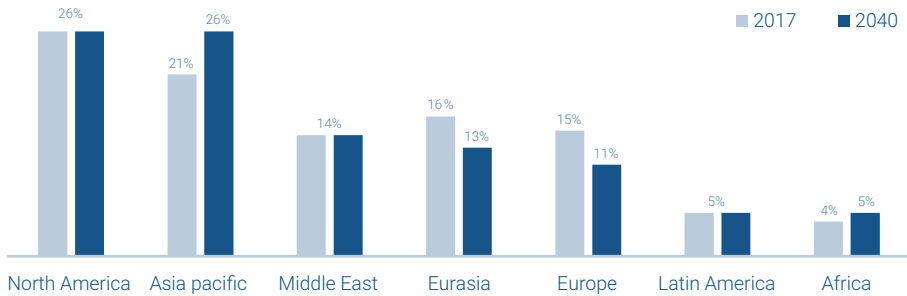
Figure 3.6. Global natural gas demand by region (bcm), and associated CAAGR (%)



Source: GECF Secretariat based on data from the GECF GGM

- ⊗ The Asia Pacific region accounts for 21% of the world's demand in 2017. Trends in this region are largely dependent on China and India; countries which are adopting policies in favour of gas in an attempt to improve air quality. While China and India are particularly significant to the global energy outlook, Asia's leading emerging markets (e.g. Bangladesh, Indonesia and Pakistan) are poised to make increasingly substantial contributions. The GECF expects demand in the Asia Pacific region to rise significantly by 79%, representing over a quarter of global gas consumption in 2040.
- ⊗ Over the historical period, the most dramatic rise in gas demand came from the Middle East. Countries in this region represented 14% of global gas demand in 2017, with Iran, Saudi Arabia and the UAE the primary drivers of consumption. As will be discussed in more detail, the Middle East will see demand for gas rising by 48% over the outlook period.
- ⊗ Gas consumption in Europe and Eurasia increased by 12% and 9% respectively, over the historical period. Russia, Germany, Turkey, the UK, Italy, France and Spain are among the largest consumers of gas in the world. Collectively, these countries will consume about 840 bcm of gas in 2040. Russia alone will consume more than half of this volume. By 2040, Europe and Eurasia will consume around 11% and 13% of global gas demand.
- ⊗ Latin America experienced a strong gas demand growth rate over the historical period, as a result of accelerated economic development coupled with high demand from the transport and power sectors. Various Latin American countries are looking at FSRUs to import LNG for the first time. Gas demand in Latin America will continue to be very weather dependent, given the massive role played by hydro in the region. Demand in the region is forecast to rise by 63%, representing about 5% of global gas consumption in 2040.
- ⊗ The largest growth in gas demand among all regions globally in the outlook period comes from Africa. Africa currently ranks bottom in the world in terms of gas consumption, responsible for only 4% of global gas demand in 2017. The main demand driver will be growth in the industry and power generation sectors. By 2040, Africa will account for 5% of the world total consumption.

Figure 3.7. Natural gas consumption by region in 2017 and 2040 (%)

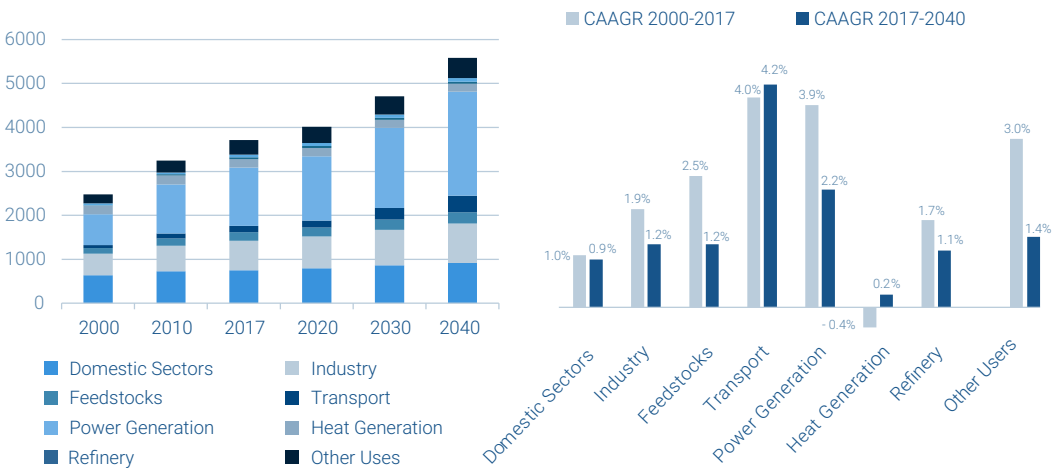


Source: GECF Secretariat based on data from the GECF GGM

Outlook by sector

As in the 2017 GGO, this edition forecasts that throughout the outlook period the transport and power generation sectors will be the main drivers of natural gas growth, with annual average growth rates of 4.2% and 2.2% respectively. These two sectors will account for about 48% of global natural gas consumption in 2040. However, the industrial sector still holds second place in terms of absolute consumption, after power generation.

Figure 3.8. Global nature gas demand by sector (bcm), and associated CAAGR (%)



Note: Data for the hydrogen sector is currently insufficient and has been omitted from these figures

Source: GECF Secretariat based on data from the GECF GGM

Power generation sector

Between 2000 and 2017 natural gas demand in the power generation sector saw significant growth at an average annual rate of 3.9%, from 700 bcm to 1332 bcm. The power sector increased its share of global consumption from 28% to 36% over the same period.

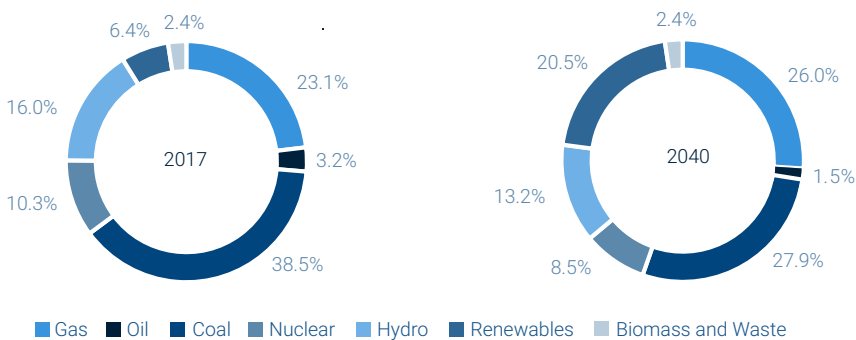
Natural gas has many advantages over oil and coal when it comes to power generation. Gas-fired generation is characterised by high thermodynamic efficiencies, lower heat rates and shorter construction lead times. Natural gas combustion produces fewer pollutants than other fossil fuels, such as nitrogen oxides (NO_x), sulphur oxides (SO_x), carbon dioxide (CO₂) and particulate matter, and consequently coal-to-gas switching in the power generation sector has played a critical role in reducing emissions.

Natural gas consumption is closely linked with electricity demand in many countries. Developments in the power generation mix directly affect demand for gas. Hence, growth in electricity demand will increase the need for gas-fired power. This report forecasts that global electricity demand will grow faster than energy and gas demand, by an average of 2.2% annually, rising from 25613 TWh in 2017 to about 42253 TWh in 2040 (including the energy sector's own use, transmission and distribution losses).

In 2017 coal played a significant role in power generation, constituting 38.5% of the global power generation mix. Coal's contribution is expected to decrease as a result of air pollution concerns, and its share will drop significantly to 27.9% in 2040. The share of gas will continue to rise, from 23.1% in 2017 to 26.0% in 2040.

In 2017 the share of renewables in the global electricity mix was about 6.4%. Significant reforms in energy policies and government support for increased renewables penetration in many countries will propel renewable energies in the power generation mix to a share of 20.5% in 2040. This report expects that, over the outlook period, the share of nuclear in the global electricity mix will drop from 10.3% to about 8.5%. Additionally, the share of hydro will decrease from 16.0% in 2017 to 13.2% in 2040. These trends indicate that in 2040, about 55% of electricity generation will come from fossil fuels.

Figure 3.9. Global power generation mix in 2017 and 2040 (%)



Source: GECF Secretariat based on data from the GECF GGM

The GECF expects that global natural gas consumption will remain concentrated in the power generation sector. A key characteristic of renewable energies, particularly wind and solar, is their intermittency and their currently limited capacity for large-scale electricity storage. The flexibility and short start-up times associated with gas-fired power generation make it well suited to provide back-up energy for intermittent renewable electricity.

Demand for natural gas in the power generation sector is forecast to increase by an overall 67%, with an annual average growth rate of 2.2% per year over the outlook period, to about 2219 bcm, and it will account for a share of 41% of total global consumption in 2040. Policies to promote natural gas and/or phase out coal-fired power plants are the main drivers behind this growth.

Domestic sectors

Global gas consumption in the domestic sectors grew by an average of 1% per annum between 2000 and 2017, from 635 bcm to 751 bcm. The domestic sector currently accounts for over 20% of total natural gas demand. More than 68% (513 bcm) was consumed in the residential sub-sector, followed by 31% (229 bcm) in the commercial sub-sector, and just 1% (9 bcm) in the agricultural sub-sector. Variations in gas consumption within the residential and commercial sub-sectors are mainly weather related, as cooler temperatures boost demand for heating.

Under the assumption that the global urban population will reach about 5.7 billion by 2040, the potential for gas consumption in the domestic sector is large. At the end of the forecast period this sector will have increased consumption by 23%, growing modestly by an annual average rate of 0.9%. The domestic sector is projected to reach approximately 924 bcm in 2040, contributing 17% to global gas demand. Around 580 bcm will come just from the residential heating and cooling sectors. The main drivers behind the increase are population and economic growth, irrespective of energy intensity improvements.

Industrial sector

In 2017 almost 18% of global natural gas demand came from the industrial sector, where consumption is driven by iron and steel, chemical and petrochemical, non-ferrous metals and non-metallic minerals production. Gas is used to produce chemicals, fertilisers, methanol, urea and ammonia, as well as in the production of fabrics, textiles, manufacturing, paints and food and beverages.

Throughout the outlook period, global natural gas demand from the industrial sector will grow at a slower pace compared to the 1.9% recorded over the historical period. Industrial demand is projected to increase by 33%, from 671 bcm in 2017 to around 892 bcm in 2040, corresponding to an annual average growth rate of 1.2% and will constitute 16% of total global gas demand. Important drivers include economic growth and switching from coal-fired to gas-fired boilers in emerging economies. The positive outlook for the chemicals industry in regions such as North America and the Middle East, as well as the need to boost fertiliser production in populated countries such as China and India, also contribute to industrial demand growth.

Transport sector

Last year around 4% of global natural gas consumption came from the transport sector. A large portion of the energy used in global transportation networks comes from petroleum-based fuels, mainly gasoline and diesel. Although the transportation sector is slowly moving away from oil to alternatives such as CNG, liquefied petroleum gas (LPG) and other alternative fuels (e.g. biofuels), in 2017 this sector accounted for more than 24% of global GHG emissions. According to the latest data from the International Association for Natural Gas Vehicles, currently four countries together account for almost two-thirds of the world's NGVs. These are: China with 6.02 million (23.2% of the world's NGVs), Iran with 4.5 million (17.2%), followed by India with 3.09 million and Pakistan with 3 million NGVs. In Europe,

Italy has the largest NGV fleet standing at approximately 1 million vehicles (1).

The UN's International Maritime Organization (IMO) adopted an initial strategy to reduce GHG emissions from ships, which are estimated to account for 3% of global GHGs emissions. Under IMO regulations, from 2020 ship owners will have to comply with a new 0.5% cap on the amount of sulphur in marine fuel, compared to the existing limit of 3.5% (2). LNG is expected to become an important alternative to heavy fuel oil due to its relatively low emissions of air polluting substances and GHG emissions, which will enable ships to meet increasingly stringent international regulations on emissions. Compared to heavy fuel oil, the use of LNG can significantly reduce emissions of SO_x, NO_x, CO₂ and particulate matter. Thus, it is expected that the move will give fresh impetus to the use of gas as a shipping fuel in the long-term.

These forecasts show that the transportation sector is the only sector with a robust gas growth rate in this outlook. Demand for natural gas as a transport fuel is projected to grow at an annual average rate of 4.2%, much faster than other sectors, with an overall increase of 160%, rising from 137 bcm in 2017 to about 357 bcm in 2040, constituting 7% of forecast global gas consumption.

Feedstock sector

Natural gas for non-energy uses is the most common energy feedstock used for agricultural chemicals, pharmaceutical products and petrochemicals. Butane, ethane and propane which are extracted from natural gas are used in fertiliser production, including ammonia and its derivatives (e.g. urea, methanol, nitric acid and ammonium nitrates). The surge in LNG usage has further resulted in additional gas demand for feedstock, driven by the US, Australia, Russia and Qatar. However, most of the growth in natural gas feedstock consumption over the outlook period is expected to originate from new methanol and ammonia projects in the US and the Middle East.

In this respect, the GECF expects gas consumption to grow at a slower pace compared to the 2.5% recorded over the historical period, at an average annual growth rate of 1.2%. Gas consumed as a feedstock will see an overall increase of 32%, rising from 195 bcm in 2017 to around 257 bcm in 2040. This will constitute approximately 5% of total global gas demand.

Other sectors

One of the main uses for gas is in the petrochemical sector, where it is used to provide hydrogen, methane, ethane, propane and butane for refinery processes. Hydrogen was introduced as a fuel source many years ago, but it has yet to play a significant role in global energy systems and a variety of uncertainties exist concerning its future contribution. There are a number of initiatives around steam reforming of methane and power to gas to create hydrogen by electrolysis (e.g. in Europe and Japan). Several fuel cells have been developed which can convert hydrogen into electricity, however hydrogen technologies have not reached the economies of scale necessary to achieve considerable market penetration.

As shown in Figure 3.8, gas used for refinery and hydrogen production is projected to grow at slower pace over the outlook period compared to that observed in the historical period, by 1.1% and 0.1% per year, respectively. Consumption in the refinery and hydrogen generation sectors will rise by 28% and 2%, from 58 bcm and 47.5 bcm in 2017,

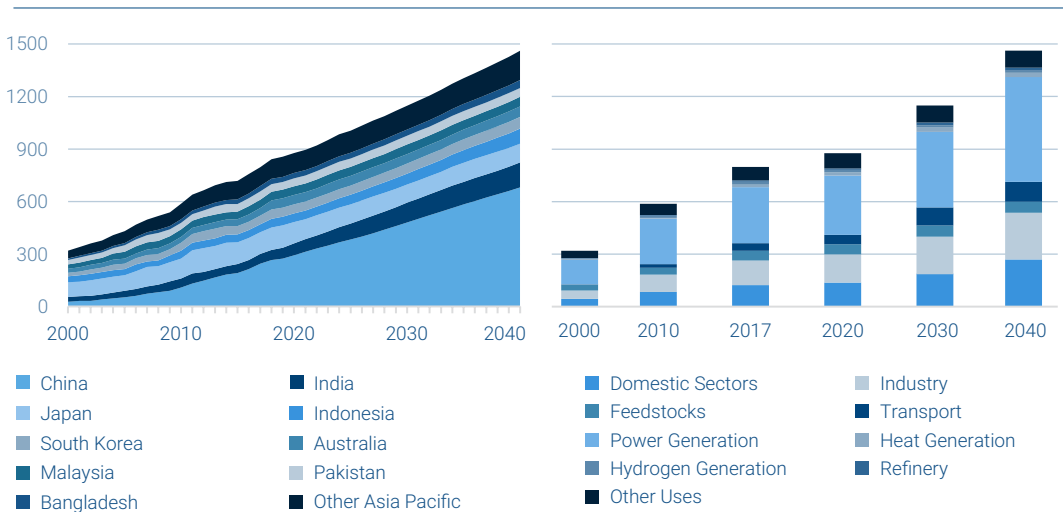
to roughly 75 bcm and 48.3 bcm in 2040, correspondingly. However, these volumes are negligible given overall levels of consumption. The heat generation sector will only experience 0.2% growth per annum over the forecast period. Heating purposes vary depending on the consuming sector (e.g. space, water, cooking heating, high and low temperature processes etc.). Approximately 185 bcm of gas was consumed for heat generation in 2017 and this figure is expected to increase by 6% overall, to around 196 bcm, which constitutes 4% of global gas consumption in 2040. Increasing efficiency in residential heating, cooling and hot water systems will be the key drivers behind the slower growth.

Outlook by region

ASIA PACIFIC

Asia Pacific is currently the second-largest consumer of natural gas, accounting for 21% of global demand. Natural gas demand in the region is projected to increase at an annual average growth rate of 2.6%, from 794 bcm in 2017 to around 1422 bcm in 2040. The use of LNG in the power sector will be significant, supported by economic growth and strong coal-to-gas switching policies. In 2017, 317 bcm (40%) of gas was consumed in this sector. The absolute quantities of gas used in this sector will continue to rise, and it is expected that by 2040, around 509 bcm (36%) of gas will be consumed by the power generation sector.

Figure 3.10. Asia Pacific natural gas demand by country and sector (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Demand in the transportation sector will also grow at a high rate, at about 5.4% per year, and it is projected that replacing current heavy fuel oil engines with LNG engines in the marine shipping sector will create more demand for gas and LNG in the region. This report forecasts gas consumption in the domestic and residential sectors will reach 254 bcm in 2040, increasing by approximately 133 bcm compared with the 2017 level.

China will account for more than 49% (about 701 bcm) of total gas consumption in the Asia Pacific region in 2040. As nuclear power capacity comes online, the outlook for Japan falls, while India's gas demand with 3.6% average annual growth, is set to be Asia's second fastest growing market. Emerging markets such as Vietnam, Indonesia, Singapore, Pakistan and Bangladesh with 4.2%, 2.8%, 2.5%, 0.6%, and 1.6% average annual growth respectively, will also significantly contribute to Asia's gas demand.

Australia

Australia's gas demand has been growing by 3.7% per year, from 23 bcm in 2000 to around 42 bcm in 2017, representing 25% of the country's energy mix. This growth was mainly related to the commissioning of gas power plants. Since 2008 the power generation sector has become the largest gas consuming sector and accounted for 14 bcm (an incremental growth of 9 bcm over the historical period) or 33% of the total gas demand in 2017. As electricity consumption between 2008 and 2015 was relatively stable at around 250 TWh, this implies the share of gas in the power generation mix almost doubled, and at present it constitutes 20%, while the importance of coal, which is a dominant fuel in the power generation markets of Australia, declined from 83% in 2000 to 62% in 2017.

The second largest share of natural gas demand in Australia came from energy industry own use. In 2017 energy-related consumption totalled 11 bcm (26%), a 170% increase from 2000, and this was attributed to usage in oil and gas extraction, as well as in liquefaction plants for LNG production. The industrial sector consumed a steady level of around 9 bcm (21%) over the last decade. The non-ferrous metals industry absorbed 40% of this volume, followed by non-metallic minerals, chemicals and petrochemicals. The domestic sectors, including residential and commercial, consumed 6 bcm (13%).

Over the forecast period, the GECF projects that Australia's gas demand will rise by an average of 1.6% per year, amounting to approximately 61 bcm in 2040. This will correspond to almost 36% of the country's energy mix. Additional gas consumption will be seen in the power generation sector, due to the country's policy of reducing coal-fired power production, and in energy industry own use driven by the completion of LNG projects (namely Wheatstone, Ichthys and Prelude). The GECF also expects a slight increase in gas demand from the industrial and domestic sectors.

In the power generation sector, most coal-fired plants are of a conventional design, and two-thirds are more than twenty five years old, with typical efficiencies of about 33–35% (3). In line with Australia's pledge under the Paris Agreement, the retirement of existing coal plants after 2030 will be inevitable. In this context, coal-to-gas switching represents a huge potential to move to a low-carbon economy. Strong commitments to renewable projects will put pressure on natural gas expansion in this sector, but in the long term gas will become more important to meet peak power demand and provide flexibility.

Given that Australia's gas system is divided into three separate gas networks (western, northern and south-eastern) each with its own supply-demand dynamic, the combination of rising gas demand and a ramp-up in LNG exports has created concerns over the market security. To avoid any potential shortages in domestic supply or possible price hikes and blackouts, the Australian government implemented a Domestic Gas Security Mechanism (ADGMS) in 2017. In accordance with its framework, it requires LNG exporters who are extracting gas from the domestic market to limit exports or find offsetting supplies in case of a declared shortfall year. Transmission pipelines that are under

construction, particularly between the eastern and northern markets, will also enhance security of supply.

Bangladesh

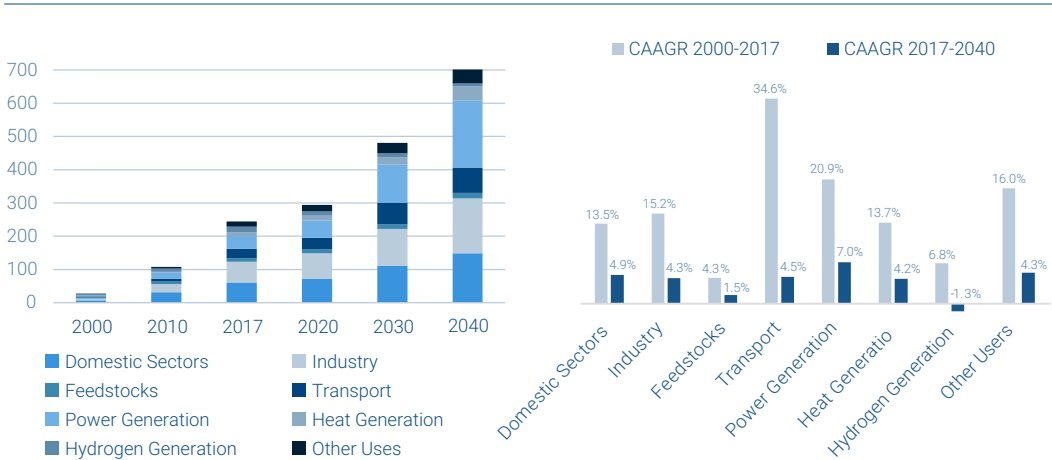
Natural gas consumption in Bangladesh increased by 7.5% per year between 2000 and 2017, from 9 bcm to over 31 bcm. This report forecasts that natural gas demand will grow by 1.6% annually over the outlook period, to about 44 bcm in 2040. In 2017 over 85% (27 bcm) of Bangladesh’s natural gas was consumed in three sectors: 17 bcm in the power sector, 5 bcm in the residential sector and 5 bcm in the industrial sector, primarily for fertilisers and textiles. Thus, power generation is the main driver of gas demand growth in Bangladesh. Gas usage here will grow to almost 19 bcm, or 44% of total consumption, over the forecast period.

The country encountered a natural gas crisis in 2009, as high levels of gas consumption forced Bangladesh’s national oil company (Petrobangla) to ration supplies to energy-intensive industries, power plants, CNG filling stations and households. To meet growing demand in a country with over 160 million people, Bangladesh has begun investing heavily in LNG infrastructure, and is planning to build three small FSRUs in offshore locations. In April 2018 Bangladesh became the newest country to begin importing LNG, and received its first 136,009 MT LNG cargo from Qatar (4). This is only the first step in a significant ramp-up of the country’s LNG imports.

China

With almost 1.4 billion inhabitants, China has the largest population of countries that consume natural gas. Gas demand grew rapidly over the historical period, by an average of 13.6% per annum, reaching 245 bcm in 2017. China’s hunger for natural gas is primarily driven by coal-to-gas switching policies, GDP expansion and industrial recovery.

Figure 3.11. China natural gas demand by sector (bcm), and associated CAAGR (%)



Source: GECF Secretariat based on data from the GECF GGM

Over the forecast period the GECF expects that gas consumption will rise by an overall 186%, to about 701 bcm with a corresponding average annual growth rate of 4.7%. This can be attributed to China’s national policies under the 13th

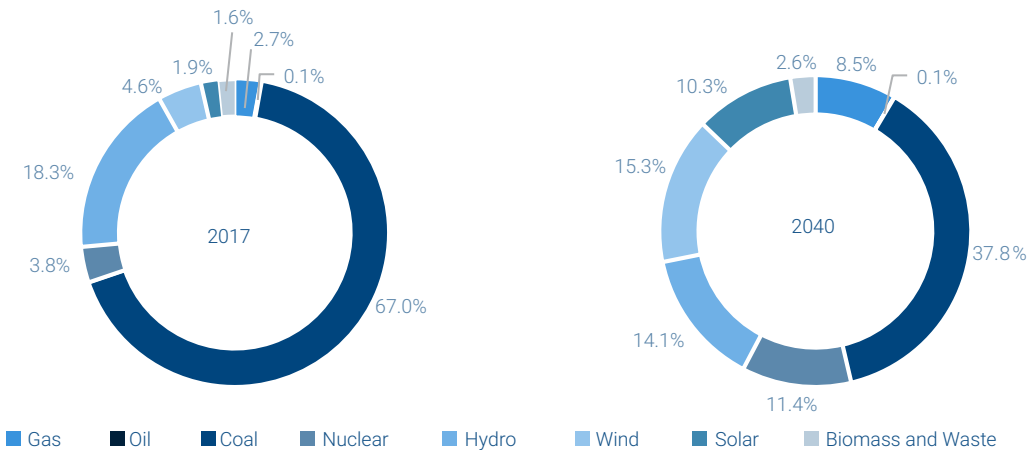
Five-Year Plan, which aims to reduce CO₂ emissions by decommissioning coal-burning power plants and making price adjustments that encourage gas consumption, as well as economic growth. At present, gas constitutes 6.6% of the country's energy mix and the government has set targets to increase that share to 15% by 2030.

In 2017 the industrial and domestic sectors consumed almost 51% of China's total gas demand, driven by government policies directed at tackling air pollution. Natural gas demand peaked last winter, as heating demand ramped-up in the industrial (63 bcm) and domestic (60 bcm) sectors. Strong growth is expected to continue over the outlook period. The industrial sector will grow at an average annual rate of 4.3% through to 2040, reaching 165 bcm. Similarly, the domestic sectors will experience a 4.9% growth rate, reaching 179 bcm over the same time horizon.

China is the world's largest GHG emitter, accounting for more than 25% of the global total. This reflects an electricity system based 67% on coal in 2017, as well as China's global leadership in heavy industries. Gas consumption in the power generation sector, where there are opportunities to substitute gas for coal, will rise sharply with an annual average growth rate of 7.0%, from 38 bcm in 2017 to about 177 bcm in 2040. It is forecast that in 2040, close to 237 GW of additional gas fired power generation capacity will come online, resulting in 8.5% of Chinese electricity generation coming from natural gas, while the share of coal will drop to 37.8%.

However, in line with China's "Energy Production and Consumption Revolution Strategy 2016-2030", it is projected that renewables and hydro power will become the main Chinese power source, at around 39.7%. Nuclear accounted for 3.8% in 2017, and by 2040 will constitute 11.4% of the Chinese electricity generation mix.

Figure 3.12. China power generation mix in 2017 and 2040 (%)



Source: GECF Secretariat based on data from the GECF GGM

In 2017, the transport sector consumed nearly 11% of China's total gas consumption, compared to only 1% in 2000. Last year the production of large and heavy-duty LNG trucks broke a new record with a total of 96,000 built, compared with just 19,600 in 2016.

This report expects demand for natural gas as a transport fuel, especially in the powered heavy-duty trucks and public transportation sectors, to grow at an annual average rate of 4.5%, rising from 28 bcm in 2017 to almost 77 bcm in 2040. As before, the main demand driver is China's policy of curbing the use of diesel and gasoline in the transportation sector and thus more natural gas vehicles will likely be introduced.

China's increasing gas demand can be consistently met by LNG - as it provides higher flexibility and is more competitive compared to other energy sources - as well as by gas pipelines. China's first LNG terminal opened in 2004 and its first major import pipeline was commissioned in 2009. Currently, China is the fastest growing LNG market in the world. In 2017, the country reached a new LNG demand record and overtook South Korea as the world's second largest LNG importer after Japan. The country imported about 38.1 million MT of LNG, up 46.4% from 2016. Currently the country has eighteen LNG regas terminals with a total capacity of 60 million MT per year, of which seven are being expanded, and another eleven are planned.

Among China's three main LNG consuming areas, the Northern region is the fastest growing. Two municipalities (Beijing and Tianjin) located in the north and an additional 26 cities experience serious air pollution compared to other regions in China. They are the main targets of the country's coal-to-gas switching policy, not only in the industrial sector and for manufacturing end-users, but also for clean heating, especially during the winter months.

In 2014 Gazprom signed a 30-year contract with CNPC for the supply of 38 bcm per year of gas via a 3,000-km direct onshore pipeline, running from the gas fields of eastern Siberia to the Chinese border in the southeast. First gas from Siberia is expected to flow into China by 2020.

Northern China's gas storage dilemma

In the winter of 2017, Northern China experienced unprecedented seasonal demand for natural gas, mainly for heating purposes. Insufficient gas storage infrastructure resulted in the region facing gas shortages. This occurred as a result of two LNG supply constraints: limited transportation capacity in the form of freight, and inadequate terminal storage and regas capacities.

There is a shortfall of LNG capacity in northern China, made evident by the fact that LNG imports there grew by only 28% year-on-year compared to 39% in southern regions. To meet seasonal demand, Tianjin, Shandong and Caofeidian in northern China began to exceed their nominal operating capacities. Due to higher operating capacities, freight transport was unable to meet demand because of physical storage limitations. In fact, the major issue regarding the transportation of LNG by truck is the limited amount that can be moved in this way. There are currently only 5,000 operating trucks that can transport LNG among import terminals.

All these issues and constraints regarding natural gas supply in northern China compelled the Chinese government to expand gas storage and pipelines (e.g. through the use of underground storage facilities). In April 2018, the National Reform Development Commission (NRDC) announced that it would boost reserves through two objectives. Firstly, by increasing and developing natural gas storage capacity to the equivalent of 16% of domestic consumption by 2020. Secondly, by promoting China's domestic gas exploration and production, specifically from shale gas and CBM. Accordingly, the state-owned China Petroleum and Chemical Corp (Sinopec) is building natural gas storage

facilities with a total capacity of 56 bcm in the northern Henan province, to ease supply bottlenecks in the peak winter season. Additionally, the need for reforms of pipeline ownership and third-party access are seen as essential to solving infrastructure issues over the longer-term.

India

Natural gas currently accounts for only 5.3% of primary energy demand in India. This is expected to change over the projection period. Demand for natural gas is projected to grow at an annual average growth rate of 3.6%, from 56 bcm in 2017 to around 127 bcm in 2040, with the largest contribution coming from LNG. Overall gas demand is expected to increase by 127%, which is equivalent to an incremental 71 bcm. This takes into account the overall forecast for India's economy, as well as rapid expansion of urban populations and energy-intensive industries.

The government is investing in gas infrastructure by creating pipelines and LNG terminals, primarily in the east and south of the country. Several projects have been completed or partially completed. The 2655-km East India pipeline (Jagdishpur-Haldia-Bokaro-Dhamra) project which was inaugurated in 2015, is expected to be fully completed by December 2020. The venture will supply gas to fertiliser plants, power plants, refineries, steel plants and other industries. The project will also provide natural gas to households and the transportation sectors of cities along the pipeline's route (5).

In 2017 more than 44% of the total gas volumes available in India were used by the feedstock and industrial sectors for the production of iron, steel, fertilisers, and textiles. Over the forecast period demand from industry and feedstocks will grow at an annual average growth rate of 5.1% (to 18 bcm) and 0.8% (to 23 bcm), respectively.

India is the world's fourth largest emitter of CO₂ and emissions grew by an estimated 4.6% in 2017. The Indian government is under intense pressure to reduce air pollution and improve public health in major cities. Following instructions from the Indian government, the country's leading fuel retailers (e.g. Petronet LNG, Indian Oil Corporation and Bharat Petroleum Corporation Ltd.) are expected to construct around twenty LNG stations to supply about 5000 trucks on five national highways.

India is also the world's largest consumer of petroleum coke (petcoke), which is the second most consumed petroleum product in the country after diesel. It is one of the cheapest fuels available for industrial consumption and is widely used for heating and electricity generation. However, burning petcoke can cause serious health and environmental problems. Petcoke contains high amounts of carbon (about 90%) and sulphur (around 3–6%), along with silicon and trace metals. Exposure to fine particulate matter generated from petcoke is potentially hazardous, and several petcoke storage facilities in the US (the main exporter of petcoke to India) have been closed due to their proximity to urban areas.

As a result of toxic air quality in Delhi, which reached public health emergency levels, the Indian Supreme Court proposed a ban on the use of petcoke and furnace oil in October 2017. A ban on imports was announced in August 2018 but included exemptions for certain industries. The Environment Pollution Control Authority for the Capital Region pointed to the availability of clean alternative fuels, such as natural gas, as evidence for making the switch. Gas infrastructure is already available to industrial areas, and it is expected that this policy will aid Delhi's gas distributors and the LNG sector.

India is expected to have about 10,000 CNG stations by 2028. The country is pushing for the production of motorcycles that run on CNG, with pilot schemes recently launched in major cities, including New Delhi and Mumbai. The government is encouraging railway companies and LNG importers to fuel trains with LNG instead of diesel. Therefore, demand for natural gas as a transport fuel is expected to grow sharply at an average annual rate of 9.7%, faster than any other sector, from 4 bcm in 2017 to about 32 bcm in 2040.

The use of gas in the power sector will account for less than 13% of India's total gas consumption in 2040, compared to a share of 23% in 2017. Gas demand in the power generation sector is set to grow at an average of 1.0% per annum, only reaching 16 bcm in 2040. This is due to the fact that coal reserves are abundant in India and will remain a key fuel source for the country's power generation sector.

As India struggles to increase its local gas production, reliance on imported LNG will continue to be high for the foreseeable future. India imports close to 50% of its gas requirements as LNG. The country has four operational LNG import and regas terminals, with the capacity to import around 22 MT of LNG, all on the west coast. Despite this, to meet growing demand, India plans to build 11 LNG import terminals over the next seven years, bringing total capacity to around 72.5 MT.

In conclusion, further growth in India's gas demand depends on various factors and policy initiatives. First and foremost, price affordability for end-use segments; the fact that the price of imported LNG is higher than that of domestic Indian gas production, the ability of end-use sectors to pay high prices for gas-fired power generation, and the fact that the availability of gas as a feedstock is limited in the country, means that increased gas demand requires continued low prices and government subsidies.

Secondly, transmission and distribution infrastructure investments in the gas sector are crucial. As the government has laid out a plan to increase the share of gas in India's energy mix to 15% by 2030, the development of gas infrastructure is the most critical enabler for reaching the target.

Price reform and investment in the gas sector are hugely complex issues in India, and the Indian authorities will need to demonstrate that policies can actually be implemented before these forecasts can be met.

Indonesia

With a population of 264 million, Indonesia is the most populous country in Southeast Asia and the fourth most populous in the world. Indonesia's population is spread over an archipelago of more than 17,000 islands that stretch over 5,100 km from east to west, and 1,800 km from north to south.

Most Indonesian gas production is offshore, and these fields are able to meet the majority of rising demand. Historically, a large amount of the country's gas production has been exported. However, as existing gas fields are maturing, and production is expected to decline, Indonesia is quickly turning into an LNG importer.

The GECF forecasts that Indonesia's gas demand will almost double from 44 bcm to about 84 bcm by 2040 relative to 2017 levels, an average annual growth rate of 2.8%. Economic growth and associated energy consumption are the

key drivers behind this shift. More natural gas will be used to fuel Indonesia's industrial sector, particularly in chemicals production and as a feedstock for fertilizer manufacturing, and there will be investment in projects for the use of gas in the power sector.

Environmental concerns and commitments to clean energy have spurred new incentives to substitute diesel fuel with natural gas in power generation and industry. The country is committed to reducing emissions by 29% by 2030. The GECF forecasts that the use of gas in the power sector will increase to 49 bcm by an average of 4.4% per year between 2017 and 2040, compared with 6.0% between 2000 and 2017.

Indonesia is Southeast Asia's largest economy, and the industrial sector contributes the most to Indonesia's GDP. The country has drawn up a road map for making it one of the world's ten biggest economies, entitled "Making Indonesia 4.0" and detailing the development of the food and beverage, textile and garment, automotive, chemical and electronics industries. We expect the use of gas in the industrial sector to rise by an overall 67%, from 12 bcm in 2017 to over 20 bcm in 2040.

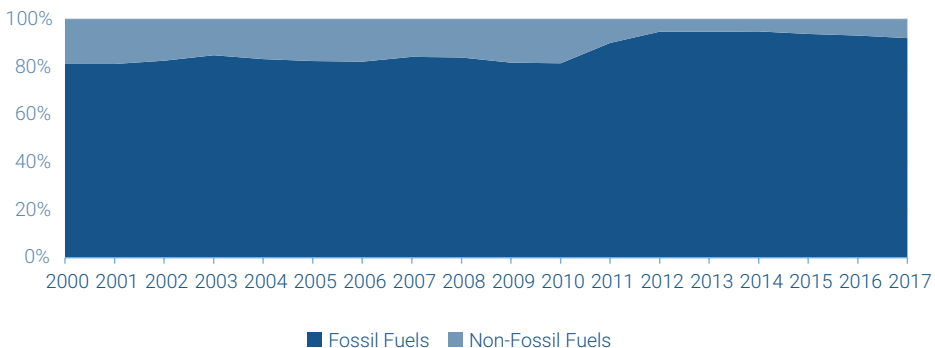
Current investments in the oil and gas sector are falling, while domestic demand is rising. The government is considering attracting as much as \$200 bn of investments to reverse the decline in its oil and gas fields. Indonesia's geographical composition makes LNG a logical solution to these adjustments in the national energy mix.

The country's long-term infrastructure development plan involves making gas supply accessible to the entirety of its archipelago, with small-scale LNG terminals designed to supply remote island regions. Currently Indonesia has four LNG terminals with a capacity of 9.5 mtpa. Several other FSRU projects are planned to meet its energy needs.

Japan

Gas demand in Japan is projected to decline over the forecast period from 125 bcm in 2017 to about 91 bcm in 2040. This is attributed to flat electricity demand and lower gas consumption in the power generation sector. Gas demand will be hampered by reinstated nuclear power capacity, coupled with aggressive renewables deployment that designated by the new 5th National Energy Plan (NEP) (6).

Figure 3.13. Japan energy demand by fuel source from 2000 to 2017 (%)



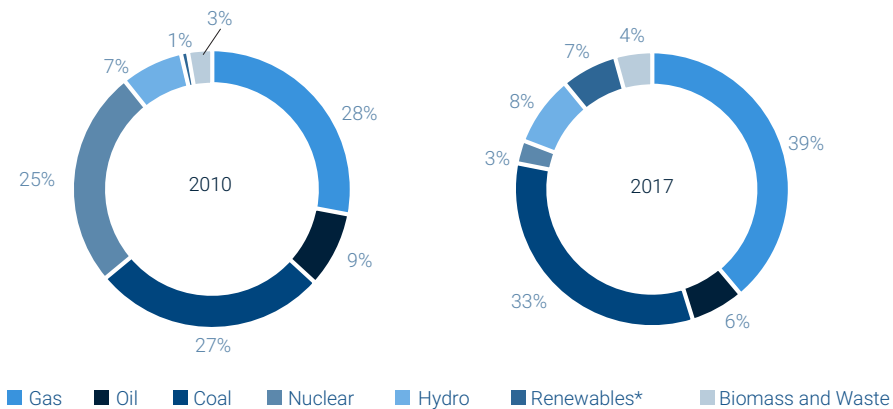
Source: GECF Secretariat based on data from the GECF GGM

While the share of gas in the Japanese electricity mix was 28% in 2010, nuclear supplied 25% of the country's power. After the Fukushima incident in 2011, Japan became increasingly dependent on fossil fuels, and imports boosted its reliance on coal and gas.

The government chose LNG to substitute for lost nuclear generation, and the share of gas increased to a record 42% in 2014. Delays in rebooting the nuclear fleet allowed natural gas to maintain its share, which totalled 39% in 2017, while nuclear supplied only 3%. Approximately 85 bcm of gas was consumed in Japan's power sector last year.

So far, eight nuclear reactors have come back into operation in Japan, and three reactors have had their operating lifetimes formally extended from 40 to 60 years. These three were due to be assessed when their original 40-year licenses expired, but it will be harder for the remaining plants to be granted the same extensions. As a result, Japan will fall short of its nuclear targets and the difference will be compensated by increased coal and gas-fired generation.

Figure 3.14. Pre- and post-Fukushima power generation mix (%)



Note: Renewable energies include geothermal, wind, and solar
 Source: GECF Secretariat based on data from the GECF GGM

Japan's gas infrastructure and transportation systems are owned by private energy companies, and insufficient investments have resulted in poorly connected gas transportation systems. This structure has created some serious problems, especially post-Fukushima when the country faced energy shortages at a time when oil and LNG prices were particularly high. The natural gas market has been liberalised to overcome the disconnectedness of the networks.

With the implementation of the Revised Gas Business Act in 2017, the formerly regulated gas sector became competitive. Because the Japanese government aimed to facilitate access to the LNG supply chain, from import terminals to distribution to end users, LNG markets were also affected. Japanese energy companies refer to the spot market to meet their domestic obligations, and for that reason prefer more flexible gas contracts.

The Japanese government has released a new version of its “Basic Energy Plan”, called the “National Energy Plan” (NEP). It aims to increase domestic energy self-sufficiency to 24% by 2030, compared with 8% in 2016, and to trim emissions by 26% by 2030, and 80% by 2050, relative to 2013 levels.

