International Energy Agency
Secure
Sustainable
Together

Outlook for Natural Gas

Excerpt from World Energy Outlook 2017

INTERNATIONAL ENERGY AGENCY

The IEA examines the full spectrum of energy issues including oil, gas and coal supply and demand, renewable energy technologies, electricity markets, energy efficiency, access to energy, demand side management and much more. Through its work, the IEA advocates policies that will enhance the reliability, affordability and sustainability of energy in its 30 member countries, 7 association countries and beyond.

The four main areas of IEA focus are:

- **Energy Security**: Promoting diversity, efficiency, flexibility and reliability for all fuels and energy sources;
- **Economic Development**: Supporting free markets to foster economic growth and eliminate energy poverty;
- **Environmental Awareness**: Analysing policy options to offset the impact of energy production and use on the environment, especially for tackling climate change and air pollution; and
- **Engagement Worldwide**: Working closely with association and partner countries, especially major emerging economies, to find solutions to shared energy and environmental concerns.

IEA member countries:

Australia
Austria
Belgium
Canada
Czech Republic
Denmark
Estonia
Finland
France
Germany
Greece
Hungary
Ireland
Italy
Japan
Korea
Luxembourg
Mexico
Netherlands
New Zealand
Norway
Poland
Portugal
Slovak Republic
Spain
Sweden
Switzerland
Turkey
United Kingdom
United States

The European Commission also participates in the work of the IEA.

International Energy Agency
Secure
Sustainable
Together

International Energy Agency
Website: *www.iea.org*

Introduction

A new natural gas order is emerging. Resources are abundant and gas is a flexible fuel that can meet multiple needs across the energy system, with lower emissions than coal or oil. However, the competitive landscape is formidable, policy pressures can evolve rapidly and gas infrastructure is not cheap. This focus on natural gas, part of the World Energy Outlook 2017 (WEO-2017), explores in detail the contours of this new gas order. It examines how the rise of shale gas and LNG are changing the global gas market as well as the opportunities and risks for gas in the transition to a cleaner energy system.

This report reprints in full the special section of the WEO-2017 covering the outlook for natural gas, which consists of four chapters (Chapters 8-11 of the full edition):

- Chapter 8 presents a **summary of the main scenarios**, covering key demand and supply trends as well as trade and investment flows. It includes a focus on the outlook for coalbed methane and on the prospects for liquefied natural gas (LNG).
- In Chapter 9 we examine **the structural transformation in the gas market that is being spurred by the rise of LNG**, in particular from the United States, in the direction of a more interconnected and globalised network. It considers the potential implications of this transition for pricing, contracts, affordability, investment and security of supply.
- Chapter 10 assesses the **environmental case for natural gas**, the lower combustion emissions of natural gas versus other fossil fuels (for both carbon dioxide [CO_2] and the pollutants that cause poor air quality), the climate risks associated with direct methane emissions to the atmosphere, and the approaches, costs and benefits of action to reduce methane emissions.
- Chapter 11 explores in detail the **role of gas in clean energy transitions** and how this plays out in different sectors and countries, and how it evolves over time. It concludes with a review of the possibilities to decarbonise gas supply itself.

The chapter draws on the broader analysis and modelling in the WEO-2017 and makes reference to three scenarios: the New Policies Scenario, the Current Policies Scenario and the Sustainable Development Scenario. They are differentiated primarily by the assumptions made about government policies. The New Policies Scenario is designed to show where existing policies as well as announced policy intentions might lead the energy sector. The Current Policies Scenario provides a point of comparison by considering only those policies and measures enacted into legislation by mid-2017. And the Sustainable Development Scenario, a new scenario in the WEO-2017, examines what it would take to achieve the main energy-related components of the "2030 Agenda for Sustainable Development" adopted in 2015 by member states of the United Nations. The three energy-related goals are: to achieve universal energy access to modern energy by 2030; to take urgent action to combat climate change; and to dramatically reduce the pollutant emissions that cause poor air quality.[1]

References to all of the scenarios are interspersed throughout the chapters. However, the primary focus in Chapters 8 and 9 is on the New Policies Scenario, while the attention shifts more towards the Sustainable Development Scenario as we investigate the role of natural gas in clean energy transitions in Chapter 11. None of the long-term scenarios examined here is an IEA forecast.

Natural gas prices

There is no single global price for gas, as there is for oil. Instead we have a range of regionally determined prices, all with their own specificities, that become gradually more interlinked as we move towards a more interconnected global market, driven by the increasing share of liquefied natural gas (LNG) in global trade, and by the increasing flexibility of this trade to seek the most advantageous commercial destination

Table I ▷ Fossil-fuel import prices by scenario

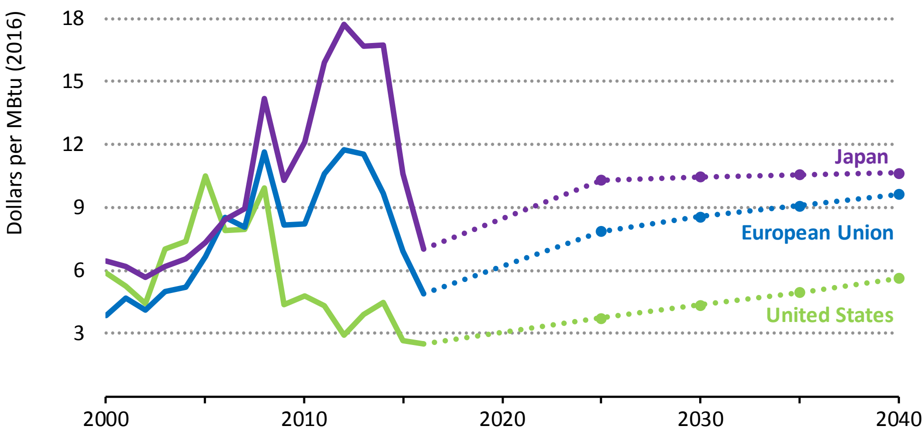
				New Policies				Current Policies		Sustainable Development	
Real terms ($2016)	**2000**	**2010**	**2016**	**2025**	**2030**	**2035**	**2040**	**2025**	**2040**	**2025**	**2040**
IEA crude oil ($/barrel)	38	86	41	83	94	103	111	97	136	72	64
Natural gas ($/MBtu)											
United States	5.9	4.8	2.5	3.7	4.4	5.0	5.6	4.3	6.5	3.4	3.9
European Union	3.8	8.2	4.9	7.9	8.6	9.1	9.6	8.2	10.5	7.0	7.9
China	3.5	7.4	5.8	9.4	9.7	10.0	10.2	10.4	11.1	8.2	8.5
Japan	6.4	12.1	7.0	10.3	10.5	10.6	10.6	10.8	11.5	8.6	9.0
Steam coal ($/tonne)											
United States	37	63	49	61	61	62	62	62	67	56	55
European Union	46	101	63	77	80	81	82	81	95	67	64
Japan	44	118	72	82	85	86	87	86	101	71	68
Coastal China	34	127	80	87	89	90	91	90	101	78	77

Notes: MBtu = million British thermal units; LNG = liquefied natural gas. The IEA crude oil price is a weighted average import price among IEA member countries. Natural gas prices are weighted averages expressed on a gross calorific-value basis. The US gas price reflects the wholesale price prevailing on the domestic market. The EU and China gas prices reflect a balance of pipeline and LNG imports, while the Japan gas price is solely LNG imports; the LNG prices used are those at the customs border, prior to regasification. Steam coal prices are weighted averages adjusted to 6 000 kilocalories per kilogramme. The US steam coal price reflects mine-mouth prices (primarily in the Powder River Basin, Illinois Basin, Northern Appalachia and Central Appalachia markets) plus transport and handling cost. Coastal China steam coal price reflects a balance of imports and domestic sales, while the EU and Japanese steam coal price is solely for imports.

[1] More information on the assumptions that underpin this analysis, including GDP, population, energy prices and technology costs, is available in Chapter 1 of the WEO-2017, which is available to download from https://www.iea.org/media/weowebsite/2017/Chap1_WEO2017.pdf

The price trajectory for North America plays a critical role in our formation of global prices. The reference price is that of Henry Hub, a distribution hub in the US pipeline system in Louisiana where the price is set entirely by gas-to-gas competition, i.e. it is a price that balances regional supply and demand (including demand for gas for export). The projected price at this hub is lower in each scenario than in *WEO-2016*. As with oil, this reflects an increase in the resource estimate for shale gas in the United States, and lower assumed costs for its production (see Chapter 9). It also reflects larger volumes of associated gas as a result of higher anticipated tight oil production.

Figure I ▹ **Natural gas prices by key region in the New Policies Scenario**



Natural gas prices in the main regions are connected by an increasingly flexible global trade in LNG

Note: See Table I for more details on natural gas price definitions.

A period of ample supply in gas markets, alongside the low level of oil prices, has brought down prices in all the major markets, even though the way that gas prices are determined varies by region. In the case of Europe, an increasing share of imported gas is priced off trading hubs, particularly in north-western Europe, but a sizeable residual volume concentrated in southern and south-eastern Europe has prices indexed in full or in part to oil product prices. In Asia, oil-indexation still remains the norm for most imported gas, but new contracts in many parts of the region are weakening this linkage by including references to other indices, including the US Henry Hub.

In our projections, we assume movement in the direction of an integrated global gas market, in which internationally traded gas moves in response to price signals that are determined by the balance of gas supply and demand in each region, i.e. by gas-to-gas competition, and the differences between regional prices reflect only the costs of transporting gas between them. In this new, more liquid market, described in more detail in the special focus on natural gas (see in particular Chapter 9), large US resources and production flexibility, combined with an LNG export industry actively seeking arbitrage opportunities, make Henry Hub not only a regional but also an important global reference for gas price formation. Exporters trying to sell gas at a level above the delivered cost of US supply ultimately find themselves priced out of the market.

Profitable export opportunities from the United States are constrained for the moment by the global supply glut. As markets find a new equilibrium in the 2020s, however, European average import prices settle around $4/MBtu (in year-2016 dollars) above the Henry Hub price in all scenarios, a differential that reflects the cost of delivering US gas to export terminals together with liquefaction and shipping costs. Oil-linked pricing is stronger in Asia than elsewhere, but this link weakens and in Japan the differentials from the US price fall to around $5/MBtu (the additional sum, compared with Europe, reflecting the extra shipping distance to Asian markets).[2]

[2] The continued differentials in average import prices between Japan and China shown in Table 1.4 reflect the additional shipping distance for LNG to Japan, compared with the main Chinese LNG terminals and the slightly lower projected border prices for Chinese pipeline imports, especially those from Central Asia.

Acknowledgements

This study was prepared by the World Energy Outlook (WEO) team in the Directorate of Sustainability, Technology and Outlooks (STO) as part of the 2017 edition of the WEO, in cooperation with other directorates and offices of the Agency. It was designed and directed by **Tim Gould**, Head of the WEO Energy Supply Outlook Division. The principal authors were **Christophe McGlade** and **Johannes Trüby**, who co-ordinated and co-led the work. **Laura Cozzi**, Head of the WEO Energy Demand Outlook Division, provided invaluable guidance throughout. The other main contributors were **Paweł Olejarnik** (lead on supply modelling), **Timur Gül** (lead on demand modelling), **Elie Bellevrat** and **Stéphanie Bouckaert** (co-leads on end-use modelling), **Brent Wanner** (lead on power), together with **Zakia Adam**, **Tord Bjørndal**, **Ian Cronshaw**, **Davide D'Ambrosio**, **Paul Hugues**, **Tae-Yoon Kim**, **Markus Klingbeil** and **Ulises Neri Flores**, with additional inputs from across the entire WEO team. **Teresa Coon** and **Eleni Tsoukala** provided essential support. **Edmund Hosker** carried editorial responsibility.

The study benefited from numerous inputs, comments and feedback from senior IEA management and IEA experts, in particular: Paul Simons, Keisuke Sadamori, Laszlo Varro, Aad Van Bohemen, Neil Atkinson, Rebecca Gaghen, Peter Fraser and Alessandro Blasi. Thanks go to the IEA's Communication and Information Office for their help, notably Astrid Dumond for production and to Bertrand Sadin for graphics.

The International Institute for Applied Systems Analysis and Paul Balcombe from Imperial College in London also provided valuable inputs to the analysis.

The work could not have been achieved without the support and co-operation provided by many government bodies, organisations and companies worldwide, notably: Ministry of Economy, Trade and Industry, Japan; Secretaría de Energia, Mexico; Energy Market Authority, Singapore; Center for Strategic and International Studies, United States; ClimateWorks Foundation; Energy Research Institute, National Development and Reform Commission, China; Environmental Defense Fund, United States; The Research Council of Norway; Gas and Oil Technologies Collaboration Programme; Oil and Gas Climate Initiative; Royal Dutch Shell and Statoil. Special thanks also go to the companies that participated in the activities of the IEA Energy Business Council (EBC) during 2017 as these generated valuable inputs to this study.

A number of workshops and meetings were organised to provide input to this study. The participants offered valuable new insights, feedback and data for this analysis.

- Technical workshop on methane emissions, Paris, 2 February 2017
- 5th IEA Unconventional Gas Forum, organised with the Centre for Coal Seam Gas and the Energy Initiative at The University of Queensland, Brisbane, 24 February 2017
- High-level Workshop on the Strategic Role of Natural Gas, organised with the Center for Strategic and International Studies, Washington, D.C., 5 May 2017

Many international experts provided input and reviewed the preliminary drafts of the report. Their comments and suggestions were of great value. They include:

Boyana Achovski	Gas Infrastructure Europe
Jason Bordoff	Columbia University, United States
Albert Bressand	Rijksuniversiteit Groningen and Columbia Center for Sustainable Investment
Mark Brownstein	Environmental Defense Fund, United States
Mick Buffier	Glencore
Jane Burston	National Physical Laboratory, United Kingdom
Nick Butler	Independent consultant
Guy Caruso	Center for Strategic and International Studies, United States
Xavier Chen	Statoil China
Jostein Dahl Karlsen	Ministry of Petroleum, Norway
Gilles De Noblet	Schlumberger
Marc Debever	EDF
Jos Dehaeseleer	Marcogaz
James Diamond	Government of Canada
Daniel Dorner	HM Treasury, United Kingdom
Jean Baptiste Dubreuil	Engie
Adeline Duterque	Engie
Pamela Franklin	United States Environmental Protection Agency
Mike Fulwood	Nexant
Rosanna Fusco	Oil and Gas Climate Initiative
Andrew Garnett	University of Queensland, Australia
Francesco Gattei	Eni
David Goldwyn	Atlantic Council, United States
Roy Hartstein	Southwestern Energy
David Hawkins	Natural Resources Defense Council, United States
Harald Hecking	EWI Energy Research and Scenarios
James Henderson	Oxford Institute for Energy Studies, United Kingdom
Doug Hengel	German Marshall Fund of the United States
Masazumi Hirono	Tokyo Gas
Neil Hirst	Imperial College London, United Kingdom
Lena Höglund-Isaksson	International Institute for Applied Systems Analysis
Didier Houssin	IFP Energies Nouvelles, France
Anil K. Jain	NITI Aayog, India
James Jensen	Jensen Associates
Jan-Hein Jesse	JOSCO Energy Finance and Strategy Consultancy
James Jewell	Department of Energy, United States
Jiang Kejun	Energy Research Institute, National Development and Reform Commission, China

Marianne Kah	ConocoPhillips
Fabian Kęsicki	E.ON
David Knapp	Energy Intelligence Group
Paweł Konzal	Chevron
Ken Koyama	Institute of Energy Economics, Japan
Vello Kuuskraa	Advanced Resources International
Sarah Ladislaw	Center for Strategic and International Studies
Benoit Lebot	International Partnership for Energy Efficiency Cooperation
Li Yao	SIA Energy, China
Liu Xiaoli	Energy Research Institute, National Development and Reform Commission, China
Antonio Lopez Rodriguez	Repsol
Joan MacNaughton	The Climate Group / Energy Academy of Europe
Pedro Antonio Merino García	Repsol
Cristobal Miller	Department of Natural Resources Canada
Tatiana Mitrova	Energy Research Institute of the Russian Academy of Sciences
Simone Mori	Enel
Gerard Moutet	Oil and Gas Climate Initiative
Isabel Murray	Department of Natural Resources Canada
Drew Nelson	Environmental Defense Fund, United States
Per Magnus Nysveen	Rystad Energy
Todd Onderdonk	ExxonMobil
Stephan Plisson-Saune	Total
Valérie Quiniou-Ramus	Total
Mark Radka	UN Environment Programme
Seth Roberts	Dow Chemical
Konstantin Romanov	Gazprom
Stephanie Saunier	Carbon Limits
Adnan Shihab-Eldin	Foundation for the Advancement of Sciences, Kuwait
Steve Shim	SK Group
Maria Sicilia Salvadores	Enagas
Pierre Sigonney	Total
Robert Siveter	Former IPIECA
Rob Smith	Department of Energy, United States
Christopher Snary	Department for Business, Energy and Industrial Strategy, United Kingdom
Jonathan Stern	Oxford Institute for Energy Studies, United Kingdom
Phil Swanson	Climate and Clean Air Coalition
Kazushige Tanaka	Ministry of Economy, Trade and Industry, Japan
Mark Taylor	Alberta Energy Regulator, Canada
Wim Thomas	Royal Dutch Shell

Noé van Hulst	Permanent Representation of the Kingdom of the Netherlands to the OECD
Eirik Waerness	Statoil
Andrew Walker	Cheniere
Paul Welford	Hess Corporation
John Westerheide	General Electric
Peter Westerheide	BASF
Steve Winberg	Batelle
William Zimmern	BP

The individuals and organisations that contributed to this study are not responsible for any opinions or judgments it contains. All errors and omissions are solely the responsibility of the IEA.

Comments and questions are welcome and should be addressed to:

Tim Gould

Directorate of Sustainability, Technology, and Outlooks
International Energy Agency
31-35, rue de la Fédération
75739 Paris Cedex 15
France

E-mail : weo@iea.org

More information about the World Energy Outlook is available at
www.iea.org/weo

Table of Contents

ANNEXES

Executive Summary

Compared with the past twenty-five years, the way that the world meets its growing energy needs changes dramatically over the period to 2040. The lead in the New Policies Scenario is taken by natural gas, by the rapid rise of renewables and by energy efficiency. Natural gas grows to account for a quarter of global energy demand in this scenario by 2040, becoming the second-largest fuel in the global mix after oil. In resource-rich regions, such as the Middle East, the case for expanding gas use is relatively straightforward, especially when it can substitute for oil. In the United States, plentiful supplies maintain a strong share of gas-fired power in electricity generation through to 2040, even without national policies limiting the use of coal.

Developing economies account for 80% of the projected growth in gas demand, led by China, India and other countries in Asia. This reflects the fact that gas looks a good fit for policy priorities in this region, generating heat, power and mobility with fewer emissions than the other fossil fuels. This includes both carbon-dioxide (CO_2) emissions and air pollutants, helping to address widespread concerns over air quality. However, much of Asia's gas requirement will need to be imported (and so transportation costs are significant) and infrastructure is often not yet in place, so policies will be required that encourage gas use. The competitive landscape is also formidable, not just due to the widespread availability of coal but also due to renewables. In many countries renewables enjoy greater policy support than gas, and – on a levelised cost basis – renewables are therefore rapidly becoming a cheaper form of new power generation, pushing gas-fired plants towards a balancing rather than a baseload role. Efficiency policies also play a part in constraining gas use: while the electricity generated from gas grows by more than half to 2040, related gas use rises by only one-third, due to more reliance on highly-efficient plants.

US LNG is helping to accelerate a shift towards a more flexible, liquid, global market, bringing into view a new global gas order. Ensuring that gas remains affordable and secure, beyond the current period of ample supply and lower prices, is critical for its long-term prospects. LNG accounts for almost 90% of the projected growth in long-distance gas trade to 2040: with few exceptions, most notably the route that opens up between Russia and China, major new pipelines struggle in a world that prizes the optionality of LNG. The transformation in gas markets is advanced by market liberalisation in Japan and other Asian economies and by the rise of portfolio players – large companies with a range of supply assets. New buyers, often smaller scale, are also appearing: the number of LNG-importing countries has risen from 15 in 2005 to 40 today. Gas supply also becomes more diverse: the number of liquefaction sites worldwide doubles to 2040, with the main additions coming from the United States and Australia, followed by Russia, Qatar, Mozambique and Canada.

In this new gas order, price formation is based increasingly on competition between various sources of gas, rather than indexation to oil. With destination flexibility, hub-based pricing and spot availability, US LNG acts as a catalyst for many of the anticipated changes in the wider gas market. This can bring dividends for gas security, although there is a risk of a hard landing for gas markets in the 2020s if uncertainty over the pace or direction of change deters new investments. Over the longer term, a larger and more liquid LNG market can compensate for reduced flexibility elsewhere in the energy system (for example, lower fuel-switching capacity in some countries as coal-fired generation is retired). We estimate that, in 2040, it would take around ten days for major importing regions to raise their import levels by 10%, a week less than it might take today in Europe, Japan and Korea.

In the Sustainable Development Scenario, as oil and coal fall back and renewables ramp up strongly, natural gas becomes the largest single fuel in the global mix – although the contribution of gas varies widely across regions, between sectors and over time. Consumption of natural gas rises by nearly 20% to 2030 in the Sustainable Development Scenario and remains broadly at this level to 2040. In energy systems heavily reliant on coal (as in China and India), where renewable alternatives are less readily available (notably in some industrial sectors), or where seasonal flexibility is required to integrate high shares of variable renewables, gas plays an important role in helping to achieve the objectives of this scenario. Satisfying gas demand growth in the Sustainable Development Scenario (and offsetting the observed declines in existing production) requires around $320 billion in annual investment across the natural gas value chain. Maintaining gas infrastructure remains important as natural gas provides a critical source of heat in many countries and a safety net for reliable power supply.

The future of natural gas is inextricably linked to credible action to minimise leaks of methane – a potent greenhouse gas – to the atmosphere. While there is an increasing number of voluntary and regulatory efforts to tackle methane emissions from the oil and gas sector, few countries have specific methane mitigation frameworks in place. We have developed a ten-point action agenda for policymakers and industry to bring about material emissions reductions based on the need to accomplish two key goals: measure and abate.

On average natural gas generates significantly fewer greenhouse-gas emissions than coal on a lifecycle basis; but that is no reason for failing to take action to reduce methane emissions from natural gas operations. We present the first global analysis of the costs of abating the estimated 76 million tonnes of methane emitted worldwide each year in oil and gas operations. Around 40-50% of these emissions can be mitigated at no net cost because the value of the captured methane covers the cost of the abatement measures. Implementing these measures in the New Policies Scenario would have the same impact on reducing the average global surface temperature rise in 2100 as shutting all existing coal-fired power plants in China.

Outlook for natural gas

A fuel for all seasons?

Highlights

- In the New Policies Scenario, global natural gas use increases by 45% in the coming 25 years, with industry accounting for a third of the growth (up from less than 20% over the last 25 years), slightly ahead of the additional gas used for power generation. Developing countries in Asia, Africa, Latin America and the Middle East account for 80% of the increase in global consumption. The tilt towards industrial gas use is particularly pronounced in the next ten years. In the second-half of the *Outlook* period, gas demand in the power sector picks up again as a move away from coal in some markets creates more room for gas to grow, alongside renewables.
- With projected growth of 1.6% per year, prospects for gas are good in the New Policies Scenario, but a return to the growth rate of 2.3% seen in the previous 25 years is not in the cards. Depending on the circumstances, renewables can facilitate or curb gas demand growth. In addition, in many gas-importing countries, especially in Asia, beating coal on cost alone is a tall order, highlighting the importance of a supportive policy environment if gas is to thrive.
- The United States adds some 300 bcm to global gas supplies over the next 25 years, more than any other country, followed by China (200 bcm), Russia and Iran (both around 145 bcm). Unconventional gas – shale gas in particular – accounts for over half of the incremental production worldwide over the period to 2040. North America continues to lead the unconventional gas revolution, but China, Argentina and Australia play increasingly important roles too.
- Long-distance trade grows by three-quarters to 1 230 bcm in 2040. The bulk of the expansion comes from LNG, which increases its share in trade from 39% in 2016 to some 60% by 2040. With the main exception of new pipelines to China from Russia and Turkmenistan, which have strong financial and political backing, complex large cross-border pipelines find it hard to advance in a world with ample supplies of LNG.
- With 140 bcm of LNG capacity still under construction, gas markets remain well supplied for the next few years. By the mid-2020s, however, market over-capacity is absorbed by import growth. Investment in new capacity therefore is needed from 2020 onwards, and much of the new supply comes from low-cost sources of gas in the United States, Russia and Qatar.
- Although the European Union remains the largest importer of gas, the Asia Pacific region accounts for some 85% of the growth in net imports, underpinning a shift in trade flows from the Atlantic basin to Asia. Much of the import growth in Asia comes from new importers in South and Southeast Asia, further strengthening the diversity and globalisation of gas markets.

8.1 Recent market and policy developments

The global gas market has been buffeted by the twin effects of a massive wave of investment in new liquefied natural gas (LNG) supply and a slowdown in demand growth that pushed growth in global gas consumption down to 1.3% per year between 2010 and 2015, compared with annual growth of 2.8% in the first decade of the 2000s. Together with lower oil prices, which have brought down oil-indexed gas prices in recent years, this has led to a marked drop in gas prices around the world. The International Gas Union estimates that the average global wholesale price of gas fell to $3.35 per million British thermal units (MBtu) in 2016 – the lowest level ever recorded in their surveys, which began in 2005.

The structural oversupply in the gas market is set to persist in the coming years as nearly 140 bcm of liquefaction capacity currently under construction becomes operational, mostly in the United States and Australia. Qatar, the world's largest exporter of LNG, meanwhile lifted its self-imposed development moratorium in early 2017, providing the basis for renewed expansion of its own export capacity. These developments have already started to reshape gas markets and will continue to do so in the future. Chapter 9 addresses the question of whether they amount to a new gas market order. However, the ample availability of gas does not mean that risks to security of supply have disappeared, as demonstrated for instance by current problems with LNG plants in Yemen, Nigeria and Algeria, and by the recent standoff between Qatar and its neighbours.

On the demand side, latest data suggest that the long-awaited demand response to lower gas prices may have finally started to happen. Global gas use is estimated to have grown by 2.6% in 2016, a marked rise over recent demand growth rates, and preliminary demand data for the first months of 2017 suggest continued momentum, notably in China. It is not yet clear whether gas demand has turned a corner, but the gas industry has certainly become more inventive: a lot of the growth in 2016 came from a multitude of relatively new and small LNG importing countries like Egypt, Pakistan and Jordan. The number of countries importing LNG has risen from 15 in 2005 to around 40 as of mid-2017. But the year also saw some remarkable developments in mature gas markets. In the United States, for the first time ever, more electricity was generated from gas than from coal in 2016. Even the European Union, where gas has had a dismal few years, saw a rise in gas use for power generation. The reasons for greater gas use varied from country to country: in the United Kingdom, it was driven by coal-to-gas switching underpinned by an administered carbon price floor. In a similar vein, Korea's new president has outlined a new energy policy programme that envisages an expanded role for gas in power generation at the expense of coal (mostly for air quality reasons) and nuclear.

Since it is relatively clean and flexible, natural gas is often seen as a fuel that can help to reduce the carbon intensity of the energy system and also contribute to improving air quality. It can achieve rapid environmental benefits when it replaces coal or oil, as demonstrated for instance by China's replacement of small coal boilers with gas boilers in industry and for heating of buildings. However, few countries have specifically mentioned gas in their Nationally Determined Contributions as part of the Paris Agreement and this raises the question what role gas might play in the transition to a low-carbon energy world (examined in Chapter 11). In this context, methane emissions from the production and transport of natural gas are an important challenge (explored in detail in Chapter 10).

Our projections suggest that gas is set to perform much better than other fossil fuels over the coming decades. However, the role of gas varies widely across different countries and regions: in this special focus on natural gas, we identify the sectors that are strongholds of gas use as well as those where gas faces an uphill battle for new consumers. The competitive landscape is changing rapidly, and gas faces challenges from coal in many markets, and from renewables in others: depending on circumstances and sectors, new low-carbon technologies can be both threats to, and enablers of, gas demand growth. On the supply side, we take a detailed look at where the additional gas might come from and how it reaches burner tips, boilers, turbines and chemical plants around the world. In addition, we examine what it might take to reassure not just policy-makers, but also an occasionally sceptical public, that gas can have a rightful place in the future of global energy.

This opening chapter summarises the overarching trends for gas demand and supply in the period to 2040 and provides the framework for the topical discussions in the following three chapters. As the analysis demonstrates, there are good reasons to be upbeat about the prospects of natural gas – its relative abundance, flexibility and environmental advantages make it a good fit for the needs of the future energy system. At the same time, there are many uncertainties and some potential pitfalls.

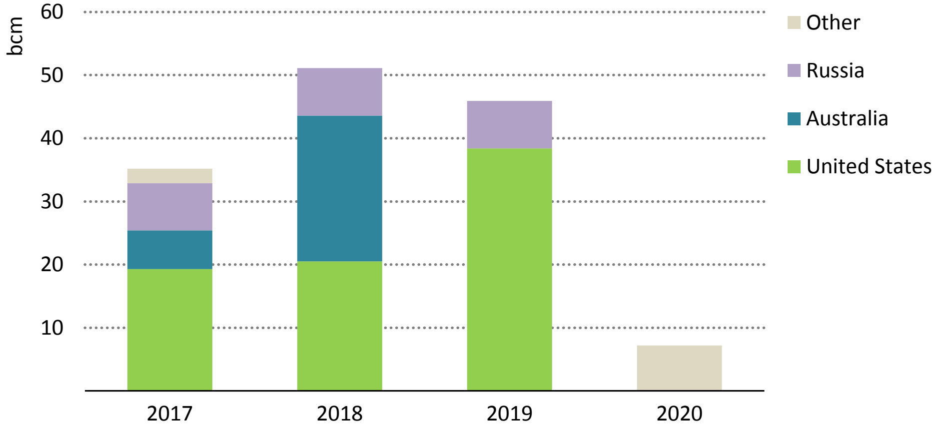
8.2 Trends to 2040 by scenario

8.2.1 Market dynamics to 2025

In the New Policies Scenario, the next ten years are characterised by the gradual rebalancing of the gas market. The United States, the world's largest gas producer, increases production more than any other country over this period, accounting for 40% of global output growth. US gas exports become central to the developing global gas market: over half of nearly 140 billion cubic metres (bcm) of global liquefaction capacity currently under construction is in the United States and it becomes the largest LNG exporting country by the mid-2020s. Major additions of liquefaction capacity also come from four Australian projects and Novatek's Yamal LNG project in Russia, and further additions from new liquefaction plants that Indonesia, Malaysia and Cameroon are currently in the process of building (Figure 8.1). These developments in the LNG market are complemented by two long-awaited new pipeline corridors anticipated to start operation in the next five years: an expanded connection between Azerbaijan, Turkey and European Union countries via the TANAP and TAP pipelines, and the "Power of Siberia" pipeline that links Russian gas fields to the Chinese market (IEA, 2017). Turkstream 1, a pipeline aimed at supplying Turkey with Russian gas via the Black Sea, has also just started construction.

Gas consumers are looking to benefit from low gas prices and procure additional volumes of LNG: there are currently over 115 bcm of new regasification capacity under construction, nearly three-quarters of which is in Asia. Our main scenario projects global gas consumption growth of 1.5% per year, on average, to 2025, considerably faster than growth for oil (0.8%) and coal (0.2%). China is the primary engine of growth, accounting for 35% of incremental gas use in the next ten years, followed by the Middle East with 17%. Gas demand is expected to fall in Japan – the largest LNG import market – in the period to 2025, but there are significant uncertainties over this trajectory related to decisions about the restarting of Japan's nuclear reactor fleet. In terms of sectoral contributions to global natural gas demand growth, industry is the frontrunner, using around 40% of the additional gas in the period to 2025, followed by the power and the buildings sector (both 18%).

Figure 8.1 ▷ Liquefaction capacity currently under construction by key countries and year of first commercial operation



Nearly 140 bcm of liquefaction capacity is under construction and slated to come online over the next few years, more than half of which is in the United States

Notes: The figure shows first year of commercial operation of LNG plants and name-plate capacity, but utilisation of plants can be expected to ramp up gradually over time. For reasons of consistency with IEA (2017), plants that had already come online in the first-half of 2017 are not shown.

Source: IEA analysis based on Cedigaz (2017).

In the light of the current low gas prices, investment activity in new liquefaction capacity has ground to a halt. With a few exceptions like the Coral floating liquefied natural gas (FLNG) vessel in Mozambique, on which a final investment decision was taken in June 2017, and the anticipated Fortuna project off the coast of Equatorial Guinea, the flow of new LNG projects has dried up. Our projections suggest that demand growth will have absorbed the supply overhang by the mid-2020s, creating a need for timely new investment if market tightening and volatility are to be avoided. Factoring in lead times, a soft landing for gas markets in the 2020s requires new investment decisions – even for brownfields and smaller projects – to be taken before 2020. However, as discussed in detail in the next chapter, managing the volume and price risks for these new investments is no simple task.

8.2.2 Long-term scenarios to 2040

In the New Policies Scenario, our main scenario, the underlying policy, macroeconomic and demographic assumptions (see Chapter 1) lead to gas consumption growth of 1.6% per year between 2016 and 2040, a stark deceleration compared to the 2.3% observed over the past 25 years (Table 8.1). In this scenario, gas expands its share in primary energy supply from 22% in 2016 to 25% in 2040. New gas projects are needed to meet the projected gas demand growth and many of these are either remote or technically challenging or require significant infrastructure construction, putting upward pressure on gas prices. By 2025, gas prices in the United States, Europe and Japan are projected to rise to $3.7/MBtu, $8.3/MBtu and $10.8/MBtu respectively (Table 1.4 in Chapter 1). Over the *Outlook* period, they increase to $5.6/MBtu in the United States, $10/MBtu in Europe and $11.1/MBtu in Japan; the long-term price differentials between markets reflect only the full cost of moving gas between them. Cumulative investment in gas supply (upstream, transmission and distribution infrastructure, liquefaction and regasification facilities) adds up to $8.6 trillion over the *Outlook* period.

Box 8.1 ▷ What happened to the "Golden Age of Gas"?

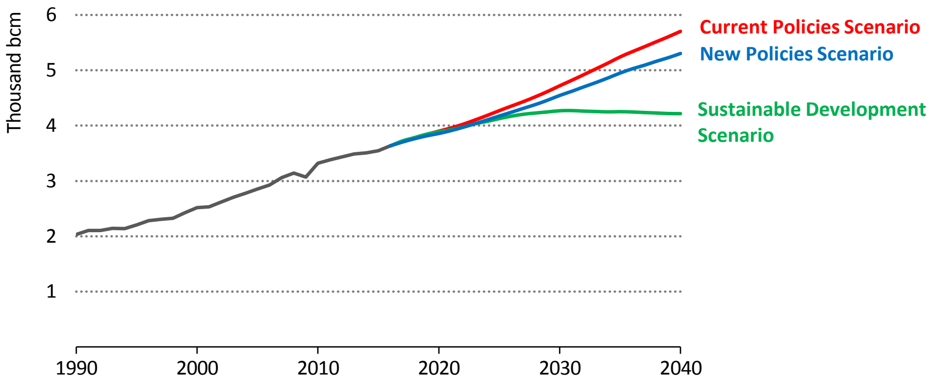
In 2011, the *World Energy Outlook* published a special report asking the question "Are we entering a Golden Age of Gas?", which posited a future in which the role of gas in the energy system expanded more rapidly than in our main scenario, reaching 25% of the global mix by 2035. This was based on a number of positive assumptions about the availability of gas (much of it unconventional) and its price, as well as the addition of policies on the demand side that would promote its use in certain countries, notably China, and in certain sectors, such as transport.

A few years on, where do we stand relative to the putative Golden Age? Natural gas prices in 2016 are very much in line with those anticipated in the "Golden Age" scenario, so in that sense the story of relative abundance has been realised. North American shale gas has been hugely successful; however, contrary to what was assumed in the "Golden Age" scenario, replication of the North American shale gas success story in other shale-rich countries has been very limited (see also Box 9.1 in Chapter 9). In terms of demand, there are substantial variations. Some countries, notably the United States and elsewhere in North America, are already well ahead of the projections in the "Golden Age" scenario; the Middle East and Latin America are also using at least as much gas as anticipated in this "optimistic" scenario. But Europe is at the opposite end of the spectrum, with gas demand having fallen substantially in the last few years. Russia and some other mature gas markets in Eurasia have likewise fallen well short of a Golden Age. Demand in much of developing Asia, notably India, as well as Africa, is also well below the projections in the Golden Age scenario, in countries where gas occupies only a relatively small share of the energy mix.

There is a question mark in the title of the 2011 report "Are we entering a Golden Age of Gas?". The answer, so far, very much depends on where in the world you are.

The Current Policies Scenario, which assumes no new measures beyond those adopted today, sees overall gas demand rise at 1.9% per year to 2040 and end up some 8% higher than in the New Policies Scenario. The share of gas in primary energy supply reaches 24% in 2040, slightly lower than in the New Policies Scenario. The main winner in this scenario is coal: in the absence of many supportive policies that underpin renewables growth in the New Policies Scenario, coal gains ground in the power sector. The share of coal in primary energy supply is 26% in 2040, compared with 22% in the New Policies Scenario. While gas does well, coal does better. The call on new gas supply projects requires a cumulative capital expenditure of $9.8 trillion over the coming 25 years: this implies that the market draws on more costly projects to satisfy demand.

Figure 8.2 ▷ World natural gas demand by scenario



Gas use is projected to increase by 1.6% per year, on average, in the New Policies Scenario

Note: bcm = billion cubic metres.

The Sustainable Development Scenario appears for the first time in this edition of the *WEO.* In this scenario, gas demand grows by 0.6% per year on average. It grows in the years up to 2030, reflecting the contribution that it can make to the environmental goals that this scenario is designed to achieve, notably in replacing coal, but an inflection point is reached around 2030, and gas consumption plateaus as improvements in energy efficiency take hold and as lower carbon fuels expand their share in primary energy supply (Figure 8.2). Nevertheless, gas still accounts for a quarter of primary energy supply in 2040, a higher level than today. Gas prices increase in the Sustainable Development Scenario but less than in the two other scenarios. Similarly, cumulative gas supply investments, at $6.6 trillion, are lower in this scenario.

8.3 A closer look at the New Policies Scenario

8.3.1 Demand

In the New Policies Scenario, global demand for natural gas increases from 3 635 bcm in 2016 to over 5 300 bcm in 2040 (Table 8.1). The additional 1 670 bcm of gas consumption that materialises over the *Outlook* period corresponds to more than twice the current gas use of the United States – the world's largest gas consumer. The average annual demand growth rate of 1.6% between 2016 and 2040 is much faster than that projected for oil or coal, which expand at 0.5% per year and 0.2% per year respectively over this period.

Table 8.1 ▷ Natural gas demand by region in the New Policies Scenario (bcm)

							2016-40	
	2000	2016	2025	2030	2035	2040	Change	CAAGR*
North America	800	961	1 045	1 068	1 109	1 143	182	0.7%
United States	669	779	834	846	867	880	101	0.5%
Central & South America	97	166	183	205	237	271	106	2.1%
Brazil	9	36	38	43	55	64	28	2.4%
Europe	606	590	604	618	633	631	41	0.3%
European Union	487	463	461	467	469	454	- 8	-0.1%
Africa	57	134	177	211	251	306	171	3.5%
South Africa	1	4	5	7	8	10	6	3.8%
Middle East	174	477	568	657	737	795	318	2.2%
Eurasia	471	575	583	593	615	636	61	0.4%
Russia	388	456	452	456	463	470	13	0.1%
Asia Pacific	314	732	998	1 167	1 331	1 472	740	3.0%
China	28	210	397	482	554	610	401	4.6%
India	28	55	97	126	155	183	128	5.2%
Japan	82	123	95	100	106	107	- 16	-0.6%
Southeast Asia	88	170	195	216	244	269	99	1.9%
Bunkers**	0	0	16	26	37	51	51	n.a.
World	**2 518**	**3 635**	**4 174**	**4 545**	**4 950**	**5 304**	**1 669**	**1.6%**

* Compound average annual growth rate. ** LNG used as an international marine fuel.

There is no single answer to the question of why gas fares better than coal and oil in this scenario: instead there are many answers that depend on the availability and price of gas in different countries, and on their end-use patterns and their policies. However, our analysis suggests four common elements that are necessary for gas to thrive over the *Outlook* period (see section 9.3.4):

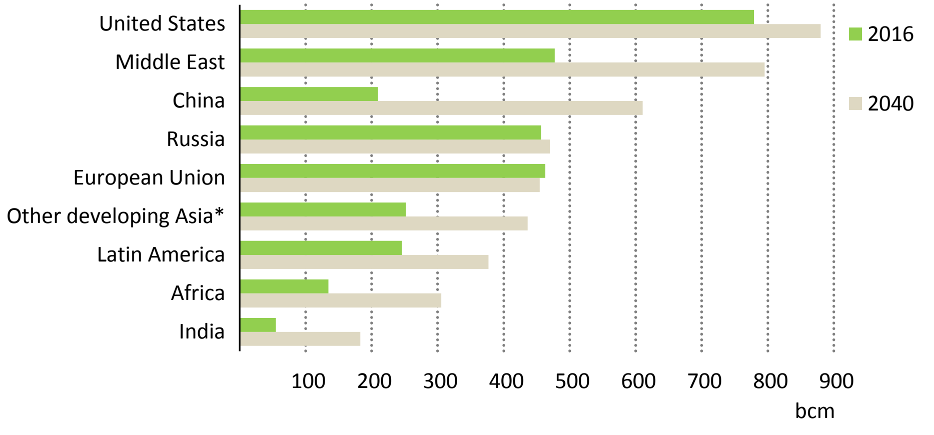
- Gas needs to be reliable and affordable: the shadow of previous disruptions to supply and of periods of price volatility can only be dispelled if costs are kept in check, investments come in a timely and cost-effective manner, and international markets function in a way that brings gas to where it is needed.

- Gas needs to be seen as part of the solution to local and global environmental problems; any doubts about this or about the gas industry's commitment to the highest practicable environmental standards may ultimately reduce its public acceptability (discussed in Chapter 10).
- Gas needs an effective institutional and policy context to underpin investment in essential infrastructure such as import terminals, storage, transmission and distribution networks or refuelling stations for gas-based vehicles or vessels.
- Gas needs its benefits to be recognised and supported through appropriate measures such as carbon dioxide (CO_2) pricing, air pollutant emission standards or electricity market designs that remunerate flexibility.

Regional trends in demand

Although gas demand expands almost everywhere in the coming 25 years – the European Union and Japan are the main exceptions – the growth is clearly concentrated in developing countries (Figure 8.3).

Figure 8.3 ▷ Gas demand in selected regions in the New Policies Scenario

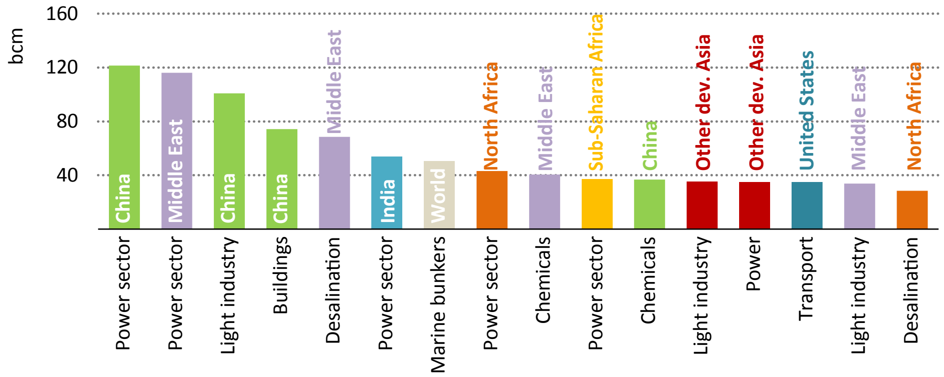


Growth in global gas demand is concentrated in developing countries

*Other developing economies in Asia.

China becomes the second-largest gas consumer in the world by 2040, only surpassed by the United States, and uses more gas than all the countries in the European Union put together (but less than the countries of the Middle East combined). With incremental annual gas use of 400 bcm, China alone accounts for almost a quarter of the additional global demand over the *Outlook* period. China's power sector, with additional demand of 120 bcm, is the single largest growth centre in our projections; its light industry (e.g. textiles, manufacturing, food and beverage) is the third-largest growth centre (Figure 8.4). The light industries are often geographically dispersed around China's large conurbations and feature rather small companies, highlighting the need for infrastructure availability to unlock this growth potential. Bringing gas to the industrial sector is a policy priority for China, not least because of the need to improve urban air quality.

Figure 8.4 ▷ Key natural gas demand growth centres, additional use in the New Policies Scenario, 2016-2040



The Chinese power sector is the single largest growth centre for gas use, but the light industries and gas-based chemical production in various countries are also major hubs

Note: Desalination, normally included in the buildings sector, has been split out for the purpose of this graph.

The **Middle East** is not too far behind China in terms of gas demand growth. The region as a whole consumes an additional 320 bcm in the period to 2040, equivalent to a fifth of global gas growth. Natural gas use is underpinned by additional gas-fired power generation (the region's electricity demand doubles over the *Outlook* period, with much of the growth coming from the buildings sector for cooling and appliances), industrial activity and growing needs for freshwater (gas is used to provide energy for desalination). Moreover, in all sectors, the scope for displacing more costly oil products makes a strong case for higher gas use. The petrochemical industries are major gas consumers in the Middle East: in the long term, several countries in the region place more emphasis on exporting higher value chemical products than on exporting gas. By 2040, the Middle Eastern gas market reaches the same size as the US market today (around 790 bcm).

The United States is a relatively mature and saturated gas market, but still sees gas demand expanding by an additional 100 bcm over the period to 2040. The primary reason is the ample availability of relatively cheap gas that stimulates consumption in the transport sector and industry (see Chapter 9). **South Asia** (e.g. India, Pakistan and Bangladesh) and **Southeast Asia** (e.g. Indonesia, Malaysia, Thailand and Viet nam) also see significant growth in demand for natural gas in the New Policies Scenario, underpinned by economic growth and the associated ramp up in electricity demand and industrial activity. **Africa's** future demand for gas is closely linked to efforts to establish or revive domestic gas markets, notably in Tanzania, Mozambique, Nigeria, Algeria and Egypt.

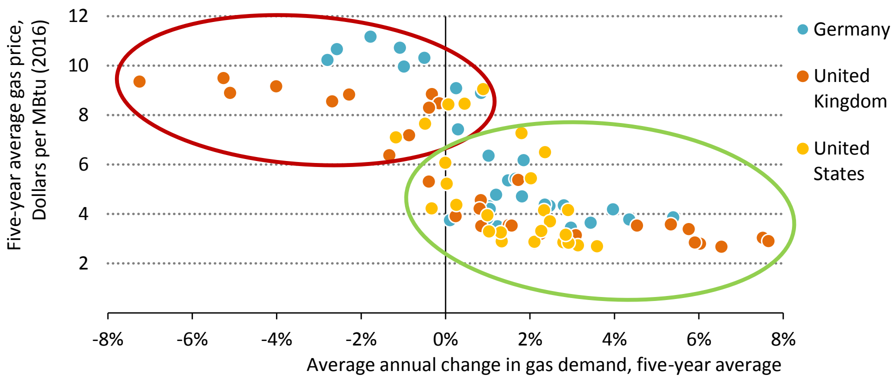
S P O T L I G H T

What's the price for gas demand to grow?

Whether consumers are willing to use gas instead of other alternatives depends on what they need the energy for, alternatives available and costs of the alternatives relative to gas. The considerations for uses such as high-temperature heat in industry, heating a house or generating electricity are very different, but in each case price matters.

Resource-rich nations in the Middle East, North Africa and Eurasia have typically provided gas to their domestic markets at regulated or subsidised prices, often as low as \$1 to \$2/MBtu. Unsurprisingly, this has led to rampant demand growth in all sectors. However, gas-importing countries such as Japan or Korea have also experienced demand growth, despite wholesale prices of \$10-16/MBtu, and Chinese gas consumption grew rapidly at prices around \$10/MBtu in recent years. So there is no one answer to the question we pose in this Spotlight.

Figure 8.5 ▷ **Change in gas demand versus price in Germany, United Kingdom and United States, 1983-2016**



Analysis of historical demand trends in the US, UK and Germany shows that gas use increased at prices below \$6/MBtu, but declined at prices above \$8/MBtu

It is nevertheless instructive to look at some recent history. Three major gas markets, Germany, United Kingdom and United States, have undergone gas market liberalisation over the past three decades. Statistical analysis of demand growth patterns at different gas prices in these three markets shows that consumption tended to increase when wholesale prices were below \$6/MBtu and to decrease when prices were above \$8/MBtu (Figure 8.5). These trends hold true for a period spanning more than three decades, with gas prices ranging between \$2/MBtu and \$12/MBtu and with competing fuel prices also showing large variations. Prices for imported gas in most regions were below \$6/MBtu in 2016, but they are projected to increase to above $8/MBtu for much of the latter half of the *Outlook* period.

Every gas market is different and the prices of competing fuels play a key role, so it cannot be concluded that there is no scope for demand growth when gas prices exceed $8/MBtu. This analysis of historical demand growth patterns nonetheless reinforces two key messages of this *Outlook*: first, in some markets – notably where gas is imported over long distances – a purely market-based allocation of gas is unlikely to deliver significant demand growth if it is not complemented by policies that encourage gas use; second, particularly in the light of efforts to liberalise gas markets in China, Japan and other major Asian importing countries, the gas industry needs to work hard on cost control to minimise the risk of losing out to other fuels and technologies.

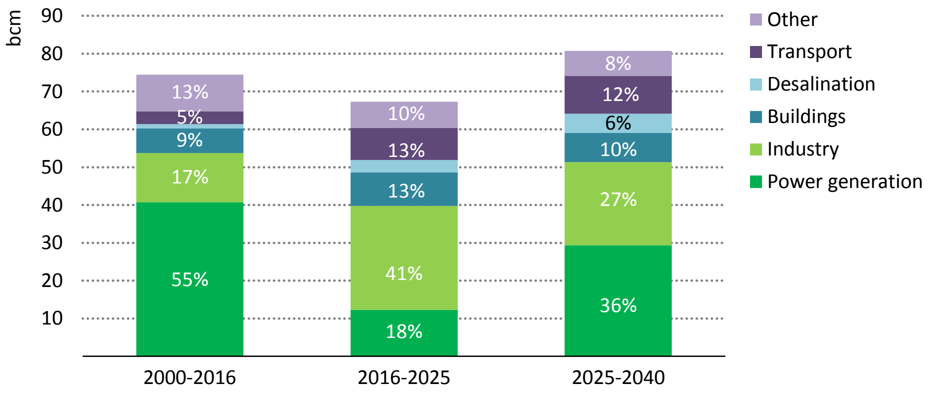
Sectoral trends in demand

With a third of the additional gas demand, industry contributes the largest share of global gas demand growth over the *Outlook* period, ahead of the power sector with 31%, buildings sector (17%) and transport (12%). However, there are important temporal and regional dynamics at play in the coming decades. In the period to 2025, industry is the undisputed growth engine, accounting for over 40% of additional gas use – a marked change compared to the past 15 years when industry contributed less than a fifth to gas demand growth (Figure 8.6). Apart from the rising gas needs of Asian industries, much of this growth materialises in the United States and the Middle East, where cheap gas stimulates growth in the petrochemical industries.

