



International
Energy Agency

**ARE WE ENTERING
A GOLDEN AGE OF GAS?**

*Special
Report*

WORLD ENERGY OUTLOOK

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INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 28 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

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 - Improve transparency of international markets through collection and analysis of energy data.
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The European Commission also participates in the work of the IEA.

Acknowledgements

This report was prepared by the Office of the Chief Economist (OCE) of the International Energy Agency. It was designed and directed by **Fatih Birol**, Chief Economist of the IEA, and the analysis was co-ordinated by **John Corben**. Principal contributors to this report were **Maria Argiri, Marco Baroni, Anne-Sophie Corbeau, Laura Cozzi, Ian Cronshaw, Dan Dorner, Matthew Frank, Timur Gül, Paweł Olejarnik, Timur Topalgoekceli, Peter Wood, David Wilkinson** and **Akira Yanagisawa**. Other contributors included **Prasoon Agarwal, Christian Besson, Amos Bromhead, Raffaella Centurelli, Dafydd Elis, Tim Gould** and **Kate Kumaria**. **Sandra Mooney** provided essential support.

Robert Priddle carried editorial responsibility.

The report benefited from valuable comments and feedback from other experts within the IEA, including Bo Diczfalusy, Didier Houssin, Jonathan Sinton and Laszlo Varro. Jane Barbieri, Muriel Custodio, Rebecca Gaghen, Anne Mayne and Bertrand Sadin were essential in readying the report for production. Thanks also go to Debra Justus for proofreading the text.

The work was made possible by the support and co-operation of many government bodies, international organisations and energy companies worldwide, notably: Edison; Energy Studies Institute, Singapore; Eni; Fortum; The Japan Gas Association; The Ministry of Economic Affairs, Agriculture and Innovation, the Netherlands; The Ministry of Petroleum and Energy, Norway; Schlumberger; Shell and Statoil.

Many experts from outside the IEA provided input, commented on the underlying analytical work and reviewed the report. Their comments and suggestions were of great value. They include:

Marco Arcelli	Enel
Georg Baeuml	Volkswagen
Carmen Becerril	Acciona Energia
Kamel Bennaceur	Schlumberger
Alexey Biteryakov	GazpromExport
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Masazumi Hirono	Japan Gas Association
James Jensen	Jensen Associates
Jostein Karlson	Ministry of Petroleum and Energy, Norway
Ken Koyama	Institute of Energy Economics, Japan
Oleg Maximov	Troika Dialog, Russian Federation
Klaus Mohn	Statoil
Ernest Moniz	Massachusetts Institute of Technology, United States

Trevor Morgan	Menecon Consulting
Roberto Potì	Edison
Dinko Raytchev	EC-DG Energy
Howard Rogers	Oxford Institute for Energy Studies, United Kingdom
Alain Sanglerat	GDF Suez
Michael Stoppard	IHS CERA
Wim Thomas	Shell
Umberto Vergine	Eni
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The individuals and organisations that contributed to this study are not responsible for any opinions or judgements it contains. Any errors or omissions are solely the responsibility of the IEA.

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The factors that drive natural gas demand and supply increasingly point to a future in which natural gas plays a greater role in the global energy mix. Global uncertainties afflicting the energy sector can be seen as opportunities for natural gas. When replacing other fossil-fuels, natural gas can lead to lower emissions of greenhouse gases and local pollutants. It can help to diversify energy supply, and so improve energy security. It can provide the flexibility and back-up capacity needed as more variable capacity comes on-line in power generation. Gas is a particularly attractive fuel for regions, such as China, India and the Middle East, which are urbanising and seeking to satisfy rapid growth in energy demand. These are the very regions that will largely determine the extent to which gas use expands over the next quarter of a century.

The global natural gas resource base is vast and widely dispersed geographically. Conventional recoverable resources are equivalent to more than 120 years of current global consumption, while total recoverable resources could sustain today's production for over 250 years. All major regions have recoverable resources equal to at least 75 years of current consumption. Timely and successful development depends on a complex set of factors, including policy choices, technological capability and market conditions. Once discovered, major gas resources can sometimes take several decades to reach production.

Unconventional natural gas resources are now estimated to be as large as conventional resources. Unconventional gas now makes up about 60% of marketed production in the United States. Coalbed methane (CBM) development is growing in Australia, while projects in China, India and Indonesia are in the early stages of development. Use of hydraulic fracturing in unconventional gas production has raised serious environmental concerns and tested existing regulatory regimes. Based on available data, we estimate that shale gas produced to proper standards of environmental responsibility has slightly higher "well-to-burner" emissions than conventional gas, with the combustion of gas being the dominant source of emissions. Best practice in production, effectively monitored and regulated, can mitigate other potential environmental risks, such as excessive water use, contamination and disposal.

The Golden Age of Gas Scenario (GAS Scenario), departing from the WEO-2010 New Policies Scenario – our base case – incorporates a combination of new assumptions that underpin a more positive future outlook for gas. These are implementation by China of an ambitious policy for gas use, lower growth of nuclear power and more use of natural gas in road transport. Ample availability of gas, much of it unconventional gas, keeps average gas prices below the levels assumed in *WEO-2010*.

The main findings and implications of the GAS Scenario are:

- **Global primary gas demand reaches 5.1 trillion cubic metres (tcm) in 2035 – 1.8 tcm more than today and nearly 0.6 tcm more than in the WEO-2010 New Policies Scenario in 2035.** The share of natural gas in the global energy mix increases from 21% to 25% in 2035, pushing the share of coal into decline and overtaking it by 2030. While gas demand expands in all regions, non-OECD countries account for nearly 80% of the total increase between 2010 and 2035, placing a premium on their adoption of efficient gas-fired technologies. China's gas demand rises from about the level of

Germany in 2010 to match that of the entire European Union in 2035. Middle East demand almost doubles, to a level similar to China's in 2035, and demand in India in 2035 is four times that of today. Power generation remains the dominant sector for gas demand and, in the GAS Scenario, gas replaces some coal in power generation in China, India and the United States. There is also a broad-based increase in gas demand growth, spanning the industry, transport and buildings sectors.

- **An increase in production equivalent to about three times the current production of Russia will be required simply to meet the growth in gas demand in 2035. Global natural gas resources can comfortably supply this demand and sustain supplies well beyond.** All regions have the potential to increase gas production and enhance overall energy security. The largest existing producers are expected to meet much of the increase in demand in the GAS Scenario, but they will be joined by China as it becomes one of the world's largest gas producers, although to satisfy rising domestic demand, imports will also be needed. The strongest centres of growth in natural gas production are expected to be the Middle East, Russia, Caspian, North America, China and Africa. Conventional gas will continue to make up the greater part of global production, but unconventional gas becomes increasingly important, meeting more than 40% of the increase in demand. Most of the growth in unconventional gas occurs in North America, China and Australia. The complex issues relating to unconventional gas production mean that these projections, especially in regions where little or no such production has been undertaken to date, are particularly subject to uncertainty. Effective, transparent and stable regulatory frameworks are still needed in some regions, particularly for unconventional gas.
- **Trade between the main world regions more than doubles, with the increase of around 620 bcm split evenly between pipeline gas and liquefied natural gas (LNG).** Natural gas markets are becoming more global and regional prices are expected to show signs of increased convergence, but the market does not become truly globalised. North America will remain largely self-sufficient and is therefore likely to be essentially isolated from inter-regional trade. China will grow to become one of the largest importers of natural gas globally, as Russia and the Caspian region increasingly export both west and east.
- **The different overall global energy mix in the GAS Scenario results in differences in the required type and scale of energy-supply infrastructure.** Cumulative investment in gas-supply infrastructure amounts to around \$8 trillion (12% higher than in the *WEO-2010* New Policies Scenario), but there is slightly reduced supply investment in other fuels. In the near term, there is an urgent need to invest in LNG capacity in some regions.
- **An increased share of natural 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°C.** Natural gas displaces coal and to a lesser extent oil, driving down emissions, but it also displaces some nuclear power, pushing up emissions. Global energy-related CO₂ emissions in 2035 are only slightly lower than those in the New Policies Scenario, at around 35 Gt. This puts emissions on a long-term trajectory consistent with stabilising the concentration of greenhouse gases in the atmosphere at around 650 ppm, suggesting a long-term temperature rise of over 3.5°C. To limit the increase in global temperature to 2°C requires a greater shift to low-

carbon energy sources, increased efficiency in energy usage and new technologies, including carbon capture and storage. The GAS Scenario assumes that support for renewables is maintained but, in a scenario in which gas is relatively cheap, there is a risk that governments' resolve in this respect might waiver, pushing gas demand even higher than projected here.

- **The pricing of gas relative to other fuels has a strong influence on fuel choice.** At the price assumed in the GAS Scenario, rapidly increasing demand is fully met, but the market progressively tightens and the gas glut identified in *WEO-2010* disappears before 2015. More gas production – including significant quantities of unconventional gas – becomes available in several regions later in the *Outlook* period: our analysis suggests that plentiful volumes of shale gas, tight gas and coalbed methane can be produced at costs similar to those in North America (between \$3-7 per MBtu). Despite increasing international trade of gas in the GAS Scenario, demand and supply developments within regions will remain influential in gas price formation. Steps to make markets more responsive to natural gas fundamentals would improve overall economic efficiency. Subsidies encouraging inefficient gas consumption are an example of policies that can distort markets and reduce efficiency. Increased consistency of regulatory and market regimes across borders will encourage investment in inter-regional pipeline infrastructure and so facilitate trade and competition. Ensuring sufficient gas storage will help dampen market volatility and improve energy security.

Are we entering a golden age of gas? Natural gas is a flexible fuel that is used extensively in power generation and competes increasingly in most end-use sectors. It offers environmental benefits when compared to other fossil fuels. Gas resources are abundant, well spread across all regions and recent technological advances have supported increased global trade. However, there will always be uncertainties: lower economic growth, greater cost or other obstacles to unconventional gas production, higher achievements in energy efficiency, changes that improve the relative competitiveness of other fuels; but uncertainty can also work the other way. Based on the assumptions of the GAS Scenario, from 2010 gas use will rise by more than 50% and account for over 25% of world energy demand in 2035 – surely a prospect to designate the Golden Age of Gas.

This report examines the factors that will drive the demand for, and supply of, natural gas in the coming decades, the conditions under which gas could play a far more prominent role in the global energy mix, and the implications that a “golden age of gas” could have for energy markets and the environment.

Section 1 sets out the results of a new global energy scenario – the Golden Age of Gas Scenario (GAS Scenario). We describe the methodological framework and assumptions that underpin this scenario; issues which are explored further in Sections 2 and 3. Section 1 presents in detail the resulting global trends in energy demand and supply (including inter-regional trade), by fuel, region and sector, and their effects on emissions and investment needs. We assess the implications of the GAS Scenario. What are the impacts on other fuels? Does a future with higher gas demand move the world closer to its climate goals? Would it enhance energy security? Will adequate supplies come forward at the prices assumed? And what happens to the current gas glut? Section 1 concludes by reflecting on the main implications of the findings.

Section 2 analyses the developments in gas supply that are shaping and will continue to shape the global picture. It quantifies conventional and unconventional gas resources and assesses the prospects for gas production and trade. This section also considers the issue of gas pricing, exploring and explaining recent market developments.

Section 3 discusses the main drivers of gas demand, including the level of global economic activity, the competitiveness of gas against other forms of energy, and the nature and effects of government policies. It analyses the environmental characteristics of natural gas to help explain its place in achieving reductions in greenhouse-gas emissions and local pollution.

The uncertainty facing the world today makes it wise to consider how unexpected events might change the energy landscape. Starting from the findings of the New Policies Scenario of *WEO-2010*, Section 4 examines the sensitivity of key assumptions and the effects of possible high-impact, but presently unexpected, future events.

The Golden Age of Gas Scenario

Highlights

- The Golden Age of Gas Scenario (GAS Scenario) takes the *WEO-2010* New Policies Scenario as its starting point, and adopts new assumptions that have the effect of building a more positive future outlook for natural gas to 2035. These new assumptions include a more ambitious policy for gas use in China, lower growth of nuclear power, greater production of unconventional gas and lower gas prices. Strong support for renewables is assumed to be maintained.
- In the GAS Scenario, global gas demand is nearly 600 bcm higher than in the *WEO-2010* New Policies Scenario in 2035 – reaching 5.1 tcm. The share of natural gas in the energy mix increases from 21% to 25%, pushing coal into decline and overtaking it by 2030. Non-OECD countries account for nearly 80% of demand growth over the period 2010-2035. China’s demand, around that of Germany in 2010, rises to match that of the entire European Union in 2035. Middle East demand almost doubles, to a level similar to China’s in 2035, and demand in India in 2035 is four times that of today. Power generation remains the dominant sector for gas demand.
- To meet the growth in demand, by 2035 annual gas production must increase by 1.8 tcm, about three times the current production of Russia. China becomes one of the world’s largest gas producers, but still imports more than half of its needs by 2035. Almost all regions see gas production increase significantly, but in Europe it continues to decline. Unconventional gas accounts for more than 40% of the global production increase, with growth mainly in North America, China and Australia.
- CO₂ emissions in the GAS Scenario are only slightly lower than the *WEO-2010* New Policies Scenario, at around 35 Gt in 2035. Where gas replaces demand for other fossil fuels (mainly coal), there is a positive effect on emissions of CO₂ and air pollutants; but where it replaces demand for nuclear, emissions rise. This puts CO₂ emissions on a trajectory consistent with stabilising greenhouse gases at around 650 ppm, resulting in a likely temperature rise of over 3.5°C in the long term. A commitment to limit the increase in temperature to 2°C would therefore require strong additional action to improve energy efficiency, greater adoption of low-carbon energy sources and new technologies, including carbon capture and storage.
- Trade between the main world regions more than doubles, with the increase of around 620 bcm split evenly between pipeline gas and LNG. In the GAS Scenario the gas glut, as defined in *WEO-2010*, dissipates before 2015. The impact and timing of the tightening differs across regions.
- The different energy mix in the GAS Scenario changes the type and scale of energy-supply infrastructure required. Cumulative investment required in gas-supply infrastructure is \$8 trillion – 12% higher than the New Policies Scenario – but this increase is offset slightly by reduced supply investment in other fuels.

Building the scenario

This section presents the results of a new scenario – the Golden Age of Gas Scenario (referred to as the “GAS Scenario”) – which describes a future in which natural gas plays a more prominent role in meeting the world’s energy needs to 2035. The methodological framework and assumptions that underpin this scenario are described. Detailed projections are presented of global trends in energy demand and supply, by fuel, region and sector, and we assess their impact on emissions and investment. In addition, the broader implications of this scenario for government policy are identified.

The GAS Scenario takes the New Policies Scenario in the *World Energy Outlook-2010* (*WEO-2010*) as its starting point (see Section 4 for more details), but incorporates some new assumptions about policy, prices and other drivers that affect gas demand and supply prospects over the *Outlook* period. These assumptions reflect plausible opportunities for gas in the energy system (see Sections 2 and 3 for more discussion). We have kept the number of changes in the assumptions to a minimum to make it easier to understand the differences in the projections between the two scenarios.

Policy and price assumptions

Assumptions about both government policies and inter-fuel competition shape the profile of natural gas demand and supply in the longer term.

The New Policies Scenario already takes account both of existing government policies and declared future intentions as of mid-2010. It assumes that new measures will be introduced to implement policy commitments that have been announced, but only in a relatively cautious manner. These commitments include national pledges to reduce greenhouse-gas emissions and, in certain countries, plans to phase out fossil-energy subsidies. The GAS Scenario incorporates three assumptions about government policies that differ from those shaping the New Policies Scenario in *WEO-2010*. These relate to China’s natural gas policy, the role of nuclear power and the encouragement of the use of natural gas as a road-transport fuel. All other policy assumptions are the same in both scenarios, including the assumption of strong policy support for renewables – driven by a commitment to reach targets – despite lower gas prices (see below).

The GAS Scenario takes into account the new natural gas-related policy included in China’s 12th Five-Year Plan, which was presented at the National People’s Congress in March 2011 and covers the period 2011-2015 (Box 1.1). China’s status as the largest energy consumer in the world, and its strong prospects for future energy demand growth, mean that its policies have major implications for the global energy picture. In the new Plan, as part of a major energy diversification strategy, China aims to achieve an 8.3% share for natural gas in the overall primary energy mix by 2015 (up from 3.8% in 2008). This equates to annual gas demand of 260 billion cubic metres (bcm) in 2015, based on China’s goal for total energy consumption. Reflecting this policy intention, the GAS Scenario anticipates gas consumption of 250 bcm by 2015. While this is slightly less than the targeted level, it is a significant upward revision from the New Policies Scenario, in which demand is projected to reach 170 bcm in 2015, itself a rise from 107 bcm in 2010.

Box 1.1 ► The impact of China's policy decisions on natural gas demand

China is currently the most important country in shaping future energy markets. Its existing energy demand and its potential for economic growth mean that its policy choices can dramatically affect the trajectory of global gas demand.

China's 12th Five-Year Plan (FYP), for the period 2011-2015, maps a path for more sustainable economic growth, focusing on energy efficiency and the use of cleaner energy sources to mitigate the effects of rapidly rising energy demand, which would otherwise increase China's dependence on imports and exacerbate local pollution. Reducing energy and carbon intensity are two key goals of the Plan. The Plan sets a target for cutting energy intensity (primary energy consumption per unit of GDP) by 16% by 2015 (energy intensity was lowered by around 20% during the 11th FYP). Carbon intensity targets, included for the first time, are in line with China's Copenhagen pledge of 40% to 45% reductions below 2005 levels by 2020. The 12th FYP establishes new targets for the primary energy mix: natural gas, nuclear and renewables are to be aggressively promoted, with provision for 120 GW of hydro, 70 GW of new wind power, 40 GW of new nuclear and 5 GW of solar. Even though China's coal use grows substantially, the share of coal in primary energy consumption drops from 66% in 2008 to 63% in 2015.