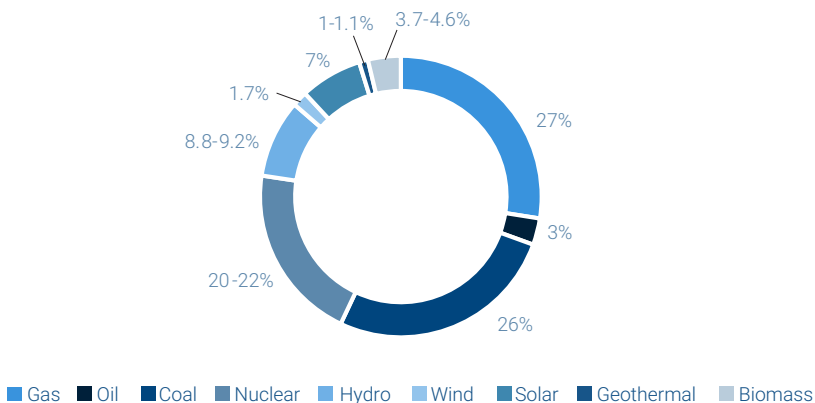
According to the 2030 NEP, gas and coal use will return to pre-Fukushima levels, oil demand will drastically decline, and nuclear energy will recover. It is expected that 22–24% of the power generation mix will be supplied by renewable energies (8.8–9.2% hydropower, 7% solar, 3.7–4.6% biomass, 1.7% wind and 1–1.1% geothermal), which represents a major shift in government policy. Additionally, 20–22% will be supplied by nuclear energy, and 56% will be supplied by fossil fuels (26% coal, 27% LNG, and 3% oil). Furthermore, the country intends to cut the share of fossil fuels in its energy mix to 76% by 2030, down from current levels of 92%.

A comparison of the pre- and post-Fukushima power generation mix with the 2030 NEP targets (Figure 3.14 and Figure 3.15), shows a marked shift from fossil fuels to renewables and hydro development. Although the government’s policy is still strongly supportive of nuclear restarts, public opposition remains. Restarts to date have been far slower than expected, and all reactors have faced legal challenges from local residents.

The nuclear target is ambitious and can only be realized if nearly all nuclear plants are granted permission to come back online under the stricter post-Fukushima regulations, and if their lifetimes can be extended beyond the standard 40 years. According to GECF projections, these factors will contribute to the significant role that LNG and renewables will play in Japan’s energy mix.

Conversely, because of energy security issues, coal will still produce 26% of Japan’s power by 2030, close to pre-Fukushima levels, but lower than the 33% seen in 2017. During the last two years Japan has opened eight new coal-fired power generators, and also aims to open another 36 coal-fired power plants in the next ten years (about 8 GW between 2015 and 2030). These can supply more electricity than the 26% designated in the new NEP 2030, and probably will, if nuclear fails to meet the new target.

Figure 3.15. Japan’s 2030 NEP targets for the power generation mix (%)



Source: Japan’s ministry for economy, trade and industry New 2030 National Energy Plan (NEP)

Japan is pushing to power the 2020 Tokyo Olympics with hydrogen, as part of its long term ambitions towards a hydrogen economy. Japanese firms are working on pilot projects in Norway and Australia to produce hydrogen fuel using wind power and coal. The intention would be to use gas produced off the coast of Western Australia to convert to ammonia and then ultimately liquid hydrogen to export to Japan.

South Korea

Gas consumption in South Korea is projected to increase at a substantially slower rate than the 5.5% recorded over the historical period, growing at an annual average of 1.3%, from 50 bcm in 2017 to 66 bcm in 2040. The forecast is approximately 14 bcm lower than recorded in last year's GGO, as the government's new 2017–2031 plan (for the power sector) outlines a move away from coal and nuclear in favour of renewables. In 2017 over 44% (around 22 bcm) of South Korea's gas was consumed in the power sector. Following two 5.1 and 5.8 magnitude earthquakes that struck the country in September 2016, LNG imports have been on the rise amid nuclear maintenance and safety checks that have led to shutdowns. South Korea currently has 24 operating nuclear reactors, with a total combined capacity of around 22,505 MW. Despite the fact that two reactors are presently under construction, the country's new electricity policy prohibits new units and denies the extension of existing operating licenses.

The outlook for natural gas consumption in South Korea remains positive. The government plans to spend about \$5.48 bn by 2031 on expanding its gas supply infrastructure, including storage and pipelines. According to the power supply plan published in January 2018, the share of coal in the electricity generation mix is expected to decrease to 36% in 2030, while that of nuclear will dip to 24%. Renewable capacity will consequently increase in order to cover 20% of total electricity consumption.

Coal, nuclear and gas accounted for 45%, 26% and 24% respectively of South Korea's power generation mix in 2017. Together they are projected to supply around 80% of the country's total electricity mix in 2040. However, the country will produce more power from renewable energies and natural gas, while gradually reducing its reliance on nuclear and coal. The use of gas in the power generation sector is forecast to increase at an annual average growth rate of 1.2%, to 29 bcm or 43% of total consumption in 2040.

Until being overtaken by China in 2017, South Korea was the second largest LNG importer after Japan, with Qatar and Australia accounting for more than 40% of total LNG imports. State-owned KOGAS, which controls 98% of South Korea's LNG import capacity, has three separate long-term agreements with Qatar to purchase up to 12.1 bcm annually in order to meet growing demand.

Pakistan

As of 2017, Pakistan became the sixth largest LNG market in Asia with imports of 4.6 MT. Pakistan's gas demand is expected to increase in order to keep pace with economic growth. The GECF predicts that demand will grow by approximately 0.6% per year, from 48 bcm in 2017 to about 55 bcm in 2040. This corresponds to a 14% increase in consumption.

In 2017 over 46% (almost 22 bcm) of Pakistan's gas was consumed in two sectors: 27% (13 bcm) in the power

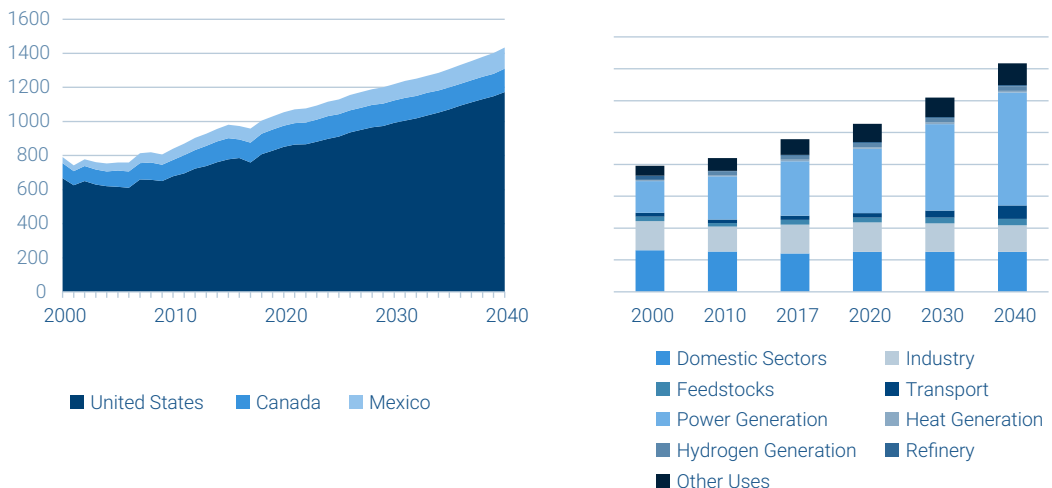
sector, and 19% (9 bcm) in the domestic sector. Within this total, there were seasonal variations in gas consumption mainly related to weather conditions (e.g. consumption in the residential heating and cooling sectors). In 2040 gas consumption in the power and domestic sectors will total over 20 bcm and 6 bcm, respectively. Pakistan's government supports the use of CNG in the transport sector as a competitive alternative to petroleum, and the country is one of the world's largest users of CNG as a transportation fuel. In 2017 natural gas demand in the transport sector was about 2 bcm, or around 4% of total gas consumption. The trend will continue, and consumption is expected to reach 2.5 bcm in 2040.

Pakistan has emerged as a potential importer of LNG, as well as an incremental gas user for power generation and industry. The country has two operational LNG import terminals. The first LNG import venture began in 2015 with the vessel *Exquisite*, an FSRU, on charter from US ship-owner Excelerate Energy and a second terminal began operation in late 2016. To meet growing gas demand, more FSRUs are expected to begin operating in Pakistan in the long-term. The start of commercial operations of three new gas-fired power plants in Punjab, with a total capacity of 3.6 GW, will increase future demand for LNG.

NORTH AMERICA

In 2017 the North American gas market accounted for 26% of global gas demand. Between 2000 and 2017, gas consumption increased by 166 bcm at an average annual growth rate of 1.1%, from 792 bcm to 958 bcm. Almost 36% of this volume was used for power generation, particularly in the US. The GECF expects that gas consumption in the region will rise by 1.8% per annum, reaching 1435 bcm in 2040. This forecast shows that North America will continue to drive global gas consumption, which is not surprising given it comprises the largest countries in the developed economy. Similar to previous trends, gas-fired power capacity additions will boost gas demand significantly. Almost 50% (about 708 bcm) of regional gas consumption will be absorbed to produce electricity. Coal plant retirements, as well as surging electricity demand, will ensure a robust increase in gas demand.

Figure 3.16. North America natural gas demand by country and sector (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Canada

In 2017 Canada was the sixth largest gas market in the world, with gas demand amounting to 116 bcm, constituting almost 34% of the country's energy mix. Between 2000 and 2017, natural gas consumption grew by 1.6% annually, increasing from 88 bcm to 116 bcm. This trend was overwhelmingly driven by the energy sector's own use, which consumed 40 bcm (34%) of gas demand in 2017.

With growing oil sands extraction in Canada, gas consumption to produce steam for in situ injections rose significantly over the historical period, by 152% (equal to 24 bcm). Throughout the forecasting period, gas usage in the oil sands industry is projected to remain relatively stable, reaching 45 bcm in 2040.

The domestic sector is the second biggest consumer of natural gas in Canada; it accounted for 27% (31 bcm) of gas demand in 2017. Domestic consumption is expected to increase slowly, by only 0.2% per year, as population and economic growth will be offset by improvements in energy efficiency. Currently, 15% (17 bcm) of gas demand is allocated to the industrial sector. We anticipate a gradual decline to 16 bcm by 2040, caused by a slight decrease in gas consumption from petrochemical production due to efficiency gains.

The GECF forecasts that natural gas demand growth in Canada will grow by 22 bcm, increasing by 0.8% annually through to 2040, and peaking at 138 bcm. Around 48% of this increase is expected to stem from additional gas consumption in the power generation sector, which has been steadily expanding since 2009 thanks to the accelerated retirement of coal-fired plants in Ontario and new gas-fired power capacity additions in Alberta.

New regulations proposed by the Canadian government will require coal, which accounted for 6% of the primary energy generation mix in 2017, to meet stricter emission performance standards by 2030 in order to comply with commitments under Paris Agreement targets. Most existing coal-fired plants will be phased out by 2030 or converted to run on natural gas. Despite the abundance of hydroelectricity in Canada, natural gas consumption in the power generation sector is projected to increase from 18 bcm currently to around 29 bcm in 2040.

Mexico

Gas consumption in Mexico rose from 36 bcm in 2000 to 82 bcm in 2017, a growth rate of 5% per annum. This substantial increase was driven by the availability of low-priced pipeline gas from the US and a shift away from fuel oil use in the power sector, to the benefit of natural gas. Despite moderate growth in electricity demand (2.4% annually, from 205 TWh in 2000 to 306 TWh in 2017), natural gas consumption in this sector grew significantly by 8.2% per year and expanded its share in the generation mix from 20% to 64%. With the commissioning of numerous CCGT plants (+23.5 GW over the historical period), natural gas demand in the power generation sector reached 40 bcm in 2017, representing 48% of total gas consumption.

Apart from power generation, the industrial sector represented the second-largest area of consumption. Thanks to a manufacturing boom, gas demand growth in Mexican industries increased by an average rate of 3% annually from 11 bcm in 2000 to 20 bcm in 2017 and constituted 24% of national consumption. Gas usage in the residential and commercial sectors remained marginal, totaling about 2 bcm or 2% of gas consumption.

Over the outlook period, gas consumption in Mexico is expected to grow by an average of 1.8% per annum, amounting to 124 bcm in 2040. New gas-fired power plants will continue to contribute to this demand. Almost 71% of gas demand increments (about 29 bcm) are forecast to come from the power generation sector. More than 8 GW of gas fired power capacity is under construction and around 20 GW is planned over the mid-term. The GECF projects that the share of gas in Mexico's electricity generation mix will maintain a dominant position, at about 62%, despite government policies to accelerate the deployment of renewable energies.

United States

Gas demand in the US is the highest in the world and accounted for nearly 20% of global demand in 2017. From 2000-2017, demand grew annually by 0.8% from 668 bcm to 759 bcm, driven by surging growth in gas consumption in the power generation sector with an average rate of 2.7% per year. In 2017, gas constituted 29% of all energy produced in the US.

The development of unconventional resources and the shale gas revolution has resulted in record gas production in the US. Technological breakthroughs have enabled US upstream companies to make advances in shale exploration and production. Consumer prices for natural gas are significantly lower in the US than other regions (apart from the Middle East), because of greater supply. The low price of gas, together with its smaller carbon footprint compared to coal, has encouraged a rapid growth in electricity generated from gas.

The domestic, power generation and industrial sectors consumed over 84% of the natural gas produced in the US in 2017. The power sector and the industrial sectors consumed 284 bcm and 143 bcm respectively, followed by the residential and commercial sectors (121 bcm and 88 bcm).

Natural gas demand is expected to grow by 54% over the next 23 years at an average annual growth rate of 1.9%, reaching approximately 1173 bcm in 2040. This will make up 43% of the US energy mix.

Through the outlook period, demand growth will be led by the power generation sector, which is forecast to grow by 115% (about 326 bcm of total projected growth). The consumption of gas in the power sector will increase at an annual average rate of 3.4%, reaching 610 bcm of total US gas demand in 2040. This corresponds to 52% of total gas demand.

Despite an increase of about 53 million in the US population over the projection period, natural gas demand in the domestic sectors will remain relatively flat. Domestic consumption will rise to roughly 216 bcm, which represents 18% of total demand in 2040. This is due to highly efficient gas-consuming equipment, such as furnaces, boilers, and water heaters.

Industrial demand is projected to decrease to approximately 131 bcm over the outlook period, mainly due to efficiency measures. This sector will account for 11% of total gas consumption in 2040. Chemicals and petrochemical industries will consume around 53 bcm and will be the most visible source of consumption. According to the US Energy Information Administration (EIA), some industries, including bulk chemical, glass, food and metal-based durables, used gas for 40% of their power and heating needs in 2017 (7). They will continue to consume the same proportion due to costs associated with fuel switching.

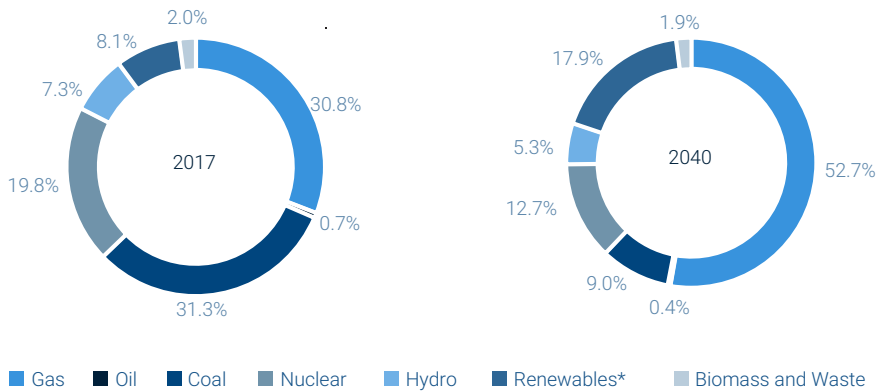
Over the forecast period, amongst all the sectors in the US, transport has the most potential for the growth with an average annual rate of 5.7%. The marine transportation sector is a potential key driver, spurred by the 2020 tightening of the marine fuel sulphur cap to a 0.5% maximum. As a result, LNG bunkering is expected to expand to most major US ports.

The US power generation mix

Shale gas has resulted in dramatic changes in the US power generation mix. Natural gas became the leading fuel in US power plants for the first time in 2016, when the amount of coal used to produce electricity fell to its lowest level since 1982. Since late 2008, gas prices have been relatively cheap compared to other energy sources. The GECF forecasts that natural gas will remain the largest energy source in US power generation and will account for nearly half of all electricity generated through to 2040. Its share is expected to reach about 52.7%, up from 30.8% in 2017. Around 130 GW of coal-fired capacity will be retired, and the share of coal is expected to decline from 31.3% in 2017 to just around 9.0% in 2040. The main driver behind the trend is the expected addition of 158 GW of gas-fired power generation capacity by 2040.

The share of renewables, including geothermal, wind, solar and tidal, is expected to exceed 17.9% of the US electricity generation mix in 2040, up from 8.1% in 2017. Decreasing costs associated with renewables, particularly solar and wind, will drive these trends.

Figure 3.17. The United States power generation mix in 2017 and 2040 (%)



Note: Renewable energies include geothermal, wind, solar and tidal
 Source: GECF Secretariat based on data from the GECF GGM

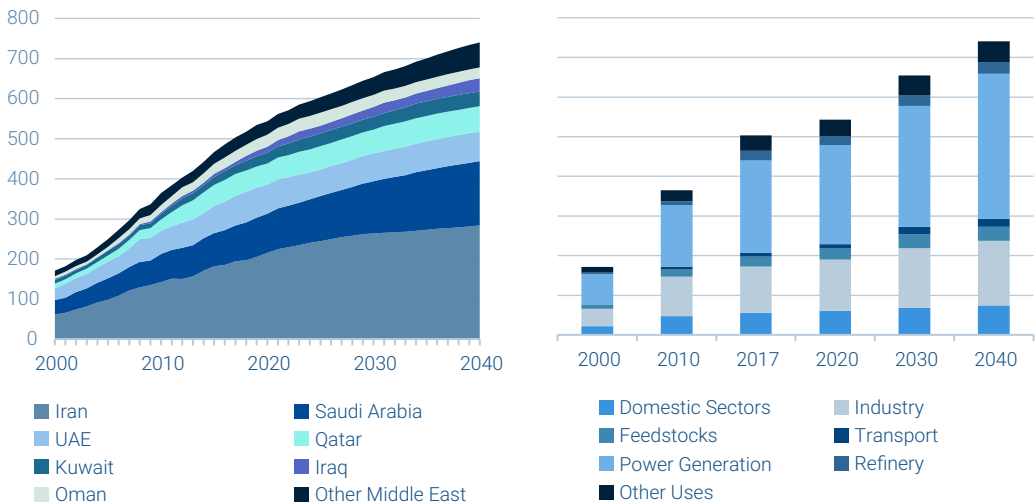
In 2017, nuclear constituted 19.8% of US electricity generation. Due to their high cost relative to other options, however, it is expected that no new nuclear power units will come online in the US in the foreseeable future. Therefore, the share of nuclear power will drop to 12.7% in 2040. The share of hydroelectricity and biomass stood at 7.3% and 2.0% in 2017 and will decline to around 5.3% and 1.9% in 2040.

MIDDLE EAST

Gas consumption in the Middle East is forecast to increase at an annual average growth rate of 1.7% over the forecast period, from 503 bcm in 2017 to around 747 bcm in 2040, substantially slower than the 6.5% recorded over the historical period. Incremental consumption in Iran, Iraq and Saudi Arabia is the main driver for the increase.

Demand will remain concentrated in the power generation sector. In 2017, 46% (233 bcm) of total demand from the region was consumed in this sector. Industrial demand came in second at about 23% (117 bcm) of total consumption.

Figure 3.18. Middle East natural gas demand by country and sector (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Iraq

Iraq is one of the largest oil producers in the world. The country's proven oil reserves are considered the fifth-largest in the world, estimated at 153 billion boe (8). Oil dominates Iraq's energy demand and constituted 81% of the primary energy mix in 2017, while natural gas provided just 16%.

Iraq's business climate has improved in parallel with political stability, and thus foreign investment in the oil and gas sector is surging. Associated gas is currently flared, but with large planned investments and by using advanced modular gas processing technology, Iraq aims to stop gas flaring by 2021. Over the outlook period, the share of gas in Iraq's energy mix will rise from 16% (9 bcm) in 2017 to about 34% (27 bcm) in 2040. This corresponds to a staggering 219% increase in gas demand through to 2040.

In 2017 almost 96% (8 bcm) of gas was consumed in the power generation sector. Iraq is pushing to substitute fuel oil-based power generation with gas, in order to allocate a greater share of oil resources for export. The GECF expects

that gas consumption in the power sector will increase at an annual average rate of 5.1% over the forecast period to around 26 bcm in 2040.

Saudi Arabia

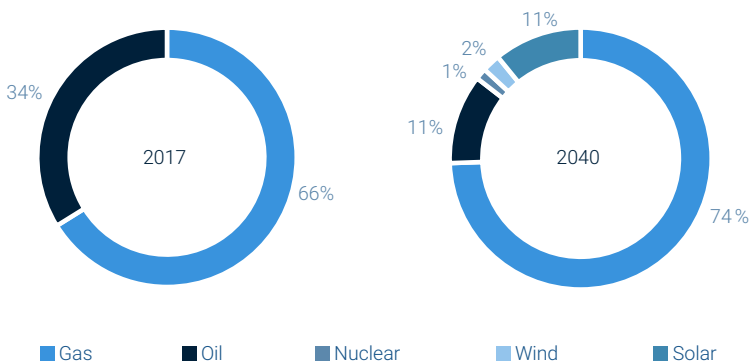
Demand for natural gas in Saudi Arabia grew by 146% over the historical period. Overall gas demand increased from 36 bcm in 2000 to 89 bcm in 2017, an annual average growth rate of 5.4%. Gas increased its share in the country's energy mix from 30% to nearly 34% while over the same period, consumption in the power sector grew at an average annual rate of 6.8%, from 21 bcm to around 65 bcm (73% of total consumption).

Gas produced in Saudi Arabia is mostly wet. In addition to methane and ethane, wet gas also contains natural gas liquids (e.g. propane and butanes) and Saudi Arabia has emerged as a growing supplier of ammonia, methanol and urea. In 2017, 14 bcm (about 16%) of total gas demand was consumed by industry.

The Middle East's second-largest natural gas consumer (after Iran), is desperate to diversify its economy away from crude oil. Saudi Arabia launched a series of reforms and initiatives in 2016, including "Saudi Arabia's Vision 2030" and the "National Transformation Program 2020." These frameworks outline various strategic objectives, including targets to boost gas production capacity and construct a national gas distribution network, with the aim of reducing the quantity of oil used for power generation and freeing up more crude oil for export.

In line with Saudi Arabia's vision, gas demand is projected to increase by 2.4% annually, reaching almost 154 bcm in 2040. With strong electricity demand and oil-to-gas switching in the power sector, the consumption of gas for the production of electricity and industrial use will increase to around 100 bcm and 34 bcm, respectively. The share of oil in the country's power generation mix will decrease sharply, from 34% in 2017 to 11% in 2040. Oil will be largely substituted by natural gas, which will make up almost 74% of Saudi Arabia's power generation mix by 2040.

Figure 3.19. Saudi Arabia power generation mix in 2017 and 2040 (%)



Source: GECF Secretariat based on data from the GECF GGM

Saudi Arabia plans to progressively remove energy subsidies to improve its budget deficit. These subsidies should be eliminated in 2023. The country announced a steep increase in gasoline prices in January 2018, and in addition, has introduced a 5% VAT on most goods and services, including gasoline and diesel (9).

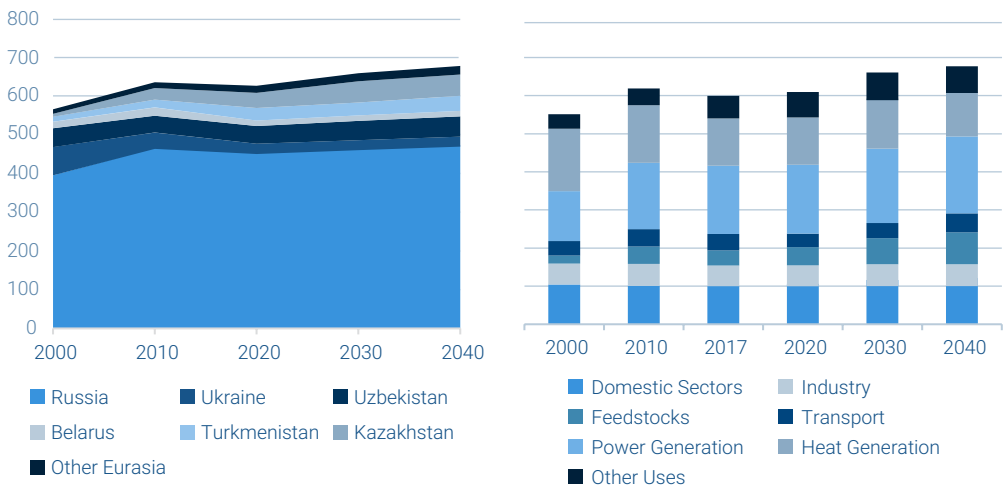
EURASIA

Natural gas plays a significant role in the energy mix of Eurasian countries, which together consumed 16% (almost 600 bcm) of the world's gas volumes in 2017. Russia is the largest gas consumer in the region, accounting for 70% of demand. Gas consumption in Eurasia is projected to increase to 681 bcm by 2040 at an annual pace of 0.6%, slightly faster than recorded over the historical period. This minor growth in absolute terms will be driven by Russia (+47 bcm), Kazakhstan (+20 bcm), Turkmenistan (+8 bcm), Ukraine (+5 bcm) and Uzbekistan (+5 bcm). Belarus gas demand will also see a 5 bcm reduction, resulting from the commissioning of a nuclear power plant and a subsequent decrease in gas consumption in the power generation sector.

The power and heat generation sectors are the main consumers of natural gas, with respective shares of 30% (179 bcm), and 21% (125 bcm) in 2017. Additionally, the domestic sectors consumed 17% (100 bcm). In spite of relatively low gas prices and stable economic growth rates in the region, the GECF forecasts a moderate increase in gas consumption for the power generation and domestic sectors of 31 bcm and 3 bcm, accordingly.

At the same time, gas demand in heat generation will decline by 10 bcm through to 2040. This will be due to high energy savings potential in the region, including energy efficiency measures, as well as the large-scale modernisation of existing CHP plants and the construction of modern gas fired power plants, which will have a stronger impact on gas demand during the outlook period.

Figure 3.20. Eurasia natural gas demand by country and sector (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Ukraine

In the period between 2000 and 2017, Ukraine's natural gas demand fell sharply from 73 bcm to 28 bcm. The share of gas in the primary energy mix reached 29%, its lowest level since the dissolution of the Soviet Union. The overall economic recession, political crises, and ongoing military conflicts have significantly influenced both primary energy demand and gas consumption. Simultaneously, this dramatic decrease allowed Ukraine to reduce its dependency on Russian gas and to meet its needs with domestic gas production and reverse flows from Europe.

Historically, the main consumers of natural gas in Ukraine were the residential, district heating (heat generation) and industrial sectors, which collectively represented 76% (22 bcm) of total natural gas demand in 2017. Over the forecast period, gas consumption is expected to increase slightly at an annual average growth rate of 0.7%, to roughly 33 bcm in 2040. This outlook is driven by a gradual economic recovery which will be offset by energy efficiency measures in heat generation and a slightly decreasing population.

Uzbekistan

Natural gas dominates Uzbekistan's energy demand and accounted for 88% of the primary energy mix in 2017. This trend will continue over the outlook period, with gas demand rising by an average growth rate of 0.4%, from 47 bcm today, to around 52 bcm in 2040.

Uzbekistan has a population of almost 32 million and a largely energy-intensive economy. The domestic sector (especially residential) is the biggest consumer of natural gas and absorbed 17 bcm (36%) of total gas volume in 2017. Gas demand in the residential sector is highly seasonal, peaking during cold winter months as a result of increased heating requirements. Although gas prices have risen for the fourth time since 2014, the GECF expects gas consumption in the domestic sector grow to 20 bcm in 2040, and account for 39% of total gas consumption.

The power sector in Uzbekistan relies mostly on gas-fired generation, which will remain the backbone of the country's energy system. Approximately 76% of electricity was generated from natural gas in 2017, and its share is projected to increase to 81% of the power generation mix in 2040. Uzbekenergo, a vertically-integrated monopoly, is investing considerably in fleet modernization to enhance energy efficiency. In this context, despite strong growth in electricity consumption (mostly in the commercial and residential sub sectors), natural gas demand in the power sector is anticipated to rise from 15 bcm in 2017 to 18 bcm in 2040.

The industrial sector consumed 6 bcm (around 12%) in 2017. A major project currently being undertaken by Uzbekneftegaz and Sasol (South Africa) is a 37,600 barrels per day gas-to-liquids (GTL) plant, which is expected to come online in 2020–2021. Another project that will boost exports of downstream refining products and petrochemicals is a gas processing and gas to-chemicals complex in the Surkhandarya region, which will produce polyolefins, including polyethylene and polypropylene, as well as olefins (ethylene glycol, rubber and other products). This facility may potentially feed off the huge reserves (over 100 bcm) from the "25 Years of Independence" gas field and the O'zbekiston Mustaqillik investment block (10). Taking into account the aforementioned projects, the GECF expects natural gas demand in the industrial sector to remain flat as energy intensity (which is currently among the highest in the world) declines over the forecast period.

EUROPE

Gas demand in Europe increased at an average annual rate of 0.7%, from 482 bcm in 2000 to 538 bcm in 2017. The continent's natural gas demand saw strong growth driven by economic recovery, increased gas usage in the power sector, and unseasonable weather patterns that increased consumption in the heating and cooling sectors. From 2017–2040, demand is projected to increase by 35 bcm, and to grow at an average rate of 0.3% per year to reach about 573 bcm in 2040. This comparatively slow growth can be attributed to energy efficiency policies, declining energy intensity, supply security concerns, the use of renewable energy and a production decline in the Netherlands.

Natural gas usage for power generation accounted for approximately 24% (131 bcm) of total consumption in 2017. Growth in the power sector slowed during the historical period, by an average annual rate of 1.4%. The consumption of gas in Europe's power generation mix was highly dependent on fuel costs, the availability of hydro and nuclear energy, efforts to reform the Emissions Trading System (ETS) and apply more robust carbon prices, as well as policies that are making renewables more attractive. Over the forecast period, a 0.8% growth rate is expected in Europe's power sector, with natural gas consumption reaching 156 bcm in 2040. This increase is partially driven by carbon prices, which are already at €19 per tonne, and a concurrent shift away from coal (11).

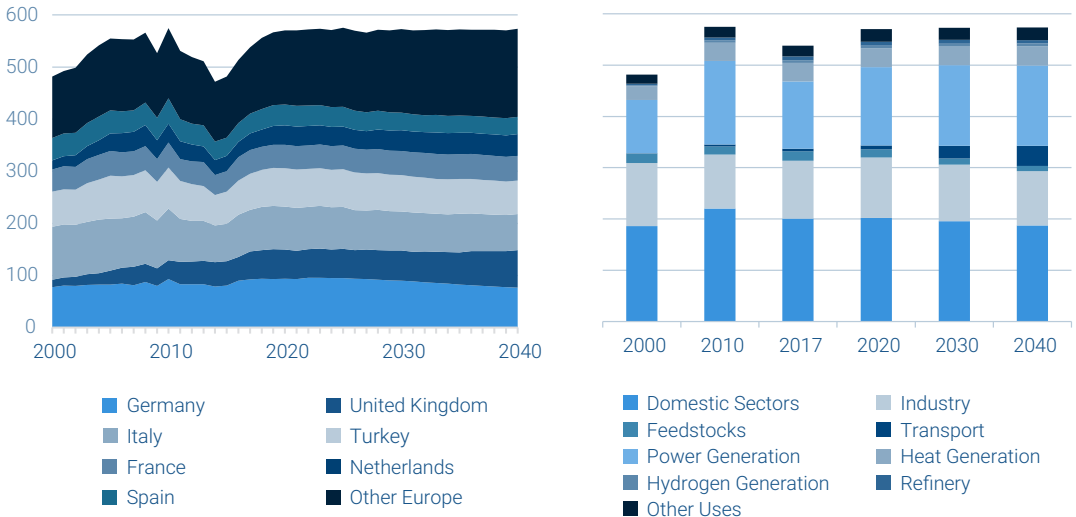
Demand from the transport sector drove consumption growth by 10.0% per year and contributed around 5 bcm in 2017. Under the Paris Agreement, the EU has committed to reducing its GHG emissions to 40% below 1990 levels by 2030. Between 2000 and 2017, emissions decreased significantly in all sectors with the exception of transport, which has seen an overall increase of 10%. The transportation sector currently produces a quarter of the EU's carbon emissions. Trucks account for approximately 5% of all vehicles but generate about 25% of emissions, which means trucks will be a key target of the transport sector's carbon reduction efforts. In this regard, the European Commission has presented a legislative proposal to implement CO₂ emissions reduction targets of 15% for new trucks by 2025, and 30% by 2030 (relative to 2019 levels). The faster development of natural gas trucks run on CNG or LNG would help to achieve this target.

Additionally, in the marine sector as of 1 January 2018, ships over 5000 gross tonnes became subject to monitoring and reporting requirements for CO₂ and sulphur emissions. The new guidelines apply to fuel consumption and accompanying cargo within all ports under the jurisdiction of Member States, and for any voyages to or from a port under the jurisdiction of a Member State.

It is estimated that relevant ships account for 55% of all ships in the EU ports, and 90% of related emissions. As a result, ship owners will have to limit sulphur in fuel, which opens opportunities for LNG. Converting to LNG as a bunker fuel is the best long-run solution for most ship operators, as it is cost-effective and readily available. Overall, this report expects a significant consumption of around 39 bcm demand for natural gas in Europe's transport sector in 2040.

The domestic sectors are the largest consumer of gas in Europe and it accounted for 37% (200 bcm) of gas demand in 2017. About 68% (137 bcm) of this volume was consumed by the residential sub-sector, and almost 30% (59 bcm) by the commercial sub-sector, demonstrating the sensitivity of European gas consumption to seasonal variability. Electrification rates and energy efficiency gains will be the main drivers behind future gas consumption in European domestic sectors. We forecast that, by adopting more efficient technologies and improving energy efficiency, the consumption of gas in Europe's domestic sectors will drop to 187 bcm, which will meet 33% of demand in 2040.

Figure 3.21. Europe natural gas demand by country and sector (%)



Source: GECF Secretariat based on data from the GECF GGM

In 2017 industrial activities had an effect on natural gas demand, mainly in Germany, the UK, Italy, Turkey, France, the Netherlands and Spain. Strong GDP growth supports the demand in this sector. These seven countries together represented more than 76% (411 bcm) of total demand in 2017, and all of them had strong growth in industrial activities. In 2040, as a result of waning energy consumption and intensity, coupled with strengthened energy efficiency policies, the consumption of gas in the industrial sector will fall to about 106 bcm.

France

France is the second-largest consumer of energy in Europe, expending about 255 Mtoe in 2017. Natural gas currently accounts for around 16% of the country's total primary energy consumption. Gas demand is expected to remain almost stagnant at 2017 levels, reaching 47 bcm in 2040. This represents 19% of France's total energy mix. The power and transport sectors are the main drivers of gas demand, as the government has pledged to shut down all domestic coal-fired power plants by 2021, and gas is a rapid and efficient means of reducing CO₂ emissions and improving air quality in the transport sector.

Historically, the largest consumers of natural gas in France were the domestic and residential sectors. Natural gas demand peaks in the winter as space heating demand increases. Consumption can vary significantly from year to year based on weather fluctuations, and in 2017 the domestic sectors consumed over 43% (20 bcm) of total demand. Due to energy efficiency gains, demand will remain almost stagnant, reaching 19 bcm in 2040.

France is an advanced and industrialized country. It has the third largest economy in Europe and the sixth largest economy in the world. The major contributors to the economy include the energy, manufacturing, agriculture, technology and transport sectors. The industrial sector holds second position in terms of gas consumption, after the domestic sector, with almost 27% (12 bcm) of total gas demand in 2017.

France is the world's second-largest producer of nuclear power after the US, and it is the primary source of power generation. However, nuclear outages in France have propelled gas demand for power generation and in 2017 the power sector consumed 7 bcm of gas. Last year the French government announced that the country may cut nuclear capacity by 14.5 GW and reduce nuclear's share of the power mix from 73% to 50% by 2025-2030. The government also aims to shut down 4.6 GW of coal-fired capacity by 2021 to reduce GHG emissions. The GECF expects that additional demand for gas in the power generation sector will grow by 0.9% per year to about 9-10 bcm in 2040.

Over the past few years interest in using NGVs has risen in France. Gas is used as a fuel for bus and truck fleets and is an economically viable alternative to diesel in freight transport. The use of gas in the transportation sector will grow at a rapid pace of 14.4% per year over the outlook period, although volumes will remain insignificant at roughly 5 bcm in 2040.

Germany

Germany is the largest energy (394 Mtoe) and natural gas consumer (93 bcm) in Europe. Natural gas accounts for 24% of the country's primary energy mix. The GECF expects Germany's gas demand to remain stagnant at almost 92 bcm over the forecast period, despite significant replacement of coal and nuclear power. Therefore, in 2040 28% of Germany's energy mix will comprise natural gas.

Germany has the highest amount of coal-fired power generation capacity in Europe. The government aims to cut CO₂ emissions from coal-fired power plants by 2030 and to halve domestic coal- and lignite-fired power capacity.

In the wake of Fukushima, Germany ordered the closure of eight of the country's oldest nuclear plants. Moreover, the government scrapped the lifetime extensions for nuclear reactors and amended the phase-out law to discontinue nuclear power generation by 2022. This decision is expected to have a significant impact on the position of natural gas in the country's power generation mix. Accordingly, this report sees strong growth in demand for gas and renewable energies. Natural gas demand for power generation is expected to grow by 2.5% annually over the forecast period, rising from 15 bcm in 2017 to over 27 bcm in 2040.

In 2017, renewable energies and hydropower accounted for more than 26% of Germany's power generation mix, second only to coal and lignite at 39%, and significantly more than gas (13%), biomass and waste (10%), and nuclear energy (12%). To help cut CO₂ emissions and achieve its climate commitments, German coal- and lignite-fired power plants are being progressively phased out, and capacity fell to about 49 GW in 2017. Wind capacities reached 56 GW, overtaking coal- and lignite-fired capacity. In 2017, solar capacities reached 43 GW. It is expected that in 2040, the share of gas will reach 14%, while renewable energies and hydropower will supply 70% of electricity.

In 2017, the domestic and industrial sectors consumed 41 bcm and 23 bcm, respectively. However, with strong energy efficiency and renewables deployment programmes, gas demand in the residential heating and industry sectors is expected to decline over the outlook period to 33 bcm and 19 bcm, accordingly.

Italy

Italy is the fourth-largest energy consumer in Europe and used around 161 Mtoe in 2017. Gas currently accounts for 36% of the country's total energy consumption. Natural gas demand is expected to fall by 0.3% per year over the outlook period, from 69 bcm in 2017 to about 64 bcm in 2040. This means nonetheless that 36% of Italy's energy mix will be supplied by natural gas in 2040.

The domestic and power sectors are the biggest consumers of gas, utilizing 28 bcm and 22 bcm in 2017 respectively. Demand for residential heating and cooling follows temperature fluctuations. Italy plans to phase out all coal-fired power generation by 2025. Gas will be key in the energy transition. Demand in the power sector continues to increase at a steady clip over the forecast period, and consumption will reach over 25 bcm in 2040. In 2017, almost 63% of Italy's electricity mix came from fossil fuels. While gas is the predominant fuel and was responsible for roughly 43% of the country's electricity production, in 2040 it will provide approximately 38% of electricity.

Natural gas demand in the transport sector was around 2 bcm of total consumption in 2017. Gas demand in this sector is expected to grow during the outlook period by 5.5% annually, reaching 6 bcm in 2040. Currently, Italy has the largest CNG car fleet in Europe, with around 1 million vehicles.

Regarding consumption in other sectors, gas use in the domestic and industrial sectors will drop modestly from 28 bcm and 11 bcm, to 26 bcm and 8 bcm, respectively. This is due to a new national energy strategy that the Italian government drew up with actions to be achieved by 2030 and beyond, in accordance with the long-term scenario envisaged in the EU Energy Roadmap 2050 for the reduction of CO₂ emissions.

Turkey

Turkey consumed approximately 54 bcm of gas in 2017, almost 16% more than the previous year. Gas demand is projected to grow at an annual average growth rate of 1.3% between 2017 and 2040, which is lower than the 8.1% growth recorded over the historical period. The domestic and power sectors will account for more than 65% of incremental growth by 2040, which can be attributed mainly to increasing use in the domestic and residential sectors. The Turkish government has announced plans for a sustainable gas supply security strategy, which will expand Turkey's underground gas storage capacity and develop the country's gas distribution network to supply 66 million (out of 81 million) inhabitants, up from the current 63 million. Consequently, this report forecasts that Turkey's consumption in the domestic sector will increase at an annual average growth rate of 2.9%, from 16 bcm in 2017 to above 31 bcm in 2040.

The share of gas in the power generation sector will fall from 38% (20 bcm) in 2017, to around 22% (16 bcm) in 2040. The reduction in natural gas demand in the power generation sector has significantly affected overall gas demand growth in the country. This can be attributed to Turkey's diversification policy for power generation away from natural gas in favour of domestic alternatives, like coal and renewables. Both are available domestically; the shift will reduce seasonality, as well as ensure energy security. Turkey plans to generate more baseload power from coal but will keep the option to use gas to meet generation for peak demand periods. Accordingly, electricity generation from gas will decline drastically, from 40% in 2017 to just over 15% in 2040.

Overall, the share of natural gas in Turkey's energy mix will decline from 31% in 2017 to 25% in 2040.

United Kingdom

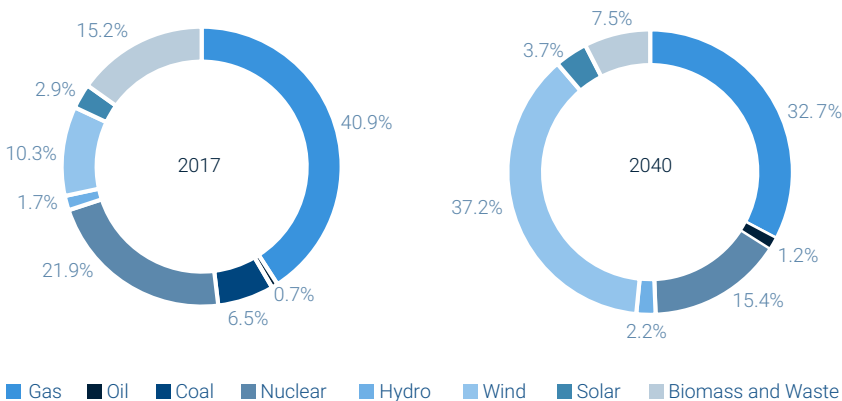
Gas demand declined by around 22 bcm in the UK, from 102 bcm in 2000 to 79 bcm in 2017, accounting for a 36% share of the primary energy mix in 2017. The fall can be attributed to a decline in power and domestic sector consumption. This trend is expected to continue over the projection period, with gas demand declining by 0.6% per annum, to about 69 bcm in 2040. The main reason for the drop is the forecast growth in renewable energies in the power generation sector, as well as increasing efficiency in gas-fired power plants.