The power sector contributes only 18% to gas demand growth to 2025. This is a symptom of gas getting squeezed between cheaper coal and strong policy-driven renewables deployment in a period in which weaker electricity demand growth in many countries limits the scope for all sources to grow. The United States is a case in point: electricity demand increases by 245 terawatt-hours (TWh) to 2025, but additional output from wind and solar photovoltaic (PV) alone provides an additional 345 TWh to the system. In light of the absence of the Clean Power Plan (the impact of the Clean Power Plan is now no longer considered in the New Policies Scenario), gas faces a battle with coal for space in a market that is contracting. The main increases in gas use in the power sector come in developing Asia, the Middle East and North Africa where economic growth is strong and, at least in the case of the Middle East, cheap gas is more readily available.

After 2025, the power sector resumes its role as the main engine for gas demand growth, accounting for 36% of additional gas demand between 2025 and 2040 (still well below the 55% share of growth achieved between 2000 and 2016). Developing Asia and the Middle East account for the bulk of the additional growth but others, notably the United States and Japan, also exhibit growth in gas demand in the power sector (see Chapter 6). However, gas demand growth in the power sector remains sensitive to how gas prices evolve compared to coal prices and how quickly the costs of variable renewables come down. In the industry sector post-2025, gas demand growth is concentrated in light industries, as the rise in gas prices around the world constrains the growth of production of gas-based chemicals. By 2040, combined gas demand from light industries in China, United States, Middle East and European Union accounts for a quarter of global industrial gas consumption. Industrial gas use in developing countries in South Asia, Southeast Asia and Africa also grows strongly over the *Outlook* period, on the assumption that transmission and distribution infrastructure will be available.

Figure 8.6 ▷ Annualised growth of global natural gas demand by sector in the New Policies Scenario



Industry propels gas demand strongly upwards in the period to 2025, but thereafter, momentum shifts to the power sector

Notes: Desalination, normally included in the buildings sector, has been split out for the purpose of this graph. Industry includes gas used as petrochemical feedstocks and for the production of liquid fuels as well as energy consumption in coke ovens and blast furnaces in all focus chapters on natural gas.

Gas demand in the buildings and transport sectors grows by 36% and over 170% respectively between 2016 and 2040. The majority of gas used in buildings today is for space heating: however, demand for space heating in most developing countries is limited (with the important exception of China) and this constrains the potential for growth in the sector, even though other end-uses such as cooking and water heating increase in importance. Desalination plants, mostly in the Middle East and North Africa, are an important element of gas demand growth (almost 100 bcm to 2040). Road transport accounts for the bulk of additional gas use in the transport sector, with growth concentrated in three countries: more than 70% of the additional gas demand in road transport comes from China and the United States (each seeing an increase of around 35 bcm to 2040) and India (an additional 22 bcm to 2040). Demand for natural gas as a shipping fuel rises, mostly due to the International Maritime Organization's regulations on sulfur emissions from vessels and energy efficiency targets; as such marine bunkering adds a further 60 bcm to demand over the *Outlook* period.

In summary, although gas does better than oil and coal, gas demand growth of 1.6% per year between 2016 and 2040 is significantly slower than the annual demand growth of 2.3% over the past 25 years. This is the result of two overarching trends: first, global total primary energy demand growth slows to 1% per year over the period, down from an annual growth rate of 1.7% between 1990 and 2016. Second, gas faces an increasingly competitive environment: gas use in power generation is curtailed in many countries by the growth of renewables and in some by less expensive coal. In the buildings sector and industry, it faces competition with electricity and constraints arising from increased energy efficiency, and the effects of these outweigh gains from new demand in areas such as shipping and road transport. Overall, the prospects for natural gas are good, but our projections suggest that the industry cannot expect a return to previous long-term growth rates.

8.3.2 Supply

Resources and reserves

The remaining resources of natural gas are sufficient to comfortably meet the projections of global demand growth to 2040 and well beyond, in all three scenarios of this *Outlook*. Proven reserves stood at some 215 trillion cubic metres (tcm) at the end of 2016, equal to around 60 years of production at current output rates (Table 8.2). Yet, remaining technically recoverable resources provide a better indicator for how much gas can be produced in the long term, and our modelling of gas production trends is thus based on resources rather than reserves. Global resources of natural gas are estimated at nearly 800 tcm, around 45% of which are unconventional gas (tight gas, shale gas and coalbed methane), deposits of which are geographically more widespread than conventional gas resources.

Table 8.2 ▷ Remaining technically recoverable natural gas resources by type and region, end-2016 (tcm)

	Conventional	Unconventional				Total	
		Tight gas	Shale gas	Coalbed methane	Sub-total	Resources	Proven reserves
North America	51	11	61	7	79	130	12
Central & South America	28	15	41	-	56	84	8
Europe	19	5	18	5	28	47	5
Africa	51	10	40	0	50	101	17
Middle East	103	9	11	-	20	123	80
Eurasia	134	10	10	17	38	172	74
Asia Pacific	45	21	53	21	94	139	20
World	**432**	**82**	**233**	**50**	**365**	**796**	**216**

Sources: BGR (2016); BP (2017); Cedigaz (2017); OGJ (2016); US DOE/EIA/ARI (2013); US DOE/EIA (2017); USGS (2012a, 2012b); IEA databases and analysis.

Production

Production of natural gas expands globally by 1 685 bcm over the next 25 years, reaching over 5 300 bcm in 2040 (Table 8.3). The United States, Russia and Iran are the three largest gas producers today, a ranking that remains unchanged over the *Outlook* period although China comes close to that of Iran by 2040.

Table 8.3 ▷ Natural gas production by region in the New Policies Scenario (bcm)

	2000	2016	2025	2030	2035	2040	2016-40	
							Change	CAAGR*
North America	763	960	1 166	1 212	1 282	1 338	379	1.4%
Canada	182	174	159	165	190	222	49	1.0%
Mexico	37	37	35	38	48	58	21	1.9%
United States	544	749	971	1 009	1 043	1 058	309	1.4%
Central & South America	102	175	178	207	242	279	104	2.0%
Argentina	41	42	53	70	90	104	62	3.9%
Brazil	7	24	28	43	60	77	53	5.0%
Europe	337	285	244	238	236	236	- 49	-0.8%
European Union	264	134	91	85	80	76	- 58	-2.3%
Norway	53	121	105	101	99	100	- 22	-0.8%
Africa	124	205	273	330	392	460	254	3.4%
Algeria	82	92	97	102	107	113	21	0.8%
Mozambique	0	5	13	32	49	64	59	11.6%
Nigeria	12	41	46	45	56	70	29	2.2%
Middle East	198	585	703	832	931	1 003	418	2.3%
Iran	59	190	243	301	332	338	149	2.4%
Qatar	25	165	182	214	240	256	91	1.8%
Saudi Arabia	38	90	107	120	131	142	52	1.9%
Eurasia	691	842	935	978	1 035	1 095	252	1.1%
Azerbaijan	6	19	37	44	51	55	36	4.6%
Russia	573	644	718	730	752	788	144	0.8%
Turkmenistan	47	80	86	102	124	141	61	2.4%
Asia Pacific	290	568	675	749	832	894	326	1.9%
Australia	33	88	149	162	188	195	107	3.4%
China	27	137	222	261	298	336	199	3.8%
India	28	31	42	59	72	84	53	4.3%
Indonesia	70	77	70	73	80	90	13	0.6%
Rest of Southeast Asia	89	146	128	131	131	127	- 19	-0.6%
World	**2 506**	**3 621**	**4 174**	**4 545**	**4 950**	**5 304**	**1 683**	**1.6%**
Unconventional	196	780	1 180	1 320	1 486	1 654	874	3.2%

* Compound average annual growth rate.

Unconventional sources account for more than half of the incremental gas output. Unconventional gas is not a homogenous group: shale gas production – especially in North America – is the clear frontrunner, adding 725 bcm to the global gas balance; next comes coalbed methane, which contributes over 60 bcm (see Focus), followed by tight gas, which contributes over 35 bcm. The United States is the undisputed growth engine for global shale gas production: output reached over 445 bcm in 2016, and we project a rise to 800 bcm by 2040. Although the surge in US shale gas production delays the shale gas boom in Canada, good quality resources and positive spill-over effects from the United States underpin a marked ramp up in Canadian shale output in the second-half of the *Outlook* period, bringing production to almost 155 bcm in 2040. China – which is estimated to hold the world's largest resources of shale gas – increases production of shale gas to almost 100 bcm in 2040, from an output level of 8 bcm in 2016. The key uncertainty for Chinese shale gas, as for all such resources outside North America, is the quality of the resource and the cost at which it can be produced (see Chapter 14). Our assessment of Argentina's shale gas outlook is relatively upbeat: the early signs from drilling activity thus far suggest a potentially prolific resource (especially in the Vaca Muerta play). Argentina has a well-established gas market and infrastructure, and an increasingly favourable regulatory environment. Against this backdrop, we project Argentinian shale gas output to rise to nearly 50 bcm in 2040; if investment is forthcoming, the resource base could support considerably higher output.

Conventional gas currently accounts for nearly 80% of the world's gas production, but this share falls back to under 70% by 2040. Unconventional gas production is well-known for high initial decline rates, but conventional gas fields also face post-peak average declines of over 7%; countering this continual drain on supply is a major challenge for the gas industry. Russia is currently the largest producer of conventional gas – the bulk of which comes from its West Siberian gas fields – and remains so over the next 25 years. Russia's total output tops 785 bcm in 2040, which is more than 20% higher than today's level. Other major conventional gas producers are Iran and Qatar, both of which exclusively produce conventional gas and see their output rising by almost 80% and 55% respectively.

Associated gas is gas produced as a by-product of oil production. Today it accounts for around 15% of the world's gas output. This share has been falling over recent decades: in 1980, associated gas accounted for a quarter of the world's gas production. We see the current 15% share staying flat in the first-half of the projection period as gas-rich tight oil production in the United States expands, before dropping off in the second-half of the projection period to around 10% in 2040.

Focus: What are the prospects for coalbed methane?

Coalbed methane, referred to in Australia as coal seam gas, is produced from coal seams, typically at depths of 800 to 1 200 metres. Relatively shallow coal seams are targeted: deep seams tend not to be economical to produce. There is a contrast here with shale gas, which is often economical at much greater depths. The primary extraction technique requires dewatering the coal seams, i.e. pumping out the formation water that effectively traps the gas in the coal seam. This typically requires a large number of vertical wells. As water is removed, gas begins to flow relatively easily. While the method of extraction may be unconventional, the product, methane, is the same as any other type of natural gas.

In common with other methods of unconventional gas production, gas recovery from each individual well is low, and depletion rates are relatively rapid. As a result, more production wells must be drilled to expand and maintain output than would be the case for typical conventional fields. While stimulation techniques of the type used for shale can be employed, in practice relatively few wells are hydraulically fractured. For example, in Australia, early exploitation of coalbed methane saw only about 6% of wells hydraulically fractured, although over time this is expected to rise to around one-third. The large volumes of water used in extraction must be treated, most commonly by reverse osmosis: while 90% of the water so treated can be reused (for example for irrigation or livestock) a concentrated saline solution remains, which initially is retained in ponds and then either crystallised and secured in specially-lined land-fills or disposed of in deep saline aquifers. This poses potential environmental risks.

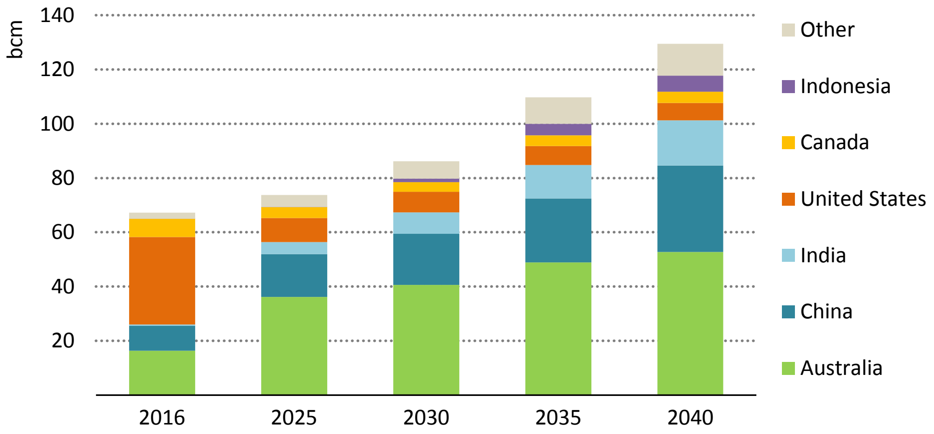
Coalbed methane resources are relatively widespread globally, but so far, production has only picked up in the United States, Canada, Australia and China, and remains at a relatively modest level in comparison to shale. Global production nearly doubled between 2000 and 2016 to 70 bcm: over the same period, shale gas output increased more than twenty-fold to 460 bcm. In our projections, global coalbed methane production increases to around 130 bcm by 2040. In the United States and Canada, higher cost coalbed methane struggles to compete with shale gas, for which costs have been dropping dramatically. In Australia, output has risen rapidly in the last ten years, mainly to support a burgeoning LNG export industry. Production is projected to increase to 35 bcm by the early 2020s, at which point Australia becomes the largest global producer of coalbed methane, and then to rise further to 55 bcm by 2040 (Figure 8.7). China has ambitious plans to increase unconventional gas production, including coalbed methane (and coal mine gas, which is gas captured and marketed from coal mining operations). Coalbed methane accounts for around 30 bcm of the 225 bcm of unconventional gas production in China in 2040. A number of developing countries, chief among them are Indonesia and India, also increase their production of coalbed methane over the period to 2040.

Although coalbed methane uses a different suite of production technologies from shale gas, it has aroused similar environmental and social concerns in a number of countries, focusing on possible water contamination, land access and fugitive emissions.[1] In Australia, for example, large-scale coalbed methane production is found only in the state of Queensland. Australia, in common with several other federal jurisdictions, regulates unconventional

1. These topics were the subject of discussion at the IEA's 5th Unconventional Gas Forum, held in Brisbane in February 2017.

gas production at the state/provincial level, and other states have effectively prohibited production via moratoria on hydraulic fracturing and/or gas development in general (Victoria, Tasmania and, most recently, Western Australia) or put it on hold pending various inquiries into adequate safeguards (New South Wales). In Queensland, a number of important regulatory approaches and institutions have been developed to address these concerns: a cumulative approach to assessing environmental and water impacts has been put in place, a statutory body for ground water impact assessments has been set up, and a specialised forum, the Gas Fields Commission, has been established to promote dialogue among the various stakeholders.

Figure 8.7 ▷ Coalbed methane production in selected countries in the New Policies Scenario



Australia leads the long-term growth in coalbed methane extraction

Costs of production for coalbed methane have proven difficult to bring down. Moreover, coalbed methane is dry, i.e. lacking the hydrocarbon liquids that are an important additional revenue source and a key factor for the rapid growth of shale gas in the United States. Even in Australia, with two decades of production experience and thousands of wells drilled, wellhead prices have stayed in the region of $3.5-4/MBtu (around 5 Australian dollars per gigajoule). Innovation is improving productivity, for example through drilling more directional wells from a single pad (which also reduces the surface footprint of projects that may have thousands of production wells), but coalbed methane has yet to demonstrate the extraordinary cost reductions seen in shale gas. At the three LNG projects in Australia that are fed by coalbed methane, upstream costs look likely on the basis of current LNG export prices to translate into low profitability on the more than $60 billion invested. Relatively high costs of production temper our overall projections for coalbed methane, compared with other sources of unconventional gas, notably shale gas.

8.3.3 Regional demand and supply insights[2]

Russia

Russia appears well placed to benefit from the world's growing gas needs – it has a huge resource base and relatively low production costs – but the remoteness of its main gas fields means that it is difficult to get the gas to the growth centres of the global gas market. Russia's gas export industry was built on bilateral trade relationships with European countries, but inflated expectations of gas demand growth in Europe and also in Russia itself and in other Eurasian countries has left Russia with more than 150 bcm of spare gas production capacity following the decision to invest in the Yamal peninsula in the mid-2000s. Russia also has ample pipeline capacity into Europe via four main arteries (via Ukraine, via Belarus, directly to Germany [Nordstream] and directly to Turkey [Bluestream]).

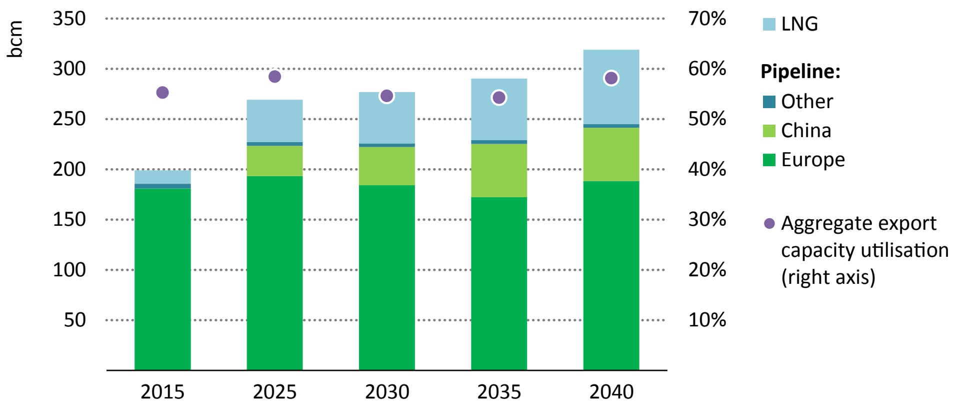
Russia's strategic focus on the European market, and reliance on pipelines for export, means that Russia has very few other export outlets for its gas, and it currently depends on the vagaries of European gas demand for some 90% of its gas exports (and hence gas export revenues). No relief can be expected from the Russian domestic gas market: our projections suggest that Russian gas demand plateaus in the coming decades, reaching a figure of 470 bcm in 2040, or 3% higher than the level reached in 2016. Gas already accounts for more than half of Russian primary energy demand and even modest energy efficiency gains in the power, industry and buildings sectors will be sufficient to keep future growth in check.

The primary goal for the Russian gas industry is thus to diversify its export options. A major step in this direction is the "Power of Siberia" pipeline to China, which is currently under construction. It is expected to come on stream soon after 2020, with the ramp up to full capacity (38 bcm) accomplished around the middle of the decade. In the New Policies Scenario, we project a further expansion of eastward pipeline capacity in the latter part of the *Outlook* period (operational from the early 2030s), which could come either from an expansion of the eastern route or from the "Altai" pipeline, a proposed link to Western China. An additional set of uncertainties for some prospective projects stems from an extension of US sanctions in August 2017 to cover Russian energy export pipelines.[3] Diversification based on LNG is well underway, with one facility operational and another one slated to gradually enter service in the coming years. But potential sites for liquefaction terminals are remote and the conditions for construction and operation of the facilities can be harsh. As a result, our projections suggest a gradual expansion of LNG capacity, despite ample availability of gas.

2. Insights on the North American gas market are presented in Chapter 9 and the Chinese gas market is discussed in Chapter 14.

3. There are several existing and prospective gas transmission corridors into Europe. *WEO* modelling of future trade flows between Russia and Europe is consistent with several of these options.

Figure 8.8 ▷ Russian gas exports by destination and aggregate utilisation of export capacity in the New Policies Scenario



Under-utilised capacity gives Russia near-term flexibility in supplies to Europe, while new pipelines to the east and LNG provide longer term diversity of markets and revenues

8

In the New Policies Scenario, Russian exports increase by two-thirds, reaching some 315 bcm in 2040 (Figure 8.8). Although it takes time, our projections see Russia successfully unlocking new gas markets, bringing dependence on the European market down to around 60% of its exports in 2040. New export infrastructure achieves higher utilisation rates than the existing connections to Europe and this brings aggregate utilisation of export capacity slightly up to almost 60% in 2040, from 55% in 2015. Nevertheless, there remains significant slack in the system, implying that Russia could increase its market share in Europe if it were willing to accept a lower price (see Spotlight in Chapter 9), although it should be noted that many European countries see diversity of gas supplies as important. It also implies that, if global gas markets were to tighten, Russia could quickly ramp up pipeline gas exports to Europe and displace some LNG there that could then be re-routed to alleviate shortages elsewhere.

Middle East

Underpinned by ample availability of gas at low regulated prices, gas demand in the Middle East expanded at a remarkable 6.8% per year over the last 25 years. However, in recent years production has had difficulties in keeping up with demand growth. Despite having access to some of the lowest cost gas in the world, the incentives for gas producers in the countries of the Middle East are, in many cases, insufficient to bring on new projects. Gas prices often still reflect the remuneration that was adequate when gas demand growth could be covered primarily with associated gas (which as a by-product of oil has very low production costs). To meet future demand growth, however, production increasingly has to shift to non-associated gas fields where project economics rely on gas rather than oil prices. Some of the non-associated gas fields, such as the recently developed Shah field in the United Arab Emirates, are moreover high in sulfur and thus more complicated and expensive to produce. A key challenge for the governments of Middle Eastern countries is thus to strike a careful balance between the commercial costs faced by producers on the one hand and the level of domestic prices on the other: domestic price rises would help to close the gap between them, but would be unpopular.

Our projections indicate that the growth of gas demand slows to 2.2% per year over the next 25 years, reaching almost 795 bcm in 2040, reflecting increasing prices (i.e. a gradual phase-out of fossil-fuel subsidies), efficiency gains and saturation effects. Nevertheless, with an additional 320 bcm of gas use, demand for gas grows by more in the region as a whole than anywhere else except China over the *Outlook* period. Power generation is the frontrunner, accounting for more than one-third of the incremental gas consumption, followed by industry which contributes nearly 30%. Displacing oil use in these sectors is a major opportunity for gas: in 2016, nearly a third of the region's power needs were generated from oil, but that share drops to around 10% in 2040. Seawater desalination is another major growth area for gas, both in large plants that combine freshwater production with electricity generation and in smaller units in the buildings sector.

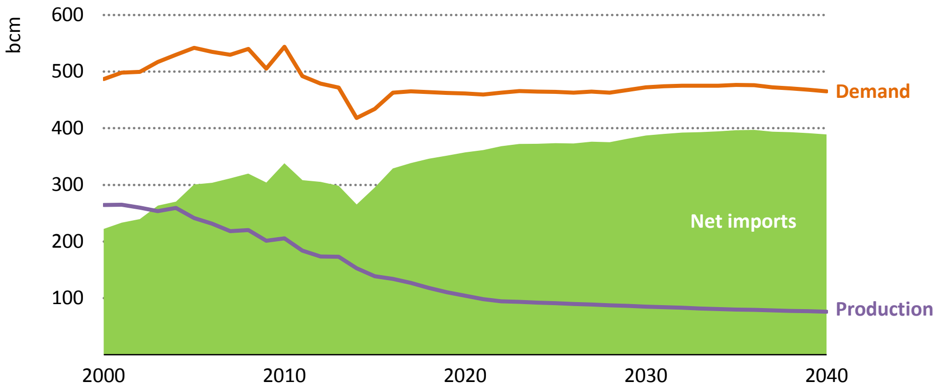
In our projections, Iran leads gas output growth in the Middle East, adding 150 bcm to the region's gas supply in the period to 2040. Although many uncertainties remain, the lifting of the main international sanctions and the recent presidential elections has raised the likelihood of foreign investment in continued development of the super-giant South Pars field (the northern part of the world's largest gas field with the other part being Qatar's North Field), with a number of Asian and European companies showing interest in participation. Satisfying domestic needs is the priority for Iranian gas producers, but we also anticipate some export growth via links to Iraq and Oman, as well as further deliveries to Turkey and, much later on the projection period, the start of a pipeline connection with Pakistan.

In early 2017, Qatar decided to lift its self-imposed development moratorium on the North Field. Such a decision had been anticipated in previous editions of the *WEO*, so does not lead to any dramatic change to our projections in this *Outlook*. Nonetheless, the lifting of the moratorium is a significant declaration of intent at a time of ample supply, reflecting a determination – and an ability, given Qatar's low-cost structure – to maintain a leadership role in global LNG. Our projections show Qatar's production increasing by 55% and reaching some 255 bcm in 2040. Most of the increase in output is geared towards the international market and Qatar remains the primary source of exports from the region.

European Union

Gas demand in European Union (EU) countries is estimated to have jumped by 7% to over 460 bcm in 2016. Greater gas use for power generation was the main driver of this trend, and the power sector remains central to the long-term prospects of gas in the European Union. The EU's target to cut greenhouse-gas emissions by 40% (compared with 1990 levels) in 2030 forces many coal plants into retirement and underpins a rise of CO_2 prices in the European Union Emissions Trading System to $35 per tonne of CO_2 in 2030 and nearly $50 per tonne in 2040. This creates space for gas in the power sector, even with renewables increasing strongly over the *Outlook* period. Another stimulus for greater use of gas in the EU power system comes from a more downbeat outlook for nuclear power. This edition of the *WEO* sees output from the nuclear power plants in EU countries dropping by 30% in the coming 25 years and installed capacity falling from 127 gigawatts (GW) in 2016 to around 85 GW in 2040 – nearly 20 GW less than in the *WEO-2016*. As a result, gas use in the power sector expands slightly in the period to 2040, and over 110 GW of new gas-fired power plants are built to replace retirements and to provide flexibility for an increasing share of variable renewables. Natural gas consumption in the European Union stays around current levels for most of the projection period before dropping slightly to 450 bcm in 2040 (Figure 8.9).

Figure 8.9 ▷ Natural gas balance of the European Union in the New Policies Scenario



Even with a flat demand outlook, the European Union's gas imports increase to 2040 as domestic output continues to decline

Domestic EU production drops sharply over the *Outlook* period to around 65 bcm in 2040, 50% below current output levels. The European market has proved its ability to adapt to rapidly changing production prospects in the past few years. When output from the super-giant Dutch Groningen field dropped by over 40% between 2013 and 2016 (production was capped due to concerns about increased seismic activity from gas extraction), the loss of some 30 bcm in the European gas balance was smoothly compensated for, triggering no major price reaction. It clearly helped that this happened at a time when plenty of gas was available on the international market. The European Union nevertheless is well placed to substitute falling domestic output with imports; it has a well-functioning and efficient internal gas market, many under-utilised regasification terminals, and a wide portfolio of pipeline import routes. The projected retirement of almost 80% of the region's coal-fired capacity however will mean the loss of a source of flexibility to respond to demand fluctuations, so gas security is set to remain an important topic on policy-makers' agendas.

Our projections see EU gas imports increase by some 60 bcm, reaching around 390 bcm in 2040. Russia remains the largest supplier of gas to the European Union, maintaining its market share of around 40%. Production in Norway – the second-largest source of imports – remains at high levels over the next few years, helped by expansions on the super-giant Troll field in the North Sea and by the coming online of the new Aasta Hansteen development in 2018. However, Norway faces the prospect of declining export availability over the longer term: after 2020 production is expected gradually to decline from just above 120 bcm to 100 bcm towards the end of the *Outlook* period. Gas production in the North Sea is mature and remaining resources in the Norwegian Continental Shelf are not sufficient to sustain current production levels and new discoveries are not expected to be sufficient to fill the gap. Further north, the Barents Sea holds more exploration promise and could potentially impact the longer term production outlook. Expanding production in the Barents Sea beyond the currently operational Snøhvit project would however require new gas discoveries and subsequent significant investments in new production facilities and infrastructure.

As Norwegian shipments drop, a range of other suppliers expands into the European market. Chief among them are US LNG suppliers, who reach a market share of just over 10% in 2025 and then keep this share in the longer term. Together with LNG from other sources, for instance from Qatar and East Africa, this means that the European Union's reliance on pipeline gas imports drops from over 85% in 2016 to two-thirds in 2040. Middle Eastern countries and suppliers from the Caspian (especially Azerbaijan) make inroads into the European market, so the diversity of pipeline gas suppliers also increases. Shale gas in Europe does not make a material difference to the EU's gas balance: although resources in some countries are promising, there are geological challenges in many places, together with political and public concerns.

Caspian region

Turkmenistan has large resources of relatively low-cost gas but faces the challenge of getting its gas from the centre of Eurasia to potential markets. Its geographic location means that it cannot opt for LNG exports (a constraint that other exporters in the region like Azerbaijan also face). Satisfying rising gas needs in the European Union, China, Pakistan or India therefore requires long-distance cross-border pipelines that transit at least one other country. Two close neighbours, Russia and Iran, are moreover themselves large gas producers, limiting their potential as export markets and their interest in being transit countries (for instance, Russia, a traditional off-taker of Turkmen gas, has reduced its purchases over the past ten years and ceased to import Turkmen gas altogether in 2016). This puts Turkmenistan at a significant disadvantage to other exporters.

The rise in global LNG trade is likely to make it harder for capital intensive, complex and politically challenging pipeline projects out of the Caspian region to secure political and financial backing. As a result, we have re-assessed the timelines of a number of pipeline projects. The fourth pipeline link between Turkmenistan and China (Line D), on which work has been suspended, is delayed considerably in our projections and enters into service only in the mid-2020s. Even more significantly, and contrary to assumptions in previous editions of the *WEO*, we no longer assume that any pipeline connection between Turkmenistan and South Asia (TAPI) is feasible by the end of the projection period. Security is one major concern for TAPI, given that the pipeline route runs through areas of Afghanistan under Taliban control. Financing and project management is a second: for the moment, Turkmengaz (the state-owned gas producer) is the sole consortium leader, but there are doubts about whether it has the capacity to spearhead a complex international project and there is, so far, no partner involved in the project from among the leading international global oil and gas companies. As well, at least for the next few years, there are questions about the commercial rationale for the project: although gas from the super-giant Galkynysh field, delivered via large-scale pipeline, should be competitive in the long term, potential customers like India and Pakistan have access to LNG at price levels that, at least for the time being, are difficult for the proposed pipeline to match.

Azerbaijan manages to place growing volumes of gas on the European market via a number of pipelines that are in an advanced stage of realisation. Nevertheless, exports from the country remain, in the long term, markedly below the level that its resource and cost base would suggest is possible.

Overall, despite the difficulties they face in getting gas to foreign markets, countries in the Caspian region increase gas production from nearly 200 bcm in 2016 to over 305 bcm in 2040. Around 55% of the region's incremental output comes from Turkmenistan, which increases output by over three-quarters to over 140 bcm, while Azerbaijan contributes a third to production growth, reaching output of 55 bcm (a tripling compared to the level reached in 2016). Kazakhstan also increases its production over the coming 25 years while that of Uzbekistan declines. Production growth in the region satisfies a 40% increase in gas demand but, even if the region does not realise its full export potential, the bulk of growth feeds pipeline exports, most importantly to China.

Australia

Australia is well on the way to becoming a major LNG exporter, with over 60 bcm of liquefaction capacity brought online in the past five years and another 30 bcm scheduled to become operational before 2020. The Australian investment wave has been plagued by major cost overruns and by some delays in starting up facilities, e.g. at the Gorgon offshore project. A rise in domestic prices also sparked a debate over the adequacy of domestic gas supply that culminated in the introduction in 2017 of a temporary gas security mechanism that would allow the government, under certain circumstances, to curtail export in favour of domestic deliveries. In our *Outlook*, projects that are currently under construction gradually ramp up, and Australian output reaches around 150 bcm in 2025 (up from just under 90 bcm in 2016) before increasing to 195 bcm in 2040. Some new projects come to fruition over the *Outlook* period, but these are mostly smaller incremental projects and there is no second investment wave comparable to the boom of the last ten years.

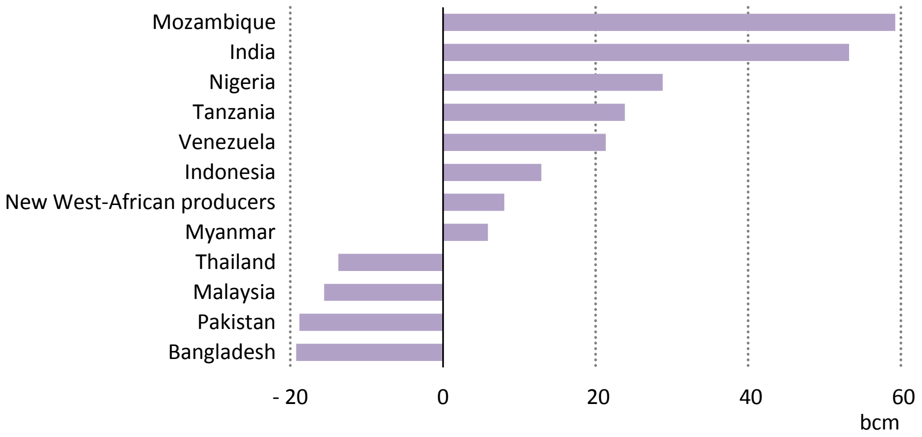
India

Gas remains a relatively minor component of the Indian energy mix, and concerns about affordability and reliability have plagued its development in many parts of the country; Gujarat, with well-developed infrastructure and relatively high gas penetration, is an exception. However, there is major growth potential in the power sector and in industry, where fertiliser manufacturing is the biggest energy user. In our projections, the use of gas for electricity generation is the largest single source of growth for gas, with over 40% of the total increase: gas provides a valuable source of flexibility to a market in which solar plays a big role but which has an evening peak in electricity demand. There is also now a more concerted push to get gas into the Indian energy system because of rising concerns about air quality in India's major cities. India already has the fifth-largest natural gas fuelled vehicle fleet in the world. This reflects the outcome of policy and programmes to encourage compressed natural gas (CNG)-based taxis, buses and two/three-wheelers in cities such as Mumbai and Delhi, and to provide adequate refuelling infrastructure to support the roll out. This provides a solid basis for a nine-fold gas demand expansion in the transport sector to over 25 bcm in 2040.

On the supply side, low domestic gas prices have been a major impediment to resource development. Recent pricing reforms, allied with the new Hydrocarbon Exploration and Licensing Policy, should help to address this. The recent decision by BP and Reliance to move ahead with deepwater gas investment represents an important vote of confidence in India's gas outlook. However, our analysis of India's gas supply costs suggests that, for the moment, most commercial new projects are marginal in the current gas price environment, and this means that most growth on the production side takes place only after 2025. Overall, with upstream reform assumed to advance, the New Policies Scenario sees domestic gas output grow from 31 bcm today to some 85 bcm in 2040 (Figure 8.10).

New infrastructure investment will be essential if gas markets and consumption are to expand in India. The prospects for gas use in the power sector are closely connected to broader electricity reforms to relieve the financial stress on the local distribution companies, which can lead them to refrain from dispatching higher cost gas-fired capacity when it is needed. Downstream infrastructure and import facilities need to grow in lockstep, which requires integrated infrastructure planning, and regulation at national level on network access. India's large coastal metropolitan areas and industrial hubs, with actual or potential access to LNG markets, provide a natural focus for gas market and infrastructure development. The New Policies Scenario assumes that steps are taken on planning and regulation, and that LNG imports rise from just under 25 bcm in 2016 to nearly 100 bcm in 2040.

Figure 8.10 ▷ Change in natural gas production in selected developing countries in the New Policies Scenario, 2016-2040



Emerging gas producers see their output increase strongly while some more established gas producers, especially in Asia, need to offset falling production with imports

East Africa

Major offshore discoveries in Mozambique and Tanzania have created high expectations for local gas market development and for a significant role for the two countries in the international LNG business. Although the resources discovered are sizeable (the discoveries in Mozambique's Rovuma basin alone are estimated at 3.5 tcm) and the upstream costs relatively low, getting the gas from the fields to consumers is not straightforward. Gas use in Mozambique is marginal and the main consumption hubs are almost 2 000 kilometres (km) to the south, around the capital Maputo. Tanzania is in a slightly more favourable position in this respect; the distance to Dar-es-Salaam is much shorter and an 8 bcm pipeline is already in place. However, even under optimistic assumptions, the domestic markets and those of neighbouring countries (notably South Africa) remain, for the foreseeable future, too small to absorb more than a fraction of the gas production from the offshore fields. Exports to growing gas markets in Asia (especially India) and Europe are thus at the core of a strategy to develop East Africa's gas resources. However, the area in which the LNG facilities are needed is remote, with implications for the complexity and cost of the construction phase. The first step towards tapping the huge resources is being made with a floating LNG vessel for the Coral development in Mozambique (Box 8.2), with onshore liquefaction trains anticipated later in the 2020s.

We project gas production in Mozambique to increase gradually to 13 bcm in 2025 before taking off in the second-half of the *Outlook* period and approaching 65 bcm by 2040, and production in Tanzania to reach 25 bcm by 2040. Gas export via onshore liquefaction terminals could accompany domestic pipeline development (pipelines that could be expanded into South Africa in the case of Mozambique or into Kenya in the case of Tanzania), but the creation of local gas demand hubs that are served via floating storage and regasification facilities (FSRU) requires less capital expenditure and may prove a more flexible way of making gas available. Although energy needs are growing quickly, the region has ample coal resources and good renewable energy potential within easy reach, so whether gas indeed makes inroads to the local energy mix hinges critically on the legal and regulatory regime and the availability of anchor consumers in power generation and industry that can underpin new infrastructure.

Box 8.2 ▷ How floating technologies can enable gas market development

Floating liquefied natural gas (FLNG) is a nascent technology that allows offshore gas fields to be tapped by a vessel containing a liquefaction unit that can produce LNG and transfer it directly onto LNG carriers. There is currently only one such vessel operational (in Malaysia), but various others are in the investment pipeline. The Prelude FLNG vessel arrived at its prospective production location off Western Australia in mid-2017. A large vessel (4.7 bcm a year) has been chosen to kick-start development of Mozambique's remote, but prolific, Coral field, while a smaller FLNG vessel (just under 2 bcm per year) is planned to produce LNG for some eight years from the tiny Kribi field off Cameroon's coast (after which it can be deployed elsewhere).

FLNG is variable in size (0.7 bcm to 5 bcm), but typically smaller than onshore liquefaction plants which require a certain size (often more than 5 bcm) to benefit from economies of scale. The vessel cost and construction time is likely to vary significantly depending on whether it is a new-build or a conversion and on its complexity. Costs for the initial projects have been relatively high, but are expected to come down: FLNG is a promising technology to unlock gas deposits that are too remote or not large enough to justify the construction of an onshore plant and subsea pipelines.

At the other end of the LNG shipping chain are Floating Storage and Regasification Units (FSRUs), which are vessels that can be moored at sea or docked in a port to regasify LNG and feed it into a transmission or distribution network (or deliver it directly to an end-user). FSRUs are an affordable, fast and flexible way to get access to natural gas supplies. Developing countries that lack existing infrastructure need to develop their gas markets gradually. One way of doing so is to establish an anchor consumer, such as a power plant, in an industrial hub and then gradually expand infrastructure from there. LNG-to-power projects are being pursued in Ghana, Namibia, Senegal and South Africa to create a domestic gas market, and FSRUs fit well with such projects because they are scalable, fast to deploy and require substantially less (sunk) capital than an onshore terminal or a large cross-border import pipeline project. The cost of a new FSRU including the necessary auxiliary facilities can be 40-50% lower than that of an onshore facility while LNG tanker conversions are even less expensive.

Currently there are over 20 FSRU terminals in operation worldwide and several more are under construction. Many of the terminals are in countries that have existing gas markets (e.g. Pakistan, Argentina, Brazil or Egypt) in order to replace or complement existing supplies, or to balance seasonal demand fluctuations. The relative ease of moving floating facilities (both FSRU and FLNG) means they can easily be redeployed, which reduces risk for investors and lowers the hurdles for access to finance that are important considerations for developing countries. Terminals have the potential to help developing countries to shift from more costly oil products or more polluting coal to gas when this would otherwise not be possible or economically viable.

Other developing countries

Infrastructure availability and gas market reform are common challenges in various gas-rich countries, and failure on either of these counts could risk stalling long-term production and consumption prospects. Nigeria, Venezuela, Myanmar and a number of emerging producers like Mauritania, Senegal or Ghana are all facing this challenge. Indonesia is another case in point: the geographical mismatch between new gas fields (mostly offshore) and demand hubs on Java and Sumatra needs to be bridged with infrastructure in order for gas to prosper domestically. An expansion of pipelines, LNG to FSRU options and even small-scale LNG supply via trucks or barges for smaller demand centres and outer islands, e.g. to displace costly and polluting diesel generators, is critical. However, the transmission sector currently suffers from a number of problems: extensive lead times for infrastructure planning, construction and commissioning; insufficient co-ordination between the different stakeholders and sectors (including the power sector); and physical bottlenecks.

The projections for Indonesia in the New Policies Scenario are based on the cautious assumption that such problems are gradually dealt with, and that pricing reform takes place, leading to gas demand growing from some 45 bcm in 2016 to nearly 100 bcm over the period to 2040. Industry accounts for 60% of the growth: in the power sector, gas continues to find it hard to compete against low-cost (and easily transportable) coal. Pricing reform is crucial: the anticipated abolition of preferential gas prices for certain industries creates a level playing field on the demand side while a gradual move towards export price-parity incentivises new investments in the upstream. Indonesian gas output is projected to rise by 17% to 90 bcm in 2040. As conventional gas production declines slightly to 2040, unconventional sources underpin the rise in output.

There is significant investment in conventional projects, but much of the new resources brought online in Indonesia serves to offset depletion from older fields. Although Indonesia holds, with East Natuna, Asia's largest untapped gas field, prospects for extracting this expensive and technically challenging resource (the gas has a CO_2 content of 70%) are uncertain, and clouded further by the ample availability of cheaper LNG, especially from Qatar and the United States, and later also Russia. In this edition of the *WEO*, we have not included production from this field in our projections.

Other significant gas producing countries in South and Southeast Asia – Pakistan, Bangladesh, Malaysia and Thailand – do not manage to offset the long-term decline of their mature production base with new projects. This provides a major opportunity for

LNG, as these countries have gas infrastructure in place, an established critical mass of gas consumers and experience in gas market regulation and operation. Although these countries emerge as important importers in our projections, this will require changes to domestic price regulation: LNG is a sustainable option if gas prices in these countries properly reflect its cost.

8.3.4 Trade and investment[4]

Inter-regional gas trade increases by 525 bcm in the period to 2040, expanding by 2.4% on average per year, a growth rate similar to that seen over the past 25 years. The importance of LNG in inter-regional trade grows markedly, with nearly 90% of the incremental volumes traded over long distances taking the form of LNG compared to just under two-thirds in the past 25 years. By the end of the *Outlook* period, a total of 1 230 bcm of gas is traded between regions, some 60% of which is LNG, up from just under 40% in 2016. The flexibility offered by LNG is one of the factors underpinning its growth. There are many reasons why this may be desirable from the customer's point of view. Flexibility is an important attribute for importing countries that do not want to commit to a long-term supply agreement because their main reason for procuring gas from the international market is to meet seasonal fluctuations of demand. Latin America is a case in point: the continent as a whole relies on hydropower for 45% of its electricity supply (in Brazil, the biggest power market, the figure is 65%), but hydropower is strongly weather dependent and seasonal. Gas-fired power plants balance the fluctuations but their comparably low utilisation rate often does not justify a dedicated pipeline (at least not initially) – a clear case for LNG, often in combination with an FSRU. Flexibility also plays an important role for countries that seek to temporarily supplement domestic production. Argentina is a good example; it is one of the few countries in Latin America with a significant need for heating, and therefore complements its domestic production, which is fairly inflexible, with LNG. Egypt is another example: it imports LNG to bridge the gap until output from its Zohr field has ramped up to full capacity. These are examples of countries that have good domestic production prospects and may only draw on LNG for a limited time but there are others – Malaysia, Thailand, Pakistan and Bangladesh to mention but a few – that face depletion of resources and that may rely on LNG for longer. The countries of Southeast Asia and India become a major force in the international LNG trade; the additional LNG imports of these countries add up to around 160 bcm in the period to 2040.

LNG also offers important security of supply benefits to countries that want to diversify their gas procurement portfolios. Security of supply was the primary reason for the construction of regasification terminals in Lithuania, Poland and Jordan (Croatia might follow soon). In these cases, it cannot be assumed that import volumes will be large: the primary purpose of the terminal is to provide optionality. As Jordan demonstrated in 2016, however, import volumes can surprise on the upside.

4. Unless otherwise stated, trade figures in this chapter reflect volumes traded between countries/regions modelled in the *WEO*, and therefore they do not include intra-regional trade.

Others may want LNG in order to replace oil products with cheaper gas. Such oil product displacement already makes a strong case for LNG imports in some parts of the Middle East (even though the region as a whole is a net exporter) and may underpin a growing role in the future for LNG in the Caribbean and in parts of Africa. Where ports are too shallow to accommodate large LNG tankers, LNG demand growth hinges on the availability of smaller vessels with the ability to deliver LNG cargoes. Our projections see small-scale LNG technologies advancing, and LNG gradually making inroads as a fuel for smaller countries and islands.

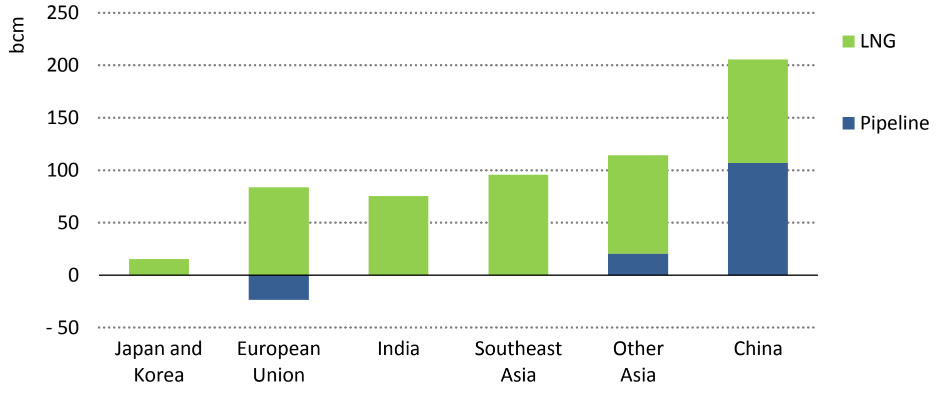
Table 8.4 ▷ Natural gas trade by region in the New Policies Scenario

Net importing regions in 2040	Net imports (bcm)			As a share of demand		
	2016	2025	2040	2016	2025	2040
European Union	-329	-374	-389	71%	80%	84%
China	-73	-177	-278	35%	44%	45%
Other Asia Pacific	52	-47	-178	17%	16%	40%
Japan and Korea	-165	-150	-181	98%	98%	99%
India	-24	-55	-99	43%	57%	54%
Other Europe	24	9	-18	16%	6%	10%
Net exporting regions in 2040	**Net exports (bcm)**			**As a share of production**		
	2016	**2025**	**2040**	**2016**	**2025**	**2040**
Russia	188	265	314	29%	37%	40%
North America	-1	119	192	0%	10%	14%
Middle East	108	134	201	18%	19%	20%
Caspian	80	87	140	40%	40%	46%
Australia	45	100	137	49%	64%	68%
Sub-Saharan Africa	29	48	106	48%	54%	50%
North Africa	42	49	47	29%	26%	19%
Central & South America	10	-6	5	6%	3%	2%

Notes: Positive numbers denote net exports and negative numbers denote net imports. Import and export totals should sum to zero; the difference in 2016 is due to stock changes.

Energy demand growth and the political will to meet this demand with a relatively clean and flexible source are the key drivers for gas import growth in China and India. No country sees its gas imports increase more than China over the coming 25 years, and total imports of 280 bcm in 2040 mean that it becomes the second-largest gas importer after the European Union (Table 8.4). Not all of these imports come from LNG (the share of LNG in Chinese gas imports stands at just under half in 2040). Although there are new links from the United States to Mexico, from the Middle East and the Caspian region to Europe, and from Iran to Pakistan, China is the only country that significantly advances large cross-border pipeline projects in our *Outlook* (Figure 8.11). By contrast, India has no planned pipelines, and it meets its additional import needs of 75 bcm in the period to 2040 entirely with LNG.

Figure 8.11 ▷ **Change in gas imports by selected region and transport mode in the New Policies Scenario, 2016-2040**

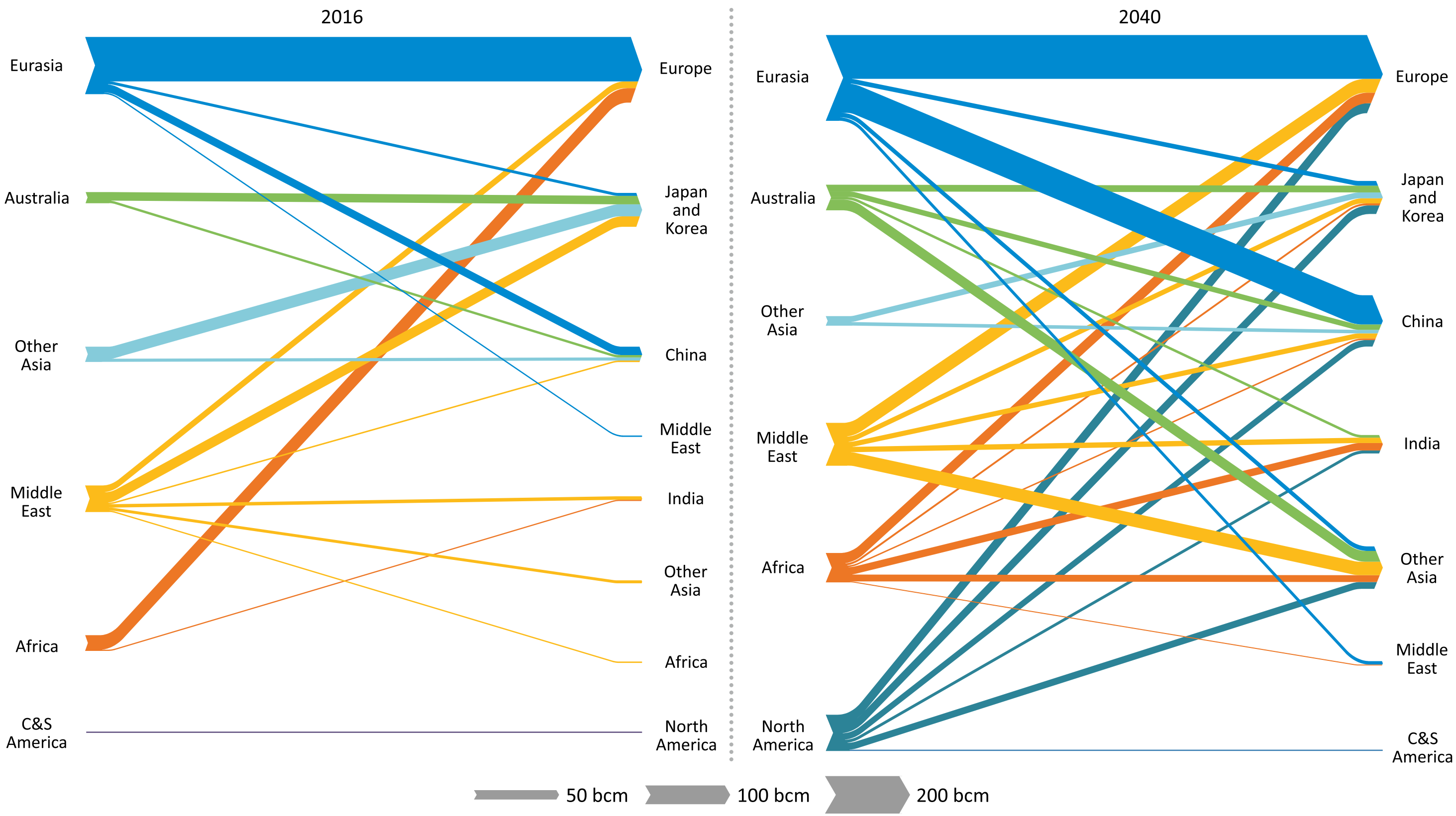


Asian countries lead the growth in global gas trade; outside China, new pipeline trade routes find it hard to advance in a market with LNG readily and flexibly available

The concentration of import growth in Asia continues to reshape inter-regional gas trade flows, underpinning a fundamental shift in the weight of trade away from the Atlantic basin to the Asia Pacific region (Figure 8.12). A growing diversity on the supply side – new exporters like the United States and later Canada and Mozambique join the club of LNG exporters – increases the interconnectivity of inter-regional gas trade. The United States, Qatar and Australia are the biggest LNG exporters in the New Policies Scenario, with the market share of the United States in inter-regional LNG trade peaking at around 25% in the mid-2020s and then declining slightly but staying above 20% for the remainder of the *Outlook* period. The global gas market not only becomes more interconnected and diverse but also sees important changes in how trade functions and how pricing is determined. These changes, and what it takes to establish a truly global gas market, are explored in detail in Chapter 9.