The 12th FYP has strong implications for natural gas use, targeting an 8.3% share in the primary energy mix in 2015 (260 bcm annually based on China's goal for energy consumption). This is a major upward shift from the 85 bcm consumed in 2008 (3.8% of energy use). While the 11th FYP aimed for a 5.3% target share for gas, this level was not attained because of China's strong growth in energy demand.

China is encouraging natural gas use in all sectors in the long term. However, in the near term priority is given to urban residential gas use and power generation, while it is discouraged in other sectors (e.g. ammonia and methanol production). Industry, the largest gas user in China today, has strong demand growth potential and reduced emissions could be achieved by switching from coal. In buildings, several factors including government policies and expanding distribution infrastructure (particularly in the coastal cities), are capable of driving higher gas penetration. Only around 10% of China's population presently has access to natural gas, well-below the world average of 40%. Power generation is also a major potential source of growth, with gas accounting for only about 1% of electricity generated in China in 2008, though gas in the power sector faces strong competition from coal, which is cheaper in most cases. Higher gas usage will depend on sustained low gas prices, environmental regulation and sufficiency of supply, as well as developments in the coal sector. Gas may also find a niche in the power sector in regions far from domestic coal supplies.

On the supply side, China is preparing for more gas. Higher prices have encouraged domestic production and attracted international companies to China's upstream sector. China's oil companies are also buying shale gas resources in North America and working with international oil companies to gain experience that can be applied domestically. A Sino-US Shale Gas Resources Cooperation Initiative was launched in 2009. China continues to install LNG regasification terminals, and plans to achieve at least 64 bcm of annual import capacity by 2015, most of which is already operational or being built. Planning for expansions and completion of pipelines is also advanced.

The GAS Scenario assumes that there will be lower global nuclear power generation capacity in the future than in the New Policies Scenario (though it is still significantly higher than today). This is a result both of fewer existing nuclear power plants having their operational life extended and fewer new nuclear power plants being built over the *Outlook* period. The reduction in nuclear power capacity is driven both by prices, as gas becomes relatively more competitive (see below) and by government policy. Following the disaster at the Fukushima nuclear power plant in Japan, many governments have reviewed the safety of existing facilities and plans for new nuclear installations. Germany, for example, has mothballed 7 GW of nuclear capacity – its oldest plants – pending a safety review. China, Thailand and others have suspended approvals for new nuclear power plants, until a safety review has been completed. The long-term impact of this disaster is not yet foreseeable, but it is reasonable to assume that it will result in one or more of the following:

- a temporary or permanent shutdown of some existing nuclear power plants;
- a shorter operating life for some nuclear plants, either as a result of early retirements or increased reluctance to extend the life of nuclear power plants;
- additional safety regulations, impacting on nuclear plant operating costs; and
- delay to, or rejection of, plans to build some previously expected new nuclear power plants.

The probability of these changes happening is arguably greatest in Organisation of Economic Development and Co-operation (OECD) countries, where existing nuclear plants are concentrated; but a slower pace of new development in non-OECD countries may also occur. Natural gas is the fuel most likely to benefit from a switch away from nuclear, because of its relative abundance, environmental benefits compared with other fossil fuels and lower capital cost, though a greater drive towards renewable energy cannot be ruled out. The GAS Scenario assumes that 330 GW of new nuclear capacity will be added from 2009 to 2035, around 10% less than in the New Policies Scenario. In terms of total capacity, the New Policies Scenario projects about 645 GW of nuclear power generation capacity in 2035, compared with 610 GW in the GAS Scenario.

The third new policy assumption introduced into the GAS Scenario, relates to natural gas use in the road-transport sector. Despite the existence of technology that would allow substitution from oil products, the penetration of natural gas in road transport is currently low, representing an estimated 12 million vehicles worldwide, and equating to around 20 bcm in gas demand (less than 1% of total road-fuel energy consumption). Natural gas use in road transport grows only slowly in the New Policies Scenario. There is significant scope for faster penetration if there is both a favourable price differential between natural gas and oil (see price assumption below) and direct government support.

While no completely new demand or supply side technologies are assumed to be deployed, the GAS Scenario does assume that governments in some countries act to encourage the introduction of greater numbers of natural gas vehicles (NGVs) than in the New Policies Scenario, consolidating the assumed increase in the competitiveness of natural gas as a road-transport fuel because of lower wholesale gas prices. Whereas the New Policies Scenario includes around 30 million NGVs in 2035, the GAS Scenario assumes that there will be around 70 million. This is still significantly below the 186 million vehicles included in a *high-impact low-probability* sensitivity case for NGVs developed in Section 4.

Price is a crucial determinant of the level of future global gas demand. The price assumptions for coal and oil in the GAS Scenario are the same as for the *WEO-2010* New Policies Scenario (though they will be reviewed for *WEO-2011*). Although the price paths in the scenarios are annual averages that follow smooth trends, in reality prices are likely to fluctuate, potentially sharply. The average IEA crude oil import price, a proxy for international prices, reaches \$105 per barrel¹ in 2025 and \$113 per barrel in 2035. The IEA steam coal import prices increase from \$97 per tonne in 2009 to \$107 per tonne in 2035.

Demand for energy services, and the fuel mix used to provide them, is sensitive to the absolute and relative levels of the price of each fuel. The fuel prices used here are assumptions not forecasts and follow the same methodology as *WEO-2010*. They are derived from assumptions about the international prices of fossil fuels, and take account of taxes, excise duties and carbon dioxide (CO₂) emissions penalties and any subsidies.

By contrast, the price assumptions for natural gas are markedly different in the two scenarios (Table 1.1). Though (like coal and oil) based on our view of the long term price needed to stimulate sufficient investment in supply to meet demand, the level of gas prices in the GAS Scenario throughout the *Outlook* period is now around \$1.50-\$2.50 per million British thermal units (MBtu) lower² in most cases than in the New Policies Scenario. Despite the observed trend of increasing globalisation of natural gas, we assume in both scenarios that the price differentials between the United States, Europe and Japan remain broadly constant. This reflects the relative isolation of these markets from one another and the cost of transport between regions.

Table 1.1 ► Natural gas import price assumptions by scenario
(in year-2009 dollars per MBtu)

	GAS Scenario						New Policies Scenario <i>WEO-2010</i>				
	2009	2015	2020	2025	2030	2035	2015	2020	2025	2030	2035
United States	4.1	5.6	6.1	6.4	7.0	8.0	7.0	8.1	9.1	9.9	10.4
Europe	7.4	9.0	9.5	9.7	10.1	10.9	10.6	11.6	12.3	12.9	13.3
Japan	9.4	11.5	11.7	11.9	12.3	12.9	12.2	13.4	14.2	14.9	15.3

Note: Natural gas prices are weighted averages, expressed on a gross calorific-value basis. Prices are for wholesale supplies exclusive of tax. The United States gas import price is used as a proxy for prices prevailing on the domestic market.

While the price path assumed for natural gas in the New Policies Scenario follows a relatively constant upward path and gas prices in the GAS Scenario also rise steadily to 2035, the shape of the path is different, the rate of increase in the GAS Scenario slowing around the middle of the *Outlook* period before accelerating again as it approaches 2035. This price path reflects our expectation of changing demand and supply fundamentals. In particular, it represents a more optimistic assumption relating to future gas supply, primarily the availability of additional unconventional gas supplies at relatively low cost. Underlying this assumption is the expectation that the potential barriers to further unconventional gas production will be largely overcome and that increased supplies

¹ All prices presented in this report are in year-2009 US dollars.

² Approximately one-fifth cheaper, but it varies by region and over time.

become available in other regions at costs comparable to those in North America (see Section 2 for more discussion). Liberalisation of gas markets, resulting in more widespread gas-to-gas competition, could contribute to lower unit gas supply costs by encouraging efficiency gains along the gas-supply chain.

While renewables are expected to become increasingly competitive as fossil-fuel prices rise and technologies mature, the strength of government support is a critical factor in determining how quickly this occurs. In the GAS Scenario, we have assumed that governments will continue to provide regulatory and financial support for renewables (*WEO-2010* estimated government support worldwide for both electricity from renewables and for biofuels totalling \$57 billion in 2009). However, lower gas prices may put pressure on some governments to review their policies and level of support.

The GAS Scenario adopts the same CO₂ price assumptions as the New Policies Scenario.³ It therefore includes the formal cap-and-trade schemes already adopted by the European Union and New Zealand. It also assumes that cap-and-trade schemes covering the power and industry sectors are established in Australia and Japan from 2013, Korea from 2015 and in all other OECD countries after 2020. The CO₂ price is assumed to converge across all of these countries to \$50 per tonne in 2035 but with differing price trajectories to that point. The lower gas prices assumed in the GAS Scenario mean that electricity prices are also lower.

Other assumptions

The GAS Scenario adopts the same population and economic growth assumptions as the New Policies Scenario in *WEO-2010*.⁴ World population is assumed to expand from an estimated 6.7 billion in 2008 to 8.5 billion in 2035, an annual average rate of increase of around 1%. The increase in global population is expected to occur overwhelmingly in non-OECD countries, mainly in Asia and Africa. All of the increase in world population occurs in urban areas. It is assumed that the world economy grows on average by 4.4% over the five years to 2015. In the longer term, the rate of growth eases as emerging economies mature. The global economy is assumed to grow by 3.4% per year on average over the period 2010-2035. In general, the non-OECD economies grow the fastest.

In building the GAS Scenario, we have used 2008 as the base year. This is consistent with the New Policies Scenario. However, 2009 and 2010 have been exceptional years in energy terms and account has been taken of these recent developments, where appropriate. After a 2% decline in global natural gas demand in 2009, estimates suggest that gas demand rebounded by around 7.5% in 2010, reaching about 3.3 trillion cubic metres (tcm), 5% higher than in 2008. However, such a large demand growth number should be interpreted with care. Stronger global economic growth in 2010 than 2009 supported a rebound in global energy demand, but the recovery was uneven across regions. Furthermore, an unusually cold winter occurred in some regions (greater heating demand) and hot summers in others (greater air conditioning demand): both increased primary gas demand in 2010 and may be masking underlying trends.

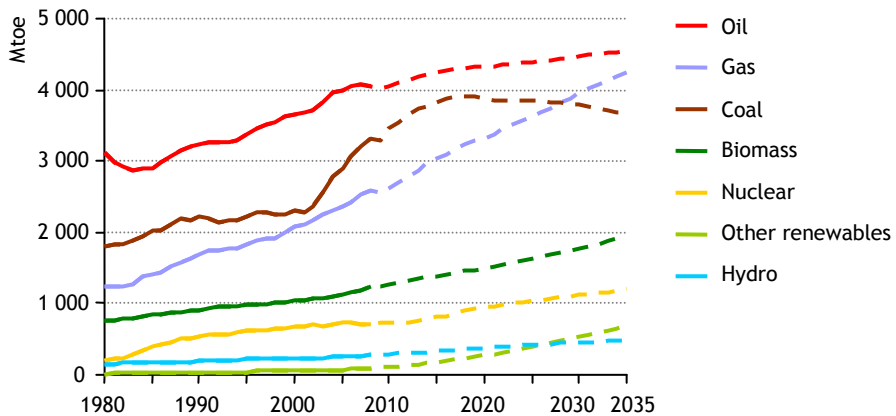
³ They therefore do not reflect some relatively small changes since the publication of *WEO-2010*.

⁴ See Chapter 1 of *WEO-2010* for detailed assumptions (IEA, 2010e).

Primary demand

In the GAS Scenario, global primary energy demand is projected to rise from around 12 300 million tonnes of oil equivalent (Mtoe) in 2008 to 16 800 Mtoe in 2035 – an increase of over 35%. This is slightly higher than in the New Policies Scenario, largely because of the assumed lower price of gas. The average rate of growth in energy demand slows during the *Outlook* period, from 1.5% per year in the period 2008-2020 to 0.9% per year in 2020-2035. The demand for all energy sources increases over the *Outlook* period. Fossil fuels (oil, coal and natural gas) account for more than half of the increase and remain the dominant energy sources in 2035 (Figure 1.1). However, the share of fossil fuels in the overall primary energy mix decreases from 81% in 2008 to just over 74% in 2035, marginally higher than in the New Policies Scenario. The rest of the increase in global energy demand through to 2035 is accounted for by renewables and nuclear power.

Figure 1.1 ▶ World primary energy demand by fuel in the GAS Scenario



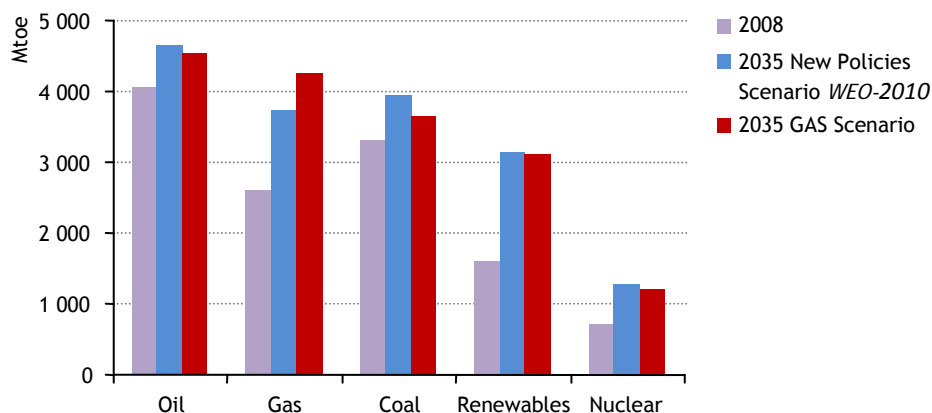
In the GAS Scenario, global primary natural gas demand is around 600 bcm higher than in the New Policies Scenario in 2035. It increases from 3.1 tcm in 2008 to 5.1 tcm in 2035 – an increase of 62% – the average rate of increase in gas demand being nearly 2% per year. Unsurprisingly, natural gas sees the strongest demand growth of all energy sources in absolute terms in the GAS Scenario.

Natural gas increases from 21% of the world's fuel mix in 2008 to 25% in 2035, compared with 22% in the New Policies Scenario. The combined effect of a strong increase in natural gas demand throughout the *Outlook* period and a decline in global coal demand from around 2020 onwards results in global demand for natural gas overtaking coal before 2030, to become the second-largest fuel in the primary energy mix. The GAS Scenario also sees demand for natural gas narrowing significantly the gap with oil by the end of the *Outlook* period.

While oil continues to be the dominant fuel in the primary energy mix (Figure 1.2), with demand increasing from 4 060 Mtoe in 2008 (85 million barrels per day [mb/d]) to just under 4 550 Mtoe in 2035 (97 mb/d), its share of the mix drops from 33% in 2008 to 27% in 2035. High prices promote further switching away from oil in the industrial sector and opportunities emerge to substitute other fuels for oil products in road-transport.

Primary coal demand increases from 3 315 Mtoe in 2008 (4 736 million tonnes of coal equivalent [Mtce]) to 3 670 Mtoe in 2035 (5 240 Mtce), a rise of 11% in the GAS Scenario. It peaks around 2018 and then declines by nearly 250 Mtoe (6%) over the remainder of the *Outlook* period. The decline between 2018 and 2035 is comparable with the annual coal demand of OECD Pacific in 2008. The projected decline in coal demand in the GAS Scenario contrasts with a levelling-off of demand from around 2020 in the New Policies Scenario.

Figure 1.2 ▶ **World primary energy demand by fuel and scenario**



The share of nuclear power in global primary energy supply increases from 6% in 2008 to 7% in 2035 – with 330 GW of new generating capacity added – but it is below the 8% projected in the New Policies Scenario. This is partly in response to the imposed assumption of a 10% fall in nuclear, but also because lower prices mean that gas competes more effectively with nuclear power for power generation. Hydro, biomass and other renewables all see their share of the energy mix increase in the GAS Scenario, the increase being about the same as in the New Policies Scenario. The absolute level of renewable energy supply is relatively unchanged from the New Policies Scenario. This is because we assume that government support for renewables is kept in place in order to meet targets, despite the lower gas prices.

The combination of more competitive gas prices, policy changes in China to 2015, a more restricted outlook for nuclear power and increased future uptake of NGVs results in a significant increase in natural gas demand over the *Outlook* period. The majority of the increase in primary natural gas demand relative to the New Policies Scenario comes at the expense of coal and oil (Table 1.2). A much smaller share comes from replacing nuclear. Renewables are relatively unchanged, in response to our assumptions.