The UK's domestic and residential sectors are the biggest consumers of gas. In 2017 the country consumed 36 bcm of gas in the domestic sector. The government has heavily invested in energy efficiency improvements in buildings and has supported the use of smart electricity or gas metering systems for more accurate energy bills. Due to energy efficiency improvements, this report expects a lower demand in the domestic and residential sectors at around 27 bcm in 2040.

Coal-fired power generation in the UK has been falling since the introduction of a tax on CO₂ emissions in 2013. In November 2015, the UK was the first country in the world to announce that all unabated coal-fired electricity generation was to be closed down by 2025. The UK achieved an unprecedented drop in carbon emissions in 2016 by making full use of natural gas over coal in power stations. The government's carbon pricing policy was the biggest driver. Coal capacity is expected to fall from the current 11 GW to just 1.5 GW by 2024, and the shortfall will be compensated for mostly by gas and renewable energies. The UK is currently the biggest user of gas in power generation in Western Europe, but natural gas demand from the power sector is expected to stagnate over the forecast period at around 23-24 bcm.

As shown in Figure 3.22, in 2017 low-carbon sources of power generation including nuclear, hydro, wind, solar, and biomass and waste, together provided a record 51.9% of the UK's electricity. However, at the same time the UK generated more electricity from gas than any other fuel at 40.9%. In 2040, it is expected that the share of gas will have fallen to 30.0%, and that there will be a 61.9% contribution from renewables, hydroelectricity, biomass and nuclear energy.

Figure 3.22. The United Kingdom power generation mix in 2017 and 2040 (%)



Source: GECF Secretariat based on data from the GECF GGM

As the UK's domestic gas production is drying up in the North Sea, the country is increasingly reliant on gas imports. Most gas imports to the UK come from Norway, the Netherlands and Qatar. Of this, the vast majority comes via pipelines, primarily from the Norwegian sector of the North Sea.

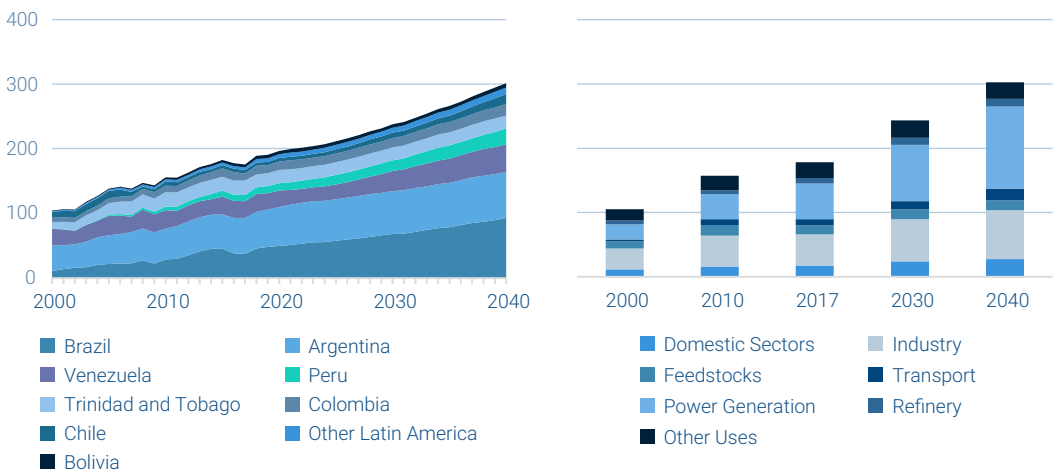
LATIN AMERICA

Latin American countries have large natural gas reserves and have the potential to produce enough gas to satisfy the region's burgeoning gas demand. Natural gas demand in Latin America is forecast to increase at an annual average rate of 2.2% over the outlook period, an overall increase of 63%, from 178 bcm in 2017 to about 291 bcm in 2040. The main drivers for the growth are economic development, an increase in population and subsidised electricity prices that encourage consumption. Demand growth comes mainly from Chile (5.3%), Peru (3.9%), Brazil (3.1%), and Venezuela (2.0%) over the outlook period.

The main drivers of future growth in the region are the power, transport and industry sectors. Many oil-fired power plants are being converted to gas-fired plants. In addition, several countries in the region are following development plans for urban and rural electrification. This report expects natural gas demand for the power sector to increase at an annual average rate of 3.4% during the forecast period. In 2040, 41% (about 119 bcm) of gas will be used by the power generation sector, followed by the industrial sector (25% or 72 bcm), domestic sector (9% or 28 bcm), transport sector (6% or 17 bcm), feedstock sector (5% or 16 bcm), and refinery sector (4% or 12 bcm).

A boost in gas demand, combined with lower domestic gas production in various Latin American countries, has triggered an increase in LNG imports. However, insufficient investment for the development of infrastructure, regulatory issues under the supervision of national petroleum companies and a lack of pipeline interconnections are all obstacles which have made gas integration a challenging process in the region.

Figure 3.23. Latin America natural gas demand by country and sector (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Argentina

The GECF forecasts Argentina's gas demand growth rate to decelerate over the outlook period relative to past trends: it is expected that the rise will be 1.2% annually, a slower pace than the 2% registered during 2000-2017. Natural gas demand will increase from 56 bcm to 74 bcm between 2017 and 2040.

The power sector in Argentina is characterized by a combination of hydro and gas-fired power plants (22% and 58% of the generation mix respectively). Gas accounted for 17 bcm or 30% of the country's total gas demand in 2017. According to projections, electricity consumption will grow at an average rate of 2.5% per year, and more than 15 GW of gas power capacity is expected to be commissioned during the outlook period. However, due to government plans on diversifying the national energy matrix (adopted in the Renewable Energy Act), the deployment of wind and solar will gradually squeeze natural gas out of the power system. It is estimated that gas consumption in the power sector will be about 24 bcm (32%) of total gas consumption in 2040, covering 50% of Argentina's power generation mix.

The increase in gas demand will be also driven by the domestic (particularly residential and commercial), and industrial sectors. It is assumed that current policy aimed at removing gas price subsidies will rationalise gas usage in the residential sector and improve gas market efficiency. In its turn, development of gas transmission and distribution capacity will serve growing demand. Domestic consumption will rise from 13 bcm to around 18 bcm (24%) of total gas demand in 2040. The industrial sector, consuming the third-largest volumes of gas with over 12 bcm in 2017, will account for 16 bcm (22%) of total gas demand in 2040. Key users are the iron and steel, chemicals and mineral sectors.

Argentina is also one of the world's largest markets for gas vehicles. Thanks to a policy of supporting the use of gas in this sector through lower tax rates in comparison to gasoline, and the availability of CNG fuelling stations, consumption in the transport sector is expected to increase from 4 bcm in 2017 to roughly 5.5 bcm in 2040.

Brazil

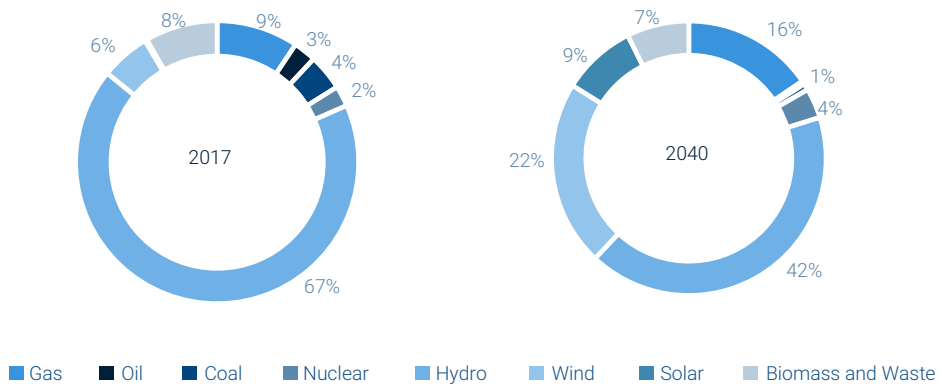
Natural gas demand in Brazil has been increasing significantly at an average growth rate of 7.4% annually, from 11 bcm in 2000 to 38 bcm in 2017. Over the outlook period the GECF forecasts gas consumption to attain 76 bcm by 2040 with a steady growth rate of 3.1% per year. This volume will allow Brazil to cement its position as the largest gas consumer in Latin America. In 2017, natural gas constituted 11% of the Brazil's primary energy mix, and almost 69% of this amount was consumed in two sectors: 42% (16 bcm) in industry, and 27% (10 bcm) was absorbed by power generation. The industrial users are metals and mining, petrochemicals, ceramics, and food and beverage. The recovery of the Brazilian economy after a severe recession in 2014-2016 as well as an expected further upswing will contribute to gas demand prospects with a corresponding growth of gas's share in the energy balance.

Gas demand in Brazil will overwhelmingly be led by the power sector, as electricity consumption is expected to more than double (from 637 TWh in 2017 to about 1271 TWh in 2040). Historically, hydro has been the main source of power generation, but hydropower is strongly weather dependent and seasonal. Moreover, the multi-year drought experienced in Brazil in recent years has required more gas-fired generation output, which has boosted gas demand, especially in 2012-2015. The share of hydro in the generation mix, consequently, has decreased since 2011 from 81% to 67% in 2017.

In accordance with the Energy Development Plan, issued in 2017, a rapid development of renewables (wind and solar) is envisaged. Given its intermittency, gas-fired generation will be promoted as a complimentary source to hydro and flexible back-up to renewable energy. One of the options, already applicable in Brazil, is LNG-to-power projects. With new gas-fired capacity brought on line during the outlook period (around 56 GW), natural gas will see 4.9% annual growth in the power generation sector up to 31 bcm in 2040, constituting 16% of electricity generation mix.

Outside the power sector, this report projects a robust increase of gas consumption in the industrial sector, with an annual average growth rate of 1.9%, to about 24 bcm in 2040.

Figure 3.24. Brazil power generation mix in 2017 and 2040 (%)



Source: GECF Secretariat based on data from the GECF GGM

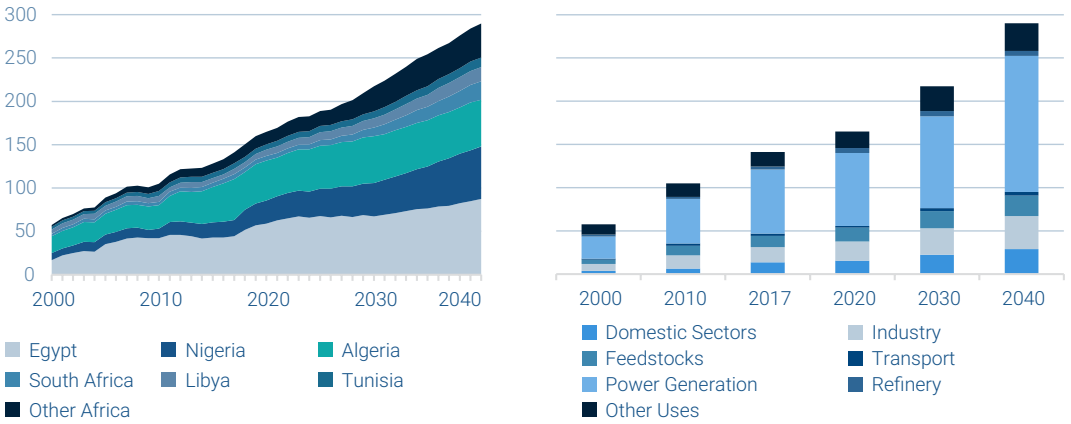
AFRICA

Africa's gas demand growth is expected to expand faster than that of any other region. Last year's GGO recorded a projected growth rate of 2.5%. This year, we expect gas demand to rise by 100% over the forecast period, at an average growth rate of 3.1% per year, from 139 bcm in 2017 to almost 278 bcm in 2040. Most of this growth is expected to come from Nigeria (+46 bcm), Egypt (+29 bcm), South Africa (+16 bcm) and Libya (+10 bcm). The rich gas reserves and developments in production from Egypt, Nigeria and Algeria, as well as population growth and the associated increase in electricity demand, are the main drivers behind this increase.

The power generation sector consumed 74 bcm in 2017 and will remain the primary driver of gas demand growth in Africa. Eleven countries in the region currently have gas-fired power plants. The Power Africa Gas Roadmap 2030 projects are facilitating investment in the electricity grid, with the intention of adding 16 GW of gas-fired generation in the region by 2030. Demand in the power sector will increase by an average of 3.0% per annum, reaching about 144 bcm in 2040.

Natural gas demand in the industrial, domestic and feedstock sectors is also expected to rise over the forecast period. These three sectors together will consume 31% (nearly 85 bcm) of Africa's total consumption. The outlook for natural gas in the refinery and the transport sector is negligible. Consumption will remain at the same magnitude as 2017 levels, at around 5-6 bcm for each sector.

Figure 3.25. Africa natural gas demand by country and sector (bcm)

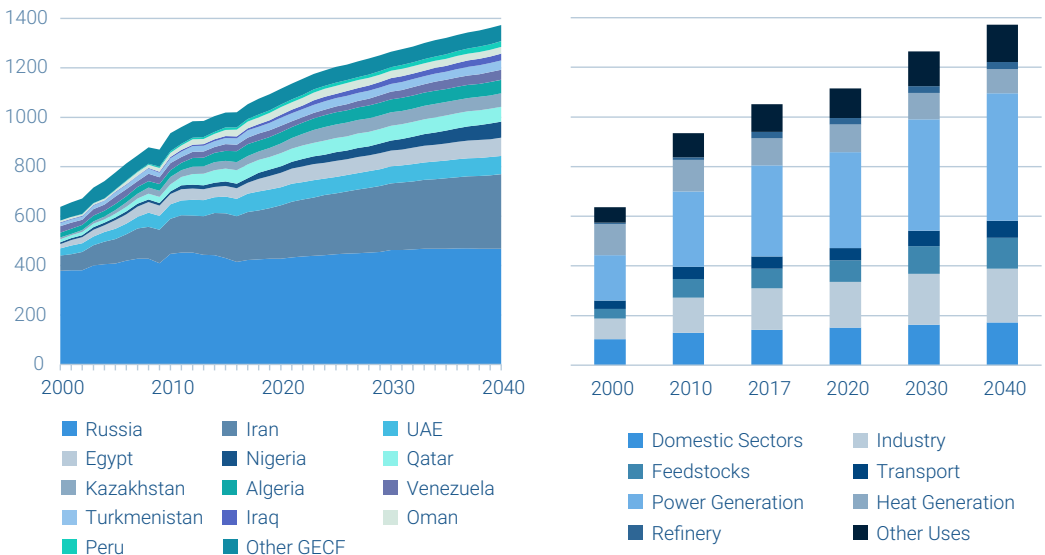


Source: GECF Secretariat based on data from the GECF GGM

Natural gas demand trends in selected GECF (Members and Observers) countries

Natural gas consumption will reach 1373 bcm in the GECF countries by 2040, increasing annually by 1.2% on average over the forecast period, slower than the 3.0% recorded over the historical period. Iran (+106 bcm), Russia (+47 bcm), Nigeria (+46 bcm), Egypt (+29 bcm), Kazakhstan (+20 bcm), Iraq (+19 bcm), Venezuela (+15 bcm), and Peru (+14 bcm)

Figure 3.26. GECF (Members and Observers) natural gas demand by country and sector (bcm)



Source: GECF Secretariat based on data from the GECF GGM

will drive this incremental consumption. Most of the GECF countries will experience economic and population growth throughout the outlook period.

The feedstocks sector is the fastest growing in the GECF countries, rising by 2.0% per annum, from 80 bcm in 2017 to over 125 bcm in 2040. The main countries driving this demand are Russia, Iran and Egypt.

In line with global consumption trends of gas use in gas-fired power generation, the power sector in the GECF countries has the second-fastest growth rate of 1.5% per year. It is expected that consumption will rise by an overall 40%, from 367 bcm in 2017 to around 513 bcm in 2040, which is equivalent to 37% of total gas demand of the GECF countries.

The third largest natural gas consuming sector is industry. Emerging economies are key drivers, with a growth rate of 1.1% over the outlook period. Industrial consumption of natural gas in 2017 totalled 166 bcm, and the GECF expects that this will increase to almost 216 bcm in 2040. Demand for natural gas in the domestic and residential sectors is also considerable, increasing to about 172 bcm in 2040, up from 143 bcm in 2017.

Algeria

Fossil fuels (mainly natural gas and crude oil) have dominated Algeria's energy demand since 1990, constituting a 99% share of the primary energy mix. Consumption of natural gas has been increasing steadily, reaching 67% in 2017. It is projected that this trend will continue, but to a lesser extent, with gas's share dropping slightly to 61% in 2040.

Algeria is a net exporter of natural gas, as the country's vast reserves and production capacity enable it to meet domestic demand completely. Demand will increase slowly, compared with the 4.5% recorded over the historical period, growing at an annual rate less than 1%, taking it from 42 bcm in 2017 to about 50 bcm in 2040. Policy measures adopted to enhance access to energy, along with economic and demographic growth, are the key determinants shaping Algeria's gas demand. It is important to mention that the forecast is approximately 6 bcm higher compared with last year's GGO, mainly because of accelerated expansion of gas usage in the residential and industrial sectors.

Most of the gas delivered to domestic markets in 2017 was consumed in the power generation sector (18 bcm or 44%) and the domestic sector, including residential and commercial (about 10 bcm or 23%). With an urban population of about 41 million people predicted by 2040, it is expected that around 16 bcm of natural gas will be consumed in each of these sectors by then. In parallel, integration of new CCGT will enhance energy efficiency, resulting in a slight decrease of power plants' gas demand.

The industrial sector consumes the third-largest volume of natural gas (5 bcm in 2017) and will account for about 10 bcm by 2040. Moreover, due to an increase in chemical feedstock use, this report expects that demand for natural gas in the feedstock sector will grow from around 3 bcm currently to almost 5 bcm in 2040.

Egypt

Natural gas consumption in Egypt increased by 5.9% per year between 2000 and 2017, from 17 bcm to 45 bcm. Fossil fuels play a pivotal role in Egypt's energy mix and in 2017, natural gas represented 45% of the country's overall energy demand.

The increase in natural gas demand over the historical period has been driven by economic and population growth, energy-intensive natural gas and oil projects, and in particular, energy subsidies. The rapid growth was also driven by high electricity demand and industrial production.

In mid-2014, Egypt's government announced a dramatic cut in subsidies over the 2014-2015 period, aiming to curb the expected budget deficit from 12% in the 2013-2014 fiscal year to 10%. The subsidy reduction led to an increase in oil prices by up to 78%, arousing fierce protests from consumers. The authorities also increased fuel prices by 47% in 2016 and increased domestic fuel prices by 50% in 2017. The Egyptian government has decided to cut electricity subsidies in the 2018–2019 fiscal year, which will raise electricity prices by 42% for industry and 21% for households. The government has also announced a price hike of between 33% and 75% for residential and commercial gas prices, starting from August 2018. The remaining subsidies are expected to be completely phased out by the end of the 2021–2022 fiscal year.

The government is encouraging energy sectors to consider natural gas as a substitute for petroleum and coal products. To satisfy growing domestic demand, Egypt has had to divert its natural gas supply away from exports to the domestic market and to rely on LNG imports to address the shortfall in consumption.

This report expects an annual average growth rate of 2.2% per year for gas demand over the forecast period. Consumption will rise from 45 bcm in 2017 to approximately 73 bcm in 2040. The power generation sector is the main consumer of gas in the country, with strong increases in electricity consumption forecast: an annual average growth rate of 3.8% is estimated, with demand growing from 190 TWh in 2017 to about 452 TWh in 2040. In 2040 more than 50% of gas (about 37 bcm) will be used for electricity generation, followed by about 17% in industry (12 bcm), and feedstocks (13 bcm) for the production of fertilizers to supply domestic agricultural and petrochemical products.

Additionally, with the aim of increasing the number of citizens connected to the gas grid, the government has developed distribution grids to achieve Egypt's "Households Natural Gas Connection Project". Therefore, gas consumption is expected to grow in the domestic and residential sectors, and this forecast estimates that domestic consumption will increase at an average rate of 6.0% per year, to above 8 bcm in 2040.

Iran

Iran holds the world's fourth-largest proved crude oil reserves, and the world's second-largest proved natural gas reserves. Iran also ranks among the world's top ten oil producers, and top five natural gas producers and consumers in the world.

The US sanctions which targeted Iran's energy sectors affected upstream foreign investments and technology development in the country's oil and gas projects. However, despite the US sanctions, Iran has continued to develop phases of its giant natural gas field at South Pars, a non-associated gas field located offshore in the Persian Gulf. The country has a high success rate in natural gas exploration, which is estimated at 79% compared to the world average of 30–35% (12).

Natural gas represented nearly 65% of the energy consumed in Iran last year, and its share will remain almost stagnant at 2017 levels in 2040. Rich gas reserves, as well as low domestic prices, are the two main reasons for such a high dependence on natural gas resources.

Gas consumption trebled between 2000 and 2017 at an annual average growth rate of 7.0%, from 62 bcm to 195 bcm. Milder political conditions in recent years, the lifting of sanctions as a result of the Joint Comprehensive Plan of Action (JCPOA) in January 2016, economic development and population growth can explain the increase.

This report expects that gas demand will keep rising to approximately 301 bcm, at an average growth rate of 1.9% between 2017 and 2040. Consumption stems from the fact that Iran has the highest subsidised fuel prices in the world and has a high energy intensity, in particular gas consumption. An Iranian subsidy reform plan was initiated in 2010, and since then the country has cut subsidies on gasoline, leading to a 75% increase in prices. In 2014 the Iranian Parliament approved fuel subsidies reductions, but there have been significant delays in their implementation, and fuel prices still remain among the lowest in the world.

As natural gas is the primary fuel source for electricity generation, the power generation sector consumes the most gas relative to other sectors, with almost 64 bcm in 2017 (33% of total gas demand). Gas-fired generation will continue to play an important role in the power sector, with around 37 GW of gas-fired projects in various stages of completion. Over the forecast period, demand in the power sector is set to grow at an average of 1.7% per annum, accounting for about 95 bcm of total consumption in 2040.

With approximately 81 million inhabitants, Iran's domestic sectors are the second-biggest consumers of gas. In 2017 over 28% (55 bcm) of Iran's gas was consumed in these sectors, of which 47 bcm was consumed in the residential heating sector. Consumption is strongly seasonal and spikes in winter months. Despite the rise in gas prices, it is expected that domestic demand will grow at an average rate of 1.5% per year, to around 77 bcm in 2040.

The industrial sector and the export of petrochemical products significantly contribute to the Iranian economy. The industrial sector consumed over 41 bcm (21% of total gas demand) in 2017. Due to the Iran's improved economic prospects, it is expected that gas consumption in the industrial sector will reach 77 bcm (26% of total consumption) in 2040.

Nigeria

Nigeria is the largest holder of proved natural gas reserves in Africa. The country has been experiencing an economic slowdown recently, but overall between 2000 and 2017, natural gas demand increased by an annual average rate of 5.1%, rising from 8 bcm to over 19 bcm. Over the forecast period demand will increase significantly by 248%, reaching about 65 bcm in 2040. This is equivalent to a 5.6% annual growth rate.

The power sector was the main driver of natural gas demand over the historical period, and currently accounts for over 39% of total gas consumption. The Nigerian Electricity Regulatory Commission plans to overhaul its electricity tariff system to improve electricity supply and the government aims to raise the number of people connected to the electricity grid from 8 million to about 20 million people. Currently Nigeria has about 12.5 GW of gas-fired power plants,

representing 83% of the country's installed capacity. Several more gas-fired power generation and combined cycle projects are planned. This forecast expects gas use in the power sector to grow at a faster pace, to around 36 bcm in 2040.

Furthermore, the natural gas sector is restricted by the lack of infrastructure to commercialize gas that is currently flared. The country estimates an average loss of \$1 billion each year due to its inability to recover and trade flared gas. Recently, the Nigerian president approved the Nigerian Flare Gas Regulations, which will be implemented to provide a commercial approach to the elimination of routine gas flares by 2020.

The key point regarding Nigeria's energy consumption is that energy prices are highly subsidised, which remains a complex issue. In 2016 Nigeria reduced the fuel subsidies to ameliorate the country's shrinking budget, resulting in a 67% increase in fuel prices. This decision aroused fierce opposition, with trade unions threatening to paralyse the country with strikes and protests akin to those initiated in 2012, when a similar decision to remove subsidies sparked massive protests.

Russia

Russia is the second-largest gas producer in the world. Natural gas is also the country's main source of energy and is at the backbone of its energy balance. Russia's gas consumption increased by 0.6%, from 379 bcm in 2000 to 422 bcm in 2017, driven by surging growth in gas demand in the feedstocks (3.6% p.a.), power generation (1.8% p.a.), and industrial (1.5% p.a.) sectors. Currently, natural gas provides around half (51%) of Russia's energy mix.

Over 2017–2040, demand is forecast to increase at an annual average growth rate of 0.5%, to almost 469 bcm in 2040. The fall in growth is mainly attributed to declining population growth. To a large extent, gas demand depends on the weather and is intricately tied to Russia's harsh winters. The rapid expansion of natural gas use over the historical period was related to growth in power and heat generation. The power sector consumed 31% (129 bcm) of natural gas demand in 2017, compared to the 25% (106 bcm) consumed for heat generation. In 2017, the consumption of natural gas in the domestic sector was only 13% (53 bcm), but still higher than transport and feedstocks, each with 8% (35 bcm). The industrial sector, mainly the chemical and to a lesser extent the metallurgy industry, consumed approximately 39 bcm, and represented 9% of total gas demand in 2017.

Gas consumption in the power generation sector increased by 1.8% per year historically and is expected to grow slowly through to 2040 at an average annual rate of 0.7%. This sector will account for 152 bcm of gas consumed in 2040, totalling 32% of overall consumption. Slower growth over the forecast period can be attributed to the expansion of nuclear and renewables in the Russian power generation mix, as well as strengthened efficiency from new gas-fired power plants.

It is estimated that gas consumption for heat generation (space heating and cooling, water heating, lighting, appliances and cooking equipment) will drop from 106 bcm to 94 bcm. In the domestic and residential sectors, gas use will decrease to around 50 bcm of the total consumption.

United Arab Emirates

Natural gas is a leading fuel in the UAE and is responsible for the majority of energy demand. Consumption has been growing consistently since 2000, at an annual average rate of 5.5%, rising from 30 bcm to around 74 bcm in 2017. This is equal to 56% of the UAE's energy mix.

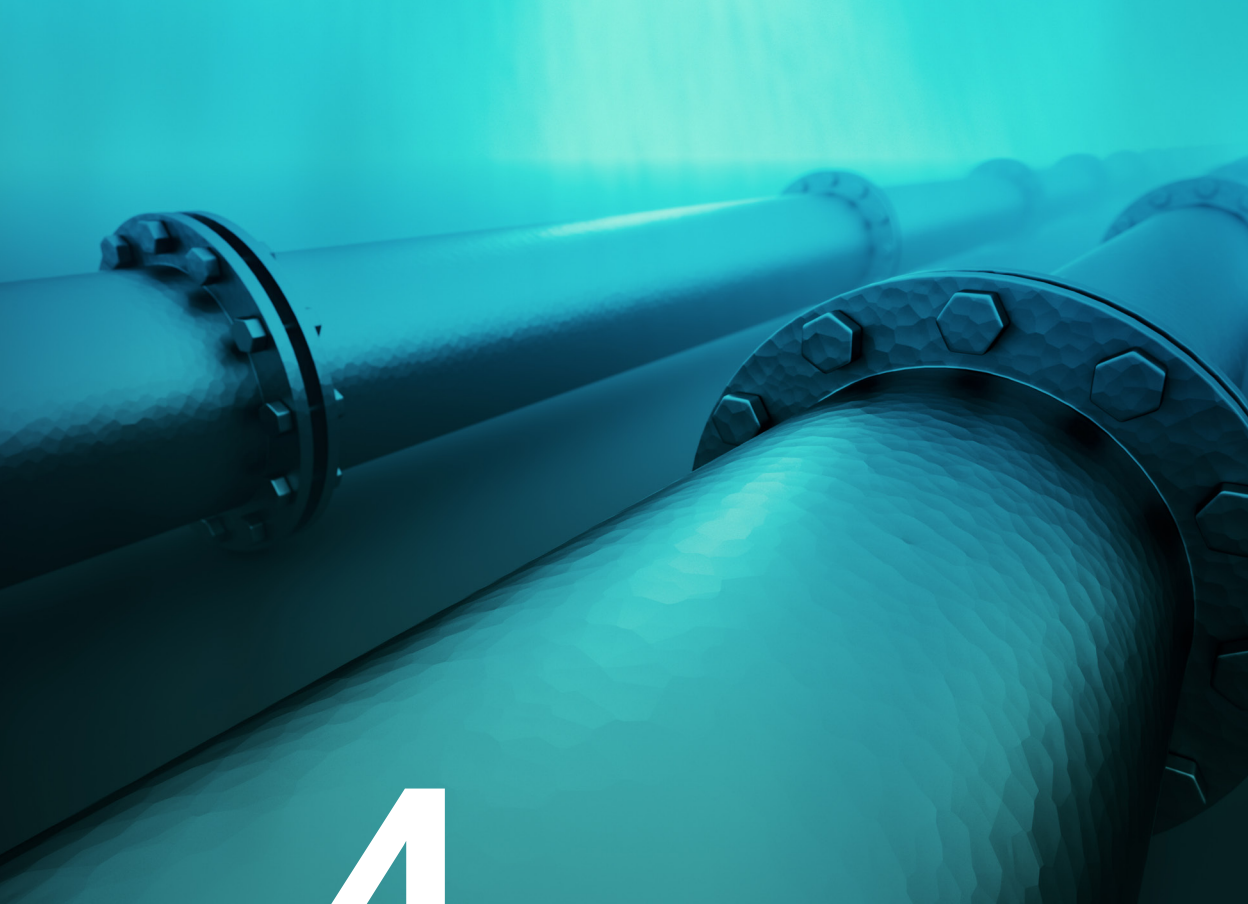
Even with considerable proved gas reserves in Abu Dhabi, the UAE imports gas in order to meet growing demand. One of the key reasons behind this trend is that the country's gas contains high amounts of sulphur and requires costly processing. Consequently, this increases technical and economic costs. As gas consumption has increased rapidly, the Dolphin gas pipeline from Qatar's North Field is set to meet demand.

The UAE has set clean energy targets for 2050 and aims to cut CO₂ emissions by 70%, increase clean energy use by 50%, and improve energy efficiency by 40%. The country is also planning to develop four Korean APR 1400 MW pressurised water reactors with a total capacity of 5600 MW, which should be finalized by 2020. As a result, we expect that natural gas consumption will remain almost stagnant at 2017 levels over the forecast period.

The power sector is the largest gas consumer. Gas-fired plants supply more than 98% of the UAE's electricity demand. In 2017 nearly 55% (40 bcm) of gas was consumed in this sector. Over the projection period the share will increase to 66% (49 bcm). Rapid economic and population growth are the main drivers.

Industry is the second largest gas consumer in the UAE, mainly as a result of petrochemical and fertilizer production. Gas consumption increased from 15 bcm in 2000 to 32 bcm in 2017 in the industrial sector, accounting for 44% of total consumption. It is estimated that this share will decrease to 32% (roughly 24 bcm) in 2040.

Along with most countries in the Middle East, the UAE's price liberalization strategy began in 2015 with the deregulation of gasoline and diesel prices. In 2017 the UAE announced a gasoline price increase of 1.6-1.8%, and a diesel price increase of 2.2%. The rationale behind the reduction in subsidies was to decrease fuel consumption and boost state finances, which have been weakened by plunging oil export revenues since 2014.



4

Natural Gas Supply Outlook

Key findings

- Overall growth in production of 1.7% p.a. is expected in the period to 2040, with total output expected to reach 5427 bcm by that date. Africa is expected to grow the fastest, albeit from a low base, while North America will be the largest contributor by 2040 with an overall share of 28% of global gas output.
- The US, Russia, China and Iran are the largest contributors to this expansion, accounting for 24.8%, 12.4%, 12.4%, and 10.5% respectively, of total change.
- The US, Russia and Iran will remain the largest individual gas producers, although Chinese gas production is expected to increase dramatically.
- One-fifth of supply growth will come from the Asia Pacific region, split between countries looking to provide solely for domestic demand, those who are established exporters and those who are looking to minimize imports.
- North America, led by the US, already produces more than one quarter of global gas production, and the region's output is set to grow by 2% p.a. to 2040.
- With Iran and Qatar leading the way, gas production in the Middle East is set to grow by 61% to 2040, with total volumes reaching 980 bcm.
- Russia dominates Eurasian gas production, contributing three quarters of the total, while Central Asian countries also make major contributions. The area as a whole will remain the second largest global gas producer, increasing output by 300 bcm over the next two decades.
- Europe is the only region in the world with a declining production outlook. In particular output from Norway and the Netherlands will fall significantly.
- The Latin American region is a relatively small producer by global standards but is expected to show growth to 2040, mainly from Argentina, Brazil and Venezuela. Argentina will show significant growth in shale gas output, while much of Brazilian gas production will come from deep-water offshore fields.
- Africa is set to grow its share of global gas production from 6% to 9% by 2040, with Mozambique, Egypt and Nigeria making the biggest contributions to this growth.
- Unconventional gas production will play an increasingly important role in the increase of global gas output, in particular as costs fall across the world. By 2040 it is estimated that one third, or around 1800 bcm, of gas production will come from unconventional resources.
- Total gas production from current GECF members will increase by one third, reaching approximately 2250 bcm by 2040. This translates to a 1.25% annual growth rate over the outlook period, which will enable the GECF to keep its share of global gas production at more than 41%.

4.1 Global natural gas production outlook

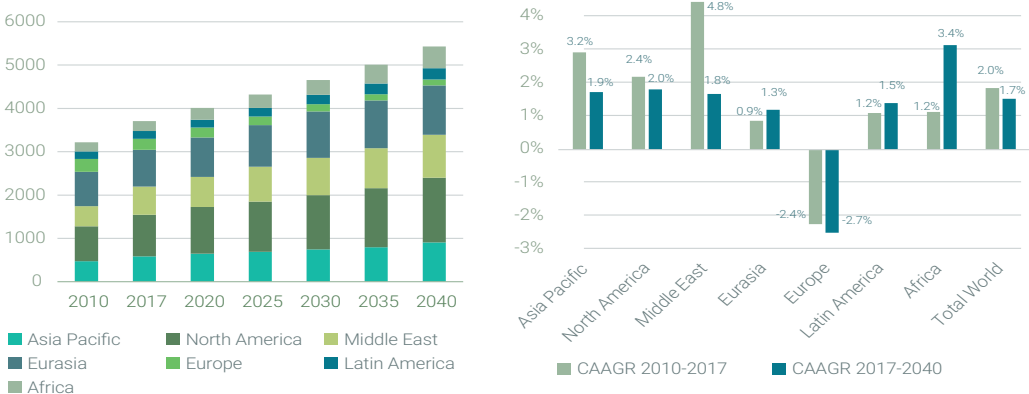
Global natural gas production¹ continued to ramp up in 2017 to reach more than 3700 bcm, around 100 bcm above 2016 levels. This overall increase masked a decline of more than 35 bcm in countries such as the Netherlands, the UK, Peru, Indonesia, Thailand, Vietnam and Mexico. This decline was offset by significant production increases in Norway, Australia, Iran and China.

Historical data shows that during recent years (from 2010 to 2017), with the exception of Europe, all regions have enhanced their gas production, with the Middle East demonstrating an annual growth rate of 4.8%, followed by the Asia Pacific region with 3.2%. Expansion in the Middle East has been driven by Iran and Qatar and, to a lesser extent, Saudi Arabia, adding 80 bcm, 53 bcm, and 19 bcm respectively to global gas production. In the Asia Pacific region, China and Australia were behind the increase, adding more than 55 bcm each to total production.

According to the latest results of the GECF GGM, global marketed gas production is anticipated to expand by around 1717 bcm over the forecast period, reaching over 5420 bcm in 2040, which is around 50 bcm above our previous forecast. The average annual growth rate is 1.7%, which translates into total growth of around 46.3% compared with the current value.

Figure 4.1 illustrates the global outlook for natural gas production as well as historical and forecast growth rates.

Figure 4.1. Global natural gas production by region (bcm), and associated CAAGR (%)



Source: GECF Secretariat based on data from the GECF GGM

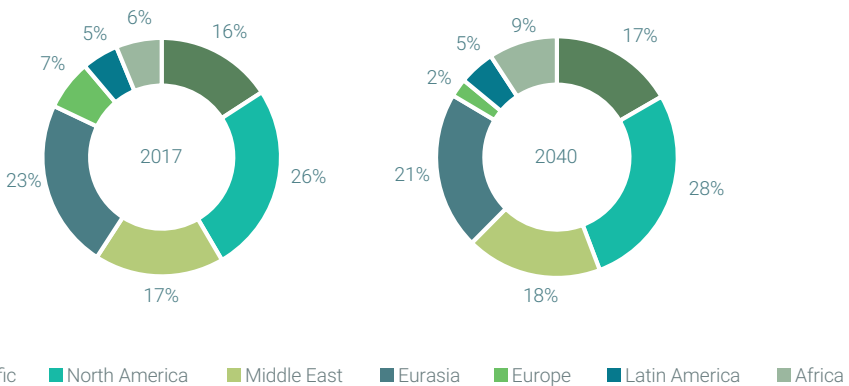
¹Unless otherwise stated, *natural gas production* and *sales gas production* both refer to *marketed natural gas production*

As Figure 4.1 shows, Africa is expected to have the largest annual average growth rate over the outlook period as a considerable amount of expansion in this region is forecast. In addition, the region's current volume of gas production is low, which makes the growth rate look more significant. Africa's gas production boom is expected to more than double output by 2040. Mozambique, Nigeria, Egypt, Tanzania, Libya and Algeria are the countries which will make the most impact.

Europe is the only region to show negative growth in both historic and forecast figures in terms of natural gas production. Norway, the Netherlands and the UK, the three main natural gas producers in Europe, are forecast to reduce their annual gas production on aggregate by around 100 bcm by 2040 which will bring Europe's share of total gas production down from 7% in 2017 to 2% in 2040 (see Figure 4.2).

Figure 4.2 also indicates that Africa, Asia Pacific, North America, and the Middle East gain share in total gas production by 2040.

Figure 4.2. Current and future outlook of the regional share in global gas production (%)



Source: GECF Secretariat based on data from the GECF GGM

The US, Russia and Iran are currently the top three natural gas producers in the world. It is forecast that this ranking will remain unchanged by 2040, in line with our previous forecast. These giant gas producers will continue to expand their exploration and will together increase production by more than 820 bcm, which will comprise around 48% of the total global incremental volume that is forecast by 2040.

China will experience the third largest expansion of natural gas production in terms of absolute volume over the forecast period, and is forecast to add 213 bcm to its total gas production by 2040.

Norway will show the largest decline in natural gas production during the forecast period with production falling by more than 55 bcm, followed by Uzbekistan and the Netherlands.

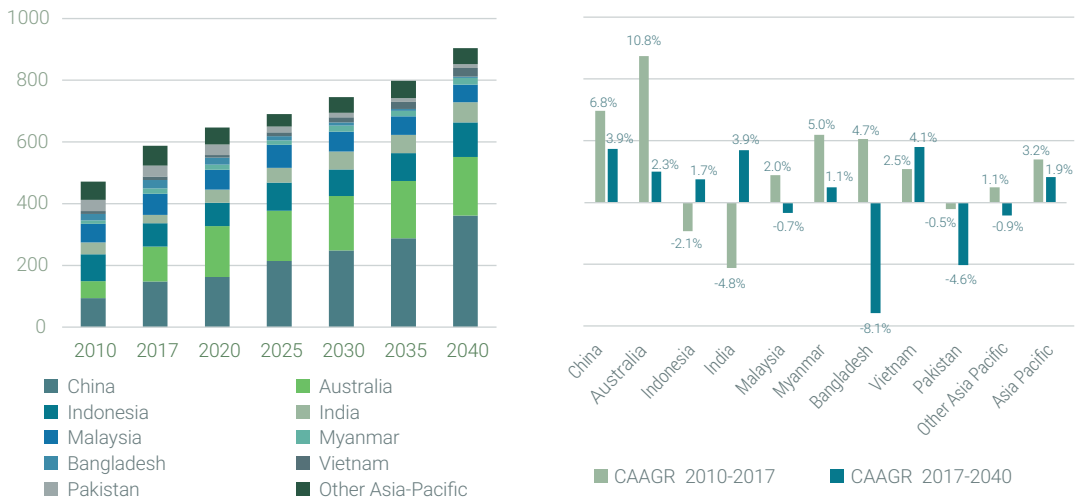
4.2 Regional natural gas production outlook

ASIA PACIFIC

One-fifth of total incremental gas production is anticipated to come from the Asia Pacific region. Australia and China are projected to drive incremental volume in the medium-term; India, Indonesia and, to a lesser extent, Vietnam and Myanmar will make their contribution in the longer-term. Three groups of countries can be identified in the Asia Pacific region based on their current and anticipated positions in global natural gas markets. The first group consists of countries that are trying to meet the largest possible share of domestic gas demand by increasing indigenous production. These countries, namely China, India and Vietnam, will contribute to slightly less than 15% of global growth during the forecast period. China alone will be responsible for an estimated 12% of the total increase in global gas production.

The second group comprises countries that are established gas exporters, such as Australia, Malaysia, Indonesia and Myanmar. These countries will try to maintain production to retain or strengthen their role in global gas markets. The last group covers other countries in the Asia Pacific region that are generally considered as natural gas importers. The group includes Japan, Korea and the Philippines - countries where only small-scale production is feasible over the forecast period.