The global gas market is currently awash with gas, largely as a result of the rapid growth of LNG supplies and our modelling suggests that, in the New Policies Scenario, the supply overhang is not absorbed by import growth until the mid-2020s. Taking lead times of three to six years for LNG projects into account, however, new investment decisions will need to be taken soon to avoid market tightening. We see much of this investment being brought forward in the United States, Qatar and Russia in the first-half of the 2020s. The United States benefits from good conditions for brownfield investment (which keeps costs low) while Qatar and Russia have access to very low-cost gas. Projects of these three exporters have a lower risk than complex new greenfield ventures, making them well-suited for expansion at a time when the gas market is undergoing transition. In the second-half of the projection period net export growth and investment is more balanced, with more greenfield activity, for instance in East Africa and Latin America.

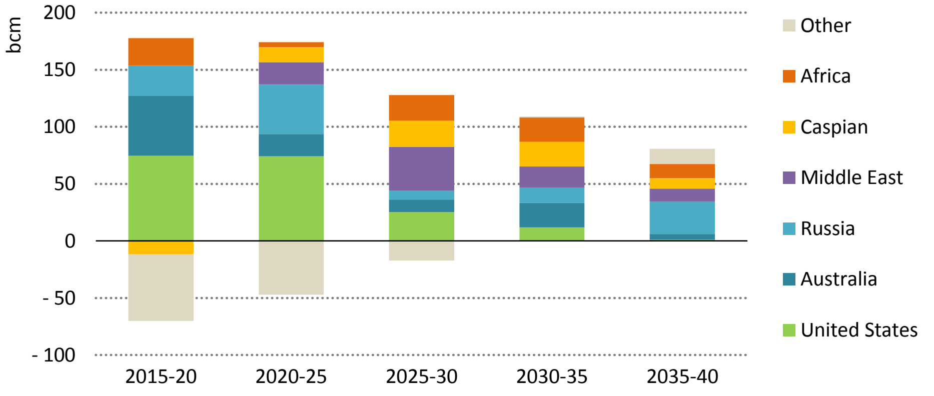
Figure 8.12 ▷ Selected global gas trade flows in the New Policies Scenario (bcm)



The rise in LNG trade underpins an increasing diversification and interconnectivity of the global gas market

Note: C&S America = Central and South America.

Figure 8.13 ▷ **Change in net gas exports by selected region in the New Policies Scenario**



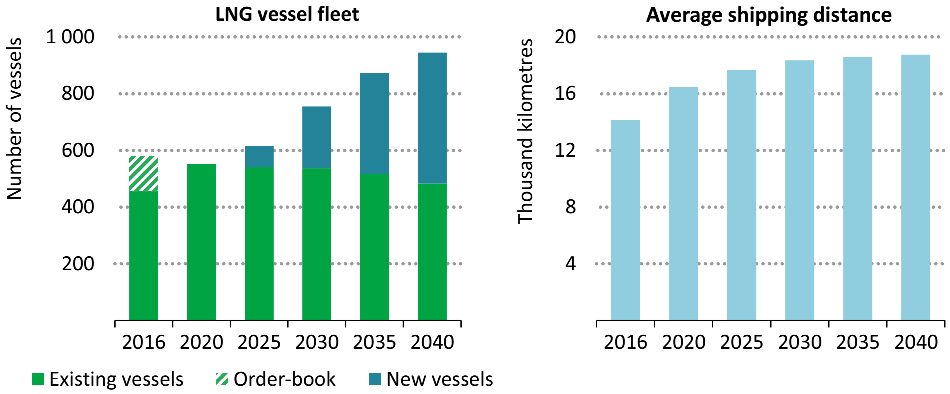
The United States, Russia and Qatar bring additional gas exports to the market in the first-half of the 2020s, fostering a smooth rebalancing

The bulk of the projects needed to meet demand over the *Outlook* period are not commercially viable at current gas price levels. This is one of the reasons why gas prices increase in the New Policies Scenario. At the same time, competition for space in the future energy mix is fierce, and investment costs need to come down if gas is to expand its share. Cumulatively, $8.6 trillion are needed in the period to 2040 for investments into the gas supply chain (upstream and midstream), accounting for more than a fifth of global supply investment in this scenario. Around a third of this investment is for infrastructure alone (transmission and distribution pipelines, liquefaction plants and regasification terminals, etc.), highlighting what a critical enabler the midstream sector is for demand growth and how disruptive constraints on infrastructure investment could be.

Focus: How is the market for LNG shipping evolving?

The LNG shipping market is currently characterised by over-capacity and low charter rates (i.e. the daily rental cost of a vessel). High and rising charter rates up to 2012 and the expectation of robust growth in LNG trade led to an ordering spree of new LNG vessels from about 2011. By the end of 2011, there were about 340 LNG vessels in operation: by the end of 2016, this number had increased to almost 460. Total LNG shipping capacity stood at around 70 million cubic metres in 2016, up 35% from 2011 levels. However, LNG trade growth fell short of expectations and, as a consequence, charter rates spiked in late-2011 before embarking on a precipitous fall, together with the utilisation rates for the LNG fleet. Average shipping distances have generally been on an increasing trend. The re-routing of LNG destined for the Atlantic market to Japan in the aftermath of the Fukushima-Daiichi nuclear accident propelled shipping distances temporarily upwards but, since 2014, shipping distances have been more in line with a gradual long-term growth path.

Figure 8.14 ▷ Evolution of the LNG vessel fleet and the average shipping distance in the New Policies Scenario



New LNG vessels are needed in the first-half of the 2020s and, with the rise of US LNG exports, average shipping distance increases

Notes: Includes only large-scale vessels (>60 000 cubic metres [m^3]). New vessels are assumed to have an average size of 172 000 m^3).

The order-book for new vessels indicates that more than 120 ships are likely to be delivered over the coming years, adding further to the size of the current LNG fleet. The current fleet is moreover relatively new (only around 6% of active LNG carriers are older than 30 years) and therefore scrappage is not likely to reduce available LNG transport capacity for a long time to come. Our New Policies Scenario, however, sees inter-regional LNG trade growing by two-thirds in the period to 2025. It also sees the emergence of the United States as a major LNG exporter boosting average shipping distances and journey durations (even with the opening of the Panama canal to large LNG tankers, the shipping distance between the US Gulf coast and Japan is up to 50% longer than from Qatar to Japan, while the distance to India is more than four-times longer than from Qatar), pushing up the utilisation of the fleet. The growth in inter-regional trade and the growing average length of journeys suggests that surplus shipping capacity will be absorbed within the first-half of the 2020s (Figure 8.14), and that more than 70 additional vessels are needed by the mid-2020s. The need for new vessels continues to grow in the long term as LNG trade keeps increasing and scrappage rates pick up with the ageing of the current fleet. By 2040, almost 950 LNG ships are travelling the world's seas in the New Policies Scenario, about twice the number of active vessels today.

The new gas order

How might LNG change the game?

Highlights

- The New Policies Scenario projects a rise of 40% in gas production in the United States to 1 060 bcm in 2040, with shale gas the main source of growth. US shale gas output increases by more than 350 bcm to 2040, adding twice the current production of Qatar to global gas supply. The bulk of the growth happens over the next ten years, and accounts for more than half of global gas output growth in that period. The ramp-up in US shale gas from 2008 to 2023 would constitute the largest increase in output from a single source in the history of gas markets.
- Annual US gas demand increases by 100 bcm over the coming 25 years, with most of the near-term growth coming from industrial consumers, but this falls well short of the huge increase in US production. Some of the amply available US shale is exported by pipeline to Mexico and Canada, but in the long term a larger share is exported in the form of LNG. Shipments of LNG from the United States surge from a low base to 115 bcm in 2025 – when the US becomes the world's largest LNG exporter – and further to nearly 160 bcm in 2040.
- US LNG has many of the characteristics – destination flexibility, hub-based pricing and spot availability – that are transforming the wider gas market and, for this reason, it accelerates structural changes in the way that gas is traded internationally.
- The new gas order is characterised by greater diversity on the supply side as the number of global liquefaction sites doubles to 2040, price formation based on competition between different sources of gas supply (oil-indexed pricing covers less than one-quarter of traded LNG in 2040, compared with 75% today); a tendency towards shorter contract durations and a greater share of spot trading; and increased contractual flexibility to seek out opportunities for arbitrage rather than trading point-to-point with a fixed group of customers.
- These changes are also underpinned by the liberalisation of gas markets in key Asian countries, which facilitates the emergence of new gas trading hubs, and by the rise of so-called portfolio players – large companies with a diversified range of supply, shipping, storage and regasification assets.
- The move towards a more diverse, flexible and liquid global gas market has important implications for investment and can bring significant benefits for energy security. In the near term, uncertainties over the market outlook and the shift in contractual and pricing arrangements are likely to favour smaller supply projects or expansions to existing facilities. The challenge for the longer term is to ensure that buyers and sellers have sufficient confidence in the emerging gas order to make it the basis for their future plans and investments.

9.1 Introduction

For decades, natural gas trade in many parts of the world has been characterised by strong bilateral ties between buyers and sellers, underpinned by binding contractual arrangements that lock them into a long-term relationship. These ties and arrangements evolved as a result of the fears of those who built highly capital-intensive pipelines that buyers might behave opportunistically once a pipeline had been finished. To mitigate such risk, sellers insisted on contracts that were long-term and included take-or-pay clauses (the buyer takes the gas or pays a penalty). Pricing was determined based on the replacement value of the gas, which in practice meant the price of oil, as the main competing fuel. Destination clauses (restricting the right to re-sell gas) prevented the buyers from seeking arbitrage opportunities and enabled price discrimination. Much of this was introduced in the early 1960s, to underpin the development of the super-giant Groningen gas field in the Netherlands. Later, these elements formed the basis for the organisation of Soviet (now Russian) gas exports to Europe.

With the rise of liquefied natural gas (LNG) trade, many of the elements that characterised pipeline-based trade were adopted for liquefied gas trade too, despite the inherently different nature of the trade relationship. Oil price indexation, take-or-pay contracts and destination clauses became common features of LNG trade in the Asia Pacific region and also of LNG trade between North Africa and Europe. As a first wave of Asian long-term contracts for LNG expired and were renegotiated in the 1990s, buyers started pushing for more flexibility such as lower take-or-pay obligations, shorter term contracts and a weakening of the oil-price linkage (the implementation of a so-called S-curve into the pricing formula reduced price volatility). But most LNG trade remained on a point-to-point basis from a specific seller to a specific buyer.

The emergence of the United States as a potential LNG importer in the mid-2000s presented a big potential market opportunity, but one that always looked likely to bring with it a challenge to the nature of the prevailing contractual arrangements. By this time, the US gas market was already highly liquid and underpinned by spot trade, so potential US gas importers were not willing to enter restrictive long-term contracts based on oil-indexed prices. Moreover, the rise of gas use in the power sector (which underwent liberalisation in many countries at that time) exposed gas to competition with coal, putting the use of oil linkage further into question. With Qatar starting to tap one of the least-cost reserves of natural gas in the North Field, the consortia developing the LNG projects were willing to accept a larger-than-usual portion of market risk and develop some capacities whose commercial fortunes would be closely tied to a growing role of spot LNG trade (both from potential buyers in the United States and the United Kingdom).

Then the shale gas revolution took off in the late 2000s in the United States, and this had marked repercussions on international LNG trade before a single cargo was imported or exported. Rapid growth in shale gas output meant that the United States would not need the large-scale LNG imports that had been anticipated. Consequently, uncontracted LNG from Qatar that had been slated for the US market (alongside other sources of LNG for instance from Nigeria, Egypt or Indonesia) needed to find a new home. In Europe, this period coincided with important gas market reforms that were aimed at improving market integration, transparency and third party access, developing bi-directional pipeline flows and increasing use of hub pricing and, from 2010, with a slowdown in gas demand. With this, the conditions were established for arbitrage between readily available cheap gas on the spot market and more costly supplies priced under existing oil-linked long-term import contracts. The combination of regulatory changes and a market awash with gas ultimately triggered a process of renegotiation of contract terms with the main pipeline exporters, chief among them Russia's Gazprom. Faced with amply available gas and depressed gas prices, Gazprom and others started to make concessions in terms of the pricing of their gas.

With US shale gas production continuing to grow robustly and prices at Henry Hub (the country's key pricing point) averaging just over $3 per million British thermal units (MBtu) over the past five years, companies in the United States started converting former LNG importing facilities into export terminals, with the intention of exporting gas based on mark-ups from domestic US prices, rather than oil. One terminal – Sabine Pass – came online in 2016 and another 70 bcm of liquefaction capacity are under construction. Together with a new wave of Australian LNG projects that continue to ramp up, nearly 140 bcm of new liquefaction capacity are set to provide exports into an already well-supplied global gas market over the next few years. This is expected to provide additional impetus for further changes in the way gas is marketed and priced, putting more pressure on the rigidities that have characterised LNG and pipeline supply arrangements in the past.

The stage is now set for the United States to move from passively influencing the LNG trade towards actively exerting influence, as it becomes one of the world's largest exporters of LNG. US LNG is available on much more flexible terms with respect to destination than gas from most other exporters. These developments are accelerating the transformation of a gas market that used to be mostly bilateral into an increasingly well-connected and liquid global market, in which price formation is based on competition between different sources of gas supply. This is uncharted territory for most of the gas industry and, while the commoditisation of gas promises to bring a better-functioning market, it brings with it a set of new uncertainties.

Will the new wave of LNG create new markets for gas, or simply re-shuffle the pack of suppliers for existing markets? What will be the reaction of Russia and Qatar, today's incumbent exporters, with some of the world's lowest-cost gas at their disposal? What will be the gas pricing benchmarks of the future, and if they do not exist already, how soon will they emerge? Are today's challenges to traditional contractual and pricing models merely symptoms of cyclical over-supply, or are changes here to stay? Is a gas market in flux capable of delivering new capital-intensive gas supply investments? These are all key questions for our *Outlook* and the answers have a profound impact on our trends and projections. Our overall judgement is that the shift towards a new gas order is long-lasting and structural. This has implications well beyond the functioning of markets and the formation of prices: it redraws the map of natural gas supply and forces a change in perspective on the gas security equation.

9.2 The US shale storm and its repercussions

With output of some 750 bcm in 2016 and a similar level of demand, the United States is the largest consumer and producer of gas in the world. A rapid increase in shale gas output has underpinned strong production growth over the last ten years. Between 2006 and 2016, shale gas production grew at an average rate of 27% per year, topping 445 bcm in 2016. During this period, the average price at the Henry Hub dropped from $6.7/MBtu in 2006 to $2.5/MBtu in 2016, although not without some ups and downs along the way. Revisions of the resource estimates have been mostly upwards in recent years, while the long-term view on US gas prices has gradually shifted in the opposite direction – this *Outlook* is no exception.

The shale gas revolution has already had profound implications for the US energy system. Much of the hardship the US coal industry is going through (see Chapter 5) and a significant share of the recent reduction seen in US energy-related CO_2 emissions (see Chapter 11) is due to the widespread availability of inexpensive shale gas. Shale gas has also displaced some pipeline gas imports from Canada and underpinned a ramp up in exports to Mexico. Facilities initially developed to import LNG are now on track to spearhead the emergence of the United States as a major LNG exporter: this will bring a further set of changes. In this section we explore the ripple effects of an upbeat view on US shale gas resources on the US energy system, impacts on energy market developments in Canada and Mexico and the repercussions for global LNG trade.

9.2.1 Production

The size of the shale gas resource and the cost of its production are the primary uncertainties for the prospects of gas production in the United States. Our modelling of US shale gas production is based on a resource estimate of 29 trillion cubic metres (tcm), some 7 tcm higher than the level that underpinned the production trends in the 2016 edition of this *Outlook*. The Marcellus – the biggest shale gas play – is at the heart of the uncertainty, but new shale gas plays such as Utica or Wolfcamp also contribute to it, and could surprise on the upside in terms of their geological quality.

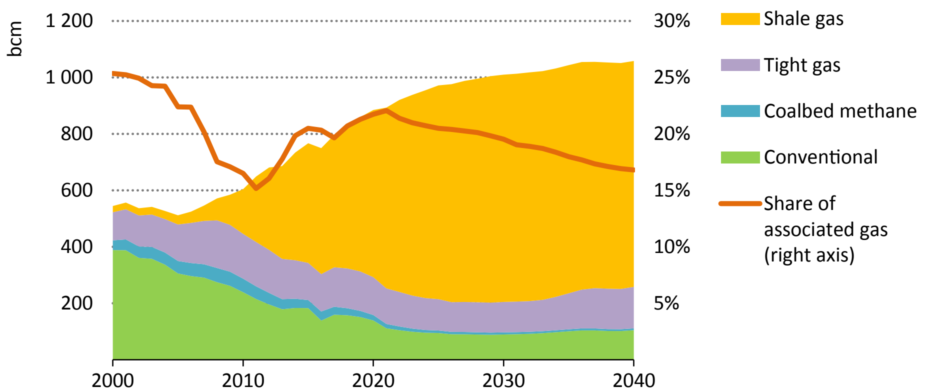
The higher resource estimate in this *World Energy Outlook (WEO-2017)* is the main driver for a more upbeat projection of US shale gas production in the New Policies Scenario, but the following policy, market and technology assumptions also underpin this year's projections:

- A competitive supply chain continues to bring down the costs of production and to lead to productivity improvements, together with an improved ability to identify and target the most productive areas of the various plays, including through the systematic application of digital technologies.
- A focus on streamlining licencing provisions for new pipeline infrastructure leads to an accelerated debottlenecking of the US gas transmission network – especially in the Appalachian and the Permian Basins where production growth is concentrated.

- US tight oil production enjoys strong growth over the medium term, meaning that low-cost associated gas production expands even more rapidly.
- Major players in the oil and gas industry consolidate promising shale acreage and execute a strategic shift in capital spending, prioritising US shale gas over larger projects with long lead times.
- The easing of certain rules on hydraulic fracturing on federal land can have an impact at the margin, but is unlikely to deliver significant upside potential as the most prolific shale gas plays are under privately owned land while the main shale gas resources that are off limits for development (e.g. the Monterey in California or the parts of the Marcellus located in New York state) cannot be unlocked by federal policy.
- One crucial assumption that we have retained from previous *Outlooks* is that the industry maintains public acceptance by applying high standards in the upstream – that is, managing effectively the environmental and social issues arising from shale gas production. In our projections, hydraulic fracturing is instrumental to 90% of US gas output by 2025, up from over three-quarters today, so any loss of public trust in this process could have a major impact.

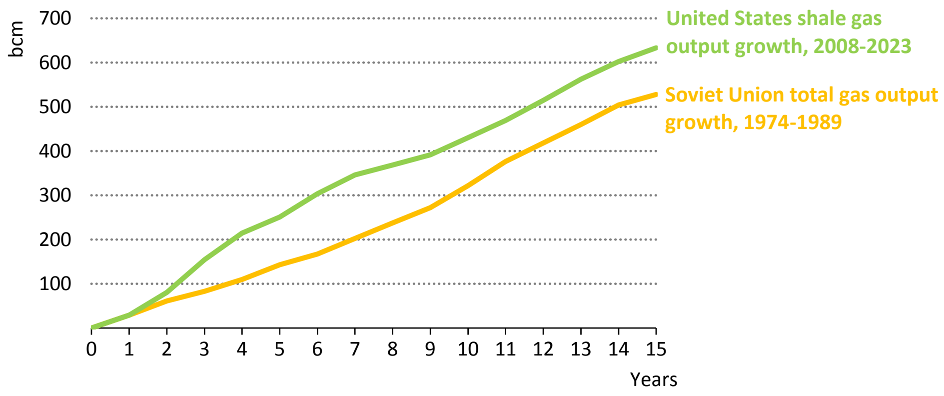
Total US gas production reaches 1 060 billion cubic metres (bcm) in 2040, over 40% higher than in 2016 (Figure 9.1). Growth is dominated by shale gas, the output of which increases by 80% in the coming 25 years, reaching 800 bcm in 2040. The ramp-up in shale gas production is particularly steep in the period to 2025; indeed, the projected increase in production would constitute the largest ramp-up in output from a single source in the history of gas markets, with a rise of over 630 bcm between 2008 and 2023 meaning a faster rate of growth than that in the Soviet Union's most rapid growth period of 1974-1989 (Figure 9.2).

Figure 9.1 ▷ US gas production by type in the New Policies Scenario



Shale gas is at the heart of US gas production prospects; its share of US gas output rises from 60% in 2016 to 80% in 2030

Figure 9.2 ▷ Rise in US shale gas output versus the steepest ramp-up in gas production in the Soviet Union



US shale growth between 2008 and 2023 is likely to be unprecedented in the history of gas markets, exceeding the growth achieved by the Soviet Union between 1974 and 1989

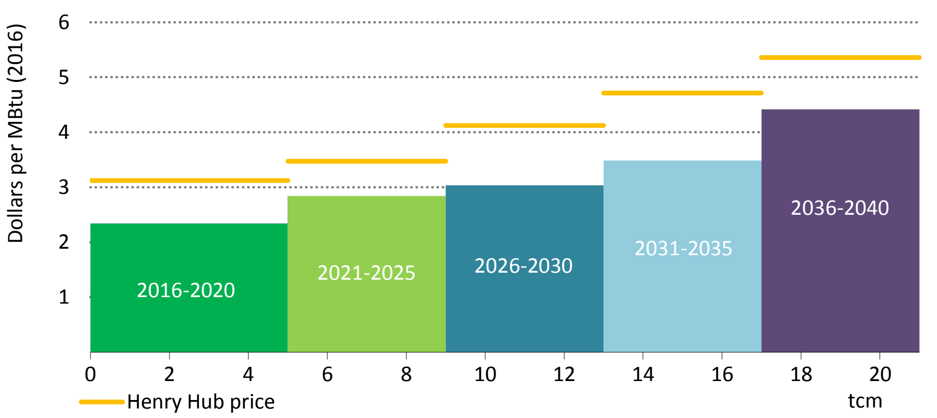
Although various shale gas plays contribute to this picture, the main engine of growth is the Appalachian Basin. Production from the Marcellus play in the Appalachian Basin has grown fivefold in the past five years, with output topping 170 bcm in 2016. If the Marcellus was a country, it would be the fourth largest gas producer, just behind Iran but ahead of Qatar. The Utica play – also located in the Appalachian Basin – has also started to ramp up and makes an important contribution to the long term rise in production. However, the surge in production has not been paralleled by an equal expansion in gas transmission infrastructure. As a result, gas trades at a significant discount in the Appalachian Basin compared with other pricing points in the United States, for instance the average price at the Dominion South hub stood at $1.5/MBtu in 2016, more than $1/MBtu below the price at the Henry Hub in that year. Timely expansion of transmission capacity, especially towards the Gulf coast and the west, is a precondition for continued strong growth from the Appalachian Basin: without it, a local glut in supply and continued discounts versus Henry Hub risk stalling investment.

Oil market fundamentals are also an important factor in our outlook for US gas production. Associated gas currently accounts for a fifth of US gas output: with the rise of tight oil production, this share has been increasing over the past few years. We see growth in associated gas output continuing until the mid-2020s, when tight oil production reaches a plateau in the New Policies Scenario, before it starts to fall back. Since associated gas is a by-product of oil extraction, it is primarily subject to oil market economics, so the growing weight of the United States in the global oil market fosters gas production growth as well. The largest tight oil play with associated gas production is the Eagle Ford (in west Texas) and the contribution of the Bakken play (in North Dakota and Montana) remains significant, but the bulk of the projected growth in associated gas production comes from the Permian Basin – also largely located in west Texas – and the Anadarko Basin[1] in Oklahoma. Producers of associated gas – especially those in the Permian – face similar challenges with pipeline bottlenecks as their peers in the Marcellus and Utica plays, especially over the coming ten years. Transmission capacity expansion from the Permian focuses on exports to Mexico and shipments towards the Gulf Coast, while additional production from the Anadarko Basin is primarily geared towards domestic consumption in the central United States.

Shale gas production trends are sensitive to the prevailing price level. In our modelling, current price levels of around $3/MBtu at the Henry Hub are insufficient to deliver the incremental production projected in the New Policies Scenario. Henry Hub prices thus rise gradually to $3.7/MBtu in 2025 and then to $5.6/MBtu in 2040. There is ample availability of relatively low cost gas in the United States and the upward revision of the resource estimate has led to a more optimistic assessment of the size and number of sweet spots, i.e. the economically most attractive portions of a shale gas deposit. Nonetheless, as the United States works through its shale gas resource base, producers are forced gradually to move away from the sweet spots to less productive zones. Continued technology learning and innovation mitigate the effect of this move on the economics of shale gas. Overall, however, the cost of new resources developed gradually increases and puts upward pressure on gas prices (Figure 9.3).

9

Figure 9.3 ▷ Average costs of resources developed in the New Policies Scenario by year and average Henry Hub price



As production moves to less productive zones and as associated gas output levels off, the average cost of new resources developed increases, putting upward pressure on prices

1. Primarily the South Central Oklahoma Oil Province and Sooner Trend Anadarko Basin Canadian and Kingfisher Counties (SCOOP and STACK) plays.

In the New Policies Scenario, over 20 tcm of shale gas resources is developed over the next 25 years in the United States. Even though not all of this is produced by 2040 (some of the developed resources have a production profile stretching beyond the time horizon of our *Outlook*), the competitive forces in the US gas industry, in combination with private resource ownership, lead to development of shale resources at a speed that is faster than in those countries where governments have defined specific policies on resource depletion (see section 9.3.4).

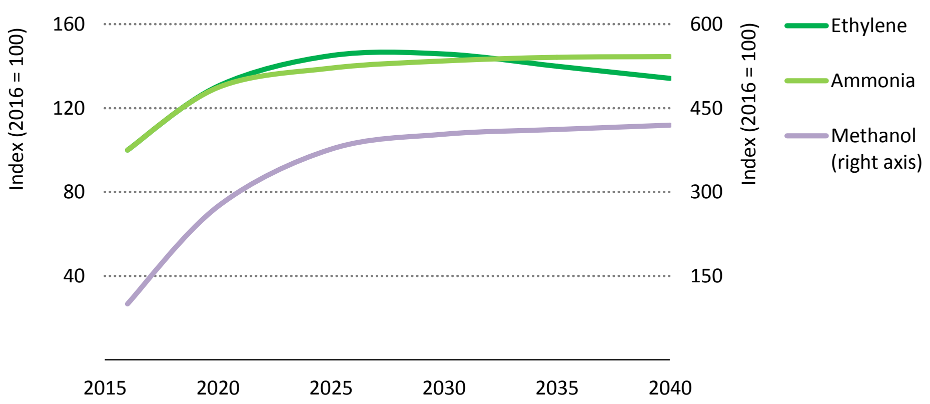
9.2.2 Implications for North America

Gas consumption in the United States – the world's largest gas consumer and a mature gas market – increases from 780 bcm in 2016 to 880 bcm in 2040, at an annual growth rate of 0.5%. Although gas slightly increases its contribution to primary energy supply from 30% in 2016 to 34% in 2040, there are limits as to how much further gas can increase its share in the US energy mix. The power sector is a case in point: the low gas prices seen over the past few years have led to an unprecedented fuel switch from coal to gas. In 2016, for the first time in US history, more electricity was generated from gas than from coal. But price sensitive fuel switching in power generation can cut both ways, and a relatively small increase in the Henry Hub price level could lead to some switching back to coal (as has been observed in the US in the first-half of 2017). The projected increase in Henry Hub prices to $3.7/MBtu in 2025 therefore limits the space for gas-fired power generation to grow in the first-half of the *Outlook* period: so does robust growth in renewable energies (for which many incentives remain in place at federal and state level); and the assumed removal of the Clean Power Plan (without it, coal-fired power plants have no CO_2 emissions constraint and can achieve higher utilisation rates in states where coal is cheaper than gas – see Chapter 5). In addition, demand growth for power slows to 0.7% per year on average in the period to 2040, whereas it was twice as fast over the past 25 years.

The production of certain chemicals (such as ammonia or methanol) uses natural gas as a feedstock while the production of base-chemicals (such as ethylene or propylene) relies on natural gas liquids. As the production process is not very labour intensive, the cost and availability of feedstock are critical for the commercial viability of such petrochemical facilities. The rapid increase in shale gas production has given the United States some of the lowest gas prices in the world and resulted in a glut of natural gas liquids, especially ethane. This has provided a boost to the petrochemical industry in the United States, triggering a large expansion of production capacity. For instance, in the period to 2025, we project the addition of some 13 million tonnes of new ethane cracking capacity in the United States, which accounts for 30% of the global additions in this period. With US ethane crackers enjoying a clear cost advantage over naphtha crackers elsewhere, US exports of base chemicals increase markedly over the projection period. Most of the growth is expected to come over the next decade: reduced availability of natural gas liquids in the second-half of our projection period constrains further expansion.

Despite a gradual increase over time, US gas prices remain among the lowest in the world in the New Policies Scenario, which also spurs growth in the production of ammonia and methanol (Figure 9.4). As with ethane crackers, there is a well-stocked investment pipeline for ammonia and methanol facilities in the United States, with the bulk of the capacity additions likewise expected over the next decade. In the period to 2025, the use of gas as a feedstock for the US petrochemical industry more than doubles to over 19 bcm, accounting for over a quarter of the worldwide increase in gas feedstock use, and it continues to grow over the longer term to 2040. Much of the growth is export-driven: ammonia and methanol are cheaper and easier to transport than LNG, and there is a strong incentive to export the final product as well as the feedstock.

Figure 9.4 ▷ Indexed production growth of selected chemicals in the United States in the New Policies Scenario

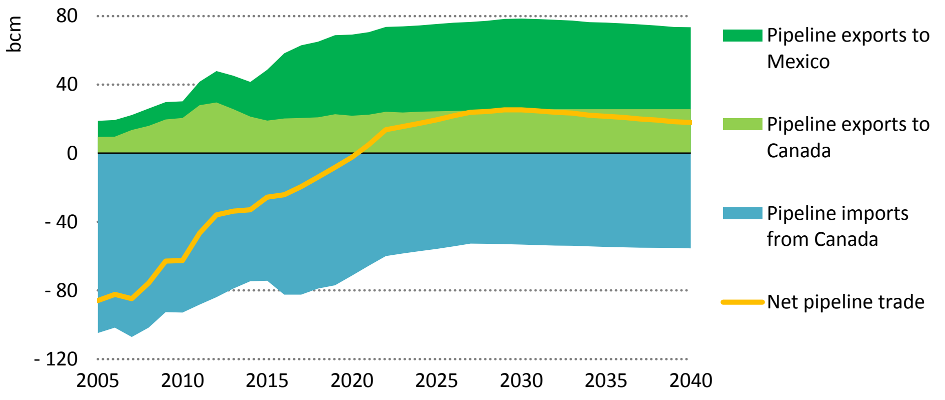


The shale gas boom and the ready availability of natural gas liquids underpin strong near-term growth in US petrochemicals output

Despite US gas prices being some 20% lower in this year's edition of the *WEO*, gas demand in the United States is only slightly higher – an additional 30 bcm in 2030 and 40 bcm in 2040 – than in last year's *Outlook*. What may seem counterintuitive at first glance is the result of a number of forces pushing in different directions that almost offset each other. Unsurprisingly, lower gas prices provide a positive stimulus for gas demand – especially in the power sector and in industry – but the absence of the Clean Power Plan (which is the main policy change compared with last year's *Outlook*) provides some upside to coal in the power sector, while a slight downward revision in the International Monetary Fund's economic outlook (a key element of our medium-term modelling) takes the edge off energy demand in general and industrial activity in particular.

Developments in the US gas market have repercussions for the neighbouring Mexican and Canadian gas markets too, as they are part of an increasingly interconnected North American transmission system. In 2005, the United States imported over 100 bcm from Canada, but the rise in shale gas production and the drop in prices have led to shipments from Canada falling by over a fifth in 2016 (Figure 9.5). Over the same period, US gas companies ramped up their exports to Canada and Mexico, pushing net US imports of pipeline gas down to around 25 bcm in 2016, compared with 80 bcm some ten years earlier. We project a continuation of these trends: imports from Canada keep falling, increasing amounts of US gas find their way to Mexico and by around 2020 the United States switches from being a net importer of pipeline gas to a net exporter.

Figure 9.5 ▷ US pipeline gas trade by destination in the New Policies Scenario

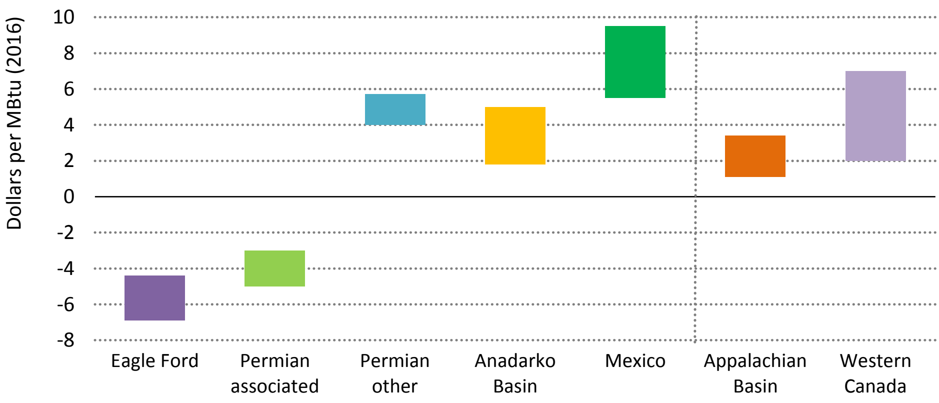


The availability of cheap gas turns the United States into a net-exporter of pipeline gas as imports from Canada decline and shipments to Mexico ramp up

Gas producers in the southern United States have the advantage of being close to the rapidly growing Mexican gas market. Economic growth and substitution of oil in various sectors of the Mexican energy system (mainly power generation and industry) underpin gas demand growth of 1.1% per year over the next 25 years – a growth rate that is twice as high as that of the United States. As of September 2017, there were 17 cross-border pipelines with a combined annual capacity of around 50 bcm in operation between Mexico and the United States, and a number of pipeline projects adding up to over 30 bcm are at an advanced stage of realisation. As pipeline expansion for the transportation of shale gas (especially from the Permian) progresses in the United States, there is scope for export growth to Mexico.

The future balance in Mexico between imported and domestically produced gas depends on a range of market and policy factors – and a key uncertainty is the extent to which Mexico pursues development of its large unconventional gas resources. Mexico does have strong potential for shale gas development (for instance, the prolific Eagle Ford play extends across the border) but the Mexican shale gas industry and supply chain are still at a very nascent stage. With US gas prices staying below $5/MBtu through the mid-2030s, importing gas from the United States remains attractive, and there is limited incentive to develop shale gas in Mexico for much of our *Outlook* period (Figure 9.6). Only in the 2030s – as costs in the United States start increasing – do we project shale gas production to pick up significantly in Mexico. By 2040, Mexico produces nearly 60 bcm of gas, of which a fifth is shale gas.

Figure 9.6 ▷ Indicative well-head breakeven cost of various shale gas plays in North America



Surging production of inexpensive shale gas in the United States delays development of more costly resources in Canada and Mexico

Notes: Negative well-head breakeven costs for the Eagle Ford and Permian plays are due to natural gas typically being a by-product of oil production in these plays. In this case, the revenues of the oil sales would be high enough to justify production of oil even if the associated gas had a negative value. Although associated gas may essentially be free at the well-head, there are still costs from its gathering, processing and transportation.

Canada has been a major gas exporter to the United States for decades. Canadian gas production is primarily located in the Western provinces of Alberta and British Columbia and has been serving US gas demand in the West, the Midwest and the East. However, the rise in shale gas production in the Appalachian Basin has reduced the call on imported gas in the eastern United States. In 2005, exports to the eastern United States accounted for some 30% of total Canadian pipeline exports to the United States, but this figure fell to just over 10% in 2016. The lower gas prices prevailing in the US market continue to impact Canadian pipeline gas exports over the *Outlook* period. For instance, the Rockies Express Pipeline, which was initially designed to transmit gas from the Western US and Canada to Ohio, was recently turned into a bi-directional pipeline; and construction has started on the Rover pipeline, which will bring gas from the Appalachian Basin to the Midwest and Ontario province. As a result, Canadian pipeline exports drop to around 55 bcm in the mid-2020s and flatten out at that level, while US pipeline gas exports to Canada increase to around 25 bcm. A larger expansion of gas exports to Eastern Canada from the Appalachian basin could even see the United States becoming a net exporter to its northern neighbour.

The abundance of shale gas in the United States also affects the pace of shale gas development in Canada (see also Box 9.1). Although Canada has potentially prolific shale gas plays, especially the liquids-rich parts of the Montney and Duvernay plays and the Horn River play (all located in western Canada), their estimated development cost is higher on average than in the Permian or the Appalachian Basin and they are further away from the demand hubs. Canadian gas production nevertheless increases markedly, reaching 220 bcm in 2040, up from 175 bcm in 2016. Shale gas is the primary source of Canadian gas production rising from 5 bcm in 2016 to over 150 bcm in 2040, but new development remains concentrated on the low-cost areas of the Montney play, with significant uptake in production from the remote Horn River pushed beyond the time horizon of our *Outlook*. A significant ramp-up in Canadian LNG projects takes place only in the 2030s (later than projected in the *WEO-2016*), with LNG export volumes reaching some 35 bcm by 2040.

Box 9.1 ▷ How the success of US shale may postpone the revolution elsewhere

It is sometimes assumed that the success of shale in the United States presages an early worldwide shale gas revolution, with other countries picking up or importing the technologies and know-how that will help them develop their own shale gas resources. But the examples of Canada and Mexico suggest a different possibility, which is that the very success of US shale may ultimately serve to hold back the prospects for successful shale development elsewhere. The shale resources in both countries hold considerable promise, but the incentives to invest in their production are diminished when wholesale prices remain low.

The same logic applies, albeit in slightly more diluted form, to more distant shale resources from Argentina to China and beyond. Outside the United States, shale remains a relatively high-cost, poorly-understood resource that poses challenges stretching from access to land and availability of water to bureaucratic hurdles. A critical mass of activity and learning is necessary to generate economies of scale and bring down breakeven prices. But getting the momentum going for this is tough. At least for the next ten years, and largely because of the success of US shale, gas is readily available at a price that limits the economic incentive to pursue shale elsewhere. As a consequence, the share of the United States in global shale output stays very high: from close to 100% today it remains at more than 90% in 2025, before tailing off to 65% in 2040 as US production falls back slightly and momentum picks up in other countries.

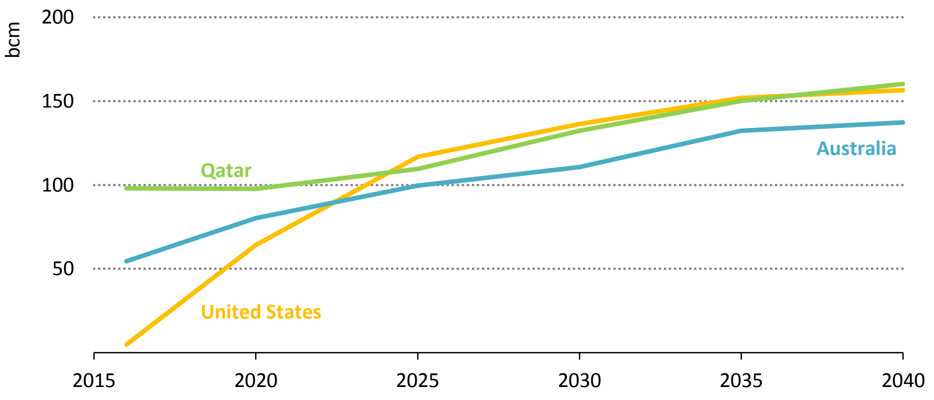
9.2.3 Implications for global market dynamics

As the North American market is not sufficiently large to absorb the very steep rise in US gas production, the stage is set for US gas to be exported elsewhere in the form of LNG. There is one LNG export facility in operation, at Sabine Pass in Louisiana, another six under construction and some 40 in various stages of realisation.[2] By 2025, US liquefaction

2. Another LNG plant, in Alaska, has been operational for decades but follows different market dynamics.

capacity is projected to reach 140 bcm, and it keeps growing thereafter to over 170 bcm in 2040. US exports grow rapidly following this ramp up in liquefaction capacity, making the United States the largest exporter of LNG in the world by the mid-2020s. Exports keep on growing after 2025, albeit at a slower pace, reaching over 160 bcm in 2040 (Figure 9.7). This leads to a jump in the market share of US LNG exporters in global LNG trade to a quarter in 2025 – a share that drops to around a fifth at the end of the *Outlook* period. Asia – with Japan, Korea, China and India at the forefront – is the primary outlet for US LNG exports although the Atlantic basin provides important markets in Europe and parts of Latin America too, especially in the coming decade (Figure 9.8).

Figure 9.7 ▷ Selected LNG exports in the New Policies Scenario

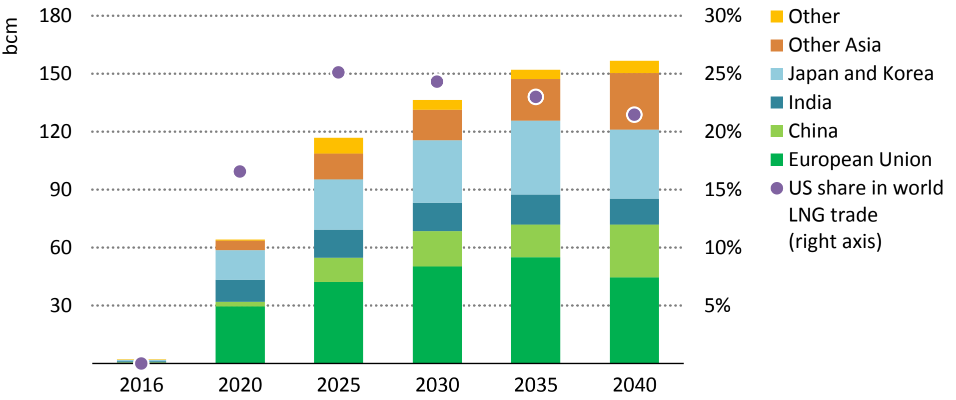


In the mid-2020s, the United States becomes temporarily the world's largest exporter of LNG

While most LNG export facilities around the world are part of integrated projects, with the export terminal being connected to a dedicated upstream source that provides the feed gas, most US LNG projects are based on a different business model and draw their gas directly from the US gas transmission network. The cost of the feed gas for a typical US project corresponds to the gas price at the nearest hub (plus transport costs) and the full delivery cost of a typical US LNG shipment therefore consists of the feed gas (plus a mark-up of typically around 15%), a fee for the use of the liquefaction facility (the so-called tolling fee), and the seaborne transport cost to the importing country.

In most cases, the off-taker of the gas from a US LNG facility is a different entity from the owner of the facility, but not the final customer, so liquefaction – booked and paid for on a long-term take-or-pay basis – becomes a self-contained midstream investment and the off-taker takes all responsibility for finding an eventual consumer for the gas. But there are interesting variations emerging on this theme. Some major gas marketers are also investing in liquefaction, as for example at the proposed Golden Pass project in Texas that is backed by Qatar Petroleum and ExxonMobil. Some US terminal operators are also getting more involved in the marketing side, for example with Cheniere (developer of the Sabine Pass and Corpus Christi liquefaction facilities) selling some LNG directly. And some US exporters are even moving away from the pricing model based on mark-ups from Henry Hub, taking some of the eventual price risk away from the buyers: the most notable example is the offer made by Tellurian to deliver gas from its proposed Driftwood LNG project in Louisiana to Asian markets at a fixed $8/MBtu price under five-year contracts from 2023.

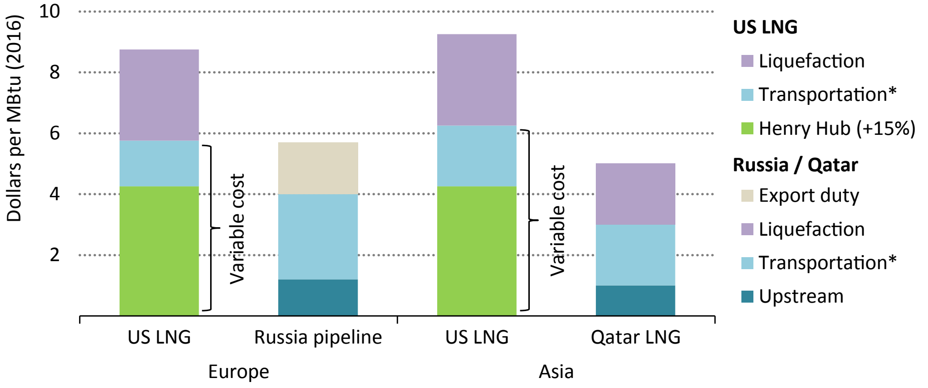
Figure 9.8 ▷ US LNG net exports by destination and market share in the global LNG trade in the New Policies Scenario



The United States becomes a heavyweight in the global LNG market, providing more than a fifth of traded volumes in the long term

Based on a Henry Hub gas price of $3.7/MBtu (the price in the New Policies Scenario for 2025), we estimate that US LNG could find its way to Europe or Asia at a full delivered cost of around $9/MBtu. (Figure 9.9). This suggests that US LNG should not necessarily be viewed as a low-cost source of supply, once all costs are taken into account. Broadly speaking, LNG exports from the United States are likely to come in as a wedge between low-cost supply projects (for instance, in Russia and Qatar), and more costly greenfield projects in various parts of the world. However, the large US gas market that feeds LNG exports can provide substantial additional LNG exports without a marked rise in prices so there is plenty of it available at a cost that many aspiring LNG exporters are likely to find hard to beat. Moreover, the conditions are favourable for an expansion of liquefaction capacities – often in the form of relatively low-cost brownfield projects – should the market call for them (see section 9.3.3). US LNG thus provides a long term price anchor in the international gas trade, an important factor for our gas price outlook (see Chapter 1).

Figure 9.9 ▹ Delivered cost of different sources of gas to Europe and Asia, 2025



Beating the delivered cost of Russian gas in Europe or Qatari gas in Asia is a tall order for US LNG

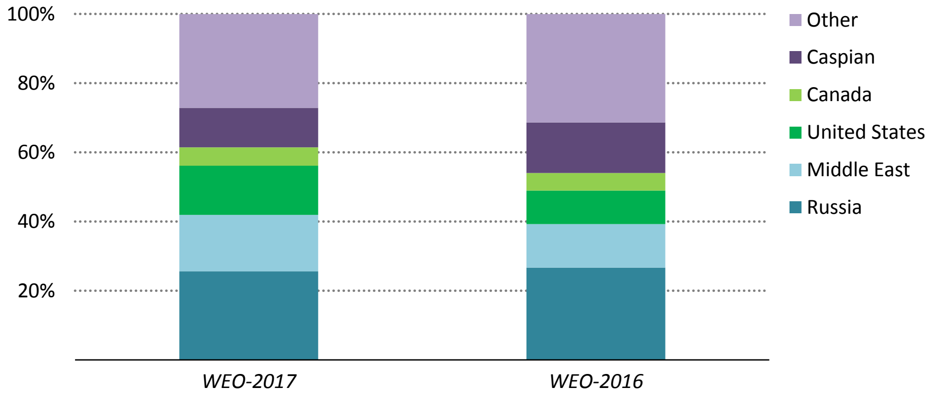
* Transportation includes regasification cost for LNG.

Compared with last year's *Outlook,* in which the United States did not surpass a market share of 10% of long-distance gas trade[3] by 2040, this edition of the *WEO* presents a significant change in trends (Figure 9.10). This has three interrelated implications for gas trade:

- US LNG comes in at a lower cost than many of the projects needed to meet gas demand in the 2016 *Outlook*. As a result, the development of some high-cost or technically challenging supply projects (some Canadian LNG, second wave Australian LNG projects or East Natuna in Indonesia) is delayed or pushed beyond the time horizon of our projections.
- Lower prices for internationally traded gas stimulate demand and also defer some production in major importing regions (e.g. in Pakistan, Bangladesh, India and China), meaning that the volume of gas traded over long distances (1 230 bcm in 2040) is some 10% higher than in our 2016 edition.
- A well-functioning and liquid LNG market makes complex long-distance pipeline projects less attractive, delaying or deterring expansion of some export-oriented gas production (for instance, in this *Outlook* we assume that large-scale pipeline connections from the Caspian or the Middle East to South Asia are not built within the next 25 years, while some other projects to Europe and China are delayed).

3. Unless otherwise stated, trade figures in this chapter reflect volumes traded between countries/regions modelled in the *WEO* (inter-regional trade), and they do not include gas trade within these regions.

Figure 9.10 ▷ Market shares in inter-regional gas trade by exporter in *WEO-2017* and the *WEO-2016*, 2040



An upbeat view on US gas exports implies a downbeat view on the development of various costly, technically challenging or remote projects around the world

9.3 The emergence of a new gas order

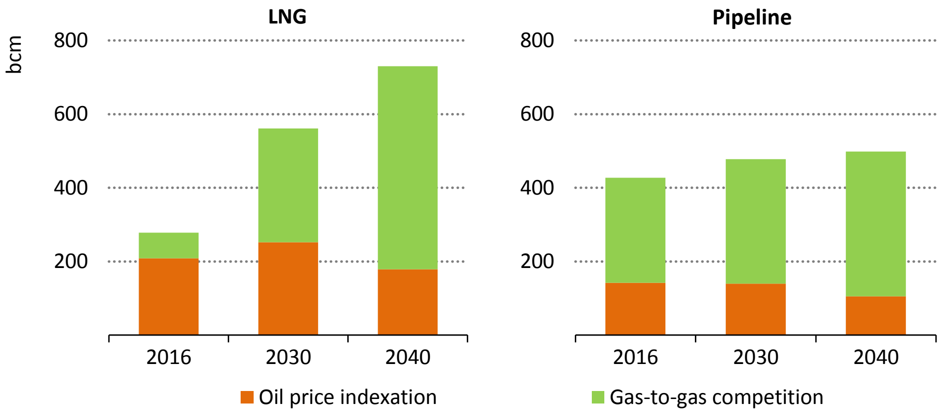
The way gas is traded internationally is changing. Destination flexibility, pricing based on gas-to-gas competition, a rise in spot deals and shorter contract durations have gradually made inroads into global gas markets. New exporters such as Australia, Angola, Papua New Guinea or Peru have come onto the stage over the past few years, increasing LNG supplier diversity, and within the next few years others such as Cameroon and Mozambique are set to join them. However, the biggest push towards a more competitive gas market comes from the rapid and large-scale ramp up of LNG from the United States, which has many of the characteristics – flexibility, hub-based pricing or spot availability – that are transforming the wider gas market. So the US gas industry is not just exporting growing volumes of gas over the next 25 years, it is also giving additional impetus to a major shift in how gas markets are organised and how trade is conducted. This has far-reaching implications for future gas markets and security of supply, accelerating a transition towards a truly global gas market.