Energy demand is expected to continue to grow much more quickly in non-OECD countries. Their primary energy demand increases by almost 65% from 2008 to 2035 in the GAS Scenario. Non-OECD countries account for over 90% of all energy demand growth globally and see their share of global energy use increase from 53% in 2008 to 64% in 2035. Faster rates of economic and population growth, urbanisation and industrial production all play a part in stimulating stronger energy demand growth than in the OECD. Despite OECD consumption increasing by around 3% over the *Outlook* period, its contribution to global

primary energy demand continues its decline from 55% in 1981 to 44% in 2008, and then to just 33% in 2035.⁵

Table 1.2 ▶ **World primary energy demand by fuel and scenario**

	2008		GAS Scenario		New Policies Scenario <i>WEO-2010</i>	
	Demand (Mtoe)	Share in energy mix	2035 Demand (Mtoe)	2035 Share in energy mix	2035 Demand (Mtoe)	2035 Share in energy mix
Coal	3 315	27%	3 666	22%	3 934	23%
Oil	4 059	33%	4 543	27%	4 662	28%
Gas	2 596	21%	4 244	25%	3 748	22%
Nuclear	712	6%	1 196	7%	1 273	8%
Hydro	276	2%	477	3%	476	3%
Biomass	1 225	10%	1 944	12%	1 957	12%
Other renewables	89	1%	697	4%	699	4%
Total	12 271		16 765		16 748	

Regional demand trends

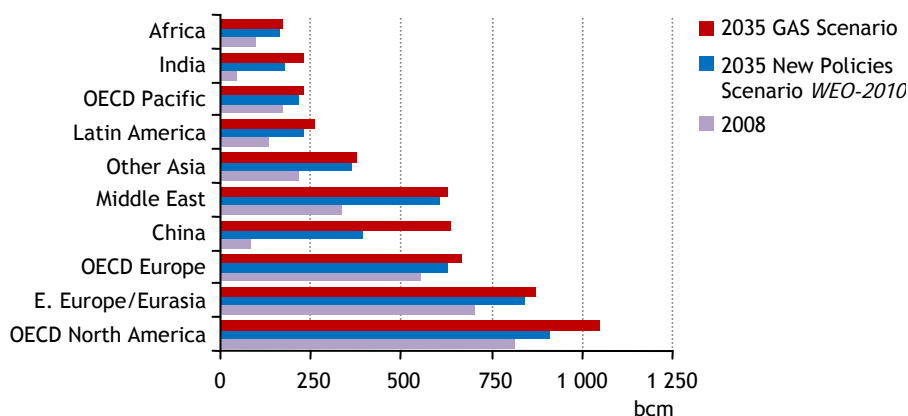
In the GAS Scenario, demand for natural gas grows in all *WEO* regions⁶ over the *Outlook* period. In the OECD, while demand for natural gas increases in absolute terms over 2008 to 2035, demand for oil and coal declines significantly. China accounts for nearly 30% of world gas demand growth. In volumetric terms, gas demand in China increases dramatically, from 85 bcm in 2008 to 635 bcm in 2035 (Figure 1.3). Overwhelmingly, this increase comes at the expense of coal. Overall, China's total primary energy demand in 2035 is slightly lower than in the New Policies Scenario. This is mainly because there is a shift from coal to gas, which can be transformed more efficiently into electricity. Gas demand in power generation in China increases relative to the New Policies Scenario, but the increase is not large in absolute terms. Gas demand increases much more in industry, which sees average annual growth of around 9% between 2008 and 2035, and in the buildings sector, where demand reaches 170 bcm, more than 80% higher than in the New Policies Scenario in 2035.

India already experiences very strong growth in natural gas demand in the New Policies Scenario, but from a low base. The GAS Scenario sees demand in 2035 boosted by around a further 57 bcm, mainly as a result of an increase in gas use in power generation and to meet transport demand. In response, oil demand in the transport sector in India falls by around 0.6 mb/d in 2035 compared with the New Policies Scenario. India's total primary natural gas demand is still only around one-third that of China by the end of the *Outlook* period.

⁵ The OECD and non-OECD shares of global energy demand do not sum to world energy demand as they do not include international marine and aviation bunkers.

⁶ Definitions of the *WEO* regions can be found online at www.worldenergyoutlook.org/model.asp

Figure 1.3 ▶ Primary natural gas demand by region and scenario



In the GAS Scenario, the Middle East sees an increase in gas demand of around 300 bcm, to reach over 630 bcm by 2035. Much of the overall increase in gas demand is a result of rapid growth in electricity demand, and increased industrial use. Demand in the GAS Scenario is around 25 bcm higher than in the New Policies Scenario, more than 60% of this increase is demand from gas-to-liquids (GTL) plants.

In Latin America, the GAS Scenario sees significantly faster gas demand growth. Brazil is the main driver of regional gas demand, growing from 25 bcm in 2008 to 98 bcm in 2035 and its share of total demand in Latin America rising from 19% to 38%. Demand growth is driven primarily by industry and power generation, including gas use for power peaking capacity in support of renewables.

Within the OECD, the United States sees the largest change in natural gas demand *vis-à-vis* the New Policies Scenario. At nearly 790 bcm in 2035, gas demand is around 18% higher. This increase is driven by the power generation and transport sectors, causing coal demand to drop by around 9% and oil demand by around 6% in 2035, compared with the New Policies Scenario. In the power sector, lower gas prices prompt increased electricity demand and therefore higher capacity additions, but it also means that gas-fired generating capacity substitutes for the most inefficient coal-fired generating capacity. In the GAS Scenario, the share of coal in the electricity generation mix declines from 49% in 2008 to 30% in 2035, and gas increases from 21% in 2008 to 27% in 2035. In the transport sector, the increase in NGVs is driven initially by commercial fleet vehicles, such as buses.

Gas demand in OECD Europe reaches nearly 670 bcm in 2035 in the GAS Scenario (Table 1.3). Power generation accounts for about three-quarters of the additional gas demand over the *Outlook* period. In Japan, demand for gas in power generation is around 10% higher in 2035 than in the New Policies Scenario. Most of this change occurs in the early part of the *Outlook* period, where demand for liquefied natural gas (LNG) increases to offset lower growth in nuclear power.

Table 1.3 ▶ Primary natural gas demand by region in the GAS Scenario (bcm)

	2008	2015	2020	2025	2030	2035	2008-2035*	Change vs. NPS 2035**
OECD	1 541	1 615	1 691	1 773	1 865	1 950	0.9%	192
North America	815	841	872	924	986	1 052	0.9%	138
<i>United States</i>	662	661	668	700	741	786	0.6%	122
Europe	555	574	608	636	653	667	0.7%	38
Pacific	170	200	210	213	226	231	1.1%	15
<i>Japan</i>	100	118	122	123	127	127	0.9%	10
Non-OECD	1 608	2 070	2 328	2 611	2 912	3 182	2.6%	405
E. Europe / Eurasia	701	755	786	824	857	876	0.8%	38
<i>Russia</i>	453	474	487	504	522	528	0.6%	25
Asia	341	576	715	864	1 049	1 244	4.9%	309
<i>China</i>	85	247	335	430	535	634	7.7%	239
<i>India</i>	42	81	104	134	176	234	6.5%	57
Middle East	335	428	470	536	592	632	2.4%	23
Africa	100	139	154	164	170	173	2.1%	9
Latin America	131	172	203	224	245	258	2.5%	26
<i>Brazil</i>	25	48	66	76	88	98	5.1%	21
World	3 149	3 685	4 019	4 384	4 778	5 132	1.8%	597
<i>European Union</i>	536	553	587	609	621	636	0.6%	38

*Compound average annual growth rate.

**NPS is New Policies Scenario.

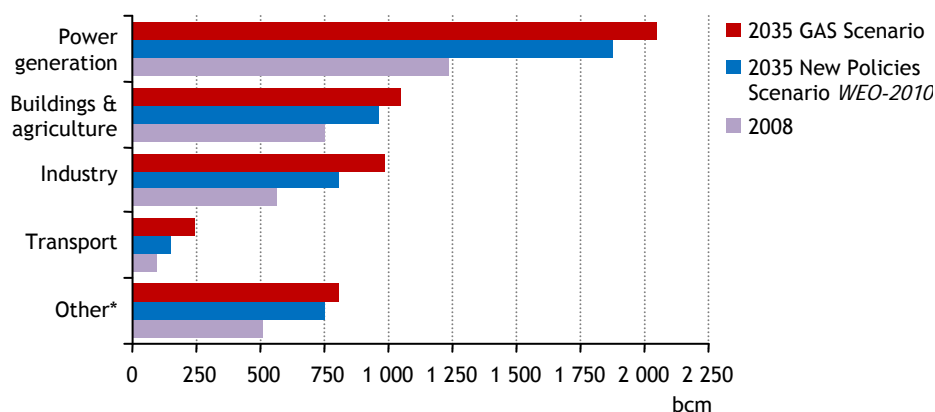
Sectoral demand trends

In the GAS Scenario, a broad increase in natural gas demand is observed across sectors, reflecting its flexibility as an energy source. The largest sector for gas demand continues to be power generation and, along with the industry sector, it experiences the biggest increase compared to the New Policies Scenario in 2035 (Figure 1.4).

In the GAS Scenario, global demand for energy as an input to power generation in 2035 is slightly lower than in the New Policies Scenario. This is despite the fact that electricity consumption in 2035 is around 1% higher than in the New Policies Scenario, in response to lower gas prices. The difference is explained by the much higher average efficiency of gas conversion in power generation.

The gas input to power generation exceeds 2 tcm by the end of the *Outlook* period. This growth reinforces the position of the power sector as by far the largest source of natural gas demand, the sector's 39% share of global natural gas demand in 2008 rises to 40% by 2035 in the GAS Scenario (compared with 41% in the New Policies Scenario).

Figure 1.4 ▶ World primary natural gas demand by sector and scenario



* Includes other energy sector and non-energy use. Other energy sector includes energy consumed in oil and gas production, gas-to-liquids transformation and distribution losses. Non-energy use includes inputs to petrochemicals.

In the GAS Scenario, the share of natural gas in electricity generation increases from 21% to 24% in 2035. This increase comes mainly at the expense of coal, as well as nuclear power, where policy decisions and less competitive prices slow down growth in this scenario. The share of oil in power generation, already small, continues to decline. Assumed support policies help ensure that the growing use of biomass and other renewables is not substantially eroded by natural gas use: there is scope for their co-existence in the power generation mix, natural gas being an option to meet peaking and variability requirements. However, with lower gas prices in this scenario, resolute government commitment to undiminished support for renewables will be required to maintain their assumed role in the energy mix. The way natural gas demand in the power generation sector responds to economic, environmental and other uncertainties, all of which will impact its desirability relative to other fuels, is elaborated in Section 3.

Total final consumption of natural gas in the GAS Scenario is projected to reach 2.5 tcm by 2035, 17% higher than in the New Policies Scenario. Demand in the buildings sector – the largest end-use sector – reaches over 1 tcm by 2035. In the OECD, further demand for gas to provide space and water heating is relatively low, but in many non-OECD countries the remaining potential is large. Demand for gas in the buildings sector more than doubles in non-OECD countries over the *Outlook* period and is nearly 80 bcm higher than the New Policies Scenario in 2035. The massive scale of construction in China drives a particularly high growth rate in gas use in the buildings sector. In comparison, growth in the OECD is less than 10% over the period and is concentrated in Europe.

In the GAS Scenario, natural gas demand in the industry sector increases by around 75% over the *Outlook* period, to reach nearly 1 tcm, 185 bcm more than the New Policies Scenario. Again, OECD countries see relatively little change in gas demand in industry over 2008 to 2035. Those countries that experience increased demand in the first half of the *Outlook* period, such as the United States, typically see this reversed later as demand declines in gas-intensive industries. In the GAS Scenario, non-OECD industrial gas demand

grows to 680 bcm; increasing from less than half of the global total in 2008 to more than two-thirds of the total in 2035 (63% in the New Policies Scenario). China’s policy decision to increase the share of gas in its energy mix accounts for much of the faster growth, with its industrial demand reaching nearly 240 bcm in 2035. Over the same time period, demand for coal in China’s industrial sector declines by nearly 50 Mtoe and oil by around 10 Mtoe. The Middle East sees natural gas demand in the industry sector grow by around 80%, to reach 105 bcm by the end of the *Outlook* period.

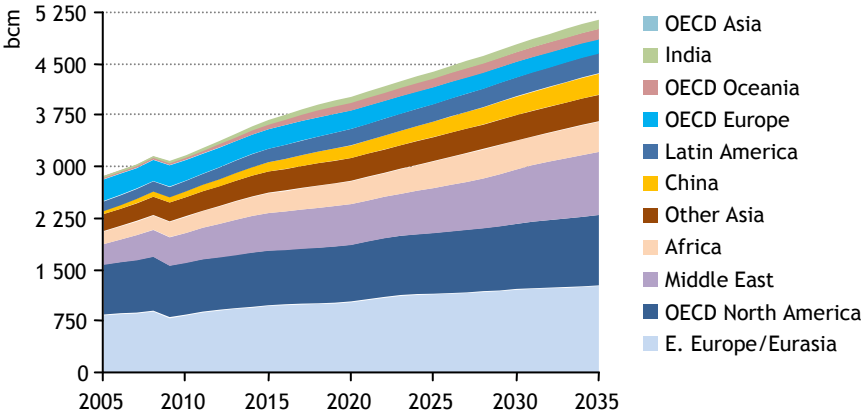
The growth in demand for gas in road transport in the GAS Scenario is the result of sustained policy support in key markets and lower gas prices making it more competitive as a road transport fuel. Natural gas use in road transport grows to 155 bcm in 2035, over 90 bcm higher than the New Policies Scenario. Road transport demand for oil in 2035 correspondingly drops by 60 Mtoe (1.2 mb/d), a reduction of just under 3%, compared with the New Policies Scenario.

Gas production

Global natural gas resources can comfortably meet demand in the GAS Scenario through to 2035 and well beyond. As always, the key question is whether investment in production will keep pace with demand at the prices assumed. Although there are important differences between regions, we judge that the costs of production, especially for unconventional gas will decline at least commensurately with the assumed decline in the average price. This is due to North American experience spreading more rapidly and resource holding countries adopting policies to encourage higher investment, primarily in order to reduce their imports.

In the GAS Scenario, total global gas production grows from an estimated 3.3 tcm in 2010 to 5.1 tcm by 2035 (Figure 1.5), an increase of more than 50%, and more than double global gas production in 2000. The average annual growth in gas production is 2% from 2008 to 2020, but then moderates to around 1.6% for the remainder of the *Outlook* period. Natural gas production increasingly comes from unconventional sources, their share of total output rising from 12% in 2008 to nearly 25% in 2035.

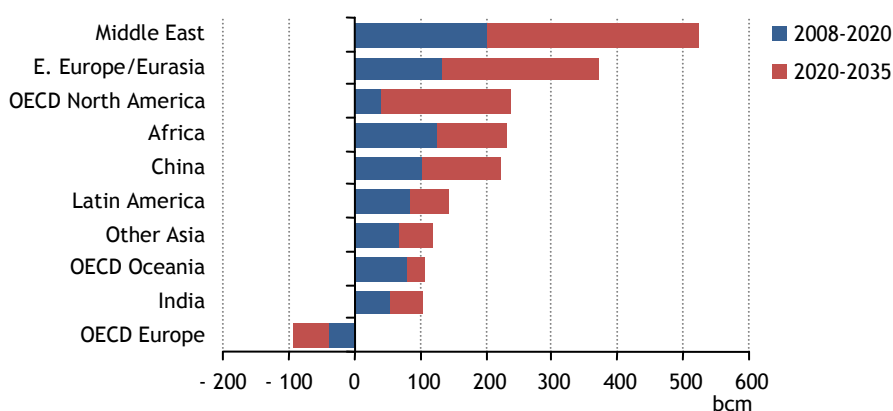
Figure 1.5 ▶ Natural gas production by region in the GAS Scenario



Regional trends

Natural gas production in non-OECD countries reaches 3.7 tcm in 2035 in the GAS Scenario: these countries account for more than 85% of the global increase in gas production over the *Outlook* period. As a result, the share of global production in non-OECD countries increases from 63% in 2008 to 73% in 2035 (it reaches 74% in the New Policies Scenario). Production in the OECD grows by around 250 bcm, reaching just over 1.4 tcm by 2035, compared with less than 1.2 tcm in the New Policies Scenario. Supply growth in the OECD satisfies only around 60% of the region's demand growth over the *Outlook* period. Worldwide, the largest existing producers, such as Russia, the United States and the Middle East, are expected to meet much of the increased demand in the GAS Scenario (Figure 1.6), but they will also be joined by China over the course of the *Outlook*.

Figure 1.6 ▶ Change in natural gas production by region in the GAS Scenario



In the GAS Scenario, the region of Eastern Europe/Eurasia (essentially Russia and the Caspian region) remains the largest gas producer throughout the *Outlook* period and Russia remains the largest gas producing country (Table 1.4). Gas production in the region grows by over 370 bcm, to reach 1.26 tcm in 2035. Production in Russia alone grows by 220 bcm over the *Outlook* period, including production from the Yamal peninsula, the Shtokman field and fields in Eastern Siberia used to supply China in the longer term. In Turkmenistan, gas production nearly doubles by 2035. Growth in regional production is expected to be strong in the near term, as the recovery from the global economic crisis continues, and the region is expected to surpass its pre-crisis peak in annual gas production and exports before 2015. Over the *Outlook* period, annual growth in regional production consistently outstrips annual growth in regional demand, supporting increases in exports. Despite this production growth, the region's share of global gas production decreases from 28% in 2008 to 24% in 2035. More than three-quarters of the growth in supply in the region is expected to be from conventional gas. Unconventional gas production grows more strongly after 2020 but it is still a relatively small share of regional production by 2035 (less than 10%).