Figure 4.3. Asia Pacific natural gas production (bcm), and associated CAAGR (%)



Source: GECF Secretariat based on data from the GECF GGM

Australia

Australia is the only established gas producer which more than doubled its production between 2010 and 2017. However, in terms of absolute incremental volume, it comes second to the US. Australia's gas production soared to over 110 bcm in 2017, after achieving an average annual growth rate of 10% since 2010. This huge expansion accounted for

11% of global incremental volume over the same period. Australia produced an additional 17 bcm of gas in 2017, which accounted for the significant growth of 18% compared with the previous year.

Australia boasts considerable gas reserves, but a large proportion of them are located offshore and stranded in remote areas. There are three separate gas markets and resource basins in Australia: the eastern, western and northern markets. One of the biggest challenges for the Australian gas market is its fragmentation, which prevents produced gas moving between these markets.

Australia's gas production began in the 1960s with the output of associated gas across the East Coast market. During the 1980s, previously commissioned projects in the Northern and Western Territories were completed. Gas was first delivered from the North West Shelf to domestic markets in 1984, with the first LNG export to Japan delivered in 1989. The gas industry on Australia's east coast began to change in the 1990s when coal seam gas was discovered in Queensland. Three LNG projects reached FIDs in 2010 and 2011, with the first trains coming online in 2015 (Queensland Curtis LNG, Australia Pacific LNG and Gladstone LNG). Following the completion of several other trains in 2016, an additional 25 mt of liquefaction capacity was delivered to the East Coast market. These projects connected Australia to the global LNG market for the first time. However, domestic consumers were affected by a tighter market and higher prices. (1)

Although significant shares of eastern LNG are being extracted from dedicated coalbed methane plays, conventional gas which could otherwise be consumed in domestic markets is also being exported. Gas has become even more valuable because of its ability to support the natural intermittency of renewables, which have continued to gain market share in the region over the last decade. Another challenge is that most long-term bilateral contracts between domestic consumers and producers are due to expire.

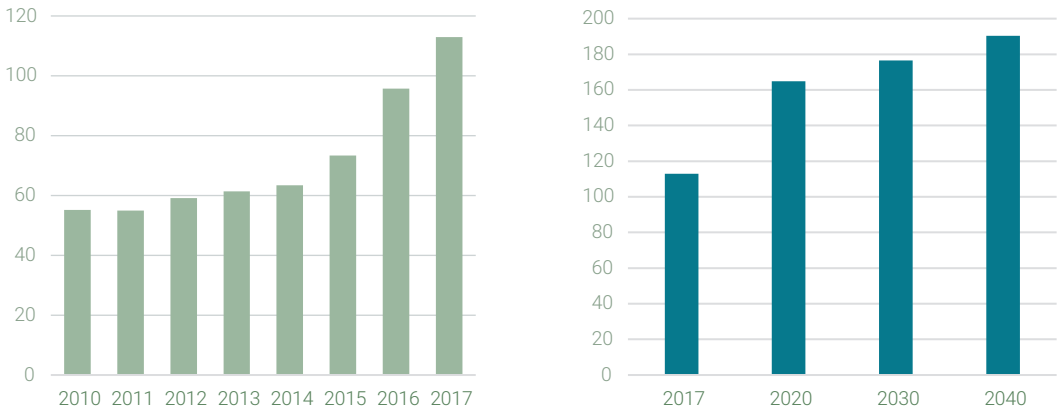
The Australian government responded to the problem of gas security in the East Coast market by implementing the Australian Domestic Gas Security Mechanism (ADGSM). The Australian Energy Market Operator (AEMO) declared a forecasted shortfall in gas supply for the 2018 and 2019 calendar years for Eastern and South-Eastern Australia, and LNG exporters on Australia's east coast committed to securing an affordable supply to the domestic market in October 2017. (2)

As part of their agreement under the ADGSM policy framework, the east coast LNG joint ventures will retain uncontracted gas from the international market until equivalent volumes have been offered domestically on competitive terms. AEMO found that Western Australia's LNG projects have sufficient reserves to meet contractual obligations and domestic requirements through to 2019; a subsequent report published by the Australian Competition and Consumer Commission found that a shortfall in gas supply for the 2018 calendar year was no longer expected. (2)

The main driver behind the expansion of Australia's gas production, historically and in the medium-term, is the start-up of LNG export projects. The most recent ones include the third train of Chevron's Gorgon LNG Projects, Wheatstone LNG and Ichthys. Prelude is expected to come online by the end of 2018, concluding a wave of eight LNG mega-projects sanctioned since 2007.

Figure 4.4 shows Australia's historical and forecast gas production, illustrating that most expansions have taken place over the last five years. Further development is expected in the medium-term, with production growth decelerating post-2020.

Figure 4.4. Australia historical and outlook for natural gas production (bcm)



Source: GECF Secretariat based on data from the GECF GGM

China

Natural gas production in China has been increasing at its fastest pace over the last four years. In 2017, China's natural gas production stood at a record high of 148 bcm having already added more than 12 bcm during the year, accounting for an 8.3% increase. The cumulative increment in China's production from 2010 and 2017 was 54 bcm, ranking China fourth after the US, Iran and Australia which achieved incremental volumes of 145 bcm, 81 bcm and 58 bcm respectively over the same period. Historical data also indicates that more than 12% of total incremental gas production during the same period came from China which only held a 4% share of global gas production in 2017.

The world's largest energy consumer established itself as the world's current sixth-largest natural gas producer after soaring investments over the last few years originating from clean energy and coal-to-gas switching policies as part of the country's overall policy of increasing cleaner energy use. Its 13th Five-Year Plan (FYP) launched in 2016, outlined some medium-term targets in energy sectors such as a reduction in coal's share of primary energy consumption to 58% and an increased use of cleaner fuels such as natural gas as well as renewables. The plan targets a share of 10% for natural gas in total primary energy consumption by 2020.

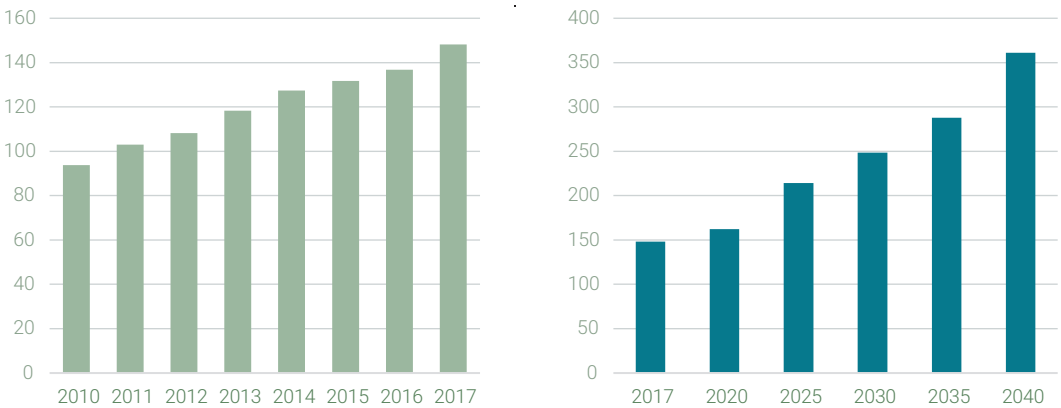
Another measure in place to boost the natural gas industry in China is the Energy Supply and Consumption Revolution Strategy which was released by the Chinese National Development and Reform Commission (NDRC) in April 2017 and which determines a set of goals for the energy sectors up to 2030. For instance, it aims to put a maximum limit on total primary energy consumption in China of 4.2 Gtoe compared to the current level of around 3 Gtoe, as well as a natural gas share of 15% of total primary energy consumption. Achieving this share would mean volumes in excess of 500 bcm, which seems a very high target, even taking into account the current volume of primary consumption. Although

eventually a considerable share of the required volumes of natural gas will be met by imports, ambitious plans in the upstream sector will be needed to increase indigenous production in order to achieve these goals. This is the reason behind the massive investment in China's upstream sector and subsequent prosperity seen in recent years. (3)

CNPC, Sinopec, and CNOOC are the most active Chinese companies in the upstream sector. Among them, CNPC - through its subsidiary PetroChina - is the most active in the exploration and production sectors. More than 75% of total gas production, the gas pipeline network and storage systems are being carried out and operated by CNPC. Sinopec and CNOOC are more involved in unconventional and offshore production. All of these NOCs have had substantial achievements in recent years, and they all emphasize their continued commitment to keeping up the pace of production expansion to achieve the targets that have been set.

For its part, CNPC is planning to expand its oil and gas production project in the Tarim basin by 20%. Tarim is located in one of the main basins under production in the western state of Xinjiang and is being operated by the company. There is a plan to build another production zone at Tarim that would add more than 5 bcm to the field's total production. In 2017 CNPC produced 65 bcm of natural gas from the Tarim basin, 6 bcm more than was produced in 2016. CNPC is also focused on the enhancement of efficiency, productivity and profitability of its projects.

Figure 4.5. China historical and forecast outlook for natural gas production (bcm)



Source: GECF Secretariat based on data from the GECF GGM

Sinopec is planning to stick to its medium-term production expansion target of 50% and this would raise the company's production to more than 40 bcm by 2020, up from 26 bcm in 2017. The company is gambling on both conventional and unconventional new gas discoveries. Sinopec plans to invest in Fulling shale gas as well as some other unconventional plays of coal-bed methane. It also will invest in the Hangjing natural gas field. (4)

The long-term outlook for China's gas production is also very promising. It is expected that more than 210 bcm will

be added to its annual marketed production by 2040 which would make the country the world's fourth-largest gas producer with volumes of around 360 bcm. At least half of this expansion is expected come from unconventional resources, such as shale gas and coalbed methane. Consequently, there is considerable uncertainty surrounding this prediction, due to the tough geology, lack of water resources and cost competitiveness.

India

Natural gas production in India declined over the last seven years by around 7% annually to around 27 bcm in 2017, a fall of more than 20 bcm. Lower international gas prices resulted in a reduced domestic gas price in India which discouraged investments by producers in the upstream sector, who perceived their cost of production to be less than the price of natural gas. In 2017 the prolonged decline of gas production which peaked in 2010 was reversed, and for the first time in the last seven years, India's production marked a positive growth of 2.2%.

India introduced several measures to relieve levels of dependency on imported oil and gas, primarily by introducing a more transparent mechanism for the pricing and marketing of domestically produced natural gas as well as by extending the exploration licenses period and making licenses easier to obtain.

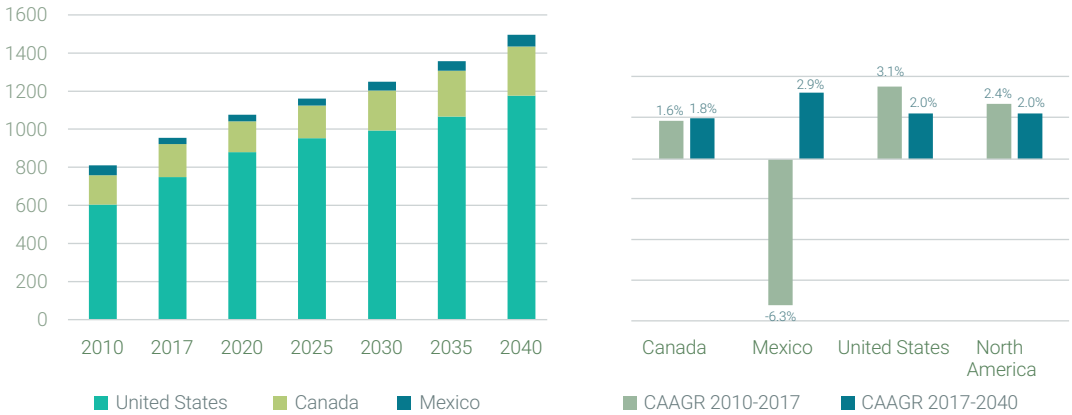
This Outlook expects a bullish trend for the future of Indian production that suggests an increase of 38 bcm in annual production by 2040 to 65 bcm, equating to growth of 140%. This escalation will contribute to a 12% total increment for the region and 2.1% of global production. India will almost triple its gas production compared to 2017 and double it compared to 2011 levels. This report expects an annual average growth rate of 3.9% over the outlook period (see Figure 4.3).

India's Oil and Natural Gas Corporation (ONGC) announced a plan to invest \$2.6bn in drilling oil and gas wells in the current fiscal year (April 2018-March 2019). The plan includes 24 development wells in the deep-water area of the KG-DWN-98/2 project as well as 30 coalbed methane wells. There are some other developments in projects on the Bengal block KG-DWN-98/2 which will come on stream in the medium-term. Therefore, the outlook for the medium-term in India is also very promising. It is expected that India will add around 20 bcm to annual production by 2025, corresponding to an annual growth rate of 7.3%. This would constitute the largest expansion to date; however, the negative impact of pricing strategies and higher costs evokes a degree of uncertainty. (5, 6)

NORTH AMERICA

More than one quarter (26%) of global natural gas production is currently based in North America. The US, the largest gas producer since 2011, is the main contributor to production in the region, currently accounting for 78% of the total. All three countries in the region are set to boost their production capacities, and all of them will maintain their shares of global production over the forecast period. The region is expected to achieve an annual growth of 2% which implies an expansion of 541 bcm or 56.7% compared with the current level.

Figure 4.6. North America natural gas production (bcm), and associated CAAGR (%)



Source: GECF Secretariat based on data from the GECF GGM

Canada

Canada is the fifth largest marketed gas producer worldwide and one of the biggest unconventional gas producers in the world. In 2017, Canada produced more than 170 bcm of marketed natural gas, of which 65% was from the Alberta Province. Natural gas production declined in Canada from 2006 to 2012, but since then, production growth has resumed thanks to the development of shale and tight gas.

Canada has made progress in expanding unconventional gas production capacity during the last ten years. The volume of unconventional production rose from less than 65 bcm in 2010 to around 100 bcm in 2017, which accounted for around 65% of total marketed production. This was mostly driven by expansion in the Montney play (from 13 bcm in 2010 to 45 bcm in 2017). The Montney Formation is a large resource of tight gas extending over the northern parts of Alberta and British Columbia, containing both wet and dry natural gas. Natural gas production from Montney tight gas began in 2007 and, currently one-third of total Canadian production is sourced from there, with British Columbia containing the most significant portion of the reserves.

The Alberta Deep basin and Duvernay in Alberta, as well as Horn River in British Columbia, are other important unconventional plays in Canada on which we have based the latest results of our modelling and these will contribute considerably to Canadian gas production over the outlook period.

Although unconventional production in Canada is making good progress, Canada will also be challenged by the global shale revolution. The expansion of shale capacities in the US, the biggest current import market for Canadian gas, as well as the modest increase in natural gas demand forecast over the medium term, means that the call on Canadian gas is expected to decrease. This will definitely create a downward impact on the total figures for the country's natural gas production unless infrastructure supporting LNG exports gains momentum and Canada achieves the ability to export

its gas in that form, as well as through existing pipelines. Any future FIDs taken for any part of the huge LNG plan in Canada will have a big impact on total gas production.

The FID recently taken by LNG Canada could be considered the beginning of this momentum, and it may act as a trigger to unlock the Canadian export market. The project, which announced its FID in October 2017, is led by Royal Dutch Shell Plc and its four Asian partners. Liquefaction capacity of 26 mt per annum has already been proposed, but approval has only been granted for the first two trains (with 13 mt).

The latest modelling results suggest that, in the medium term, total production will stabilize, but that growth will resume after 2026 reaching around 260 bcm in 2040. This will amount to 50% growth and a CAAGR of around 1.8% over the outlook period.

Mexico

Since 2010 Mexico's natural gas production has fallen from more than 51 bcm to less than 30 bcm. More than three-quarters of total natural gas production in Mexico is in the form of associated gas, hence any change in the volume of oil output affects total natural gas production. During the last seven years, oil production has decreased due to the depletion of reserves and low oil prices and this has been the main reason behind the declining gas production, in addition to the natural ramp down in production from non-associated gas reserves.

Mexico holds more than 200 bcm of conventional proven gas reserves. The country also has a high potential of shale gas reserves, estimated at more than 15 tcm. The Tampico-Misantla Basin is located in the country, and Mexico also shares the Eagle Ford Basin with the US, as well as significant offshore deposits.

As part of the country's energy reform, Mexico has signed several contracts since June 2017 to produce oil and gas in the shallow waters of the Gulf of Mexico. However, it will take time before these recent efforts will make an impact on the market, so our latest modelling results suggest a continuous ramping down in Mexico's gas production until 2022 when a reverse trend is expected to begin. This Outlook projects that total gas production in Mexico will increase by slightly less than 30 bcm by 2040 which represents a significant CAAGR of 2.9% over the period 2017-2040 compared with the poor historical annual negative growth rate of -6.3% over the last seven years.

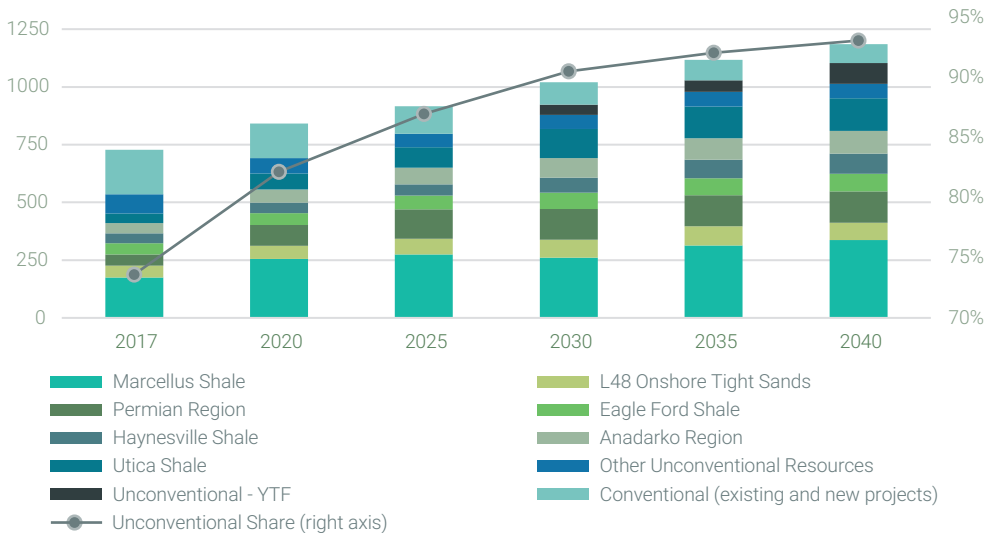
United States

The US has been the world's biggest natural gas producer since 2011. The country has added more than 140 bcm to its annual production since 2010 thanks to the huge expansion in unconventional production capacities mostly in the Appalachian Basin (Marcellus and Utica shale plays), the Permian Basin in Texas and the Eagle Ford shale play. Total unconventional production in the US increased from 270 bcm in 2010 to 530 bcm in 2017. This has offset a decline in conventional gas production, which amounted to around 120 bcm over the same period. Progress in unconventional production is the result of technological and economic advancement as well as the increased number of drilling activities driven by higher oil and gas prices in recent years. In 2017 the main basins that contributed most to total gas production included the Appalachian Basin, mostly in Pennsylvania, Ohio and West Virginia, the Permian Basin in Texas, and Haynesville play in Louisiana respectively.

Compared with other shale plays, including the Appalachian, gas is more costly to produce in Haynesville as the shale is in deeper formations. From 2013 to 2016 when the oil price was low, production from this region more than halved from around 200 mcm/d to less than 95 mcm/d with the number of drilling rigs being reduced from 200 to 20. (7)

This Outlook projects that the US will maintain its position as the largest gas producer over the forecast period. More than 420 bcm of natural gas will be added to annual production mostly from unconventional resources. This progress on unconventional production means the share of unconventional gas will reach 93% compared with around 74% currently. This huge expansion accounts for a growth of 57% forecast over the outlook period. Modelling results also anticipate that a quarter of increased global gas production over the outlook period will be from the US. In addition, the US's share of global gas production will rise from 20.3% currently to 21.6% in 2040.

Figure 4.7. United States gas production outlook (bcm, %)

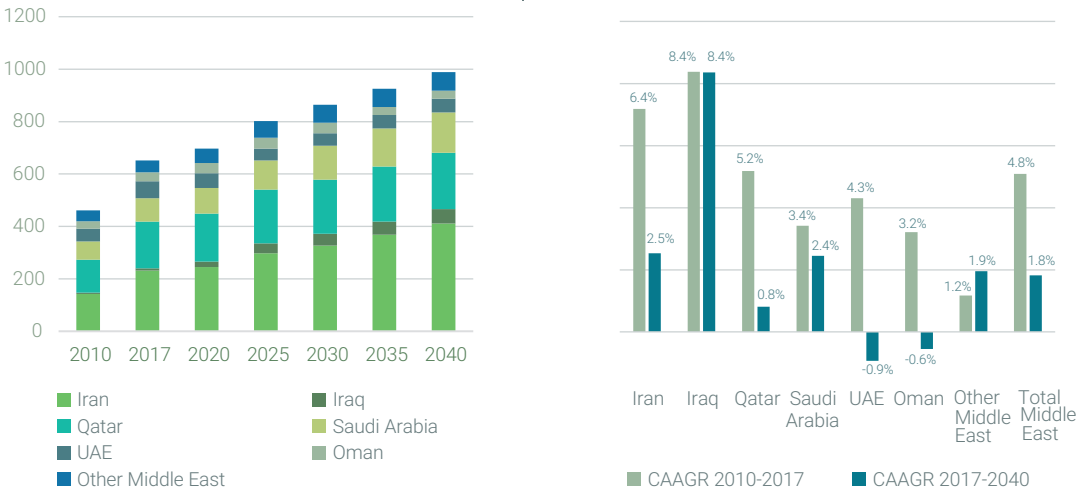


Source: GECF Secretariat based on data from the GECF GGM

MIDDLE EAST

The Middle East is the third biggest region in terms of natural gas production after North America and Eurasia. It contributed 17% of total produced gas in 2017, equivalent to slightly more than 650 bcm. The main gas producers in the region include Iran and Qatar with total marketed production of 400 bcm which accounts for more than 63% of the region's production. The Middle East is expected to make very promising progress in terms of annual gas production over the forecast period. This Outlook suggests that the Middle East will increase its annual gas production to more than 980 bcm by 2040, representing a growth of 52% or an annual average growth of 1.8%. On this measure, it comes third after Africa and North America. Iraq, Saudi Arabia, Oman and the UAE will all enhance or maintain their production over the outlook period.

Figure 4.8. The Middle East natural gas production (bcm), and associated CAAGR (%)



Source: GECF Secretariat based on data from the GECF GGM

Saudi Arabia

Gas production in Saudi Arabia has followed an ongoing and steady trajectory over the last 28 years. Since 2000, the country has more than doubled its marketed gas production to reach over 90 bcm in 2017. All gas produced in Saudi Arabia is consumed in the domestic sectors, mostly in power generation, desalination and industry. The Outlook expects that Saudi Arabia's gas production will keep ramping up over the forecast period to reach more than 150 bcm in terms of annual marketed gas production by 2040. Since some other countries in the Middle East will also enhance their gas production, Saudi Arabia's regional share of marketed gas production will be maintained at around 14.8% over the outlook period.

Iran

Iran holds around 18% of the world's proven natural gas reserves, totalling approximately 34 tcm. More than 60% of the country's natural gas reserves are located offshore, and around 80% of total proven gas reserves are non-associated fields. Iran's largest gas field is the South Pars field, which comprises more than a quarter of its total proven reserves and accounts for 65% of the country's current natural gas production. This giant field is the world's largest gas reserve and is a non-associated gas field located off the southern coast of Iran. Other major gas fields in Iran include Kish, North Pars, Tabnak, Forouz and Kangan. High concentrations of condensate in Iran's natural gas fields give Iranian gas reserves an advantage and make exploration projects even more profitable.

Iran has been the third largest gas producer after the US and Russia since 2011. As mentioned in Chapter 3, despite sanctions imposed by the US on the Iranian energy sector, Iran has enhanced its gas production capacity significantly by around 51% since 2010, equivalent to an increase of more than 80 bcm in the production of marketed gas. This figure excludes the enhancement of associated gas production that is used to reinject oil wells for Enhanced Oil Recovery

purposes. The country achieved an annual average growth of 6.4 % over the period between 2010 and 2017. Currently, more than one-third of the Middle East's marketed gas production is sourced from Iran, equivalent to around 6.2% of global marketed gas production.

The outlook for Iran's natural gas production is very promising. The prosperity is mostly the result of concerted efforts in the development of the South Pars field, which experienced a major breakthrough as the country launched five phases early in the fiscal year. In this context, the country signed a contract with a partnership headed by Total to develop Phase 11 of the South Pars field. Total withdrew from the project due to the sanctions imposed by the US, with its share being taken by CNPC. This phase is expected to bring an increase of 20 bcm above current production volumes by 2021. Other efforts, like the MoU signed with Saipem concerning the development of the Toos gas field project, and the MoU signed with KOGAS over the development of the Balal gas field, indicate that production of Iranian gas will continue to surge over the medium- and long-term.

This Outlook forecasts that Iran's marketed gas production will expand significantly by around 180 bcm to more than 410 bcm by 2040; this will be the fourth largest expansion of gas production in the world over the outlook period. This major development maintains the country's position as the third largest gas producer in the world. Modelling results also suggest that more than 11% of global gas production expansion over the outlook period will be sourced from Iran which means that the country will be producing 42% and 8% of Middle East and total world gas production respectively in 2040. This expansion will give Iran a huge boost in gas export capacity, both through LNG and pipelines.

Qatar

Following the lifting of the moratorium on the expansion of its giant North Field, Qatar Petroleum (QP) is moving forward with its primary plans to increase Qatar's LNG output by 30% - from 77 mt to 100 mt per year. This was disclosed by QP President and CEO at the 27th World Gas Conference in Washington as well as at GASTECH 2018 in Barcelona. In September 2018, QP announced it had raised its target to achieve 110 mt of liquefaction capacity. The company has released a statement that it now plans to proceed with a fourth mega LNG train with a capacity of around 8.6 mt/year on top of the three planned mega trains that were previously scheduled to come online by 2024. (8,9)

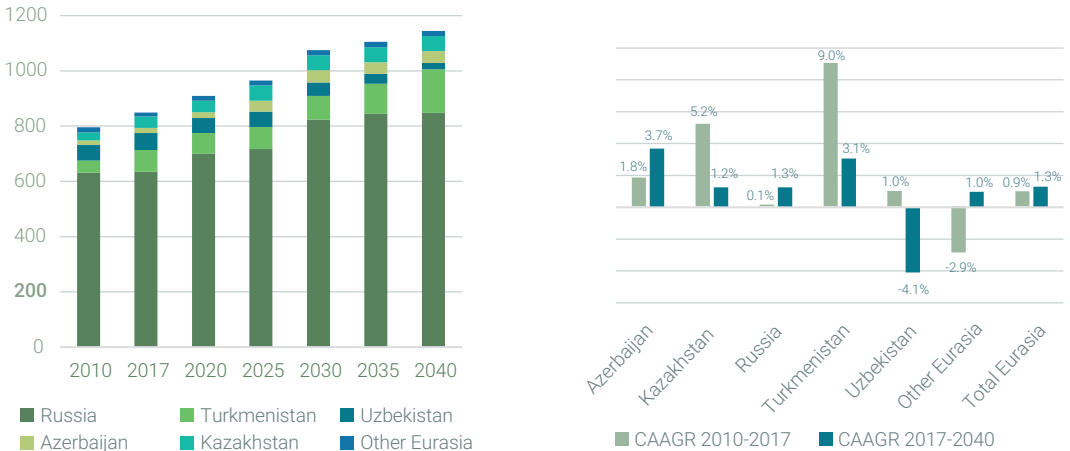
Modelling results based on these aforementioned developments and announcements suggest a very promising expansion in Qatar's gas production capacity in the medium-term. This Outlook expects that Qatar's production will expand to more than 205 bcm by 2025 which represents an annual growth rate of 2.3% and overall growth of 20%.

EURASIA

Eurasia is the second largest producing region after North America for natural gas output, with around 849 bcm in 2017. Three-quarters of total gas production in the region is sourced from Russia, with other contributors including Turkmenistan, Uzbekistan, Kazakhstan and Azerbaijan with shares of 9%, 7%, 5% and 2% respectively. It is forecast that all these contributors will improve their production capacity over the outlook period with the exception of Uzbekistan. The region is assumed to expand its gas production by 300 bcm to maintain its position as the second largest gas producing region in the world. Russia, Turkmenistan and Azerbaijan will be the main contributors to this expansion. Turkmenistan is expected to double its production to around 160 bcm by 2040 thanks to the expansion of pipeline export facilities that will enable the country to invest in extraction projects. Expansion in the Galkynysh field is also

partly behind this increase. Azerbaijan is also expected to grow its production by commissioning other phases of the giant Shah-Deniz field as well as three phases of Absheron, located located offshore in the Caspian Sea. Total EP Absheron, a subsidiary of Total in partnership with SOCAR and Engie, is developing the field. This Outlook expects that the first phase will come online after 2023 and plateau at 4.8 bcm by 2025. Other phases are also expected to add another 7 bcm to total production by the end of outlook period.

Figure 4.9. Eurasia natural gas production (bcm), and associated CAAGR (%)



Source: GECF Secretariat based on data from the GECF GGM

Russia

Currently the Russian Federation is the second largest gas producer in the world and the largest natural gas exporter. There is a very promising picture for the future of Russia’s gas production both in the medium-term and in the long-term. In the medium-term, expansions in pipeline infrastructure to Europe and Asia will drive a significant expansion in production expected to total around 80 bcm by 2025. This expansion will mostly be driven by an increase in gas production from East Siberia, the Yamal Peninsula and, to a lesser extent, Sakhalin. The Outlook suggests that Russian gas production will increase by 13% to reach volumes of more than 715 bcm over the same period.

In the Yamal peninsula, Gazprom’s project in the Bovanenkovskoye field has already added more than 80 bcm to the country’s annual gas production. It is expected that with the commissioning of a third gas production facility, production will plateau there at around 110 bcm. In September 2018, Gazprom announced the beginning of a start-up scheduled in 2018. In addition, pre-development of Kharasaveyskoye, another large field in the peninsula, is expected to start in 2019. The latest results of modelling suggest that this field, as well as the Bovanenkovskoye field, will contribute significantly to production expansion in the longer-term. (10)

Fields in the Irkutsk and Yakutia production centres also are expected to add significant volumes to production, driven by gas exports through the West Siberian pipeline project that is expected to come online in the near-term.

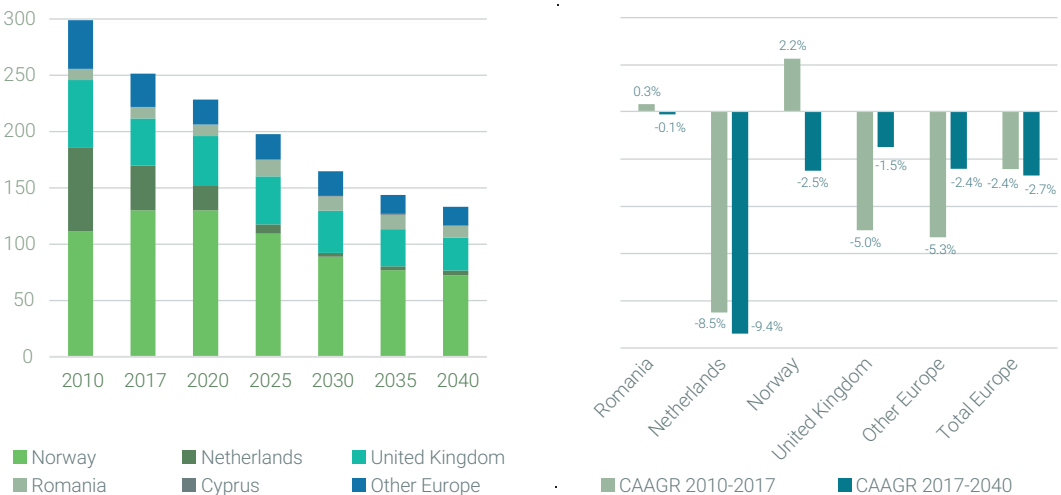
In the long-term, the gas production outlook for the Russian Federation is very promising. This outlook forecasts that Russia will add around 212 bcm to its gas production by 2040, allowing it to maintain its position globally as the second largest gas producer. This expansion translates to a growth of 33.5% overall and an average annual growth rate of 1.3%.

In 2040, Russia is expected to account for 16% of the world's produced gas, slightly less than the current share of 17.2%. The country will contribute 12.4% of absolute growth in the world's annual gas production over the forecast period.

EUROPE

Europe is the only region with a bearish outlook for natural gas production across all regions. Almost all gas producers in the region are expected to see a reduction in their gas production over the outlook period. The biggest fall will be experienced by Norway, responsible for more than half of the gas produced in Europe, which will see a significant fall of around 50 bcm over the outlook period. However, Norway will remain the largest gas producer in Europe accounting for a slightly greater share of total European gas production. The Netherlands also will contribute to the overall negative trend for European gas production, with production there declining by around 35 bcm by 2040.

Figure 4.10. Europe natural gas production (bcm), and associated CAAGR (%)



Source: GECF Secretariat based on data from the GECF GGM

Total European gas production by 2040 is forecast to stand at about 130 bcm, less than half of 2010 production volumes. Historical trends in the last seven years have also been bearish in terms of gas production, with most gas producers in Europe seeing a decline over the period. Norway is an exception, marking a positive annual growth rate of more than 2.2% over the period.

Europe's share of global natural gas production is forecast to decrease to 2% compared with the current share of slightly less than 7%.

Norway

Norway has established itself as an important gas producer within Europe. It is also the third largest natural gas exporter worldwide after Russia and Qatar. The Troll field, the largest offshore European gas field, is the main field under production in Norway. Announced investments in the new phases of this giant field, as well as some other Norwegian gas fields, will result in a rise in gas production over the medium-term. The latest calibrated results of the GECF GGM suggests an increase of around 8 bcm by 2022. However, in the longer-term, the Outlook expects a ramp down of production mostly due to the depletion of the aged field and a lack of sufficient investment in the upstream gas sector including exploration activities. In other words, without new discoveries, exploration and commercial production, declining trends beyond 2022 are expected with YTF resources having a vital role over that period. Most of these YTF resources are expected to be in the Barents Sea.

The Netherlands

The Netherlands is also an important gas producer in the region with a production level of around 40 bcm in 2017 which accounted for 16% of total European gas production. Around half of this volume is sourced from the Groningen field and the rest from smaller Dutch fields. Both categories are expected to reduce their contribution to total Dutch gas production. Groningen is due to be shut down according to a plan launched in May 2018 by the Dutch Ministry of Economic Affairs and Climate Policy. The latest results suggest that gas production in the Netherlands will decrease by 35 bcm to 5 bcm by 2040.

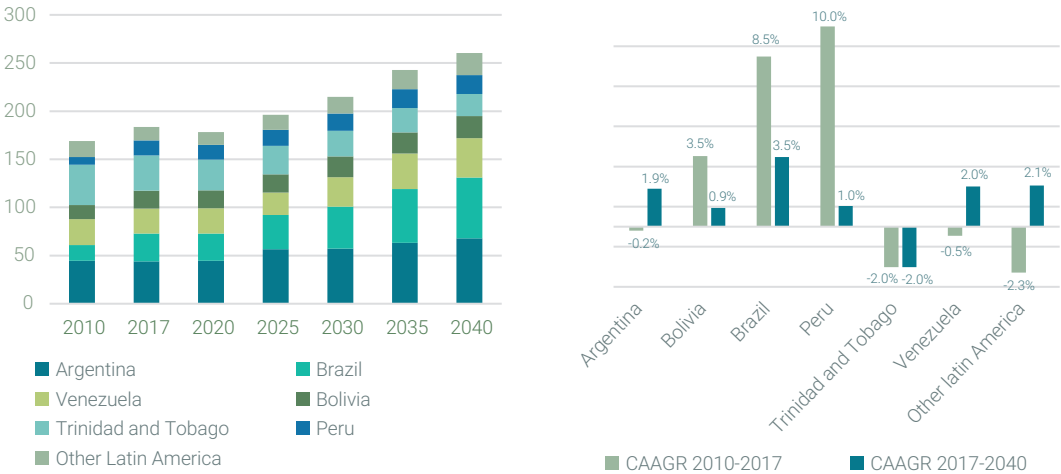
LATIN AMERICA

Latin America is considered a prosperous region in terms of almost all types of conventional energies. Apart from a very rich fossil fuel resource base, the region also has great potential from renewables thanks to the geological diversity of the region. For instance, well-developed hydropower has made this renewable energy a key source of power generation in some parts of the continent, specifically in Brazil.

Latin America, including Caribbean countries, is currently the smallest producer globally, with less than 190 bcm of natural gas production. This volume of production is mostly sourced from Argentina, Trinidad and Tobago, Brazil, Venezuela, Bolivia, Peru and Colombia in order of significance. Almost all of them, except for Trinidad and Tobago, are expected to increase their gas production over the forecast period. As a result, the region is expected to boost its gas production by 76 bcm to more than 260 bcm by 2040 which will enable the region to overtake Europe's gas production by then. According to the latest results of the GECF GGM, Latin America will expand its gas production by 41% over the forecast period and will produce 4.8% of global annual gas production in 2040.

Most of this expansion is forecast to be driven by Argentina, Brazil and Venezuela -totalling around 80% of regional expansion. Bolivia, Peru and Colombia will contribute to the remaining 20% of regional expansion by adding a total of 15 bcm to production from the region.

Figure 4.11. Latin America natural gas production (bcm), and associated CAAGR (%)



Source: GECF Secretariat based on data from the GECF GGM

Argentina

Argentina is the largest gas producer within Latin America. The country produced 44 bcm in 2017, which was around 8 bcm more than Trinidad and Tobago, the second largest gas producer in the region. This volume of production which represents approximately a quarter of region’s production is mostly sourced from the Neuquén Basin. This basin currently contributes slightly less than 60% of Argentina’s production, followed by the Astral (23.6%), Golfo San Jorge (11.7%) and Noroeste (5%) deposits.

Supported by higher hydrocarbon commodity prices, investment has risen during the last year and has resulted in increased natural gas production. Over the first eight months of 2018, natural gas production expanded by around 5% year-on-year.

Based on the latest results of the GECF GGM, a significant increase in Argentina’s gas production in the short-, medium-, and long-term is forecast. In the medium-term, it is expected that Argentina will expand its production by around 12 bcm by 2025 which translates into a considerable annual average growth rate of 3.1%.

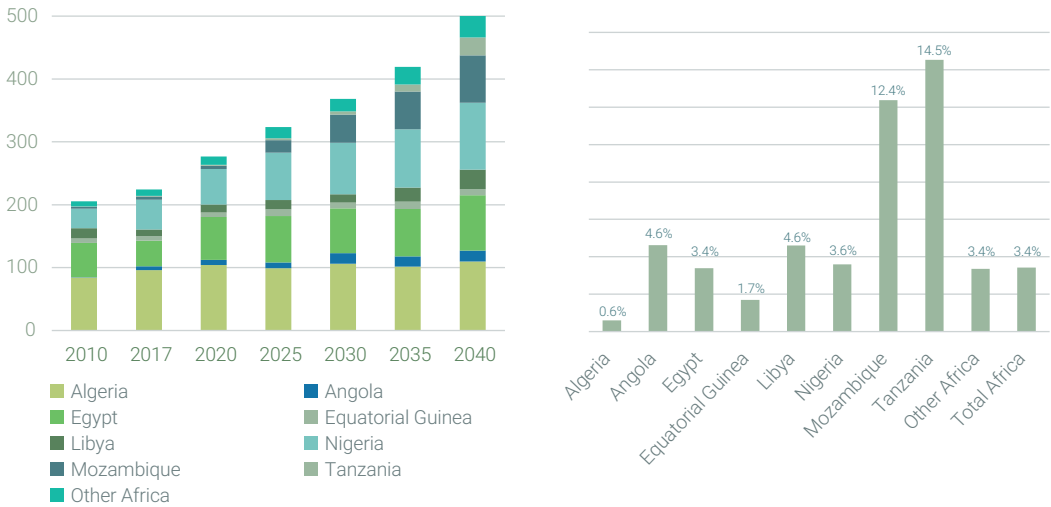
Vaca Muerta, one of the biggest shale oil and gas deposits in the world, will have an important role in this expansion. The infrastructure needed to transport materials is currently under development, and investment in Vaca Muerta is expected to reach more than \$13bn by the end of 2018 and to be maintained at \$20bn annually from 2019 onwards. In September 2018, Shell announced the last stages of the pilot development and full-scale development of Shell’s Vaca Muerta block is expected to commence in 2019. (11)

AFRICA

The prospects for natural gas production in Africa are considerably promising. Africa is rich in energy resources, but oil and gas resources are relatively underdeveloped. Africa contributed only 6.2% to total marketed gas production in 2017; however, this Outlook suggests that this share could reach 9.2% by 2040. That means Africa's annual gas production will expand by around 270 bcm over the forecast period.

The GECF GGM projects that production in Africa will grow from 230 bcm in 2017 to more than 500 bcm in 2040. This corresponds to a 117% increase and a CAAGR of 3.4% over the outlook period. Mozambique, Egypt and Nigeria will contribute the most to this expansion, with 24%, 20%, and 15%, respectively. Libya, Algeria, Tanzania, Angola and Cameroon are also expected to develop their upstream sectors and expand the capacity of their natural gas production. Nigeria, Algeria and Angola contributed substantially to African production from 2010 to 2017, while Libya and Egypt experienced negative growth.

Figure 4.12. Africa natural gas production by country (bcm), and associated CAAGR (2017-2040) (%)



Source: GECF Secretariat based on data from the GECF GGM

GECF countries have added substantial shares to their total gas production in Africa. Five GECF Member Countries are located in Africa (Algeria, Egypt, Equatorial Guinea, Libya and Nigeria). Collectively, they contributed approximately 206 bcm to marketed gas production in 2017 and accounted for slightly less than 90% of the total gas produced. With the rise of other market players in the region, namely Mozambique, Tanzania and Angola, the GECF market share is projected to decrease to 70% in 2040.

Algeria

Algeria is the largest natural gas producer in Africa. In 2017, the country's marketed gas production amounted to around 95 bcm. This corresponds to 42% of Africa's total marketed production and 2.6% of global marketed production.