9.3.1 Pricing of gas

Gas pricing can take various forms and the preferred method varies regionally. Gas-to-gas competition is now the most widespread form of pricing mechanism globally, used for around 45% of gas sales, followed by regulated prices (30%) and oil price indexation (20%) (IGU, 2017). Virtually all gas that is bought and sold in North America is subject to gas-to-gas competition, and in Europe some 65% of the gas trade is based on this pricing mechanism (more so in Northwest Europe, less so in the Mediterranean and Southeast).

In Asia, oil price indexation is the dominant pricing method, used for nearly 70% of gas sales in 2016. Regulated gas prices are not uncommon across the developing world but are most widespread in the resource-rich Middle East, where some three-quarters of gas sales are regulated. Oil-price indexation prevails in the LNG market where three quarters of the sales volumes are based on the price of oil (a share that has been largely constant over the past five years as most of the LNG trade growth materialised in regions where alternatives to oil-linkage are still scarce). In cross-border pipeline trade, pricing based on gas-to-gas competition has gradually increased its share, at the expense of oil-price indexation, to 60%, up from around 35% five years ago (Figure 9.11).

Figure 9.11 ▷ Global long-distance gas trade by transport mode and pricing method in the New Policies Scenario



In Asia, US LNG sparks a transition of LNG pricing away from strict oil price indexation

Note: Traded volumes of gas based on hybrid pricing formulas are split proportionally according to the estimated shares of oil price indexation and gas-to-gas pricing.

The way gas is priced is expected to change substantially over the *Outlook* period. The gradual removal of fossil fuel subsidies in gas exporting countries leads to the introduction of market-based elements of price formation in the Middle East and Southeast Asia. Similarly, gas market reform in China, expected to progress in the first-half of the *Outlook* period, leads to a larger share of market-based pricing there (see Chapter 14). But the changes in gas pricing are most pronounced and far-reaching in international gas trade. Europe has already been witnessing a marked shift away from oil-price indexed imports, with pipeline gas increasingly traded at prices determined at the European hubs (see also Box 9.2). The combination of a demand shock (in the aftermath of the 2008-2009 financial crisis), a surge in the availability of LNG and progress in the development of the EU internal gas market (the Third Energy Package) led to a gas glut in Europe in the late 2000s, forcing pipeline gas suppliers to adapt their pricing terms. This trend is set to continue over the *Outlook* period, as growing volumes of US LNG, the price of which follows the fundamentals of the US gas market, flow onto the global market and maintain the pressure on other European suppliers, notably Russia, to move towards hub-based pricing (see Spotlight).

S P O T L I G H T

Will Europe become the battlefield of a price war?

Russia provided 43% of the European Union's gas import needs in 2016, and plays a central role in Europe's gas market. Although the revenues it earns from gas are much smaller than those from oil exports, they are still very important for Russia's budget. The emergence of the United States as a major LNG exporter with the ability and ambition to export to Europe could lead Gazprom (which retains a monopoly on Russian pipeline gas exports) to react. Gazprom has a strong competitive position in the European market: existing long-term contracts of up to 100 bcm in 2025 (at 70% take-or-pay level), low production costs, more than 150 bcm of spare gas production capacity, and plenty of pipeline export capacity to Europe. Gazprom has the means to keep US LNG exports to Europe at bay. But will it choose to do so?

In the short run, variable supply costs are the relevant factor in determining whether a company should sell gas at a given price. The variable costs of US LNG add up to some $6/MBtu, in 2025, for deliveries to Europe. Russia's variable costs depend to a large degree on the value of the rouble, but it is reasonable to assume that Gazprom can comfortably supply gas at the level that matches US imports and even undercuts them. If Gazprom chooses to lower its price, however, it gains market share but reduces the value of its gas sales – a strategy that can only be profitable up to a certain point. Where exactly this point is depends on a range of considerations, but in our view a price war that brings European gas prices down to the variable costs of US LNG exports is not in the interest of either Gazprom or US exporters. Nor is such a strategy commercially sustainable in the long term: neither Russian nor US companies are likely to bring new supplies on stream if they cannot recoup the full cost of their existing assets. If a price war were to unfold in Europe, it would also be a sign of collective failure of the LNG industry to unlock new demand in more profitable markets. Cut-throat competition in Europe is thus likely to be a last resort.

The New Policies Scenario is based on the assumption that Gazprom will accommodate some US LNG in the growing European import market in order to keep prices at a sustainable level. Russian exports to the European Union stay flat at just under 150 bcm over the period to 2040, and Russia keeps its market share at around 40%. US LNG reaches a market share of some 12% in the early-2030s but this then falls as US LNG exports are gradually rerouted to the more profitable Asian market. The competition between Gazprom and US exporters brings significant benefits to consumers, helping gas to maintain its foothold in the European energy mix.

Box 9.2 ▷ What's the problem with oil price indexation?

In the early days of the gas industry, linking the price of gas to that of oil was an effective way to incentivise investment in major gas projects, while helping consumers to manage the price risks of switching away from oil. Gas markets look different today: the primary competitor for gas is often now coal, and – as the example of North America makes clear – a well-functioning gas market, with prices determined by competition between various sources of gas, can offer sufficient incentive for very large-scale investments.

Oil and gas markets have diverged in recent years, and therefore linking the price of the one to the other calls into question the most important function of prices, namely, signalling scarcity and triggering timely investment where and when it is needed. It cannot be taken for granted that gas-to-gas competition generally delivers lower prices than oil-indexation but it certainly delivers "correct" prices in the sense that they reflect the value of gas, not that of another product. If, as is the case in our New Policies Scenario, oil prices rise faster than gas prices, this puts strains on the system as those buyers locked into oil-indexed gas contracts face economic hardship and seek ways to benefit from cheaper spot gas. If on the other hand oil prices were to stay lower for longer, oil-indexed prices would suggest ample availability of gas at a time when new investment was needed.

Well-functioning gas markets therefore require a price that reacts to changes in the supply-demand balance for gas (which is not the case if prices follow fluctuations in the oil market), but a competitive gas market does not follow automatically from a switch in pricing mechanism. Important prerequisites for gas-to-gas competition include the existence of various sources of gas supply that can actually compete in a market and the possibility for buyers to re-sell and ship the gas within their market to other buyers. LNG, which is inherently more flexible than a bilateral pipeline, can stimulate competition, but this needs to be complemented in gas-importing markets by gas market liberalisation and the development of liquid and transparent pricing points.

Although oil price indexation is still deeply entrenched in gas trading in Asia, the region could soon replicate the conditions that triggered the shift away from oil-price indexation in Europe. In our projections, the oil price increases to just under $85 per barrel in 2025 and to around $95 per barrel in 2030, and this rise in prices puts upward pressure on oil-indexed gas prices.[4] Our projections suggest that US exporters will be able to supply the Asian market at lower prices than are likely to result from many such oil-indexed gas prices, giving US exporters substantial headroom in the Asian market to undercut oil-indexed gas contracts, and putting the suppliers who use them under pressure to amend them.

4. For instance, an oil price of $90 per barrel, in an oil-linked contract with a slope of 13% and a constant of $0.8/MBtu, would mean a delivered gas price of $12.5/MBtu. The US gas price, however, remains below $4/MBtu in 2025 and reaches $4.4/MBtu in 2030, suggesting that US exporters can supply to the Asian market at less than $10/MBtu in that time frame.

The liberalisation of gas markets in Japan and China and their introduction of third-party-access is set to boost the number of buyers that can purchase competitively-priced LNG on the short-term market and undercut the position of those whose gas is procured at higher oil-linked prices. This implies strong pressure to loosen the contract terms either via renegotiations (or possibly, as was the case in Europe, via litigation). The shift from a seller's to a buyer's market has already given rise to a number of cases of contract renegotiations: a prominent example is Petronet (a major Indian LNG buyer) which succeeded in convincing RasGas (a key gas exporter from Qatar) to make concessions regarding the oil linkage and take-or-pay provisions in its long-term contract. An important enabler for the move away from strict oil-price indexation in Asia is the development there of at least one liquid and transparent pricing reference point or a recognised gas hub (Singapore, Japan, Shanghai and Chongqing are all viable candidates with different advantages and disadvantages).

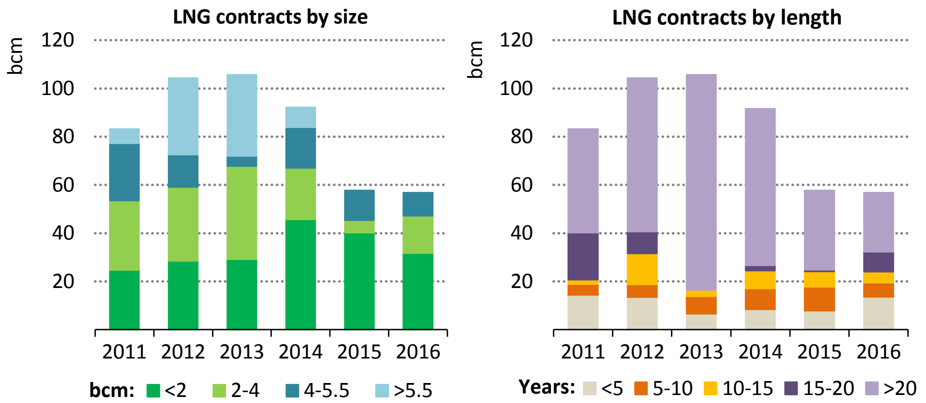
By 2040, our estimates in the New Policies Scenario suggest that more than three-quarters of LNG trade worldwide is based on gas-to-gas competition. What is left in terms of oil-indexation at the end of the *Outlook* period are mostly legacy contracts concluded through to the mid-2020s, with very few contracts concluded in the 2030s still based on strict oil indexation (although this would not exclude some hybrid pricing formulas, in which references to oil product prices co-exist with hub-based pricing, as companies look for a balanced way to manage risks in some markets). The evolution for pipeline trade is not as straightforward. Pipeline imports in Europe rapidly move towards prices set by gas-to-gas competition, but new pipeline projects in Asia (e.g. connections between China, Russia and the Caspian region) often lack a viable alternative to oil linkage: the development of liquid gas trading hubs in China is not assumed to be accomplished before the mid-2020s. The share of oil-price indexed gas trade does not drop as rapidly as for LNG.

9.3.2 Contracts in gas trade

International gas trade is dominated by contractual supply and offtake agreements that specify the duration and the size of the gas delivery and often come with a number of additional terms such as destination and take-or-pay clauses. Destination flexibility can also be implicitly restricted by a delivery ex-ship agreement, which does not restrict the right to resell the gas but requires the gas to be first unloaded (i.e. regasified) and then reloaded (i.e. liquefied) before it can be sold to another buyer, which is expensive. Only if the LNG is sold on a free-on-board basis can the buyer easily re-route the vessel to another destination.

The current glut of LNG and the slowdown in approvals of new large-scale supply projects is reflected in changes in the duration and size of recently concluded contracts. Over the past three years, fewer consumers committed to long-term gas offtake, underpinning a trend towards shorter contract duration (Figure 9.12). This trend has triggered an uptick in spot trade, although the volume of gas spot trade sales is still small compared to spot sales in oil and coal markets. Contracts have also become smaller in terms of volume, indicating that consumers are wary about committing themselves to large amounts of future gas supplies.

Figure 9.12 ▷ Total volume of LNG contracts concluded between 2011 and 2016 by size and duration



Recent LNG contracts have tended to be much shorter in length and smaller in size than previous ones

Destination clauses are under attack from various sides. After the European Commission found destination clauses to be incompatible with European competition law in the early 2000s, Japan's Fair Trade Commission has now concluded that such clauses are potentially also at odds with the country's Antimonopoly Act and has suggested that contracts should not contain resale restrictions. The growing volumes of US LNG, which are generally flexible and free from destination restrictions can be a valuable bargaining chip in a buyer's market when consumers (re-)negotiate with their suppliers. Destination flexibility seems to be on this rise: gas from the Cameroon Floating LNG (FLNG) and Mozambique's Coral FLNG projects reportedly sold on a free-on-board basis, and various Indian and Chinese buyers are also reported as having secured destination flexibility in recent contracts.

With buyers generally over-contracted and few new LNG projects moving to final investment decision, contracting activity has slowed down considerably. Only a few new long-term supply contracts are likely to be concluded in the near term as the LNG market works through its current overcapacity. However, from the early 2020s onwards, new LNG capacity is likely to be needed in the market, implying new contracts which would typically be concluded well before new capacity comes on stream. This comes as a number of legacy contracts – especially in Asia – expire. In the period to 2025 over 150 bcm of supply agreements expire (representing some 35% of the contracts in place in 2015). Some 80 bcm of the expiring contracts have Asia as a final destination.

How this new contracting cycle evolves in Asia will be an important pointer for the long-term evolution of the LNG market. The views of Japan's Free Trade Commission on destination clauses and the availability of flexible LNG from the United States, are together likely to lead to a significant shift away from such clauses in future LNG contracts, promoting spot sales and liquidity in the LNG trade, and the pressure for change will only strengthen if anti-trust regulators in other importing countries, for instance Korea, take the same view as those in Japan.

The outlook for long-term contracts in Asia is more difficult to assess. On the one hand, some major LNG importers – for instance Japan and China – are moving ahead with electricity sector reform and this could make gas demand less predictable for their utilities (as their plants will increasingly be dispatched according to their rank in the merit order), especially when account is also taken of rapid increases in the deployment of variable renewables. On the other hand, much of the growth in demand for LNG comes from developing countries that are seeing rapid electricity demand growth within regulated power systems. With good visibility of future gas needs, they may feel more comfortable with long-term contracts, especially since it will take time for a liquid forward/futures market to become established.

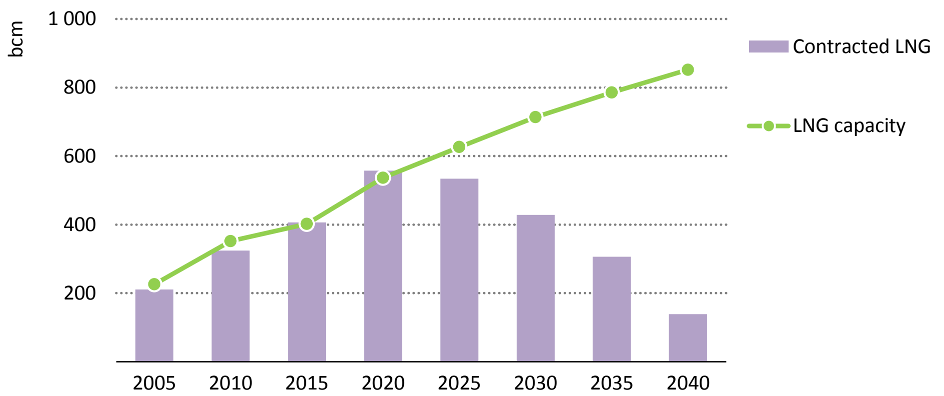
We may thus be entering a "hybrid period" in which various forms of supply arrangements – long-term and short-term, large and small, oil-indexed, hub-based and spot – coexist and compete with each other, reflecting the different needs of buyers and sellers alike. In the long-term, though, the direction of travel appears clear: a marked shift towards spot trade, contracts covering smaller volumes and shorter durations, and a distinct move away from destination clauses and oil-price indexation.

9.3.3 Investments and security of supply

The international market is currently awash with gas and projected import growth does not absorb the supply overhang in full until the mid-2020s. But new LNG projects are likely to need to be approved well before this point is reached if the market is to function smoothly in future, since lead times for such facilities can range between three and six years. In the New Policies Scenario, some 580 bcm of new liquefaction capacity is built over the *Outlook* period (corresponding to around 80 LNG trains) and 40% of this comes on stream over the 2020s. In total, cumulative investments of $8.6 trillion are needed for gas supply over the next 25 years. Most of the plants that are currently under construction and scheduled to come online through the early 2020s have secured long-term offtake arrangements for most of their output (Figure 9.13). However, the next wave of projects – anticipated to come online from the mid-2020s – has not (yet) concluded contracts and their investors need to cope with a market environment that is in flux.

Many companies undertaking major projects claim that oil-price indexation, long-term contracts and elements like take-or-pay and destination clauses are essential to provide the certainty needed to approve a capital-intensive LNG (or pipeline) project. Oil supply projects – which are no less capital intensive – do not however require any of the elements that LNG investors call for, because they are selling into a liquid and transparent market with a well-established pricing mechanism. A key question is thus whether investors and financiers have sufficient confidence in the emergence of a new gas market order to move ahead with projects. The speed at which the market (including the forward market) becomes deeper and more liquid is crucial; so too the speed at which reliable and transparent price indices are developed that can be used for spot and long-term contracts. There is also room for innovation on the financing side to find alternative ways to manage the risks associated with long-term capital-intensive projects. In our view, during the next investment wave, in the 2020s, prospective projects are unlikely to find a long queue of highly creditworthy offtakers prepared to make long-term procurement commitments. Contracts are set to remain an important element of risk mitigation in LNG project financing, but investors and lenders are likely to have to accept a larger exposure to spot market risks and opportunities, which will become easier to manage as relevant markets develop.

Figure 9.13 ▷ Already contracted versus projected global LNG capacity in the New Policies Scenario



From the early 2020s onwards, new contracts may be needed to underpin investment decisions for the construction of additional liquefaction capacities

Investment in a market that is undergoing transition has a number of implications for financing. Fewer guaranteed future cash-flows (from long term contracts with take-or-pay clauses) reduce the ability to finance a project with a high share of debt, potentially requiring the investor to provide more equity. But fewer guaranteed cash-flows also requires investors to be attentive to future risks of demand, including those related to policies addressing climate change (Chapter 11). In any event, cost control is paramount – lenders are likely to be willing to provide financing even if the project is not fully covered with contracts, but only if the economics are compelling (see next section). The focus may shift to brownfield and smaller, modular projects (including floating LNG plants) as their lower capital costs and shorter payback period allows investors to accept shorter contract durations.

In addition, some smaller LNG exporters may be good at their core activity – producing and liquefying gas – but have less experience in managing risk and commercialising gas. This provides a business opportunity for companies that specialise in handling market risk, including risks related to incomplete contract coverage of new projects, which may involve providing the link between exporters and smaller, less creditworthy buyers in developing countries. Aggregators and trading houses have started to act as intermediaries and mitigate the risk of both producers and consumers by contracting significant amounts of LNG capacity and marketing the gas globally (Box 9.3). In terms of volume, around half of the contracts concluded between 2010 and 2016 are held by aggregators. The changing market environment provides plenty of scope for commercial innovation and a greater role for such players in the global LNG trade. Another way of hedging price and volume risk is vertical integration i.e. upstream producers investing into downstream assets, and consumers acquiring stakes in production and export facilities (for instance, Gazprom has been pursuing plans to acquire or build gas-fired power plants in Europe and China; US gas producers have entered joint ventures with logistics companies to roll out refuelling infrastructure for LNG trucks; and Chinese gas importing companies and European utilities are active in upstream and midstream development).

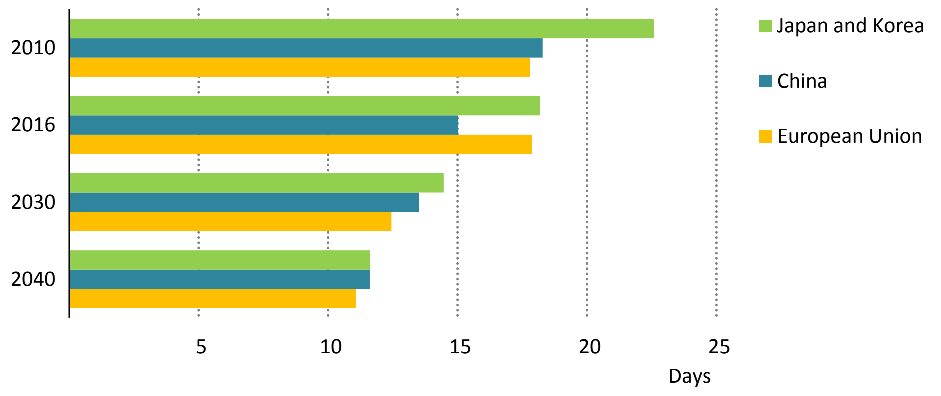
Box 9.3 ▷ The role of aggregators in LNG trading

Aggregators have been a key force in underpinning the growth in LNG supplies over the last decade. They have supported the development of new LNG projects by committing to significant volumes in emerging LNG supply regions such as Australia and the United States. Aggregators, also called portfolio players, are typically international oil and gas companies or large utilities with global operations that, in addition to having their own equity LNG production, have enhanced their supply portfolios by signing up to long-term deliveries from other LNG projects. These supply portfolios can in turn be used to provide LNG to a range of existing and new customers. The portfolio business model started to develop in the mid-2000s, as BG Group expanded its LNG trading and marketing activities. Since then, a variety of companies such as Shell, Total, BP, Engie, and Gas Natural Fenosa have emerged as portfolio players. Aggregators are attractive to LNG producers because of their typically large balance sheets and strong creditworthiness. They are also attractive to buyers, due to their portfolio of different supply sources and the scope this provides for contract flexibility in terms of length and volume. A well-supplied market in the coming years could put the business model under pressure, as aggregators are taking on significant volume and price risks, but our projections suggest the possibility to grow a sustainable and profitable LNG portfolio over the longer term as market conditions tighten. A revival of aggregator interest in signing up for new LNG contracts and underpinning new investment in supply would be an important indicator that a second LNG wave is on the horizon.

Increasing competition, more flexible trading arrangements and growing diversity of suppliers over the *Outlook* period would bring benefits for security of gas supply. LNG, which can easily be re-routed, reaches a share of 60% in inter-regional trade in 2040, up from less than 40% in 2016. Another measure of diversity is the number of liquefaction sites operating worldwide (each of which can contain multiple projects or trains) which has grown two-and-a-half-times since 2000, reaching nearly 40 in 2016. In the New Policies Scenario, the anticipated number of sites increases to around 80 by 2040. The expansion of LNG trade means that, at any given time, more LNG cargos are travelling the world's seas: today, some 290 LNG cargos are delivered per month on average, a number that increases to 660 in 2040 in our projections. The emergence of new market participants also increases the density of the LNG trade network (e.g. an expansion of China's LNG imports brings additional LNG tankers to a region that has a number of other large importers).

As the LNG market evolves, so it becomes better equipped to respond to sudden calls for additional imports, as might be required in the event of a disruption on a major import pipeline or a demand shock (of the sort witnessed in the aftermath of the Fukushima-Daiichi accident). Greater availability of shipments and greater flexibility of flows means that the time it would take to divert LNG tankers and bring the gas to a new destination drops significantly over the *Outlook* period. We estimate that, by 2040, major LNG importers would be able, on average, to increase their LNG deliveries by 10% in just over ten days, a week less than estimated for 2016 in the case of Japan and Korea, and the European Union (Figure 9.14). The drop is less pronounced for China, as the country's growing import needs offset some of the positive effects from greater flexibility of the LNG trade.

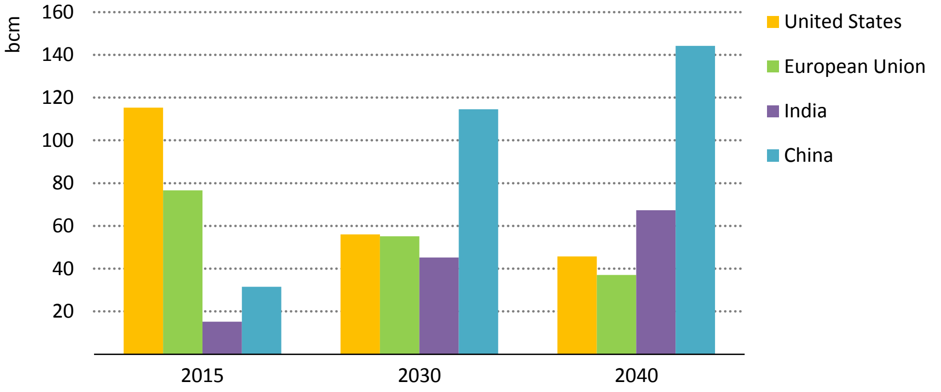
Figure 9.14 ▷ Estimated average time to procure an extra 10% of LNG import volumes by selected importer in the New Policies Scenario



As LNG trade expands and becomes more diversified, major LNG importers are able to meet an unforeseen 10%-spike in their LNG import demand in much less time than today

The benefits to gas security from the expansion in LNG supply are particularly significant as they can help to compensate for prospective losses of flexibility in other parts of the energy system, that might arise from the depletion of domestic gas fields in importing regions or the reduced possibilities, in some markets, to switch away from gas if prices rise. The power sector is typically an important provider of flexibility, as utilities often have the ability to switch to other fuels if gas becomes too costly, unlike most households or industrial consumers. In this regard, our projections highlight some countervailing trends. On the one hand, in the period to 2030, coal-fired power plant capacity decreases by nearly 40% in the European Union and by over 20% in the United States (oil-fired capacity also drops in both systems by more than 60% to 2030), reducing the fuel switching capability in these power systems markedly (Figure 9.15). On the other hand, over the same period, gas makes inroads to various coal-heavy power systems, e.g. in Southeast Asia, India and China, increasing the flexibility there.

Figure 9.15 ▷ Annualised potential to reduce demand for gas by switching to coal in selected power systems



The ability to temporarily switch away from gas decreases in the US and the European Union as coal plants are closed, but increases in China as more gas plants are built

Whether the increased price elasticity in developing countries can offset the reduced price responsiveness in various advanced economies hinges on the effectiveness of energy market reform in these countries in the first-half of the *Outlook* period. A well-functioning internal gas market (with third-party access to regasification terminals and pipeline infrastructure, ownership unbundling, transparency and unified network codes etc.) is a prerequisite for the efficient allocation of gas during periods of scarcity or high prices and the identification of consumers that are willing to cut back on their gas use. Electricity market liberalisation also contributes to flexibility because it underpins plant dispatch according to marginal generation cost, triggering a fuel switch if needed. Various countries are undertaking reform of their gas and electricity markets over the coming years – prominent examples are China (see Chapter 14), Japan and various countries in Southeast Asia – and successful implementation would contribute to the ability of the demand side to react to supply shocks (Box 9.4).

Box 9.4 ▷ How can Asian consumers benefit from the changes in gas markets?

For decades the "Asian premium" has been a key feature of global gas markets. To a degree, such a premium – the notion that gas is systematically more expensive in East Asia than in Europe or North America – can be justified by geography. Theoretically, in a well-functioning gas market, in which US exporters are the marginal suppliers, arbitrage opportunities would keep prices in Japan no more than $2/MBtu above the price level in Europe (representing the difference in shipping cost between Europe and Japan). However, for long periods the Asian price remained above the level justifiable by marginal supply costs, because of a lack of competition in the market; this premium price level has contributed to coal's competitive edge in many Asian power systems. The transformation of LNG markets creates a huge opportunity for gas users in Asia.

Even with a more efficient and competitive LNG market and lower wholesale prices, there is no automatic guarantee that changes will trickle down to the final consumers of the gas. If domestic markets remain monopolised, with physical and regulatory barriers preventing market entry and keeping end-users away from international LNG markets, the LNG market transformation will simply transfer rents from the LNG producers to the incumbent utilities of Asia. Some of these utilities have a high exposure to expensive long-term contracts and this may limit their immediate interest in the emergence of an efficient competitive domestic market.

Having sufficient infrastructure available for third-party use is the basis of an efficient gas market. Most global gas infrastructure was originally developed by integrated monopolies, but regions where gas markets are efficient today have implemented unbundling measures, forcing the separation of infrastructure from commercial activities and ensuring its non-discriminatory operation. Experience has shown that ownership unbundling, which leads to the creation of completely independent infrastructure entities, can – in sufficiently mature gas markets – lead to transformative results. Experience in Europe and the United States has also shown that there are very strong synergies between efficient gas and electricity markets, indicating that there is much to be said for an integrated approach to structural energy sector reforms.

Most Asian importers lack a dense domestic pipeline network, as LNG terminals have been developed one by one to serve the main consumption hubs. While geography limits interconnectivity between countries, especially in Japan and Southeast Asia, there is considerable scope within countries for better linkages between demand centres and multiple LNG terminals. Third party access can attract new infrastructure investment – for example in pipelines and regasification terminals – if regulators ensure cost recovery and prevent conflicts of interest. Due to geology, underground storage is unlikely to play a similar role in some parts of Asia as it does in Europe and North America. Where there is little gas storage, access to LNG becomes even more important as a way of providing flexibility. Exchange of information and the sharing of experiences between gas traders in Asia and those in other parts of the world is another potential way to enhance market efficiency (a recent memorandum of understanding between Japan and the European Union points in this direction).

Investors in gas supply typically try to avoid under-utilised liquefaction facilities and pipelines, although this can bring benefits to the system as a whole by cushioning price volatility and reducing the amplitude of cycles. However, there is occasionally some slack in the system and this can increase its resilience. At present, for instance, Russia has ample spare production capacity and is well connected to the European market. In a period of gas scarcity, Russia could increase its shipments to Europe in order to free up some LNG that could then be re-directed elsewhere (although this could lead to uneasiness about the high exposure to Russian gas in some European countries). This would however be a possibility only if there is LNG available which is not tied to a specific location through a destination clause (or through another restriction that hinders easy re-routing of LNG such as a delivery ex-ship clause).

From a slightly longer-term perspective, another important element for security of supply is the availability of cheaper and more scalable LNG projects that make it possible for market participants to respond more quickly to price peaks. Technological innovations like FLNG may have a useful role to play in this respect. In the United States, a well-established construction and engineering industry and a large number of existing facilities provide ideal conditions for US exporters to rapidly bring new brownfield projects on stream if market signals justify this. Qatar is another country with the capacity for relatively low-cost and rapid expansion of liquefaction capacity in such circumstances, now that it has lifted its self-imposed development moratorium.

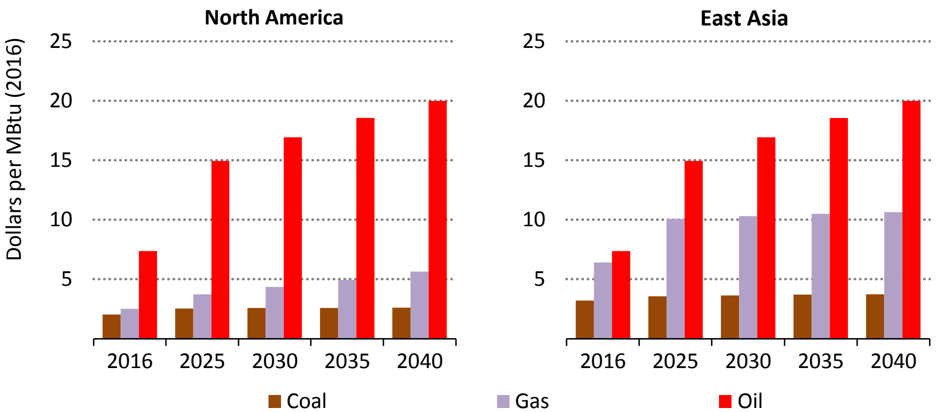
9.3.4 Affordability of gas

Gas prices are currently at low levels around the world. The International Gas Union estimates the average global price of gas at $3.35/MBtu in 2016, the lowest level ever recorded in their surveys (IGU, 2017). On average in 2016, prices in the European Union and Japan were some 60% below the peak reached in 2012. These low prices have led many gas consumers to hope that high gas prices are gone for good. However, the current low gas prices are a signal of oversupply, and there is a risk that prices at this level may not trigger sufficient investment activity. In the long term, only gas prices that cover the full cost of gas supply and provide sufficient incentive to invest into new projects are sustainable, implying a rise in gas prices around the world.

The lower energy density of gas, compared to oil or coal, means that transportation takes a relatively high share of the delivered cost, making geographical proximity to resource-rich areas an important determining factor for affordability. Gas transportation infrastructure is very capital-intensive, and moving gas also means using or, occasionally, losing volumes along the way (for instance, boil-off on LNG vessels, own-use in liquefaction plants and compressor stations, or leakage in pipelines). The cost of transporting gas over long distances is, for the same energy content, between seven- and ten-times more expensive than oil or coal, which is why gas prices in different regions would continue to vary substantially even in a globalised gas market. For new investment projects, the longer the distance over which gas has to be transported, the more favourable the economics of LNG are likely to be over pipelines.

How the economics work for gas depends also on how the fuel is used and what alternatives are available. This can vary widely across different parts of the energy sector and will also vary over time with the falling cost of key renewable technologies (see Chapter 11). In industry, for example, gas has a clear competitive advantage where it displaces more costly oil products (Figure 9.16). Light industries (e.g. manufacturing, textiles, food and beverages) that rely on coal may also be willing to switch to gas, even if it is more costly, simply because gas is more convenient and cleaner. The competition to gas in the buildings sector, by contrast, comes from electricity, the direct application of renewables, e.g. from heat pumps, and from energy efficiency. In the transport sector, natural gas can provide an alternative to oil products for freight and maritime uses, but electricity is emerging as the preferred way to move away from oil for passenger vehicles.

Figure 9.16 ▷ Fuel price evolution in North America and East Asia in the New Policies Scenario



Gas has a clear cost advantage over oil, but beating coal on commercial terms in gas-importing regions is a difficult task

The power sector, which accounts for 30% of the growth in global gas use over the *Outlook* period, is a different case again. In Asia, the target region for the bulk of the LNG exporters, coal is hard to beat on straight commercial terms in baseload power generation, confining gas plants to the provision of mid-merit and peak load power, except where they are given preference because of environmental considerations. Gas also has to compete for market share with renewables, which are growing fast and enjoy significant policy support and falling costs: while it is true that providing flexibility for the integration of wind and solar PV is an important opportunity for gas-fired power plants, the volumes of gas consumed for this task are considerably smaller.

Increased competition on the supply side, a critical component of the new gas order described in this chapter, can help to make gas more affordable in the long term. Compared with the steam coal market, which is characterised by a high degree of competition and low rents, in the gas market some large exporters have managed to command prices that far exceed their full costs (in part by limiting the speed at which they develop new resources). The entry of new suppliers into the LNG market and the rise in exports from the United States, a country where resource rents are traditionally low, is set to limit the scope to extract additional revenue in this way.

A more competitive environment creates pressures all along the supply chain. Cost discipline becomes paramount for new projects to move ahead. The technology improvements that unlocked shale gas as a low-cost resource in the United States have been instrumental in the transformation of global gas markets, and this could yet have an impact in other countries with promising unconventional resources. However, it appears less likely that a similar step-change in costs is on the horizon for gas transportation, where the main cost elements are steel, cement, specialised equipment for refrigeration and liquefaction (for LNG) and construction services. For new pipelines and LNG facilities, the gains are more likely to be incremental, via careful choice and design of projects and greater use of modular and/or standardised approaches to construction. The main area of innovation is likely to be greater deployment of floating technologies, both for liquefaction and regasification (see Box 8.2 in Chapter 8).

Governments in resource-rich countries may also feel pressure to change the design of production sharing agreements or fiscal instruments like specific taxes, royalties and export duties. Without such changes, marginal projects may struggle to move ahead in a more competitive environment, especially given the recent decision from Qatar, one of the world's lowest-cost suppliers, to expand its LNG capacity. New gas-supply projects already receive favourable treatment in some jurisdictions: Russia, for example, levies a 30% export tax on traditional pipeline gas exports in addition to upstream taxes, but LNG projects such as Novatek's Yamal LNG are exempt.

There is also a chance that future gas markets may be less prone to volatility than in the past. The new gas order is set to be more sensitive to shifts in regional prices (that, in turn, are increasingly likely to be driven by the dynamics of gas-to-gas competition), and a diverse range of LNG suppliers can be expected to seek out opportunities for arbitrage rather than trading point-to-point with a fixed group of customers. Gas consumers may also be willing to accept a slight premium for gas if that enables investment in additional sources of flexibility, such as spare liquefaction capacity or storage, that assures them of price stability.

9.3.5 What underpins our New Policies Scenario?

Our gas production and inter-regional gas trade projections to 2040 assume various changes in the way the gas market functions, many of which are driven by the growing importance of LNG. This evolution of the gas market broadly follows three phases:

- The period to the early-2020s is characterised by continued oversupply, low prices and subdued investment activity as LNG export projects that are currently under construction, mostly in the United States, Australia and Russia, come on stream.

- The years between the early and the late 2020s see a wave of new gas supply projects going ahead as demand increases, fostering a smooth rebalancing amidst a rapidly changing and uncertain market environment.
- The latter part of our projection period witnesses the emergence of a truly global, liquid and competitive gas market in which the interplay of supply and demand determines a set of prices that suppliers and buyers both trust sufficiently to use as the basis for their future plans.

Our modelling of gas demand and supply trends requires us to make a number of assumptions and judgement calls in each of these phases. The second phase, which is at the heart of the transition towards the new gas market order, is also at the heart of the uncertainty. The emergence of this new gas order is particularly sensitive to two premises. First, we assume that diverging oil and gas price trajectories in the New Policies Scenario provide a strong impetus for change, making gas which is priced off a hub more attractive than oil-linked gas supplies and hastening the removal of oil-indexation in Asia and elsewhere. A sustained period of cheap oil could delay this evolution substantially (see Spotlight on the Low Oil Price Case in Chapter 4). Second, we assume that the removal of contractual rigidities, the gradual move towards gas-to-gas pricing (including the establishment of a liquid Asian hub), the rise in spot and short term trading and the strengthening of competition – all major elements of this phase – do not impede investors' and lenders' confidence in the commercial viability of new gas projects. Instead, they create a benign gas market environment with a level of trust in the market that underpins a growing reliance on gas imports around the world. However, quite the contrary could also happen: investors and financiers could prefer to take a 'wait-and-see' approach, preparing the ground for another major boom-and-bust cycle.

This second assumption is a particularly crucial one. Failure to bring on timely new investment implies (temporary) tightness and price volatility, which could jeopardise the perception of gas as a reliable and affordable source of energy in key gas-importing countries. Some well-established gas consumers could revert to securing their supplies through restrictive long-term agreements, slowing the pace of structural change in the gas market order. Moreover policy-makers in importing countries could lose trust in gas, delay gas infrastructure development, and ease the pursuit of policies that foster gas use to achieve environmental objectives. These responses could in turn mean a reduction in the 1.6% of annual growth in gas demand in the New Policies Scenario, as countries move to coal or renewables (or a combination of the two). The bright future we outline for gas in the New Policies Scenario cannot therefore be taken for granted – it requires the concerted efforts of policy-makers and industry leaders to navigate the stormy seas of transition in order to position gas as a reliable and affordable fuel.

The environmental case for natural gas

How do methane emissions tip the balance?

Highlights

- As the cleanest burning fossil fuel which emits few local air pollutants, natural gas has many advantages in a world concerned about carbon emissions and air quality. However, methane emissions along the natural gas value chain, if they are not abated, threaten to reduce the climate benefits of using natural gas.
- Oil and gas operations are not the only anthropogenic source of methane emissions, but they are likely the largest source from the energy sector. We estimate that global oil- and gas-related methane emissions in 2015 were 76 Mt, more than half of which stemmed from natural gas operations. Eurasia and the Middle East are the highest emitting regions, accounting for nearly half of the total emissions globally, followed by North America. The uncertainty in oil and gas methane emissions levels is high, but enough is known to conclude that these emissions cannot be ignored and that they represent a clear risk to the environmental credentials of natural gas.
- Our estimate of methane emissions from natural gas operations corresponds to an emission intensity of 1.7%. On average natural gas generates significantly fewer greenhouse-gas emissions on a lifecycle basis than coal. Yet, that is no reason for failing to take action to reduce methane emissions from natural gas operations. By developing first-of-a-kind marginal abatement cost curves, we estimate that it is technically possible to reduce global methane emissions from oil and gas operations by roughly 75%, and that emissions could be reduced by 40-50% just by implementing approaches that have no net costs, as the value of the captured methane is higher than the cost of the abatement measure.
- There is an increasing number of voluntary and regulatory efforts to tackle methane emissions from the oil and gas sector. Worldwide implementation of the abatement measures that have positive net present values in the New Policies Scenario would require a step-change in ambition, and few countries outside North America have specific mitigation frameworks in place. But this would have the same impact on reducing the average global surface temperature rise in 2100 as shutting all the coal-fired power plants in China today. Methane emissions reduction policies are also critical in the Sustainable Development Scenario, despite the lower levels of fossil-fuel consumption.
- We have developed an action agenda for policy-makers and industry, based on the need to accomplish two key goals: measure and abate. Measurement is critical to assess the efficacy of policy actions and to assure the public of effective implementation. Abatement is critical to reduce emission levels.

10.1 The environmental credentials of natural gas

The case for gas to play an expanded role in the future of global energy is inextricably linked to its credentials as a solution to environmental problems. In a world in which concerns about air quality and climate change loom large, but in which there are limits to how quickly renewable energy options can be scaled up and some sectors in which low-carbon energy options are hard to find, natural gas offers many potential benefits. Gas combustion emits fewer carbon-dioxide (CO_2) emissions per unit of energy output than coal or oil, plus fewer local air pollutants than coal, oil or bioenergy. The use of natural gas is also often more efficient than coal in numerous transformation and end-use sectors. Gas-fired power plants are well-suited to the demand for flexible operation that comes with a rising share of variable renewables in the power mix. But, on the other side of the ledger, gas does have drawbacks; it still results in CO_2 emissions when combusted and, most significantly, it is itself a potent greenhouse gas if emitted directly to the atmosphere.

There is very little dispute over the emissions associated with natural gas combustion, but there is less consensus over the level of direct methane emissions that occur during its production, transportation and consumption. This is an issue for natural gas, as uncertainty over the level of emissions raises questions about the extent of its real environmental benefits. This chapter aims to identify the sources of this uncertainty and explore what actions can be taken to reduce both uncertainty and emissions. After an initial review of the environmental case for and against natural gas, the chapter focuses in detail on the issue of methane emissions.

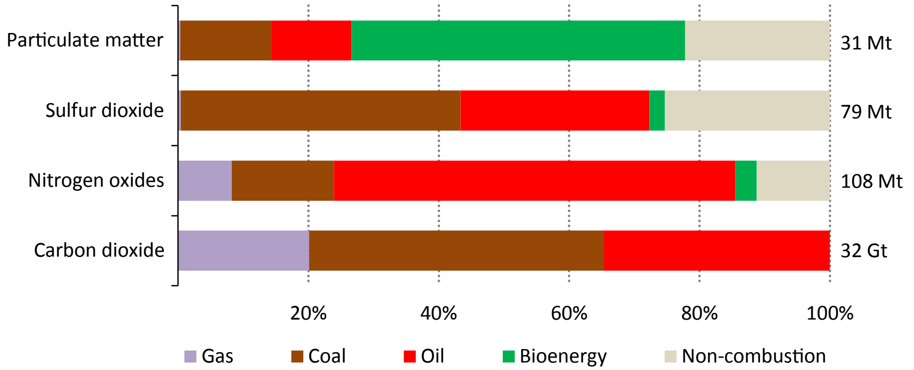
The first task is to understand the nature and volume of methane emissions worldwide, and the extent to which they come from the energy sector – and, within this sector, from oil and gas – in each case assessing the key gaps in today's knowledge and data. The section of the chapter dealing with these issues concludes with a discussion of what different assumed methane emissions levels from the gas supply chain would mean for the relative climate benefits of gas versus coal. The chapter then describes what is being done by countries around the world to address the issue, and the economic and climate costs and benefits of further action. The concluding section provides guidance for policy-makers and others looking to step up their commitment to methane abatement.

10.1.1 Assessing the environmental credentials of natural gas

The emissions that arise from the combustion of natural gas are well-known and show clear advantages for gas relative to other fossil fuels and, for particulate emissions, a favourable comparison with bioenergy. In relation to CO_2, the combustion of natural gas results in emissions savings of some 40% relative to coal for each unit of energy output. The advantage over oil is less striking, but still substantial: CO_2 emissions from gas combustion are around 20% lower than for oil. Quantifying the CO_2 savings from natural gas use is a complex business (discussed in more detail in Chapter 11) but it is undeniable that gas has played an important part in recent positive CO_2 emissions trends in many countries and in the overall flattening of global energy-related emissions since 2014.

The edge of natural gas over the other combustible fuels is reinforced by looking at the emissions of the main air pollutants: fine particulate matter ($PM_{2.5}$), sulfur oxides, mainly sulfur dioxide (SO_2), and nitrogen oxides (NO_X). These three pollutants are responsible for the most widespread impacts of air pollution, either directly or once transformed into other pollutants via chemical reactions in the atmosphere. Controlled burning of natural gas releases very few particulate emissions into the air. In global terms, the combustion of wood and other solid fuels are responsible for more than half of current $PM_{2.5}$ emissions, mainly in developing Asia and sub-Saharan Africa where bioenergy is still widely used as a cooking fuel (Figure 10.1).

Figure 10.1 ▷ Share of natural gas in total energy-related emissions of selected air pollutants and CO_2, 2015



Compared with other sources, natural gas makes only a minor contribution towards today's emissions

Notes: Mt = million tonnes; Gt = gigatonnes. Non-combustion emissions are process emissions in industry and non-exhaust emissions in transport.

The relationship between fuel use and pollutant emissions is not straightforward as it depends on fuel grades and qualities, the nature of the combustion process and whether or not post-combustion control technologies are applied. But differences in emission levels across the fossil fuels emerge very clearly from the data. Coal use dominates global emissions of SO_2 – a cause of respiratory illness and a precursor of acid rain – followed by emissions from oil. Although most fossil fuels contain sulfur when extracted, this is removed as soon as practicable after production from the natural gas stream, both for safety reasons and to avoid corrosion to pipelines; for these reasons, SO_2 emissions from the use of natural gas are negligible. In addition, unlike emissions from the combustion of coal, natural gas does not emit any mercury or other heavy metals. Combustion of natural gas does produce NO_X, which can trigger respiratory problems and the formation of other hazardous particles and pollutants. However, gas accounts for less than 10% of global energy-related NO_X emissions. The majority of NO_X emissions are attributable to oil products (especially diesel) used in the transport sector: a lot of car and truck exhaust fumes are emitted in urban environments at street level, which has a major impact on urban air quality and public health.

These generally low-emission characteristics of natural gas help to underpin its status as a relatively clean fuel compared to other fossil fuels. But that does not necessarily give natural gas a clean bill of health. There are three main arguments regularly made against natural gas (including both conventional and unconventional gas)[1] questioning its suitability as a long-term answer to the world's energy and environmental challenges. The first is that, while preferable to coal, it is still a significant and growing source of CO_2 emissions and so cannot be exempt from efforts to tackle climate change (discussed in detail in Chapter 11). The second is that methane emissions along the gas value chain are potentially at a scale that they could negate some of the climate advantages claimed by gas when combusted; this is the key question addressed in this chapter. The third is that the process of extracting natural gas is associated with an unacceptable level of social and environmental risk.

Box 10.1 ▷ Public acceptance of unconventional gas: the "Golden Rules"

- Measure, disclose and engage, involving meaningful and timely engagement with local communities, establishing key environmental baselines before drilling and disclosure of key operational data, including on hydraulic fracturing.
- Watch where you drill, taking into account established settlement patterns and local ecology, plus key geological and hydrological factors, such as the presence of faults or water supplies and sources.
- Isolate wells and prevent leaks, through ensuring well integrity and preventing and containing surface spills.
- Treat water responsibly, by reducing freshwater use, and paying close attention to treatment, storage and disposal of waste water.
- Minimise air emissions by reducing flaring, eliminating venting and paying careful attention to other emissions.
- Consider the cumulative and regional effects of large-scale drilling and production operations, especially for water, but also for truck traffic, noise and other local disruptions.
- Ensure consistently high, ongoing environmental performance, with properly resourced regulators, encouraging performance-based and full cradle-to-grave regulation.

On the last point, the *World Energy Outlook (WEO)* has argued consistently that gas will only flourish in the global energy mix if important social and environmental concerns regarding

1. Unconventional gas includes coalbed methane, shale gas and tight gas. Just over 20% of global gas production is currently unconventional, a share that rises to just over 30% in the New Policies Scenario in 2040.

its extraction are addressed. In relation to unconventional gas, these issues were addressed in detail in a *WEO* special report, *Golden Rules for a Golden Age of Gas* (IEA, 2012), which set out seven overarching principles, or "Golden Rules", designed to provide guidance to policy-makers, regulators and industry in developing balanced, effective regulatory regimes for unconventional gas (Box 10.1).

Application of these principles can ensure a level of environmental performance that earns a "social licence to operate" for industry, paving the way for large-scale gas development. The alternative is to run the risk of social and political backlash. The challenge in ensuring public acceptance is well illustrated by the patchwork of different policy approaches governing unconventional gas development in different parts of the world, and within individual countries. This includes moratoria on hydraulic fracturing in many parts of Europe as well as in certain states or provinces in the United States, Canada and Australia.

10.2 Methane emissions: how big is the problem?

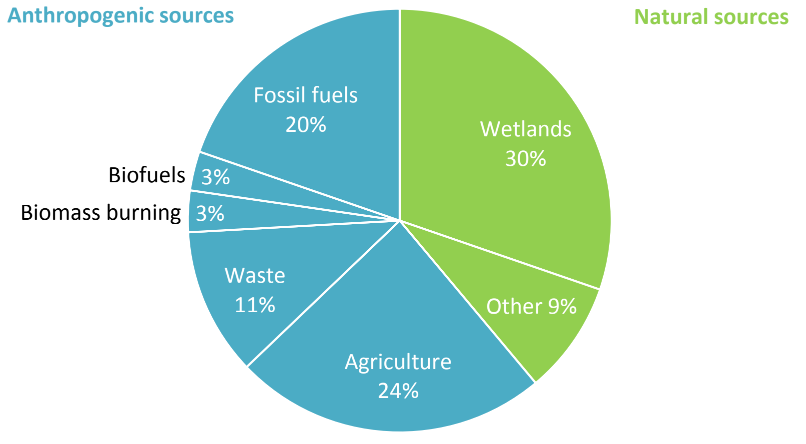
The concentration of methane in the atmosphere is currently around two-and-half times greater than pre-industrial levels (EPA, 2016). Like CO_2, methane (CH_4) is a potent greenhouse gas and this rise has important implications for climate change. Unlike CO_2, however, methane only exists in the atmosphere for around 12 years (Myhre et al., 2013), which complicates the calculation of its impact on global warming (Box 10.2). It is estimated that in 2012, the latest date for which comprehensive data are available, global methane emissions from all sources were around 570 million tonnes (Mt). This includes emissions from natural sources, which account for about 40% of annual emissions, such as wetlands, fresh water, geological seepage, melting permafrost[2] and oceanic sources, and from anthropogenic sources, which account for about 60%, such as agriculture, waste and the energy sector (Figure 10.2). The largest source of anthropogenic methane emissions is agriculture, responsible for around 140 Mt of emissions in 2012, closely followed by the energy sector (including emissions from coal, oil, natural gas and biofuels). Global methane emissions are estimated to have risen by around 5% since the first-half of the 2000s, most likely as a result of increases in emissions from agriculture (Schwietzke et al., 2016; Nisbet et al., 2016).