Table 1.4 ► Natural gas production by region in the GAS Scenario (bcm)

	2008	2015	2020	2025	2030	2035	2008-2035*	Change vs. NPS 2035**
OECD	1 157	1 175	1 237	1 280	1 343	1 404	0.7%	216
North America	797	805	837	891	961	1 035	1.0%	189
<i>Canada</i>	175	149	166	184	189	192	0.3%	18
<i>United States</i>	575	608	618	647	709	779	1.1%	173
Europe	307	281	270	250	232	213	-1.4%	6
<i>Norway</i>	102	106	114	123	128	127	0.8%	5
Pacific	53	90	130	139	149	156	4.1%	21
<i>Australia</i>	45	84	126	136	147	155	4.7%	21
Non-OECD	2 010	2 509	2 782	3 104	3 435	3 728	2.3%	381
E. Europe / Eurasia	886	967	1 019	1 136	1 203	1 257	1.3%	80
<i>Russia</i>	662	706	720	801	842	881	1.1%	67
<i>Turkmenistan</i>	71	83	104	116	127	136	2.4%	8
Asia	376	512	604	673	748	823	2.9%	170
<i>China</i>	80	137	185	222	264	303	5.0%	119
<i>India</i>	32	67	88	102	119	135	5.5%	34
<i>Indonesia</i>	74	87	95	102	109	119	1.8%	9
Middle East	393	550	594	657	793	917	3.2%	116
<i>Iran</i>	130	143	154	179	226	279	2.9%	44
<i>Qatar</i>	78	166	182	197	238	260	4.5%	35
<i>Saudi Arabia</i>	74	95	100	107	125	139	2.3%	15
Africa	207	288	331	386	415	438	2.8%	3
<i>Algeria</i>	82	121	136	156	163	168	2.7%	6
<i>Nigeria</i>	32	42	57	79	102	119	5.0%	6
Latin America	148	193	233	253	276	292	2.6%	12
World	3 167	3 685	4 019	4 384	4 778	5 132	1.8%	597
<i>European Union</i>	216	185	165	136	113	93	-3.1%	0

*Compound average annual growth rate.

**NPS is New Policies Scenario.

Non-OECD Asia sees gas production more than double between 2008 and 2035, reaching 823 bcm. This growth is led by China which, having tripled gas production between 2000 and 2008, more than triples it again between 2008 and 2035, reaching just over 300 bcm in the GAS Scenario. China becomes the third-largest gas producer globally by the middle of the *Outlook* period. Its share in global production increases from 2.5% in 2008 to almost 6% in 2035. Production will come from established gas producing areas, such as Sichuan province, and newer areas, such as the Ordos basin. Despite this increase in indigenous production, China relies increasingly on imports. There is a rapid increase in imports early in the *Outlook* period – from 5 bcm in 2008 to 110 bcm by 2015 – and in 2035, domestic gas

supply in China is able to meet only around half of domestic demand. With China's conventional gas production reaching a peak by the middle of the projection period, unconventional gas emerges as a key growth source, driven by coalbed methane (CBM) in Ordos, Juggar and Qingshui basins. However, unconventional gas production in China is currently low, making achievement of the projected rate of increase subject to considerable uncertainty (see Section 2).

India's gas production grows faster in the GAS Scenario than in the *WEO-2010* New Policies Scenario, going from 32 bcm in 2008 to 135 bcm (rather than 100 bcm) by the end of the *Outlook* period. By 2035, gas production in India has overtaken that of Norway and rivals that of Turkmenistan. Despite this growth, the gap between domestic supply and demand widens over the course of the *Outlook* period. Conventional gas production peaks and begins to decline during the period, but production of unconventional gas increases sufficiently to sustain the projected overall growth (potentially in areas such as the state of West Bengal, where the first shale gas well was drilled in 2010). Looking across other countries in Asia collectively, gas production will continue to increase over the *Outlook* period, but demand will increase more quickly, gradually reducing the availability of gas for export.

Natural gas production experiences strong growth in the Middle East, as the region continues to develop its vast resource base. Production in the Middle East more than doubles over the *Outlook* period, reaching 920 bcm by 2035 (15% more than in the New Policies Scenario). Production increases more quickly than domestic demand, freeing up significant additional supply for export. Qatar is expected to see particularly strong production growth in the early part of the *Outlook*, as newly built LNG plants increase throughput and the Pearl GTL project comes into operation. In contrast, we project that most of the expected growth in Iran's gas production will occur later in the period, as current international sanctions limit technology transfer and hold back LNG projects. An important factor influencing new gas development in the region will be whether domestic gas prices are permitted to rise to a level that stimulates investment.

Gas production in Africa increases from around 210 bcm in 2008 to 440 bcm in 2035 in the GAS Scenario (only marginally higher than in the New Policies Scenario), outstripping growth in demand and increasing the volume of gas available for export. Algeria and Nigeria are the main sources of this production growth, the vast majority of which is expected to be in the form of conventional gas. Production growth in Algeria tends to occur earlier in the *Outlook* period, along with expansion of the related export infrastructure, whereas growth in Nigeria comes later. Production growth elsewhere in other sub-Saharan Africa countries also occurs later in the *Outlook* period.

Natural gas production in Latin America increases from around 150 bcm in 2008 to 290 bcm in 2035 in the GAS Scenario. The increase in production stays marginally ahead of the increase in domestic demand, widening slightly the opportunity for export. Conventional gas is expected to dominate production in this region throughout the *Outlook* period. Brazil and Venezuela are expected to be the main sources of this incremental production, both developing LNG export terminals.

Production in North America increases by 30% over the *Outlook* period, to stand at more than 1 tcm in 2035 (it reaches around 850 bcm in the New Policies Scenario). The rate of increase in production essentially keeps pace with gas demand in the region throughout the *Outlook* period. It therefore continues to satisfy almost all demand within the region, eliminating the need to source significant volumes of gas from international markets. In global terms, the region sees its share of production decline from around 25% in 2008 to 20% by 2035. While North America remains a marginal net importer of gas throughout the *Outlook* period, this is mainly in response to rising demand in Mexico (driving higher imports). The United States retains its position as the world's second largest gas producer. Production of unconventional gas in the North America region grows from around 360 bcm in 2008 to 670 bcm in 2035, mainly in the United States but also increasingly in Canada. Unconventional gas (mostly shale gas) increases from being less than half of overall gas production in the region in 2008 to nearly two-thirds in 2035.

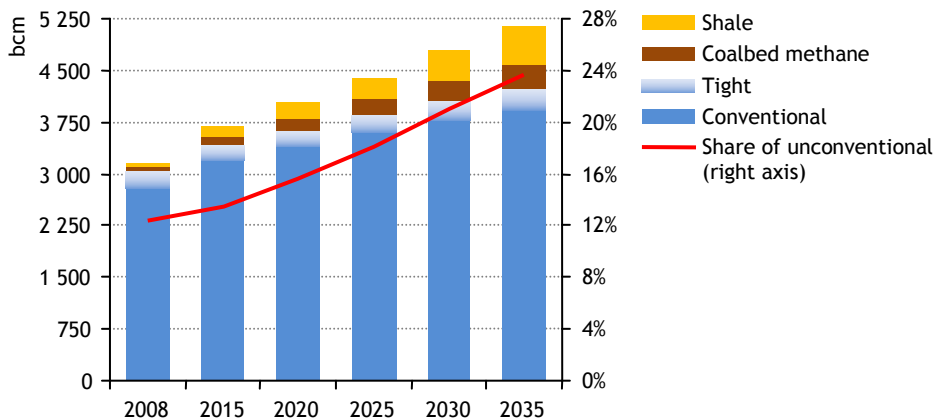
In the GAS Scenario, OECD Europe sees a relatively steady decline in gas production, from around 310 bcm in 2008 to about 210 bcm in 2035 (about the same level as in the New Policies Scenario). This means that regional supply goes from servicing one-half of demand to around one-third by 2035. Norway is expected to account for more than half of production in OECD Europe in 2035. Conventional gas will continue to dominate the production picture throughout the *Outlook* period. Exploration for unconventional gas is taking place in Europe, with Poland a particular focus (see Box 2.2 in Section 2), but unconventional gas supply in the region is still small at the end of the period.

The GAS Scenario sees strong production growth in OECD Oceania, reaching 155 bcm by 2035 (around 20 bcm more than the New Policies Scenario). Gas production in this region is dominated by Australia, which sees production grow to levels higher than Norway by 2020. Most conventional gas projects centre on developments offshore of western and northern Australia, including in the remote Browse basin. Australia also becomes increasingly reliant on unconventional gas (notably CBM), which grows from less than 10% of production in 2008 to around 45% in 2035.

Production by type

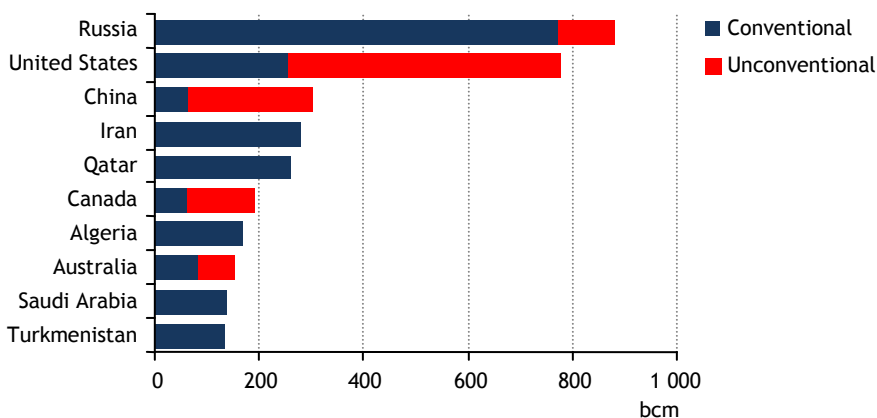
In the GAS Scenario, conventional gas continues to make up most global production throughout the *Outlook* period. While conventional gas production increases from 2.8 tcm in 2008 to 3.9 tcm in 2035, its share of total gas production declines (Figure 1.7). Unconventional gas production meets more than 40% of the increase in demand over the *Outlook* period and is projected to reach 1.2 tcm in 2035 (versus 0.9 tcm in the New Policies Scenario). As a result, the share of unconventional gas in global gas production increases from 12% in 2008 to 24% in 2035 (19% in the New Policies Scenario).

Figure 1.7 ▶ Natural gas production by type in the GAS Scenario



As in the New Policies Scenario, most of the increase in unconventional gas production in the GAS Scenario comes from shale gas and CBM. We project that the share of shale gas in global gas production reaches 11% in 2035, while that of CBM reaches 7% and tight gas 6%.⁷ Unconventional gas production is currently concentrated in the United States and Canada. By the end of the *Outlook* period, unconventional gas also reaches a significant scale in China (CBM and shale), Russia (tight gas), India (shale) and Australia (CBM, for example from the Bowen and Surat basins) (Figure 1.8). Although understanding of the scale of unconventional gas resources globally is improving, the complex issues related to unconventional gas production mean that future production projections are subject to a large degree of uncertainty, particularly in regions where little or no such production has been undertaken to date (see Section 2).

Figure 1.8 ▶ Largest gas producers by type in the GAS scenario, 2035



⁷ Definitions of tight gas vary across countries and regions. See Section 2 for more detail.

Inter-regional gas trade

WEO-2010 highlighted a glut of global gas-supply capacity, emerging as a result of the economic crisis (which depressed gas demand), the continuing boom in unconventional gas production in the United States and a wave of new global LNG liquefaction capacity. The global financial and economic crisis in 2008 and 2009 led to a sudden and pronounced drop in gas demand worldwide (see Section 3). Demand fell most heavily in the OECD and in Eastern Europe/Eurasia, but demand slowed markedly in some other non OECD regions too. This led to the emergence of a significant amount of over-capacity in gas production and transportation capacity. This over-capacity was exacerbated by the accelerating pace of investment in unconventional gas production facilities in the United States, despite falling demand and prices. This reduced the need of the United States to import gas, either as LNG or by pipeline from Canada.

The drop in global demand occurred just as a wave of new LNG liquefaction capacity became available. Between the beginning of 2009 and the end of 2010 around 100 bcm of capacity was commissioned (although technical difficulties led to delays in full utilisation in some cases). This capacity was not the primary cause of the glut: the investment decisions had been taken before the economic crisis and, if demand for gas had continued rising in 2008 and 2009 at the rate of previous years, most of the new capacity would have been needed. But the timing meant that competition between these plants and existing LNG suppliers and pipelines intensified. Most long-term supply contracts into Europe and Asia provide for minimum volume commitments; the remaining volumes of gas were sold on a spot basis, albeit at prices well below the levels of oil-indexed prices under long-term contracts. Most buyers of gas under long-term contracts reduced their purchases as much as their contractual obligations would allow. Pipeline suppliers to Europe – particularly Russia and Algeria, who largely resisted calls to reduce their price – saw their exports fall heavily in 2009.

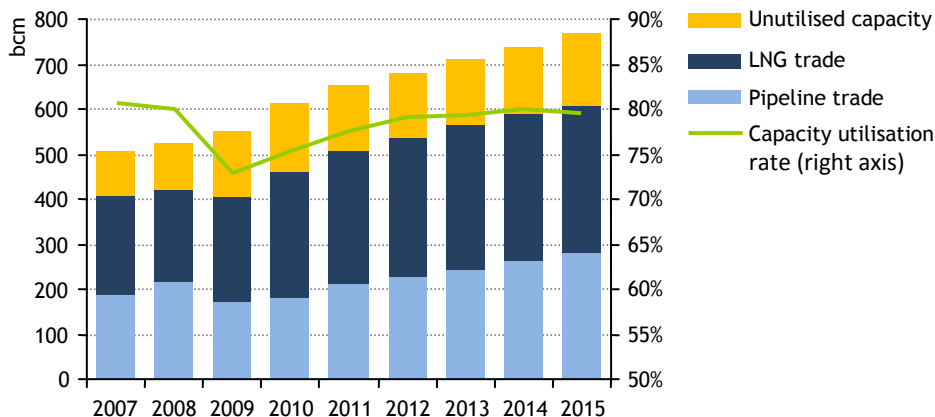
Preliminary data suggests that the glut reduced in 2010 in response to a sharp rebound in gas demand, primarily as a result of exceptionally cold weather across the Northern Hemisphere and robust economic recovery in the emerging economies, especially Asia. We estimate that global gas demand increased by around 7.5% in 2010. Even with such a strong rebound, excess supply capacity remains – albeit reduced – and some of the factors that have driven gas demand growth in 2010 may not necessarily recur, at least in the same way or to the same extent, in future years.

WEO-2010 used inter-regional natural gas transportation capacity as an indicator of the gas glut globally, on the basis that production capacity is generally at least as big as the capacity of the LNG plants and large-scale cross-border pipelines. Use of this same indicator shows that, as one would expect, the excess of supply capacity over demand declines more rapidly in the GAS Scenario than in the New Policies Scenario. We estimate that additional demand drives the capacity utilisation rate from less than 75% in 2009 to pre-crisis levels⁸ of around

⁸ As stated in *WEO-2010*, it is to be expected (in part) that utilisation rates will not recover fully to the levels reached in the mid-2000s, as part of the incremental pipeline capacity that is being built is designed to substitute for, rather than supplement, existing capacity: this is especially the case with new Russian export lines to Europe. Also, the availability of gas to supply some existing pipelines, to which they are dedicated, will tend to fall as the source fields mature and production declines.

80% before 2015 (Figure 1.9). In the New Policies Scenario, capacity utilisation declined to around 70% before rebounding more slowly (so reaching more normal capacity utilisation closer to 2020).

Figure 1.9 ▶ Natural gas transportation capacity between major regions in the GAS Scenario



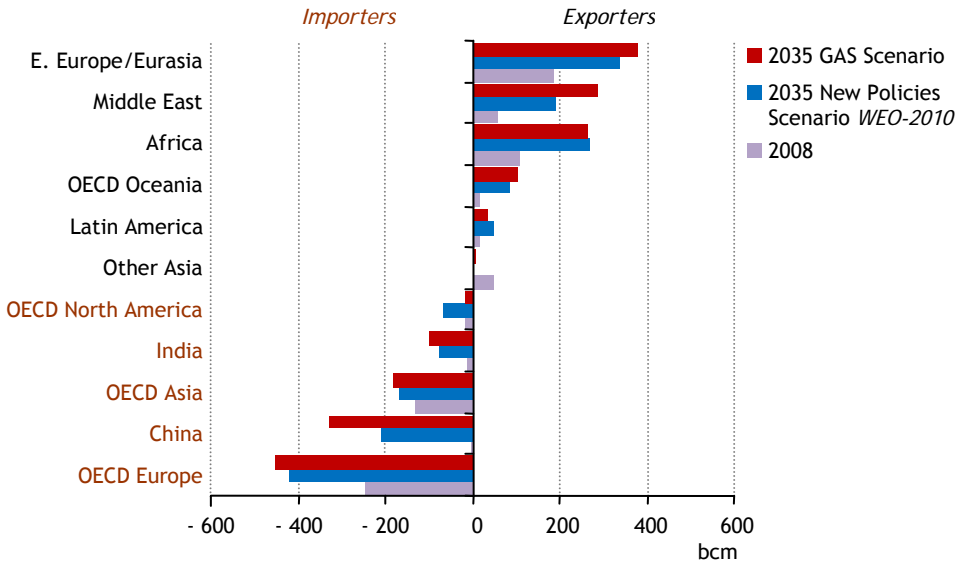
In the GAS Scenario, the recovery in global demand is driven strongly by Asia, meaning that unutilised LNG capacity falls more quickly than that of pipelines. The speed of this reduction could result in the market for traded gas tightening before 2015. Gas demand growth in Europe is expected to recover more slowly and the new transport capacity being added in the region means utilisation of pipeline capacity at pre-crisis levels might not occur for several years. Persistent over-capacity would reinforce pressure for greater flexibility in pricing arrangements, possibly weakening the influence of oil-indexation in long-term supply contracts.