Algeria has been challenged by field maturity in recent years but has succeeded in maintaining production. For example, production from the Salah gas field has already commenced. Gas production in the In Amenas field and associated gas production from the Gassi Touil and El Merk projects are being maintained at full capacity.

Other efforts have also been made to enhance the gas sector. The substantial Hassi R'Mel field has maintained production. Algeria has also enhanced rates of extraction in associated gas production. Other projects have also come online, such as Reggane Nord in December 2017. The Reggane Nord gas fields have been producing at full capacity of 8 mcm/d (2.8 bcm per year) since the beginning of 2018. This project is the first of its kind in south-western Algeria, but the region is expected to play a considerable role in Algeria's future gas production. The project is being undertaken by a consortium named Groupement Reggane Nord, with Sonatrach, Repsol, DEA Deutsche Erdoel AG and Edison holding shares of 40%, 29.25%, 19.5% and 11.25%, respectively. (4, 7)

As the third largest holder of shale gas reserves, Algeria has promising potential for developing shale. The country is expected to commence shale gas production in the medium-term, with announcements made that production will begin in the early 2020s.

Mozambique

Total gas resources in Mozambique are estimated at around 5500 bcm, making Mozambique the fourth largest natural gas resource holder in Africa. This huge potential of gas makes the country a very noteworthy player in the future of gas supply and trade.

The first natural gas discovery in Mozambique dates back to the 1960s when Pande was discovered, followed by Buzi and Temane. At the time, all three discoveries were deemed unsuitable for commercial development. Eventually, after several project studies, Sasol inked a contract to buy natural gas from Mozambique for a duration of 25 years through a proposed pipeline between Temane in Mozambique and Secunda in South Africa. This allowed Mozambique to emerge as an exporter and production became considerable after 2004, reaching more than 5 bcm in 2017. Most gas produced in Mozambique is exported to South Africa through the aforementioned 850 km pipeline.

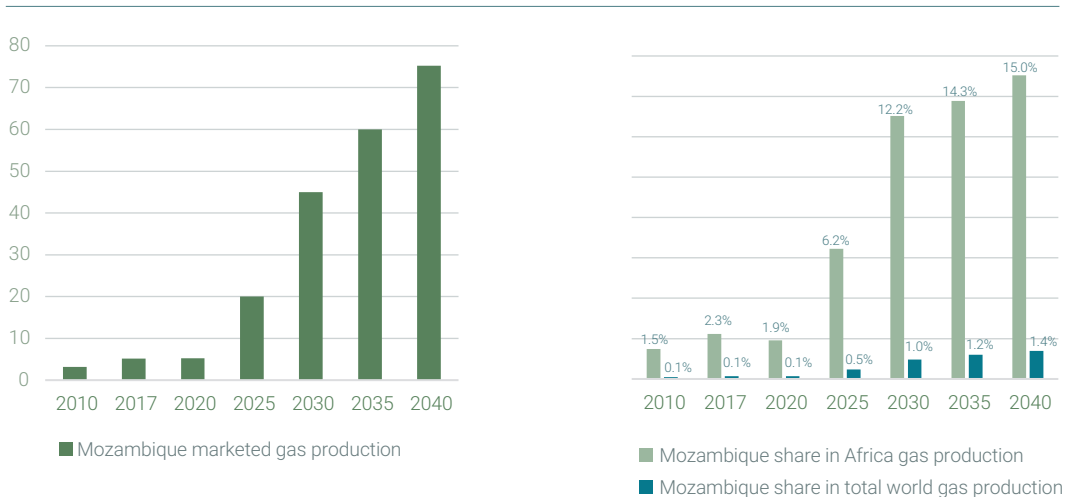
Mozambique and Tanzania are currently the only East African countries which are gas producers; both are expected to play an increasingly significant role in gas markets. Several international companies, such as Anadarko, Eni, Equinor, Petronas and Sasol are active in Mozambique's upstream sector. In the Rovuma Basin, for example, Anadarko operates Block 1 and Eni operates Block 4, and their progress has significantly increased mid-term production estimates.

Natural gas production in Mozambique has been driven by South Africa's commitment over the past 25 years to import gas produced in Temane. As Figure 4.13 shows, total production exceeded 5 bcm in 2017, but the outlook for gas production suggests a big increase on these figures. Currently, Mozambique accounts for slightly more than 2% of Africa's total gas production and less than 0.5% of global gas production.

As seen in Figure 4.13, the outlook for Mozambique's natural gas production is very promising. The latest modelling results from the GECF GGM suggest that Mozambique will add around 70 bcm to marketed production by 2040. That will bring Mozambique's share of African production up to 15%. This huge expansion is the result of planned projects, a

significant resource base, a reduction in production costs driven by advancement in deep-water techniques, and rising domestic and regional demand, as well as the future global call for natural gas.

Figure 4.13. Mozambique marketed gas production and market shares (bcm, %)



Source: GECF Secretariat based on data from the GECF GGM

Egypt

Egypt has made great progress in developing the Al Zohr and East Nile Delta projects, both of which commenced production ahead of schedule. The giant Al-Zohr field was discovered in mid-2015, and the first phase of production came online at the end of 2017. The second production unit of the Al Zohr project was announced to come online in the first quarter of 2018, bringing total production capacity from the field to 23 mcm/d or 8.4 bcm/yr. August 2018 was the next milestone in developing this mega-project, with capacity expanding to 49.5 mcm/d or 18 bcm/yr. This progress is expected to continue throughout 2019, boosting production capacity to 28 bcm/y by the end of 2019. Once the project is completed, it will allow the country to be relatively self-sufficient in natural gas and result in savings of around \$1bn/yr. The field contains an estimated 860 bcm of gas reserves and the operators are Eni (60%), Rosneft (30%) and BP (10%).

The Egyptian Ministry of Petroleum is aiming to maintain exploration efforts by launching bid rounds. The Egyptian state-run gas company, EGAS, and the Egyptian General Petroleum Corp (EGPC) are considering launching bids for 27 concession areas in the Mediterranean Sea. They have also signed a \$105m exploration contract with Italian Eni and another Egyptian oil company to undertake oil and gas exploration off the coast of northern Sinai.

In February 2018, BP started gas production from the first phase of the Atoll project, which is located in the North Damietta concession in the East Nile Delta. The project was completed seven months ahead of schedule and more than one third below cost.

Tanzania

Tanzania's estimated gas reserves are currently around 1.4 tcm. Most of those reserves are located offshore. The country started natural gas exploration more than 40 years ago, with the first discovery taking place on an island named Songo in 1974. Eight years later, a second discovery at Mnazi Bay was made in the Mtwara Region. The first discovered natural gas reserves were located both on- and off-shore and the first gas was produced in 2004. The Mnazi Bay discovery also contributed to the commercial production of natural gas two years later in 2006. These first two commercializations of gas discoveries in the country encouraged future exploration which has led to the considerable reserve base in Tanzania seen today. Currently, giant companies such as BG Group, Equinor, ExxonMobil and Ophir Energy are active in 4 blocks (1 to 4) where the fields such as Mnazi, Jodari, Tangawizi, Zafarani, Papa and Chewa have already been proved off the east coast of the country.

Tanzania started to produce gas on a commercial scale in 2007 when total marketed production amounted to more than 0.5 bcm. Since then production has increased at a moderate pace reaching more than 1.5 bcm in 2017. The long-term outlook for Tanzania's gas production is optimistic.

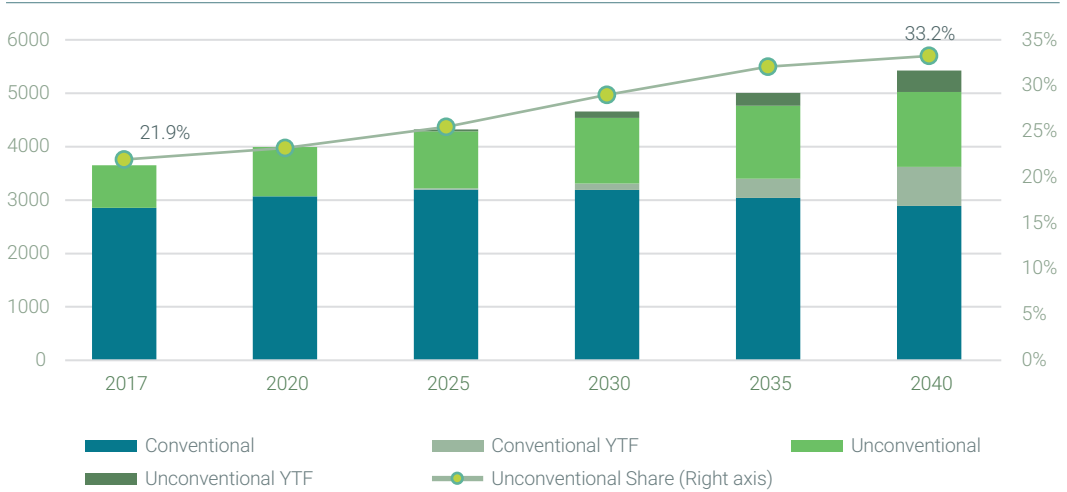
Currently, most of the offshore fields in Blocks 1 to 5 operated by BG, Ophir, Equinor and others are located up to 90 km off the east coast of Tanzania, at a depth of between 1000 and 1500 metres. In some cases, the fields are more than 2000 meters below sea level. Moreover, they are spread over an area of more than 200 kilometers. This situation makes production very costly and time-consuming and engenders increased risks regarding the technologies for extracting these deepwater resources and the gathering infrastructure. This is the main reason why expansion of gas production in Tanzania is forecast to face a period of delays, with prime development time expected to be sometime after 2030.

4.3 Unconventional and YTF gas production outlook

Advancement in shale gas extraction, as well as other types of unconventional gas resources, will result in a considerable reduction in production costs across the entire production chain. Figure 4.14 illustrates how the share of unconventional production develops over the outlook period. Currently, slightly more than one-fifth of total natural gas production is sourced from unconventional resources. This is mostly due to the significant production in the US and to a lesser extent in Canada, Australia and China. It is forecast that Argentina will contribute to the volume of unconventional production in the medium-term; in the longer-term Algeria, Oman, Russia and Saudi Arabia will become unconventional gas producers.

YTF unconventional resources will also take a vital role in developing this kind of production in some countries, specifically China, and to a lesser extent Saudi Arabia and Algeria. It is forecast that China will produce around 180 bcm from YTF unconventional resources in 2040, which will account for half of its total forecast production. Therefore we can see that the discovery and exploration of unconventional plays is a vital issue in expanding production in certain countries. It is forecast that slightly less than 1400 bcm of natural gas will be produced from existing proven unconventional plays by 2040 located in the US, Canada, China, Australia, Argentina, Oman and other producing countries. Also, around 400 bcm of production will be sourced from YTF unconventional resources by 2040.

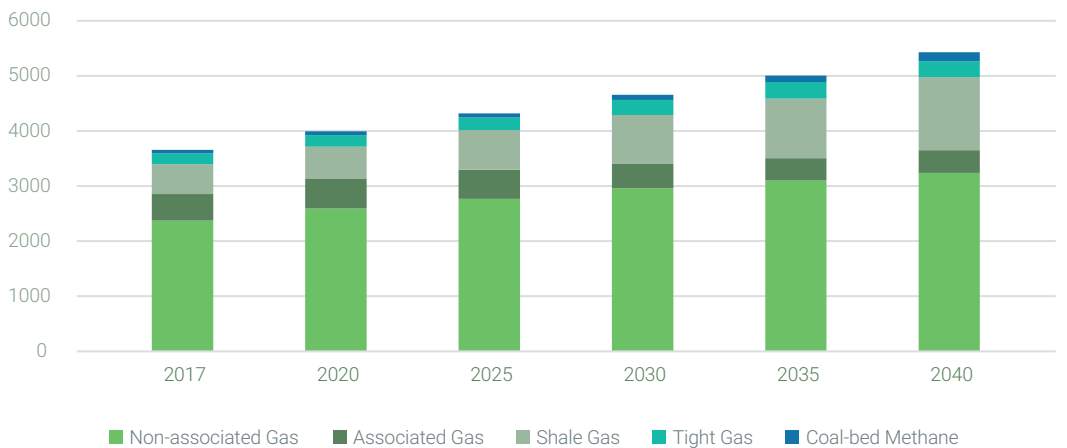
Figure 4.14. Global conventional and unconventional gas production (bcm, %)



Source: GECF Secretariat based on data from the GECF GGM

Shale gas development is the main factor behind unconventional expansion over the outlook period. Production from shale plays has been developing in the last decade especially in North America. Accordingly, these advancements in extraction technologies from shale such as hydraulic fracturing have resulted in reduced costs that enable economic production even with lower oil and gas prices. Figure 4.15 presents the outlook for gas production by type of hydrocarbon. Associated and non-associated gas is also illustrated by separate bars to show how these types of hydrocarbon are forecast to contribute to the total natural gas production over the forecast period.

Figure 4.15. Global gas production by type of hydrocarbon (bcm)



Source: GECF Secretariat based on data from the GECF GGM

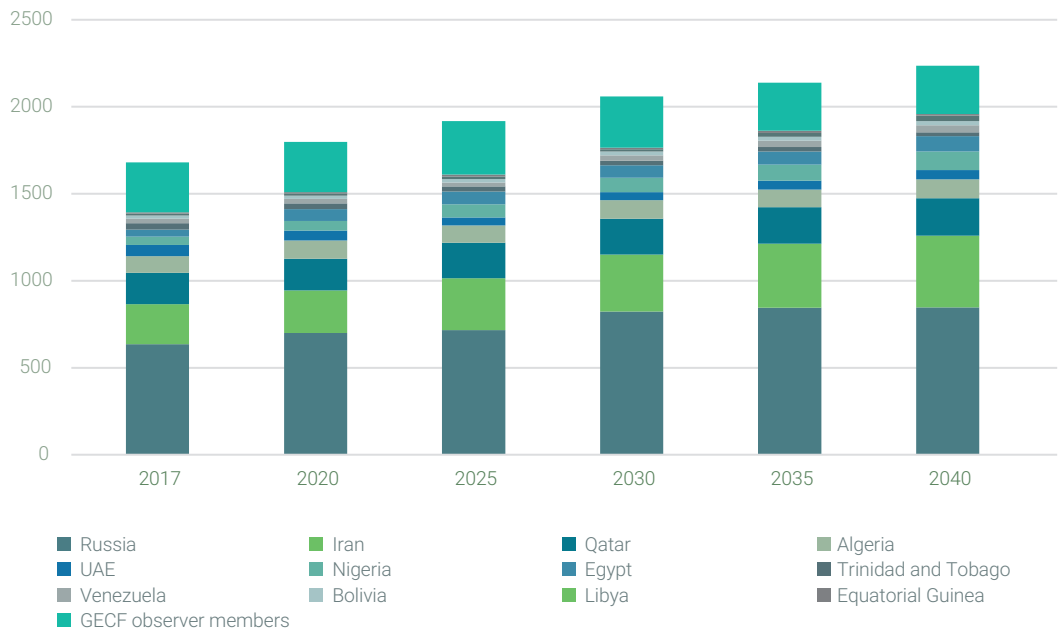
4.4 GECF Countries' gas production outlook

Most GECF countries will maintain or expand gas production capacity over the outlook period. We expect that total gas production from current GECF members will increase by one third, reaching approximately 2250 bcm by 2040. This translates to a 1.25% annual growth rate over the outlook period, which will enable the GECF to keep its share of global gas production at more than 41%.

Russia (31%), Iran (26%) and Nigeria (8.7%) are expected to be the largest contributors to incremental gas production volumes. Russia, Oman and Algeria are expected to contribute the most to unconventional gas production.

The Outlook also expects development in natural gas production among observer members. Iraq is expected to add more than 45 bcm in annual production by 2040, compared with 10 bcm currently. Iraq will contribute around 7% to the GECF's total incremental gas production over the forecast period. Azerbaijan and Kazakhstan are also forecast to increase their gas production by 2040.

Figure 4.16. GECF countries' gas production outlook (bcm)



Source: GECF Secretariat based on data from the GECF GGM



5

Gas Trade and Investment



Key findings

- The global gas trade is expected to have grown by 38.6% by 2040, at 1.4% per annum, and reached 1616 bcm, sourcing 29.8% of global gas demand in 2040.
- The LNG sector will be more dynamic, growing at 2.5% to 729 bcm, while pipeline trade will expand more slowly at a rate of 0.7% per annum to reach 887 bcm.
- The natural gas export capacity increases that started in 2016 and will continue until to 2025 are expected to be the largest seen so far. With rapid expansion of LNG capacity in the medium-term, the share of LNG exports will rise from its current 35% to 43% by 2030, and further to 45% by 2040.
- Out of 1616 bcm imported in 2040, 878 bcm will come from the GECF Members, which corresponds to a market share of 54%.
- By 2040, we expect most of the additional import demand for natural gas to come from Asia Pacific and Europe, with total increases of over 300 bcm and 150 bcm respectively.
- Currently, 27 countries are net exporters of natural gas, but this could rise to up to 35 countries by 2030, including many African countries, and this total could then be maintained through to 2040.
- To meet growing demand for natural gas and avoid energy crises by 2040, there is a need to invest \$7.9 trillion in additional natural gas production capacity and gas trade infrastructure.
- As production shifts to unconventional sources, the investment requirements from the gas industry will increase, with production projects aimed at the premium Asian market expected to break-even, even for the most expensive gas deposits such as unconventional gas production in China.
- LNG investment and capacity additions will slow down in the medium-term, but will continue for market entrants in Africa and Eurasia and for technologically developed projects in North America which can feed from a competitive gas market. Total investment into LNG and regasification is expected to accumulate to \$270 bn by 2040.

This chapter outlines the prospects for the global natural gas trade and investment perspectives. It contains two subchapters: the trade subchapter examines the outlook for pipeline and LNG flows, as well as the prospects for the necessary gas trade infrastructure over the outlook period, while the gas investment subchapter considers the financing requirements that underlie the Outlook's projections for supply and trade.

It is worth noting that the GECF GGM uses contract and infrastructure databases to prioritize the delivery of all volumes of natural gas that are already contracted (called "obligated trade"), although prioritization does not necessarily guarantee there is enough feed gas or transport capacity to deliver.

The remaining volumes of natural gas bound for export, if any, are offered on the market and priced according to a cost curve of production and shipping components. As demand is satisfied, the market clearing process establishes natural gas prices for gas-to-gas competition volumes, while considering all the imposed technical, financial and market restrictions. Re-export flows are not evaluated separately, and in this sense all trade flows reported are final destination flows.

It should be noted that there is strongly conflicting historical data provided by different sources. Unless otherwise stated, this chapter utilizes data from the GECF GGM, which is compiled on a country level and includes both inter-regional and intra-regional trade flows. Aggregate trade flow volumes are therefore higher than those based on a comparable database that only considers inter-regional flows (such as the one behind IEA's gas trade projections).

As for the investment requirements, the capital intensity factors that are used vary both by region and by facility type, based on the production entity database and gas trade node network of the GECF GGM.

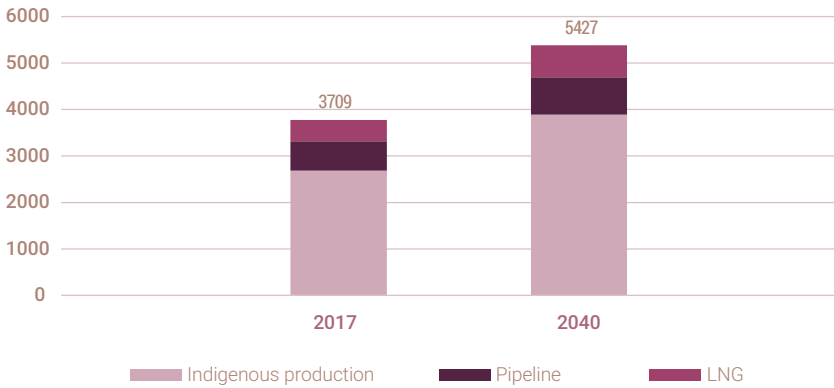
By 2040, the global gas trade is expected to grow by 38.6% to reach 1616 bcm, which corresponds to a growth rate of 1.4% per annum. We expect the LNG segment to be more dynamic, growing at 2.5% to 729 bcm, and pipeline trade to expand at a slower rate of 0.7% per annum to 887 bcm. The share of the GECF is expected to reduce from 62% to 54%, although this assumes no new members join the GECF.

The global investment requirements for 2018-2040 amount to \$7.9 trillion in 2017 prices, of which over \$7.5 trillion in 2017 prices is required for upstream gas projects as many countries, including GECF Members, are starting to produce from unconventional gas deposits at a higher marginal cost. This compares to \$2.9 trillion in 2017 prices invested in upstream gas over 1990-2017. The costs and capital intensity for the transport infrastructure, such as pipelines, liquefaction and regas plants, are expected to be in line with previous years.

5.1 Global gas trade

In 2017, out of 3709 bcm consumed to satisfy global natural gas demand, 1166 bcm was imported (including 720 bcm from GECF Members). The share of imports, comprising about 30% of total natural gas consumption, is projected to fluctuate slightly around this level for 2017-2040 (see Figure 5.1). According to the projection, out of 5427 bcm global natural gas demand in 2040, 1616 bcm would be imported (including 878 bcm from GECF Members).

Figure 5.1. Sources for global gas import (bcm)



Source: GECF Secretariat based on data from the GECF GGM

The demand and supply trends behind this outlook are different for each region. In Europe, the projected decrease in indigenous production would require more imports, as the demand for natural gas is expected to stagnate. At the same time, in Latin America, the assumed growth in indigenous production (such as Vaca Muerte field) would actually decrease the imported share while in Asia Pacific (mostly in Chinese unconventional gas plays), massive upstream investment would allow the share of imports to increase just slightly.

Trade infrastructure prospects

For the purposes of this Outlook, we consider only three types of natural gas export infrastructure: LNG facilities, export pipelines and regas facilities, all of which are key to shaping global gas trade flows. In the GECF GGM, infrastructure links points of production and consumption and is developed according to the assumptions outlined below.

The pace of development for LNG carrier fleets, both marine vessels and the emerging fleet of road trucks (especially in China), is expected to adapt to market needs and as such influences the gas trade only through cost elements. In recent years, road trucking of LNG has emerged as the last-mile infrastructure aimed at avoiding pipeline bottlenecks. However, due to very high marginal costs, this is expected to expand only for intra-country retail supplies (and predominantly in China, where it reached an estimated 18 mt in 2017).(1)

The global gas trade infrastructure will also see significant capacity increases in both pipeline and LNG by 2040. The global pipeline export network is expected to add over 450 bcm of capacity by 2040. This only refers to the capacity of pipeline projects which cross official state borders, and not to the supporting pipeline networks.

Of note is the record expected increase in pipeline export capacity from Eurasia to Europe and Asia, totalling 250 bcm, with half of that directed to the Asian market. When pipelines from the Middle East and Central Asia are included, the growth in pipeline capacity for the Asian market is expected to be more than 200 bcm, including intraregional export pipelines.

Project-wise, by 2030 this includes the completion of Central Asia-China gas pipeline D, the Turkmenistan-Afghanistan-Pakistan-India pipeline (TAPI), the Iran-Pakistan pipeline, and both routes for the Power of Siberia pipelines. In the same timeframe, for supplies to the European market, pipeline capacity is expected to be expanded with completion of the Southern Gas Corridor (via Transadriatic pipeline or TAP), Nord Stream 2 and 3, and the Turkish Stream pipelines. Also, several intra-EU gas pipeline interconnectors to be built in Europe are expected to make the European market significantly more integrated.

LNG infrastructure will see a much faster build-up than pipelines. An important factor which contributes to the faster development of an LNG export project is that it requires far fewer intergovernmental negotiations than a pipeline, and is much less affected by geopolitical tensions. For regas projects these drivers are even stronger.

Global regas capacity is estimated at 715 mtpa (970 bcm) as of 2017, as compared to 370 mtpa liquefaction capacity. By 2040, regas capacity is projected to grow to 1030 mtpa (1400 bcm) as liquefaction capacity grows to 695 mtpa (945 bcm).

The biggest regas capacity additions to 2040 are expected in Asia Pacific, while biggest liquefaction capacity additions are expected in the North America, Africa, Eurasia and Asia Pacific. This includes several 2018 project announcements such as Qatar's Ras Laffan facility expansion to 110 mtpa as well as the FID (final investment decision) taken on 14 mt of LNG Canada's first two trains. (2)

Global gas trade trends

By 2040, we expect most additional import demand for natural gas to come from Asia Pacific and Europe, with total increases of over 300 bcm and 150 bcm, respectively (see Table 5.1). This will be met in the medium-term via supply increases from Eurasia and the Middle East, and in the longer-term via new supply from Africa as well.

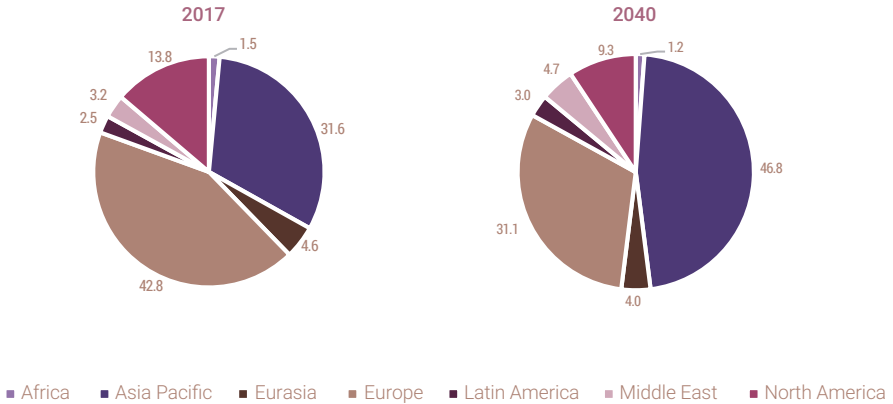
Asia Pacific will account for the highest share of global imports from 2030 onwards, while the share held by the European market will progressively diminish. By 2040, Europe's share of global imports will decline by 10 percentage points (see Figure 5.2).

Table 5.1. Global gas balances ([+] surplus, [-] deficit) (bcm)

Region	2017	2020	2030	2040
Africa	93	110	138	206
Asia Pacific	-197	-207	-354	-510
Eurasia	227	302	409	464
Europe	-278	-349	-408	-439
Latin America	6	-18	-19	-31
Middle East	104	139	203	203
North America	15	23	30	107

Source: GECF Secretariat based on data from the GECF GGM

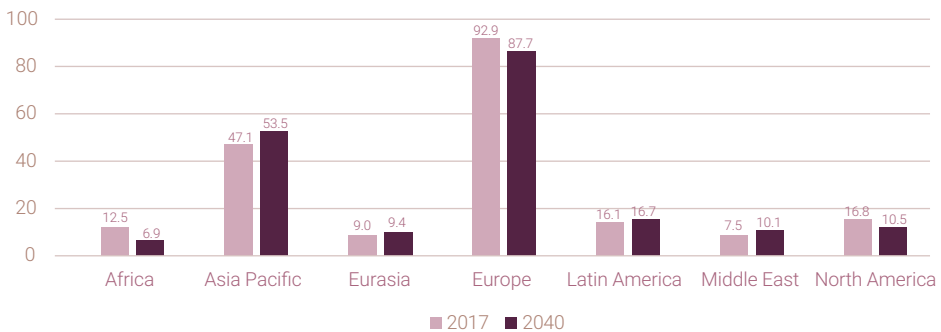
Figure 5.2. Share of natural gas imports by region, (%)



Source: GECF Secretariat based on data from the GECF GGM

However, in terms of share of imports in regional consumption, the biggest will be in Europe. Indigenous supply in the region is projected to follow a long-term decline and demand response will not be sufficient to reduce an almost 100% dependence on imports. The Latin American market, on the other hand, will be much less dependent on exports by 2040 as indigenous supply is expected to grow strongly. Vigorous growth in demand will increase the share of imports in the Asian region, while for the North American region supply growth will precipitate a further decrease in the share of imports (see Figure 5.3).

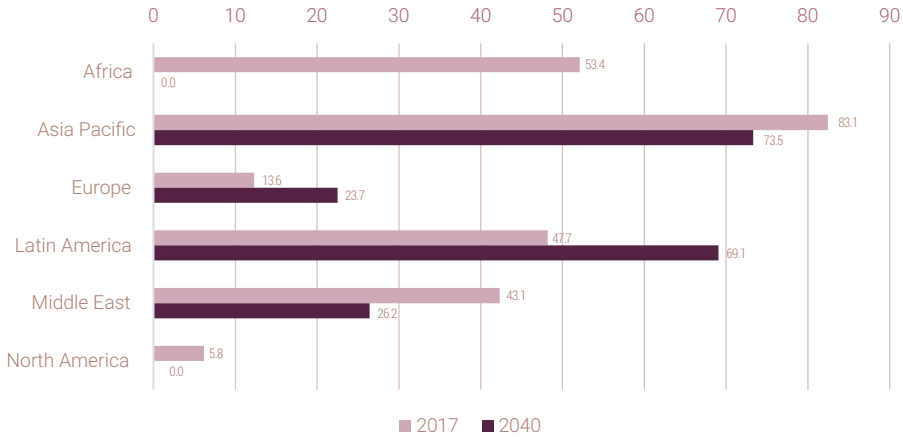
Figure 5.3. Imported volumes as a share of regional gas consumption (%)



Source: GECF Secretariat based on data from the GECF GGM

The main increase in LNG imports as a share of total gas imports will come from Asian market growth, as well as from increasing LNG supplies to Europe (see Figure 5.4). We project that most additional gas demand will be met by the increase in supply from the same exporters, thus the diversification of gas imports will increase in Asia and stay constant or decrease in the rest of the world.

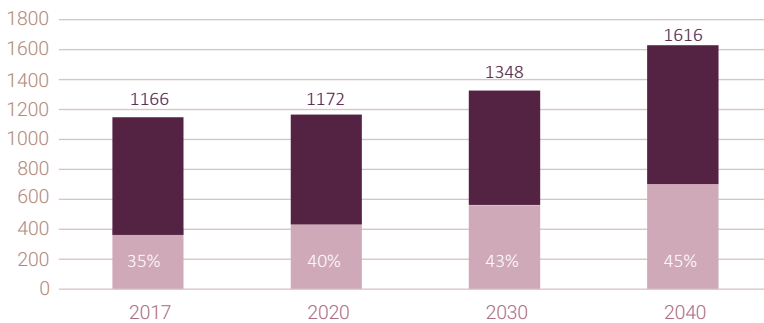
Figure 5.4. LNG's share of natural gas imports by region (%)



Source: GECF Secretariat based on data from the GECF GGM

The natural gas export capacity increases which started from 2016 and which will continue until 2025 are the largest ever seen. With rapid expansion of LNG capacity in the medium-term, the share of LNG exports will rise from its current 35% to 43% by 2030, and further to 45% by 2040 (see Figure 5.5). The highest transport capacity additions in LNG are expected to come from Australia, Qatar, Russia and the US, while most pipeline capacity additions are expected to be from Iran, Russia and Turkmenistan.

Figure 5.5. Global gas trade via pipeline and LNG (bcm) and share of LNG trade (%)



Source: GECF Secretariat based on data from the GECF GGM

Currently 27 countries are net exporters of natural gas, but up to 35 countries could become net exporters by 2030 and hold that status through to 2040, including several African countries. Of those, Table 5.2 lists the emerging gas exporters – countries with projected exports of more than 1% of global gas trade in 2040 that were net importers or exported less than 0.5% of global gas trade as of 2017. Egypt is included as it was net natural gas importer from 2014 to 2017, but it should be noted that for the previous ten years the country was a net natural gas exporter.

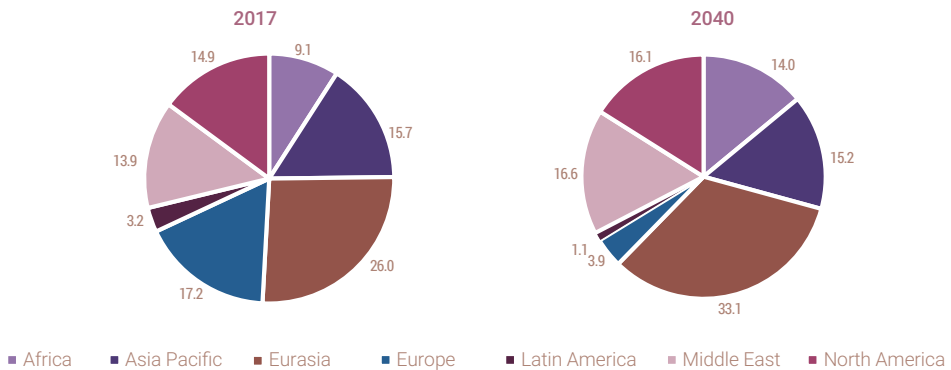
Table 5.2. Emerging net natural gas exporting countries as of 2040

Timeframe for country exports to exceed 1% share of global exports	Countries
2018 - 2020	Azerbaijan, Egypt
2020 - 2030	Angola, Iran, Iraq
2030 - 2040	Libya, Mozambique

Source: GECF Secretariat based on data from the GECF GGM

The number of importers is also projected to grow, with many countries forming so-called “niche markets”, typically with LNG imports well below 3 mtpa. Figure 5.6 outlines the regional composition of gas exporter countries. In terms of regions, the biggest increase in the global share of exports is expected in Africa, which will increase its share of global exports from 9% to 14%. Eurasia is expected to increase its share by eight percentage points, while Europe’s share of global exports is expected to drop from 17% to 4% over the next 23 years.

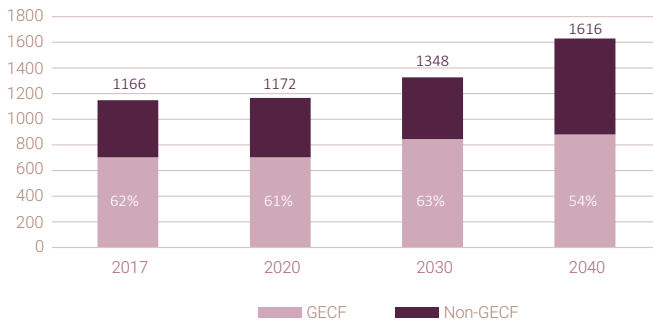
Figure 5.6. Share of natural gas exports by region (%)



Source: GECF Secretariat based on data from the GECF GGM

GECF countries are already supplying most of these growing markets (except for North America), and will increase their exports by an additional 200 bcm over the Outlook period (Figure 5.7). The GECF’s share of demand growth will potentially decrease as some new gas exporters emerge, especially in Africa. The GECF’s share is calculated assuming the same member composition, and would materially change should countries join or withdraw from the GECF.

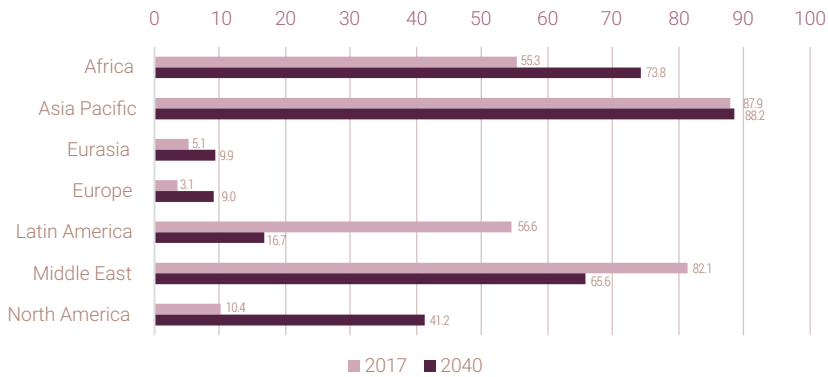
Figure 5.7. Global gas exports (bcm) and GECF share in global exports (%)



Source: GECF Secretariat based on data from the GECF GGM

The share of exports comprising LNG will see some structural shifts as exporters are increasingly turning to this technology to speed up capacity build-up (Figure 5.8). There will be significant structural changes in Eurasia as its share of exports increases to almost 10%, in North America, where it rises to over 40%, and in Africa, where new exports will be predominately LNG.

Figure 5.8. The share of gas exports supplied via LNG by region (%)



Source: GECF Secretariat based on data from the GECF GGM

Natural gas trade and pricing mechanisms

Investors and banks require predictable and manageable project revenue streams, and the pricing mechanism is one key component to this. The natural gas trade has historically featured long-term contracts with “take-or-pay” arrangements and oil-indexed natural gas export prices. Most of the industry still follows suit, although the push of European consumer countries to extend gas-to-gas competition to gas imports has led to a consistent expansion of hybrid gas pricing formulas. As of 2017, surveys (3) estimate the share of export volumes significantly linked to oil at 42%-70% in Europe, 84% in Asia and 70% in Latin America in 2017 (see Chapter 1).

Attempts at establishing gas trade hubs showed mixed progress globally in 2017. There was ample liquidity in European hubs (TTF trading volumes caught up the NBP in 2017-2018), with hub-traded volumes in 2017 more than ten times

greater than the level of natural gas consumption in the EU. However, over 80% of the trade is over-the-counter (OTC), and thus there is no indication of how the price was calculated in those trades and whether it was benchmarked to an exchange index or some hybrid index. Additionally, for south-eastern European countries, the role of hubs on the gas market is minimal.

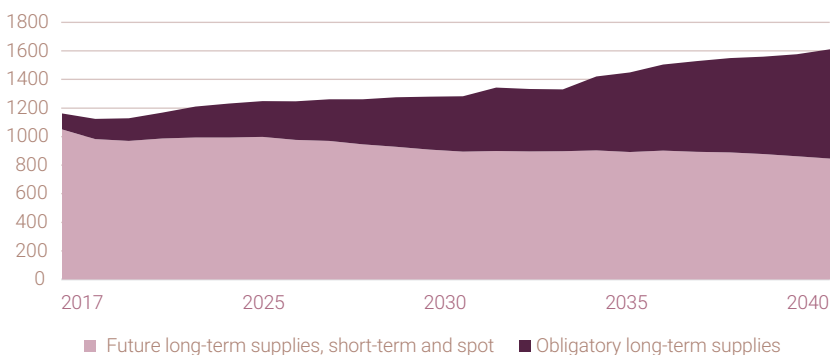
An Asian gas price benchmark is still absent, with the best benchmark candidates like the Japan Korea Marker (JKM) sometimes not having a single physical trade for a week or more in some months, despite trading volumes having expanded significantly over 2017. Also, as some experts have pointed out, the JKM index has design features that could make it problematic to use for physical settlement trades. With the absence of a reliable Asian benchmark, some customers tie the gas pricing formula to European hubs, creating a link to a market with largely different features.

For the LNG market as a whole, the global LNG body, the International Group of Liquefied Natural Gas Importers (GIIGNL) indicated (4) that in 2017, 27% of global LNG volumes were traded on a spot or short-term basis (up to four years), as compared to 28% in 2015. LNG trade accounted for about 35% of global gas imports as of 2017, and the IGU indicates that 72% of LNG trade flows are oil-linked.

Thus, while consumers are actively pushing producers to move to gas-hub pricing, it strongly depends on the regional market, and even for the most liquid ones outside the US, it is unclear whether significant export volumes could be reliably sold through gas-hubs on a day-to-day basis. The national gas companies in GECF Member countries (including Gazprom) are currently developing an integrated gas export marketplace, specifically designed to answer this question. Until these marketplaces or hub trading provide a price benchmark and market design that are both reliable and liquid, “take-or-pay” conditions remain the only contract instruments available to make gas projects bankable.

We expect that in the long-term, the increase in LNG exports and gas market reforms will precipitate a rise in uncontracted volumes. In 2018 about 87% of gas exports were supplied on the basis of existing contracts, but the share of supplies under existing contracts (obligated trade) will decline to 47% by 2040 (see Figure 5.9). This means additional natural gas export volumes will be offered on the spot and short-term market (non-obligated trade), even assuming existing contracts are renewed, extended or re-negotiated.

Figure 5.9. The volume of obligated vs. non-obligated trade (bcm)



Source: GECF Secretariat based on data from the GECF GGM

International trade prospects for the main regional natural gas markets

In total, 65 countries imported more than 0.5 bcm in 2017 and over 70 countries are expected to import more than that in 2040. The top 20 markets imported over 82.3% (960 bcm) out of the 1166 bcm imported in 2017 (see Table 5.3 in the Annex). These markets are expected to cover 73.5% (1188 bcm) by 2040. Concerning the two largest natural gas markets, the biggest Asian buyers imported 330 bcm in 2017 and that volume is expected to grow to over 600 bcm by 2040. The largest European buyers imported 360 bcm in 2017 and are expected import 345 bcm by 2040.

Table 5.3. Top 20 natural gas importer markets in 2017 and 2040

2017			2040		
	Country	Imports, bcm		Country	Imports, bcm
1	Japan	118.7	1	China	286.0
2	Germany	109.9	2	United States	91.7
3	China	94.6	3	Japan	90.5
4	United States	85.5	4	Germany	79.7
5	Italy	63.7	5	Turkey	63.2
6	Turkey	54.5	6	South Korea	62.0
7	South Korea	53.5	7	Italy	61.5
8	France	52.2	8	India	58.6
9	Mexico	50.3	9	Mexico	56.1
10	United Kingdom	48.3	10	France	47.5
11	Netherlands	36.2	11	Spain	40.9
12	Spain	32.0	12	United Kingdom	39.5
13	India	28.8	13	Malaysia	32.0
14	Canada	24.8	14	Netherlands	29.4
15	Chinese Taipei	20.3	15	Pakistan	28.0
16	UAE	19.2	16	UAE	27.6
17	Belarus	18.8	17	Chinese Taipei	24.6
18	Belgium	18.6	18	Belgium	23.8
19	Ukraine	15.0	19	Poland	23.3
20	Thailand	14.7	20	Bangladesh	22.3

From the perspective of exporting to regional markets, the outlook for European and Asian gas markets will be presented in more detail, given their dominant role as importers. While imports to Canada, Mexico and the US comprised about 13.8% (160.6 bcm) of global imports in 2017 and are expected to comprise 10.2% (147.8 bcm) of imports in 2040, these markets are largely isolated as a result of geographical and political factors. Local pipeline systems connect the US, Canada and Mexico, while LNG imports into the region, including those from GECF Members (Equatorial Guinea, Nigeria, Peru and Trinidad and Tobago), amounted to less than 4 bcm in 2017 and are expected to cease after 2033. For the purposes of this subchapter, supplier countries for each market are listed by order of expected supply volumes.