Estimates of methane emissions are subject to a high degree of uncertainty. There are two key methods for estimating emissions levels: "top-down" and "bottom-up". Top-down methods first measure the atmospheric concentration of methane (whether at global, regional or facility level) using remote measurement devices such as permanent ground or tower-based measuring stations, or dedicated aircraft, vehicles or satellites. Changes in the atmospheric concentration of methane over time are then "inverted" to estimate what annual emissions must have been to yield these changes. The uncertainty in this calculation of total emissions arises from the fact that methane concentrations are measured at an elevation or at a distance from the emissions source; this complicates the

2. Permafrost is frozen soil, rock or sediment, usually found in high latitudes or beneath the seabed in polar regions. It can contain large quantities of CO_2 and CH_4, which can seep out if the ground melts.

attribution of emissions to specific sources, due to dispersion in the atmosphere (despite the use of atmospheric flux models that account for variables such as wind speed). Some studies distinguish between emissions from fossil fuels and from other sources based on the specific methane isotopes detected (Schwietzke et al., 2016), but in general assigning emissions to precise sources using a top-down method is very difficult.

Figure 10.2 ▻ Sources of methane emissions, 2012



Attributing methane emissions to specific sources is difficult, but human activity is likely to be responsible for the majority of the 570 Mt emissions in 2012

Source: Saunois et al. (2016).

The alternative bottom-up approach tackles the issue from the opposite angle. Measurements are taken directly at the source (such as a leaky piece of equipment) and so are more accurate in terms of location of the source and the volume of methane emitted. But the key shortcoming is that certain sources may not be detected. In the oil and gas sector, for example, there is a huge number of potential sources of emissions worldwide: each oil and gas installation consists of thousands of individual pieces of equipment that could be continuous or sporadic sources of fugitive emissions. It is impractical and cost-prohibitive with current technologies to measure, and monitor in real time, emissions from all potential sources on a continuous basis using a bottom-up method.

There have been recent attempts to combine the top-down and bottom-up approaches: using atmospheric measurements to constrain the annual level of emissions in a certain region and using a bottom-up method to apportion this between different sources (Zavala-Araiza et al., 2015a). These methods hold promise, and will be aided by improving bottom-up estimates and new approaches to measuring atmospheric concentrations at higher resolutions. Identifying practical actions that can be taken to reduce further the current uncertainties will be very important: so will reducing methane emissions levels despite the uncertainties that exist.

Box 10.2 ▷ The pitfalls of global warming potentials (GWP)

Two key characteristics determine the impact of different greenhouse gases on global warming: the ability of a gas to absorb energy and the length of time it remains in the atmosphere. There are various ways to combine these factors to estimate the effect on global warming; the most common is the global warming potential (GWP), which is the ratio of the energy absorbed by a tonne of a greenhouse gas to the energy absorbed by a tonne of CO_2 over a given timeframe. This measure is used to express a tonne of a greenhouse-gas emitted in CO_2 equivalent terms, in order to provide a single measure of total greenhouse-gas emissions (in CO_2-eq). Methane has a much shorter atmospheric lifetime than CO_2 (around 12 years compared with centuries for CO_2), but absorbs much more energy while it exists in the atmosphere. The Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) indicated a GWP for methane between 84-87 when considering its impact over a 20-year timeframe (GWP_{20}) and between 28-36 when considering its impact over a 100-year timeframe (GWP_{100}) (Myhre et al., 2013).[3] Alternative metrics have been suggested, such as the global temperature potential (GTP), the ratio of the temperature increase after a specific number of years resulting from a tonne of a greenhouse gas relative to that of CO_2, but these too vary markedly depending on the timeframe considered.

There are a number of difficulties associated with the use of GWPs despite their prevalence in national greenhouse-gas emissions accounting frameworks and climate policy discussions. The use of a single GWP implies a constant impact from emitting a tonne of CH_4 when the actual impact varies significantly over time. GWP_{100} and GWP_{20} values have also been updated in successive IPCC reports as scientific knowledge advances. This has led to confusion given the trade-off between using the most recent value and using a more dated value but maintaining consistency. As well, and perhaps most importantly, the choice of GWP_{100} or GWP_{20} has a major impact on the apparent potency of CH_4, and so the importance placed on the level and timing of emissions mitigation as well as any assessment of the relative emissions reduction benefits of gas vis-à-vis coal or oil. The choice of the most appropriate timeframe depends on the emissions scenario in question, for example if or when there is a peak in the global temperature rise, and can be relatively subjective.

Here we avoid any reliance on GWP (or GTP) in assessing the importance of reducing CH_4 emissions from oil and gas operations. All quantities of methane are presented in million tonnes of CH_4 and are not converted into CO_2-eq. Instead we use the climate model MAGICC[4] (Meinshausen et al., 2011), widely employed in studies assessed in the IPCC reports, to estimate the impact of different CH_4 emissions pathways on the

3. The ranges for the GWP over a certain timeframe arise from whether the methane comes from a fossil or biospheric source and whether or not potential climate-carbon feedbacks are included. These feedbacks are processes that lead to a change in the carbon cycle, such as a decrease in the level of CO_2 emissions absorbed by forests instigated by the temperature change from the methane emitted.

4. MAGICC = Model for the Assessment of Greenhouse Gas Induced Climate Change.

average global surface temperature rise in 2100 (in degrees Celsius [°C]). Since the temperature rise has a near-linear relationship with cumulative CO_2 emissions, we compare the temperature differences in 2100 under these CH_4 emissions pathways with the cumulative quantities of CO_2 that would yield similar temperature differences.

10.2.1 Methane emissions from the energy sector

Methane emissions from the energy sector in 2012 are estimated at between 100 Mt and 200 Mt.[5] This includes emissions from the extraction of oil, natural gas and coal, natural gas transport and consumption by end-users, and the consumption of bioenergy.

Coal seams contain methane, referred to as coal mine methane (CMM), which can be released during the coal mining process. As the world's biggest producer and consumer of coal, China is by far the largest emitter of CMM. China's National Development and Reform Commission estimated that coal-related methane emissions in 2005 in China amounted to 15 Mt, but there is large measure of uncertainty about this, with sources suggesting emissions in 2005 could have ranged anywhere from 5 Mt to 35 Mt (Ju et al., 2016). Chinese coal production has increased by around 50% since 2005, and so current CMM emissions are likely much higher. Globally, it is estimated that CMM emissions in 2012 could range between 30 Mt and 60 Mt (Saunois et al., 2016). Methane can be released in various ways during coal mining, including from the degasification and ventilation systems in underground coal mines (necessary to avoid explosions); exposed coal seams in surface (or open pit) mines; abandoned mines; and post-mining activities such as storage and transport. The concentration of methane in the emitted air varies significantly by source. Wells drilled to degasify mines produce methane in high concentrations while that in the air from ventilation systems is low (less than 1%) as the methane content in the mine shafts has to be diluted by circulating air in order to create safe working conditions. The concentration of methane in coal seams depends on the type of coal and the geological conditions at the time of formation and subsequent burial of the coal seams.

The lower the concentration of methane, the more technically and economically difficult it is to abate. Around two-thirds of CMM in the United States comes from underground mine ventilation systems with a further 15% from surface mines (EPA, 2017a). This means that close to 80% of all CMM in the United States has a low methane concentration. Technologies do exist to burn low-concentration CMM as a primary or supplementary fuel in turbines and industrial boilers, but doing so economically can be challenging. The only option to recover CMM from surface mines is via pre-mining drainage, which is a lengthy process. Emissions from operational surface coal mines are diffuse and therefore difficult to capture and recover. As 65% of the world's coal comes from underground mines, capturing

5. This range is based on the lowest top-down estimate of Saunois et al. (2016) and the upper end of the estimates of Schwietzke et al. (2016). We also make allowance for the finding of Petrenko et al. (2017), which indicate that estimates of emissions from natural geological sources could be overestimated (and so emissions from oil, gas and coal production and consumption are underestimated) by at least 35 Mt.

CMM from the degasification systems of underground mines is probably the most effective solution: it can then be used in power generation either onsite or off-site. The methane concentration of gas from degasification wells can be up to 95% and thus sufficiently high to be sold directly. There is some technical potential to reduce methane emissions from coal mining and many efforts have aimed at just that: the Global Methane Initiative, for example, lists nearly 250 CMM abatement projects currently in progress around the world.

Methane emissions from biomass and biofuels occur during their production in some instances (for example, if produced using anaerobic digestion) and during their combustion when low oxygen availability results in an incomplete burn. The amount of methane emitted depends both on the material being burned and the burning conditions. A key source is the traditional use of biomass for cooking in developing countries. Directly mitigating these emissions is difficult, but moves towards more modern cookstoves that have a chimney or fan to aid combustion could help to lower emissions, as could the replacement of traditional biomass by stoves fuelled by liquefied petroleum gas, natural gas or solar (see Chapter 3). This chapter focuses on assessing and mitigating methane emissions from oil and gas operations rather than coal or bioenergy for a variety of reasons:

- Recent studies estimate that oil and gas operations combined are the largest source of methane emissions from the energy sector (Saunois et al., 2016; Schwietzke et al., 2016).
- Recent studies also indicate that the technical abatement potential (both in absolute and relative terms) for methane emissions from oil and gas is greater than that for coal or bioenergy (Höglund-Isaksson, 2012).
- Methane emissions captured during oil and gas production or transport can often be monetised directly and so emissions reductions could result in economic savings or be carried out at low cost (explored in more detail in section 10.4).
- The role of natural gas in the energy sector transition is of particular importance in the wider context of the special focus on natural gas in this year's *WEO*. In the Sustainable Development Scenario, coal consumption falls rapidly, lowering methane emissions from coal by default. In contrast, global natural gas consumption continues to grow for a period of time in the Sustainable Development Scenario (see Chapter 11).

10.2.2 Methane emissions from oil and gas operations

In examining methane emissions from oil and gas operations, it is important to define the scope of emissions and relevant terms (Box 10.3). Our analysis examines emissions sources along the full oil and natural gas value chains, except for any emissions that occur within industrial or residential buildings (on the basis that the abatement technologies and options for these end-use emissions are materially different than those for the value chain up to the end-use consumer). For simplicity, the oil and gas sectors are divided into upstream and downstream segments and then further into the subsectors of production, gathering and processing, refining, transmission and distribution.[6] The production subsector includes

6. This categorisation matches the reporting standards set by the IPCC and used in national inventories of methane emissions.

all onshore and offshore oil and gas facilities from either conventional or unconventional reservoirs. Liquefaction of natural gas, transportation either by pipeline or as liquefied natural gas (LNG) and regasification are included in downstream processes in our methane emissions estimation (Figure 10.3).

Box 10.3 ▷ Methane emissions glossary

Emissions (or emissions level) are the mass of methane emitted into the atmosphere, usually expressed in million tonnes.

Emission factor is the average rate of emissions from a specific source such as a piece of equipment, a facility or a country. The source of emissions is sometimes referred to as the activity variable (or activity data), with methane emissions often calculated by multiplying an activity variable by an assumed emission factor.

Emission intensity is the ratio of the volume of methane emitted to the volume of natural gas produced (upstream) or transmitted and distributed (downstream) expressed as a percentage.[7]

Fugitive methane emissions occur from leakages that are not intended, for example because of a faulty seal or leaking valve.[8]

Vented methane emissions are the result of intentional releases, often for safety reasons, due to the design of the facility or equipment (e.g. pneumatic controllers) or operational requirements (e.g. venting a pipeline for inspection and maintenance).

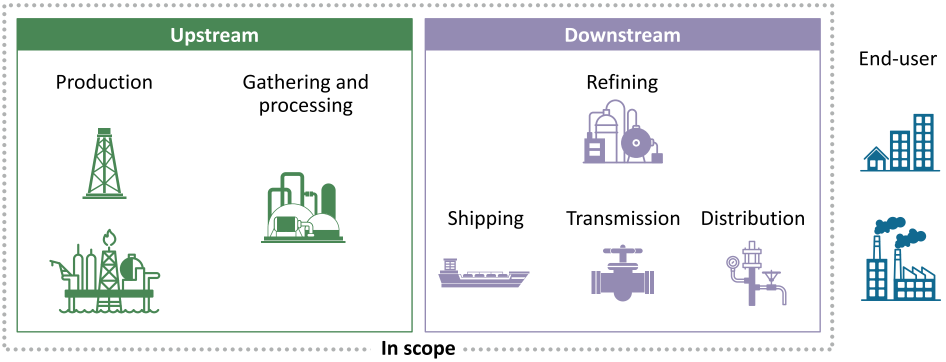
Incomplete flaring methane emissions can occur when natural gas that cannot be used or recovered economically is burned instead of being sold or vented. The vast majority of the natural gas is converted into CO_2 and water, but some portion may not be combusted and is released as methane into the atmosphere.

Super-emitters are emissions sources within a sector or subsector that account for the majority of measured or estimated emissions. Definitions vary as to how to categorise super-emitters: studies have suggested anything between the top 5-15% of sources, and some refer to the sources with the largest emissions while others refer to the sources with the largest emission factors.

7. Emission intensity data are presented in different ways by various sources. In some cases it is the ratio of natural gas emitted to natural gas produced: since natural gas is not entirely methane (the methane content can range from 80% to 100%), this will differ from the percentage used here. The ratio of methane emitted to natural gas produced also varies slightly according to whether it is presented in energy, mass or volume terms. The mass of methane emitted is converted to a volume using a density of 0.68 kilogrammes per cubic metre (kg/m^3). Marketable production is used in the denominator of the ratio. This is the volume of oil or gas that can be sold after impurities are removed and any volumes consumed onsite are subtracted; this differs from raw production, which is the volume of oil or gas that is collected from the reservoir.

8. This differs from the definition used in the IPCC Inventory guidelines (IPCC, 2006) and UNFCCC inventory accounting system (UNFCCC, 2016) in which fugitive emissions are a parent category encompassing leakage, vented and incomplete flaring emissions.

Figure 10.3 ▷ Scope of methane emissions included in analysis



This analysis considers emissions from oil and gas production, processing, refining, transmission and distribution but excludes emissions associated with end-user consumption

Uncertainty in methane emissions from oil and gas operations

There is a great deal of uncertainty about the level of emissions from oil and gas operations. Emissions levels and abatement potentials are based on sparse and sometimes conflicting data, and there is a wide divergence in estimated emissions at the global, regional and country levels. Here we explore the current approaches to measuring and reporting emissions from oil and gas operations and examine why there is such a high degree of uncertainty. Using a wide range of data sources and our survey of a number of countries and companies, we provide a new estimate of current oil and gas methane emissions worldwide.[9]

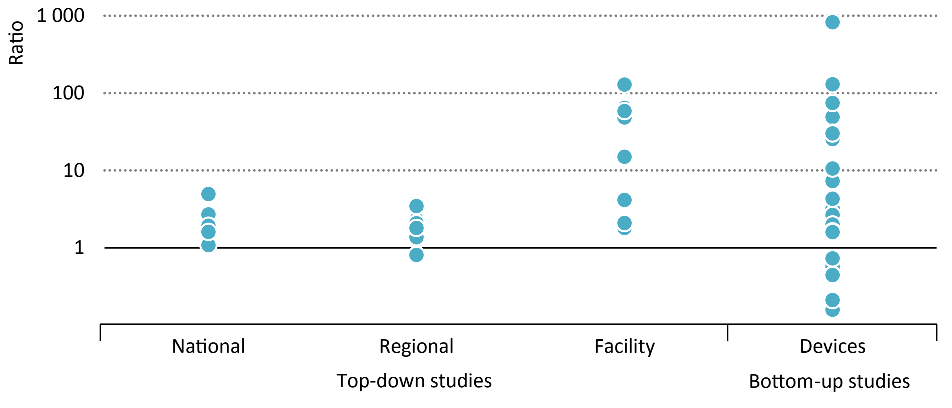
The issue of methane emissions from oil and gas operations grew in prominence as the unconventional oil and gas revolution began to take off in the United States. Analysing the methane emissions from this new source of production, some initial studies suggested there were severe leaks across the natural gas value chain (Howarth et al., 2011). These studies were controversial and leaks were later found to be lower than had been estimated (Cathles et al., 2012) but they stimulated a wave of new independent academic studies and measurement surveys. As a result, the majority of published studies on methane emissions from oil and gas operations are concerned with the United States.

Initially, the studies were top-down, relying on atmospheric samples taken at national or regional (basin) level. But it became increasingly evident that bottom-up studies were required to augment the picture. These studies demonstrated not only that there is wide

9. As part of the *WEO-2017* analysis, we conducted a survey of IEA member countries and major oil and gas producing, transmission and distribution companies. The survey sought to understand better the perspectives of the oil and gas industry as well as policy-makers concerning oil- and gas-related methane emissions and their knowledge and approaches to measuring, monitoring and reporting emissions.

variation in the emission factors at various scales (equipment, facility, regional or national level), but also that, in general, measured emission factors were much larger than the equivalent inventory or industry standard emission factors (Figure 10.4). A wide sample of measurements needs to be taken to ensure the full distribution of emissions sources are included in a survey, but there are many practical difficulties in doing so. For example, permission is required to gain site access and this may only be granted by "best-performing" companies. Moreover, facilities do not emit a constant level of emissions, potentially skewing the measurement if only a single reading is taken, while attributing emissions to a specific point source can also be problematic.

Figure 10.4 ▷ Ratio of measured emission factors to assumed or estimated emission factors from pre-2014 studies in the United States



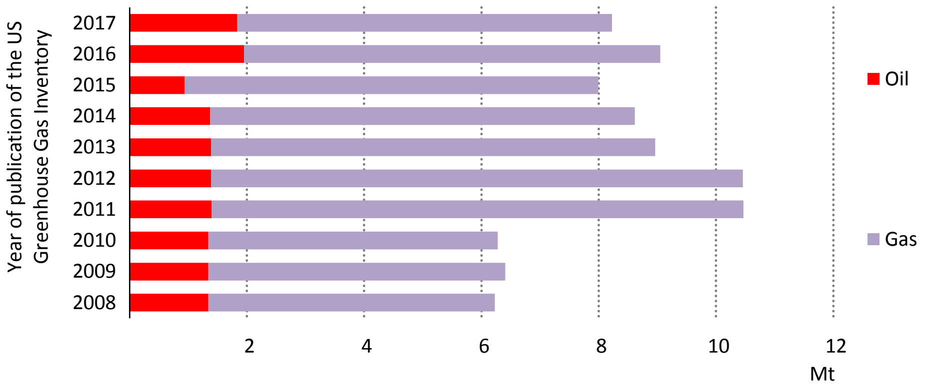
Measured emission factors exhibit a wide distribution, but can be much larger than the assumed inventory or industry standard emission factors

Note: A ratio of one indicates that measurements and assumed emission factors agree.

Source: Brandt et al. (2014).

Recent studies have greatly improved the state of knowledge of emission levels in the United States (Marchese et al., 2015; Allen et al., 2014), and this is reflected in changes to the US Greenhouse Gas Inventory published annually since 2008. There have been a number of major retroactive revisions for US methane emissions as a result of new data, refined modelling approaches and changes in methods, all with the aim of improving the accuracy of the estimates over time (Figure 10.5). Year-on-year changes over the ten published inventories for the year 2005 vary between plus and minus 25% of the latest estimate from the 2017 report, which provides a good indication of the underlying uncertainty in estimates. Some issues have also been identified that remain to be resolved, such as how to take account of emissions from abandoned oil and gas wells, and how so-called "super-emitters" should be incorporated into the inventory (Box 10.4).

Figure 10.5 ▷ **Reported oil- and gas-related methane emissions for 2005 from the US Greenhouse Gas Inventory annual reports**



Historical methane emissions estimated for the United States have been revised considerably, highlighting the inherent underlying uncertainties

Sources: Various editions of US EPA Greenhouse Gas Inventory (EPA, 2017a).

A number of other countries, including Russia and others in Europe, have also paid attention to the issue of methane emissions for quite some time, but few comprehensive measurement studies outside the United States are available. The main source of emissions reporting is the national inventories reported by 43 countries (mostly advanced economies) to the United Nations Framework Convention for Climate Change (UNFCCC, 2016). There are, however, some problems with the generation of these numbers. In particular, many countries use the default emission intensities published by the IPCC, which are based upon datasets from the early 2000s (IPCC, 2006). These are split between emission intensities for developed and developing countries and the choice of which dataset to use can have a major impact on estimated methane emissions. For example, in its 2015 inventory, Russia used the emission intensities for developing countries and reported methane emissions of around 12.7 Mt from natural gas operations in 2013. In its 2016 inventory, it was decided that the emission intensities for developed countries were more appropriate and so Russia modified its methane emissions from natural gas operations in 2013 to around 5.8 Mt, a 55% reduction simply as a result of a change in the calculation method.[10] There are also major data gaps affecting the Middle East, Africa, South America and developing countries in Asia as a result of countries not submitting regular inventories. For these reasons, we have avoided directly using the national inventories submitted to the UNFCCC in generating our estimate of current emission levels by country.

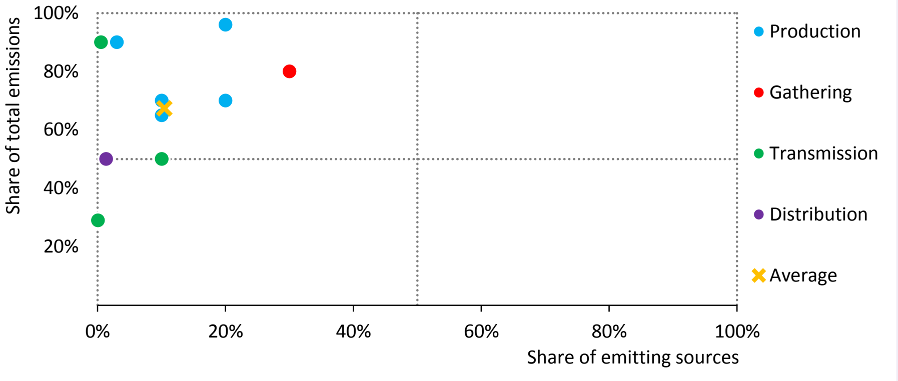
10. Russia plans to make further changes to its methane inventory as all reported sub-categories (exploration, production, processing, transportation, distribution, flaring and venting) for oil and gas will be re-assessed in the future with country-specific emission intensities.

Box 10.4 ▷ Super-emitters: what are they and why are they problematic?

There is substantial evidence that oil and gas methane emissions are highly variable across regions, supply chain routes, processes and equipment (Balcombe et al., 2017; Brandt et al., 2016). While the majority of possible emissions sources exhibit low emission rates, a relatively small number of sources have frequently been found to cause the majority of emissions. This causes a highly skewed or "heavy tailed" distribution over emissions, leading to the term "super-emitter". The top 10% of emitting sources on average contribute around 70% of total emissions (Figure 10.6).

Super-emitters can appear for both conventional and unconventional production across all stages of supply chains. Typical examples include: malfunctioning devices (e.g. valves that are stuck open), human error (e.g. accidentally leaving storage tank hatches open), and the loss of seal integrity on compressors. Most measurements to date have been gathered in the United States, but super-emitters are likely to exist across all supply chains globally. There is an unpredictable element to vents and leaks, and so super-emitters tend to be transient both in time and in geography. This complicates their detection and repair: it may nevertheless be possible to minimise their occurrence and length of duration through preventative maintenance, effective operational strategies to minimise errors, and regular leak detection and repair programmes. There would be great benefit in doing so, and it has been suggested that successfully reducing emissions from super-emitters to "normal" levels could reduce emissions by around 65-85% (Zavala-Araiza et al., 2015b).

Figure 10.6 ▷ Measurement studies for various facilities indicating the prevalence of super-emitting sources



Super-emitters exist across all supply chain subsectors, with the top 10% of emitting sources on average contributing 70% of total emissions

Source: Balcombe et al. (2017) based on studies from the United States, Canada and Russia.

Many leading oil and gas companies publish estimates of methane emissions from their operations (usually reported in annual sustainability reports). Again, there is a high degree of uncertainty in these estimates. Companies tend to estimate methane emissions at the device level using equipment counts and recognised industry standard emission factors, but the range of standards used for emission factors is wide, and it is usually the location of the company headquarters that determines which standards are applied across a company's portfolio (e.g. North American versus European industry standards). Some companies augment these estimates with direct and indirect measurements of devices and facilities. However, the scope and frequency of measurements vary widely. Although companies usually monitor emission levels, they often do not carry out any direct quantification measurements. For example, in enclosed areas, as often encountered on offshore platforms or enclosed compressor stations onshore, methane emissions need to be monitored constantly to alert operators to any leaks to avoid the potential of a flammable or explosive gas-air mix developing and endangering personnel and the installation (Bylin et al., 2010). However, while these monitors detect emissions levels, they generally do not quantify volumetric methane flow rates. Further, if a leak is detected, it may be impractical or unsafe to try to quantify the level of methane that has been emitted as the priority is to find the source and eliminate it as soon as possible.

Method for estimating current and future global methane emissions[11]

10

Our approach to estimating methane emissions from global oil and gas operations relies on generating country-specific and type-specific emission intensities that are applied to production and consumption data on a country-by-country basis.[12] Since emissions in the United States have been analysed more fully than those in other countries, our starting point is the 2017 US Greenhouse Gas Inventory. Along with a range of other data sources, including our survey of companies and countries, we have used this to generate separate oil and gas emission intensities for three types of production (onshore conventional, onshore unconventional and offshore) and for the downstream activities. These emission intensities are then further segregated into fugitive, vented and incomplete flaring emissions where relevant. This process provides a total of 19 separate emission intensities for upstream and downstream oil and gas in the United States.[13]

These US emissions intensities were then scaled to provide emission intensities across all other countries. This scaling is based upon a range of auxiliary country-specific data. For upstream emission intensities, the scaling is based on the age of infrastructure and type of operator within each country (international oil company, independent or national

11. Further details on the method used to generate methane emission estimates can be found in the World Energy Model section of the *WEO* website: *www.iea.org/publications/weo/weomodel/.*

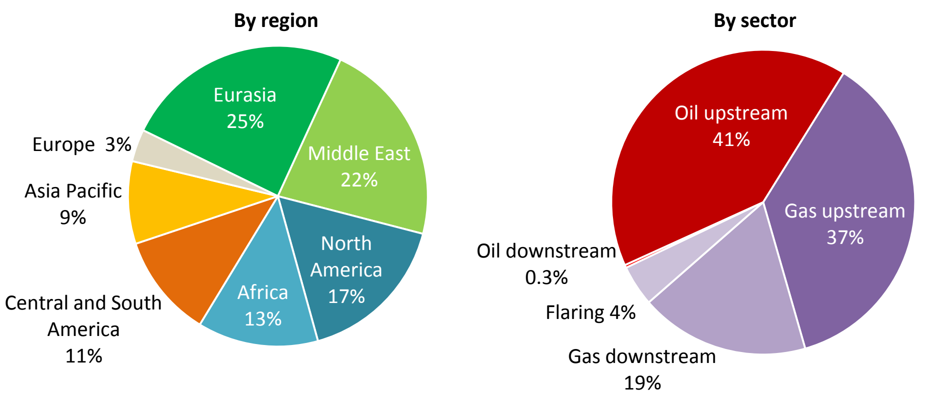
12. It is currently not feasible to generate more specific emission factors (e.g. at an equipment or facility level) at global scale because comprehensive data do not exist.

13. These 19 categories comprise the three upstream and one downstream emission intensities multiplied by two for vented and fugitive emissions, multiplied by two for oil and gas plus three for incomplete flaring from each upstream type of production.

oil company). For downstream emission intensities, country-specific scaling factors were based upon the extent of oil and gas pipeline networks and oil refining capacity and utilisation. A further factor affecting both upstream and downstream is the strength of regulation and oversight.[14] A wide range of other emission data sources were consulted to help calibrate the relative importance of these factors, including various independent direct measurement studies and confidential data provided by a number of global oil and gas companies. These auxiliary data were particularly important to scale emission intensities for Africa, the Middle East and Asia, for which there is almost no direct measured or reported data. The scaling factors that were compiled for the majority of countries lie between 0.7 and 3.6, with outliers in countries with very low regulatory strength and oversight.

We estimate global oil and gas methane emissions in 2015 to be around 76 Mt, some 55% of which are from natural gas operations (Figure 10.7). The 42 Mt emissions from natural gas correspond to a global average emission intensity of just over 1.7%. Just under 60% of total oil and gas emissions are vented (i.e. are intentional releases), 35% are fugitive (i.e. are unintentional releases) and the remainder are from the incomplete combustion of flares. The top ten countries are responsible for two-thirds of global oil and gas emissions, with Eurasia and the Middle East the two highest emitting regions: they account for nearly half of total global emissions.

Figure 10.7 ▷ Regional and sectoral breakdown of methane emissions from oil and gas operations, 2015



Natural gas operations account for around 55% of our estimated 76 Mt methane emissions in 2015, with Eurasia and the Middle East the largest emitting regions

14. This incorporates government effectiveness, regulatory quality and the rule of law as given by the Worldwide Governance Indicators compiled by the World Bank (2017).

Our estimate of 76 Mt is generally in line at the global level with the limited number of other assessments of oil and gas methane emissions (Figure 10.8).[15] However there is a very large discrepancy with the emission intensities reported by industry at the global level. One finding from our industry survey was that the majority of companies in both the upstream and downstream oil and gas sectors considered their methane emission intensities to be around 0.1% of volumes produced or transmitted. This corresponds with the findings reported in assessments by industry organisations: one recent estimate covering the emissions from 43 major oil and gas companies reported a global average emission intensity for oil and gas production of just under 0.1% (IOGP, 2015). If it were to be assumed that these companies are fully representative of the industry worldwide, then global oil and gas methane emissions would be around 15 Mt, 80% lower than our estimate (and those from other sources).

This major discrepancy requires further investigation, but we think there are three possible explanations why such a gap exists:

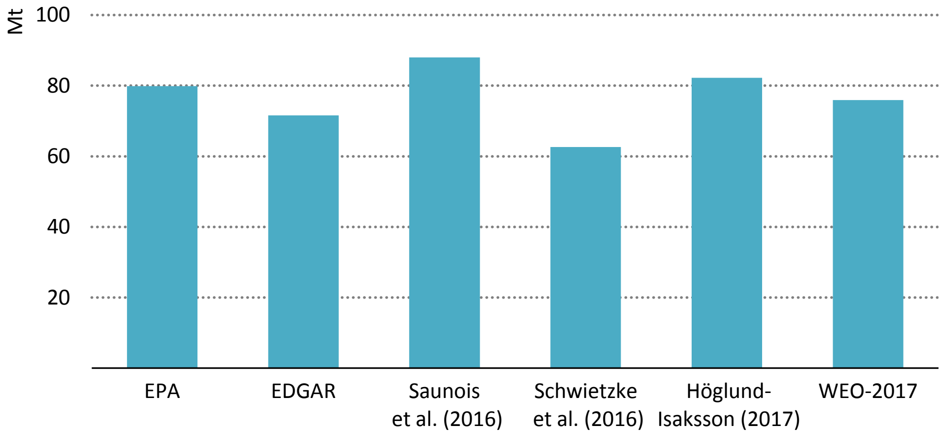
- The industry may be underestimating its emissions by relying on average emission or activity factors that are not truly representative of actual levels. This could be because the highly skewed distribution of emissions (as a result of super-emitters) is not accurately captured by the use of a single average emission factor, which is too low as a result, or because there are potential emissions sources that are not taken into account. It could also be because the default emission factors used when estimating emissions from equipment or facilities are not revised to account for leaks that are detected. The magnitude of the leak may be unknown (given the emphasis on repairing the leak rather than quantifying the level of emissions) or there may simply be no mechanism in place to modify the default emission factor used by that company.
- The dataset used to generate a global "industry estimate" may be skewed. In other words, the emission factors that have been reported by companies may not be truly representative of what is achieved by the industry as a whole. The companies that responded to our survey, or that contribute to assessments compiled by industry associations, may be those that pay most attention to emissions levels and are the "best-performers" in their peer group. Other companies not included in the dataset could have much larger emission factors and be responsible for a large proportion of emissions.
- The top-down studies may be misallocating emissions to the oil and gas sector. It could be that some emissions are assumed to originate from the oil and gas industry but in fact come from other sources such as coal, agriculture or natural sources.

With the current state of knowledge, it is impossible to be certain which of these is most likely to be correct. It is possible that more than one or indeed all may apply to a certain degree. The fundamental problem is that too few direct measurements have been taken

15. There are some larger differences in the apportioning of emissions between oil and gas within these sources. For example, Schwietzke et al. (2016) indicate that around 80% total emissions are from gas while Höglund-Isaksson indicates 40%. It is unclear, however, how these splits between oil and gas are made.

(or made available publicly) that span the variety of operators, types of operations, and countries that need to be investigated to gain a full understanding of global oil and gas methane emissions.[16]

Figure 10.8 ▷ Comparison of recent assessments of global oil- and gas-related methane emissions



Our WEO-2017 estimate of 76 Mt oil and gas methane lies in the range of other studies

Notes: As these studies were generated over the last five years, they reference different base years (or periods), ranging from 2010 to 2015. EPA = US Environmental Protection Agency; EDGAR = Emissions Database for Global Atmospheric Research.

Sources: EPA (2012); Joint Research Centre (2013); Saunois et al.(2016); Schwietzke et al.(2016); Höglund-Isaksson (2017).

S P O T L I G H T

Lifecycle greenhouse-gas emissions: how do gas and coal compare?

The CO_2 emissions from the combustion of natural gas are certainly lower than those from coal. But are they also lower when assessing full lifecycle greenhouse-gas (GHG) emissions, after taking account of methane emissions released across the natural gas value chain?

The global warming potential is often used to combine CO_2 emissions and methane into a single CO_2-equivalent term. While there are a number of problems with the use of the GWP in this way (Box 10.2), it still provides a useful starting point for comparisons between various fuel types as long as different timeframes are considered. The relative emission intensity of natural gas and coal is also affected by how the fuels are used: the conversion of natural gas into electricity tends to have a higher efficiency than coal

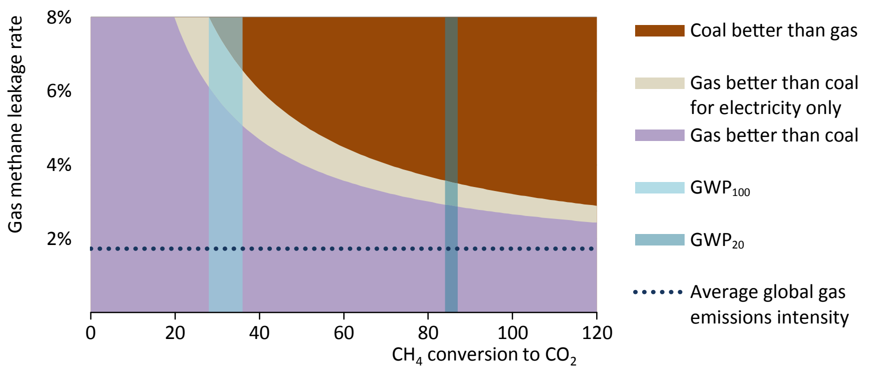
16. The Climate and Clean Air Coalition, Environmental Defense Fund and the Oil and Gas Climate Initiative are initiating a series of scientific studies to quantify oil and gas methane emissions and emission factors in areas outside the United States.

meaning that emissions are lower for natural gas if given in terms of electricity produced instead of heat. Methane emissions from coal, which we estimate to be 40 Mt globally (although this too is subject to a high degree of uncertainty), also need to be taken into account (see section 10.2.1).

Considering the relative GHG intensity of the two fuels over a 100-year timeframe, if the emission intensity of gas is below 5.5%, then gas has lower lifecycle emissions than coal (Figure 10.9). If the emission intensity lies between 5.5% and 7.5%, then natural gas would have lower lifecycle emissions for electricity, but not for heat. When considering the warming potential over a 20-year timeframe, then the emission intensity must be below 3% for natural gas to be cleaner than coal.

Our estimate of methane emissions from natural gas gives a global emission intensity of just over 1.7%. This means that gas on average generates far fewer greenhouse-gas emissions than coal when generating heat or electricity, regardless of the timeframe or GWP in question. However, the emission intensity of gas is likely to exceed 3% in some countries, in which case it would be worse than coal (measuring warming potential over a 20-year timeframe). Even if natural gas is always better than coal, however, simply comparing it to the most emission-intensive fuel is setting the bar too low. If the rapid and drastic emissions reductions required in deep decarbonisation scenarios are to be achieved, it is not sufficient for natural gas simply to result in fewer GHG emissions than coal: it is clear from the Sustainable Development Scenario that the emission intensity of natural gas needs to fall to as low a level as is practicable (section 10.4).

Figure 10.9 ▷ Greenhouse-gas emission intensity of natural gas compared with coal



The global average emission intensity of gas is low enough for gas to result in fewer GHG emissions than coal regardless of the timeframe considered

Notes: GWP_{20} = global warming potential over a 20-year timeframe; GWP_{100} = global warming potential over a 100-year timeframe, based on the ranges from the Fifth IPCC Assessment Report (IPCC, 2014). The average global gas emission intensity of 1.7% is based on our estimate of 42 Mt methane emissions from natural gas operations in 2015.

10.3 Tackling methane emissions

There is a variety of voluntary and regulatory efforts underway to tackle the issue of methane emissions in the oil and gas sector. The main technical challenge facing all of these efforts is how to detect and measure emissions in a comprehensive and cost-effective manner. The fundamental problem is the current lack of availability of innovative detection systems that can provide effective monitoring and quantification of emissions at low cost. The actual abatement technologies that can prevent vented and fugitive emissions, by contrast, are reasonably well-known (Box 10.5). The challenge here is to incentivise their deployment, via voluntary or regulatory means. In many cases, investment in abatement technologies is economic; the saved gas pays quickly for the installation of better equipment or the implementation of new operating procedures. However, some solutions require substantial investments that, depending on the gas price and volumes of gas saved, may not be recouped in full by the operator or may pay back only over a much longer period (and some abatement options may also be easier to implement at the design stage rather than through retrofitting existing assets). In this section, we review the experience of different voluntary and regulatory approaches, highlighting those that have led to significant reductions in methane emissions.

Box 10.5 ▷ Selected sources of methane emissions and mitigation options

There are multiple potential sources of fugitive and vented methane emissions in oil and gas operations during production, gathering, processing, and transmission and distribution. Some of the key sources are explained below along with the technologies or remedial measures that can be employed to prevent or reduce them.

Well completion: transforms a conventional or unconventional well that has been drilled into a producing one. For unconventional wells, this involves hydraulic fracturing after which a period ensues when some of the fracturing fluid flows back to the surface, potentially carrying methane with it. This was a major source of emissions when unconventional gas production first began in the United States, but reduced emissions completions (also known as "green completions") are now mandatory for the vast majority of wells.

Liquids unloading: a process where liquids are removed from the bottom of a gas well to increase the flow of gas. This can involve temporarily shutting in the well to increase pressure and then venting to atmosphere. Use of a plunger lift along with modern control technologies to conduct unloading instead can reduce emissions by up to 95%.

Glycol dehydrators: commonly used to remove water from produced natural gas. Water vapour produced in this way is typically vented to atmosphere and is likely to contain low concentrations of methane. The installation of separators or a vapour recovery unit is the key mitigation mechanism.

Compressors: maintain pressure in pipelines as gas and oil are gathered and transported. Compressors are a major source of both fugitive emissions (unintended leaks through seals) and vented emissions (gas can be released when units are temporarily shut down). Replacing seals, installing a degassing system, and moving quickly to replace moving parts are the key ways to reduce or eliminate emissions.

Pneumatic devices: control flow rates, temperatures, liquid levels and pumping systems. They use pressurised gas to create mechanical movement and can utilise natural gas since this is already pressurised. Pneumatic devices release gas by design: even though they only vent small volumes, the large number of devices that exist throughout the gas supply chain means that overall emissions can be large. Replacing these devices with electrical-driven controllers (where grid or decentralised electricity is available) or those that use pressured air rather than natural gas would eliminate these emissions entirely.

Liquid storage tanks: crude oil and condensates that are produced can be stored onsite in tanks. Methane can be dissolved in these liquids, which can evaporate, enter the vapour space of the tank and be vented to atmosphere. The main mitigation measures are to install a vapour recovery unit or to flare the natural gas.

Voluntary efforts

Increased attention to methane emissions has generated a number of national and international partnerships (Table 10.1). Many of these initiatives focus on best practices and on promoting awareness and use of abatement technologies. Some of them are oriented towards specific quantitative targets: the ONE Future initiative in the United States, for example, aims to achieve an average rate of methane emissions across the entire natural gas value chain that is 1% or less of total natural gas production. A lot of these initiatives are focussed on the United States, but an increasing number have an international dimension.

A common denominator for many of these efforts has been to improve the uptake of specific emission abatement technologies. The US Environmental Protection Agency currently lists around 70 such technologies covering compressors, pipelines, pneumatic controls, tanks, valves, wells and recommended practices for direct inspection and maintenance. The quoted capital cost range per technology varies from less than $1 000 to more than $50 000 with estimated payback periods of a few months to three years (although payback periods are highly contingent in practice on natural gas prices and the cost of capital). The use of these technologies and practices helped yield a near 30% reduction in the overall emission intensity of natural gas in the United States between 2005 and 2015 (Figure 10.10). The sustainability reports of various companies indicate that their methane emissions outside the United States have also dropped, due to the adoption of better design, leak detection and repair programmes (LDAR) and operational changes.

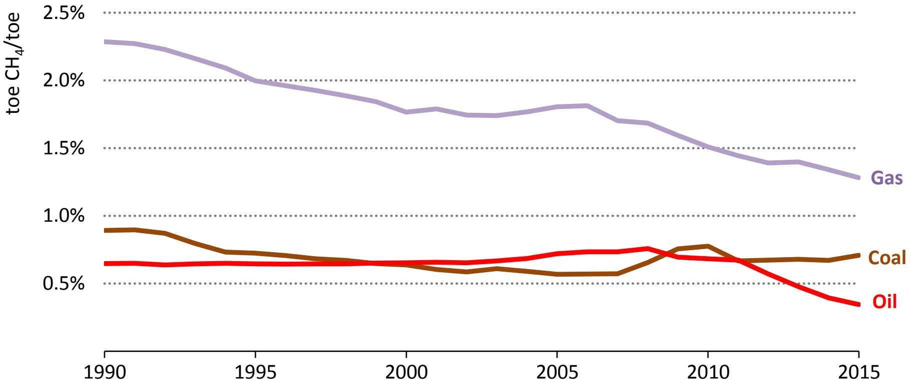
Table 10.1 ▷ Major voluntary methane emissions reduction initiatives

Name	Objective	Stakeholders / members
Natural Gas STAR Program (since 1993)	Encourage adoption of methane reduction technologies in US oil and gas industry.	US government, oil and gas industry.
Global Methane Initiative (since 2004)	Promote methane abatement, recovery, and use by focusing on biogas, coal mines and oil and gas systems.	Industry, governments, UNECE, Climate and Clean Air Coalition.
Natural Gas STAR Program International (since 2006)	Implement methane reduction technologies in international oil and gas sectors.	Industry, governments (under Global Methane Initiative).
Oil & Gas Methane Partnership an initiative of the **Climate and Clean Air Coalition** (since 2014)	Provide protocols for companies to survey and address emissions and a platform for them to demonstrate results.	Ten oil and gas companies, governments, UN Environment, World Bank, Environmental Defense Fund.
ONE Future (since 2014)	Achieve an average rate of methane emissions across the entire natural gas value chain that is 1% or less of total natural gas production.	Ten US natural gas companies.
Methane Challenge Program (since 2016)	Provide a mechanism through which US oil and gas companies can make more specific and transparent commitments to reducing methane emissions.	US EPA and 41 US founding partners (companies).
Oil and Gas Climate Initiative (since 2014)	Improve methane data collection and the understanding of the natural gas lifecycle, and select and deploy cost-effective methane management technologies.	Ten major international oil and gas companies.

Voluntary efforts to reduce emissions have to date understandably focussed on the technologies or practices with the shortest payback periods, as discussed in more detail below. Leak detection and repair (LDAR) programmes have established themselves as a key approach to reducing fugitive emissions. This involves identifying emissions via infra-red cameras on a regular basis (with the regularity being defined by the operator) and repairing leaks as soon as possible (Box 10.6).[17] Other indicators of leaks are also used, such as pressure monitoring and permanently installed monitors that check that explosive atmospheric conditions are avoided for the sake of safety, especially in offshore installations. While these voluntary programmes have yielded important emissions reductions, some data suggest that their impact may have slowed somewhat in recent years (EPA, 2015). This suggests either that most of the low-hanging abatement fruit has now been picked or that there has been a slowdown in the number of operators choosing to take voluntary emissions reduction action, raising the question of whether voluntary efforts have reached a point of diminishing returns and whether further emissions reductions may therefore require regulatory intervention.

17. Circumstances in which immediate repair may not be possible include if equipment has to be ordered, leaky equipment cannot easily be accessed or if the repair requires non-routine operational shut downs.

Figure 10.10 ▷ **Methane emission intensity of oil, gas and coal in the United States**



Mitigation efforts in the United States are bearing fruit as emission intensities have been declining since the mid-2000s; the emission intensity of coal has been more stable

Notes: Gas intensity is the sum of upstream emissions divided by US production and downstream emissions divided by US consumption. Intensities here are the ratio of tonne of oil-equivalent (toe) methane emitted to tonne of oil-equivalent fuel and so differ slightly from the other emission intensities presented (which are the volume ratio).

Source: EPA (2017).

Box 10.6 ▷ **What you can learn from your LDARs**

Leak detection and repair (LDAR) programmes are an essential instrument to reduce methane emissions, but standards and practices vary widely by operator and type of equipment. Not all companies undertake such programmes, but for those that do, the frequency of inspections can range from a weekly cycle to once every two to three years. Our industry survey and separate interviews with operators, conducted as part of the research for this chapter, have provided some insights into the experience of operators with their LDAR programmes:

- There is an important element of "learning by doing" with LDAR. While initial programmes can be relatively ad hoc, the assessment of risk and frequency becomes progressively more sophisticated with time.
- LDAR increases awareness of the issue, demonstrating to operators (including local staff) that leaks can occur, which can help stimulate further action on abatement.
- Maintaining detailed records of leaking components/equipment is essential to maximise the opportunities for learning. Analysis can then be used to identify opportunities for implementing early maintenance practices to prevent leaks before they occur. Analysis of LDAR results can also identify areas or sources where there is a need for more frequent surveys.

- Many leaks can be repaired immediately when observed and a significant majority of leaks can be repaired within 15 days.
- Companies support the conclusion reached in various studies that the benefits from abatement through LDAR outweigh the cost, particularly in the early period of its application.
- One company that has applied a rigorous LDAR programme confirmed that the benefits, in terms of saved gas, tend to diminish over time (as they should with effective action) while the costs tended to remain stable. The calculation of "savings" in this instance needs to account for the likelihood that emissions would increase in the absence of an effective programme.
- Emerging innovations in methane detection technology, such as aerial surveys, are likely to enable more frequent monitoring, and potentially to enable continuous detection, making it possible to find and fix large leaks much more quickly and cheaply than at present.

Regulatory approaches

There are limits to what can be achieved by voluntary action both because the pool of those willing to take such action may be limited and because the actions themselves may fall short of what is desirable from a public policy perspective. If voluntary measures prove inadequate, regulation can be very effective in reducing emissions further: for example, one study on methane emissions from the completion of natural gas wells showed that the use of green completions, which are now mandatory in the United States for new wells, reduced methane emissions during this stage of operations by about 99% (Allen et al., 2013). However, finding the right balance in regulation is challenging and of course is affected by shifts in technology and in policy priorities: in this area, as in many others, countries take different approaches.

Methane emissions can be addressed via operational safety or environmental regulations (mainly pertaining to air quality) for volatile organic compounds (VOCs).[18] Very few countries have comprehensive approaches to methane recovery and use, but a few have set specific national targets for methane emissions reduction. The most advanced body of regulation on oil and gas methane emissions is in North America. Among other major oil and gas producers, Russia and Norway are examples of the (relatively few) countries that have specific regulation on emissions.

A common element across many regulatory systems is a reporting requirement. In the United States, for example, all industrial facilities that emit more than 25 000 metric tonnes of CO_2-equivalent have to report their emissions to the federal Greenhouse Gas Reporting

18. Methane is usually excluded from air quality regulations (often phrased as "VOCs excluding methane"), but because methane emissions tend to be accompanied by emissions of other VOCs, regulating VOCs can lead to reductions in methane emissions.

Program (GHGRP). It is estimated that the data collected by this programme covers about a third of the US oil and gas methane emissions (EPA, 2017b). The data are used to track, compare and reduce emissions, and to help develop policy and regulatory approaches. A similar programme exists in Australia called the National Greenhouse and Energy Reporting scheme. In Russia, companies are required to report methane emissions (on which they are taxed), and the government has the right to conduct announced and unannounced checks to verify the reported levels, with fines for any under-reporting. In Norway, each oil and gas facility estimates and reports methane emissions annually using a common estimation method that relies on standard emission factors; methane emissions from venting are taxed.

A number of countries go beyond simple reporting requirements and have introduced specific regulatory requirements for different types of oil and gas operations. Whether at local or national level, the focus tends to be on specific areas of high risk or high potential benefit (such as those discussed in Box 10.5). In the United States, for example, several states have their own regulation and standards on methane emissions that accompany or amplify obligations arising from federal rules. California, Colorado, Ohio, Pennsylvania, Utah and Wyoming all have state-level regulations: these vary in scope, but all require mandatory inspection of facilities (via LDAR or equivalent) at varying intervals. In Canada, the provinces of Alberta, British Columbia and Saskatchewan have regulatory measures in place to address venting and flaring from upstream oil and gas operations. A further discussion of some of the key principles to be considered in the design of new regulations is provided in section 10.5.

10.4 Costs and benefits of action on methane emissions

It is clearly important to understand the scope for reductions in methane emissions from oil and gas operations, and the likely costs of achieving those reductions. In this section we combine the previous discussion on the specific sources of methane emissions, the technological mitigation options, and the voluntary and regulatory efforts that have been made, and use the information we have gathered to build a comprehensive global picture of the magnitude and costs of oil and gas methane emissions reduction. We illustrate this by constructing new "marginal abatement cost curves" for global methane emissions. These tools have been used before to examine the technical potential and costs of reducing methane emissions in countries in North America (ICF, 2016a, 2016b), but we explore new ground here by constructing state-of-the-art curves that look at the global picture to describe in detail the emissions reductions and monetary costs (and savings) that can result from the use of different abatement technology options. To build a holistic picture of the costs and benefits of tackling emissions from oil and gas operations, we then examine what different ambition levels for reducing methane emissions globally could mean in terms of actual emissions and how this might affect future climate change.