Inter-regional trade by region and type

An expected further major expansion of LNG availability means that international trade in natural gas is expected to play an increasingly important role in global energy supply. In the GAS Scenario, the volume of natural gas traded between the major *WEO* regions more than doubles over the *Outlook* period, reaching more than 1 tcm by 2035, compared with around 940 bcm in the New Policies Scenario.⁹ A higher level of trade in the GAS Scenario reflects faster demand growth in the main importing countries, in particular China (Figure 1.10). The volume of inter-regional gas trade continues to increase through the projection period in the GAS Scenario and accounts for around 20% of total gas use in 2035. Between 2010 and 2035, inter-regional trade through pipelines increases by around 330 bcm. Over the same period, inter-regional trade in the form of LNG increases by around 290 bcm, with LNG holding about a 50% share of overall trade by 2035.

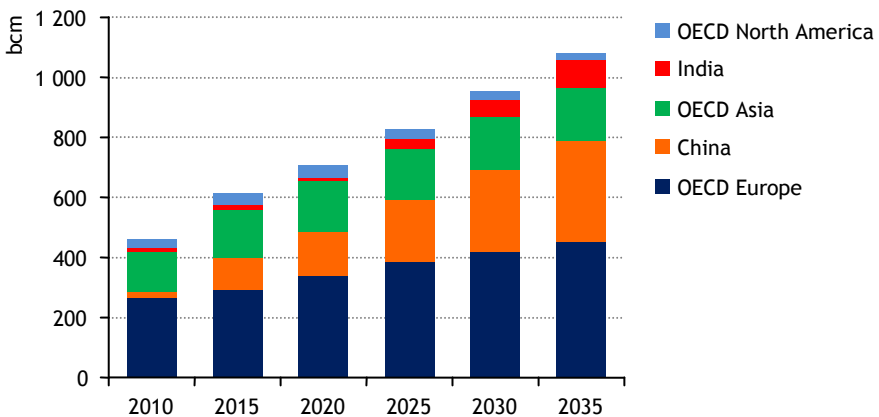
⁹ Based on the major *WEO* regions, i.e. OECD North America, India, OECD Asia, China, OECD Europe, Other Asia, Latin America, OECD Oceania, Africa, Middle East and Eastern Europe/Eurasia.

Figure 1.10 ▶ Net gas trade by major region and scenario



In net terms, OECD Europe is estimated to have imported more than 260 bcm of natural gas in 2010. This represents around 50% of the region’s total primary gas supply and nearly 60% of all gas traded between major *WEO* regions (Figure 1.11). Domestic gas production is projected to decline and demand to increase in the GAS Scenario, pushing up imports to around 450 bcm by 2035 (about 30 bcm more than in the New Policies Scenario), nearly 70% of total primary gas supply in the region. Europe’s share of total inter-regional gas trade decreases to around 40% in 2035. The sources of its imports are expected to become more diversified, with a growing share of LNG.

Figure 1.11 ▶ Natural gas net imports by major region in the GAS Scenario



In the GAS Scenario, the growth in China's demand for gas imports dwarfs that of other regions, rising from around 20 bcm in 2010 to 330 bcm in 2035 (in the New Policies Scenario, imports reach only 210 bcm). China's transition is so rapid that it goes from importing less than one-fifth as much gas as OECD Asia in 2010, to overtaking it around 2025, becoming the second-largest import market globally (after Europe). This dramatic increase in imports reflects the inability of domestic supply to satisfy the new demand targets, particularly in the near term. The GAS Scenario requires an increase in imports of natural gas to around 110 bcm in 2015 (at least half as LNG), a very ambitious rate of increase, highlighting the need to rapidly create the necessary import infrastructure and secure sufficient supply contracts. China quickly broadens its supplier base and, by the end of the *Outlook* period, is importing significant volumes of gas by pipeline from Eurasia and LNG from Australia, the Middle East and Africa. This is on top of a rapid increase in its own production of unconventional gas. By 2035, China becomes the world's largest LNG importer, absorbing one-third of global LNG supply.

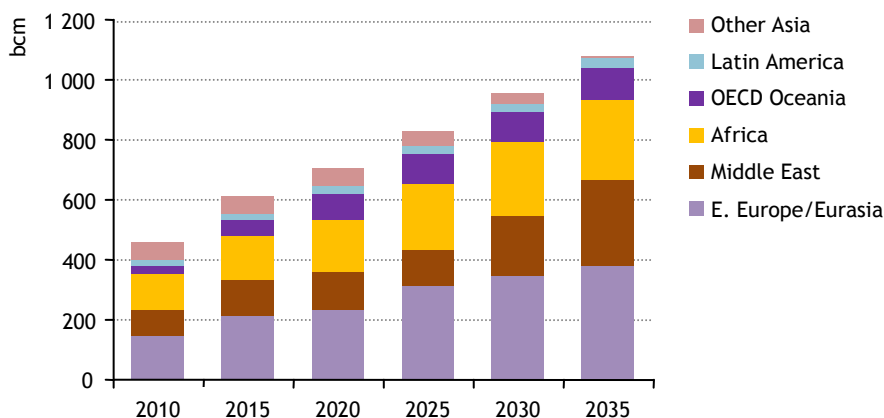
Dependence on LNG imports in OECD Asia continues to increase in the GAS Scenario, going from 130 bcm in 2010 to 180 bcm in 2035. Within OECD Asia, the strongest increase in demand for gas imports occurs in the near term and is due to greater LNG needs in Japan. Outside OECD Asia, the GAS Scenario also sees India move from being a small gas importer in 2010 to importing around 100 bcm by 2035, slightly more than 40% of its total primary gas supply. Growth in India's import demand is skewed towards the period after 2020.

In OECD North America, unconventional gas helps domestic production keep pace with increasing demand in the GAS Scenario. Overall, the region maintains its status as a marginal net importer (due to Mexico) throughout the *Outlook* period and remains relatively isolated from the other gas markets.

In the GAS Scenario, net exports from Eastern Europe/Eurasia region (essentially, Russia and the Caspian) are expected to rebound quickly and surpass 2008 levels before 2015. The level of net exports from the region continues on a strong upward trajectory and more than doubles from 2010 levels by 2035, reaching nearly 380 bcm (Figure 1.12). Over the *Outlook* period, net exports increase as a proportion of overall gas production, reflecting the fact that production growth outstrips domestic demand. Regional gas exports to China increase from a low level in 2010 to a level near that of OECD Europe by 2035. In the GAS Scenario, answering the question whether supplies from Russia and the Caspian are exported east or west is therefore simple: they go both ways.

In Africa, net gas exports increase from 120 bcm in 2010 to 265 bcm in 2035 in the GAS Scenario. Many of the region's largest existing gas producers achieve rapid growth. This growth tends to be greater later in the *Outlook* period. Exports continue to be a mix of pipeline gas and LNG. By around the middle of the *Outlook* period, Africa's exports of LNG exceed those from the Middle East.

Figure 1.12 ▶ Natural gas net exports by major region in the GAS Scenario



Over the *Outlook* period, gas production growth in the Middle East is well in excess of the region’s own demand requirements, resulting in an increased capacity to export. By 2035, net exports have grown to 290 bcm (from 85 bcm in 2010). Europe and Asia continue to be the two most important destinations for exports throughout the *Outlook* period, but Europe becomes a relatively larger market towards the end of the period.

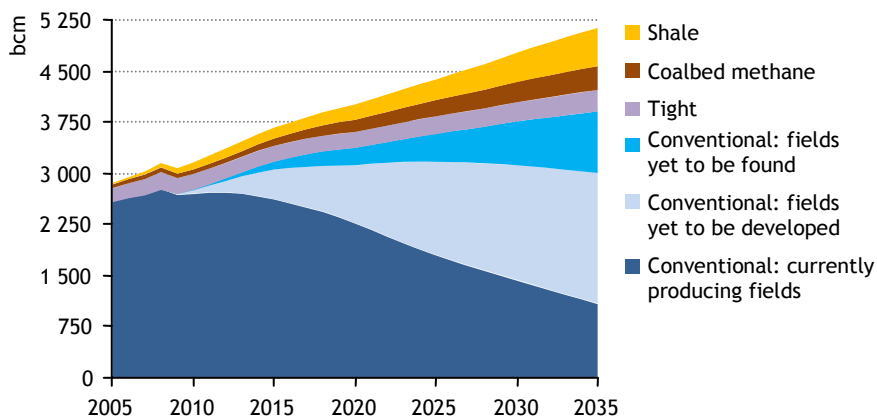
Net exports of LNG from Australia increase from an estimated 25 bcm in 2010 to over 100 bcm by 2035. The strongest increase is seen in the first-half of the *Outlook* period, with 50 bcm of LNG capacity coming online by 2016. These exports go predominantly to Asia.

In the GAS Scenario, increases in gas production in Latin America broadly keep pace with increased demand, maintaining its position as a marginal net exporter, but at a higher level in volumetric terms.

Investment in gas production and transportation

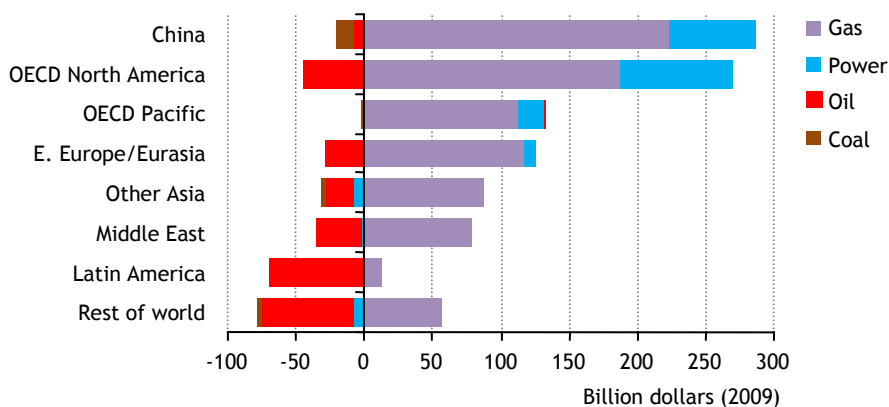
To meet the increase in energy demand in the *WEO-2010* New Policies Scenario requires investment of around \$33 trillion (in year-2009 dollars) in energy supply infrastructure over the *Outlook* period. While overall energy demand in the GAS Scenario is only slightly higher than the New Policies Scenario in 2035, the energy mix is different and this has an impact on the type and scale of investment required. In the GAS Scenario, output from currently producing conventional gas fields decline, and supply only around 20% of total gas production in 2035 (Figure 1.13). Around 1.6 tcm of new production is, therefore, required in 2035 simply to offset the decline from conventional gas fields producing in 2010. This highlights the scale of investment that will be required simply to maintain current production levels.

Figure 1.13 ▶ World natural gas production by source in the GAS Scenario



To meet the higher natural gas demand in the GAS Scenario the cumulative investment required in supply infrastructure is around \$8 trillion – 12% higher than in the New Policies Scenario. This increase is slightly offset by the reduced levels of investment required for other fuels (Figure 1.14). The net additional energy-supply infrastructure investment required in the GAS Scenario over the *Outlook* period is more than \$700 billion higher than the New Policies Scenario.

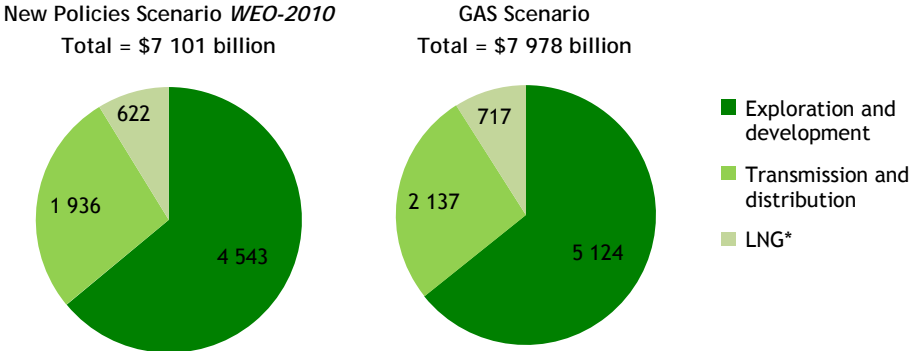
Figure 1.14 ▶ Incremental investment in energy-supply infrastructure by fuel and region in the GAS Scenario relative to the *WEO-2010* New Policies Scenario



While the majority of the net additional investment in the GAS Scenario is in gas-supply infrastructure, some is also required in the power sector. Lower gas prices translate into lower electricity prices, which increase electricity demand. This increase in electricity demand – nearly 1% higher than in the New Policies Scenario – translates into a requirement for cumulative additional investment of \$12 billion in power generation capacity. This is considerably lower than it would be if the additional electricity demand were met using the same power generation mix as in the New Policies Scenario. The increase in electricity demand in the GAS Scenario also drives a need for additional cumulative investment of \$140 billion in transmission and distribution networks.

Around 65% of the total cumulative gas-supply investment required is in the upstream sector (Figure 1.15), both to find and develop new greenfield sites and minimise the decline at existing fields. In the GAS Scenario, cumulative investment in gas exploration and development amounts to \$5.1 trillion (in the New Policies Scenario it is \$4.5 trillion). This increase reflects both the increased gas demand and a greater emphasis on developing unconventional gas fields. Cumulative investment required in gas transmission and distribution over the *Outlook* period is estimated to be around \$2.1 trillion, around 10% higher than the New Policies Scenario. At around \$720 billion, investment in LNG capacity in the GAS Scenario is 15% higher than in the New Policies Scenario, reflecting increased demand.

Figure 1.15 ▶ World cumulative investment in gas-supply infrastructure by scenario



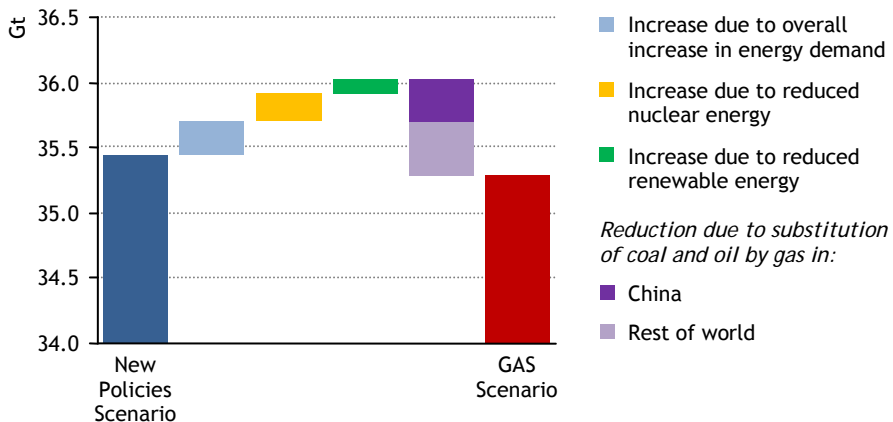
* Total in the New Policies Scenario and GAS Scenario include an additional \$74 billion and \$86 billion of investment in LNG carriers, respectively.

Energy-related emissions

Energy-related CO₂ emissions in the GAS Scenario follow a path similar to that in the New Policies Scenario, reaching 35.3 gigatonnes (Gt) in 2035, a mere 160 million tonnes (Mt) lower than emissions in the New Policies Scenario in that year. In the absence of a global cap on CO₂ emissions, although lower gas prices encourage displacement of demand for more carbon intensive fuels (coal and oil), they also boost energy consumption and lead to the displacement of some low-carbon fuels, such as nuclear and, to a lesser extent, renewables. This therefore results in a set of competing interactions. Considering each separately, the effect of increased demand in the GAS Scenario relative to the New Policies Scenario is an increase in CO₂ emissions of 260 Mt in 2035 (Figure 1.16). CO₂ emissions are also increased by the reduction in nuclear and renewable energy, adding 220 Mt and 100 Mt respectively in 2035. In contrast, the substitution of gas for coal, and to a lesser degree oil, reduces CO₂ emissions by 740 Mt in 2035, more than compensating for the sum of the other effects. China alone accounts for 315 Mt of this reduction (43%) as a result of implementing its policy decision in the 12th Five Year Plan to increase the share of its energy mix met by gas.

Overall, the GAS Scenario puts CO₂ emissions on a long-term trajectory consistent with stabilising the atmospheric concentration of greenhouse gases at around 650 ppm, resulting in a probable temperature rise of more than 3.5°C in the long term, well above the widely accepted 2°C target. Widespread deployment in gas applications for power generation and industry of technologies, such as carbon capture and storage (CCS), has the potential to reduce emissions from gas consumption significantly in the long term, which could result in stabilisation at lower levels, but the GAS Scenario does not allow for this in the period to 2035.

Figure 1.16 ▶ CO₂ emissions in the GAS Scenario relative to the New Policies Scenario, 2035



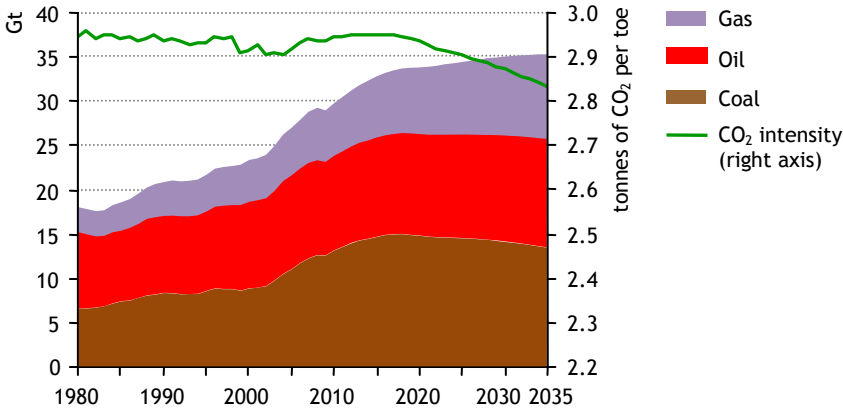
Emissions from coal peak before 2020, at 14.8 Gt, and decline on average 0.6% per year thereafter (Figure 1.17). Gas accounts for 60% of incremental CO₂ emissions from 2008 to 2035, oil for 25% and coal for the remainder. CO₂ emissions from coal in 2035 are just 7% higher than in 2008, while gas emissions increase by two-thirds. Though demand for coal and oil are relatively lower than in the New Policies Scenario, the share of all fossil fuels in total energy demand in 2035 is very slightly higher in the GAS Scenario, at just over 74%, as gas fills the gap left by the reduction in nuclear. However, CO₂ emissions do not grow as much as the demand for fossil fuels, as the average CO₂ intensity of fossil fuels falls from 2.93 tonnes of CO₂ per tonne of oil equivalent (toe) in 2008 to 2.83 toe in 2035.