The Asian natural gas market

There are new national markets emerging in Asia, including Bangladesh and Indonesia, which do not yet import gas but are expected to account for over 30 bcm by 2040. Some markets, such as Malaysia and Pakistan, will become full-fledged importers instead of niche markets and are expected to add 45 bcm by 2040. However, most new imports, will be taken by China, totalling around 200 bcm. For India, infrastructure bottlenecks and energy policy uncertainty will most likely limit the rise of natural gas imports.

The gas trade is evolving in the Asian market and this will affect trade projections. The US is actively pushing for the new rules in the Asian gas market via the Asia EDGE (Enhancing Development and Growth through Energy) initiative and Japan is making efforts to build regas facilities in Asia. US-China trade tensions have already led to a 10% tariff on the US LNG and significant non-tariff restrictions. Meanwhile, new players will be entering the market as projects in Russia, Mozambique and the US will ramp up LNG production, and new pipelines from Iran, Turkmenistan and Russia will be completed.

China

Imports into China are projected to increase by over 240 bcm, from 87 bcm in 2017 to over 330 bcm in 2040. The increase is expected to be transported both via pipeline (over 110 bcm) and LNG (over 130 bcm), mainly from Russia, Qatar, Turkmenistan and Australia, but also Malaysia, Iran, Mozambique, and Indonesia.

The Chinese market currently lacks flexibility, as internal pipeline and storage infrastructure is underdeveloped. There is a planned increase in storage capacity in the country to over 15 bcm in 2020 and 35 bcm in 2035, reaching 5.9% of consumption compared to 4.9% as of 2017. While there are reports that Sinopec's storage projects are more ambitious and could provide storage for over 65 bcm, this would still provide just 9.2% of consumption, compared to almost 20% for the European gas system. The persistent lack of flexibility could lead to lower utilization rates in pipeline projects as the gas will have nowhere to go once it has arrived in China. In several cases, a rapidly increasing LNG trucking fleet can make up for the lack of flexibility in the pipeline system, but this will further increase the price of LNG. In this Outlook, we assume the flexibility of national pipeline and storage systems will be improved to levels consistent with the full utilization of future pipeline and LNG projects.

The Chinese gas market is also characterised by ambitious projections for unconventional resources, which are more costly to produce and geologically challenging (see Chapter 4 for details). Meeting the government target of doubling output to 30 bcm by 2020 will be difficult and so far the gas produced is very expensive (see Section 5.2). If indigenous production from unconventional sources is limited, more imports will need to be sourced to satisfy growing natural gas demand.

India

India is expected to more than double natural gas imports, from 27 bcm in 2017 to over 62 bcm in 2040. The increase in imports into India is projected to be sourced from both pipeline (about 16 bcm) and LNG (over 17 bcm), with total imports coming mainly from Mozambique, the US, Qatar, Iran, and Russia. With a strong build-up in indigenous production (mainly sourced from deepwater, see Chapter 4), import growth will be undercut after several production projects ramp-up volumes after 2030.

Additional pipeline supply of over 25 bcm will be transported by pipelines from Iran (via Oman) and Turkmenistan (via Pakistan and Afghanistan). The TAPI pipeline is currently under construction, and more capacity will be in place if planned pipeline projects from Myanmar and Bangladesh are launched. Talks of a giant 90-bcm Iran-Pakistan-India (IPI) project have stalled and the project is expected to be limited to an Iran-Pakistan pipeline for the time being. Internal connectivity will probably be provided by the JHBDPL project that will connect the western gas network with eastern Indian states and create gas distribution networks in eastern cities.

While regas capacity will ramp-up quickly, it is the connectivity that could prevent gas imports from reaching final consumers. Total regas capacity in India is expected to top 100 mtpa by 2020 and provide gas to the whole coastal area.

Japan

In Japan import volumes are projected to decline from 111 bcm in 2017 to less than 90 bcm by 2040 as a result of reduced demand. All imports come in the form of LNG, mainly from Australia, the US, Russia and Qatar. No additional pipeline or LNG infrastructure is likely to be constructed, as there is ample regas capacity in Japan (topping 190 mtpa or 255 bcm).

Japan is attempting to become a natural gas hub in the Asia Pacific region, and is planning to utilise the engineering and marketing capabilities of regional gas companies. These efforts were unveiled this year in a \$10 billion program to support regas and pipeline infrastructure in emerging gas importing countries. The mandates of NEXI (Nippon Export and Investment Insurance) and JOGMEC (Japan Oil, Gas and Metals National Corporation) were changed, allowing for export credit support for infrastructure projects.

Japan is also at the forefront of efforts to change the Asian LNG market structure in favour of shorter-term gas-to-gas competition. Japan's leading LNG importer company, JERA, spearheaded efforts in cooperation with CNOOC and KOGAS to create the world's largest gas importer consortium. While it is unlikely that Japan will use competition law to violate existing long-term contracts (like European countries did in 2011), the Japan Fair Trade Commission (JFTC) prohibited destination clauses starting from 2016. Japanese importers have announced that they will not accept destination clauses in the new contracts from 2019, enabling them to redirect the shipments globally and facilitate trading, including in the Asia Pacific region where shipments are still largely bound by destination clauses. Concerning the contract duration, the biggest LNG importer, JERA, has announced that it has a target below 42% for long-term contracts by 2030.

South Korea

South Korea's natural gas imports are expected to increase from 50 bcm in 2017 to over 66 bcm in 2040. All imports will be in the form of LNG, mostly from Qatar, Australia, the US and Russia.

There is an ongoing negotiation process between Russia, North Korea, South Korea and China on the Transkorean pipeline. However, any progress on the pipeline requires significant diplomatic warming between North and South Korea, as well as North Korea and the US, and includes complex solutions in gas, oil, railroad, electricity and telecommunications infrastructure.

With a regas capacity of about 90 mtpa (122 bcm), South Korea is well-supplied with LNG import infrastructure, and no major additions are expected for the time being. More domestic and probably small-scale import infrastructure will be needed if the planned program to stimulate city and industrial gas consumption is to be successful.

The European natural gas market

In Europe, natural gas imports are expected to grow slowly because indigenous production will decline over the outlook period and the accelerated penetration of renewables will slow down additional gas demand. With a lot of new pipeline capacity coming online before 2025 and ample regas capacity, most European countries are not planning significant additions up to 2040, with total expected additions of 33 mtpa (45 bcm), in addition to the existing 143 mtpa (195 bcm) of capacity. With a lot of competing projects proposed, some of the planned regas capacity might be cancelled.

While the imports are slowing down, a market transformation is still ongoing. European gas pipeline infrastructure upgrades, both recent and planned, will enable markets to be more integrated. Most upgrades are not limited to a single European country, but also connects main consumer markets, such as Germany, Italy, France and the UK. Market transformation also includes new gas hub and competition regulation that has severely impacted existing contracts, pending resolution between several natural gas exporters and the European Commission. The resolution (5) already mentions the removal of any destination and resale restrictions, and enables the transfer of export contracts to the "competitive Continental Western European gas markets." This means indexation to the European gas hub-based prices and granting the European Commission authority over price mechanisms and EU arbitration.

Germany

German natural gas imports are expected to decline by a quarter, from 94 bcm in 2017 to 75 bcm in 2040, as demand falls as a result of direct electricity imports and higher penetration of renewables. All gas is expected to be imported via pipeline, mainly from Russia, with the exception of sporadic LNG purchases.

Pipelines will dominate gas imports, at least up to 2040, due to the cost advantage. The gas transported via the Nord Stream 2 pipeline (55 bcm) is expected to be online by the end of 2019 and will compensate for the fall in indigenous production and production declines from the Netherlands, once the challenge posed by the transition from low-calorific to high-calorific gas is overcome. In 2018, German and European connectivity was greatly increased because the TENP (The Trans Europa Naturgas Pipeline) and Transitgas pipelines were made bidirectional, enabling reverse flows from Italy to Germany and France. This gives the option to transmit gas from the Southern Gas Corridor to German and French gas markets.

A German LNG terminal near Hamburg with a capacity of 2-3.5 mtpa (5 bcm) has been mooted, but the FID has not yet been taken, even though RWE already contracted more than half of the volume. If built, this project will likely remain the only German regas terminal, as the country is already well-supplied with piped gas from Russia and Norway.

Italy

Imports into Italy are expected to slightly decrease, from 63 bcm in 2017 to 58 bcm in 2040. Around 90% (60 bcm) will be supplied by pipeline, mainly from Algeria, Russia, Azerbaijan, Iraq and Qatar.

With an existing 11 mtpa (15 bcm) of regas capacity and strong local opposition to new projects, additional capacity of up to 24 mtpa (32 bcm) will likely be suspended or scrapped by 2040. There are several prospective pipelines in Southern and Eastern Europe that are expected to greatly increase gas market flexibility in Italy and in Europe, in general.

First, there is the reverse of the Tarvisio and Passo Gries into Switzerland and Austria, which links the PSV (Punto di scambio virtuale) gas trading hub to several others, including the TTF. Second, there is a new 10-bcm TAP pipeline scheduled for 2020 to bring TANAP and Turkish Stream gas to Southern Europe. There are plans for this to be expanded to 20 bcm in the future. There has also been some progress on the ITGI (Interconnection Turkey-Greece-Italy) pipeline but the FID has still not been taken.

France

Imports into France are expected to slightly increase, from 44 bcm in 2017 to 47 bcm in 2040, mainly from Nigeria and Russia. The wild card for the imports might be unconventional gas exploration, which is currently facing very strong public opposition.

In the import flow structure, LNG is expected to take over from pipeline supplies, going from 25% in 2017 to 72% of imports by 2040. So far, French companies have announced plans to expand the existing 12 mtpa (16 bcm) of regas infrastructure to accommodate for increasing LNG demand. These plans assume an additional 10 mtpa (13 bcm) of regas capacity in the medium-term.

The French gas strategy requires integrating the national market and creating a single marketplace by the end of 2018. This has been achieved, with the exception of infrastructure upgrades that involve low-to-high calorific value conversion for respective pipelines. The 8-bcm MidCat pipeline project has been stalled. This would allow the connection of the southern French market with Spain, but no FID has yet been taken.

United Kingdom

The UK's natural gas imports are expected to decline from 48 bcm in 2017 to 39 bcm in 2040, as energy transition and energy efficiency squeezes demand for natural gas. The share of LNG imports is expected to grow from 13% in 2017 to 46% in 2040, as pipeline imports from Norway yield to diversified LNG supplies, mainly coming from Angola towards 2040. The wild card for imports might come if unconventional exploration and production efforts (resumed in 2018 after a seven-year pause) may lead to higher levels of indigenous production.

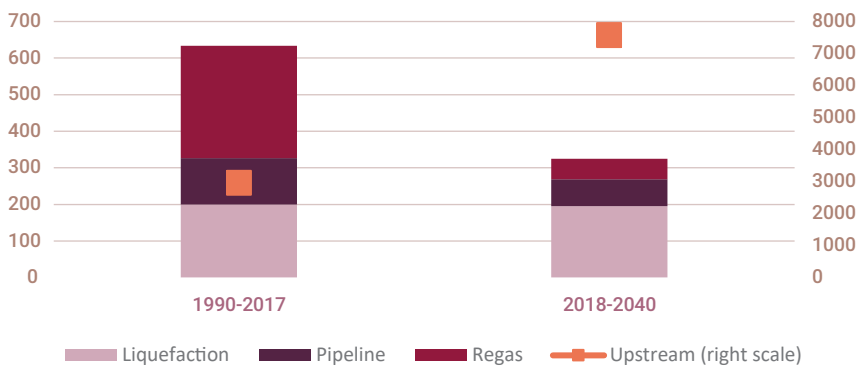
With a regas capacity of 35 mtpa (48 bcm), the UK is well-positioned to receive additional LNG cargoes in the future. An additional 7 mtpa are under consideration but no FID has been taken. The UK has increased flexibility via a system of pipeline connections to European gas infrastructure but currently lacks adequate gas storage capacity following the decommissioning of the Rough storage facility, which brought the UK's storage capacity to below 4% of consumption. This level of national flexibility is insufficient, and most flexibility will come from LNG imports, through European interconnectors. So far, there are no FIDs for the projects that could replace defunct Rough storage.

5.2 Gas investment

To meet growing demand for natural gas by 2040, the GECF calculates that \$7.9 trillion is needed to invest in additional natural gas production capacity and the aforementioned gas trade infrastructure. This subsection details the estimates for the upstream and infrastructure investment required. All the subsequent investment estimates are provided at constant 2017 prices and are not discounted.

Although most of this \$7.9 trillion earmarked for gas investment is needed in the natural gas exploration and production sectors trade infrastructure still requires investment of over \$325 bn in 2017 prices (see Figure 5.10) by 2040. The gas investment outlook is thus shaped both by trade infrastructure and upstream investment needs.

Figure 5.10. Global gas industry investment by purpose (2017 USD bn)

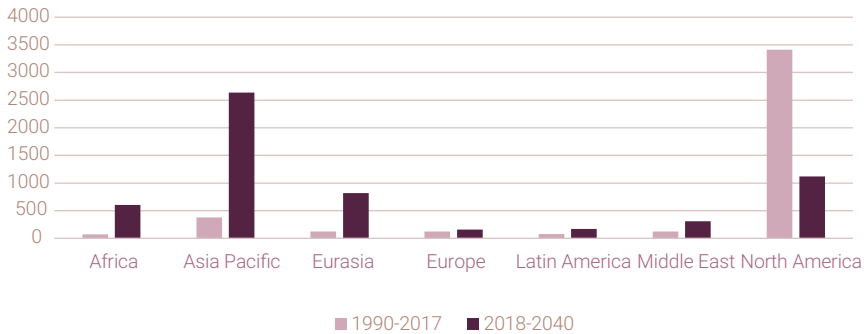


Source: GECF Secretariat based on data from the GECF GGM

As production shifts to unconventional sources, the investment requirements from the gas industry will increase both in and outside the GECF. The developments already planned in Algeria and Mozambique will drive African investment (see Figure 5.11) while, after 2035, capital intensity for projects in Siberia is also expected to rise as the development of unconventional sources is anticipated.

Eurasian investment will additionally pick up being coupled with more pipeline investment, while in Asia Pacific and North America liquefaction capacity and unconventional production will be the main drivers of investment.

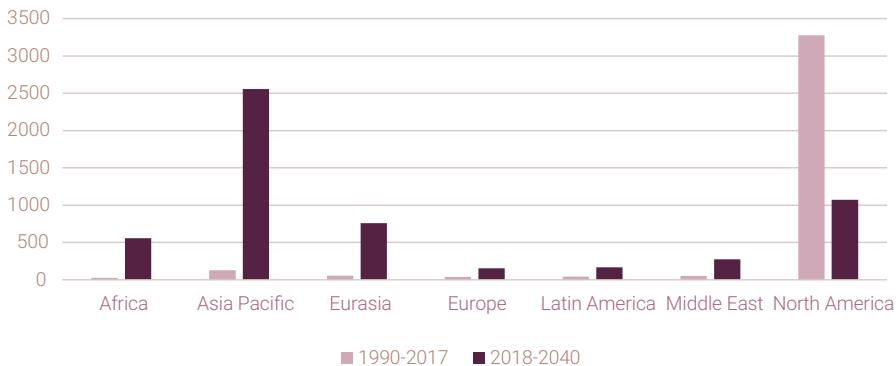
Figure 5.11. Regional structure of gas industry investment (2017 USD bn)



Source: GECF Secretariat based on data from the GECF GGM

Production projects aimed at the premium Asian market will be the most attractive, and are expected to break even for even the most expensive gas deposits such as unconventional gas production in China, which has the four times the capital intensity of US unconventional gas production (see Figure 5.12). It is worth noting that in China, energy security considerations will drive production development in addition to the Asian gas premium.

Figure 5.12. Regional structure of investment into production (2017 USD bn)

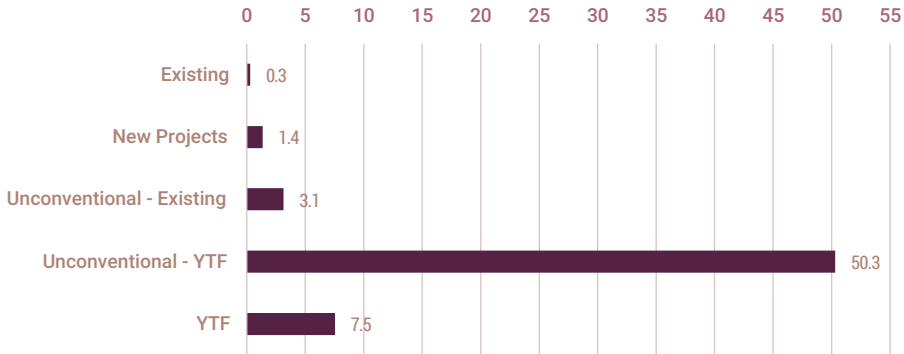


Source: GECF Secretariat based on data from the GECF GGM

Figure 5.13 displays average capital intensity for different sub-types of production projects, calculated as total capital requirement (not discounted) in constant prices per the amount of production over 1990-2040. It does not reflect production costs but only the capital requirement to put the respective projects online.

Production projects in the future will have a higher capital intensity as production will shift from onshore conventional

Figure 5.13. Capital intensity estimates of gas production projects by type of field, 1991-2040, (2017 USD/mmBtu, not discounted)



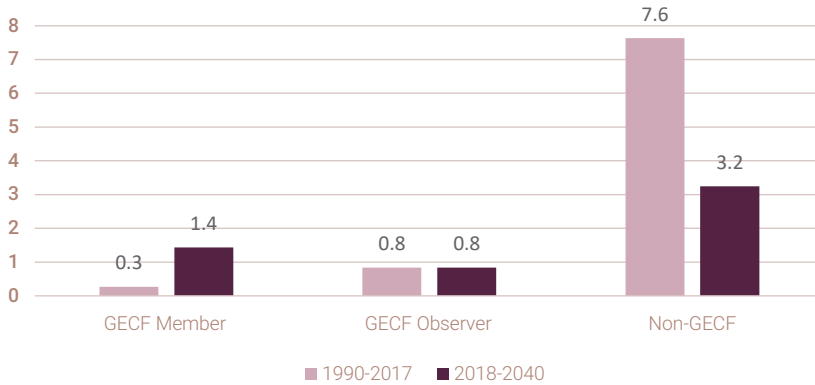
Source: GECF Secretariat based on data from the GECF GGM

to offshore and unconventional sources. This is reflected in the increase in average capital intensity for gas projects for 2018-2040, which will reach \$4.2/mmBtu compared to the \$2.4/mmBtu (both in 2017 dollars, not discounted) observed for 1990-2017.

While a current capital intensity estimate for unconventional YTF resources of \$50.3/mmBtu (in 2017 dollars, not discounted) might seem prohibitive, it is generally in line with the logic of upstream development. The capital costs of developing most existing unconventional gas projects used to be prohibitive historically because of huge fixed costs and long infrastructure break-even timescales. However, as the fixed costs are borne and upstream infrastructure is put in place, unconventional gas resources become cheaper to develop in some countries. For instance, in 1991-2017 existing unconventional fields had an estimated overall capital intensity of \$18.2/mmBtu, while producing on those projects for 2018-2040 would only cost \$0.7/mmBtu (both in 2017 dollars, not discounted).

As leading gas producers, GECF countries are expected to retain cost leadership even as supply shifts to unconventional and offshore sources. Figure 5.14 details the cost of investment per unit of overall gas production. The advantage of projects in the GECF countries is that they already have gas infrastructure in place, and thus upstream development in the same deposits requires much less investment than for most producers outside the GECF which have not yet developed a costly gas infrastructure.

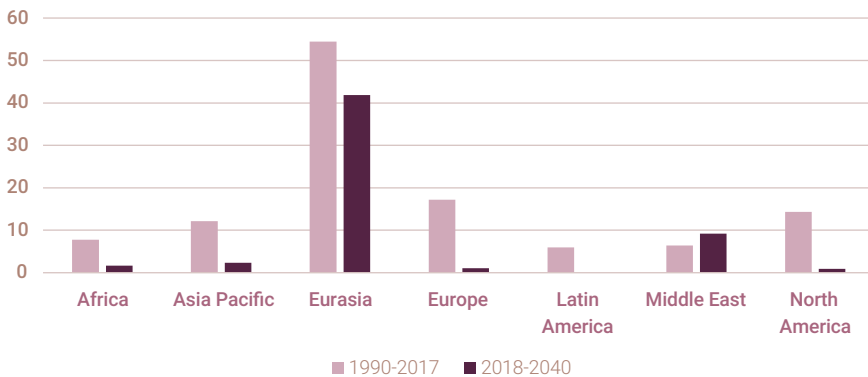
Figure 5.14. Capital intensity of gas production, (2017 USD/mmBtu, not discounted)



Source: GECF Secretariat based on data from the GECF GGM

The expansion of the gas trade infrastructure will see more LNG facilities in every region, while pipeline expansion will be focused in Eurasia and the Middle East. This current edition of the Outlook marks a moment when a significant part of investment into most Eurasian pipelines (SCP, TANAP, Nord Stream 2, Turkish stream and the Power of Siberia) has already been made, but supply from those projects is just beginning to flow (Figure 5.15). That is partly why future planned Eurasian pipeline investment is \$10 bn behind the historical value, amounting to just \$57 bn.

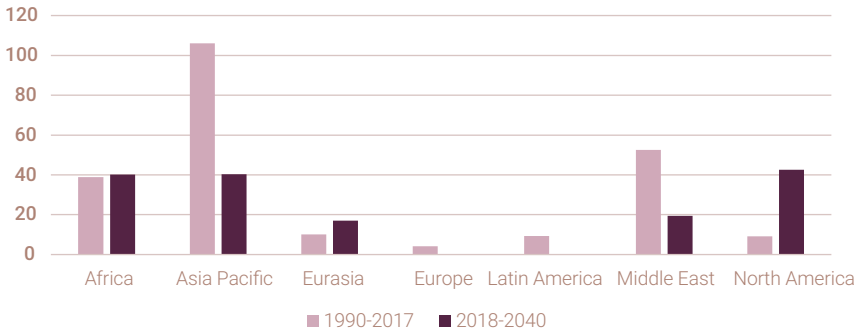
Figure 5.15. Regional structure of pipeline investment (2017 USD bn, not discounted)



Source: GECF Secretariat based on data from the GECF GGM

Investment into liquefaction and regas facilities will continue at a more modest pace. As additional piped gas enters Asian markets, the wave of liquefaction projects re-scheduled for the early 2020s will be further rescheduled, and cost and placement efficiency will increase as FSRU and FLNG penetration grows. LNG investment and capacity additions will continue for market entrants in Africa and Eurasia, as will technologically developed projects in North America with a feed-in access to a competitive gas market, amounting to \$325 bn globally by 2040.

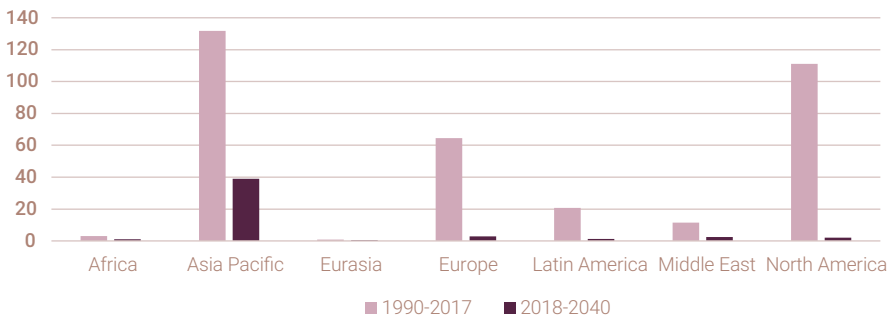
Figure 5.16. Regional structure of liquefaction investment, (2017 USD bn, not discounted)



Source: GECF Secretariat based on data from the GECF GGM

As for regasification, the penetration of FSRU and, probably, FLNG power stations is expected to increase the efficiency of investments, reducing the need for much construction. Regas facilities are much less capital intensive than all the other infrastructure, and most regas construction in Europe and Asia has already been completed, leaving investment in new regas facilities to the emerging economies with a preference for FSRUs, meaning very low capital costs. These factors lead to a low level of prospective regas investment up to 2040.

Figure 5.17. Regional structure of regasification investment (2017 USD bn, not discounted)



Source: GECF Secretariat based on data from the GECF GGM



6

Alternative Scenarios



Key findings

- GECF has developed a Carbon Mitigation Scenario (CMS) and a Technology Advancement Scenario (TAS) that reflect accelerated energy transitions when compared to the Reference Case Scenario (RCS). TAS+ scenario assesses the combined effects of carbon mitigation policies in the CMS and technology progress in the TAS.
- Results from these scenarios' modelling suggest that natural gas could increase its share and play a central role in achieving the energy transition, by substituting for coal, being a partner to renewables and improving energy efficiency.
- By 2040, natural gas and renewables shares will respectively reach 27.7% and 7.8% in the CMS, increasing from 26% and 6% in the RCS. The consideration of technology advancement, as highlighted in the TAS+, will further improve these shares to 28.5% and 9.3% respectively. Conversely, coal's share is anticipated to decline strongly to 16.6 % in the CMS and 14.3% in the TAS+.
- TAS+ highlights the non-negligible reduction potential of primary energy demand, estimated at around 1000 Mtoe by 2040. The global cumulative energy saving over the 2017-2040 period compared to the RCS is estimated at more than 9500 Mtoe.
- The power sector is the main contributor to the global demand reduction in the CMS due to higher carbon prices and an improvement of average energy efficiency of power generation with the penetration of gas-fired plants and renewables. Average energy efficiency improvements in the CMS are due to the substitution effect in the power sector rather than technology advancement.
- Efficiency improvement related to technology progress in buildings, residential and commercial appliances, transport, power and industry sectors will drive an additional reduction in total primary energy demand in the TAS+ compared to the CMS. This reduction will offset the upside effect on energy demand due to increased electrification of final energy consuming sectors.
- Energy-related CO₂ emissions are expected to reach 34.2 GtCO₂ in the CMS by 2040, decreasing by more than 4 GtCO₂ compared to the RCS, and this level will drop to around 32.3 GtCO₂ in the TAS+.
- In the CMS, the bulk of emissions reduction is driven by changing the power generation mix with more renewables and natural gas penetration. The additional emissions decrease in the TAS+ is mostly achieved in industry and buildings, due to large energy efficiency improvements and electrification of these sectors. Aggressive electrification of final sectors due to technical enhancement and digitalization in the TAS+ will increase the prospects of electricity generated and then reduce the role of power in mitigating CO₂ emissions.

6.1 Background

Energy systems around the world are engaged in a transition process, which is reflected in profound structural changes in the ways in which energy is produced, supplied and consumed. Increasing international commitments aimed at achieving the 2030 Sustainable Development Agenda and the Paris Agreement are driving this transition, as these global frameworks aim to address sustainability challenges and climate change concerns through enhanced policy actions.

There is no single pathway defining the energy transition. Countries have different specificities in terms of energy resources, demand dynamics, and development conditions, including access to technology and financial resources. Countries are also facing various challenges and opportunities that determine which approaches they take in terms of motivation, objectives, policy choices and governance. Taking these differences into account, it is more appropriate to talk about energy transitions in the plural (1).

The momentum behind energy transitions brings large uncertainties to the future energy landscape, and can be translated into different energy development pathways resulting from various driving forces at national, regional and global levels. Understanding these forces, as well as their potential impact on natural gas resources, is of paramount importance for the GECF. One of the key questions that needs to be investigated in this regard is: what role will natural gas play in energy transitions?

The GECF has developed two alternative scenarios that reflect accelerated energy transitions when compared to the Reference Case Scenario (RCS). The Carbon Mitigation Scenario (CMS) aims to assess the effects that strengthened CO₂ mitigation policies have on global energy mixes. The Technology Advancement Scenario (TAS) takes into account expected progress in energy technologies across the energy supply chain.

Methodology

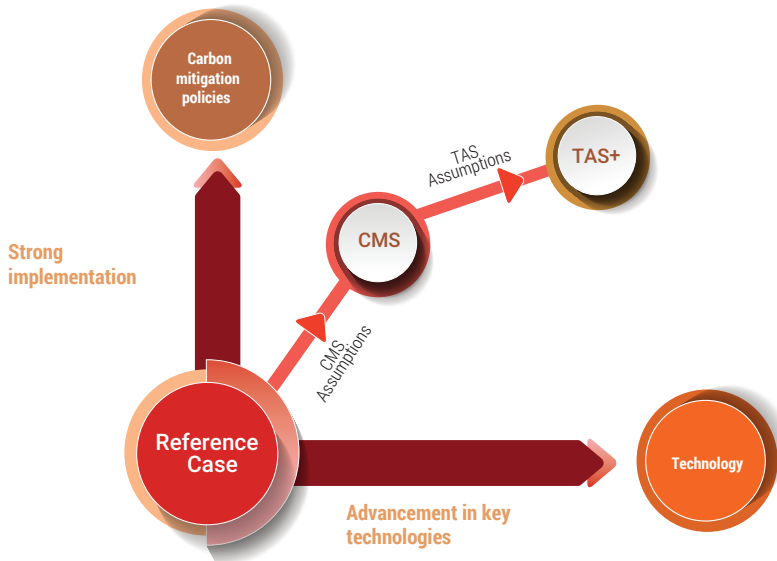
The approach used to assess these two scenarios is to focus on critical parameters and driving forces that will support the changes in each scenario compared to the RCS. The CMS examines two shifts that are considered potential outcomes of carbon mitigation policies: i) a changing power generation mix that results from policy support for less carbon-intensive fuels and renewables and, ii) increased electrification in the transportation sector as a result of policy support for electric vehicles. In this scenario, technology advancement will mostly follow the current trends.

The TAS focuses on technological progress in areas that are considered key to deployment potential. Technological progress is particularly reflected in the development of energy efficient technologies and cost improvements.

In order to contrast the two scenarios, compare their impacts on the global energy mix and assess their effect on the role of natural gas, the TAS builds upon the assumptions applied in the CMS, while the CMS builds upon the assumptions applied in the RCS (see Figure 6.1). This approach allows us to analyse the combined effects that carbon mitigation policies and technology advancement have on the energy mix and natural gas mix in particular. The scenario generated from both CMS and TAS assumptions, when subsequently applied to the Ref. Case, is called the TAS+.

Figure 6.1 illustrates the proposed approach and demonstrates how the two scenarios deviate from the RCS (2). It considers the two strategic dimensions that reflects critical uncertainties and shape scenario assumptions, namely carbon mitigation policies and technology. Table 6.1 highlights some of the main assumptions that are factored in both the CMS and the TAS.

Figure 6.1. Illustrative representation of the CMS and TAS+ compared to the GECF RCS



Source: GECF Secretariat

Table 6.1: Global assumptions in CMS and TAS

	RCS	TAS+*	
		CMS	TAS
Macro-economic drivers	<p>World real GDP growing 3.4% yearly on average over the outlook period</p> <p>Southeast Asia and India will remain the engines for global growth up to the 2040s, despite deceleration to over 4.0% by 2040 for Southeast Asia and over 4.9% for India in PPP terms</p> <p>Balanced growth for developed economies will continue as their growth is already driven by increasing labour productivity</p>	Macro-economic drivers are assumed to be at the same levels as in the RCS	Macro-economic drivers are assumed to be at the same levels as in the RCS
Carbon price assumptions	<p>Carbon pricing is expected to see progress in certain countries</p> <p>Large disparities persist in pricing levels, reflecting country-specific conditions and climate ambitions</p> <p>Implementation of EU ETS reforms Phase IV and UK carbon price (still connected to EU ETS)</p>	<p>Increased carbon price references are implemented in several countries (e.g. China, South Korea, Canada, US, and the EU ETS)</p> <p>Increase based on an assessment of policy ambitions and reforms that might support higher carbon price references</p>	

	<p>ETS reference price: \$40/tCO₂ (2030) – \$55/tCO₂ (2040)</p> <p>UK carbon price floor: \$63/tCO₂ (2030) – \$75/tCO₂ (2040)</p> <p>China carbon scheme: \$13.8/tCO₂ (2030) – \$17/tCO₂ (2040)</p>	<p>Reference prices by 2040 in selected countries:</p> <p>EU ETS: \$130/tCO₂</p> <p>UK: \$148/tCO₂</p> <p>China: \$40/tCO₂</p>	<p>No changes assumed for carbon prices compared to RCS.</p>
Renewables capacities	<p>Incremental capacities between 2017 and 2040:</p> <p>Solar PV: 2000 GW Solar CSP: 15 GW Onshore wind: 1000 GW Offshore wind: 250 GW Hydro: 440 GW Pump storage: 125 GW</p>	<p>Incremental capacities between 2017 and 2040 are increased due to policy support and renewable schemes: Solar PV: +80% Solar CSP: +30% Onshore wind: +50% Offshore wind: +30% Hydro: +30% Pump storage: +70% (assumed to play a key role in managing renewable intermittency)</p> <p>Renewable costs are assumed to follow the same trends as in the RCS</p>	<p>Advancement in on-shore and off-shore wind turbine technologies has been quantified by improving unit size, efficiency, and utilization rates, and by reducing the levelized cost of supply by 20% (compared with the CMS)</p> <p>Advancement in PV systems has been quantified similar to wind turbines (above)</p> <p>Batteries are implemented in the power sector, which can perform shifting peak demand and compensate for intermittency</p> <p>Digitization results in the introduction of smart grids, which can act as peak-shavers</p>

<p>Gas-fired capacities</p>	<p>Incremental capacities between 2017 and 2040:</p> <p>CCGT: 900 GW</p> <p>OCGT: 80 GW</p>	<p>Incremental capacities between 2017 and 2040 are increased due to policy support**</p> <p>Incremental CCGT capacities increased by more than 50%</p> <p>Incremental OCGT capacities increased by 30% (reflecting the higher need of peaking power plants to support renewables intermittency)</p>	<p>More potential for gas to power; increased demand could be captured through technology advancement:</p> <p>Advancement in CCGT has been quantified by improving efficiency, utilization rates, and plant factors, and by reducing the levelized cost of supply (compared with the CMS)</p>
<p>Coal and oil-fired capacities</p>	<p>Incremental capacities between 2017 and 2040:</p> <p>Total coal capacities: +70 GW</p> <p>Large Scrubbed Steam Turbine: +100 GW</p> <p>Large Un-Scrubbed Steam Turbine: -190 GW</p> <p>Integrated Gasification Combined Cycle (IGCC): +70 GW</p> <p>Fluidised Bed Combustion (FBC): + 80 GW</p>	<p>Coal retirement pace accelerated in countries announcing phase-out or strong limitations to coal (e.g. France, the UK, Korea, China)</p> <p>Total coal capacities between 2017 and 2040 are decreased by around 400 GW</p> <p>Retirement pace is higher for the un-scrubbed and scrubbed coal power plants and there is less development of IGCC and FBC</p> <p>Oil-fired capacities assumed to halve (especially in Asia, Latin America and the MENA region)</p>	<p>Clean coal technologies are assumed to have advanced (e.g. greater efficiencies and lower costs) resulting in greater deployment, especially in Asia</p>

Transport sector	Share of electric vehicles: 14.6% by 2040	Larger penetration of electric vehicles (around 20% of the car fleet by 2040)	<p>Advancement in Battery Electric Vehicles (BEVs)</p> <p>EVs are deployed in greater numbers, especially in OECD countries and China</p> <p>Advanced fleets are introduced in the marine sector; greater penetration of LNG as a bunker fuel</p>
Domestic sector	<p>Significant improvement in domestic energy efficiency due to policy support (strengthened performance standards, building codes and price signals, such as a reduction in energy subsidies)</p> <p>For instance: CAAGR (2017-2040) for the energy consumed by households = 0.004% (world) and -0.3% (OECD countries)</p>	<p>This scenario does not implement carbon mitigation assumptions in the domestic sector (such as higher efficiency)</p> <p>The only carbon mitigation action modeled is strengthened carbon taxation in some countries (e.g. in European countries)</p> <p>Energy efficiency improvements follow RCS assumptions</p>	<p>Newly constructed homes feature energy efficiency improvements (e.g. insulated windows, reflective roofing) for a 10% increase in efficiency gains</p> <p>Efficiency improvement of new (not existing) equipment and home appliances is assumed to be around 10% for selected countries, mostly in OECD and developing countries</p> <p>Development of off-grid or stand-alone power plants; off-grid power plants assumed to be more available in remote areas, with a 5% increase in selected countries</p>

* TAS+ is an abbreviation of TAS + CMS

** For instance: Extended US policy support to gas infrastructure development and upstream projects is assumed to improve the availability of domestic gas at relatively low prices and to support gas in power sector.

6.2 Carbon Mitigation Scenario

The CMS aims to assess the effects that strengthened CO₂ mitigation policies will have on the global energy mix. It also attempts to highlight the role of natural gas in supporting countries' climate commitments, especially after the adoption and ratification of the Paris Agreement.

As can be seen in the vertical dimension of Figure 6.1, the CMS will take into account reinforced mitigation policies compared to the RCS, specifically policies affecting the power sector. The CMS assumes that CO₂ mitigation will be primarily achieved through stronger implementation of measures that will favour the development and penetration of the less carbon intensive and cost efficient options. It also assumes that these measures will recognize the key role of natural gas in meeting countries' commitments.

The position of the CMS on the horizontal axis reflects our consideration that no major technological breakthroughs will occur, and that technological advancement will follow the same trends as the RCS. However, we assume that less-costly and proven energy efficient technologies, particularly in the power sector, will be more widely disseminated and encouraged by policies and technology transfer.

The focus on the power sector is motivated by the fact that it still represents a big share of CO₂ emissions (around 35% of total emissions in 2017). The power sector is also expected to significantly contribute to emissions reductions, given the large spectrum of proven technologies and options that can be used to produce electricity with fewer carbon emissions. Moreover, a large proportion of CO₂ mitigation policies target the power generation sector, making it central to future decarbonisation efforts.

Detailed policy assumptions in the CMS

This section highlights the main policy assumptions that affect the power sector in the CMS across various domains including renewables and non-renewables, as well as carbon pricing.

Renewable energy policies

In the CMS, renewables, in particular solar and wind, are expected to see continued policy support, which allows many countries, especially those announcing renewable targets, to achieve more progress with renewables compared to our RCS.

Renewable support schemes and power market design will be improved in many areas in order to tackle the integration challenge of large intermittent renewable power supplies, and also to achieve greater cost efficiency for renewables development. Synergies between gas and renewables will be significantly promoted, since gas allows for improved power system flexibility and can efficiently balance intermittency.

In this scenario, natural gas will contribute significantly to the renewables integration challenge. Table 6.2 displays the main renewable policy assumptions for key markets in the RCS and CMS.

Table 6.2: Targets and renewables policy assumptions in key markets in the CMS vs. the RCS

	Renewables	RCS	CMS
US	No national targets; state-level targets take a leading role (e.g. California = 60% by 2030 and 100% by 2045)	<ul style="list-style-type: none"> ☞ Implementation of federal tax credits for renewables ☞ Introduction of tax on solar panel imports ☞ Increasing role of communities, state and local governments and the private sector in supporting renewables 	<ul style="list-style-type: none"> ☞ Strengthened commitments of states to support renewables in line with state level targets ☞ Extension of renewable tax credits (post 2022) ☞ Cost decrease will improve renewable competitiveness
EU	Renewable share in gross energy consumption: 20% (2020) and 32.5% (2030). Upward revision of the target	<ul style="list-style-type: none"> ☞ Strengthened measures to support more ambitious targets in the new EU renewable directive, but disparities between countries persist ☞ Increasing use of market-oriented renewable schemes, including auctioning and feed-in premiums, as well as renewable certificate trading ☞ Electricity market reforms improve ability to integrate renewables; natural gas will play an important role in supporting renewables deployment 	<ul style="list-style-type: none"> ☞ Renewables policy (EU directive and electricity market) will succeed in supporting strong growth for renewables, especially solar PV and wind ☞ The EU will meet its renewables target ☞ Natural gas still plays a major role in supporting renewable deployment

<p>China</p>	<p>Share of non-fossil fuels in the energy mix: 15% (2020) and 20% (2030)</p>	<ul style="list-style-type: none"> ⌚ Slowdown of renewables progress compared to recent trends, driven by decisions to reduce subsidies and to cap solar projects ⌚ Cost decreases and auctioning of new capacity support continued growth over the long-term ⌚ Implementation of measures to improve power system flexibility and management of renewables curtailment ⌚ Gas will play a key role in providing flexibility for intermittent renewables 	<ul style="list-style-type: none"> ⌚ Policy support (mixture of market based schemes and direct government support) in addition to cost decreases will drive strong penetration of renewables ⌚ Gas will play a key role in providing flexibility for intermittent renewables
<p>India</p>	<p>Share of non-fossil fuels in power generation: 40% of installed capacity by 2030</p>	<ul style="list-style-type: none"> ⌚ Cost decreases and auctioning of new capacity will support large renewables progress ⌚ Funding issues, persisting power grid bottlenecks; competition from coal and unstable fiscal policy will constrain the country in meeting its targets 	<ul style="list-style-type: none"> ⌚ Policy support in addition to cost decreases will drive strong penetration of renewables, mainly solar PV ⌚ Non-fossil fuel target in power generation will be achieved by 2030 ⌚ Solar PV target will be achieved by 2020; strong capacity growth after 2025 to support electricity demand growth and the decrease of old coal capacities ⌚ Gas will play a role in achieving more flexible power systems

Latin American Countries	<p>Mexico: Share of non-fossil fuels will be more than 35% by 2024, and more than 40% by 2035</p> <p>Argentina: 20% of electricity consumption by 2025</p> <p>Brazil: 48% share of renewables in the energy mix by 2026; 23% share of non-hydro renewables in power generation by 2030</p>	<ul style="list-style-type: none"> ⌚ Auctioning will be a key driver in supporting the development of renewable capacities ⌚ Reinforcing networks to integrate renewables will be a major challenge in the region 	<ul style="list-style-type: none"> ⌚ Strengthened policy support and cost reduction will play a role in sustaining renewables ⌚ Auctioning for low price capacities expected to drive strong renewables penetration (solar and wind in particular) ⌚ Key Latin American players (Mexico and Brazil) expected to achieve their renewable targets
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Non-renewable energy policies

The CMS considers extended policy support for gas infrastructure development (e.g. the LNG supply chain), network integration and upstream projects, which will contribute to improving gas availability and accessibility. In this regard, many supporting instruments are considered which will stimulate the gas value chain, such as investment incentives and strengthened cooperation frameworks.