10.4.1 Marginal abatement cost curves

There are practical differences between emissions reduction action across different parts of the value chain that contribute to a wide variety of abatement costs. While replacing or retrofitting a piece of equipment on a well pad or implementing a new upstream operating practice may be relatively easy, replacing worn-out gas distribution pipes buried underground in congested urban areas is considerably more difficult. The level of emissions that comes from these different sources varies widely, and so too does the benefit in terms of the reduction in emissions. There are also likely to be some sources of emissions that are impractical to eliminate entirely: temporary emergency releases of methane may be necessary to avoid explosions, while even the highest quality compressors can vent small volumes of methane during their normal operations.

Marginal abatement cost curves are useful tools to combine all of these considerations into a single, comprehensive picture.[19] These curves take emission levels in the absence of any mitigation options and then describe the reductions that can be achieved using different technologies (by moving from left to right along the horizontal axis) at different costs or savings (as given on the vertical axis). When viewed at the global level, steps on the curve describe the reduction potentials and costs of technologies in a given country mitigating a specific source of emissions. One important aspect of these curves is that, since natural gas is a valuable product, the methane that is recovered can often be sold. This means that deploying certain abatement technologies can result in overall savings if the value received for the methane sold is greater than the cost of the technology. A complicating factor is that in some countries the operator that would need to make the investment does not own the gas (for example, the processing or transmission segments in the United States), and so would not capture the value of the methane that is recovered. However, since we examine this issue from a global, societal perspective, we assume that that any methane that is recovered can be re-sold, regardless of what contractual arrangements between different companies may be required to lead to this result. The credit obtained for selling the gas is determined by the wellhead gas price[20] in all regions (rather than the gas import prices as shown in Table 1.4) because of the need to allow for the costs of transporting the recovered gas as well as other fees and royalties that are levied. Actions that result in savings are shown below the horizontal axis in a marginal abatement cost curve: the more negative the value, the more cost-effective deployment of the technology would be.

19. The marginal abatement cost curves were generated using the IEA methane emissions model that was developed in collaboration with ICF, using IEA data and input assumptions. Further details can be found in the *World Energy Model* section of the *WEO* website: *www.iea.org/publications/weo/weomodel/.*

20. Wellhead prices are the effective price of natural gas that an operator would use to decide whether to develop a new natural gas project. They can be calculated in a number of ways but one example is to take the price that gas can be sold to consumers and subtract the cost of transportation (including taxes) back to the location of the project.

To construct these curves we disaggregate the 19 emissions sources identified in section 10.2.2 for each country (such as vented emissions from conventional gas production) to a total of 86 equipment-specific emissions sources covering the whole oil and gas value chain (e.g. vented emissions from compressors or vented emissions from storage tanks). This disaggregation is largely based on the United States following the catalogue of emissions sources published in the US Greenhouse Gas Inventory (EPA, 2017a). However we make modifications for country-specific details based on other data sources and discussions with relevant stakeholders. For example, it is assumed that a much larger share of downstream emissions in Qatar result from LNG plants than is the case in the United States, and that gas-driven pneumatic devices are a much less significant source of emissions in many countries than is the case in the United States.

Around 50 different known abatement technology options are identified to mitigate emissions from these equipment-specific sources. Each of these technologies has a specific capital and operating cost, lifetime, emissions reduction potential and applicability (i.e. to what percentage of equipment can the technology be applied given potential practical constraints).[21] Analogues with the United States were again used for these technology-specific factors but costs and applicability were modified for country-specific details. For example, it is assumed that solar-powered electric pumps cannot be deployed as widely in high-latitude countries (and if they are, that costs will be higher) and that labour costs in developing countries in Asia are lower. LDAR programmes are the key mechanism to mitigate fugitive emissions from the production, transmission or distribution segments of the value chain. The costs of inspection differ depending on the segment in question: given travel time, it takes longer to inspect a compressor on a transmission pipeline than in a production facility. It is assumed that inspections can be carried out annually, twice a year, quarterly or monthly in the marginal abatement cost curves below, with each option appearing as a separate step. In increasing the regularity of inspections, the cost for each visit is the same but the incremental level of emissions avoided is lower. More frequent LDAR therefore costs an increasing amount relative to the amount of fugitive emissions that are avoided.

A marginal abatement cost curve describes the technical reduction potential in a specific year. The various components however will not be static over time. Oil and gas production and consumption levels change, meaning that "baseline" emissions levels will change. Natural gas prices also change, meaning that the apparent cost of technologies will change because the revenue received from selling the gas saved will differ. The costs of some technologies moreover will fall over time as a result of innovation and learning.

21. The cost and revenue from each technology is converted into net present value using a discount rate of 10% and divided by the volume of emissions saved to give the cost in dollars per million British thermal units (MBtu).

Methane emissions abatement curves

The marginal abatement cost curves for methane emissions from oil and gas operations, split by source and by region, are shown in Figure 10.11 and Figure 10.12. Of the current 76 Mt of oil and gas methane emissions, 58 Mt would be avoided if all technologies and approaches were to be deployed, a 75% reduction from current levels. With 2015 gas prices, some 50% of methane emissions (38 Mt) could be avoided just by using technologies and approaches that would pay for themselves through the captured methane that can be sold. Further reductions would start to rely on technologies or approaches that would cost money rather than saving it, either because the gas cannot be monetised (if it is flared for example) or because capital and operating costs are larger than the revenue that would be received from selling the gas recovered.

Figure 10.11 ▻ Global marginal abatement cost curve for oil and gas methane emissions by source, 2015

It is technically possible to reduce global oil- and gas-related methane emissions by 58 Mt, a 75% drop from levels today. Emissions of 38 Mt – or 50% – can be mitigated using measures with positive net present values

Source: IEA methane emissions model developed in collaboration with ICF.

The marginal abatement cost curves are quite sensitive to prevailing natural gas prices. The curves presented here rely on 2015 prices,[22] which were markedly higher than 2016 prices in a number of regions. If 2016 prices were to be used, the level of possible emissions reduction globally with measures that have positive net present values would drop from 50% to 40%.

22. Gas prices from 2015 are used in the marginal abatement cost curves presented because these are more illustrative of the prices seen throughout the New Policies Scenario.

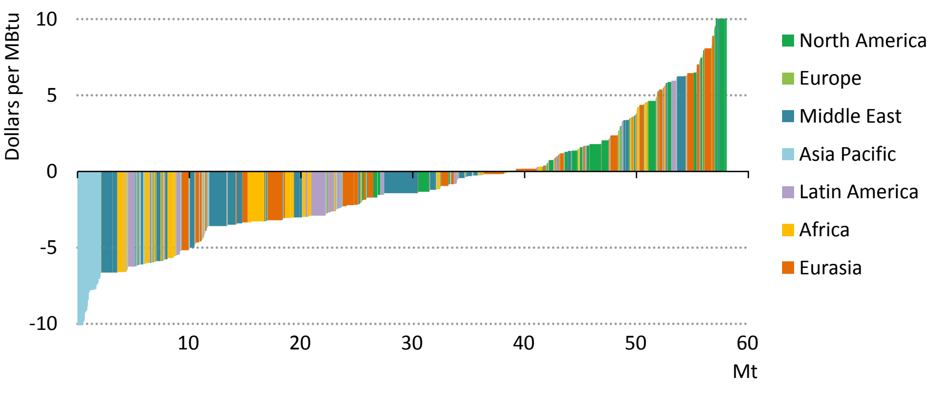
There are differences between the level of mitigation technically possible for oil and for gas: over 80% of methane emissions from oil operations can be avoided globally compared with less than 75% of methane emissions from gas. For fugitive emissions from both oil and gas, a maximum of 85% can be captured by introducing monthly LDAR programmes. It can be more difficult to apply remedial measures to some vented sources of emissions, and this is more evident for gas than for oil. While use of a plunger lift can reduce emissions from liquids unloading substantially, its effectiveness varies according to reservoir-specific properties, and it is not practicable to install plunger lifts on all gas wells (Box 10.5). The abatement potential for vented emissions from the downstream gas sector is much lower – here it is technically possible only to avoid 25% of vented emissions – as a large portion of emissions from compressors during gas transmission by long-distance pipeline are impossible to eliminate entirely, even with state-of-the-art equipment.

There are differences in the level of mitigation for oil and for gas that are possible with measures that generate an overall level of profit: over 60% of methane emissions from the oil sector can be avoided with measures that have positive net present values compared with 40% for natural gas (assuming 2015 gas prices). This is because the technical mitigation potential for upstream oil operations is higher, and because a greater proportion of oil production globally takes place in regions with higher gas prices than is the case for gas. In addition, it is more expensive to mitigate downstream emissions than upstream emissions, and while the downstream sector accounts for a very small proportion of total oil-related methane emissions (which mainly occur at refineries) it accounts for around 35% of total natural gas emissions (Figure 10.7). This is because any leaks during the transport of natural gas would cause methane to be emitted, whereas most methane is removed before oil is transported long distances. Downstream emissions for natural gas could occur anywhere along the length of the transmission pipelines and so could occur across a wide geographic area. Inspecting and repairing the potential sources of fugitive emissions therefore takes a long time. Upstream (and downstream oil) fugitive emissions are much more concentrated in discrete facilities and it is generally quicker and less expensive to inspect and repair these than is the case for downstream gas. Nevertheless, there is plenty of scope to reduce the costs of LDAR for both upstream and downstream operations, and programmes are already underway to explore the potential use of long-distance or aerial (drone based or fixed-wing aircraft) detection and measurement systems.

Since a high level of emissions can be mitigated using measures that pay for themselves from the methane recovered, an open question remains why these have not already been widely adopted. There is no single explanation for this, and reasons vary from country-to-country. Possible causes include a lack of awareness of the level of emissions or the cost-effectiveness of abatement, competition for capital within companies with a variety of investment opportunities, the measures not having sufficiently quick payback periods to satisfy companies, and the possibility of split incentives (where the owner of the equipment does not directly benefit from reducing leaks, or the owner of the gas does not see its full value). New policy and regulatory approaches might be necessary to overcome these hurdles (see section 10.5).

Regions that have the highest wellhead natural gas prices have the greatest proportion of emissions that can be mitigated at zero or negative overall costs. In many developing Asian economies the price that can be obtained for any methane recovered is relatively high (i.e. around $11/MBtu in 2015). Labour costs – a key component of the overall cost of LDAR – are relatively low. As a result, some technology options can be carried out while saving around $10/MBtu,[23] and two-thirds of methane emissions could be avoided across developing countries in Asia through the use of technologies that would pay for themselves through the methane recovered. In North America, in contrast, labour costs are generally higher and natural gas prices across the continent more closely match the price of Henry Hub (i.e. around $2.7/MBtu in 2015). Similarly, the wellhead price of natural gas in Russia and many of the Caspian countries is a fraction of the prices paid by importing countries given the cost of transport and the taxes levied on exports. However there are still a number of positive net present value measures that can be deployed: in North America, for example, around 20% of total oil- and gas-related methane emissions could be eliminated using technologies with negative or no overall costs.[24] Reducing oil and gas methane emissions remains a cost-efficient way of reducing greenhouse gas emissions compared with other mitigation strategies.

Figure 10.12 ▷ Marginal abatement cost curve for oil- and gas-related methane emissions by region, 2015



The cost of mitigation is generally lowest in developing countries in Asia and the Middle East, and generally highest in areas that have low wellhead gas prices

Source: IEA methane emissions model developed in collaboration with ICF.

23. The vertical axis on the marginal abatement cost curves is given in terms of natural gas prices in US dollars per MBtu on the assumption that natural gas is 83% methane (by energy content). So, for example, a technology with no cost of abatement with a wellhead gas price of $5/MBtu, will appear with a saving of $6/MBtu in the figure.

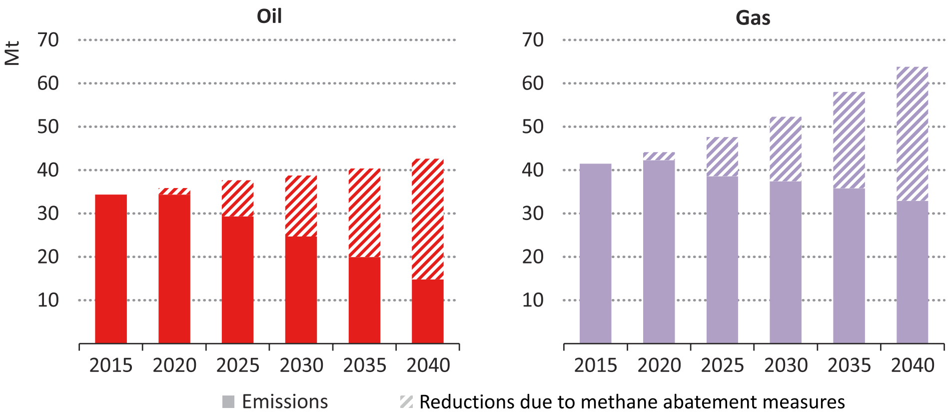
24. The finding that 20% of emissions can be reduced using measures with positive net present values is similar to that in a detailed study undertaken by ICF specifically examining North American methane emissions abatement (ICF, 2016b).

Methane emissions in the New Policies and Sustainable Development Scenarios

Changes to oil and gas production in various countries from different types of production (such as conventional or unconventional sources) affect the levels of methane emitted by the oil and gas sector. Since oil and gas prices also change, this yields a dynamic marginal abatement cost curve that evolves over time and that varies according to scenario.

In the New Policies Scenario, if there are no explicit efforts to reduce methane emissions, then methane emissions would rise to over 105 Mt in 2040. However the proportion of total emissions that could be reduced using measures that result in overall savings or have no net cost would increase to 60%, given the increase in natural gas prices around the world (the reduction is 50% at 2015 prices). The measures in place to support emissions reduction targets in North America lead to some abatement there, and it is likely that a proportion of the other emissions reductions that can be deployed while generating some level of profit would also be implemented over time. It is assumed that measures which consistently have positive net present value throughout the New Policies Scenario are fully deployed and, as a result, global oil and gas methane emissions fall to around 50 Mt in 2040 (Figure 10.13). There is a larger reduction for oil that reflects the fact that a greater proportion of emissions can be mitigated with measures that generate overall savings than is the case for natural gas. The absolute reduction in methane emissions from natural gas between 2015 and 2040 is also offset to some extent by a large increase in gas consumption over this period. Emissions from natural gas in 2040 are around 35 Mt, with the global average emission intensity for natural gas (including both upstream and downstream emissions) in 2040 falling to just under 1% (compared with 1.7% today).

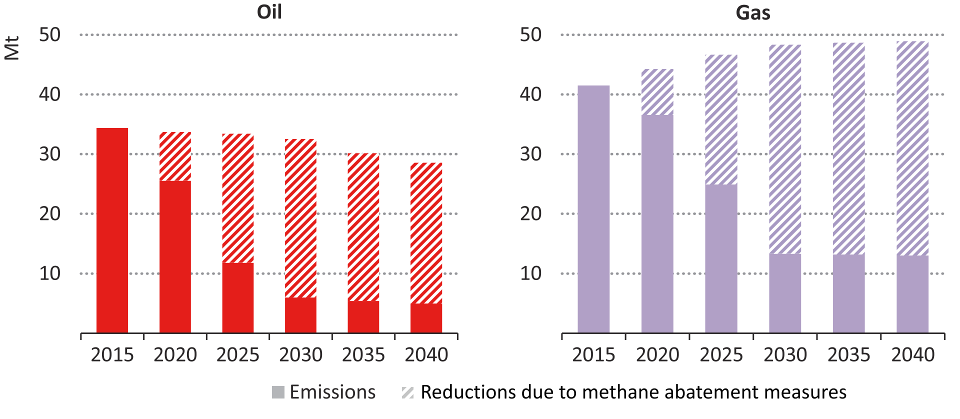
Figure 10.13 ▷ Oil- and gas-related methane emissions in the New Policies Scenario with and without abatement measures



Implementing measures with positive net present values reduces oil and gas methane emissions to around 50 Mt in 2040, 55% lower than they would have been otherwise

In the Sustainable Development Scenario, methane emissions would be lower than in the New Policies Scenario, even in the absence of any explicit methane reduction policies simply because overall oil and gas consumption is lower. As a result, the "baseline" level of methane emissions in 2040 (i.e. the level of emissions without any mitigation efforts) in the Sustainable Development Scenario would be 77 Mt, similar to today's levels. Gas prices in the Sustainable Development Scenario in 2040 are generally higher than today (although lower than in the New Policies Scenario) and so around 55% of this 77 Mt could be mitigated with measures that generate savings or have no net cost. This level of reduction is, however, unlikely to be sufficient for the use of natural gas to be compatible with the deeply decarbonising global energy system posited in the Sustainable Development Scenario. It would therefore be necessary to implement even those measures that would not pay for themselves via the value of the methane that is captured and subsequently sold. Global oil and gas methane emissions in 2040 fall to less than 20 Mt (Figure 10.14).[25] Emissions from natural gas in 2040 are just over 10 Mt with the global average emission intensity falling to just over 0.4%.

Figure 10.14 ▷ Oil- and gas-related methane emissions in the Sustainable Development Scenario with and without abatement measures



Emissions fall to less than 20 Mt in 2040, 75% lower than they would have been without any mitigation efforts

25. The 2015 *WEO* special report on *Energy and Climate Change* included a "Bridge Scenario" that aimed to reduce total upstream oil and gas emissions in 2030 by 75% relative to an "Intended Nationally Determined Contributions scenario". This is similar to the relative level of reductions seen here but there are important differences in absolute terms. The baseline level of methane emissions is different, the New Policies Scenario in this *Outlook* assumes that positive net present value measures are implemented by 2030, and the Sustainable Development Scenario contains more ambitious emissions reductions.

10.4.2 Climate impacts of methane emissions abatement

Although many actions to reduce methane emissions should save money, the key reason for tackling these emissions is to avoid the release of a potent greenhouse gas. The most common approach for assessing the impact of emissions reductions on climate change is to convert the tonnes of methane emitted (or saved) into CO_2 equivalent levels using methane's GWP.[26] However, we consider it best to avoid using GWPs when considering the climate impacts of mitigating methane emissions because this conversion is easily misinterpreted or misused and because there is such a wide divergence between the different figures that result (Box 10.2). Our approach is to use the climate model MAGICC, widely used in studies assessed in the IPCC reports (IPCC, 2014), to estimate the impact of reducing methane emissions on the average global surface temperature rise in 2100. As explained in the *WEO-2016*, the global temperature rise is almost linearly proportional to cumulative emissions of CO_2, with the amount of CO_2 emitted over a given timeframe often referred to as the "CO_2 budget". However, methane emissions also have a major impact on the temperature rise: a specific CO_2 budget can only be associated with a temperature rise by making assumptions on non-CO_2 emission rates. Since methane has a much shorter life span than CO_2, its contribution to climate change is better examined in terms of emission flows rather than cumulative emissions. A permanent reduction in the rate at which methane is emitted would increase the remaining CO_2 budget for a specific temperature rise and vice versa.

10

MAGICC is used to estimate the impact of the methane emissions trajectories on the temperature rise in 2100 (Figure 10.13 and Figure 10.14). We focus on the temperature rise in 2100 partly because this reflects the public and academic discourse surrounding the interpretation of the long-term temperature goals in the Paris Agreement and partly because if global CO_2 emissions were to reach net-zero in the Sustainable Development Scenario in 2100 this is approximately the date when the global temperature rise would peak. If we were to examine a closer date, say 2050 rather than 2100, the temperature impacts of policies to reduce methane emissions would be larger.

To carry out this calculation, it is necessary to extend the projection for the "baseline" level of methane emissions in the New Policies and Sustainable Development Scenarios from 2040 to 2100. Therefore assumptions are made about the levels of fossil-fuel consumption consistent with the general ambition of the scenarios. For example, if CO_2 emissions in the Sustainable Development Scenario drop to zero by 2100, this would mean that fossil-fuel

26. For example, the methane emissions reduction policies in the Sustainable Development Scenario yield an annual reduction of around 55 Mt of methane in 2040. The 100-year GWP indicates that one tonne of methane is equivalent to around 30 tonnes of CO_2, and so this reduction would be equivalent to reducing annual CO_2 emissions by 1.7 Gt CO_2-eq. The 20-year GWP indicates that one tonne of methane is equivalent to around 85 tonnes CO_2, and so avoiding 60 Mt methane would be considered a saving of over 4.5 Gt CO_2-eq.

consumption would be much lower than at present.[27] For the methane trajectories with explicit mitigation policies, reductions relative to the baseline level are kept constant from 2040 onwards separately for oil and gas. We examine the different methane trajectories, keeping all other variables constant to isolate the impact of the methane abatement policies on the median temperature rise in 2100.[28]

In the New Policies Scenario, implementing the methane emissions reduction measures that have positive net present values by 2040 (and maintaining them thereafter) would reduce the temperature rise in 2100 by 0.07 °C compared with the trajectory that has no explicit reductions. While this may not sound like a large difference, in climate terms it is immense. To yield the same reduction in the temperature rise in 2100 by reducing CO_2 emissions would require emitting 160 billion fewer tonnes CO_2 over the remainder of the century. This is a huge level of reduction. It would be broadly equivalent to the CO_2 emissions saved by immediately shutting all existing coal-fired power plants in China; or every second car sold globally from today being electric (and running on zero-carbon electricity); or immediately refurbishing all homes in developed countries to a zero-carbon standard.

The methane emissions reductions in the Sustainable Development Scenario are more stringent than the New Policies Scenario; however the "baseline" level of emissions is also lower given the need to reduce the long-term level of CO_2 emissions. The methane emissions reduction policies in the Sustainable Development Scenario lower the 2100 temperature rise by around 0.06 °C. Failure to tackle methane emissions would therefore require reducing global CO_2 emissions by an additional 140 billion tonnes CO_2 – a significant difference, especially in the context of the decarbonisation efforts already necessary in the Sustainable Development Scenario. Indeed, despite the need to reduce CO_2 emissions in the Sustainable Development Scenario, and therefore reduce fossil-fuel consumption, it remains critical to advance methane emissions reductions policies as these will still have a major long-term impact on the temperature rise.

10.4.3 Summary of costs and benefits

We estimate that between 40% and 50% of global oil- and gas-related methane emissions today could be abated by deploying technologies and abatement measures that have positive net present values. This is because the value of the methane that is saved is greater than the capital and operating costs of the mitigation mechanisms. Measures to reduce fugitive emissions in the upstream sectors that can be avoided

27. It is important to recognise that even if there are no net CO_2 emissions in 2100, this does not necessarily mean that no fossil fuels will be consumed: fossil fuels are not combusted in some sectors (notably in petrochemicals); fossil-fuel combustion can be equipped with carbon capture and storage to mitigate CO_2 emissions; and the use of some "negative-emissions" technologies could offset some level of fossil-fuel combustion.

28. The level of CO_2 emissions and other non-CO_2 forcers differ between the New Policies Scenario and Sustainable Development Scenario. If different baseline methane emissions levels were to be examined, then the impact of methane abatement policies on the temperature rise would differ.

using LDAR programmes are some of the most cost-effective, given the concentration of potential emissions sources in a small area. With a number of promising detection and measurement technologies on the horizon, these costs could fall even further. Indeed as natural gas prices rise and the cost of technologies fall, the percentage of emissions that can be mitigated at zero or negative cost will rise over time. The results vary from scenario to scenario:

- In the New Policies Scenario, in the absence of any direct emission reduction efforts, global methane emissions from oil and gas operations would rise to over 105 Mt in 2040. Given announced methane emissions reduction policies and by using technologies that would pay for themselves through the capture and sale of the methane, this is reduced to 50 Mt in 2040. The benefits of doing so are enormous.
- In the Sustainable Development Scenario, methane emissions are projected to be lower because overall oil and gas consumption is lower. Again a large portion can be mitigated using measures that would pay for themselves through the methane that is recovered. But only implementing these technologies and measures will not be sufficient in this scenario: failure to go further would make the climate objectives of this scenario harder to achieve and impede the role that natural gas can play in the energy sector transition.

10.5 An agenda for action

The actions required to tackle the issue of methane emissions from oil and gas operations need ultimately to accomplish two goals: measure and abate. The majority of the oil and gas methane assessments undertaken to date that are in the public domain are based on estimates and indirect measurements, rather than direct measurements. Yet measurement is critical not just to advance scientific understanding of the problem but also to assess the efficacy of policy actions and to assure the public that the issue is being addressed. The same is true for methane emissions from coal.

Measurement needs to be distinguished from detection and monitoring. While it may be common for the industry to monitor methane emissions levels for safety reasons, it is much less common for emissions to be quantified in a rigorous way on a continuing basis. If leaks are detected, the focus is on finding and repairing the leak rather than assessing how much methane may have been emitted. There are large data gaps for multiple major gas producing and consuming regions, including Russia and the Middle East, that need to be addressed. Policies, and the regulations to support policy goals, therefore need to ensure that measurements are undertaken, that they are robust, and that they are reported publicly.

The technologies that can reduce methane emissions are well documented, well understood and, for the most part, widely available. Furthermore, a large portion of emissions can be abated using technologies and actions that would pay for themselves through the methane saved and sold (section 10.4). But implementing abatement is often the real challenge. This is especially the case when an operator does not have a good understanding of the baseline level of emissions or have a well-established strategy to deploy emission abatement actions. Encouraging and supporting operators to quantity emission levels, undertake an assessment of the costs of abatement, and to publish results would help to identify the most cost-effective mitigation measures available and to spread best practice approaches more widely.

Alongside voluntary efforts of the sort described in section 10.3, policy and regulation will be central to overcoming these issues. Measures are likely to be best carried out in a series of stages to help maximise effectiveness and efficiency. We do not seek here to provide a detailed roadmap but rather to provide a broad overview of the key considerations and principles that could inform strategies for methane emissions reduction.

Emphasise data gathering: a first step should be to improve data gathering and reporting. Uncertainty about current emissions levels is high, and reducing this through direct measurement is critical to improve understanding of the issue, to measure progress against goals, and to develop and refine objectives and targets. One option would be to include a regulatory obligation to detect, monitor and quantify methane emissions from a sufficiently large representative sample of operations. This would include a clear set of guidelines for what is expected in terms of measuring emissions such as a standardised performance benchmark for methane detection and quantification. It might also include a requirement to measure methane emissions before any site preparation or drilling takes place for new oil and gas developments: a baseline or background level of emissions could then be established to determine whether emissions levels are related to operations that subsequently take place there.

Set an overall goal: a lack of detailed measured emissions levels should not preclude the introduction of emission abatement goals. These can be expressed both in broad, qualitative terms and also as specific, quantitative and time-bound targets. In each case, there should be provisions to update or upgrade the goal to reflect the improvement in understanding as new data become available. An announced goal can also provide an important channel for public awareness and a yardstick against which emissions data and different abatement options can be measured.

Foster innovation: the need for technology innovation that delivers reliable measurement of emissions at low cost is a key technology gap and needs to be a focus both for public support and private initiatives. Supporting research, development and deployment of technologies for methane emissions detection and measurement will facilitate emissions reductions in the future.

Maximise transparency: measurement and analysis protocols (including existing datasets) could be shared among industry and regulators to facilitate consistent approaches to quantification and abatement and to help spur implementation. A harmonised measurement performance standard would help avoid dissimilar data being produced in different countries or regions and thus promote comparisons and underpin transparency. Transparency will be valuable not just for policy-makers and regulators, but also for companies, and it will help the industry as a whole to build public confidence in abatement efforts. Measurement data, whether from dedicated site-specific studies or routine LDAR campaigns, should be made available publicly. The voluntary programme FRACFOCUS, which provides a public depositary for disclosing chemicals used during the hydraulic fracturing process in the United States, provides a potential model here. This programme is designed to help allay public concern over potential water contamination during the production of unconventional oil and gas, and provides strong encouragement for operators to reduce chemical use. A similar public-record disclosure system could be developed for methane emissions to help build trust in emissions data from the industry and actions taken to reduce methane leaks.

Ensure widespread engagement during the design of regulations: it is essential to explain why regulation is required, and then consult on how it is going to be achieved, with the aim of securing support and buy-in from as broad a stakeholder group as possible. A notable and successful feature of the approach to formulating regulations in North America was the intensive and lengthy consultation period with industry, key suppliers, academia, local communities, and environmental and non-governmental organisations.

Incentivise collaboration: industry partnerships between international and national oil companies can provide a powerful impetus to the adoption of best practices in regions where the policy and regulatory framework is less developed. Ensuring collaboration between different regulatory bodies, including those in other countries, will help to ensure consistency and facilitate collaboration, as well as encouraging the widespread adoption of best practice for regulation.

Establish sufficient enforcement: a critically important element of any regulatory approach is enforcement. Among other things, effective enforcement means deciding how oversight and regulation should be carried out, establishing which institution is to be charged with regulation or enforcement, providing leadership and resources for that institution, and working out the penalties for non-compliance.

Incorporate flexibility into measurement and abatement policies: this might take various forms, including allowing for adjustments to overall goals over time if interim milestones are exceeded or not met. The key to demonstrating progress to a given goal is the consistent measurement, reporting and verification that abatement has occurred. This can be supported by independent and transparent evaluation of policies, outcomes and the cost-effectiveness of abatement.

Focus on outcomes: in deciding the specific practices, standards, technologies, certification systems or quantitative limits to be introduced, it is important to bear in mind the overarching goal for emissions reduction, and to focus on the outcomes to be achieved. This would allow companies to choose whichever option has the lowest cost or to invest where it will be most efficient. One particular area to focus on is the timely detection and elimination of super-emitting sources. In some cases it may also be better to incentivise action by industry rather than penalise failure to comply.

Encourage new corporate thinking on methane emissions reduction: while some companies view the minimisation of methane emissions as a central pillar of their operations, others appear to attach much less importance to it. Dialogue, policies and regulatory frameworks may be able to help to change views and help to mobilise the financing necessary to achieve emissions reductions. The evolution of approaches to safety could provide a good model for the approach to methane emissions. Safety regulation was seen decades ago by some in the industry as making operations more difficult and simply adding to costs, but is today almost universally recognised as a way to ensure that the highest practicable standards are observed across the industry in day-to-day operations.

Despite many improvements in recent years, there are still a large number of questions that remain open in any assessment of methane emissions from oil and gas operations. These include the contribution of the oil and gas industry to total anthropogenic methane emissions, the efficacy and transparency of current practices for measuring and reporting methane emissions, the cost-effectiveness of abatement opportunities, and the balance between regulatory and voluntary approaches to mitigation. Yet, enough is known already to state unequivocally that reducing methane emissions from oil and gas operations is an essential component of action to address climate change. A lot is already being done, but our analysis also suggests that additional measures can be undertaken, often in ways that make rather than cost money. The case for further action is compelling. Failure to act would represent a clear risk to the environmental credentials of natural gas.

Natural gas in a changing energy world

Is gas part of the solution?

Highlights

- Natural gas demand grows in the New Policies Scenario, supporting a number of environmental goals, especially in the fast-growing conurbations of Asia. Strong growth in industrial gas consumption helps tackle local air pollution, while the ability of gas-fired power plants to operate flexibly makes them a valuable complement to the rising deployment of wind and solar PV generation.
- Increased gas use, by itself, is far from sufficient to meet global climate objectives. Yet gas demand rises in the Sustainable Development Scenario, accompanying the very rapid expansion of low-carbon technologies and improvements in efficiency. Annual gas use increases by some 20% between 2016 and 2030, reaching nearly 4 300 bcm, and remains broadly at this level until 2040. As the demand for other more emissions-intensive fossil fuels falls, gas overtakes coal in the mid-2020s and oil in the mid-2030s to become the largest single fuel in the global energy mix.
- The opportunities for gas in the Sustainable Development Scenario vary by sector and region. In the power sector, where there is scope to displace coal, as in many developing Asian economies, baseload gas generation continues to grow. Yet the main role for gas-fired power is to provide flexibility to help integrate high levels of variable renewables, reinforcing links between gas and electricity security. Industry accounts for the largest share of gas demand growth, as there are fewer low-carbon options for the provision of high-temperature heat. In transport, natural gas helps reduce CO_2 and air pollutant emissions in sectors where electrification is a less viable option, most notably in road freight and international shipping.
- The main growth markets for natural gas in the Sustainable Development Scenario are China and India, where projected gas demand is even larger than in the New Policies Scenario. Meeting demand from these markets underpins continued growth in global gas trade, most notably for LNG.
- Around $320 billion in annual investment across the natural gas value chain is required to 2040 in the Sustainable Development Scenario. Maintaining gas infrastructure remains important as natural gas provides a critical source of heat in many countries and a safety net for reliable power supply.
- The long-term role of gas will be shaped not only by the pace of the transition to a low-carbon future, but also by the success of efforts to minimise the environmental footprint of gas use. This includes progress on methane emissions reductions, carbon capture and storage and the exploration of alternative uses for gas infrastructure to convey renewables-based gases such as biogas or hydrogen.

11.1 Introduction

Reconciling rising demand for energy services with the imperative to limit harmful energy-related emissions creates potential opportunities for natural gas – especially if the issue of methane leakage is effectively addressed (see Chapter 10). By displacing more polluting fuels, gas has played a role in shaping the trajectory for lower energy-related CO_2 emissions and pollutant emissions that cause poor air quality. Today's energy world, in which coal and oil still account for 60% of primary energy consumption, continues to offer opportunities for natural gas to curb emissions in the years ahead. Although the share of natural gas in the global energy mix continues to rise in both the New Policies and Sustainable Development scenarios, the story behind the numbers is not a simple one. Countries have different starting points, domestic resources and development pathways. The scope for natural gas to substitute for more polluting fuels is shaped by the extent to which renewable energy sources and other low-carbon options are deployed, which depends in turn on the speed of the transition and the strength of targets to reduce emissions. Consequently, the role that gas plays in achieving environmental goals varies widely by scenario, across regions, across sectors, plus it evolves over time.

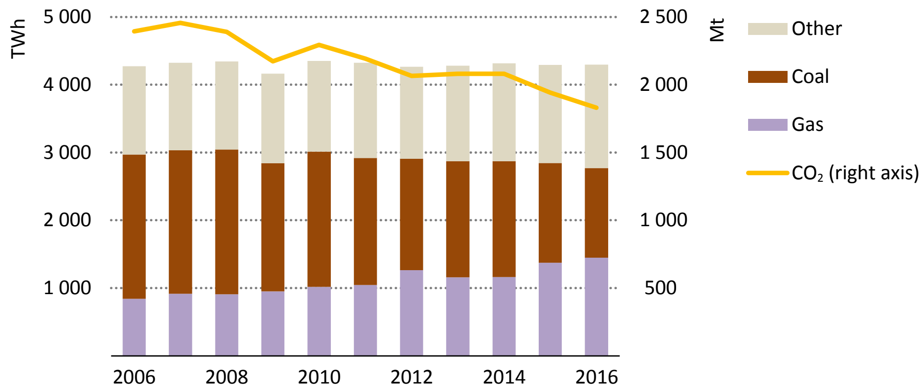
This chapter explores in detail the role of gas in a changing energy system. It uses the most recent data and our scenario projections to illustrate the areas where gas could take centre stage, where it is more likely to play a supporting role, and where it might have only a walk-on part. Although the main focus is on the role of natural gas in a decarbonising energy sector, the chapter concludes with a review of the possibilities for decarbonising the gas supply itself, whether via carbon capture and storage (CCS) or increased use of renewable gas, such as biogas or hydrogen.

11.2 Historical perspectives on coal-to-gas switching

Since the combustion of natural gas results in lower carbon-dioxide (CO_2) emissions per unit of output than is the case with coal, replacing coal with gas leads to a reduction in overall CO_2 emissions. Coal-to-gas-switching has been observed in a number of countries, with the United States offering a recent pertinent example. When domestic production from shale began to take off from around 2006, US natural gas prices fell dramatically, which encouraged the use of more gas and less coal. Nearly all of this coal-to-gas switching occurred in the power sector. In 2006, coal provided 50% of total electricity generation in the United States, while gas accounted for less than 20%. As of 2016, the share of coal was just over 30%, with natural gas overtaking coal and rising to nearly 35%. This was a major reason, alongside the expansion of generation from renewables, why US power sector CO_2 emissions dropped by nearly 25% over this period despite there being no major change in overall electricity demand (Figure 11.1). Total energy sector CO_2 emissions in the United States fell by around 15% between 2006 and 2016 – a key contributor to the flattening in global CO_2 emissions in recent years.

The availability of cheap gas was the key catalyst for the contrasting fortunes of coal and gas in the United States, but there were two other critical ingredients. The first was an availability of significant spare gas-fired power generation capacity. The second was the established liberalised electricity market: this allowed lower gas prices to feed through smoothly into changes in the power mix. These two factors were also critical for the most recent surge in coal-to-gas switching in the power sector of the United Kingdom in 2016 (Box 11.1). In the UK case, however, an additional catalyst was a relatively robust price for CO_2, which gave UK coal-to-gas switching a notable extra impetus compared with other parts of Europe where the CO_2 price was lower.

Figure 11.1 ▷ US electricity generation by fuel and related CO_2 emissions



US power sector CO_2 emissions fell by nearly 25% between 2006 and 2016, largely as a result of coal-to-gas switching

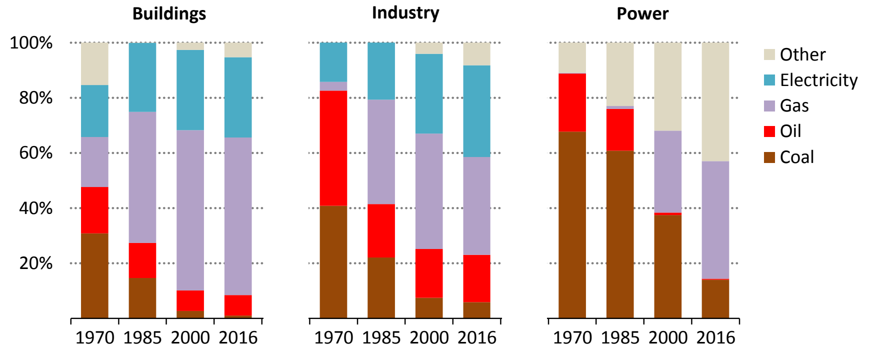
Note: TWh = terawatt-hours; Mt = million tonnes.

The conditions that led to coal-to-gas switching in the United States and the United Kingdom have some atypical features compared with the situation in many other parts of the world. No country has yet replicated at scale the US experience with shale gas. Most developing economies with large coal-fired power fleets do not have liberalised markets that would allow a quick response (in terms of generation mix) to economic conditions favouring the use of gas, nor (with the notable exception of China) is a CO_2 price on the horizon. Switching is therefore more likely to occur because of an explicit decision to favour the use of gas and to invest in new gas infrastructure (as seen, for example by the coal-to-gas switching that occurred in the United Kingdom between 1970 and 2000). Furthermore, while the impact of coal-to-gas switching on reducing CO_2 emissions within the United States and United Kingdom is unambiguous, such clear-cut examples are relatively rare. In regions with rising energy demand, if a new gas-fired power plant is built rather than a new coal plant then this may increase absolute emissions levels but reduce emissions relative to what they would have been otherwise. This is of particular importance in considering the emissions impact of constructing new gas infrastructure in developing economies and highlights the importance of comparing the role of natural gas across different scenarios and of considering linkages across the energy system as a whole. For example, if the coal displaced by gas stays in the ground, the impact of coal-to-gas switching on overall emissions levels is quite different from a case in which the coal is consumed in other parts of the economy or in other countries.

Box 11.1 ▷ Historical coal-to-gas switching in the United Kingdom

In April 2017, the United Kingdom enjoyed its first day without coal power since the Industrial Revolution. While this does not herald the final demise of coal in the United Kingdom, it underscores a trend that has been underway for many years. In 1970, coal comprised over 40% of total UK primary energy supply while natural gas accounted for less than 10%. By 2000, these shares had reversed: coal's share in the energy mix dropped to around 15% while that of natural gas rose to nearly 40%. Various phases can be identified across the end-use and transformation sectors that explain the dynamics of this transition (Figure 11.2).

Figure 11.2 ▷ Historical fuel consumption shares by sector in the United Kingdom



Rapid coal-to-gas switching in the United Kingdom occurred in the buildings and industrial sectors in the 1970s and in the power sector in the 1990s.

Note: Other includes town gas (in 1970 only), heat, renewables and nuclear.

Between 1970 and 1985, natural gas replaced coal to meet the majority of energy demand in the buildings and industry sectors. Coal consumption in both sectors fell by over 60% while natural gas soared. The contrasting fortunes for the two fuels mirrored changes in production and prices during this period: natural gas production from the North Sea more than doubled while there was a sharp fall in coal production. Retail natural gas prices dropped by over 30% in real terms between 1970 and 1980 while coal prices increased by more than 25%. This provided the impetus for both residential and industrial consumers to switch from the use of coal to gas. The transition was helped by the fact that the United Kingdom already had a network of pipes running into households which had been built for town gas,[1] around 10 million tonnes of oil equivalent (Mtoe) of which was consumed in 1970. While new high-pressure transmission and distribution pipelines needed to be constructed to transport the natural gas, it proved possible to use the low-pressure town gas pipes for natural gas.

A different picture emerges in the power sector. Gas use was only permitted from the early 1990s and the ability to use natural gas in a privatised and liberalised market, for which efficient, low-cost combined-cycle gas turbines (CCGTs) were readily obtainable, resulted in a "dash-for-gas". Around 20 gigawatts (GW) of new gas capacity was built during the 1990s, which was accompanied by a 40% drop in coal use in the power sector. Significant change in the power sector has recently reappeared on the scene: there was a dramatic 60% drop in power sector coal consumption in 2016, spurred by a fall in gas prices compared to coal, as well as by strong policy signals, including a carbon-floor price (effectively a CO_2 tax) and a commitment to the phase-out of all coal power plants by 2025. Efficiency measures and an increase in generation from renewables offset a large portion of this drop in coal use, but gas consumption in the power sector still rose by 40% in 2016.

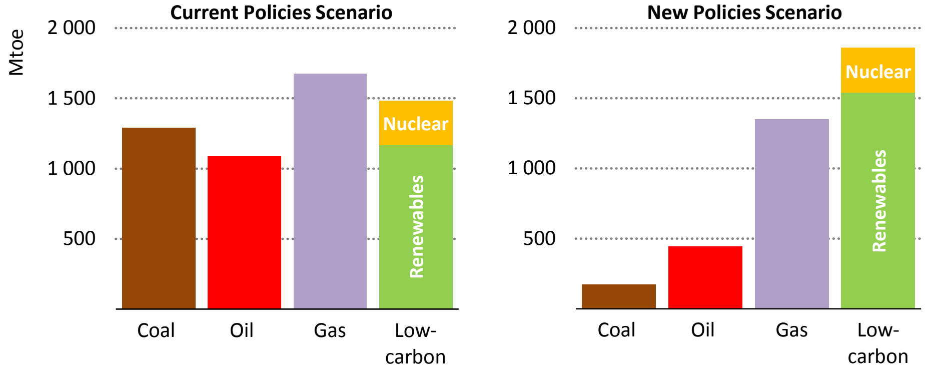
A sizeable reduction in CO_2 emissions in the United Kingdom has accompanied this coal-to-gas switching. In the power sector, for example, CO_2 emissions dropped by nearly 20% during the 1990s even though electricity generation grew by over 10%. Coal remains part of the energy mix in the United Kingdom (around 6% of primary energy supply in 2016), but the potential scope for future coal-to-gas switching is now much more limited than in the past: a situation mirrored in many other advanced economies.

11.3 Natural gas use in the New Policies Scenario

Natural gas makes a major contribution to meeting energy demand growth in the New Policies Scenario, with global demand rising by 45% between 2016 and 2040. This is distinctly higher than the pace of growth in coal demand, which rises by 5% between 2016 and 2040, and also of oil, which rises by 10%, making gas the only fossil fuel to exhibit significant growth in the New Policies Scenario (in contrast to the Current Policies Scenario) (Figure 11.3). Energy-related CO_2 emissions grow by around 150 million tonnes (Mt) each year on average in the New Policies Scenario (reaching 36 gigatonnes [Gt] in 2040), a marked slowdown in the annual average growth rate observed between 1990 and 2016 of around 450 Mt each year.

1. Town gas, manufactured from coal, is a mixture of hydrogen, carbon monoxide, methane and other gases.

Figure 11.3 ▷ Change in global primary energy demand by scenario, 2016-40



All fossil fuels grow in the Current Policies Scenario, while gas is the only fossil fuel to show significant growth in the New Policies Scenario

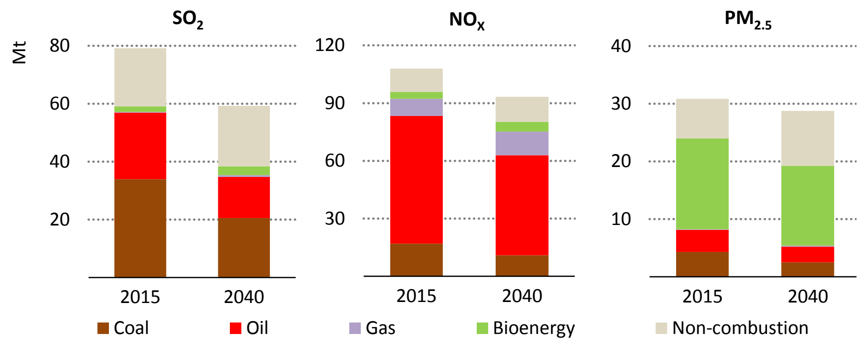
Note: Renewables are converted to primary energy equivalent using the physical energy content method, see *www.iea.org/statistics/resources/questionnaires/faq/*.

Measuring the environmental impact of natural gas consumption in the New Policies Scenario requires the examination of changes that occur at sectoral and regional levels. With a few notable exceptions (including China), gas consumption is usually not an explicit focus of sustainability policies at national level. Cost reductions for renewable technologies are opening cost-effective and direct routes to a low-emissions future, and renewables together with energy efficiency are usually the instruments of choice for policy-makers seeking to achieve environmental goals. In terms of existing emissions reduction targets, fewer than 30 of the 162 pledges made as part of the Paris Agreement explicitly mention that natural gas will be used to help achieve their goals. Growth in renewables and deployment of efficiency measures naturally leave less room for other fuels to satisfy energy demand, including natural gas. Nonetheless, the increase in natural gas plays a critical role in the New Policies Scenario in limiting the growth of coal demand, facilitating the integration of variable renewables, and reducing many local air pollutants, while ensuring that energy demand is satisfied (Box 11.2).

Box 11.2 ▷ The role of natural gas in improving air quality

The combustion of natural gas produces virtually no sulfur dioxide (SO_2) emissions and negligible levels of fine particulate matter ($PM_{2.5}$), although it does result in significant levels of nitrogen oxides (NO_X); around 10% of global NO_X emissions in 2015 came from the use of gas. Emissions of all three of these air pollutants fall in the New Policies Scenario to 2040 (Figure 11.4) and increased gas use makes a significant contribution towards a reduction in SO_2 and $PM_{2.5}$ emissions. In China, for example, the near-tripling of natural gas consumption between 2016 and 2040 helps to displace large quantities of coal, providing around 15% and 5% of the overall reduction in SO_2 and $PM_{2.5}$ emissions (respectively) in China over this period. The impact is most pronounced at the local level, where gas provides part of the solution to the debilitating air pollution problems found in many large cities. In China, gas is favoured as a way to displace coal use in small- and medium-size urban industrial facilities. Gas-fired power plants could also make a difference in other countries if the policy and regulatory environments provide the right incentives.

Figure 11.4 ▷ Global air pollutant emissions in the New Policies Scenario



Global SO_2 emissions fall by 25%, NO_X emissions by 15% and $PM_{2.5}$ emissions by just over 5% between 2015 and 2040

Note: Non-combustion emissions are process emissions in industry and non-exhaust emissions in transport.

Sources: IEA; International Institute for Applied Systems Analysis.

Outside urban areas, the largest source of $PM_{2.5}$ is the use of biomass in inefficient cookstoves in developing economies, which is most prevalent in rural locations that do not have existing gas infrastructure. Developing new networks is expensive even in areas with high population density, so the potential for pipeline gas to provide a cleaner alternative looks very limited. Natural gas can, though, play an indirect role as the extension of urban gas distribution networks can free up liquefied petroleum gas (LPG), which can then be supplied to rural consumers.

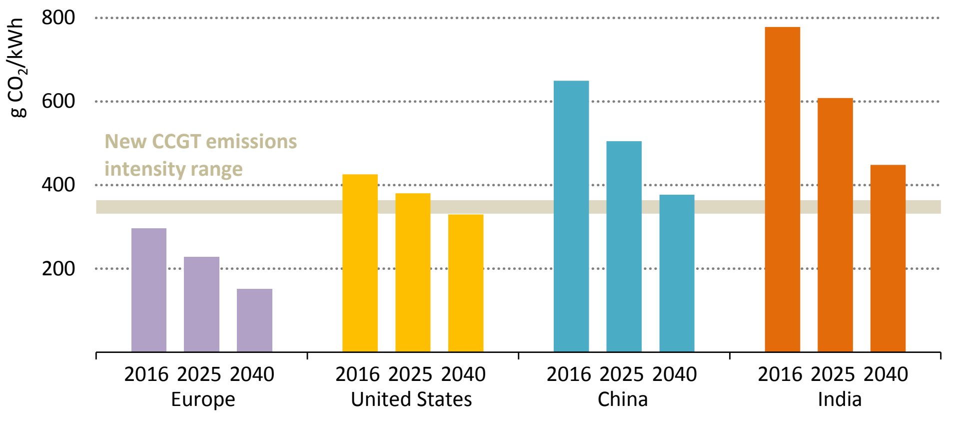
As global gas consumption rises in the New Policies Scenario, so do emissions of NO_X from its combustion and by 2040 gas is the source of around 15% of total NO_X emissions. While this is still much less than oil, the introduction of pollution control devices could reduce emissions of NO_X from natural gas further, particularly post-combustion control technologies in the power and industry sectors. However, these would require additional policy support or regulation beyond the measures that have been implemented or announced by governments.

11.3.1 Analysis by sector and region

Power sector

The power sector has been the arena for much of the recent coal-to-gas switching, but it is also the sector where renewable energy options are at their most competitive, with the prospect in many markets that the levelised costs of certain renewable technologies will fall below the level of thermal generation (see Chapter 6). Overall, low-carbon options account for two-thirds of new capacity installed in the New Policies Scenario, but investment in gas is nonetheless robust, including as an option to reduce emissions. The emissions intensity of a new CCGT is around 350 grammes of carbon-dioxide per kilowatt-hour (g CO_2/kWh). This is above the average emissions intensity in Europe (although there is a wide variation among European countries), but it lies below the average level in many other parts of the world (Figure 11.5). In these regions, this means that the addition of new CCGT plant improves the emissions performance of the power sector. In China and India, for example, around 150 GW and 90 GW of new gas-fired capacity (the majority of which are CCGTs) are projected to be installed between 2017 and 2040. These additions not only ensure these countries can meet rising electricity demand, but play a role in displacing coal power plants that might have been built otherwise and so lower the average emissions intensity of electricity generation.

Figure 11.5 ▷ Average CO_2 emissions intensity of electricity generation in selected regions in the New Policies Scenario



In key developing economies, the average emissions intensity of power generation remains above emissions from a new CCGT plant through to 2040

Similarly, in the United States, 260 GW of new gas-fired capacity is constructed between 2017 and 2040, while almost no new coal power plants are built, which helps to reduce the emissions intensity of US electricity (alongside increases in renewables capacity). In Europe, 170 GW of coal capacity reaches the end of its life over the period to 2040. Gas-fired electricity generation in Europe overtakes coal in the early 2020s and soon becomes the leading source of electricity generation (surpassing nuclear), until the late 2030s when it is overtaken by wind. The average emissions intensity of electricity falls to around 230 g CO_2/kWh in 2025 and just over 150 g CO_2/kWh in 2040.