In the GAS Scenario, CO₂ emissions in OECD countries broadly follow the same emissions path of the New Policies Scenario. The power and industry sectors are subject to a carbon price in both scenarios. Emissions from other sectors do not significantly change, as the reduction in emissions due to the substitution of gas for more carbon-intensive fuels is offset by higher emissions due to higher gas demand.

CO₂ emissions in non-OECD countries grow by more than 50% over the *Outlook* period to 23.8 Gt, 200 Mt less than in the New Policies Scenario in 2035 and a cumulative 1.5 Gt lower over the projection period. China's CO₂ emissions are around 210 Mt (2%) lower in 2035 in the GAS Scenario, as implementation of policies in the 12th Five Year Plan and lower gas prices encourage quicker replacement of more polluting coal plants by more efficient gas-fired plant. In India, CO₂ emissions are 100 Mt lower as a result of the increased uptake

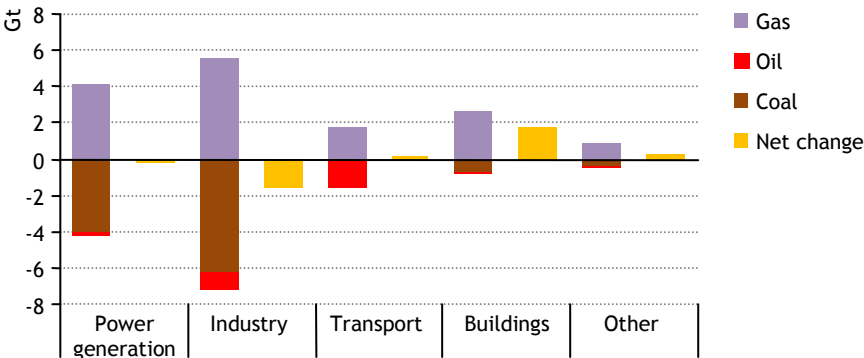
of gas-fired power generation and natural gas vehicles. The transition economies see a net increase in emissions of 100 Mt, as gas fuels the increase in electricity demand and substitutes for nuclear generation.

Figure 1.17 ▶ World energy-related CO₂ emissions by fuel in the GAS Scenario



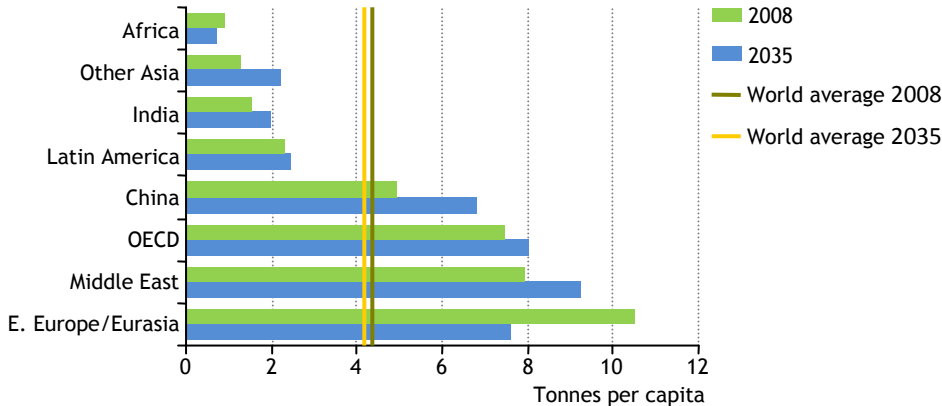
Sector-by-sector, the change in CO₂ emissions relative to the New Policies Scenario shows some interesting differences. A relative shift away from coal in power generation and industry leads to a reduction in emissions compared to the New Policies Scenario, although in the case of power generation this is small, due to reduced reliance on nuclear power and higher electricity demand. In industry, the fall in CO₂ emissions is larger. Buildings see an increase in emissions accounted for by slightly higher overall demand and by lower-cost gas crowding out some renewables as well as fossil fuels (Figure 1.18, also see Table 3.3).

Figure 1.18 ▶ Change in cumulative energy-related CO₂ emissions by sector and fuel in the GAS Scenario relative to the New Policies Scenario, 2009-2035



World average CO₂ emissions per capita have been increasing sharply since 2000. Like the New Policies Scenario, the GAS Scenario sees the upward trend in CO₂ per capita emissions peak at 4.5 tonnes around 2015 and then decline steadily to reach 4.2 tonnes by 2035 (Figure 1.19). There are significant variations across regions, with Africa, Latin America and much of Asia still being considerably below the global average. China’s per capita CO₂ emissions grow substantially over the *Outlook* period, converging with those of the European Union around 2020 at 6.5 tonnes. After this point, per capita emissions in the European Union continue to fall, while those of China continue to climb, reaching 6.8 tonnes in 2035, still lower than the OECD average of 7.6 tonnes, but well above the European Union’s 5.5 tonnes.

Figure 1.19 ▶ Per-capita energy-related CO₂ emissions by region in the GAS Scenario



Natural gas also produces lower emissions of other pollutants – sulphur dioxide (SO₂), nitrogen oxides (NO_x) and particulate matter (PM_{2.5}) – than coal or oil. As a result, use of gas at the expense of other fossil fuels can be expected to improve air quality, particularly in urban areas. In the GAS Scenario, global SO₂ emissions fall substantially over the *Outlook* period to 73.3 Mt in 2035 (Table 1.5). They are around 2% lower in 2020 than in the New Policies Scenario and 4% lower by 2035. In non-OECD countries, the switch from coal to natural gas has a large impact on SO₂ emissions. Compared with oil and coal, natural gas emits lower amounts of NO_x, which cause acidification and contribute to ground-level ozone formation. Global emissions of NO_x in the GAS Scenario reach 80.2 Mt in 2035. This is a drop of 4.6 Mt compared with 2008 and around 1% lower in 2035 than in the New Policies Scenario. Similarly, with natural gas emitting almost no particulate matter (which, together with NO_x is the main cause of smog formation and the subsequent deterioration of urban air quality), global emissions of PM_{2.5} in the GAS Scenario decrease in 2035 by 1.6 Mt, compared with 2008 and are 1% lower than in the New Policies Scenario.

Table 1.5 ▶ Emissions of key air pollutants by region and scenario
(thousand tonnes)

	GAS Scenario			New Policies Scenario <i>WEO-2010</i>		Change in GAS Scenario versus New Policies Scenario	
	2008	2020	2035	2020	2035	2020	2035
Sulphur dioxide (SO₂)							
OECD+	22 765	12 756	10 557	12 745	10 717	0.1%	-1.5%
OME	48 590	42 064	34 087	43 365	36 835	-3.0%	-7.5%
Other Countries	22 475	24 582	28 612	24 608	28 711	-0.1%	-0.3%
World	93 830	79 403	73 256	80 718	76 263	-1.6%	-3.9%
Nitrogen oxides (NO_x)							
OECD+	32 402	18 867	15 795	18 720	15 672	0.8%	0.8%
OME	31 866	32 699	34 838	32 966	35 504	-0.8%	-1.9%
Other Countries	20 551	21 729	29 607	21 691	29 799	0.2%	-0.6%
World	84 820	73 295	80 241	73 377	80 975	-0.1%	-0.9%
Particulate matter (PM_{2.5})							
OECD+	4 006	3 499	3 741	3 448	3 689	1.5%	1.4%
OME	17 368	15 392	13 108	15 648	13 519	-1.6%	-3.0%
Other Countries	19 239	20 696	22 150	20 698	22 186	-0.0%	-0.2%
World	40 614	39 588	38 998	39 794	39 394	-0.5%	-1.0%

Note: 2005 is the base year of these projections and 2008 is estimated by IIASA. OECD+ includes all the OECD countries plus non-OECD EU countries. Other Major Economies (OME) includes Brazil, China, Russia, South Africa and the countries of the Middle East.

Source: IIASA (2011) for the IEA.

Implications of the GAS Scenario

The GAS scenario deliberately sets out to test the implications of a more positive future for natural gas, on the basis of assumptions more favourable to natural gas than those adopted in the New Policies Scenario of the *WEO-2010*. The International Energy Agency is not advancing this scenario as more or less probable (variations are illustrated in Section 4); but the new assumptions do reflect evident trends. Nor is the GAS Scenario offered as the preferred scenario of the IEA: it has both positive and negative features and it is for policymakers to decide how far they wish to intervene to shape any such future. The results do, however, provide clear insights for policymakers and we seek to draw these out here.

Demand implications

Natural gas appears well-placed to respond to the significant increase in global energy demand that could occur in the period to 2035. There are widespread signs that natural gas demand is already growing strongly and the GAS Scenario shows that natural gas can play a bigger role in the global energy mix.

The GAS Scenario shows demand for natural gas increasing in all regions, but that demand growth is heavily weighted towards non-OECD countries. Their rate of economic growth and energy policies will be the principal drivers of changes in global energy markets. Future gas supply and transport capacity need to be located so as to cater for their needs. Ensuring they can and do adopt efficient gas-fired technologies, especially in the power sector, should be given high priority.

Demand in China will be the most important determinant of future global demand for gas. From being only slightly bigger than that of Germany in 2010, China's natural gas demand expands to around that of the entire European Union by 2035. To realise its ambitious 12th Five Year Plan, China will need to import around 50 to 60 bcm of LNG in 2015, about the current import level of the European Union.

The flexibility of natural gas as a fuel means that substantially higher demand could arise in a number of sectors. While power generation remains the dominant sector for gas demand, in the GAS Scenario we observe a broad-based increase in growth also in the industry, transport and buildings sectors.

Production implications

Natural gas is an abundant resource, widely dispersed globally. Global natural gas resources can amply meet demand through to 2035 and well beyond, even at the lower assumed gas price.

Each region holds natural gas resources equivalent to at least 75 years worth of supply at current consumption levels. There is the potential to increase gas production in all regions and thereby enhance overall energy security, but realising this potential is not assured. Current gas production is more narrowly concentrated and the largest existing producers are expected to meet much of the increased demand in the GAS Scenario, though they will be joined by China as it becomes one of the world's largest gas producers. The strongest growth in natural gas production is expected in the Middle East, Eurasia, North America, China and Africa. Conventional gas will continue to make up the bulk of global production but unconventional gas becomes increasingly important, accounting for 25% of global supply in 2035 and meeting more than 40% of the increase in demand in the GAS Scenario.

Complex issues surround unconventional gas production and mean that future projections are uncertain, particularly in regions where little or no such production has been undertaken to date. Effective, transparent and stable regulatory frameworks have yet to be widely developed to respond to social and environmental concerns, such as water use and disposal, without deterring resource development. The absence, or poor design, of such frameworks can discourage investment or result in adverse environmental impacts, such as increased emissions from venting or flaring.

Implications for the gas glut

The combination of a sudden fall in demand in 2008-2009 and a surge in supply and transport capacity led to the gas glut highlighted in *WEO-2010*. Preliminary data suggests that the glut decreased in 2010, due to the sharp rebound in gas demand, primarily as a result of exceptionally cold weather across the Northern Hemisphere and robust economic recovery in the emerging economies, especially Asia. Additional demand in the GAS Scenario drives capacity utilisation rates back to pre-crisis levels before 2015.

Transportation and investment implications

The volume of natural gas traded inter-regionally is expected to increase, with both LNG and pipeline gas playing important roles. North America will remain largely self-sufficient and is likely to be largely isolated from inter-regional trade. China will grow to become one of the largest importers of natural gas worldwide. Its reliance on imported gas to meet its demanding targets will rise rapidly in the near term.

The different energy mix in the GAS Scenario changes the type and scale of the required infrastructure. In order to meet the higher gas demand, cumulative investment in gas-supply infrastructure is around \$8 trillion, some 12% higher than the New Policies Scenario. Investment in gas increases throughout the supply chain. Over the *Outlook* period as a whole, the emphasis is on investment in exploration and development, particularly for unconventional gas sources. In the near term, investment in LNG capacity is also a particular focus.

Emissions implications

When burned, natural gas emits less CO₂ and local pollutants than other fossil fuels; but it compares less favourably in this respect with nuclear power and renewables. Much therefore depends on the particular changes in the use of other fuels. Though gas is the most benign fossil fuel in terms of CO₂ emissions, in the GAS Scenario these emissions are only slightly lower than in the New Policies Scenario, at about 35 Gt. This emissions trajectory is consistent with stabilising the atmospheric concentration of greenhouse gases at around 650 ppm, resulting in an average global temperature rise of over 3.5°C. To limit the increase in global temperature to 2°C would require much improved energy efficiency, a greater shift to low-carbon energy sources and wide application of new technologies, including plants fitted with CCS.

It follows that an increased share of natural gas in the global energy mix is not enough, on its own and with today's technology, to avert serious climate change, though natural gas has an important role to play in complementing low-carbon energy solutions by providing the flexibility needed to support a growing renewables component in power generation. Significant opportunities remain for natural gas to replace other fossil fuels in end-use sectors and, in the right circumstances, gas could deliver long-term environmental and energy security benefits.

Market implications

The costs of production and transport infrastructure are an important factor in long-term price setting. The GAS Scenario shows the role for unconventional gas growing significantly, initially in North America and then spreading later in the *Outlook* period to other regions, at costs in the range of \$3/MBtu to \$7/MBtu. While many undeveloped conventional gas resources are remote, offshore or technically complex, and current costs to develop them are relatively high, improvements in technology (such as floating production and LNG facilities), can be expected to keep downward pressure on costs.

At a regional level, it seems clear that the United States and Canada will continue to enjoy relatively low gas prices, the pricing mechanisms in these countries continuing to apply strong competitive pressure to move prices towards costs. North America should play only a minor role in net global LNG trade. In the short to medium term, rapid growth in Asian

gas demand puts pressure on supply (notably LNG) and consequently prices, but also stimulates greater supply investment, both within the region and externally. In importing countries where governments continue to exercise price controls, increasing imports will stimulate pressure to change policies, and reforms would, in turn, incentivise increased domestic gas production.

Gas import reliance will increase in Europe and different pricing mechanisms will coexist (see Section 2 for more discussion of pricing mechanisms). In the short to medium term, the extent of competition from Europe and Asia for Pacific and Atlantic LNG will influence how far prices in these regions converge. The main gas exporting countries will continue to diversify their markets and be influenced by the relative pricing in the importing markets in Europe and Asia.

Pricing mechanisms in gas markets will continue to evolve, to better balance the needs of producers and consumers in different sectors and regions. The current role of oil-linked pricing will weaken, particularly in the power sector, where pricing mechanisms based on competing sources of generation (potentially including carbon pricing) are likely to play a greater role.

The move towards more efficient markets, based on natural gas fundamentals, will support overall economic efficiency. As demand grows, pressure to remove subsidies that encourage inefficient gas use will increase. Increased consistency of regulatory and market regimes across borders will encourage investment in inter-regional infrastructure, facilitating trade and competition. Greater trade may, of course, lead to faster convergence of prices over the long term. While natural gas markets are becoming more global, and regional prices show signs of increased convergence, they do not become truly globalised in the GAS Scenario.

The potential to expand gas supply

Highlights

- The global natural gas resource base is vast and widely dispersed geographically, with conventional recoverable resources equivalent to over 120 years of current global consumption, while total recoverable resources could exceed 250 years. All major regions have recoverable resources equal to at least 75 years of current consumption. Despite plentiful resources, timely and successful development of gas resources depends on a complex set of factors, including commercial and policy choices, geological characteristics, technological capability, sufficient and timely investment and market access. Once discovered, major gas resources can still sometimes take decades to reach production.
- Unconventional gas resources, comprising shale gas, tight gas and coalbed methane (CBM) are estimated to be as large as conventional resources. Our analysis suggests that plentiful volumes can be produced at costs similar to those in North America (between \$3/MBtu and \$7/MBtu). Unconventional gas now accounts for about 60% of production in the United States. CBM development is growing in Australia, while projects in China, India and Indonesia are in the early stages of development.
- Mergers, acquisitions and partnerships are spreading expertise in producing unconventional gas, with over \$100 billion of transactions completed since 2008. These deals reflect confidence in the potential for significant gas production growth outside North America, particularly in Asia.
- Although hydraulic fracturing has been practised since the 1940s, the rapid expansion of its application to unconventional gas production has put existing regulatory frameworks to the test and raised environmental concerns. These centre on water availability, use and potential contamination and on greenhouse-gas emissions from shale gas production. We estimate that shale gas produced to proper standards of environmental responsibility has slightly higher “well-to-burner” emissions than conventional gas, with the combustion of gas being the dominant source of emissions.
- International trade in natural gas is set to grow as a new wave of liquefied natural gas (LNG) projects comes on-line. LNG liquefaction capacity, only 270 bcm in 2008, is projected to reach 450 bcm in 2015 and 540 bcm in 2020. Together with an expected expansion of regasification capacity, this will offer increased flexibility and diversity of supply.
- Pricing mechanisms are likely to become more reflective of market conditions, including the prices of competing energy sources, such as coal, other gas supplies and in some cases oil. The pace and extent of this change will hinge to some degree on how long the overcapacity in global gas supply persists.