The environmental qualities of gas are being promoted in many countries which are experiencing pollution in urban areas. Countries announcing gas penetration targets, especially China and India, are assumed to make progress in line with their announced targets and to significantly increase gas-fired capacities in the power sector, which is the major focus of the CMS. Other countries that have potential for greater penetration of gas (over more carbon-intensive energy sources), such as countries in Southeast Asia, are expected to make progress in mitigating CO₂. Table 6.3 highlights the gas policy assumptions in the RCS and CMS for selected markets.

Coal

The CMS considers the strengthened implementation of air pollution emission standards and taxes on coal, which will increase the cost of producing electricity and support the decommissioning of coal-fired capacities. Additionally, phasing out of coal or limitations on coal use will be strongly applied in countries having made announcements in this regard. Table 6.4 displays the main coal policy assumptions in the RCS and the CMS.

Table 6.3: Gas policy assumptions in key markets in the CMS vs. the RCS

	RCS	CMS
US	<ul style="list-style-type: none"> Implementation of policies that promote upstream exploration, expediting the permit process for gas infrastructure development, and weakened environmental regulations 	<ul style="list-style-type: none"> Extended policy support to gas infrastructure development Availability of domestic supply at relatively low prices will drive the increase of gas usage for power
China and India	<ul style="list-style-type: none"> Gas continues to be supported through market and price reforms, infrastructure development and clean air programs; difficulties are expected in achieving ambitious targets, especially in India 	<ul style="list-style-type: none"> More policy support to gas penetration (infrastructure, domestic production, emissions standards) will increase gas market shares, especially in power generation China: share of gas in the power mix expected to reach 15% by 2030 and around 23% by 2040 (respectively 7% and 10% in the RCS) India: share of gas in the power mix increases to 4% by 2025, but still not compatible with the ambitious policy target (medium term target for primary energy mix around 15% by 2025)
Southeast Asia	<ul style="list-style-type: none"> Policy support to gas market integration, particularly in the context of ASEAN partnerships, but competition from cheap coal to satisfy growing energy needs will affect gas penetration potential 	<ul style="list-style-type: none"> More policy support to natural gas, but still high usage of coal
EU	<ul style="list-style-type: none"> Policy support to some infrastructure projects, especially those considered in the framework of EU gas priority corridors, but market design and geopolitics may cause delays in their execution Implementation of CO₂ emissions standards (550 g/kWh) for generation capacity; participating in capacity mechanisms will support the flexible role of natural gas 	<ul style="list-style-type: none"> More policy support to natural gas (infrastructure, emissions standards), but competition between natural gas and renewables will be a key driver over the long-term

Table 6.4: Coal policy assumptions in key markets in the CMS vs. the RCS

	RCS	CMS
US	<ul style="list-style-type: none"> ⌚ Policy measures to revive the coal industry will not be very successful in supporting coal demand ⌚ Market fundamentals are expected to predominate over policy supports and to continue to hit the coal industry 	<ul style="list-style-type: none"> ⌚ Market fundamentals as well as policy limitations at state levels will lead to a strong phase out of coal fired capacities
China	<ul style="list-style-type: none"> ⌚ Important progress towards the coal limitations targeted in the 13th Five-Year Energy Plan, driven by the closure of inefficient coal-based power plants and industries, and strengthening CO₂ and pollutants' emissions standards 	<ul style="list-style-type: none"> ⌚ More aggressive policies against coal will lead to a strong reduction of coal power generation capacities; coal-fired capacity is expected to reach 40% of its present level by 2040
India	<ul style="list-style-type: none"> ⌚ Coal is expected to continue to play a key role, given the challenges of meeting ambitious targets for the penetration of alternative sources (renewables, nuclear and gas) ⌚ Coal policies are assumed to focus mainly on improving efficiency and low emission coal-based technologies in order to keep pollution under control 	<ul style="list-style-type: none"> ⌚ Implementation of strengthened emission standards and coal taxation will lead to less coal-fired capacity, but coal still contributes largely in meeting growing electricity demand
EU	<ul style="list-style-type: none"> ⌚ Implementation of announced coal phase out plans in countries such as the UK, France, Finland and Portugal ⌚ Delays are expected compared to the announced targets due to internal challenges (competitiveness and security of supply) 	<ul style="list-style-type: none"> ⌚ Aggressive phase out of coal-fired capacities in the EU ⌚ Almost all EU countries will quit coal for power generation by 2040

Nuclear

The CMS considers no additional policy support to nuclear compared to the RCS, where nuclear is expected to see non-negligible growth (around 1.4% between 2017 and 2040). This assumption is motivated by the fact that more aggressive penetration of nuclear remains constrained by high investments costs (due to safety requirements), waste treatment issues, availability of skilled labour, and fuel availability challenges in some emerging economies.

Carbon pricing

Carbon prices are expected to increase significantly in the key markets, either in the form of carbon taxes or carbon market prices. Specifically, emissions trading systems (carbon markets) will be implemented and reinforced in the main markets which are considering this initiative, such as China, South Korea and Canada.

CO₂ price references from carbon markets are assumed to increase over the long-term, reflecting extended efforts to improve the functioning of these markets and also to increase their role in reducing CO₂ emissions.

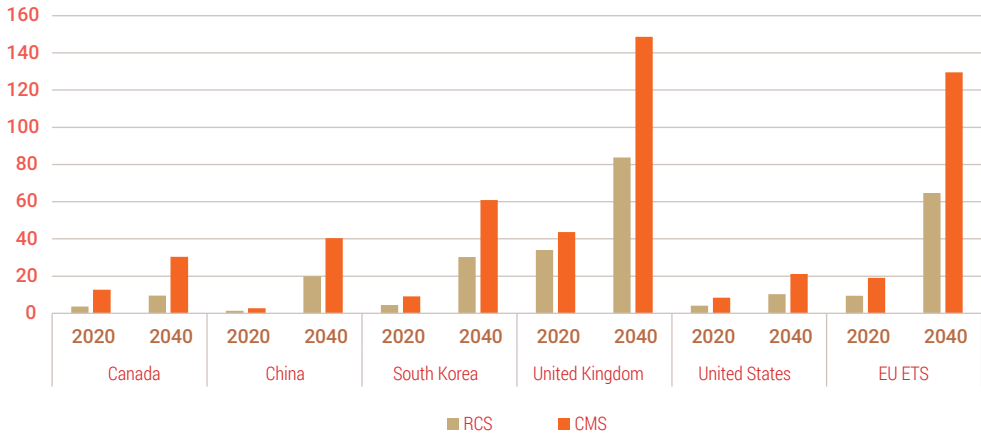
Particularly, CO₂ prices will increase significantly over the long-term in Europe driven by EU ETS Phase III and IV reforms that integrate mechanisms aimed at supporting increasing trends of carbon prices and addressing the imbalances between the supply and demand of CO₂ emission allowances.

Regulated carbon price supports that add to carbon markets' reference prices are also assumed to play a role in some key markets, such as France and the UK, in order to sustain higher carbon price levels. In the UK, the reference price is expected to reach \$148/tCO₂ in 2040, reflecting aggressive mitigation policies.

As highlighted in Figure 6.2, under the CMS, carbon prices are assumed to double in Europe, China and the US between 2020 and 2040 when compared to the RCS. (For the US, we take the average carbon market prices in California and the Regional Greenhouse Gas Initiative.) For Europe, the average EU ETS reference prices are expected to reach around \$20/tCO₂ in 2020 and \$130/tCO₂ in 2040. Chinese carbon prices are assumed to reach around \$40/tCO₂ in 2040.

For Canada, the price of carbon is forecasted to increase significantly from the RCS, reaching around \$30/tCO₂ in 2040 (compared to \$10/tCO₂ in the RCS). This increase is supported by the strong ambition of the Canadian government to use carbon markets in order to address climate change issues.

Figure 6.2. Carbon prices in the RCS vs. the CMS



Source: GECF Secretariat based on data from the GECF GGM

Electrification of the transport sector

Electrification of the transport sector is one of the key drivers behind carbon mitigation. Several countries, especially China, India, Japan and some European countries, are undertaking measures to increase electricity usage in transport, mainly by supporting the penetration of EVs. Some countries have also considered the introduction of binding targets and mandates for car makers to produce and sell low-emission vehicles, including EVs (zero emission vehicle mandates). These mandates have already been enforced in some US states, such as California, while China and the EU are considering the possibility of introducing them within the framework of their decarbonisation policies. India has announced its support for electricity usage under the framework of an ambitious plan (the National Electric Mobility Mission Plan 2020). The CMS assumes that policies will significantly support the penetration of EVs. These policies will result in a 20% EV share in the CMS by 2040, compared to a 15% share in the RCS.

6.3 Technology Advancement Scenario

Energy balance projections are highly dependent on economic, technological, social and political circumstances. Among these, technical innovation is partially driven by complex drivers and feedback mechanisms between the other three factors. Policy measures which alter the economic environment through financial incentives and supports, can propel technological advancements and intentionally promote the development of specific technologies.

Putting supporting policies in place and improving the financial circumstances surrounding technological development are the best ways to ensure the deployment of clean and efficient technologies across the energy supply chain and in end-use sectors. The most feasible way to deal with the negative and inevitable consequences of climate change is to introduce advanced technologies and to improve current conventional technologies through wise and supportive policy measures.

Technologies play an increasingly critical role in developing more efficient and sustainable ways to satisfy human needs. Technology, science and innovation feature prominently in the SDGs. SDG target 7A highlights the need to

enhance cooperation and access to energy research and technology, including energy efficiency and cleaner fossil fuel technologies; SDGs 9.4 and 9.5 address the need to upgrade the technological capabilities of industrial sectors and to support technology development, research and innovation in developing countries; and finally, SDG 17 has an explicit focus on capacity building, technology transfer and cooperation.

Technology, science and innovation are considered the core pillars of the SDG 'Means of Implementation.' This focus in the 2030 Agenda underscores the importance of technology development and the need for concerted integration of technological advancements in long-term energy systems forecasts.

The TAS explores the impact of technological advancement across the energy supply chain, as well as in consuming sectors. It considers the implementation of new and innovative technologies, as well as the advancement of conventional technologies that are readily available. The objective of the TAS is to examine how technology can affect the future energy system and to evaluate the impact of technologies on energy markets.

The definition of advanced technologies used in this scenario includes those technologies which are still under development but promise to deliver significant value or those which have yet to gain substantial market shares. It is important to note that there is unevenness in the pace at which advanced technologies are commercialized and transferred, as well as in the distribution of technology possession across developed, emerging and developing economies.

Energy systems are not only affected by innovative technological breakthroughs, but also by enhancements in conventional technologies, like power-plants, CCS, and CHP technologies. While these technologies have been around for decades, recent and ongoing developments have focused on reducing energy consumption (and therefore the marginal cost of production), as well as increasing thermal efficiency and decreasing associated GHGs.

These and other advancements may have significant effects on the rate and scale at which technologies are deployed and, consequentially, their role in final energy consuming sectors. Technologies which are specifically applied to mitigate GHG emissions are also subject to policy interventions. Therefore, their development reflects the political and economic landscape.

The TAS considers these complex interactions by assuming which technologies are most likely to develop, as well as predicting their impact on final energy balance projections. The TAS applies these assumptions to the CMS in order to simulate the impact of specific advancements in energy sector technologies.

The role of technologies in the energy system

Technology is a very broad term. From an academic point of view, any practical application of knowledge can be translated into technology (3). According to this definition, humans have been using technologies since the dawn of time to satisfy their needs in an increasingly efficient manner. Energy technologies can be defined as any knowledge-based system that facilitates people's ability to benefit from energy. In this context, we can say that an energy technology is any set of tools or instruments that makes it possible to extract use from an energy carrier (i.e. a substance that contains energy, such as natural gas). These instruments can be sophisticated, such as a refinery or an air conditioning

system, or - depending on the scale and definition of system boundaries applied - the technology can be as basic as the pipes or screws used in their construction. These varying definitions demonstrate that technologies can be considered on a variety of aggregated levels.

A Reference Energy System (RES) is a schematic representation of all the resources and activities required to supply various energy carriers through to consumer sectors (4). This analytical framework is used to examine the network of processes and activities involved in the entire energy supply chain, including exploration, extraction, treatment, conversion, transportation and distribution to the end users. Each resource, treatment, process or activity is represented by a box that is linked to the following step along the supply chain. This approach captures the technological elements involved in the delivery of energy and allows us to examine the existing and future technologies that are integrated into the supply chain, in order to model the possible outcomes of alternative development paths.

This analytical technique has been applied to the development of the TAS, to illustrate the system boundaries used in our conceptual model, as well as the capabilities of the GECF GGM. This RES, the GECF Reference Energy Technology Map (RETM), is featured in Figure 6.3.

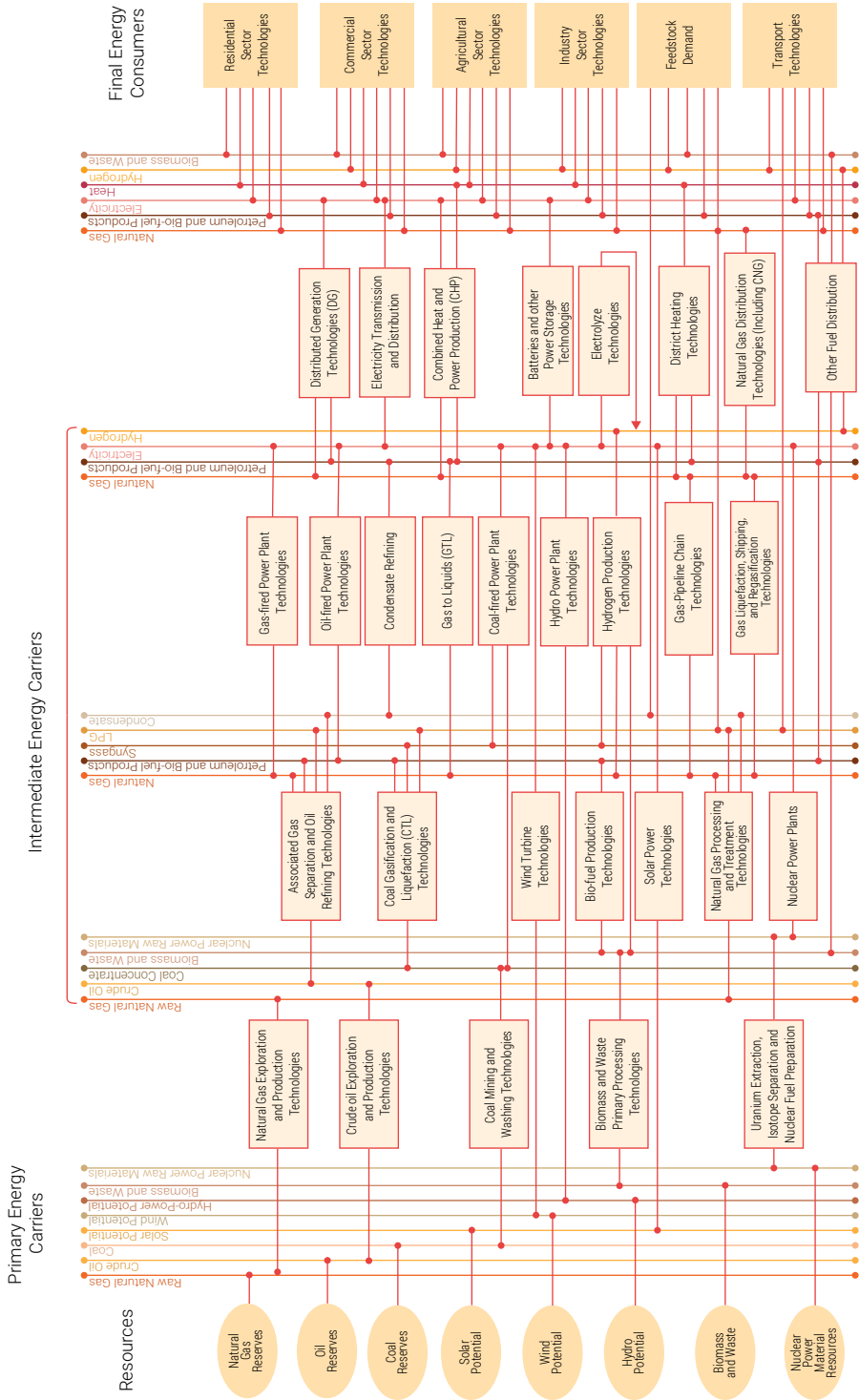
Figure 6.3 illustrates the levels of aggregation used to define 'technology' from the perspective of the RETM. This energy system was conceptualized for the purposes of scenario development and consists of various levels, characterized by primary, intermediate and final energy carriers. Beginning with energy extraction and ending with final consuming sectors, the RETM maps the entire energy value chain that forms the baseline of the TAS. Within these aggregate levels, energy technologies are nested among intermediate energy carriers. There are various technology sets featured in the RETM, each one linked with a primary energy carrier, like natural gas or coal. In order to illustrate the relationship between specific energy technologies at various levels of the energy supply chain, a more detailed RES is needed.

It is important to note that the pictorial representation of a RES becomes more complex with the addition of more technologies and resources. Due to the intensive nature of energy systems modelling, several energy carriers which feature in the RETM (as well as their associated technologies) were omitted from detailed consideration. Energy supply chains with higher granularity are provided for natural gas and coal in the following sections.

Even at this relatively coarse level of aggregation, we see a variety of technologies that affect final energy consumption:

- ⊗ Technologies specific to the natural gas supply chain, such as those involved in offshore drilling, CO₂/sand fracturing, hydraulic fracturing and the LNG sector.
- ⊗ Technologies involved in the supply chains of other energy carriers that are substitutes for natural gas, such as renewables and coal.
- ⊗ Technologies embedded in end-use sectors, which convert final energy carriers (like gas and liquid fuels) to useful energy carriers (like heat and light). These technologies include, but are not limited to, consumer appliances.
- ⊗ Energy conservation technologies, such as double-glazed windows and other thermal insulations.
- ⊗ Technologies related to environmental concerns, like carbon capture technologies, which can also be used for enhanced oil recovery (EOR).

Figure 6.3. GECF reference energy technology map (RETIM)



Source: GECF Secretariat

Methodology

The objective of the TAS is to identify technologies that are most likely to advance within the context of the RETM, and to assess whether they are beneficial or competitive for natural gas. An attempt has been made to conceptualize a scenario that considers new parameters in sectors that are expected to see rapid development on an anticipated scale, like renewable energies. In order to explain how various assumptions were applied in the model, it is first necessary to describe the structure and limitations inherent in the GECF GGM. Because the GGM is the central modelling tool applied in this analysis, understanding the model's design will allow for a better understanding of how the TAS is implemented and processed.

The GGM is a modular modelling tool that benefits from a variety of methodologies, such as linear programming and econometric time-series. The energy price and macroeconomic sub-models feed end-use energy demand. End-use demand includes, but is not limited to, the commercial, residential, agricultural, industry and transportation sectors. The final consuming sectors encompassed in the demand sub-model estimate energy needs, such as the demand for heat, electricity and other intermediate fuels (like petroleum products, hydrogen, etc.). Some final sector technologies, such as vehicles, industrial machinery and residential appliances, affect energy demand and, consequently, the modelling results generated for this sector.

Based on projections of activity from transformation technologies, primary energy demand is determined. Some technologies in this sector, like power plants, refineries and other conversion technologies, are included in this sub-model. Because econometric time-series methodologies are utilized in the transformation sector energy demand sub-model, any set of assumption on these technologies impacts overall results and, accordingly, the gas supply and trade sub-models. The resulting projections generated for primary energy demand need to be met with indigenous supply or trade.

The trade sub-model utilizes linear programming. All technology advancement assumptions along the natural gas supply chain must be imposed into the optimization process. This means that the GGM is very sensitive and responsive to any changes in the gas sector. For instance, any supply discoveries (in production from both conventional and unconventional resources) can change the results dramatically. An extended technology RES was designed specifically for the natural gas supply chain to determine all layers and technology categories in this sector at a more detailed scale. This will be presented and elaborated upon in the following section.

Based on the iterative progress of the GGM, after running linear programming, the marginal cost of supply feeds into the price sub-model and we can see an iterative circuit. The model runs a series of iterations until it converges to a set of consistent prices, as well as demand and supply projections based on the assumed acceptable difference between the two latest iteration results.

The converged energy balance projections by fuel, sector and technology are then used to calculate CO₂ emissions. In this sub-model technologies such as CCS can have an impact on the total system. The TAS considers technologies that are likely to be deployed from 2018 through to 2040.

The functioning of the GECF GGM affects the assumptions imposed in the TAS. The following key areas are considered:

- ⊙ As previously mentioned, technologies utilized along the natural gas supply chain can significantly affect the model results, and are therefore very important for the development of the TAS. The TAS considers technologies being used in the power generation sector, as they affect demand for electricity and the need for new power capacities.
- ⊙ Moreover, the TAS will consider the implementation of renewable energy technologies, such as wind turbines. These technologies are considered due to the rapid scale at which they are developing and being deployed, with projections showing that renewables will become the fastest growing energy sources through to 2040. As these technologies are expected to have a significant impact on energy balance projections, they have been included in this analysis despite being competitive to natural gas in the power generation sector.

Energy supply chains: A selection of impactful technologies

Natural gas supply chain

The natural gas supply chain is very complex compared with other energy carriers. This is primarily due to the variety of resources available (e.g. conventional and unconventional), and the flexibility of natural gas usage in diverse end-use sectors, as well as along intermediate levels of the RETM.

For instance, natural gas can be extracted from oil reserves as associated petroleum gas (APG) and also from non-associated gas fields. Since APG is considered a by product in the oil industry, it does not need huge capital investment in terms of extraction, drilling and well completion. On the other hand, extracting natural gas from remote oil fields requires infrastructure, such as pipelines, sweetening and dehydrating units that impose significant expenses. One of the technologies that can deal with this problem is GTL. This example demonstrates that an advancement in an existing technology at the conversion (intermediate) level might have significant effects on upstream development. Injecting associated gas into the origin oil well is another solution for this problem, which in most cases is used for EOR.

Natural gas is the only energy carrier with this massive variety of usage. It can be reinjected into oil wells to enhance oil recovery; it can be combusted to provide heat for industrial processes or power generation; it can be fed into conversion technologies as a feedstock to produce petroleum or petrochemical products (like GTLs and gas to chemicals [GTCs]); or it can also be compressed as CNG to be used as a fuel for the transportation sector, among other options.

The TAS takes technologies along the gas supply chain into special consideration, given the fact that any of these technological developments can have a substantial impact on natural gas systems. However, important bottlenecks and challenges exist (such as developing infrastructure to access remote fields and unconventional plays, the introduction of floating production, and advancements in liquefaction and storage technologies). To capture all of the processes and activities that exist along the natural gas value chain, an extended technology map has been designed to illustrate the many categories of technologies embedded in gas supply systems.

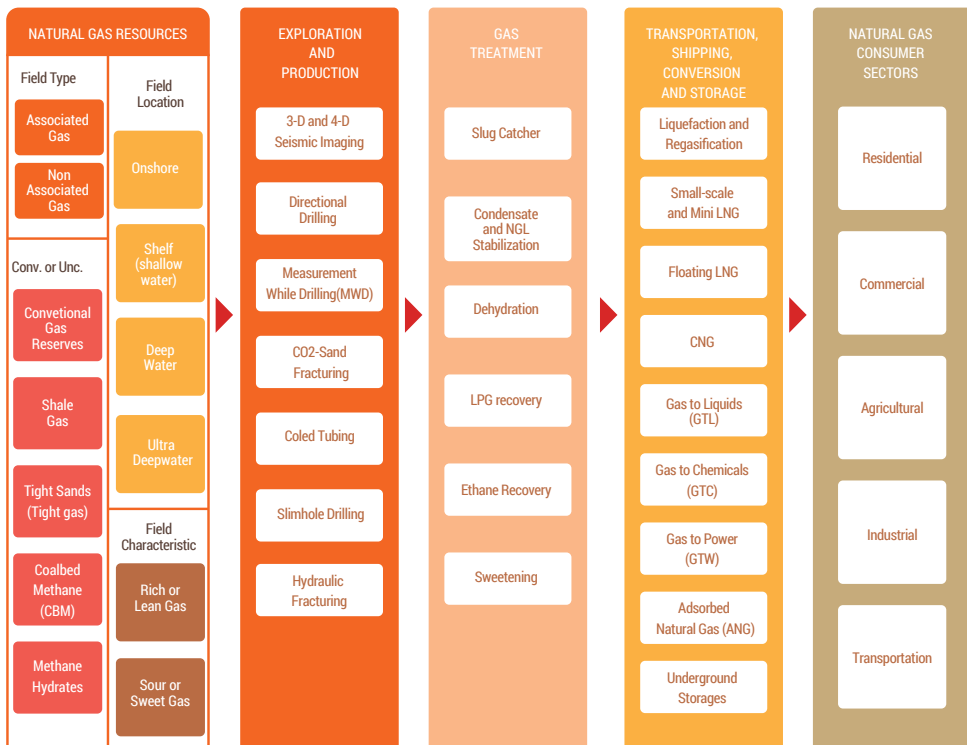
Figure 6.4 categorizes natural gas resources according to field type, location, resource specification and conventionality

of reserves. Each category has technological specifications that must be considered. The next level provides a simplified overview of the many technologies which are used in gas discovery, exploration, drilling and production. For example, directional drilling (DD) and measurement while drilling (MWD) are implemented for a variety of hydrocarbon reserves like natural gas and are vital parts of shale gas production, as are the shale gas technologies involved in hydraulic fracturing. In next level, gas treatment technologies are illustrated.

Unlike the GECF RETM, the technology map featured in Figure 6.4 introduces technologies inside specific levels and, in some cases like the one discussed above, some of these appear on one level. There is a need for certain technologies to be considered in combination, depending on field categories.

FLNG technologies refer to floating facilities and operations that make LNG production possible in offshore and deep-water fields. These revolutionary technologies have allowed natural gas producers to tap into remote geographic locations where vast gas reserves are located.

Figure 6.4. GECF natural gas technology map



Source: GECF Secretariat

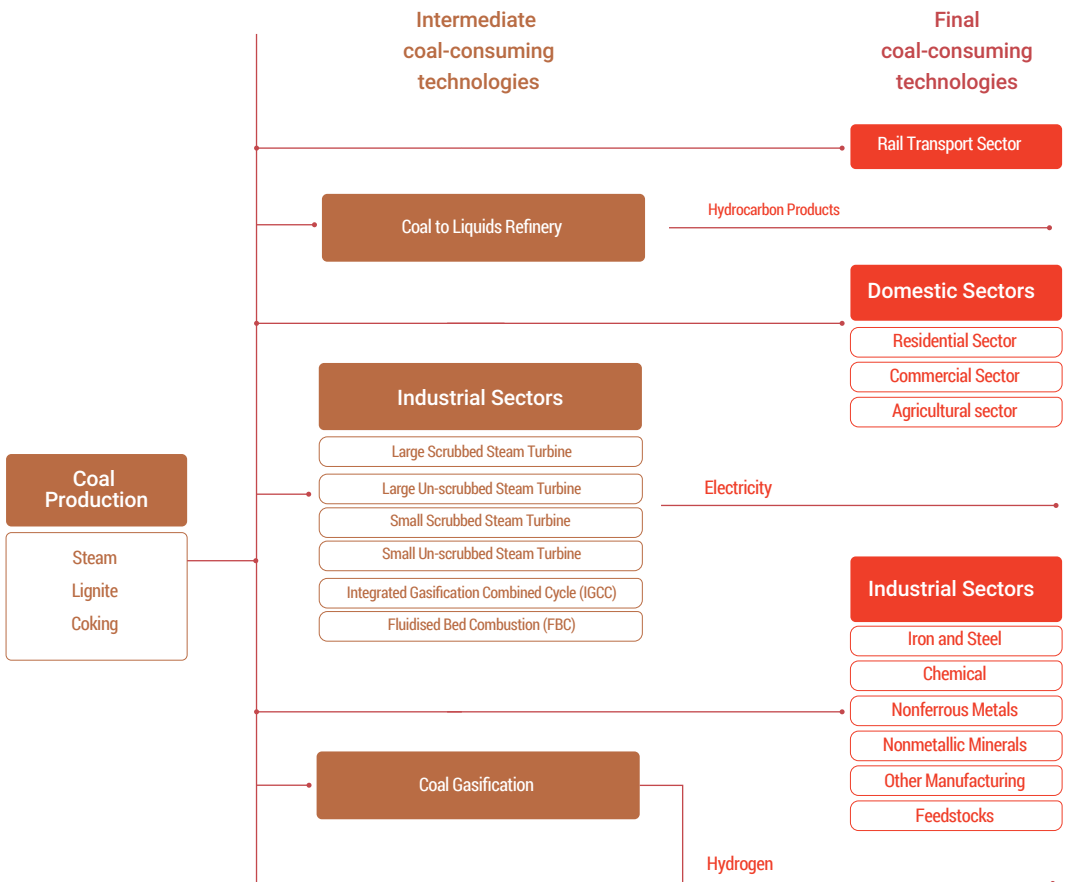
FLNG technologies are considered extremely important for the future utilization of natural gas resources. They will be thoroughly examined in subsequent versions of this report.

The coal supply chain

Coal was introduced to the energy system long before oil and gas. Among solid fuels, coal is the largest source of energy and is found in most countries.

A detailed RES is provided for the coal supply chain based on GGM considerations (see Figure 6.5). In the TAS, we try to investigate what would happen in the energy system if we observe progress in characteristics of coal technologies, especially among the more advanced technologies like the Integrated Gasification Combined Cycle (IGCC).

Figure 6.5. GECF GGM coal supply chain



Source: GECF Secretariat based on the GECF GGM

Figure 6.5 shows the coal supply chain across three levels. The first level outlines the types of coal reserves and production processes. In the GGM and accordingly in the TAS, we do consider this issue in depth. The third level consists of final sectors that consume coal and is also not particularly important in the TAS, since most coal consuming technologies at this level are not expected to advance; rather they are being substituted by other technologies, especially in the transportation and industry sectors.

The second level in Figure 6.5 covers the conversion technologies that transform coal to other fuels or electricity. In the TAS we need to investigate the impact of that progress in advanced coal power plants or coal to liquid (CTL) technologies.

Some countries are considering installing facilities to produce liquid fuels via indirect liquefaction (i.e. coal gasification into syngas and then transformation into liquid fuel), which South Africa has been undertaking since the 1950s. Countries are also seriously exploring direct coal liquefaction technologies for fuel production. China has taken the lead in constructing direct CTL plants, and it is likely that more countries will do the same. The high rate of CO₂ emissions is an important barrier to the deployment of these technologies. For example, a coal gasification plant actually produces more CO₂ than a traditional coal power plant, so this issue needs to be taken into account.

Carbon capture and storage (CCS)

CO₂ capture technologies separate CO₂ from other gases produced during fossil fuel combustion or industrial processes, such as cement, steel, and chemicals manufacturing. Once captured, the CO₂ is transported and stored in deep underground geological formations and depleted hydrocarbon reservoirs, or used in EOR.

CCS technologies and techniques are well established, with the first large-scale project using CO₂ for EOR dating back to the early 1970s. Currently, there are around 20 large-scale and more than 100 small-scale CCS projects operating or under construction. The majority of the projects currently in operation (over 75%) are used for EOR.

The rationale behind CCS application relates to its role in reducing energy-related CO₂ emissions, as well as improving production from mature oil fields. CCS is the only available option for significantly mitigating emissions from industrial sectors, where there are limited substitutions available for the processes inherent in iron, steel and cement production. While there is established recognition that CCS is vital to deep emissions reductions, policy support fluctuates and there has been relatively limited investment in large scale CCS projects to date. The absence of targeted policies and government funding programmes, coupled with the financial risks involved in CCS deployment, have hindered innovation in CCS component technologies.

Of the three major stages of CCS (i.e. capture, transport and storage), transport technologies are the most developed and technically mature. R&D regarding CO₂ storage focuses on identifying adequate storage sites, monitoring leakage from storage reservoirs, and evaluating the environmental risks associated with injection. These efforts have a limited effect on the deployment of CCS technologies and solely address environmental concerns.

The majority of R&D on CCS technologies is focused on reducing the costs and energy penalties associated with CO₂ capture. Because the TAS evaluates the impact of technologies on energy markets and focuses on addressing

technological developments that affect the energy supply chain and consuming sectors, this analysis will exclusively focus on technologies involved in the capture and separation of CO₂.

The following represent the three basic processes utilized in CO₂ capture:

- ⊙ Pre-combustion: applied in IGCC systems, where CO₂ is removed from a syngas that is generated from fossil fuels or biomass. Pre combustion capture is primarily used in industrial processes.
- ⊙ Post-combustion: capture processes are the most mature CCS technologies. CO₂ is separated from flue gases after fossil fuels are combusted, most often using amine-based or aqueous ammonia solvents.
- ⊙ Oxycombustion: involves using oxygen for the combustion of fuel, resulting in water vapour and CO₂. There is currently only one oxy-fuel combustion facility in early development, meaning that this technology is the least promising, due to a lack of large-scale application.

The TAS assumes moderate technical advancements in CCS technologies when compared to the RCS. However, the cost of their deployment remains relatively high and this could undermine competitiveness, especially when used in power generation.

Selected renewable technologies

Almost one fifth of global energy demand will be met by renewable energies in 2040 (including hydro and biomass). These energy carriers will become the fastest growing energy sources, with an average annual growth rate of around 2.5% per annum in terms of energy demand

The term 'renewables' encompasses a wide range of technologies used in the generation of bioenergy (biomass and waste), hydropower, solar (photovoltaics and concentrated solar power), wind (onshore and offshore), and marine (tidal and wave) energy. Due to the structure of the GECF GGM, bioenergy resources are considered separately from other renewables and are therefore excluded from our classification. Of the remaining renewable energy sources, the largest increase in installed capacity is projected to come from solar and wind, with an average annual increase of approximately 9% and 6% respectively.

These projections are partially based on the rate at which solar and wind technologies are developing, with the aid of policy mechanisms designed to propel their deployment. For example, the number of patents filed for the development of renewable technologies has increased 50-fold between 2000 and 2016. Almost 75% of the patents filed in 2016 were allocated to developing solar and wind energy.

This significant growth in the development of solar and wind technologies, coupled with their projected long-term contribution to the global energy mix, supports the rationale for including them in the GECF TAS. The TAS considers advancements in solar photovoltaics (PV) and concentrated solar power (CSP), as well as onshore and offshore wind turbines.

The challenge of intermittency in renewable technologies such as wind and solar is the most controversial issue standing in the way of their deployment. Advancement in batteries in terms of efficiency, life cycle and cost reduction will substantially enhance the market penetration of renewables. Therefore, technological advancement in batteries

needs to be considered to assess how they might evolve in competition with natural gas as a way of dealing with the issue of renewables' intermittency.

6.4 Scenario Results

World primary energy demand

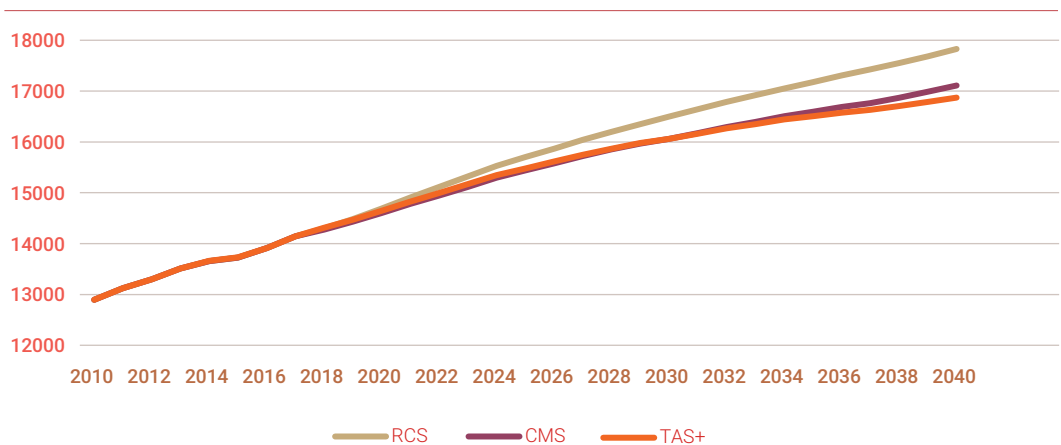
Compared to the RCS, primary energy demand in the CMS is expected to observe less growth momentum over the 2017-2040 period, estimated at around 0.83% annually (compared to a CAAGR of over 1% in the RCS over the same period). Lower growth prospects in the CMS reduce global primary energy demand by around 720 Mtoe in 2040, corresponding to energy savings of more than 4% compared to the RCS (see Figure 6.6).

Figure 6.6 shows that even more energy demand reductions are anticipated in TAS+. When all the assumptions from the CMS and TAS are implemented, total primary energy demand in 2040 is estimated at around 16870 Mtoe. This is 240 Mtoe less than what is projected in the CMS and approximately 1000 Mtoe less than what is projected in the RCS. This significant reduction in total primary energy is equivalent to 5.4% of the energy savings in the RCS. Cumulative energy savings over the 2017-2040 period are estimated at more than 9500 Mtoe.

TAS+ considers technology advancement assumptions in addition to the policy assumptions already considered in the CMS, in order to contrast the two scenarios (see Section 6.1). The CMS forms the base case for the TAS+, to which technology-related assumptions, particularly energy efficiency and cost improvements, are implemented.

The power sector is the main contributor to global demand reductions in the CMS, with around 560 Mtoe conserved through to 2040. The two driving forces behind this reduction are: i) higher carbon prices which affect energy demand in power generation, and ii) the closure of coal-fired power plants (to the benefit of gas and renewables)

Figure 6.6. Total primary energy consumption outlook in different scenarios (Mtoe)



Source: GECF Secretariat based on data from the GECF GGM

which improves average energy efficiency. Efficiency improvements result from fuel substitution, as opposed to technological development (which is incorporated in the TAS).

In the transportation sector, policy support to EVs in CMS is expected to reduce oil consumption by approximately 90 Mtoe in 2040 when compared to the RCS. This occurs because oil is substituted by electricity.

Results from TAS+ suggest that efficiency gains stemming from technological improvements in buildings, residential and commercial appliances, transport, electricity generation and industry will drive additional reductions in total primary energy demand when compared to the CMS. This reduction will compensate for increasing electricity demand in final consuming sectors, which is driven by electrification of appliances and industrial equipment, as well as by further expansion of EVs.

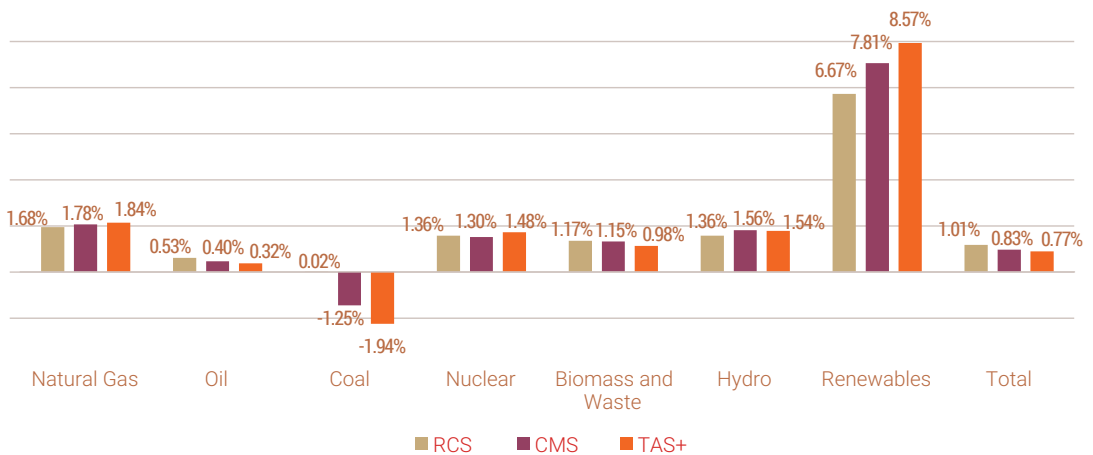
When compared to the RCS, TAS+ forecasts higher electricity demand and an additional 3400 GW of power capacity by 2040. This is 28% more than the RCS, indicating that electrification will significantly and positively impact the power sector, while total primary energy consumption is reduced.

Primary energy demand by fuel

Figure 6.7 depicts average growth rates for primary energy carriers in the RCS, the CMS and the TAS+. Natural gas demand annual growth between 2017 and 2040 is expected to rise from 1.68% in the RCS to 1.78% in the CMS, and further to 1.84% in the TAS+. Coal is projected to decline by around 1.3% and 2% annually in the CMS and the TAS+, respectively, after exhibiting stable long-term evolution in the RCS.

The significant decline of coal in the CMS is mainly driven by Asia Pacific, Europe and North America. China is expected to lead this decline, with a demand reduction of more than 700 Mtoe between 2017 and 2040, compared to an anticipated reduction in the RCS of around 340 Mtoe. China will also lead gas demand growth in the CMS, with

Figure 6.7. Primary energy consumption CAAGR (2017-2040) in different scenarios (%)



Source: GECF Secretariat based on data from the GECF GGM

incremental gas demand totalling nearly 450 Mtoe (estimated at 390 Mtoe in the RCS). This growth will be supported by coal to gas substitution in the power sector. Coal is expected to see further demand reductions in the TAS+, totalling approximately 2% average annual decline over the outlook period, and driven by progress in renewables and gas-fired power generation technologies.