In many markets, the space to expand gas-fired capacity further is constrained by the rapid deployment of renewables. Yet gas-fired capacity also plays an important additional role in helping to integrate variable renewables into power systems. Gas-fired power plants are relatively cheap to build (compared with other dispatchable forms of generation) and technically able to ramp up quickly when needed. This means that they are well suited to provide support if there are periods of low generation from variable sources. This applies for short-term fluctuations in electricity generation, and even more so for large seasonal variations in supply and demand. In Europe, for example, there is limited solar potential during the winter months, but significant demand for winter heating based on electricity, and gas-fired generation can step in to fill the gap. When playing this supporting role, the level of electricity generated (and volumes of gas consumed) may be relatively low, but having infrastructure capable of producing electricity when it is required is critical to ensure the stability of power supply.

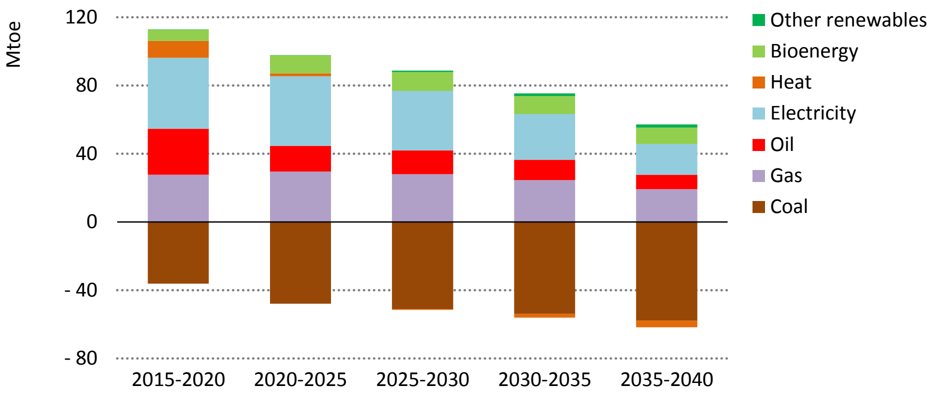
Industry sector

Industry is the sector that sees the largest increase in gas use in the New Policies Scenario: consumption grows by over 550 billion cubic metres (bcm) between 2016 and 2040, around one-third of the increase in global gas demand. Most of this growth stems from increases in the Asia Pacific region and China in particular, where gas consumption by industry increases by over 150 bcm. While gas is not the only fuel to grow in the Chinese industrial sector – the use of electricity expands and there are increases in oil consumption (as a petrochemical feedstock) and renewables – the increases in gas largely mirror the declines in coal consumption (Figure 11.6). This reflects broader changes in the structure of industrial output from heavier to lighter branches, but it is also the product of a straight substitution in many urban areas where coal-fired boilers are systematically replaced, largely with gas-fired alternatives, as part of the drive to tackle poor air quality. The increase in gas use in China is central to the 20% reduction in CO_2 emissions and a 40% reduction in SO_2 and $PM_{2.5}$ emissions from China's industrial sector that occurs between 2016 and 2040. A similar pattern of falling coal consumption and rising gas consumption is also observed in the industrial sectors of many advanced economies.

Transport sector

Gas demand in transport rises by over 200 bcm between 2016 and 2040 in the New Policies Scenario, two-thirds of which stems from increases in road transport (Figure 11.7). China, the United States and India are the main sources of this growth, where gas is used both in freight and passenger vehicles (the latter notably in India), helping to reduce $PM_{2.5}$ emissions in built-up areas. In the maritime sector, a switch away from heavy-fuel oil to natural gas occurs primarily to reduce local air pollution, most notably sulfur emissions. In October 2016, the International Maritime Organization announced plans to introduce a 0.5% cap on the sulfur content of marine fuels to be implemented from 2020 onwards (the sulfur

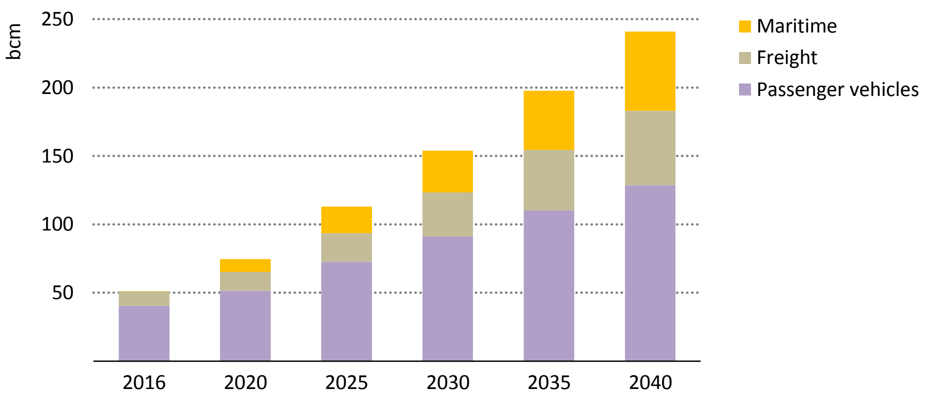
Figure 11.6 ▷ Change in industrial energy consumption in China by type in the New Policies Scenario



The growth in industrial gas consumption in China largely mirrors the decline in coal use, providing important reductions in CO_2 and air pollutant emissions

content of heavy-fuel oil is often as high as 3.5%). In the New Policies Scenario, this is met by a combination of switching from heavy-fuel oil to low-sulfur fuels (diesel or low-sulfur heavy fuel oil), the installation of scrubbers and, in the longer term, an increase in the use of liquefied natural gas (LNG) as a bunker fuel: gas use as a bunker fuel increases to 50 bcm in 2040.

Figure 11.7 ▷ Global gas consumption in road and maritime transport in the New Policies Scenario



The growth in gas consumption in road transport helps avoid $PM_{2.5}$ emissions in built-up urban areas and helps the maritime sector meet new SO_2 emissions standards

Buildings sector[2]

Natural gas use in buildings grows by around 280 bcm between 2016 and 2040 in the New Policies Scenario. Nearly all of this increase occurs in developing economies, with consumption in advanced economies broadly constant to 2040. The main expansion takes place in China, one of the few countries where a significant winter residential heating requirement is not already covered by an extensive gas distribution network. The increase in gas use in buildings in China brings numerous air quality benefits when it replaces coal and biomass (which are gradually pushed out of the system). As described in Box 11.2, increased urban residential gas use in other developing countries can also bring indirect benefits for rural areas: LPG is currently used in many urban areas for cooking and, if this is displaced by natural gas, it becomes available to be used in modern cookstoves in rural locations, where it displaces biomass. This is a major policy consideration behind the expansion of urban gas distribution networks in India. Gas use for space and water heating, and cooking in advanced economies is already widespread, and the implementation of efficiency measures avoids the need for any substantive rise in gas consumption: growth in energy demand that does occur in the buildings sector is typically met by electricity.

11.3.2 Limits to the environmental contribution of gas

A range of considerations affects the contribution of natural gas to environmental and sustainability gains in the New Policies Scenario. Given that global coal use in this scenario remains around current levels in 2040 (55% of which is steam coal for power generation), it is evident that – even with a 45% increase in global gas consumption – the scope for gas to substitute for coal is far from exhausted. There are, however, practical, commercial and policy-related reasons why coal-to-gas switching does not proceed more quickly. As discussed in Chapter 8, coal is often cheaper than gas, especially in many Asian economies where gas is imported and coal is produced domestically. There are also infrastructure constraints, which limit countries' ability to import and transport gas, while CO_2 pricing, which can tip the commercial calculation in favour of gas, but which can also further accelerate the deployment of renewables, is not widespread (Box 11.3). In some countries with large coal reserves, moreover, the emerging policy preference appears to be based on achieving emissions reductions through a combination of renewables and high-efficiency coal, rather than renewables and gas.

The clearest limitation on this role is that increased gas use, in itself, is far from sufficient to achieve international climate objectives or to provide for dramatic reductions in all air pollutants. This has long been recognised in *World Energy Outlook (WEO)* analysis; it was a central conclusion of our special report in 2011 when we asked the question "Are We Entering a Golden Age of Gas?" (IEA, 2011), "An increased share of gas in the global energy mix is far from enough on its own to put us on a carbon emissions path consistent with an average global temperature rise of no more than 2 degrees Celsius". The next step is

2. The buildings sector includes energy used in residential, commercial and institutional buildings.

therefore to examine how natural gas fares in the Sustainable Development Scenario, which explicitly targets action to tackle climate change as well as to minimise energy-related air pollution (see Chapter 3).

Box 11.3 ▷ Is CO_2 pricing the answer for gas?

Energy policies have a marked effect on the relative prices of using different fuels and one particular area of interest for gas markets is the scope and level of CO_2 pricing. If CO_2 prices are low, the use of coal may be more economic than natural gas. If prices are high this could tip the balance in favour of low- or zero-carbon sources (including efficiency measures). The impact of CO_2 prices on gas consumption will also depend on the inertia within different parts of the energy system, and so they can be expected to have a different impact over the short term and over the long term.

To illustrate, we look at the impact of CO_2 prices on power markets in the European Union and China in the New Policies Scenario. We split this into competition for fuel switching within existing infrastructure and competition between fuels for investment into new infrastructure, using the relevant prices and costs from this scenario.

For fuel switching within existing infrastructure, competition between existing fossil-fuelled power plants in countries in the European Union is fierce, as electricity demand growth is sluggish and the share of low-carbon sources is rising. A CO_2 price in the range of $50-80 per tonne of CO_2 (tCO_2) by 2025 would expand the market opportunities for existing gas-fired power plants. In China, the rapid build-up of coal-fired capacity since 2000 has exceeded the pace needed to satisfy demand. For gas-fired power plants to displace generation from this large fleet of new and efficient coal plants would require a CO_2 price in the range of $90-170/$tCO_2$ by 2025, with this range rising slightly in real terms thereafter.

For new generation capacity, a CO_2 price above $25/$tCO_2$ in 2025 would favour investment in new gas-fired capacity in Europe in place of new coal-fired capacity. However, if the price were to reach $30-40/$tCO_2$ the economics would start to favour onshore wind instead of gas and at $60-120/$tCO_2$ would favour solar PV instead of gas. This upper bound falls over time as the costs of wind and solar PV continue to decline while natural gas prices increase: shortly after 2030 there would be no CO_2 price range at all that would favour gas (based on generation costs alone). In China, there is an even more limited window of opportunity for CO_2 prices to favour gas over renewables. By 2020, the costs of wind and solar PV are projected to fall to near parity with new gas-fired capacity, meaning that any CO_2 price would shift investment towards renewables. Gas-fired capacity offers services beyond electricity generation, notably flexibility, and if these services are valued and compensated, they will also have an impact on investment decisions. These additional revenue streams become increasingly important to support continued investment in inflexible technologies, especially where variable renewables become the lowest cost source of generation.

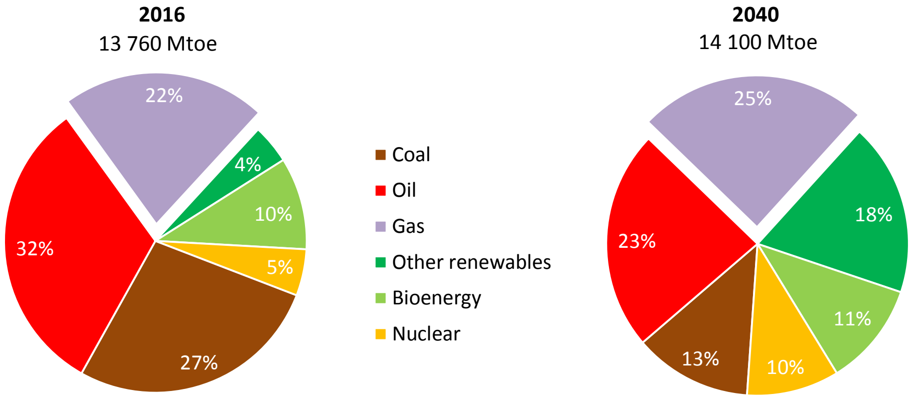
This demonstrates that it is impossible to indicate a single range of CO_2 prices that will encourage gas consumption. The range will vary across regions, sectors and over time and indeed in some cases a window of opportunity may not exist at all. The primary purpose of CO_2 prices is to reduce CO_2 emissions, not to support gas, and so it is not wholly surprising that the introduction of CO_2 prices will not automatically or unambiguously benefit natural gas.

11.4 Natural gas in the Sustainable Development Scenario

Since the combustion of natural gas results in CO_2 and NO_X emissions, the opportunities for gas are naturally more constrained in the Sustainable Development Scenario than in the New Policies Scenario. Nonetheless, the characteristics of natural gas relative to other fossil fuels continue to make it an important part of many decarbonisation strategies, especially in countries where today's carbon intensity is high and in those sectors and applications where lower carbon alternatives are unavailable at scale or are less cost effective.

Overall, gas demand worldwide grows to nearly 4 300 bcm in 2030 in the Sustainable Development Scenario – some 20% higher than today's levels – before plateauing around this level. This contrasts sharply with the picture for coal and oil, which drop globally by over 50% and 25% respectively between 2016 and 2040. Gas overtakes coal in the mid-2020s and oil in the mid-2030s to become the largest single fuel in the global energy mix (Figure 11.8).

Figure 11.8 ▷ Global primary energy demand in the Sustainable Development Scenario



Although falling behind the combined share of renewables, gas becomes the largest single fuel in 2040

As described in more detail in Chapter 3, energy sector CO_2 emissions in the Sustainable Development Scenario fall to around 18.5 Gt in 2040, roughly half the level of the New Policies Scenario. In the 2030s, the annual decline in emissions exceeds 3%, dropping in absolute terms by over 650 Mt every year, with the largest contributions by far to these reductions coming from energy efficiency and the use of renewables in power generation, heat and transport (biofuels). CCS accounts for just under 10% of the emissions reductions in 2040, around a third of which stems from the use of gas with CCS in the power and industrial sectors. By 2040 there are 165 GW gas-fired CCS electricity plants worldwide, and around 10% of gas consumed in industry is in installations fitted with CCS. The contribution of fuel switching, largely in the form of coal-to-gas but also oil-to-gas in some transport sectors, is smaller, accounting for less than 5% of the emissions reductions in 2040.

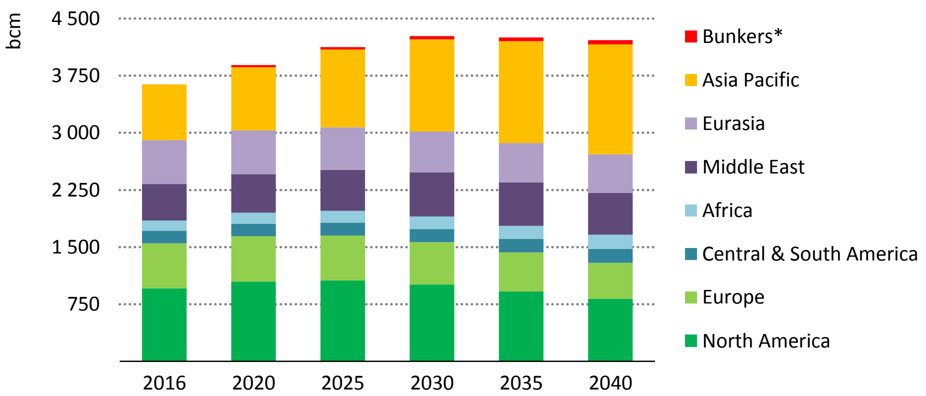
As well as limiting CO_2 emissions, the Sustainable Development Scenario aims to achieve universal energy access to modern energy by 2030 and to reduce dramatically local pollutants that cause poor air quality. Achieving universal access to modern energy by 2030 means that 1.3 billion people gain access to electricity by 2030 and 3.2 billion people gain access to clean cooking by 2030. There are also dramatic reductions in local pollutants: $PM_{2.5}$ and SO_2 emissions both fall by around 80% from today's levels by 2040, while NO_X emissions drop by 60%.

11.4.1 Analysis by sector and region

The Asia Pacific region leads the way in terms of increases in natural gas demand in the Sustainable Development Scenario (Figure 11.9). Between 2016 and 2040, demand nearly doubles, most notably in China and India, and by 2040 one-third of global gas demand is in the Asia Pacific region (compared with 20% today). In China and India, gas consumption is consistently higher throughout the Sustainable Development Scenario than in the New Policies Scenario. Gas demand in Africa and Central and South America also grows throughout the Sustainable Development Scenario, but to a much smaller extent (an increase of 70 bcm between 2016 and 2040 compared with over 700 bcm in the Asia Pacific region). In North America, gas consumption increases until the 2020s; growth then levels off and demand begins to drop from 2025 onwards. Meanwhile gas consumption in Eurasia falls steadily over the period to 2040. The slowdown in global gas demand growth, and the slight decline in total demand after 2030, reflects declines in mature gas markets outweighing the continued growth in the Asia Pacific region.

Coal's share of total primary energy demand (TPED) decreases over time in all major regions in the Sustainable Development Scenario, but there are differing patterns in the evolution of natural gas (Figure 11.10). In China and India, where coal currently dominates the energy mix and gas has a relatively small share, there are steady increases in the share of natural gas. In contrast, in Eurasia, where gas today accounts for over 50% of total demand and coal comprises a far lower percentage, the share of gas falls noticeably. The Middle East has a similar level of gas in its energy system to Eurasia but almost no coal consumption; it therefore sees a minor increase in the share of gas to 2025, but thereafter a large

Figure 11.9 ▷ Gas demand by region in the Sustainable Development Scenario

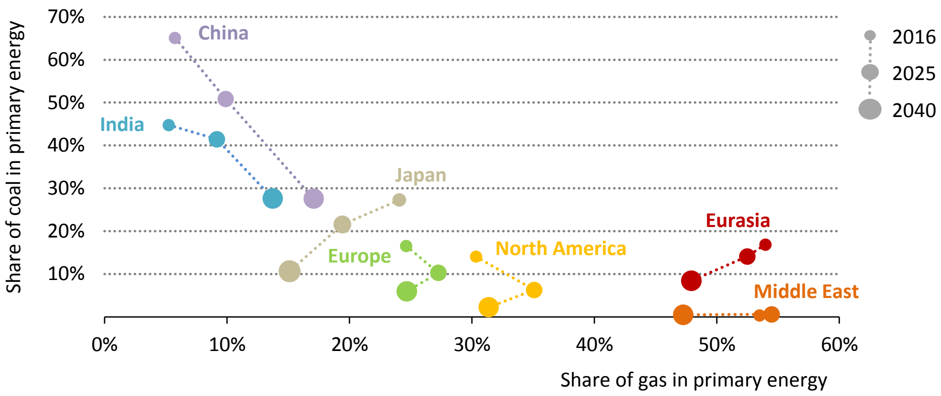


Gas demand in the Asia Pacific region grows, while demand in more mature gas markets starts to decline

* LNG used as an international marine fuel.

decrease as gas starts to become too emissions-intensive to be consistent with the emissions reductions required. In North America and Europe, where the current share of natural gas is around 25-30%, the share of gas grows markedly to 2025, to replace coal. After 2025, as renewables continue to grow apace, both coal and gas decline.

Figure 11.10 ▷ Share of coal and gas in energy demand in selected regions in the Sustainable Development Scenario



While the share of coal in total primary energy demand falls in all key regions over time, changes to the share of gas vary markedly between regions

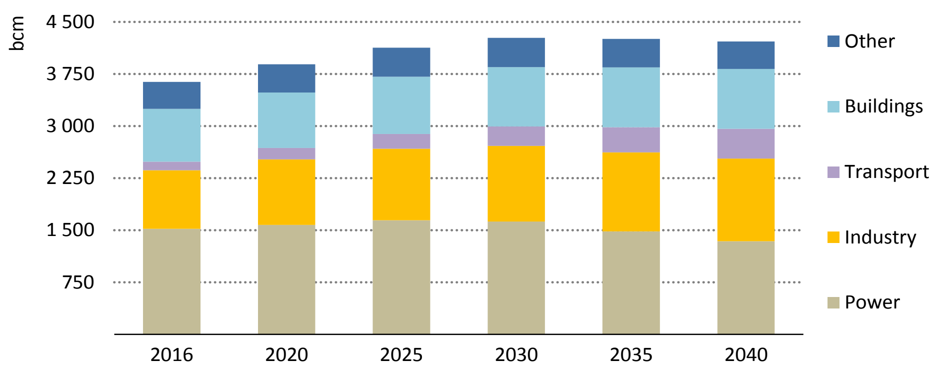
Considering these trends, regions can be broadly separated into three groups (Table 11.1). First, there are regions such as Japan and Russia, in which gas consumption falls throughout the Sustainable Development Scenario, suggesting that gas has relatively limited additional potential to help in the energy sector transition. Second, there are regions such as North America and Europe where gas consumption increases for a certain period before declining in later years, suggesting that gas has the potential to make a larger contribution to the transition than it is doing currently, but only for a limited period. Third, there are developing gas markets where consumption rises over an extended period to 2040 and gas makes a sustained contribution towards decarbonisation.

Table 11.1 ▷ Gas demand by region in the Sustainable Development Scenario relative to the New Policies Scenario

		Sustainable Development Scenario demand (bcm)				Difference with New Policies Scenario			
	2016	2025	2030	2035	2040	2025	2030	2035	2040
North America	961	1 061	1 009	916	822	1%	-6%	-17%	-28%
United States	779	871	827	740	651	4%	-2%	-15%	-26%
Central & South America	166	166	172	175	182	-9%	-16%	-26%	-33%
Brazil	36	33	35	40	45	-13%	-19%	-27%	-30%
Europe	590	593	556	516	471	-2%	-10%	-19%	-25%
European Union	463	459	420	385	342	-1%	-10%	-18%	-25%
Africa	134	157	165	173	188	-11%	-22%	-31%	-38%
South Africa	4	6	8	10	13	18%	20%	27%	25%
Middle East	477	537	579	569	547	-5%	-12%	-23%	-31%
Eurasia	575	560	536	518	508	-4%	-10%	-16%	-20%
Russia	456	434	410	386	374	-4%	-10%	-17%	-20%
Asia Pacific	732	1 019	1 209	1 335	1 441	2%	4%	0%	-2%
China	210	398	507	601	665	0%	5%	8%	9%
India	55	120	157	189	237	23%	24%	23%	30%
Japan	123	87	88	76	57	-8%	-13%	-28%	-47%
Southeast Asia	170	198	219	226	238	2%	1%	-7%	-11%
Bunkers	0	33	41	50	57	103%	57%	33%	13%
World	**3 635**	**4 127**	**4 269**	**4 252**	**4 217**	**-1%**	**-6%**	**-14%**	**-20%**

The reasons for these differing trends become clearer when we examine changes at a sectoral level (Figure 11.11). In the power and industry sectors, natural gas aids decarbonisation both by replacing coal-fired generation and by helping to integrate large shares of renewables-based generation into the power mix. In transport, gas has more limited potential to help decarbonisation but plays a critical role in reducing local air pollution. In the buildings sector, gas demand growth at a global level is much more muted, but this masks the fact that demand falls in advanced economies and rises in developing economies. In some developing economies, gas plays a role in helping to achieve universal energy access, which carries with it secondary benefits for reducing CO_2 emissions and air pollution.

Figure 11.11 ▷ **Gas demand by sector in the Sustainable Development Scenario**



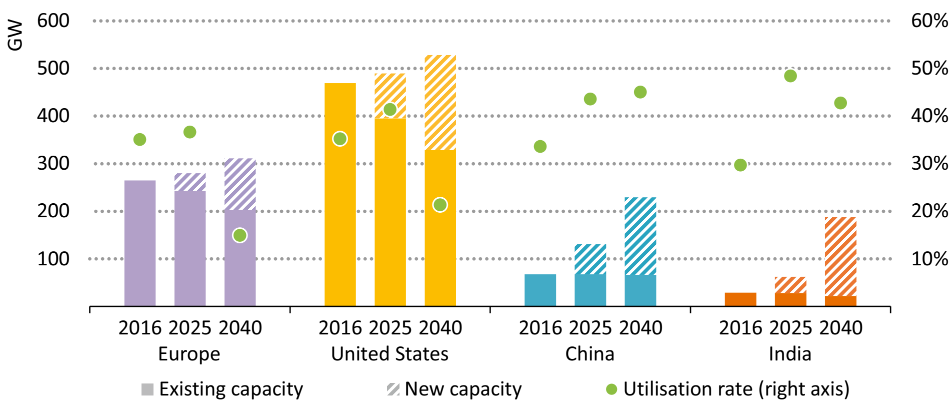
Gas use in the power sector peaks in the mid-2020s, but this is largely offset by continued growth in transport and industry

Power sector

In the Sustainable Development Scenario, the global power sector moves rapidly along the road to decarbonisation, with renewables accounting for almost two-thirds of total generation by 2040. Natural gas still has some scope to play a role in the power sector for unabated mid-load or baseload generation, and as a flexible power source to support the integration of variable renewables by providing balancing capacity: its scope potentially increases if used in conjunction with CCS.

11

Figure 11.12 ▷ **Natural gas-fired capacity and average utilisation rates in selected regions in the Sustainable Development Scenario**

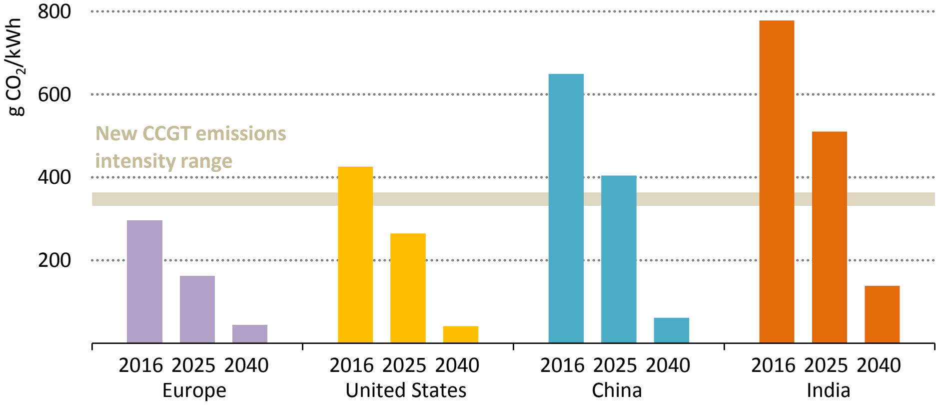


Gas power plant utilisation drops markedly after 2025 in advanced economies, despite continued capacity additions, but remains much higher in China and India

Notes: Includes gas-fired power plants equipped with CCS. Existing capacity = installed capacity as of 2016.

There is a window of opportunity for natural gas to comprise a significant share of mid-load or baseload generation in many advanced economies. In Europe and the United States, for example, there is a need to displace coal generation as quickly as possible from the electricity mix between 2016 and 2025 in the Sustainable Development Scenario. During this period, generation from variable renewable electricity technologies increases rapidly – annual average growth is around 12% in the United States and 7% in Europe – but this is still not fast enough to offset entirely the loss of generation from coal-fired power plants. In the United States, generation from coal drops by over 800 TWh between 2016 and 2025 (equivalent to losing around 20% of today's electricity generation) and, while generation from wind and solar increases by over 530 TWh, gas-fired generation is needed to fill the gap. In Europe, wind and solar offset 80% of the 520 TWh reduction in coal but, again, increases in gas generation provide much of the remainder. The average utilisation of new and existing gas-fired power plants therefore increases to close to 40% in 2025 (Figure 11.12). However, this window of opportunity is time limited: after 2025, with coal increasingly removed from power systems and an ever-increasing CO_2 price, the tide turns against the use of gas-fired generation to provide baseload supply, and utilisation rates drop in both Europe and the United States. The average emissions intensity of generation in Europe falls to just over 160 g CO_2/kWh in 2025 and to 45 g CO_2/kWh by 2040 (Figure 11.13).

Figure 11.13 ▷ Average CO_2 emissions intensity of electricity generation in selected regions in the Sustainable Development Scenario



The situation varies by region, but the role of gas-fired generation evolves quickly as the power sector decarbonises

The situation in China and India is very different: the key issue in these regions in the power sector throughout the Sustainable Development Scenario (as was the case in the New Policies Scenario) is not so much replacing existing coal power plants but rather displacing coal power plants that might otherwise have been built. The average emissions intensity of power generation in both countries still lies above new CCGTs into the late 2020s, implying that any new contribution to electricity demand by CCGTs leads to emissions savings. This means that the average utilisation rate of gas power plants stays at higher levels than in Europe and the United States (around 45%) and gas continues to form a critical component of mid-load and baseload generation. Nevertheless, by 2040, there are clear signs in this scenario that CCGTs are becoming a relatively emissions-intensive way of generating mid-load or baseload electricity.

In all regions, even if utilisation drops, gas-fired capacity continues to help with the integration of variable renewables into the power system. This does not rely on gas alone: flexibility can also come from potentially dispatchable low-carbon power sources, including hydropower and pumped-hydro storage; demand-side management (see Chapter 7); better interconnections; batteries or the use of hydrogen-based power systems (see section 11.6); or indeed from coal-fired plants. Fossil fuel use with CCS could also play this role, but this has high upfront capital costs (compared with plants without CCS) and would therefore be a very expensive means of providing back up or flexibility to the power system. The advantage of gas-fired generation, among this portfolio of flexibility options, is that it offers a way to balance not only short-term variations in supply and demand (for which a variety of alternatives are available), but also seasonal variations (for which batteries, in particular, are less suited).

Gas-fired CCS plants, however, could be used as baseload generation where high utilisation rates can help offset the large upfront capital costs. In the Sustainable Development Scenario, CCS is first fitted to gas power plants in 2025 and around 165 GW is in place worldwide by 2040. This accounts for around 7% of global gas-fired power capacity at that time, 85% of which is installed in the United States and China. While more CCS and higher levels of deployment are possible, progress on CCS has been slow to date, and a bigger role for it in future appears to depend on new financing and legal frameworks to help overcome the commercial and incentive obstacles that exist (Box 11.2).

Industry sector

The largest increase in gas consumption in the Sustainable Development Scenario is in industry, which accounts for 60% of the net increase in global demand to 2040. Gas use in light industry and in the chemical branches grows to the largest extent (by 280 bcm between 2016 and 2040). This occurs even with wider uptake of energy efficiency measures, structural changes in the sector, the displacement of gas by alternatives such as renewables and heat pumps for low-temperature heat (see Chapter 7), and increased use of bioenergy for high-temperature heat, triggered by strengthening CO_2 prices and efficiency regulations. This increase in gas demand in light industry and chemicals is significantly lower than the 475 bcm rise in the New Policies Scenario.

Demand for natural gas also increases in the energy-intensive manufacturing branches of steel and cement in the Sustainable Development Scenario. Today coal is often the most cost-effective fuel to generate high-temperature heat needed in iron and steel making because it is also used as a reducing agent and the infrastructure is in place to transport coal to the industrial facilities. This means that iron and steel making is not only very energy-intensive but also has a high average CO_2 emissions intensity (around 3 tCO_2 per tonne of oil equivalent (toe) of fuel input). In cement manufacturing, a wide variety of low quality fuels, such as petroleum coke, are combusted to generate the heat necessary to produce cement and so it too has a high emissions intensity (around 3.5 tCO_2/toe). The emissions intensity of natural gas is around 2.3 tCO_2/toe, so fuel switching to natural gas brings significant emissions reduction benefits in these industrial branches. Some zero-carbon options to generate high-temperature heat (such as the use of bioenergy) are also available.

Another option that could yield even larger emissions reductions in iron and steel production and cement is to use natural gas with CCS. However, in many industrial facilities it would probably be more economic to continue to use the current fuel source, often coal, and to equip it with CCS, rather than both to convert to the use of natural gas and to equip with CCS. As a result, the uptake of natural gas fitted with CCS in the industrial sector in the Sustainable Development Scenario is lower than for other fuels: 10% of industrial gas use is fitted with CCS in 2040 compared with around 20% for coal. The use of gas in iron and steel making (as well as in aluminium production) is also affected by increased recycling efforts. The re-melting of recycled scrap requires processes that predominantly use electricity, such as an electric arc furnace, rather than natural gas.

Transport sector

Switching to natural gas offers a way to reduce both air pollution and CO_2 emissions in parts of the transport sector. Gas demand in this sector more than triples by 2040 in the Sustainable Development Scenario, and increases by a factor of five in the road transport segment. While electrification is the preferred route to low-emissions mobility for passenger cars (in most cases), gas makes a notable contribution to emissions reductions in road freight and shipping.

The key factor currently holding back the adoption of natural gas in road transport is the lack of refuelling stations. Vehicle natural gas use in the Sustainable Development Scenario therefore expands most in regions where natural gas consumption in the residential and industry sectors supports the required infrastructure. Additional policy support is vital for this to occur. The stringent fuel-economy and emissions standards introduced in the Sustainable Development Scenario reduce oil consumption for transport, but also tend to discourage the use of natural gas in advanced economies. In China and India, the desire to develop networks for electric charging stations may edge out a widespread development of natural gas refuelling stations. Nevertheless, the need to tackle air pollution rapidly means that natural gas can play an important role during the transition when electric vehicles are still in their initial deployment phase, or in specific transport sectors such as road freight, where natural gas is one of the few alternative fuel options that can reduce both air pollutant and CO_2 emissions. Global gas use in road freight grows by around 80 bcm between 2016 and 2040 in this scenario. Gas use in road transport makes particular progress in the Middle East as the widespread availability of inexpensive natural gas makes it economic in both freight and passenger vehicles.

In the maritime sector, the use of LNG rather than heavy-fuel oil as a bunker fuel could provide around a 25% reduction in CO_2 emissions. While this is an important reduction, it is not sufficient to achieve the CO_2 emissions reductions required under the Sustainable Development Scenario: enhanced energy efficiency measures, the use of wind assistance and advanced biofuels are all necessary to avoid an increase in emissions. There is a push to eliminate sulfur emissions beyond the announced 0.5% cap on the sulfur content of marine fuels to be implemented from 2020 onwards in the Sustainable Development Scenario, and this is the key reason why consumption of gas as LNG grows to nearly 60 bcm in 2040 (15% higher than in the New Policies Scenario).

One key risk for the use of natural gas as a transport fuel is the potential for "methane slip". This is when some fraction of the natural gas used in an engine is not fully combusted and escapes as methane to the atmosphere. Recent reports have suggested that methane slip in ships could be as high as 2-3% of gas consumption (Ricardo-AEA, 2016). Methane is a more potent greenhouse gas than CO_2 and so unless this is controlled it could eliminate a large portion of (or even in some cases perhaps exceed) the potential emissions savings from the lower combustion emissions of gas compared with oil (see Chapter 10).

Buildings sector

The main role played by natural gas in the buildings sector in the Sustainable Development Scenario is to help achieve universal energy access.[3] This occurs primarily through the expansion of local gas distribution networks in urban areas such as Lagos and Delhi. Not only does this provide a basic level of energy to many but it also expands the overall level of energy service demand. As discussed, the expansion of gas is generally limited to urban areas but this can still be to the benefit of rural locations, as LPG that is displaced in urban areas can then be used in rural ones. The use of natural gas to help achieve energy access also has some positive secondary effects on decarbonisation and air pollution. Replacing LPG with natural gas helps to reduce both sulfur and CO_2 emissions, while replacing the use of bioenergy almost entirely eliminates emissions of particulate matter. Residential gas use in the Sustainable Development Scenario in developing economies grows by 85 bcm between 2016 and 2040, in addition to a 105 bcm increase in the services sector.

The situation is different in advanced economies, where achieving energy access is not an issue. Gas distribution networks continue to provide a valuable energy service to consumers in the residential and service sectors, as their wholesale replacement is not cost effective, but gas consumption nonetheless declines due to the implementation of stringent efficiency measures. At the margin, and for new buildings in some markets, the installation of new gas boilers increasingly gives way to technologies such as solar water heaters and heat pumps. These are already competitive in Japan and France, and become competitive in an increasing number of markets as technology learning and economies of

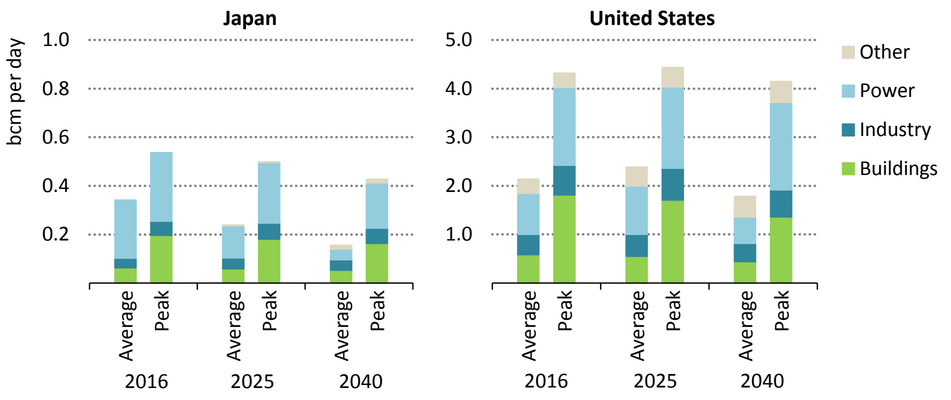
3. Also see *Energy Access Outlook: from Poverty to Prosperity*, *World Energy Outlook Special Report* (IEA, 2017a).

scale help to reduce costs (and as domestic gas prices increase from today's levels). Gas use in buildings in advanced economies falls steadily throughout the Sustainable Development Scenario by 90 bcm between 2016 and 2040, some 20% below today's levels.

Focus: The role of gas infrastructure

The optimal layout and size of mid-stream gas infrastructure, transmission and distribution networks in particular, depends on the variability of gas consumption and, importantly, the maximum level of gas consumption within a year (often called peak gas demand). In regions with a high share of gas use for heating, such as in North America, the European Union and Russia, gas infrastructure that can handle major differences in gas demand between a summer day and a winter day is essential.[4] Many developing economies face rapidly rising gas demand in both the New Policies and Sustainable Development scenarios and have yet to develop fully their gas infrastructure. Understanding differences between average and peak demand is therefore important to ensure that infrastructure in these economies is designed accordingly.

Figure 11.14 ▷ Average and peak natural gas demand in Japan and the United States by sector in the Sustainable Development Scenario



Natural gas use for heating and power generation drives peak gas demand

The relationship between average gas demand and peak gas demand within a country depends on the composition of sectoral demand (Figure 11.14). The contribution of the industry and transport sectors to a country's peak gas demand is quite predictable, broadly proportional to changes in annual demand, but the heat and power sectors are much

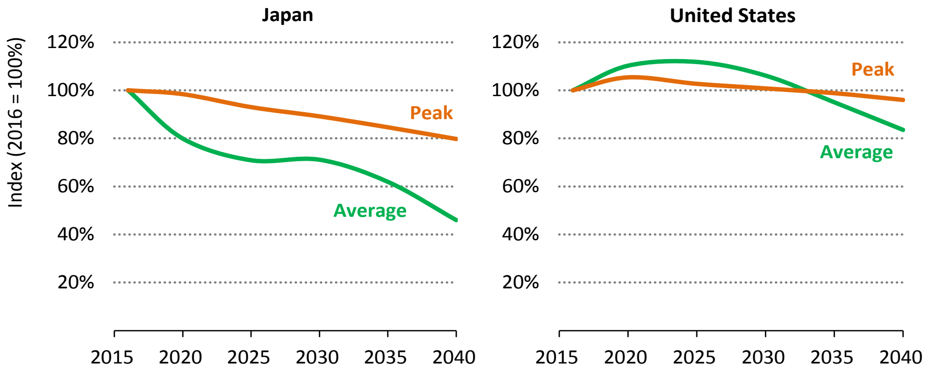
4. This demand seasonality is also reflected in a marked spread between summer and winter gas prices in these countries, which has underpinned investment into seasonal gas storage.

less straightforward. Gas-fired power plants are an important provider of flexibility, and so, even if installed gas capacity lies idle for large parts of the year, there may be individual hours or days when nearly all of the available capacity is used to balance the natural fluctuations of variable renewable sources. For heating in buildings, electrification reduces average gas demand, but does not necessarily decrease peak demand significantly if the electricity powering the heating systems is generated using gas-fired power plants. For systems with high winter heating demand and a large share of solar photovoltaic (PV) in their generation mix, the strains on the gas network may therefore be significant even if overall gas demand is in decline.

In the Sustainable Development Scenario, two-thirds of the growth in gas consumption in developing economies between 2016 and 2040 is in the industry and transport sectors. Demand growth for winter heating is minor (with the exception of China) and where gas is used in buildings for cooking or water heating there is limited seasonality in demand patterns. The challenge for many developing economies in designing gas networks is therefore very different to that faced by many of today's mature gas markets when they were planning their infrastructure: there is in particular a much smaller need for seasonal storage infrastructure (although storage may still be needed for security of supply purposes).

The evolution of peak gas demand also governs the amount of existing gas infrastructure that has to be maintained in mature gas markets in order to safeguard energy security. In Japan, for example, average gas demand in the Sustainable Development Scenario drops by over 50% between 2016 and 2040, yet peak demand only falls by 20% (Figure 11.15). Similarly, in the United States average gas demand drops by 16% over the same period, yet peak demand falls by less than 5%. In systems where gas demand and peak load are both in decline, it is safe to assume that existing infrastructure is broadly capable of handling the projected changes in utilisation. However, investment to maintain this infrastructure is critical: while this maintenance and refurbishment investment can potentially fall over time, it can only fall in parallel with peak demand rather than average demand. Furthermore, there may be a higher need for flexible natural gas storage that can provide gas promptly at times of peak demand. There may be little economic incentive for market operators to maintain equipment that they expect to be needed only very occasionally. Capacity markets have been developed in some countries wherein companies receive revenue to maintain electricity generation capacity so that it is available when needed. Similar mechanisms may be needed to maintain gas distribution and storage infrastructure: while the overall volumes of gas consumed in many regions may be lower than at present, it is critical to have volumes available when they are required. With power sector balancing needs increasingly important for peak gas demand, gas security and electricity security become ever more closely linked, requiring an integrated policy approach.

Figure 11.15 ▷ Average and peak natural gas demand in Japan and the United States in the Sustainable Development Scenario



Peak gas demand falls by less than average gas demand over period to 2040

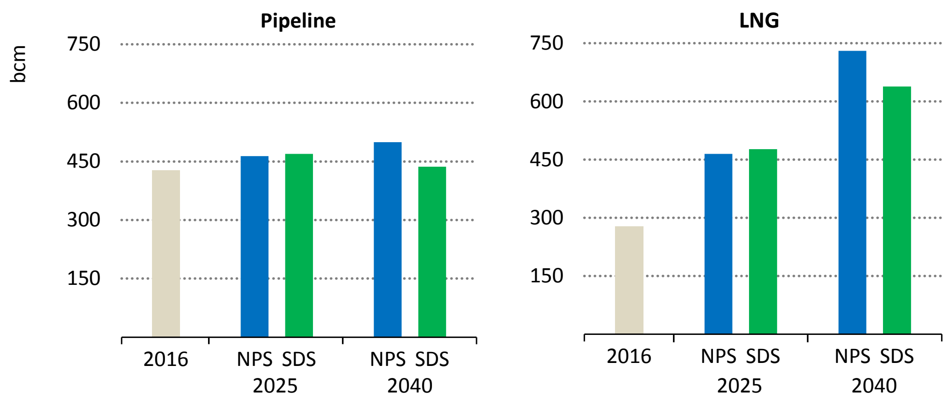
11.5 Trade and investment

LNG and pipeline trade

Inter-regional gas trade grows throughout the New Policies Scenario: pipeline trade increases by around 20% between 2016 and 2040, while LNG trade soars by more than 150%. As a result the volume of gas traded over long distances by LNG surpasses that traded by pipeline in the mid-2020s (Figure 11.16). The growth in pipeline and LNG trade in the Sustainable Development Scenario over the period to 2025 is broadly similar to that in the New Policies Scenario. During this period, the bulk of the increase in global pipeline trade comes from a 55 bcm increase in exports to China (see Chapter 9). Global pipeline trade peaks soon after 2025 in the Sustainable Development Scenario, with exports to Europe from Russia falling by around a third between 2025 and 2040. Russia offsets some of its losses to Europe by increasing exports to China, but it faces stiff competition from countries in the Caspian region and so by 2040 its pipeline exports have fallen back to 2016 levels (having been over 20% higher in the mid-2020s).

Global LNG trade in the Sustainable Development Scenario continues to grow at a robust pace to 2030. LNG imports to Europe, Japan and Korea remain broadly flat throughout the 2020s, but demand for LNG continues to grow in developing economies in Asia. LNG is critical in these regions to meet energy demand that might otherwise be provided by coal. After 2030, LNG demand in Europe, Japan and Korea drops by 30%, offsetting most of the sustained growth in other Asian countries. The United States and Australia lead the way in terms of LNG export growth in the first ten years of the Sustainable Development Scenario, but there is also around 35 bcm growth in exports from both Russia and the Middle East. After 2025, the largest contribution to LNG markets comes from the United States, where exports expand to just over 140 bcm in 2040.

Figure 11.16 ▷ Global pipeline and LNG trade by scenario



Pipeline and LNG trade grow to a similar extent to 2025 in both scenarios. Trends then diverge, with the New Policies Scenario seeing more growth in LNG trade.

Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

The relative merits of pipeline and LNG trade in the Sustainable Development Scenario are affected by how much gas is used in transporting it to its destination. In pipelines, a portion of the gas transported is consumed in compressor stations to maintain pressure and allow the flow of the gas. In LNG, liquefaction of natural gas prior to transport is an energy-intensive process requiring the gas to be cooled to -162 °C. The gas flowing to the often-remote facility is generally used to provide this energy and around 10% is consumed as a result (although this percentage varies seasonally and regionally). There are further (albeit smaller) losses during shipping, referred to as "boil off", with gas often used to power the LNG tanker and regasification.

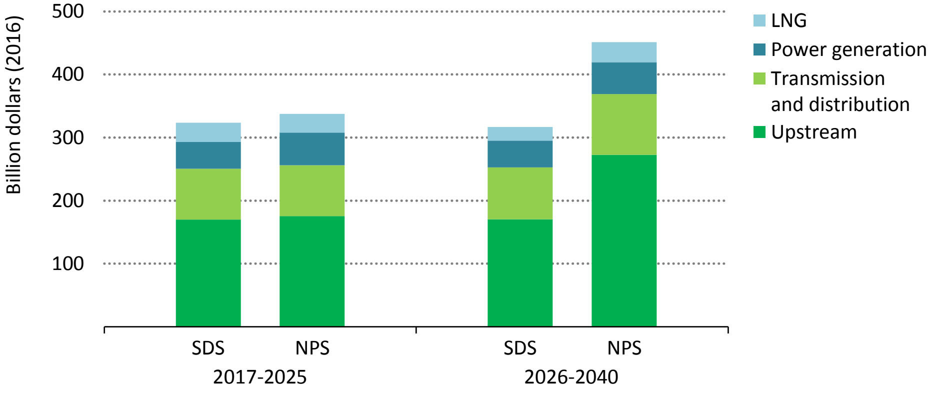
11

Gas consumed during both modes of transport depends on the distances involved but generally, at present, LNG results in higher gas use for transportation. For example, around 7% of the gas transported by pipeline from Russia to Europe is consumed, while 13% would be consumed for LNG travelling a similar distance. In the Sustainable Development Scenario, CO_2 taxes are imposed on most major energy consuming sectors and, if applied to the transport of natural gas, would result in meaningful increases to transport costs. In 2040, for example, CO_2 prices are \$140/tCO_2 in Europe and \$125/tCO_2 in Russia, which could increase the cost of pipeline imports by around \$0.5 per million British thermal units (MBtu) and LNG imports by close to \$1/MBtu. There are options to reduce these emissions to mitigate these increases: LNG facilities could use solar power for the liquefaction process rather than the incoming natural gas, while compressors in new transmission pipelines could tap into the electricity grid rather than generating power on-site using natural gas. These options would reduce the proportion of gas that is used during transformation and transmission as well as the overall level of CO_2 emissions.

Investment in natural gas infrastructure[5]

On average $360 billion annual investment into the natural gas supply chain is needed in the New Policies Scenario to 2040 (a cumulative investment of $8.6 trillion).[6] The largest share, averaging nearly $240 billion every year, is for the upstream (Figure 11.17) this is necessary not only to meet the 45% increase in demand over the period to 2040, but also to offset the underlying declines in gas production. The observed decline rate for conventional gas fields that have passed their peak is over 7% per year and the decline rate for unconventional gas production is even steeper. There is also $90 billion annual investment in transmission and distribution gas networks, half of which is required to maintain existing networks in mature regions (North America, Europe, Japan, Korea and Russia).

Figure 11.17 ▷ Average annual investment into gas infrastructure by scenario



Investment to 2025 is broadly similar in the Sustainable Development and New Policies Scenarios but a sharp divergence emerges thereafter, particularly in the upstream sector

Note: NPS = New Policies Scenario; SDS = Sustainable Development Scenario.

Cumulative investment in the Sustainable Development Scenario between 2016 and 2040 is just over $6.5 trillion. However, the trajectory of gas demand over this period poses a variety of challenges for investment in related infrastructure. Investment in new assets has to be sufficient to meet rising gas demand in the short term while being as compatible as possible with the transition over the longer term. Average annual upstream gas investment remains around $170 billion in the Sustainable Development Scenario; in the period after 2025 this amount is needed not to satisfy any major increase in demand but rather to offset

5. Infrastructure is used here to refer to assets along the natural gas value chain including supply, mid-stream assets, such as LNG and transmission and distribution pipelines, and gas-fired power plants.

6. Investment values for upstream natural gas include the capital costs of associated gas and non-associated gas assets and make allowance for how investments for natural gas liquids are shared between oil and gas.

underlying declines in production. In contrast, demand for LNG begins to wane after 2030 in the Sustainable Development Scenario and few new facilities are needed: the average level of investment in the period after 2025 is therefore 30% lower than the level before 2025.

Differences between the New Policies and Sustainable Development scenarios help inform which major investment decisions made in the short-to-medium term could be termed "no regret" options. The level of LNG trade and investment into new export terminals is broadly similar over the next ten years in the two scenarios: while operators may receive less revenue in the Sustainable Development Scenario (since prices are somewhat lower), it should still be sufficient to provide a reasonable rate of return. Similarly, new pipelines transporting natural gas to China as well as the infrastructure to distribute and consume it (especially in the power and industry sectors) are needed in both the New Policies and Sustainable Development scenarios: the upstream projects supplying these emerging markets also remain robust. After 2025, with a discernible slowdown in the growth in natural gas demand in the Sustainable Development Scenario, average annual investment globally is around 30% lower than the New Policies Scenario raising the question of whether there is a risk of some natural gas assets becoming stranded.