Global natural gas resources are vast and widely dispersed geographically. They have the potential to meet rising demand for many decades to come. However, the complexity, large capital costs and long lead times of production facilities and transportation infrastructure constrain the pace at which gas resources can be exploited. Uncertainty about prospects for demand always affect investment decisions – together with the normal set of technical, financial and geopolitical risks associated with new projects – and the uncertainties today are no less than usual. In 2009, the global financial and economic crisis led to the biggest drop in worldwide gas demand in 35 years. But uncertainty can also represent opportunity, for example gas demand bounced back strongly in 2010. Gas suppliers must now gauge the strength and durability of that rebound. They must also consider the impact of other major developments in the industry, including the prospects for replicating the growth in unconventional gas production in North America in other parts of the world and the impact that this would have on worldwide gas trade.

This section examines the important issues relating to gas supply from the initial identification of gas resources through to international trade and methods of pricing. It starts by identifying the many complex issues that must be overcome before production of gas resources can begin. It goes on to estimate the size of global natural gas resources and reserves, broken down by region and type of gas, and to consider the costs associated with their development. Current levels of global gas production are then examined, together with future supply and transportation prospects and possible medium-term capacity constraints. Particular focus is given to the global potential of unconventional gas and the possible environmental impact of gas production and transportation. In addition, this section looks at changes that can be observed in how natural gas contracts are priced.

Preconditions for the development of gas supplies

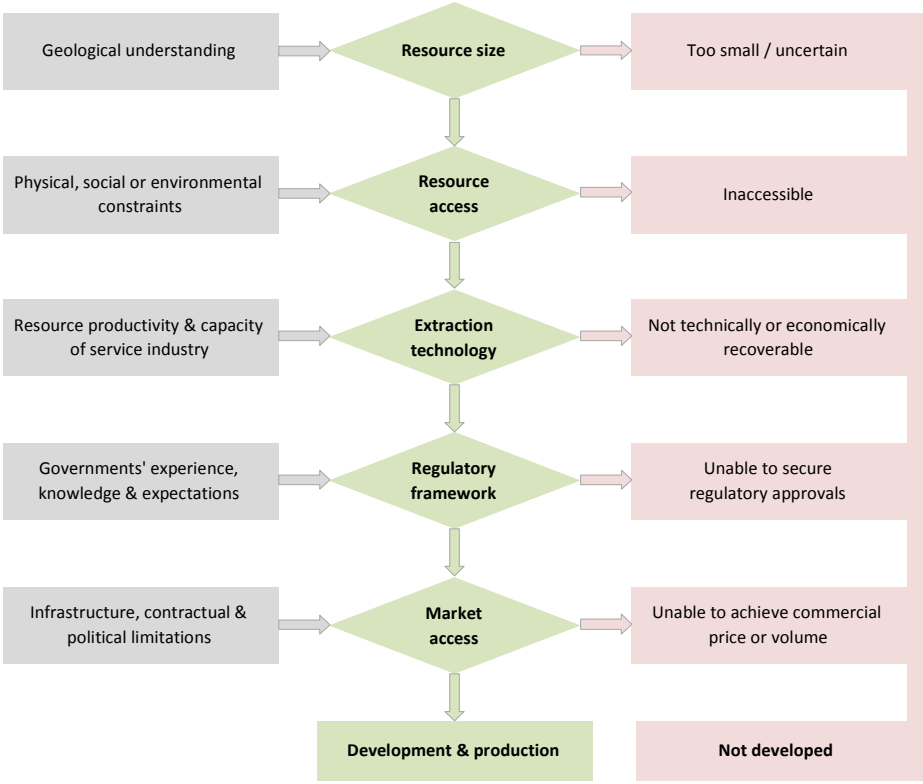
The long-term potential for expanding gas supplies in any particular region or country is dependent on the size and quality of the resource base. But several other factors are also important in determining whether, and how quickly, resources can be developed. The main factors that must be resolved for a natural gas resource to move into development and production are shown in Figure 2.1. Host country energy policies are of central importance and can influence all other factors. Gaining access to the resources is a priority. For example, if a land owner clearly owns the respective mineral rights, the benefit that owner can count on will be an incentive for development.¹ Timely development of appropriate environmental standards and regulation can assist operators in overcoming resistance to development from local communities.

Another key factor in developing gas resources is the availability of appropriate extraction technology, including processes, equipment and personnel. Technologies continue to evolve, increasing recovery per well and reducing unit costs. A key element in the success of North American shale gas production has been combining cost-effective horizontal drilling, a technique developed over the last 30 years, with hydraulic fracturing, which has been practised since the 1940s. Markets can deliver a remarkably flexible response, but there is a limit to the pace at which the capacity of the oil field-services sector to deliver these technologies can be expanded and unit costs be reduced to levels at which they can be widely and successfully deployed.

¹ This is the case for most resources in the United States.

The regulatory and fiscal framework needs to find the right balance between the need to minimise adverse environmental and social impacts, and the need to supply energy and to capitalise on national resources. If regulations are imprecise or inadequate, or operators do not follow best practices, the local impact of a development may create substantial opposition from neighbouring communities or non-governmental organisations. Conversely, if regulations are unnecessarily restrictive or tax rates too high, they will drive-up costs, reduce the competitiveness of gas and possibly stop development altogether.

Figure 2.1 ▶ Factors determining the viability of natural gas developments



Access to markets offering adequate price levels is also a major factor. Gas is expensive to transport, whether by pipeline or as liquefied natural gas (LNG), so resources located close to centres of demand will generally enjoy an economic advantage over those that are distant. In markets where extensive pipeline systems are already built, regulations about third party access to such infrastructure can be important as a means of minimising transport costs. Long-term sales-purchase agreements can offer security of both demand and supply, binding together producers and consumers, but the reasonable need for flexibility of both supplier and purchaser must also be provided for. Supplies from geographically more remote locations may also be regarded as less secure, especially where the gas is shipped by pipeline across a number of different countries. Geopolitics can

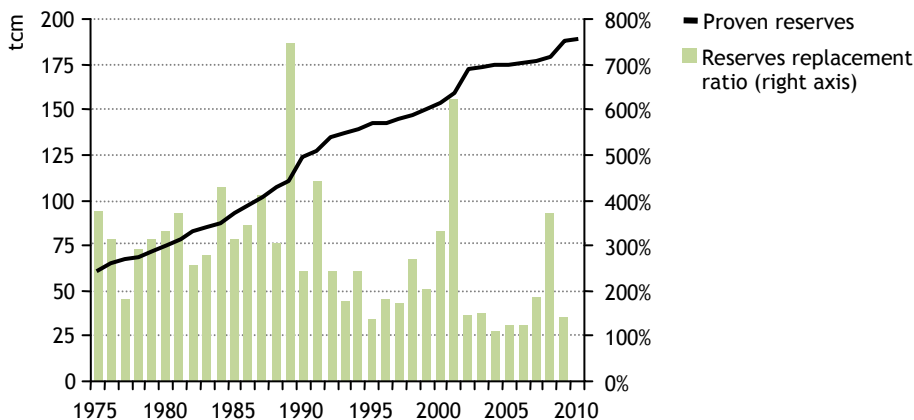
sometimes be a barrier to investment, even where the economics of a given project may be compelling. Domestic price regulations that result in prices that are below market levels discourage or impede investment.

Each of these factors needs to be successfully addressed before a particular large new development can progress or a region develops its natural gas resources into marketable supplies. This explains why it can sometimes take decades for gas resources to be commercially developed. For example, the Gorgon gas field offshore Western Australia, was discovered in 1980, but the final investment decision to proceed with development of the field as part of a large-scale LNG project was taken in 2009. The giant Shtokman field in the Russian Arctic Sea was found in 1988, but still awaits a final investment decision. Many other discovered fields are yet to be developed; and in some cases, where associated gas is produced together with oil, the gas is flared (burnt) due to the absence of a market for it. For these reasons, the rate of growth in production in each country, relative to the size of its resource base, can vary enormously.

The gas resource base

While the world’s natural gas endowment is known to be very large, its exact size is unknown as many regions remain poorly explored. Unconventional gas resources could yet turn out to be even larger than those of conventional gas (Box 2.1). The effectiveness of production in converting resources in the ground into recoverable gas (known as the recovery factor²) could also increase. Both of these factors mean that global resources could be larger than currently estimated.

Figure 2.2 ▶ Evolution of world proven natural gas reserves



Note: Reserves replacement ratio is gross reserve additions divided by annual production. Proven reserves are net volume at the beginning of the year.

Sources: Cedigaz (2010); IEA databases.

² Recovery factor is the percentage of the resource in-place (the total amount of gas in the ground) that can be economically recovered.

The world's proven reserves³ of gas at the start of 2010 stood at 190 trillion cubic metres (tcm) (Figure 2.2). This is around twice the amount of gas produced to date, and equivalent to more than 50 years of production at current rates. Other sources estimate similar amounts for proven reserves, with differences due to alternative definitions, estimation techniques and reporting standards. Proven reserves of gas have increased steadily since the 1970s, as technological advances and exploration success have consistently resulted in reserves being identified faster than they have been produced. Increases in reserves have come both from newly discovered fields and from upward revisions of volumes in fields in production or being appraised. Estimates of proven reserves are based on operators' public filings or government records, while estimates of recoverable resources are based on IEA analysis of future hydrocarbon developments.

Gas resources by region and type

The ultimately recoverable resources of conventional gas worldwide are estimated to be around 400 tcm, based on current technology and prices. This is equal to more than 120 years of current annual production. Based on data from several sources, we estimate that remaining ultimately recoverable resources of shale gas worldwide amount to 204 tcm, coalbed methane (CBM) resources 118 tcm and tight gas 84 tcm (Table 2.1). Combining estimates of conventional and unconventional gas shows that there are globally recoverable resources equal to over 250 years of current production and that every region has at least 75 years of current consumption. Thus the gas resource base is vast and geographically diverse, with the potential to meet demand for many decades.

Table 2.1 ▶ Remaining recoverable resources of natural gas and indicative production costs by type and region, January-2010

	Conventional		Tight Gas		Shale Gas		CBM	
	tcm	\$/MBtu	tcm	\$/MBtu	tcm	\$/MBtu	tcm	\$/MBtu
E. Europe & Eurasia	136	2-6	11	3-7			83	3-6
Middle East	116	2-7	9	4-8	14			
Asia/Pacific	33	4-8	20	4-8	51		12	3-8
OECD North America	45	3-9	16	3-7	55	3-7	21	3-8
Latin America	23	3-8	15	3-7	35			
Africa	28	3-7	9		29			
OECD Europe	22	4-9			16			
World	404	2-9	84	3-8	204	3-7	118	3-8

Note: Resources estimated to be below 5 tcm have been excluded. Costs are included only for regions with demonstrated production results. Costs are in real 2009 dollars and are based on the economics of gas production only, not taking into account the value or cost of any liquids production or the costs of transportation. However, some costs for associated gas production are shared with liquids production costs, thereby lowering overall costs for the associated gas. Costs are estimated on a life-cycle basis and include phased finding and development capital costs, operating expenditures and decommissioning costs, all discounted by the cost of capital. MBtu is million British thermal units.

Source: IEA analysis.

³ Various frameworks exist to categorise gas resources by the degree of confidence there is that they can be recovered technically and economically (IEA, 2010b). Proven reserves have the highest degree of confidence.

Box 2.1 ▶ Types of gas resources

Gas deposits are generally classified as conventional or unconventional resources. Conventional gas dominates worldwide production, accounting for over 85% of total marketed output today. Moreover, most oil fields contain resources of both oil and gas, and oil production usually includes production of “associated gas”. Conventional gas reservoirs are found in many differing geological settings over a wide range of depths, temperatures and pressures. Sometimes the hydrocarbon gases are contaminated with non-hydrocarbon gases, such as carbon dioxide or hydrogen sulphide (rendering the gas sour) or nitrogen, which lowers the energy content. Such contaminants complicate development and can significantly increase costs.

Unconventional natural gas resources include tight gas, shale gas, CBM and gas hydrates. Tight gas formations are generally defined as having permeability (*i.e.* the ability for gas to flow through the rock) of less than a specific threshold. This makes the development of these resources more challenging. Nonetheless, gas has been produced from tight sands for over 40 years in North America, with new technologies constantly being developed to improve productivity.

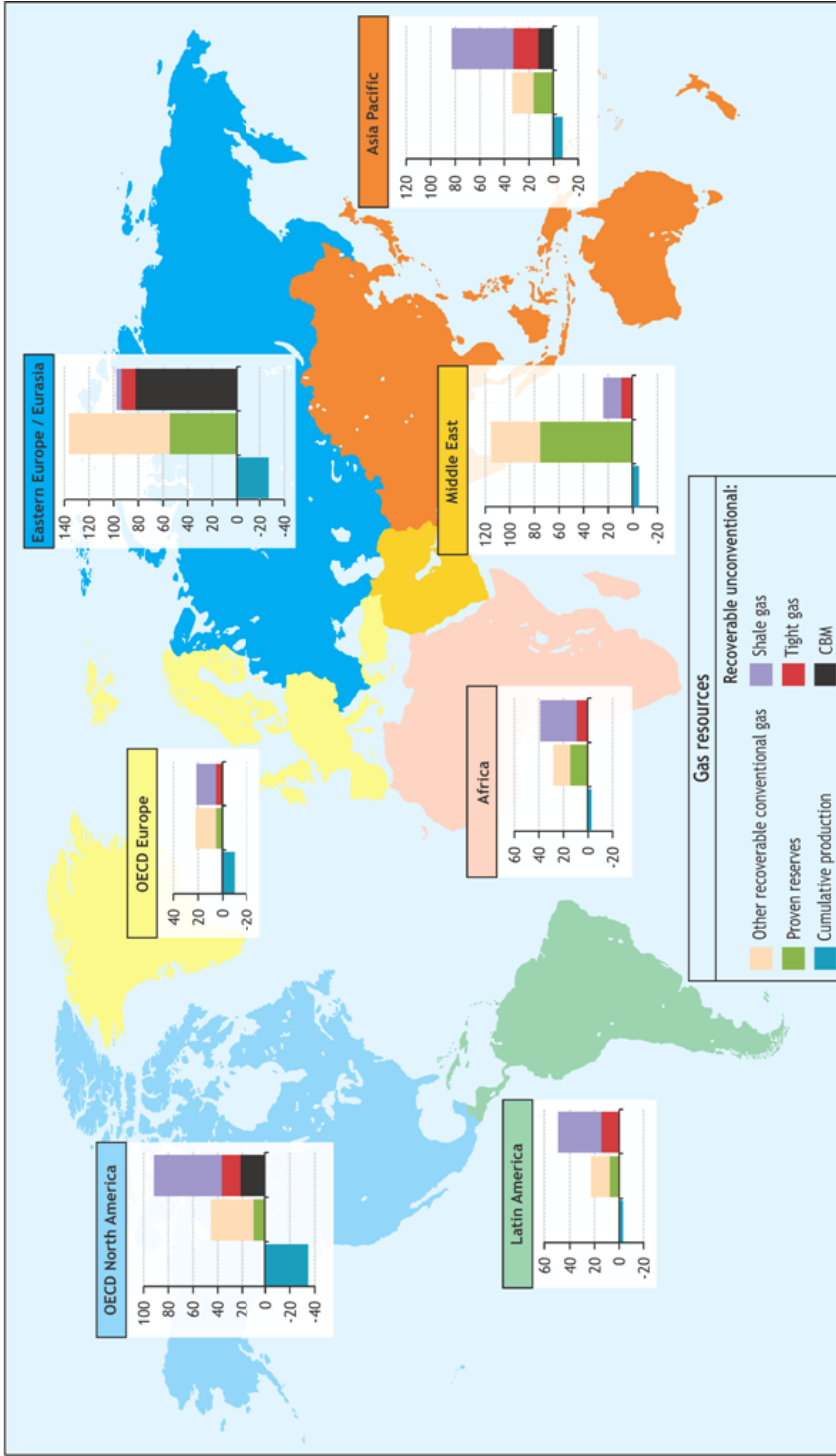
Shale gas is found in commonly occurring rock formations rich in organic matter, loosely classified as shale. Such formations have been known about for almost 200 years, but until recently most were regarded as uneconomic to develop because of the very low rock permeability, which yielded wells with very low (*i.e.* uneconomic) production rates. However, in recent years operators have been successfully applying horizontal drilling techniques combined with multi-stage hydraulic fracturing to achieve economic production rates in a number of regions in North America.

CBM is natural gas contained in coalbeds, trapped in the fractures and on the surface of the coal. CBM is a severe hazard to mining operations and extraction of CBM was initially undertaken to make mines safer. However, since the late 1980s, commercial production has taken-off in the United States, where it accounts for about 10% of total gas production. Canada, Australia and China also produce CBM.

Underground Coal Gasification (UCG) has the potential to recover far more energy from coal seams than CBM. The UCG process produces a mixture of gases consisting mainly of hydrogen, carbon monoxide and methane, which can be used as a fuel or chemical feedstock. The technique has a long history in Eurasia, and extensive trials have been undertaken in Europe and North America since the mid 1940s and more recently in Australia. However progress has been slow and there is only one commercial operation today, in Uzbekistan; so despite the large potential resource of up to 146 tcm (WEC, 2007), UCG production is not considered further in this report.