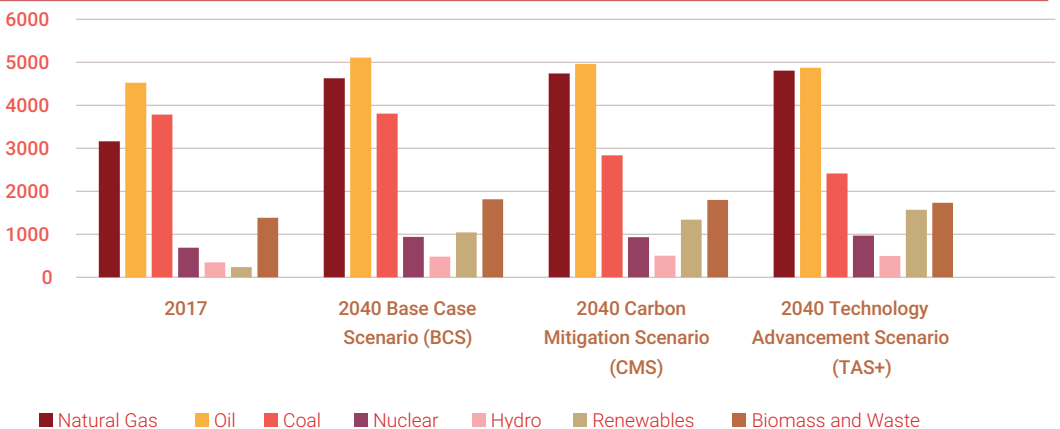
Renewables are an important focus in the CMS, which aims to assess their potential impact on global energy systems and the transition towards low-carbon economies. The CMS projects that renewable energies (excluding hydro and biomass) will grow at an average annual rate of 7.8% between 2017 and 2040. This corresponds to a 1.1 percentage point increase compared to the RCS. Asia Pacific, particularly China and India, will drive the acceleration of renewables, especially solar. Demand for renewables will increase by more than 450 Mtoe between 2017 and 2040 in China and India, which is 150 Mtoe higher than incremental demand in the RCS. This increase is driven by continuous policy support and cost declines.

TAS+ also sees a promising future for renewables. Anticipated technological advancements in wind turbine, solar PV and CSP technologies will contribute to their accelerated deployment.

Policy support for renewables in China and India will be implemented through a combination of market-based mechanisms (including auctioning and tradable certificates) and through direct government intervention in the form of funding incentives and subsidies. The CMS also assumes that these two countries will be able to significantly reduce the curtailment of renewables through reinforced grid networks and improved flexibility of power systems. Gas-based power plants will play a key role in supporting this flexibility.

Oil demand growth is expected to decrease at an annual rate of 0.4% in the CMS and 0.32% in the TAS+, compared with 0.53% in the RCS. Oil demand reductions in the CMS and TAS+ are driven by greater penetration of EVs (representing a respective 20% and 23% of the passenger vehicle fleet in the CMS and TAS+ by 2040), as well as by the decreasing role of oil-fired power generation, mainly in emerging and developing countries.

Figure 6.8. Global primary energy demand trends by fuel type in all scenarios (Mtoe)



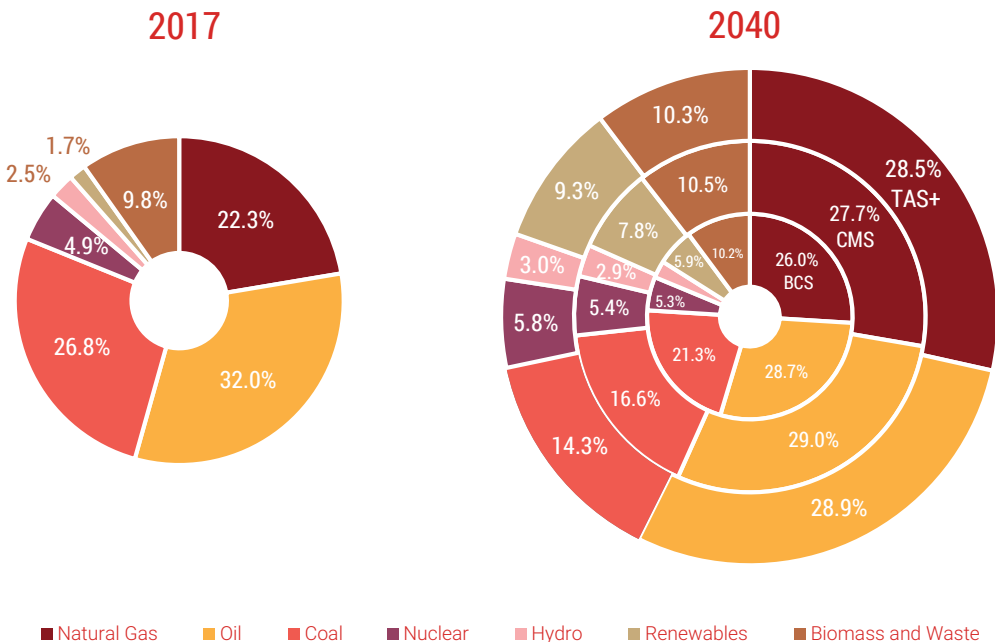
Source: GECF Secretariat based on data from the GECF GGM

The CMS does not expect further policy support for nuclear energy and additional nuclear capacities are not imposed on the RCS. As a result, the progress of other alternatives to nuclear in producing power, especially renewable energies and gas, contribute to the decrease in the average annual growth rate of nuclear from 1.4% to 1.3% over the forecast period. The growth prospects of renewables, natural gas, coal and oil in the CMS and TAS+ will lead to significant changes in the primary energy mix by 2040 (see Figure 6.8).

In the CMS, demand for natural gas and renewables is expected to be 110 Mtoe and 290 Mtoe higher respectively than in the RCS. Conversely, demand for coal and oil is expected to be 960 Mtoe and 162 Mtoe lower respectively. The substitution momentum in the power sector, coupled with the progress of EVs, is anticipated to be favourable for natural gas and renewables.

Adding the technology advancement assumptions to the CMS (as highlighted in the TAS+) increases natural gas demand by 65 Mtoe, amounting to more than 4800 Mtoe by 2040. The share of natural gas in total primary consumption will reach 27.7% and 28.5% respectively in the CMS and the TAS+ by 2040 (compared with 26% in the RCS). The share of renewables will also rise from 6% in the RCS to 7.8% in the CMS and 9.3% in the TAS+. If we include hydro and biomass/wastes, renewables' contribution will reach 21.3% in the CMS and 22.6% in the TAS+, significantly surpassing the share of coal. The role of coal in primary energy is, therefore, anticipated to decline significantly and reach 16.6% in the CMS and 14.3% in the TAS+ by 2040 (its share was 21.3% in the RCS).

Figure 6.9. Global primary energy mix in 2017 and 2040 by fuel type in all scenarios (%)



Source: GECF Secretariat based on data from the GECF GGM

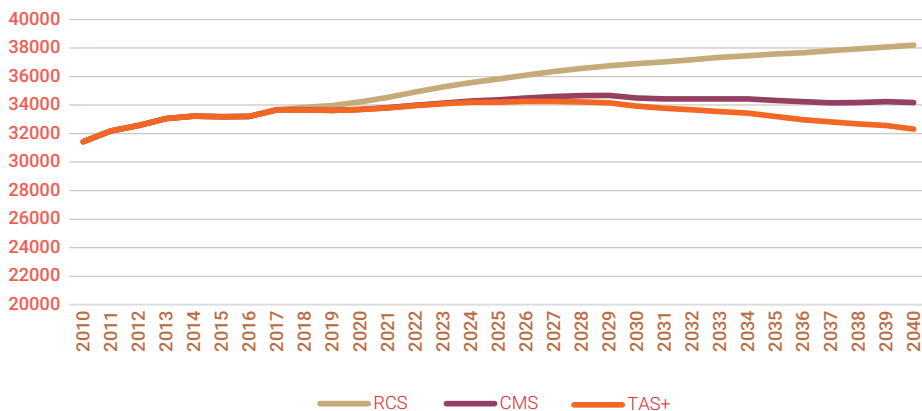
Global energy-related CO₂ emissions

Energy-related CO₂ emissions are expected to reach 34.2 GtCO₂ in the CMS by 2040. This will drop to around 32.3 GtCO₂ in the TAS+, which accounts for technology advancements in some carbon reduction options (e.g. efficiency improvement or electrification of final sectors), in addition to expected carbon mitigation efforts in the CMS. These 2040 emissions figures translate to non-negligible reductions compared to the RCS, estimated at 4.1 GtCO₂ in the CMS and nearly 6 GtCO₂ in the TAS+. The total CO₂ emission trajectory shows that emissions are expected to peak by 2030 in the CMS and by 2026 in the TAS+, meaning that emissions trends will be affected by anticipated technological developments in carbon-free and carbon mitigating technologies.

In the CMS, the bulk of emissions reductions comes from a changing power generation mix with renewable and natural gas penetration. This sector is expected to reduce its emissions by around 3.5 GtCO₂ amid the total 4.1 GtCO₂ reduction forecast for 2040 in this scenario. However, for TAS+, additional reductions (around 2 GtCO₂ by 2040) are expected to be achieved, with main contributions from the industrial and residential sectors, due to energy efficiency improvements and electrification. Reductions from the industry and buildings sectors are expected to compensate for increasing emissions from the power sector (Power related emissions are more than 1 GtCO₂ higher in TAS+ compared to the CMS by 2040). The aggressive electrification of final sectors due to technical enhancements in the TAS+ will accelerate electricity generation and reduce the efficacy of the power sector in mitigating CO₂ emissions.

In CMS, the transportation sector is anticipated to reduce emissions by nearly 300 MtCO₂, mainly as a result of the reduction of oil products demand in this sector. The consideration of further penetration of EVs in TAS + due to improved technology and reduced costs is expected to further reduce emissions by around 150 MtCO₂. Although the TAS in this outlook assumes moderate technical advancements in CCS when compared to the RCS, this technology will not be significantly implemented due to the still prohibitive costs as well as to the fact that CCS reduces the overall efficiency of power plants. That means CCS needs a significant breakthrough in terms of cost reduction and technical innovation to become economically competitive and viable in the energy system.

Figure 6.10. Prospect of global energy related CO₂ emissions (MtCO₂)



Source: GECF Secretariat based on data from the GECF GGM

ANNEX I: THE ESSENTIALS

Table 1.1: Population outlook by region, million					
	2000	2017	2020	2030	2040
World	6125	7531	7777	8534	9194
GECF	575	744	778	887	1002
GECF Members	480	619	647	737	833
Asia-Pacific	3432	4101	4202	4475	4639
China	1261	1386	1401	1417	1393
India	1053	1339	1383	1513	1605
Japan	128	127	126	122	115
Southeast Asia	518	641	660	718	760
Eurasia	281	289	292	294	293
Russia	146	144	144	141	136
European Union	487	509	511	513	510
North America	415	492	506	548	583
United States	283	326	334	359	379
Latin America	424	516	530	571	599
Brazil	175	209	214	225	232
MENA	313	438	460	528	589
Sub-Saharan Africa	679	1074	1161	1485	1855
South Africa	46	57	59	64	69

Source: UN World Population Prospects rev. 2017

*Rounding may lead to minor differences between totals and the sum of their individual components.

Table 1.2. GDP growth rates

Region	2018-2020	2021-2025	2026-2030	2031-2035	2036-2040	Mean growth rate
World (PPP)	2.8	3.7	3.4	3.1	3.0	3.4
GECF	2.2	3.2	2.8	2.7	2.6	2.9
GECF Members	2.2	3.3	2.8	2.7	2.6	2.9
Asia-Pacific	4.0	5.2	4.5	3.9	3.6	4.4
China	4.7	5.9	4.8	3.7	3.3	4.7
India	5.6	6.9	5.8	5.2	4.9	5.9
Japan	0.6	1.0	0.9	0.8	0.6	0.8
Southeast Asia	3.8	4.8	4.5	4.2	4.0	4.5
Eurasia	1.7	2.2	2.0	1.7	1.7	1.9
Russia	1.4	1.8	1.7	1.4	1.3	1.6
European Union	1.4	1.7	1.6	1.6	1.5	1.6
North America	1.7	2.0	2.0	2.1	2.1	2.1
United States	1.7	2.0	1.9	2.0	2.0	2.0
Latin America	2.0	3.2	3.2	3.1	3.1	3.1
Brazil	2.3	3.2	3.0	2.9	2.9	3.0
MENA	2.9	4.0	3.4	3.2	3.1	3.5
Sub-Saharan Africa	2.5	3.8	3.6	3.4	3.1	3.5
South Africa	1.0	2.1	2.9	3.0	3.0	2.6

Table 1.3. Medium-term economic outlook by region, 2018-2025

Region	2017	2018	2019	2020	2021	2022	2023	2024	2025	Mean growth rate 2017-2025
World (PPP)	3.6	3.7	3.8	3.8	3.8	3.8	3.7	3.7	3.6	3.7
GECF	1.9	2.4	2.9	3.1	3.3	3.3	3.2	3.2	3.1	3.1
GECF Members	1.7	2.3	2.8	3.1	3.4	3.4	3.2	3.2	3.1	3.1
Asia-Pacific	5.6	5.5	5.4	5.3	5.4	5.3	5.2	5.1	5.0	5.3
China	6.8	6.5	6.2	6.1	6.2	6.0	5.9	5.7	5.5	6.0
India	6.8	7.4	7.6	7.6	7.4	7.2	6.7	6.5	6.5	7.1
Japan	1.6	1.1	0.7	0.4	1.1	1.1	1.1	1.1	1.0	0.9
Southeast Asia	5.1	5.1	5.2	5.1	5.0	4.9	4.8	4.7	4.6	4.9
Eurasia	2.1	2.3	2.3	2.3	2.4	2.3	2.2	2.1	2.0	2.2
Russia	1.8	2.1	1.8	1.8	1.8	1.9	1.8	1.7	1.7	1.8
European Union	2.5	2.1	1.9	1.8	1.8	1.7	1.7	1.7	1.7	1.8
North America	2.3	2.4	2.3	2.1	2.1	2.2	2.0	2.0	2.0	2.1
United States	2.2	2.5	2.2	2.1	2.0	2.1	1.9	1.9	1.9	2.1
Latin America	0.8	1.5	2.6	3.0	3.1	3.2	3.2	3.2	3.3	2.9
Brazil	0.9	2.1	3.3	3.8	3.2	3.2	3.2	3.2	3.1	3.2
MENA	2.0	3.2	4.1	4.3	4.4	4.1	4.0	3.9	3.8	4.0
Sub-Saharan Africa	2.6	3.1	3.3	3.5	3.7	3.8	3.8	3.8	3.8	3.6
South Africa	0.8	1.0	1.3	1.5	1.6	1.9	2.0	2.4	2.7	1.8

Table 1.4. Main energy markets price projections

Fuel		2017	2020	2030	2040
Oil 2017\$/bbl	Brent	54	63	70	70
Natural gas, 2017\$/mmBtu	Henry Hub, US	3.2	2.7	4.1	4.8
	Asian Import Gas Price	6.8	7.4	9.6	10.0
	European Import Gas Price	5.3	4.7	8.5	9.4
	Latin American Gas Price	3.4	4.4	5.5	5.6
Thermal coal, 2017\$/t	Richards Bay, South Africa	77	85	76	78
	Amsterdam-Rotterdam-Antwerp	76	84	83	83
	Newcastle, Australia	81	94	81	82
	Chinese (internal)	78	91	83	83
	Indian (coastal)	81	92	86	86
	Russian	22	24	31	44
Carbon, 2017\$/tCO2	Japanese Trading System	0	5	14	30
	European Emission Trading Scheme	5	10	28	65

Table 3.1. Global primary energy demand by fuel type

Region					Mtoe
	2017	2020	2030	2040	CAAGR 2017-2040
Natural Gas	3161	3409	3983	4633	1.7%
Oil	4527	4667	5069	5109	0.5%
Coal	3788	3704	3843	3805	0.0%
Nuclear	692	737	830	943	1.4%
Hydro	352	373	434	480	1.4%
Renewables	237	335	691	1047	6.7%
Biomass and Waste	1387	1466	1653	1813	1.2%
Total Primary Energy Demand	14144	14691	16502	17829	1.0%

Table 3.2. Fuel shares of total primary energy demand

Region	2017	2020	2030	2040
Natural Gas	22%	23%	24%	26%
Oil	32%	32%	31%	29%
Coal	27%	25%	23%	21%
Nuclear	5%	5%	5%	5%
Hydro	2%	3%	3%	3%
Renewables	2%	2%	4%	6%
Biomass and Waste	10%	10%	10%	10%

Table 3.3. Global natural gas demand by sector

Region	2017	2020	2030	2040	bcm
					CAAGR 2017-2040
Domestic Sectors	751	791	864	924	0.9%
Industry	671	723	805	892	1.2%
Feedstocks	195	203	239	257	1.2%
Transport	137	148	249	357	4.2%
Power Generation	1332	1459	1786	2219	2.2%
Heat Generation	185	192	196	196	0.2%
Refinery	58	61	69	75	1.1%
Other Uses	333	374	415	458	1.4%

Note: Data for the hydrogen sector is currently insufficient (48 bcm in 2017), and has been omitted from Table 3.3.

Table 3.4: Natural gas demand by region					bcm
Region	2017	2020	2030	2040	CAAGR 2017 - 2040
North America	958	1054	1220	1435	1.8%
Asia Pacific	794	861	1107	1422	2.6%
Middle East	503	543	660	747	1.7%
Eurasia	599	608	666	681	0.6%
Europe	538	570	573	573	0.3%
Latin America	178	197	234	291	2.2%
Africa	139	162	206	278	3.1%
GECF (Members & Observers)	1053	1116	1266	1373	1.2%

Table 3.5: The world biggest gas consumers					bcm
Region	2017	2020	2030	2040	CAAGR 2017 - 2040
United States	759	851	991	1173	1.9%
China	245	294	484	701	4.7%
Russia	422	428	463	469	0.5%
Iran	195	216	270	301	1.9%
Saudi Arabia	89	98	130	154	2.4%
Canada	116	124	132	138	0.8%
India	56	67	109	127	3.6%
Mexico	82	79	97	124	1.8%
Japan	125	118	91	91	-1.4%
Indonesia	44	50	61	84	2.8%
Germany	93	94	90	76	-0.8%
Brazil	38	48	62	76	3.1%
Argentina	56	59	65	74	1.2%
UAE	74	73	69	74	0.0%
Egypt	45	58	63	73	2.2%
Turkey	54	56	58	72	1.3%
United Kingdom	79	83	75	69	-0.6%
South Korea	50	54	58	66	1.3%
Nigeria	19	27	41	65	5.6%
Italy	69	73	69	64	-0.3%
Australia	42	53	55	61	1.6%
Qatar	55	53	59	61	0.4%
Kazakhstan	35	39	55	55	2.0%
Malaysia	47	44	50	52	0.5%
Uzbekistan	47	46	50	52	0.4%

Table 4.1: Natural gas production by region					bcm
Region	2017	2020	2030	2040	CAAGR 2017 - 2040
Asia Pacific	588	647	746	904	1.9%
North America	955	1076	1249	1496	2.0%
Middle East	652	697	864	988	1.8%
Eurasia	850	910	1075	1145	1.3%
Europe	251	229	165	133	-2.7%
Latin America	184	178	215	260	1.5%
Africa	230	275	345	500	3.4%
Total World	3709	4010	4658	5427	1.7 %

ANNEX II: REGIONAL GROUPINGS

Advanced economies: OECD regional grouping, plus Bulgaria, Croatia, Cyprus, Latvia, Lithuania, Malta and Romania

Africa: North Africa and Sub-Saharan Africa regional groupings

Asia Pacific: Afghanistan, Australia, Bangladesh, Bhutan, Brunei Darussalam, Cambodia, China, Chinese Taipei, Cook Islands, Democratic People's Republic of Korea, Fiji, French Polynesia, Hong Kong, India, Indonesia, Japan, Kiribati, Korea, Lao People's Democratic Republic, Macau (China), Malaysia, Maldives, Mongolia, Myanmar, Nepal, New Caledonia, New Zealand, Pakistan, Palau, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Thailand, Timor-Leste, Tonga, Vanuatu, and Viet Nam

Caspian: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan, and Uzbekistan

Developed Asia: Australia, Japan, Korea, New Zealand

Developing Asia: Afghanistan, Bangladesh, Bhutan, Brunei Darussalam, Cambodia, China, Chinese Taipei, Cook Islands, Democratic People's Republic of Korea, Fiji, French Polynesia, Hong Kong, India, Indonesia, Kiribati, Lao People's Democratic Republic, Macau (China), Malaysia, Maldives, Mongolia, Myanmar, Nepal, New Caledonia, Pakistan, Palau, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Thailand, Timor-Leste, Tonga, Vanuatu, and Viet Nam

Developing economies: All other countries not included in the "advanced economies" regional grouping

Eurasia: Caspian region and Belarus, Moldova, the Russian Federation, and Ukraine

Europe: European Union and Albania, Bosnia and Herzegovina, Gibraltar, Iceland, Montenegro, Norway, Serbia, Switzerland, the Former Yugoslav Republic of Macedonia, the Republic of Moldova, and Turkey

European Union: Austria, Belgium, Bulgaria, Croatia, Cyprus, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, the Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, and the United Kingdom

GECF Members: Algeria, Bolivia, Egypt, Equatorial Guinea, Libya, Islamic Republic of Iran, Nigeria, Qatar, Russia, Trinidad and Tobago, the United Arab Emirates, and Venezuela

GECF Observer Members: Azerbaijan, Iraq, Kazakhstan, Netherlands, Norway, Oman, and Peru

Latin America: Antigua and Barbuda, Argentina, Aruba, Bahamas, Barbados, Belize, Bermuda, Bolivia, Brazil, British Virgin Islands, Cayman Islands, Chile, Colombia, Costa Rica, Cuba, Dominica, Dominican Republic, Ecuador, El Salvador, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Montserrat, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Saint Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, Saint Vincent and the Grenadines, Suriname, Trinidad and Tobago, Turks and Caicos Islands, Uruguay, and Venezuela

Middle East: Bahrain, the Islamic Republic of Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, the United Arab Emirates, and Yemen

Middle East and North Africa (MENA): Middle East and North Africa regional groupings

North Africa: Algeria, Egypt, Libya, Morocco, and Tunisia

North America: Canada, Mexico, and the United States of America

OECD: Australia, Austria, Belgium, Canada, Chile, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Korea, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, the Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey, United Kingdom and the United States.

Southeast Asia: Brunei Darussalam, Cambodia, Indonesia, Malaysia, Myanmar, Philippines, Singapore, Thailand, and Viet Nam

Sub-Saharan Africa: Angola, Benin, Botswana, Burkina Faso, Burundi, Cabo Verde, Cameroon, Central African Republic, Chad, Comoros, Côte d'Ivoire, Democratic Republic of the Congo, Djibouti, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea Bissau, Kenya, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Mozambique, Namibia, Niger, Nigeria, Republic of the Congo, Réunion, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Sudan, Swaziland, Togo, Uganda, United Republic of Tanzania, Zambia, and Zimbabwe

ANNEX III: ABBREVIATIONS

ACE	Affordable Clean Energy rule (US)
ADGSM	Australian Domestic Gas Security Mechanism
AEMO	Australian Energy Market Operator
AI	Artificial Intelligence
AV	Autonomous vehicle
BEV	Battery electric vehicles
BLM	United States Bureau of Land Management
bn	Billion
CAAGR	compound annual average growth rate
CBM	coalbed methane
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CH ₄	methane
CHP	combined heat and power
CNG	compressed natural gas
CNPC	Chinese National Petroleum Company
CO ₂	carbon dioxide
CPP	Clean Power Plan (US)
CPS	carbon price support
DOI	United States Department of the Interior
EAU	emission allocation unit
EB	Executive Board (GECF)
EC	European Commission
ECB	European Central Bank
EIA	Energy Information Administration (US)
EOR	enhanced oil recovery
EPA	US Environmental Protection Agency
EU	European Union
EV	electric vehicle
FID	final investment decision
FSRU	floating storage regasification unit
FYP	Five-Year Plan
GCP	Global Carbon Project
GDP	gross domestic product
GECF	Gas Exporting Countries Forum
GGM	Global Gas Model
GGO	Global Gas Outlook

GHG	greenhouse gas
GIIGNL	International Group of Liquefied Natural Gas Importers
GTL	gas to liquids
ICE	internal combustion engine
IEA	International Energy Agency
IED	Industrial Emissions Directive
IMF	International Monetary Fund
IMO	International Maritime Organization
INDC	Intended Nationally Determined Contribution
ITGI	Interconnection Turkey-Greece-Italy
JCPOA	Joint Comprehensive Plan of Action
JFTC	Japan Fair Trade Commission
JKM	Japan Korea Marker
JOGMEC	Japan Oil, Gas and Metals National Corporation
JPY	Japanese yen
LCV	light commercial vehicle
LFPR	labour force participation rate
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MER	market exchange rates
NAFTA	North American Free Trade Agreement
NBP	National Balancing Point (UK gas hub)
NDCs	Nationally Determined Contributions
NEXI	Nippon Export and Investment Insurance
NGO	non-governmental organisation
NGV	natural gas vehicles
NOx	nitrogen oxides
OCS	Outer Continental Shelf
OPEC	Organization of the Petroleum Exporting Countries
PHEV	Plug-in hybrid electric vehicles
PPP	purchasing power parity
PSPP	Public Sector Purchase Programme
PSV	Punto-di-scambio-virtuale
PV	photovoltaic

R&D	research and development
RBI	Reserve Bank of India
RES	Reference Energy System
RPS	renewable portfolio standards (US)
SDGs	Sustainable Development Goals
SOx	sulfur oxides
SCP	Southern Caucasus Pipeline
TANAP	Trans-Anatolian gas pipeline
TAP	Trans Adriatic Pipeline
TAPI	Turkmenistan-Afghanistan-Pakistan-India pipeline
TEC	Technical and Economic Council
TENP	The Trans Europa Naturgas Pipeline
TPES	total primary energy supply
TTF	Title Transfer Facility (Dutch gas hub)
UAE	United Arab Emirates
UK	United Kingdom
UN	United Nations
US	United States
USD	United States Dollar
VAT	value-added tax
WEF	World Economic Forum
WHO	World Health Organization
WTI	West Texas Intermediate
WTO	World Trade Organization
YTF	yet-to-find

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ANNEX V: CONVERSION FACTORS AND DEFINITIONS

From\To	CM	mmBtu	toe	GJ	Therms	CF	T LNG	CM LNG	MWh
CM (S)	1	0.034	0.0009	0.035797	0.34	35.31	0.0007252	0.001639	0.009944
mmBtu	29.47	1	0.02519	1.0548	10.00	1040.59	0.021	0.048	0.293
toe	1169.59	39.69	1	41.868	396.93	41303.70	0.8481	1.917	11.63
GJ	27.94	0.9480	0.0239	1	9.48	986.52	0.0203	0.0458	0.2778
Therms	2.947	0.1000	0.0025	0.1055	1	104.06	0.0021	0.0048	0.0293001
CF	0.02832	0.000961	0.00002421	0.0010	0.009610	1	0.000021	0.000046	0.00028
T LNG	1379	46.80	1.1791	49.36	468.00	48699	1	2.26	13.71
CM LNG	610.0	20.70	0.5216	21.84	207.02	21542	0.4423	1	6.066
MWh	100.57	3.413	0.0860	3.600	34.13	3551	0.073	0.16	1
BOE	151.9	5.155	0.1299	5.438	51.55	5364	0.1101	0.2490	1.5104
TC	701.8	23.82	0.6000	25.12	238.16	24782	0.5089	1.1504	6.9780

NATURAL GAS							LNG			
MJ/ Nm3 (GCV)	kCal/ Nm3 (GCV)	kWh/ Nm3	(N)bcm/ mtoe	(S)bcm/ mtoe	MJ/ Sm3 (GCV)	kCal/Sm3 (GCV)	kWh/ Sm3	Btu/Scf (GCV)	mmBtu/ Tonnes LNG	47
41.959	10,022	11.66	1.1087	1.1696	39.775	9500	11.049	1068	CM/Cubic meters LNG	610

Note: Each of the gas production entities has its own calorific value so the specific value is used for these flows to convert into the energy content. For this reason values that appear in the production entity tables and in the supply data tables that aggregate the volumes may be different from the production values using standard conversion factors

Agriculture

Includes all energy used on farms, in forestry, and for fishing [ISIC Divisions 01 – 03].

Associated gas

A natural gas found in contact with or dissolved in crude oil in the reservoir.

Barrel of Oil Equivalent (BOE)

The term allows for a single value to represent the sum of all the hydrocarbon products that are forecast as resources. Typically, condensate, oil, bitumen, and synthetic crude barrels are taken to be equal (1 bbl = 1 BOE). Gas and NGL quantities are converted to an oil equivalent based on a conversion factor that is recommended to be based on a nominal heating content or calorific value equivalent to a barrel of oil.

Biofuels

Liquid fuels derived from biomass or waste feedstocks, including ethanol and biodiesel.

Biomass and waste

Renewable organic materials, such as wood, agricultural crops or wastes, and municipal wastes, especially when used as a source of fuel or energy. Biomass can be burned directly or processed into biofuels such as ethanol and methane.

Bunkers

Includes both international marine bunkers and international aviation bunkers.

Coal

Includes primary coal (hard coal, lignite, coking, and steam coal) and derived fuels (including patent fuel, brown coal briquettes, coke oven coke, gas coke, gas-works gas, coke-oven gas, blast-furnace gas, and oxygen steel furnace gas). Peat is also included.

Coalbed methane

Natural gas contained in coal deposits. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. [Also called coal-seam gas or natural gas from coal.]

Condensate

A mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from NGLs in two respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGL includes very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensate.

Contracts for Difference

A mechanism of hedging the price of electricity for renewables between renewable generators and counter parties (for instance Low Carbon Contracts Company in the UK). It allows the generators to receive a pre-agreed

level for the duration of contracts (the strike price). Under this mechanism, when the market price for electricity generated (the reference price) is below the strike price agreed in the contract, compensation is paid by the counter party. On the other side, when the reference price is above the strike price, the renewable generator pays the counterpart.

Conventional resources

Resources that exist in porous and permeable rock with buoyancy pressure equilibrium. The PIIP is trapped in discrete accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a down dip contact with an aquifer, and is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.

Cost tranche

A set of production entities grouped according to a defined cost range.

Curtailement

According to National Renewable Energy Laboratory, curtailment is a reduction in the output of a generator of variable renewable energy from what it could otherwise produce given available resources like wind or sunlight. Variable renewable energy curtailment is usually used as a way to reduce the production of energy that cannot be delivered due to lack of power system flexibility.

Distributed energy system

Include systems which generate and deliver energy services (Power, cooking, or heating services) in an independent way from centralised systems. For renewable power, they include particularly off grid renewable generators such as home solar panels.

Domestic

The domestic sector includes energy used in the residential, commercial and agricultural sectors. Domestic energy use includes space heating and cooling, water heating, lighting, appliances, and cooking equipment.

Dry gas

Natural gas remaining after hydrocarbon liquids have been removed before the reference point. It should be recognized that this is a resources assessment definition and not a phase behaviour definition. (Also called lean gas.)

Electricity generation

Defined as the total amount of electricity generated by power only or combined heat and power plants including generation required for own-use. This is also referred to as gross generation.

Energy sector

Covers the use of energy by non-energy sector and the energy losses in converting primary energy into a form that can be used in the final consumption sectors. It includes losses by gas works, petroleum refineries, blast furnaces, coke ovens, coal and gas transformation, and liquefaction. It also includes energy used in the distribution network. Transfers and statistical differences are also included in this category.

Enhanced oil recovery (EOR)

The extraction of additional petroleum, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes, and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called improved recovery.)

Existing gas production facilities

Those that are in production as of 2017.

Feed-in premium

A renewable policy support mechanism which offers a compensation based on markets conditions. In this mechanism, electricity from renewable energy sources is sold on the electricity spot market and renewable producers receive a premium on top of the market price of their electricity production. No premium is paid if market prices are higher than the reference tariff level.

Feed-in tariff

A renewable policy support mechanism which offers a fixed compensation to renewable energy producers, providing price certainty and long-term contracts that help finance renewable energy investments. The level of compensation is based on the cost of generation of each technology.

Feedstock

Includes refinery feedstocks and petrochemical feedstocks.

Final Investment Decision (FID)

Project approval stage when the participating companies have firmly agreed to the project and the required capital funding.

Flare gas

The total quantity of gas vented and/or burned as part of production and processing operations (but not as fuel).

Gas exports (upstream volumes)

Gas volumes shipped by a gas exporting country to an importing country including all the losses (pipelines, liquefaction, shipping, and regasification).

Gas hydrates

Naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cage-like structure or clathrate. At conditions of standard temperature and pressure, one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Gas hydrates are included in unconventional resources, but the technology to support commercial maturity has yet to be developed.

Gas imports (end use volumes)

Net gas volumes delivered by an exporting country to an importing country, not including the losses during the shipment.

Heat energy

Obtained from the combustion of fuels, nuclear reactors, geothermal reservoirs, the capture of sunlight, exothermic chemical processes, and heat pumps which can extract it from ambient air and liquids. It may be used for heating or cooling, or converted into mechanical energy for transport vehicles or electricity generation. Commercial heat sold is reported under total final consumption with the fuel inputs allocated under power generation.

Heat generation

Refers to fuel use in heat plants and combined heat and power (CHP) plants.

Heat Plants

Heat plants, refers to plants (including heat pumps and electric boilers) designed to produce heat.

Hydropower

The energy content of the electricity produced in hydropower plants.

Industry

Includes fuel used within the manufacturing and construction industries. Key industry sectors include iron and steel, chemical and petrochemical, nonferrous metals, non-metallic minerals, and other manufacturing.

International aviation bunkers

Includes the deliveries of aviation fuels to aircraft for international aviation. The domestic/international split is determined based on departure and landing locations and not by the nationality of the airline.

International marine bunkers

Covers those quantities delivered to ships of all flags that are engaged in international navigation. The international navigation may take place at sea, on inland lakes and waterways, and in coastal waters. Consumption by ships engaged in domestic navigation is excluded. The domestic/international split is determined because of the port of departure and port of arrival, and not by the flag or nationality of the ship.

Nationally Determined Contributions (NDCs)

Intended Nationally Determined Contributions (INDCs) after their ratification by individual governments. They include the countries' GHG mitigation and adaptation pledges submitted to the UNFCCC in the framework of the Paris Agreement.

Natural gas liquids (NGLs)

A mixture of light hydrocarbons that exist in the gaseous phase in the reservoir and are recovered as liquids in gas processing plants. NGLs differ from condensate in two principal respects: (1) NGLs are extracted and recovered in

gas plants rather than lease separators or other lease facilities, and (2) NGLs include very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensates.

Natural gas production capacity

The potential volumes of natural gas ready to be produced by developed wells and processing units associated with a production entity.

Natural gas production

Marketed production including domestic sales and exports

Natural gas proven reserves

Refers to existing reserves, new projects, and unconventional (existing) gas resources.

Natural gas

Portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in a reservoir, and which is gaseous at atmospheric conditions of pressure and temperature. Natural gas may include some amount of non-hydrocarbons.

New project gas production

Fields that have been discovered but have yet to be developed or are in development.

Non-energy use

Fuels used for non-energy products excluding use as feedstock in petrochemical plants. Examples of non-energy products include gas works, cooking ovens, lubricants, paraffin waxes, asphalt, bitumen, coal tars, and oils as timber preservatives.

Nuclear

Refers to the primary energy equivalent of the electricity produced by a nuclear plant, assuming an average conversion efficiency of 33%.

Oil

Includes demand for crude oil both conventional and unconventional and petroleum products include refinery gas, ethane, LPG, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, heavy fuel oil naphtha, and other oil products (white spirit, lubricants, bitumen, paraffin, waxes, and petroleum coke) and natural gas liquids but excludes biofuels and synthetic oil based products.

Oil sands

Sand deposits highly saturated with natural bitumen. Also called "tar sands." Note that in deposits such as the western Canada oil sands, significant quantities of natural bitumen may be hosted in a range of lithologies, including siltstones and carbonates.

Petrochemical feedstocks

The petrochemical industry includes cracking and reforming processes for the purpose of producing ethylene, propylene, butylene, synthesis gas, aromatics, butadiene and other hydrocarbon-based raw materials in processes such as steam cracking, aromatics plants, and steam reforming.

Power generation

Refers to fuel use in electricity plants and combined heat and power (CHP) plants.

Probable reserves

An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Production entity

A gas field, or group of gas fields located in the same zone, or gas geological prospects from which marketed natural gas production is expected to be available and economically viable.

Production signature

A curve that models the rate at which the remaining recoverable gas reserves will be produced, without damaging the corresponding reservoir.

Proved reserves

Those quantities that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations

Refinery feedstocks

Processed oil destined for further processing (e.g. straight run fuel oil or vacuum gas oil) other than blending in the refining industry. It is transformed into one or more components and/or finished products. This definition covers those finished products imported for refinery intake and those returned from the petrochemical industry to the refining industry.

Renewables

Geothermal, hydropower, solar photovoltaics (PV), concentrating solar power (CSP), wind and marine (tide and wave) energy for electricity and heat generation.

Reserves

Those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied

Residential

Energy used by households including space heating and cooling, water heating, lighting, appliances, electronic devices, and cooking equipment.

Shale gas

Although the terms shale gas and tight gas are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight gas production.

Tight gas

Gas that is trapped in pore space and fractures in very low-permeability rocks and/or by adsorption on kerogen, and possibly on clay particles, and is released when a pressure differential develops. It usually requires extensive hydraulic fracturing to facilitate commercial production. Shale gas is a sub-type of tight gas.

Total final consumption

The sum of consumption by the different end-use sectors. TFC is broken down into energy demand in the following sectors: industry, transport, domestic (including residential, commercial and agriculture), and feedstock uses.

Total primary energy demand

Represents domestic demand only and is broken down into power generation, heat generation, refinery, energy sector, non-energy sector, and total final consumption.

Transport

Fuels and electricity used in the transport of goods or persons within the national territory irrespective of the economic sector within which the activity occurs. This includes fuel and electricity delivered to vehicles using public roads or for use in rail vehicles; fuel delivered to vessels for domestic navigation; fuel delivered to aircraft for domestic aviation; and energy consumed in the delivery of fuels through pipelines. Fuel delivered to international marine and aviation bunkers is presented only at the global level and is excluded from the transport sector at a domestic level

Unconventional gas production

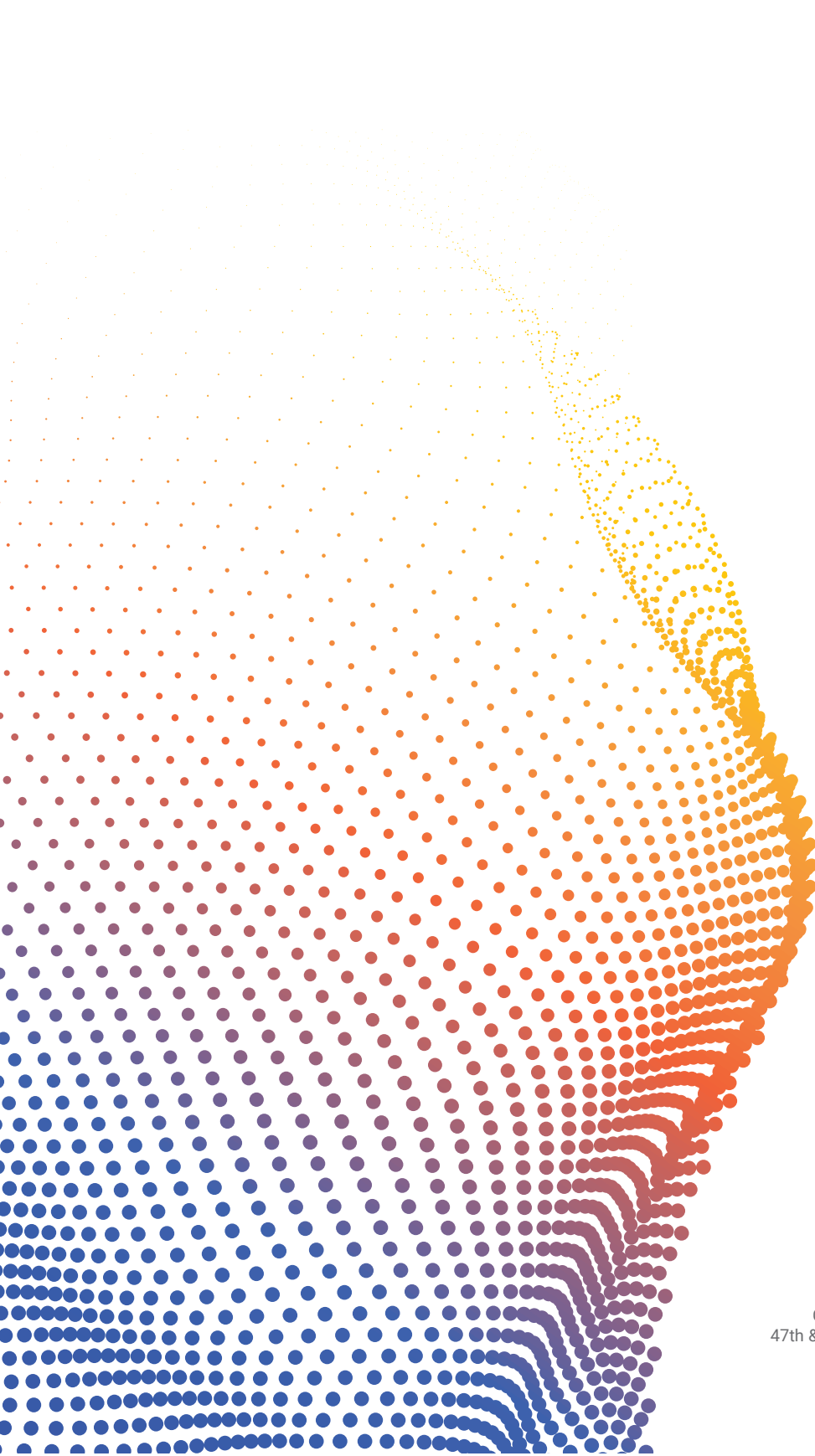
Fields that are associated with gas resources that are from either coal bed methane, tight shale, or other resources that require special development techniques.

Unconventional resources

Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and lack well-defined OWC or GWC (also called “continuous-type deposits”). Such resources cannot be recovered using traditional recovery projects owing to fluid viscosity (e.g., oil sands) and/or reservoir permeability (e.g., tight gas/oil/CBM) that impede natural mobility. Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).

Yet-to-Find (YTF)

Refers to the theoretical volume of undiscovered gas reserves, calculated based on the probability of finding reserves in certain geological areas. YTF also assumes that technological advancements will make it economically feasible to extract the gas in the future.



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