Focus: Stranded natural gas assets[7]

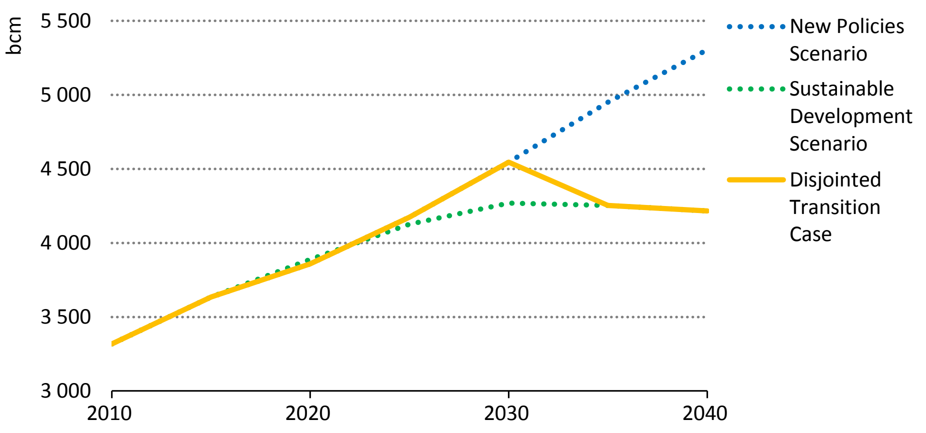
As discussed, the observed decline rate for conventional gas fields that have passed their peak is over 7% per year and the decline rate for unconventional gas production is much steeper. Global gas demand in the Sustainable Development Scenario remains broadly constant throughout the 2030s: if gas production is to meet this demand, declining fields therefore have to be offset by developing new reserves and by discovering and developing new resources. The prices and investment levels in the Sustainable Development Scenario are designed to ensure that sufficient new projects are brought online to balance supply and demand while ensuring all generate an adequate return. When governments pursue unambiguous policies to decarbonise the energy system, as set out in the Sustainable Development Scenario, there is unlikely to be widespread stranding of upstream natural gas assets: the same is true for LNG and pipeline assets.

For the power sector, there are some stranded gas power plant assets. However this is limited because operators of natural gas generating capacity receive revenue for maintaining generating capacity in the Sustainable Development Scenario. We estimate that cumulative stranded capital in gas-fired power generation capacity amounts to just under $7 billion to 2040, which can be compared with the $1 trillion invested in gas power plants to 2040 in the Sustainable Development Scenario. Advanced economies see the majority of stranded gas-fired power plant assets because they tend to seek deeper emissions reductions in the power sector sooner than in developing economies.

7. Stranded assets are defined as capital investment in fossil-fuel infrastructure that ends up failing to be recovered over the operating lifetime of the asset because of reduced demand or lower prices resulting from climate policy.

While there is only a limited stranding of assets in the Sustainable Development Scenario, in reality it can be difficult for investments to anticipate future policies and market developments, and supply can get out of line with demand levels, leading to price volatility. If a sudden change in policies were to bring about an abrupt and unexpected shift in demand, there is a risk that some investments may fail to recover the capital spent on them, since many assets in the energy sector have long lead times and lifetimes. We constructed a "Disjointed Transition Case" for oil markets in the *WEO-2016* to explore the impact of an unforeseen abrupt policy change on investments, based on oil demand following the New Policies Scenario but then dropping sharply to the level of the 450 Scenario.[8] This was found to lead to large financial losses for the upstream oil industry: the later the delay in the transition to a trajectory consistent with the Paris Agreement, the bigger the losses. A similar "Disjointed Transition Case" for gas markets would see demand (including LNG and pipeline imports) following the New Policies Scenario up until 2030, then transitioning suddenly over a five-year period to the demand trajectory in the Sustainable Development Scenario (Figure 11.18). The impact of a disjointed transition on gas markets, however, is not as clear-cut as it is for oil.

Figure 11.18 ▷ Global gas demand in a "Disjointed Transition Case"



A disjointed transition would not materially impact stranded upstream assets as the decline in demand is less than the observed decline in producing fields

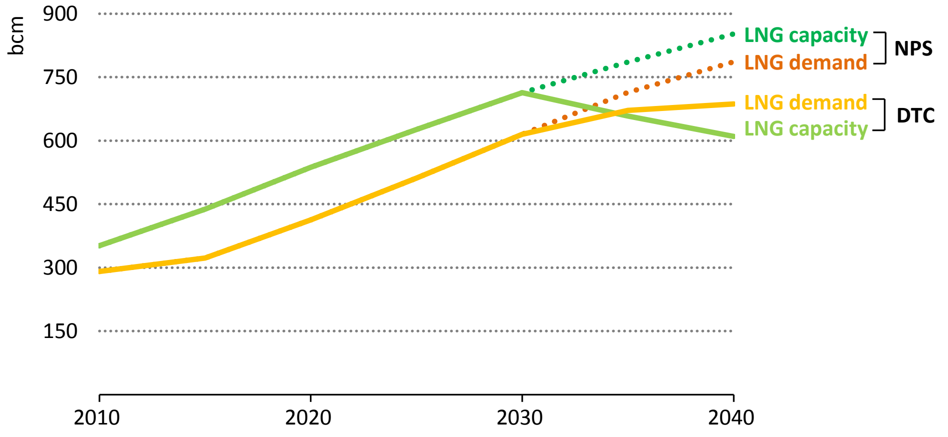
For gas production, the switch to the Sustainable Development Scenario under the Disjointed Transition Case would bring about a reduction of nearly 300 bcm in gas consumption in the space of five years. However, this impact is less severe than was the case for oil: in a Disjointed Transition Case global gas demand would decline by around 1.3% each year over the five-year period between 2030 and 2035 compared with a near 5% annual drop in oil demand over the same period. Indeed, the decrease in gas demand would still be much

8. The 450 Scenario modelled in the *WEO-2016* aimed to limit the temperature rise in 2100 to below 2 °C.

less than the observed decline in producing fields. As a result, there would still need to be investments in new sources of production to offset underlying declines, even during the five-year adjustment period, which would limit the risk of stranded upstream natural gas assets.

For LNG, capacity grows by over 270 bcm between 2016 and 2030 following the trend in the New Policies Scenario. There is, however, not nearly as large a shock to LNG demand from 2030 with the shift to the Sustainable Development Scenario as there is to overall gas demand. Overall LNG exports continue to rise even with the sudden shift to the trend in the Sustainable Development Scenario (Figure 11.19). Indeed, if no new capacity were to be built after 2030, global LNG capacity in the Disjointed Transition Case would be gradually eroded over subsequent years as facilities reached the end of their technical lifetimes and were taken out of operation, which would increase the utilisation of remaining facilities. Global liquefaction capacity in the Disjointed Transition Case in 2040 would be around 610 bcm, lower than the level of LNG exports. No export facilities would need to be closed prematurely and all facilities that exist in 2040 would be needed (indeed new facilities would need to be built): the risk of stranded LNG export facilities therefore looks limited in this case.

Figure 11.19 ▷ Global liquefaction capacity and demand in the New Policies Scenario and the "Disjointed Transition Case"



LNG demand continues to rise even in a disjointed transition and older facilities reaching the end of their technical lifetimes would limit the level of stranded export terminals

Note: NPS = New Policies Scenario; DTC = Disjointed Transition Case.

For pipeline assets, following the trend in the New Policies Scenario, around 180 bcm new pipeline capacity would be built in the Disjointed Transition Case between 2016 and 2030. Around one-third of this is to transport gas to China from Russia and the Caspian region. Since gas demand in China is higher in the Sustainable Development Scenario than in the New

Policies Scenario, all of this new pipeline capacity continues to be used in our projections to 2040, even after the transition to the Sustainable Development Scenario in 2030. In fact, more pipeline capacity would need to be built after 2025 to satisfy the continued increase in China's gas demand. However, pipelines built over the next fifteen years to export gas to more mature regions would be at much more risk. For example, between 2016 and 2030 some 75 bcm new pipeline capacity would be built in the Disjointed Transition Case in order to bring gas to European markets. Between 2030 and 2035, however, European gas demand would drop by nearly 100 bcm, and it would decline by a further 50 bcm over the subsequent five years. Much of the new pipeline capacity would not be required and there is a risk that some assets could become stranded.

11.6 Decarbonising gas supply

Significant and rapid progress in eliminating methane emissions from the production, transmission and distribution of natural gas is a vital component of the energy sector transition envisaged in the Sustainable Development Scenario. As discussed in Chapter 10, methane emissions from the natural gas value chain are 70% lower in 2040 than today's levels in the Sustainable Development Scenario. Failure to tackle these emissions comprehensively would not only reduce the climate advantages offered by natural gas compared with other fuels, but also reduce the remaining emissions space commensurate with achieving the objectives of Paris Agreement.

In regions where natural gas consumption declines in the Sustainable Development Scenario, the utilisation of existing infrastructure drops and this poses challenges for network operators and owners. For natural gas to become a zero-carbon fuel itself, CCS is essential (Box 11.3). There are, however, alternative options to make use of this infrastructure and that could lower the emissions intensity of the gas delivered and so aid in the energy sector transition. Two examples are bio-methane and hydrogen.

Biogas is a mixture of methane (CH_4), CO_2 and small quantities of other gases produced either through the gasification of biomass or by the anaerobic digestion of organic matter by bacteria and enzymes in an oxygen-free environment. Biogas can either be used directly, close to where it is produced, or be upgraded to remove the CO_2 (and other contaminants) to yield a pure stream of bio-methane. Bio-methane can be transported in a similar way to natural gas. Just over 60 bcm of biogas was produced globally in 2015, the majority of which was used in electricity and heat plants. One option for the future is to blend bio-methane with natural gas, which helps reduce the overall CO_2 intensity of the gas stream and could help prolong the utilisation of existing natural gas infrastructure in a low-emissions future: a number of countries already permit bio-methane injection into the gas network. An alternative option would be to use a pure stream of bio-methane in gas-fired power plants that provide flexibility to the electricity grid.

The potential of biogas and bio-methane are critically dependent on the availability and cost of the required feedstocks: municipal waste, animal by-products and dedicated energy crops are all suitable options. However, the cost of producing bio-methane is estimated to range between \$6/MBtu and \$17/MBtu if using waste as a feedstock and between \$20/MBtu and \$50/MBtu if using dedicated energy crops (IRENA, 2017). While the lowest cost bio-methane from waste may be cost competitive with natural gas, it is unlikely to have a substantial effect on overall natural gas consumption. The production cost of bio-methane using energy crops in particular is likely to be prohibitive. Costs would need to come down materially for biogas and bio-methane to form a central part of a low-carbon energy system.

Hydrogen could play a role in the low-carbon transition in a variety of ways. At present the largest user of hydrogen in the energy sector is industry, where hydrogen is created by steam reformation of natural gas and consumed on-site in the manufacture of ammonia and methanol or in the refining sector. To be useful in the energy transition, however, hydrogen will need to be generated using low- or zero-carbon energy sources and is likely to need to be transported over longer distances.

One way to produce hydrogen is by using electricity, often referred to as power-to-gas. This is of particular interest in the context of variable renewables. As the capacity of variable renewables grows, so does the risk of mismatches between electricity generation and demand. If more electricity is generated than the system needs, then, unless it can be stored or used, some capacity has to be curtailed and electricity is "lost" as a result. In the Sustainable Development Scenario, one-third of the world's electricity is supplied by wind and solar PV in 2040, and as much as 8% of variable electricity generation could be lost because of curtailment in the United States, European Union and India, unless there is scope to store it or to make use of it. The curtailed electricity in these three regions could provide around 20 Mtoe of hydrogen, roughly 2% of their natural gas demand in 2040 in the Sustainable Development Scenario. However, this may be prohibitively expensive. While the costs of the electricity would be very low (since it would otherwise be lost), the capital costs of hydrogen-production facilities are high and facilities are unlikely to be economic if they can only operate intermittently. It may well be that it makes more sense to produce hydrogen using dedicated generation facilities (solar, wind, hydropower or nuclear).

The question of how to transport hydrogen to end-users is also important. One possibility is to inject hydrogen into the natural gas stream within existing pipelines. The low-pressure distribution network could probably cope with relatively high injection levels; indeed the distribution pipelines in many countries originally transported town gas, which was around 30-50% hydrogen (Melaina, Antonia and Penev, 2013). There could be more of a problem with the transmission gas network, however, as elevated concentrations of hydrogen can lead to pipeline corrosion. Nevertheless, with only minor modifications, the transmission network could cope with up to around 10% hydrogen blended into the natural gas stream (Altfeld and Pinchbeck, 2013). Perhaps the biggest problem is that the ability of end-users to consume a blend of hydrogen and natural gas is rather limited. Many existing natural gas turbines, for example, could only handle around 1% hydrogen injection for performance and safety reasons (although they may be capable of tolerating 5-15% injection with some modifications).

Considering these difficulties, we estimate that hydrogen injection could displace around 100 bcm of natural gas consumption across the global energy system in 2040, which could help to reduce CO_2 emissions from some difficult-to-decarbonise end-uses. For example, the need for very high temperatures in some industry branches mean these cannot easily switch from natural gas or coal to renewables and electricity: using a mixture of natural gas and hydrogen would lower the emissions intensity of the delivered heat.

Box 11.4 ▷ Can natural gas be a zero-carbon fuel?

For natural gas to play a major role in a fully decarbonised global energy system – the ultimate post-2040 aim of the Sustainable Development Scenario – it will be necessary in the long term for its consumption to result in almost no CO_2 emissions. The key technology for this is CCS. At present CCS faces a number of challenges, not least that it requires additional capital investment and reduces operational efficiency, but does not directly generate any extra revenue (although the captured CO_2 can sometimes be used for enhanced oil recovery, as in PetraNova in Texas [United States] and Boundary Dam in Saskatchewan [Canada]). At present, policy support is insufficient to overcome the cost and financing barriers that are inhibiting deployment. However, if CCS reaches the point where it can be commercially deployed, then natural gas could be used in a variety of ways:

- Gas-fired power plants equipped with CCS would result in near-zero CO_2 electricity as discussed above.
- To produce a dedicated supply of pure hydrogen: this could be used in chemical synthesis in industry or to help decarbonise large vehicles, such as for freight or maritime transport, where the potential for electricity may be constrained by the need for inordinately large batteries. Indeed, analysis has suggested that the cost of using hydrogen in trucks, including the cost of dedicated hydrogen infrastructure, could become comparable to that of plug-in hybrid trucks (IEA, 2017b). However, while the distribution network may be able to handle a pure stream of hydrogen, an entirely new transmission network along with new end-user equipment would likely be required, which would entail significant cost.
- To produce hydrogen-rich chemicals, such as ammonia, which are easier to store and transport than a stream of pure hydrogen gas. Ammonia is currently used in industry in the production of nitrogen fertilisers: there has also been some recent renewed interest in the possibilities offered by ammonia as an energy carrier and as a fuel (especially for stationary applications such as balancing variable renewables and in industrial facilities).

Definitions

This annex provides general information on terminology used throughout *WEO-2017* including: units and general conversion factors; definition of fuels, processes and sectors; regional and country groupings; and abbreviations and acronyms.

Units

Area	Ha	hectare
	km^2	square kilometre
Coal	Mtce	million tonnes of coal equivalent (equals 0.7 Mtoe)
	Mtpa	million tonnes per annum
	gce	grammes of coal equivalent
Emissions	ppm	parts per million (by volume)
	Gt CO_2-eq	gigatonnes of carbon-dioxide equivalent (using 100-year global warming potentials for different greenhouse gases)
	kg CO_2-eq	kilogrammes of carbon-dioxide equivalent
	g CO_2/km	grammes of carbon dioxide per kilometre
	g CO_2/kWh	grammes of carbon dioxide per kilowa -hour
Energy	boe	barrel of oil equivalent
	toe	tonne of oil equivalent
	ktoe	thousand tonnes of oil equivalent
	Mtoe	million tonnes of oil equivalent
	MBtu	million British thermal units
	kcal	kilocalorie (1 calorie x 10^3)
	Gcal	gigacalorie (1 calorie x 10^9)
	MJ	megajoule (1 joule x 10^6)
	GJ	gigajoule (1 joule x 10^9)
	TJ	terajoule (1 joule x 10^{12})
	PJ	petajoule (1 joule x 10^{15})
	EJ	exajoule (1 joule x 10^{18})
	kWh	kilowa -hour
	MWh	megawa -hour
	GWh	gigawa -hour
	TWh	terawa -hour
Gas	mcm	million cubic metres
	bcm	billion cubic metres
	tcm	trillion cubic metres
	scf	standard cubic foot

Mass	kg	kilogramme (1 000 kg = 1 tonne)
	kt	kilotonnes (1 tonne x 10^3)
	Mt	million tonnes (1 tonne x 10^6)
	Gt	gigatonnes (1 tonne x 10^9)
	tU	tonnes of uranium
Monetary	$ million	1 US dollar x 10^6
	$ billion	1 US dollar x 10^9
	$ trillion	1 US dollar x 10^{12}
Oil	b/d	barrels per day
	kb/d	thousand barrels per day
	mb/d	million barrels per day
	mboe/d	million barrels of oil equivalent per day
Power	W	watt (1 joule per second)
	kW	kilowatt (1 watt x 10^3)
	MW	megawatt (1 watt x 10^6)
	GW	gigawatt (1 watt x 10^9)
	TW	terawatt (1 watt x 10^{12})
Water	bcm	billion cubic metres
	m^3	cubic metre

General conversion factors for energy

Convert to:	**TJ**	**Gcal**	**Mtoe**	**MBtu**	**GWh**
From:	multiply by:				
TJ	1	238.8	2.388 x 10^{-5}	947.8	0.2778
Gcal	4.1868 x 10^{-3}	1	10^{-7}	3.968	1.163 x 10^{-3}
Mtoe	4.1868 x 10^4	10^7	1	3.968 x 10^7	11 630
MBtu	1.0551 x 10^{-3}	0.252	2.52 x 10^{-8}	1	2.931 x 10^{-4}
GWh	3.6	860	8.6 x 10^{-5}	3 412	1

Note: There is no generally accepted definition of boe; typically conversion factors vary from 7.15 to 7.40 boe per toe.

Currency conversions

Exchange rates *(2016 annual average)*	**1 US Dollar equals:**
British Pound	0.74
Chinese Yuan Renminbi	6.64
Euro	0.90
Indian Rupee	67.19
Indonesian Rupiah	13 308.33
Japanese Yen	108.79
Russian Ruble	67.06
South African Rand	14.71

Source: OECD National Accounts database, October 2017.

Definitions

Advanced biofuels: Sustainable fuels produced from non-food crop feedstocks, which are capable of delivering signifi ant life-cycle greenhouse-gas emissions savings compared with fossil fuel alternati es, and which do not directly compete with food and feed crops for agricultural land or cause adverse sustainability impacts. This definitio di ers from the one used for “advanced biofuels” in the US legislation which is based on a minimum 50% lifecycle greenhouse gas reduction and which, therefore, includes sugar cane ethanol.

Agriculture: Includes all energy used on farms, in forestry and for fishing.

Back-up generation capacity: Households and businesses connected to the main power grid may also have some form of “back-up” power generation capacity that can, in the event of disruption provide electricity. Back-up generators are typically fuelled with diesel or gasoline and capacity can be from as litt e as a few kilowatts. Such capacity is distinc from mini-grid and off-grid systems that are not connected to the main power grid.

Biodiesel: Diesel-equivalent, processed fuel made from the transesterifi ation (a chemical process that converts triglycerides in oils) of vegetable oils and animal fats.

Bioenergy: Energy content in solid, liquid and gaseous products derived from biomass feedstocks, biogas and waste. It includes solid biomass, biofuels and biogas.

Biofuels: Liquid fuels derived from biomass or waste feedstocks and include ethanol and biodiesel. They can be classifi d as conventional and advanced biofuels according to the technologies used to produce them and their respecti e maturity.

Biogas: A mixture of methane and carbon dioxide produced by bacterial degradation of organic ma er and used as a fuel.

Buildings: The buildings sector includes energy used in residential, commercial and institutiona buildings, and non-specified other. Building energy use includes space heatin and cooling, water heatin , lightin , appliances and cooking equipment.

Bunkers: Includes both internationa marine bunkers and international aviation bunkers.

Capacity credit: Proportion of the capacity that can be reliably expected to generate electricity during times of peak demand in the grid to which it is connected.

Clean cooking facilities: Cooking facilities that are considered safer, more effici t and more environmentally sustainable than the traditional facilities that make use of solid biomass (such as a three-stone fi e). This refers primarily to improved solid biomass cookstoves, biogas systems, liquefied petroleum gas stoves, ethanol and solar stoves.

Coal: Includes both primary coal (including lignite, coking and steam coal) and derived fuels (including patent fuel, brown-coal brique es, 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 (CBM): Category of unconventional natural gas, which refers to methane found in coal seams.

Coal-to-gas (CTG): Process in which mined coal is fi st turned into syngas (a mixture of hydrogen and carbon monoxide) and then into "synthetic" methane.

Coal-to-liquids (CTL): Transformation of coal into liquid hydrocarbons. It can be achieved through either coal gasifi ation into syngas (a mixture of hydrogen and carbon monoxide), combined using the Fischer-Tropsch or methanol-to-gasoline synthesis process to produce liquid fuels, or through the less developed direct-coal liquefaction technologies in which coal is directly reacted with hydrogen.

Coking coal: Type of coal that can be used for steel making (as a chemical reductant and heat source), where it produces coke capable of supporting a blast furnace charge. Coal of this quality is also commonly known as metallurgical coal.

Conventional biofuels: Fuels produced from food crop feedstocks. These biofuels are commonly referred to as fi st-generation and include sugar cane ethanol, starch-based ethanol, fatty acid methyl esther (FAME) and straight vegetable oil (SVO).

Decommissioning (nuclear): The process of dismantling and decontaminating a nuclear power plant at the end of its operational lifetime and restoring the site for other uses.

Decomposition analysis: Stati ti al approach that decomposes an aggregate indicator to quanti y the relati e contribution of a set of pre-defined factors leading to a change in the aggregate indicator. The *World Energy Outlook* uses an additi e index decomposition of the type Logarithmic Mean Divisia Index method I (LMDI-I).

Demand-side integration (DSI): Consists of two types of measures: actions that influenc load shape such as energy effic ncy and electrifi ation; and actions that manage load such as demand-side response.

Demand-side response (DSR): Describes actions which can influenc the load profil such as shifting the load curve in tim without a ecting the total electricity demand, or load shedding such as interrupting demand for short duration or adjusting the intensity of demand for a certain amount of time.

Dispatchable generation: Refers to technologies whose power output can be readily controlled – increased to maximum rated capacity or decreased to zero – in order to match supply with demand.

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 services: Energy that is available to end-users to sati fy their needs. This is also sometim s referred to as "useful energy". Due to transformation losses the amount of useful energy is lower than the corresponding final energy. Forms of energy services include transportation machine drive, lighting or heat for space heating

Ethanol: Refers to bio-ethanol only. Ethanol is produced from fermenting any biomass high in carbohydrates. Today, ethanol is made from starches and sugars, but second-generatio technologies will allow it to be made from cellulose and hemicellulose, the fib ous material that makes up the bulk of most plant ma er.

Gas (also referred to as natural gas): Comprises gases occurring in deposits, whether liquefi d or gaseous, consisting mainly of methane. It includes both "non-associated" gas originating from fields producing hydrocarbons only in gaseous form, and "associated" gas produced in association with crude oil as well as methane recovered from coal mines (colliery gas). Natural gas liquids (NGLs), manufactured gas (produced from municipal or industrial waste, or sewage) and quantitie vented or fla ed are not included. Gas data in cubic metres are expressed on a "gross" calorific value basis and are measured at 15 °C and at 760 mm Hg ("Standard Conditions"). Gas data expressed in tonnes of oil equivalent, mainly for comparison reasons with other fuels, are on a "net" calorific basis. The di erence between the "net" and the "gross" calorific value is the latent heat of vaporisation of the water vapour produced during combustion of the fuel (for gas the net calorific value is 10% lower than the gross calorific value).

Gas-to-liquids (GTL): Process featuring reaction of methane with oxygen or steam to produce syngas (a mixture of hydrogen and carbon monoxide) followed by synthesis of liquid products (such as diesel and naphtha) from the syngas using Fischer-Tropsch catalyti synthesis. The process is similar to those used in coal-to-liquids.

High-level waste (HLW): The highly radioacti e and long-lived waste materials generated during the course of the nuclear fuel cycle, including spent nuclear fuel (if it is declared as waste) and some waste streams from reprocessing.

Heat (end-use): Can be obtained from the combustion of fossil or renewable fuels, direct geothermal or solar heat systems, exothermic chemical processes and electricity (through resistance heating or heat pumps which can extract it from ambient air and liquids). This category refers to the wide range of end-uses, including space and water heatin , and cooking in buildings, desalination and process applications in industry. It does not include cooling applications

Heat (supply): Obtained from the combustion of fuels, nuclear reactors, geothermal resources and the capture of sunlight. It may be used for heating or cooling, or converted into mechanical energy for transport or electricity generation. Commercial heat sold is reported under total final consumption with the fuel inputs allocated under power generation

Hydropower: The energy content of the electricity produced in hydropower plants, assuming 100% effic ncy. It excludes output from pumped storage and marine (tid and wave) plants.

Industry: Includes fuel used within the manufacturing and construction industries. Key industry branches include iron and steel, chemical and petrochemical, cement, and pulp and paper. Use by industries for the transformation of energy into another form or for the production of fuels is excluded and reported separately under other energy sector. Consumption of fuels for the transport of goods is reported as part of the transport sector, while consumption by off-road vehicles is reported under industry.

International aviation bunkers: Includes the deliveries of aviation fuels to aircraft for international aviation. Fuels used by airlines for their road vehicles are excluded. The domestic/i ternational split is determined on the basis of departure and landing location and not by the nationality of the airline. For many countries this incorrectly excludes fuels used by domesti ally owned carriers for their international departures.

International marine bunkers: Covers those quantitie 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/i ternational split is determined on the basis of port of departure and port of arrival, and not by the flag or nationality of the ship. Consumption by fishing vessels and by military forces is also excluded and included in residential, services and agriculture.

Investment: All investment data and projections reflect "overnight investment", i.e. the capital spent is generally assigned to the year production (or trade) is started, rather than the year when it actually incurs. Investments for oil, gas and coal include production transformation and transportation; those for the power sector include refurbishments, uprates, new builds and replacements for all fuels and technologies for on-grid, mini-grid and o -grid generation as well as investment in transmission and distribution. Investment data are presented in real terms in year-2016 US dollars.

Lignite: Type of coal that is used in the power sector mostly in regions near lignite mines due to its low energy content and typically high moisture levels, which generally makes long-distance transport uneconomic. Data on lignite in the *WEO* includes peat, a solid formed from the partial decomposition of dead vegetation under conditions of high humidity and limited air access.

Lignocellulosic feedstock: Crops culti ated to produce biofuels from their cellulosic or hemicellulosic components, which include switchgrass, poplar and miscanthus.

Liquid fuels: The classifi ation of liquid fuels used in our analysis is presented in Figure C.1. Natural gas liquids accompanying tig t oil or shale gas production are accounted together with other NGLs under conventional oil.

Lower heating value: Heat liberated by the complete combustion of a unit of fuel when the water produced is assumed to remain as a vapour and the heat is not recovered.

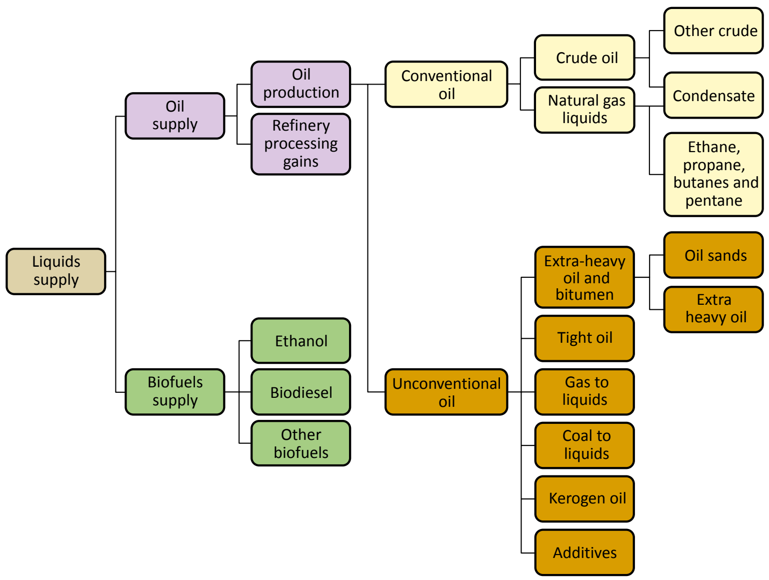
Middle distillates: Include jet fuel, diesel and heating oil.

Mini-grids: Small grid systems linking a number of households or other consumers.

Modern energy access: Includes household access to a minimum level of electricity; household access to safer and more sustainable cooking and heating fuels and stoves; access that enables producti e economic activity; and access for public services.

Modern renewables: Includes all uses of renewable energy with the exception of traditiona use of solid biomass.

Figure C.1 ▷ Liquid fuels classification



Modern use of solid biomass: Refers to the use of solid biomass in improved cookstoves and modern technologies using processed biomass such as pellets.

Natural gas liquids (NGLs): Liquid or liquefi d hydrocarbons produced in the manufacture, purifi ation and stabilisation of natural gas. These are those portions of natural gas which are recovered as liquids in separators, field facilities or gas processing plants. NGLs include but are not limited to ethane (when it is removed from the natural gas stream), propane, butane, pentane, natural gasoline and condensates.

Non-energy use: Fuels used for chemical feedstocks and non-energy products. Examples of non-energy products include lubricants, paraffi waxes, asphalt, bitumen, coal tars and oils as timber preservati es.

Nuclear: Refers to the primary energy equivalent of the electricity produced by a nuclear plant, assuming an average conversion efficiency of 33%.

Off-grid systems: Stand-alone systems for individual households or groups of consumers.

Oil: Oil production includes both conventional and unconventional oil (Figure C.1). Petroleum products include refine y gas, ethane, liquid petroleum gas, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirit, lubricants, bitumen, paraffi waxes and petroleum coke.

Other energy sector: Covers the use of energy by transformation industries and the energy losses in converting primary energy into a form that can be used in the final consuming sectors. It includes losses by gas works, petroleum refin ries, blast furnaces, coke ovens, coal and gas transformation and liquefaction. It also includes energy used in coal mines, in oil and gas extraction and in electricity and heat production. Transfers and stati ti al di erences are also included in this category.

Power generation: Refers to fuel use in electricity plants, heat plants and combined heat and power (CHP) plants. Both main activity producer plants and small plants that produce fuel for their own use (auto-producers) are included.

Pre-salt oil and gas: These resources are referred to as such because they predate the formation of a thick salt layer, which overlays the hydrocarbons and traps them in place.

Productive uses: Energy used towards an economic purpose: agriculture, industry, services, and non-energy use. Some energy demand from the transport sector (e.g. freight-related) could also be considered as producti e, but is treated separately.

Renewables: Includes bioenergy, geothermal, hydropower, solar photovoltaics (PV), concentrating solar power (CSP), wind and marine (tid and wave) energy for electricity and heat generation

Residential: Energy used by households including space heating and cooling, water heatin , lightin , appliances, electronic devices and cooking equipment.

Resistance heating: Refers to direct electricity transformation into heat through the joule e ect.

Self-sufficiency: Corresponds to indigenous production divided by total primary energy demand.

Services: Energy used in commercial (e.g. hotels, office catering, shops) and institution buildings (e.g. schools, hospitals, offices) Services energy use includes space heating and cooling, water heatin , lightin , equipment, appliances and cooking equipment.

Shale gas: Natural gas contained within a commonly occurring rock classified as shale. Shale formations are characterised by low permeability, with more limited ability of gas to fl w through the rock than is the case with a conventional reservoir. Shale gas is generally produced using hydraulic fracturing.

Solid biomass: Includes charcoal, fuelwood, dung, agricultural residues, wood waste and other solid wastes.

Steam coal: Type of coal that is mainly used for heat production or steam-raising in power plants and, to a lesser extent, in industry. Typically, steam coal is not of suffici t quality for steel making. Coal of this quality is also commonly known as thermal coal.

Tight oil: Oil produced from shales or other very low permeability formations using hydraulic fracturing. This is also sometim s referred to as light tight oil.

Total final consumption (TFC): Is the sum of consumption by the di erent end-use sectors. TFC is broken down into energy demand in the following sectors: industry (including manufacturing and mining), transport, buildings (including residential and services) and other (including agriculture and non-energy use). It excludes international marine and aviation bunkers, except at world level where it is included in the transport sector.

Total primary energy demand (TPED): Represents domestic demand only and is broken down into power generation other energy sector and total final consumption

Traditional use of solid biomass: Refers to the use of solid biomass with basic technologies, such as a three-stone fire, often with no or poorly operating chimneys.

Transport: Fuels and electricity used in the transport of goods or persons within the national territory irrespecti e 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 internationa marine and aviation bunkers is presented only at the world level and is excluded from the transport sector at the domestic level.

Variable renewable energy (VRE): Refers to technologies whose maximum output at any tim depends on the availability of fluctu ting renewable energy resources. VRE includes a broad array of technologies such as wind power, solar PV, run-of-river hydro, concentratin solar power (where no thermal storage is included) and marine (tidal and wave).

Waste storage and disposal: Activi s related to the management of radioacti e nuclear waste. Storage refers to temporary facilities at the nuclear power plant site or a centralised site. Disposal refers to permanent faciliti s for the long-term isolation of high-level waste, such as deep geologic repositories.

Water consumption: The volume of water withdrawn that is not returned to the source (i.e. it is evaporated or transported to another location) and by definitio is no longer available for other uses.

Water sector: Includes all processes whose main purpose is to treat/process or move water to or from the end-use: groundwater and surface water extraction long-distance water transport, water treatment, desalination water distribution wastewater collection wastewater treatment and water re-use.

Water withdrawal: The volume of water removed from a source; by definitio withdrawals are always greater than or equal to consumption

Regional and country groupings

Advanced economies: OECD regional grouping and Bulgaria, Croatia Cyprus[1,2], Latvia, Lithuania, Malta and Romania.

Africa: North Africa and sub-Saharan Africa regional groupings.

Asia Pacific: Southeast Asia regional grouping and Australia, Bangladesh, China, Chinese Taipei, India, Japan, Korea, Democratic People's Republic of Korea, Mongolia, Nepal, New Zealand, Pakistan, Sri Lanka and other countries and territories.[3]

Caspian: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

Central and South America: Argentina Bolivia, Bolivarian Republic of Venezuela, Brazil, Chile, Colombia, Costa Rica, Cuba, Curaçao, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Suriname, Trinidad and Tobago, Uruguay, and other countries and territories.[4]

China: People's Republic of China, including Hong Kong.

Developing economies: All other countries not included in the "advanced economies" regional grouping.

Eurasia: Caspian regional grouping and the Russian Federation

Europe: European Union regional grouping and Albania, Belarus, Bosnia and Herzegovina, Gibraltar, Iceland, Israel[5], Kosovo, Montenegro, Norway, Serbia, Switzerland, the Former Yugoslav Republic of Macedonia, the Republic of Moldova, Turkey and Ukraine.

European Union: Austria, Belgium, Bulgaria, Croatia Cyprus[1,2], Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain, Sweden and the United Kingdom.

1. Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

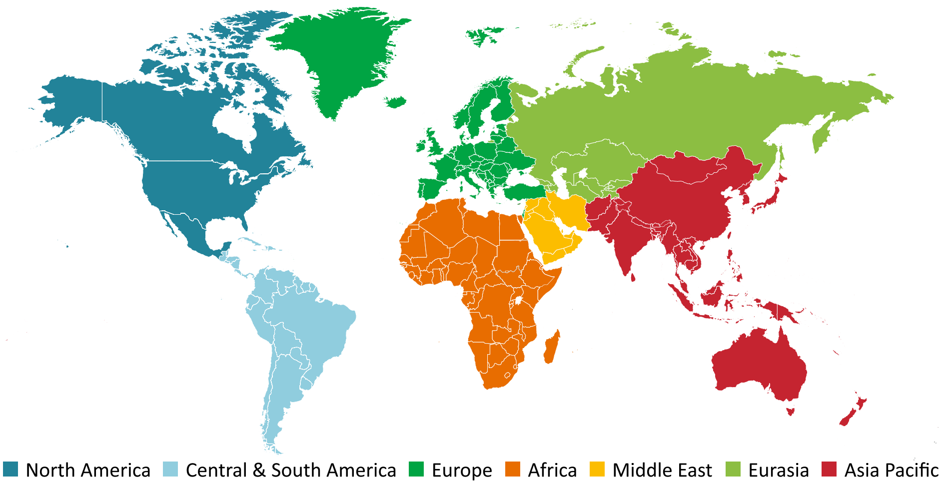
2. Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

3. Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, the Lao People's Democratic Republic, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste and Tonga and Vanuatu.

4. Individual data are not available and are estimated in aggregate for: Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, Bonaire, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guiana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, Saba, Saint Eustatius, Saint Kitts and Nevis, Saint Lucia, Saint Vincent and the Grenadines, Saint Maarten, Turks and Caicos Islands.

5. The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Figure C.2 ▷ ***World Energy Outlook* main country groupings**



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

IEA (International Energy Agency): OECD regional grouping excluding Chile, Iceland, Israel, Latvia, Mexico and Slovenia. Based on membership status as of mid-2017.

Latin America: Central and South America regional grouping and Mexico.

Middle East: Bahrain, the Islamic Republic of Iran, Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, the Syrian Arab Republic, the United Arab Emirates and Yemen.

Non-OECD: All other countries not included in the OECD regional grouping.

North Africa: Algeria, Egypt, Libya, Morocco and Tunisia.

North America: Canada, Mexico and United States.

OECD (Organisation for Economic Co-operation and Development): 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 United States. Latvia became a member of the OECD in July 2016, and its membership is not yet reflec ed in *WEO* projections for the OECD.

OPEC (Organization of Petroleum Exporting Countries): Algeria, Angola, Ecuador, Equatorial Guinea, Gabon, Islamic Republic of Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela.

Southeast Asia: Brunei Darussalam, Cambodia, Indonesia, Lao People's Democrati Republic, Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam. These countries are all members of the Association of Southeast Asian Nations (ASEAN).

Sub-Saharan Africa: Angola, Benin, Botswana, Cameroon, Republic of the Congo, Côte d'Ivoire, Democratic Republic of the Congo, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Mauritius Mozambique, Namibia, Niger, Nigeria, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania, Togo, Zambia, Zimbabwe and other countries and territories.[6]

Abbreviations and Acronyms

APEC	Asia-Pacific Economic Cooperatio
ASEAN	Association of Southeast Asian Nation
BEV	ba ery electric vehicles
CAAGR	compound average annual growth rate
CAFE	corporate average fuel-economy standards (United States)
CBM	coalbed methane
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CEM	Clean Energy Ministerial
CFL	compact fluorescent lamp
CH_4	methane
CHP	combined heat and power; the term co-generation is sometim s used
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CO_2-eq	carbon-dioxide equivalent
COP	Conference of Parti s (UNFCCC)
CPS	Current Policies Scenario
CSP	concentrating solar power
CTG	coal-to-gas
CTL	coal-to-liquids
DER	distributed energy resources
DSI	demand-side integratio
DSR	demand-side response
EOR	enhanced oil recovery
EPA	Environmental Protection Agency (United States)
EU	European Union
EU ETS	European Union Emissions Trading System
EV	electric vehicle
FAO	Food and Agriculture Organization of the United Nation
FDI	foreign direct investment

6. Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cabo Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Réunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland, Uganda and Western Sahara.

FOB	free on board
GDP	gross domestic product
GHG	greenhouse gases
GTL	gas-to-liquids
HDI	human development index
HFO	heavy fuel oil
IAEA	International Atomic Energy Agency
ICT	information and communication technologies
IEA	International Energy Agency
IGCC	integrated gasifi ation combined-cycle
IMF	International Monetary Fund
IOC	international oil company
IPCC	Intergovernmental Panel on Climate Change
LCOE	levelised cost of electricity
LCV	light-commercial vehicle
LED	light-emitting diode
LNG	liquefi d natural gas
LPG	liquefi d petroleum gas
LULUCF	land use, land-use change and forestry
MER	market exchange rate
MEPS	minimum energy performance standards
NDCs	Nationally Determined Contribution
NEA	Nuclear Energy Agency (an agency within the OECD)
NGLs	natural gas liquids
NGV	natural gas vehicle
NPS	New Policies Scenario
NPV	net present value
NOC	national oil company
NO_x	nitrogen oxides
NPS	New Policies Scenario
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of Petroleum Exporting Countries
PHEV	plug-in hybrid electric vehicles
PLDV	passenger light-duty vehicle
PM	particul te ma er
PPA	power purchase agreement
PPP	purchasing power parity
PSH	pumped storage hydropower
PV	photovoltaic
R&D	research and development
RD&D	research, development and demonstratio
RRR	remaining recoverable resource
SDS	Sustainable Development Scenario

SME	small and medium enterprises
SO_2	sulfur dioxide
SWH	solar water or solar water heaters
T&D	transmission and distributio
TES	thermal energy storage
TFC	total final consumptio
TPED	total primary energy demand
UAE	United Arab Emirates
UN	United Nation
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
URR	ultim tely recoverable resources
US	United States
USGS	United States Geological Survey
VRE	variable renewable energy
WACC	weighted average cost of capital
WEO	World Energy Outlook
WEM	World Energy Model
WHO	World Health Organizatio

References

Chapter 8: Outlook for natural gas

BGR (German Federal Institu e for Geosciences and Natural Resources) (2016), *Energiestudie 2016, Reserven, Ressourcen und Verfügbarkeit von Energierohstoffen* (Energy Study 2016, Reserves, Resources and Availability of Energy Resources), BGR, Hannover, Germany.

BP (2017), BP Stati ti al Review of World Energy 2017, BP, London.

Cedigaz (2017), Cedigaz Databases, Cedigaz, Rueil-Malmaison, France, *www.cedigaz.org*.

IEA (International Energy Agency) (2017), *Medium-Term Natural Gas Market Report*, OECD/IEA, Paris.

– (2012), *Golden Rules for a Golden Age of Gas: World Energy Outlook Special Report*, OECD/IEA, Paris.

OGJ (Oil and Gas Journal) (2016), "Worldwide Crude Oil Reserves Down, Production Holds Steady", *OGJ* 114 (12), Pennwell Corporation Oklahoma City, OK., United States.

US DOE/EIA (US Department of Energy/Energy Information Administration) (2017), *Assumptions to the Annual Energy Outlook 2017*, US DOE/EIA, Washington, DC.

US DOE/EIA/ARI (US Department of Energy)/(Energy Information Administration) (Advanced Resources International) (2013 and updated December 2014), *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States*, US DOE/EIA, Washington, DC.

USGS (United States Geological Survey) (2012a), "Assessment of Potential Additions to Conventional Oil and Gas Resources of the World (Outside the United States) from Reserve Growth", *Fact Sheet 2012–3052*, USGS, Boulder, CO., United States.

– (2012b) "An Estim te of Undiscovered Conventional Oil and Gas Resources of the World", *Fact Sheet 2012–3042*, USGS, Boulder, CO., United States.

Chapter 9: The new gas order

IGU (International Gas Union) (2017), *Wholesale Gas Price Survey 2017*, Barcelona, Spain.

Chapter 10: The environmental case for natural gas

Allen et al. (2014), "Methane Emissions from Process Equipment at Natural Gas Productio Sites in the United States: Pneumatic Controllers", *Environmental Science and Technology*, 49 (1), 633–640.

Allen et al. (2013), "Measurements of Methane Emissions at Natural Gas Production Sites in the United States", *PNAS,* 110(44), 17768–17773.

Balcombe et al. (2017), "The Natural Gas Supply Chain: The Importance of Methane and Carbon Dioxide Emissions", *ACS Sustainable Chemistry & Engineering,* 5(1).

Brandt et al. (2016), "Methane Leaks from Natural Gas Systems Follow Extreme Distributions , *Environmental Science and Technology,* 50, 12512–12520.

– (2014), "Methane Leaks from North American Natural Gas Systems", *Science,* 343(6172), 733–735.

Bylin et al. (2010), *Designing the Ideal Offshore Platform Methane Mitigation Strategy*, Society of Petroleum Engineers, Rio de Janeiro, Brazil.

Cathles et al. (2012), A commentary on "The Greenhouse-Gas Footprint of Natural Gas in Shale Formations" by R. Howarth, R. Santoro and A. Ingra ea, *Climatic Change*, 113(2), 525–535.

EPA (US Environmental Protection Agency) (2017a), *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2015*, EPA, Washington, DC.

– (2017b), *Greenhouse Gas Reporting Program (GHGRP), www.epa.gov/ghgreporting/ghgrp-petroleum-and-natural-gas-systems*, accessed 10 September 2017.

– (2016), *Climate Change Indicators: Atmospheric Concentrations of Greenhouse Gases*, *www.epa.gov/climate-indicators/climate-change-indicators-atmospheric-concentrations-greenhouse-gases*, accessed August 2017.

– (2015), *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013,* EPA, Washington, DC.

– (2012), *Global Anthropogenic Non-*CO_2 *Greenhouse Gas Emissions: 1990–2030,* EPA, Washington, DC.

Höglund-Isaksson, L. (2017), "Bo om-Up Simulations of Methane and Ethane Emissions from Global Oil and Gas Systems 1980 to 2012", *Environmental Research Letters,* 12.

– (2012), "Global Anthropogenic Methane Emissions 2005–2030: Technical Miti atio Potential and Costs", *Atmospheric Chemistry and Physics*, 9079–9096.

Howarth et al. (2011), "Methane and the Greenhouse Gas Footprint of Natural Gas from Shale Formations , *Climatic Change*, 679–690.

ICF (ICF Internationa) (2016a), *Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems*, ICF, Fairfax, VA., United States.

– (2016b), *Summary of Methane Emission Reduction Opportunities Across North American Oil and Natural Gas Industries*, ICF, Fairfax, VA., United States.

IEA (International Energy Agency) (2012), *Golden Rules for a Golden Age of Gas: World Energy Outlook Special Report,* OECD/IEA, Paris.

IOGP (International Association of Oil and Gas Producers) (2015), *Environmental Performance Indicators – 2014 Data*, IOGP, London.

IPCC (Intergovernmental Panel on Climate Change) (2014), Climate Change 2014 Synthesis Report, IPCC, Geneva.

– (2006), 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Institu e for Global Environmental Strategies (IGES), Hayama, Kanagawa, Japan.

Joint Research Centre (2013), *Emission Database for Global Atmospheric Research (EDGAR), release EDGARv4.2 FT2010*, *http://edgar.jrc.ec.europa.eu*, accessed August 2017.

Ju et al. (2016), "A New Approach to Estim te Fugiti e Methane Emissions from Coal Mining in China", *Science of the Total Environment,* 543, 514–523.

Marchese et al. (2015), "Methane Emissions from United States Natural Gas Gathering and Processing", *Environmental Science and Technology*, 10718−10727.

Meinshausen et al. (2011), "Emulating coupled atmosphere-ocean and carbon cycle models with a simpler model, MAGICC6: Part I – Model Description and Calibration , *Atmospheric Chemistry and Physics*, 1417–1456.

Myhre et al. (2013), "Anthropogenic and Natural Radiati e Forcing", in Stocker et al. *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*, Cambridge University Press, Cambridge, United Kingdom and New York.

Nisbet et al. (2016), "Rising Atmospheric Methane: 2007–2014 Growth and Isotopic Shi ", *Global Biogeochemical Cycles,* 30 (9), 1356–1370.

Petrenko et al. (2017), "Minimal Geological Methane Emissions during the Younger Dryas-Preboreal Abrupt Warming Event", *Nature*, 548, 443–446.

Saunois et al. (2016), "The Global Methane Budget 2000–2012", *Earth System Science Data,* 8, 697–751.

Schwietzke et al. (2016), "Upward Revision of Global Fossil Fuel Methane Emissions Based on Isotope Database", *Nature*, 88–91.

UNFCCC (United Nations Framework Convention on Climate Change) (2016), *National Inventory Submissions*, *http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/9492.php*, accessed June 2017.

World Bank (2017), *Worldwide Governance Indicators*, *http://info.worldbank.org/governance/wgi/index.aspx#home*, accessed 20 July 2017.

Zavala-Araiza et al. (2015a), "Reconciling Divergent Estim tes of Oil and Gas Methane Emissions", *PNAS*, 15597–15602.

– (2015b), “Toward a Functional Definitio of Methane Super-Emi ers: Applicatio to Natural Gas Production Sites”, *Environmental Science and Technology*, 8167–8174.

Chapter 11: Natural gas in a changing energy world

Al eld, K. and D. Pinchbeck (2013), “Admissible Hydrogen Concentrations in Natural Gas Systems”, *Gas for Energy*.

IEA (International Energy Agency) (2015), *Storing CO_2 through Enhanced Oil Recovery*, OECD/IEA, Paris.

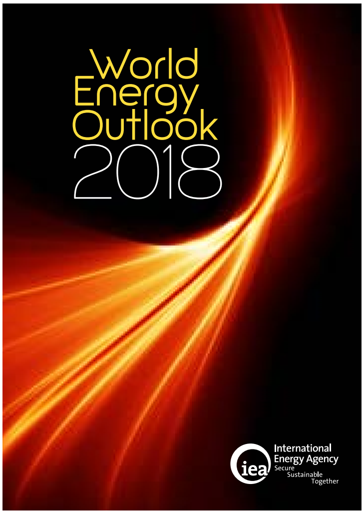
– (2011), *Are We Entering a Golden Age of Gas?*, OECD/IEA, Paris.

IRENA (International Renewable Energy Agency) (2017), *Biogas for Road Vehicles*, IRENA, Abu Dhabi.

Melaina, M., O. Antonia and M. Penev (2013), *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*, National Renewable Energy Laboratory, Golden, CO., United States.

Ricardo-AEA (2016), “*The Role of Natural Gas and Biomethane in the Transport Sector”,* Ricardo-AEA, Didcot, United Kingdom.

World Energy Outlook 2018



The *World Energy Outlook* is the gold standard of long-term energy analysis. The 2018 edition provides updated analysis to show what the latest data, technology trends and policy announcements might mean for the energy sector to 2040. It also outlines an integrated way to meet multiple sustainable development goals: limiting the global temperature rise in line with the Paris Agreement, addressing air pollution, and ensuring universal access to energy.

These points of orientation allow for rigorous thinking about the future against a backdrop of cost reductions in key clean energy technologies, the continued vitality of shale in the United States, and the fast-changing dynamics of energy investment.

This year's Outlook includes a special focus on two critical areas:

- **Electricity**: The future is electrifying, with low-carbon technologies on the rise and electricity demand set to grow at twice the pace of energy demand as a whole. But what will tomorrow's power sector look like? How will it incentivise investment and ensure reliable supply, and what share of our total energy needs can ultimately be met by electricity?
- **Producer economies**: How are traditional oil and gas-exporting countries adapting to a new price and policy environment, and what might be the implications for these economies of longer-term structural changes in demand?

The 2018 *World Energy Outlook* also examines the emissions intensities of different sources of oil and gas as well as what can be done to reduce them, and extends our ground-breaking Sustainable Development Scenario to include the linkages between energy and water.

RELEASE: 13 NOVEMBER

For more information, please visit our website: ***www.iea.org/weo/***

IEA/OECD possible corrigenda on: www.oecd.org/about/publishing/corrigenda.htm

IEA Publications,
International Energy Agency
Website: www.iea.org
Contact information: www.iea.org/about/contact/
Layout in France by DESK - November 2017
(612017271E1) ISBN: 9789264282308
Cover design: IEA, photo credits: Shutterstock