Gas hydrates are a lesser known unconventional gas resource. Hydrates are an ice-like solid formed from a mixture of water and natural gas in cold northern regions or in deepwater offshore sediments. In-place resources are thought to be huge, with some studies estimating a total worldwide resource of between 1 000 tcm and 5 000 tcm (Milkov, 2004), but they are intrinsically difficult to develop. Only a handful of experimental tests have so far been conducted and it is unlikely that exploitation on any significant scale will occur before the end of the *Outlook* period, so gas hydrates are not considered further in this report.

Figure 2.3 ▷ World natural gas resources by major region, January 2010 (tcm)



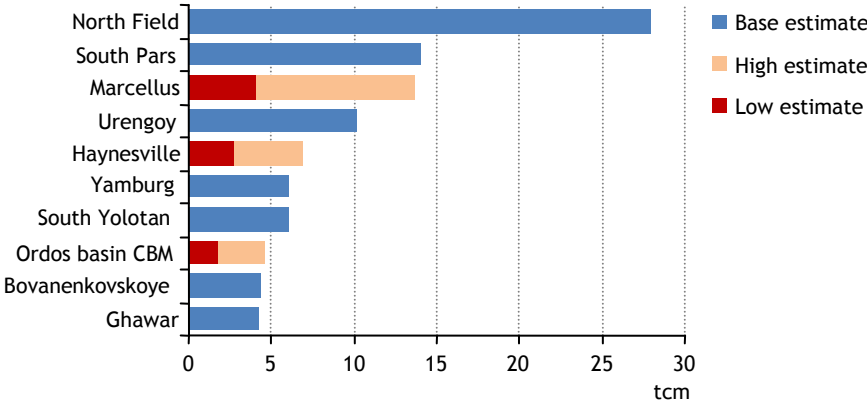
This map is for illustrative purposes and is without prejudice to the status of or sovereignty over any territory covered by this map.

Sources: Cedigaz (2010); USGS (2000 and 2008); BGR (2009); US DOE/EIA (2011); Kuuskraa and Stevens (2009); Gazprom (2010); IEA estimates and analysis.

Our estimates of recoverable resources of unconventional gas are based on estimates of resources in-place taken from Rogner (1997) updated with recent data, including a new assessment of worldwide shale gas resources from the US Energy Information Administration (EIA) (US DOE/EIA, 2011), to which we have applied recovery factors that have been demonstrated by operators to be achievable. The EIA assessment covers 48 shale gas basins in 32 countries and puts technically recoverable shale gas resources in those countries and in the United States at 187 tcm; China has the biggest resources (36 tcm), followed by the United States (24 tcm), Argentina (22 tcm) and Mexico (19 tcm).

Eastern Europe/Eurasia have the largest known natural gas resources, which are concentrated in the countries of the former Soviet Union (Figure 2.3). The Middle East benefits from large volumes of gas associated with oil. Total recoverable resources are well distributed geographically, but more than half of the world’s proven reserves are concentrated in Russia, Iran and Qatar in large conventional gas fields. North America and Europe are at the lower end of proven reserves, even though North American reserves have benefited from substantial additions of unconventional gas. Unconventional gas now accounts for nearly one-quarter of total North American proven gas reserves. Proven gas reserves in the OECD are only 18 tcm, equal to just under 10% of the world total, or about 16 years production at the current rate.

Figure 2.4 ▶ Estimated initial recoverable resources of the world’s largest known natural gas fields and unconventional gas deposits



Note: Low and high case estimates for recoverable resources of unconventional deposits in the Marcellus, Haynesville and Ordos basins indicate the range of uncertainty.

Sources: Cedigaz (2010); US DOE/EIA (2011); official national statistics and other industry sources; IEA estimates and analysis.

The size of unconventional gas resources has only recently started to become clearer, though petroleum geologists have been aware of the presence of such resources for many years. Although almost all production of unconventional gas has occurred in North America to date, success there has spurred interest in other parts of the world. Two of the largest identified unconventional gas fields (Marcellus and Haynesville in the United States) would rank respectively as the third and fifth-largest gas fields of any type in the world (Figure 2.4), if based on optimistic assumptions of recovery and extent of deposits. CBM in

China's Ordos basin will also feature among the world's ten biggest, if production proves to be viable over the entire basin. The world's other largest gas fields are in Qatar (North Field), Iran (South Pars), Russia (Urengoy, Yamburg and Bovananekovskoye), Turkmenistan (South Yolotan) and Saudi Arabia (Ghawar, which is the world's largest oil field).

Development and production costs

Assuming that the factors determining the viability of specific developments are positive (Figure 2.1), how quickly resources will be produced depends largely on the cost of development and transport to market. In general, greenfield gas developments involve large upfront investments and long lead times before first production and have long payback periods. Such projects typically cost more than adding incremental developments to producing fields, because they require new infrastructure. For this reason, the development of unconventional gas resources outside North America and conventional resources in virgin areas tends to be relatively more costly.

We estimate that the cost of developing and producing gas (not including transportation from the wellhead), expressed in dollars per unit of gas, discounted over the production life, ranges from about \$2 per million British thermal units (MBtu) to over \$9/MBtu (Table 2.1), depending on the resource type and its location. Conventional gas in the Middle East and in Eastern Europe/Eurasia is generally the cheapest to produce. Gas resources that use mature technologies, or are located in areas where oil or gas production is already undertaken, typically benefit from both experience and infrastructure that reduces their development costs. Conversely, costs are higher for gases contaminated with impurities (Box 2.1), because additional equipment and experience are required, and for Arctic and deep-water projects, because they are located in a challenging environment far from existing infrastructure.

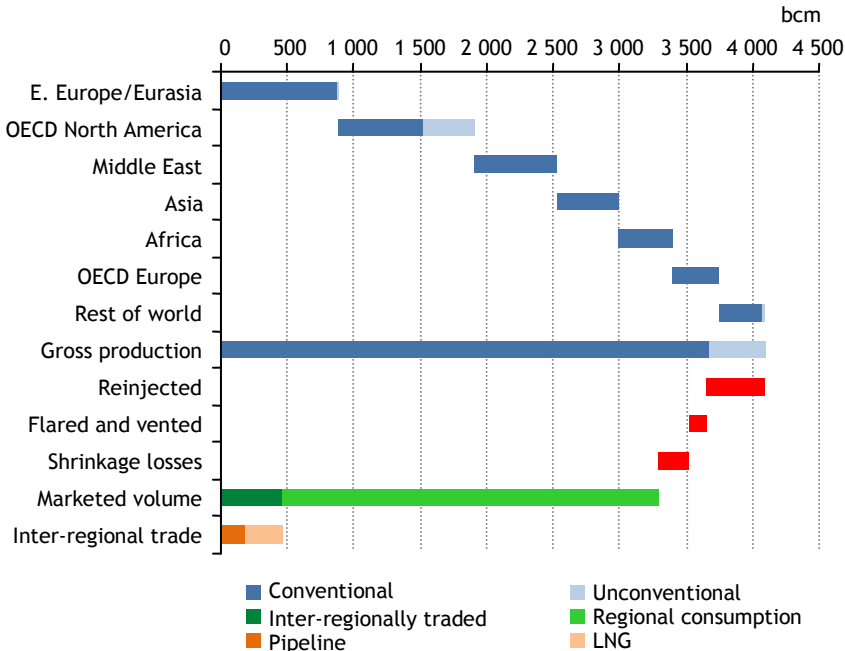
The rapid development of shale gas in North America has been driven by (and contributed to) a fall in unit costs, as technology and experience have overcome geological and other challenges. A significant volume of shale gas is now thought to cost between \$4-6/MBtu to produce, which compares favourably with most sources of gas elsewhere in the world that are not already in production. This cost range is an important driver in the GAS Scenario, enabling competitive pricing of unconventional gas in the world market and allowing gas to increase its share in the energy mix.

Global supply trends

Marketed global gas production has doubled over the past 30 years to an estimated 3.3 tcm in 2010 (Figure 2.5). Russia and the United States are the largest gas producers with levels of around 600 bcm in 2010, three times higher than the third-largest producer, Canada. Over the past decade the Middle East and Asia have emerged as major producing regions and each now represents around 13% of global production. Production of unconventional gas has also risen substantially in recent years and is estimated to represent around 13% of marketed global gas production as of 2010. Production of unconventional gas in North America doubled in the previous eight years to reach more than 350 bcm in 2010.

Around 20% of gross gas volumes produced never reach the market. Some of this gas is used for reinjection in oil fields (as a way to prolong and maintain oil output), some is flared, some is lost because of “shrinkage” due to the extraction of natural gas liquids (NGL) and some is utilised as fuel in production facilities. The amount of gas that is flared has declined in recent years, as policies have been adopted to curb this wasteful practice. Much of the remaining potential to reduce flaring, which is significant, is likely to be exploited within the next decade or so. Russia, where large volumes of associated gas are flared from oil fields in western Siberia, is targeting a 95% utilisation rate for associated gas by 2012 and has made progress towards this goal. In March 2011, Nigeria unveiled a \$25 billion plan to reduce flaring by utilising the gas, notably in power generation.

Figure 2.5 ▶ Estimated worldwide natural gas flows, 2010



Sources: IEA databases and analysis; Cedigaz (2010).

Medium-term capacity constraints

When assessing the medium-term developments in gas supply, a fundamental question is whether new production can be brought on-stream in a timely manner to meet rising demand or whether supply constraints may appear in certain regions. Indeed, there is a fundamental asymmetry between the slow pace at which new supply capacity can be brought on-stream and the speed at which demand can vary, as illustrated by the estimated 7.5% increase of gas demand in 2010. In addition, even where prices are high enough to stimulate new investment, there are practical constraints on how quickly capacity can be added because of limits on the amount of equipment that can be mobilised and on the capacity of the oil and gas industry to meet demand for services. Similar constraints on the ability to add new LNG and pipeline capacity can also hold back upstream developments.

Globally, there is currently ample spare gas-supply capacity, despite the recent rebound in demand, because demand growth slowed in 2008 and demand fell heavily in 2009 as a result of the financial and economic crisis. Moreover, the recovery in demand in 2010 was in large part caused by exceptionally cold weather across the northern hemisphere, such that demand growth in 2011 may slow (unless unusually cold weather reoccurs, which was not the case in early 2011).

The long lead times involved in major gas-supply projects, especially those involving long-distance pipelines and LNG chains, mean the maximum amount of supply that could be attained within the next five years is already fairly well known (although project delays may result in lower capacity than currently planned). We estimate that global supply capacity (of marketed gas) in 2015 could not exceed 3.75 tcm.

Towards 2020, there is greater scope for production to grow faster than projected in *WEO-2010*, on the back of projects launched in the next three to four years. Nonetheless, it would appear unlikely, given physical constraints on the pace of new capacity additions, that global supply capacity (of marketed gas) could exceed about 4.15 tcm by 2020. Beyond 2020, capacity could be expanded substantially if the gas industry was confident in the prospect of persistent and substantial long-term growth in demand.

Regional production developments and potential

The Eastern Europe/Eurasia region, encompassing Russia and other former Soviet Union countries, has enormous gas resources; but parts of the region are a long way from markets and geopolitical factors complicate investment and cast doubt on how quickly capacity can be expanded. Production fell heavily in 2009, by around 12%, as a result of the economic crisis, which depressed demand both in domestic markets and for exports. Russian demand (largely driven by cold weather) and exports to neighbouring states recovered in 2010, but domestic demand across the region fell again in early 2011 due to milder weather; exports to Europe have still not recovered to pre-crisis levels, notwithstanding cold weather and import growth estimated at 16% in Europe in 2010.

Russian output from the traditional production region of Nadym-Pur-Taz continues to decline. The development of huge, but costly new reserves on the Yamal peninsula began in 2008, just before gas demand fell. Much of the transportation infrastructure is now in place, but the speed at which the fields themselves will be developed will depend on the pace of recovery in Russian export markets. Russia has also been seeking to develop markets in the far east of the country, starting exports of LNG from Sakhalin in 2009. Exports could be accelerated further, following the acquisition by Gazprom of the 2 tcm Kovykta field in March 2011. Future expansion of Sakhalin LNG or of the promising but remote fields in Eastern Siberia and the Russian far east all appear costly, but buyers in China seem more prepared to pay higher prices for imported gas than in the past.

Gas output in OECD Europe fell by 20 billion cubic metres (bcm), or 6%, between 2005 and 2010 and production is expected to continue on this downward trend. Norway's production is continuing to increase, rising by more than 20 bcm over the five years to 2010, but future increases are unlikely to be sufficient to compensate for the continued sharp decline in production in the United Kingdom and continental Europe. In particular, future production in the Netherlands will be limited due to the decline of the small fields and the policy cap on production at the Groningen field. New conventional gas developments are unlikely to

alleviate this decline, even in the longer term; however significant unconventional resources have been estimated, but it remains to be seen whether, or in which time frame, these will be developed.

In Australia, production and exports are set to expand further in the next few years. Four major LNG export projects are under construction, fuelled both by conventional and unconventional gas. Australia benefits from large gas resources and the only obstacle to it becoming a leading LNG exporter lies in the risk of construction delays and cost escalation due to workforce shortages, as large projects compete for limited manpower in Australia and also in neighbouring Asia Pacific countries where other LNG liquefaction projects are under construction.

North American production is on a two speed trend: in the United States, there is healthy growth in production, driven by shale gas, whereas production is falling in Canada due to a combination of lower export demand (and thus price) into the United States and the long-term decline of the western Canadian conventional gas basins. Key questions for future development are whether the combination of environmental concerns and low gas prices will dampen or reverse production growth (in particular shale gas) in the United States and whether Canada will find new outlets for its production, particularly if unconventional gas production grows strongly, possibly through LNG exports or new gas-to-liquids (GTL) projects.

In the Middle East, production costs are relatively low, although new gas resources are likely to be more expensive to develop than existing production, which is often associated with oil. This is a particular problem in countries where gas prices are kept artificially low and may be insufficient to cover the cost of development. In addition, political issues, such as the moratorium on future development of the North Field in Qatar or internal discussions in Iraq on the pace of development of gas resources in relation to the expected expansion of the domestic gas market, contribute to delay in the development of some gas fields. Saudi Arabia is currently pursuing a number of gas opportunities that are expected to start production by the middle of this decade. Recent discoveries also mean that Israel could turn from an importer into an exporter.

With the adoption of the 12th Five-Year Plan for the period 2011-2015, China has switched its focus to non-coal energy sources, including gas. This change is assumed in the GAS Scenario, leading to substantial growth in gas production in China. China's national oil companies (NOCs) have stepped up their investment in indigenous gas production, with a new focus on unconventional gas deposits. India has increased its production from 32 bcm in 2008 to an estimated 52 bcm in 2010, with the start of Reliance's Krishna Godavari KG-D6 field. The Krishna Godavari basin is expected to be the source of additional supplies, while India is also investigating its CBM and shale gas opportunities.

North Africa, currently responsible for three-quarters of the continent's gas output, is likely to remain the major centre of African production. However, even before the unrest and conflict across parts of the region in 2011, some of the main exporting countries, notably Egypt, were struggling to fulfil export commitments. Production increases in sub-Saharan Africa seem likely to be led by Nigeria, but major new producers and exporters are expected to emerge: Angola, for example, will start exporting LNG in 2012. Recent deepwater discoveries in Mozambique and Tanzania in eastern Africa look promising, but will be difficult to develop.

In Latin America, gas production is expanding most rapidly in Brazil, where output is expected to increase by one-third over the next five years and the pending development of pre-salt fields should turn the country into a net gas exporter. Peru is producing markedly more gas after the start-up of the 6.1 bcm Peru LNG liquefaction plant in mid-2010. Other countries in the region have struggled to raise output, despite having sizeable resources. Insufficient upstream investment has caused production to stagnate in Argentina and Bolivia. Even with the largest reserves in Latin America, Venezuela has seen gas production decline from a peak of 31 bcm in 1998 to 22 bcm in 2009, and the country is now confronted with gas shortages and is importing from Colombia. Venezuela's resource potential is nonetheless large and promising, particularly with the recent discovery of the (estimated) 450 bcm Perla field in 2009.

The global potential of unconventional gas

Unconventional gas⁴ may hold the key to expanding the long-term role of gas in the global energy mix. Already, the unconventional gas revolution has reshaped the market in the United States and lastingly affected global gas markets. Over the last decade, substantial LNG regasification capacity was built in anticipation of the United States becoming a large importer. However, the unexpected and substantial rise in domestic gas production during that period, particularly from shale gas, has reduced import needs, leaving these facilities underutilised and freeing-up LNG for other markets (notably Asia and Europe). The situation has changed so quickly that proposals to export LNG from North America are now being seriously advanced. While unlikely to become a reality before 2015, these proposals illustrate the profound change that has taken place in the outlook for LNG trade flows.

Production of unconventional gas has also grown fast in other regions. Australia produces small amounts of CBM (around 5 bcm in 2010) and is set to become the first CBM-based LNG exporter, with two projects sanctioned (Gladstone LNG and Queensland Curtis) and four others planned. Future CBM developments in Australia will require careful attention to sensitive water management issues. China, India and Indonesia are all actively seeking to develop their unconventional gas potential. CBM continues to be a major focus of activity, but China and India are also considering the development of domestic shale gas.

China's first licensing round for shale gas acreage is expected in mid-2011. Participants must commit to both a minimum investment and a minimum number of wells to be drilled and hydraulically fractured. The criteria are intended to maximise exploration within the offered acreage and to assist Chinese companies to acquire fracturing knowledge, either by setting up joint ventures with international oil companies or by investing abroad to gain expertise. To further encourage production, prices for domestic wellhead gas were increased by 25% in June 2010 and pipeline infrastructure is being built, albeit slowly, with only the 2 bcm Quinshui connection to the West-East pipeline completed so far. These measures are designed to incentivise shale gas and CBM production from large resources like those of the Sichuan and Ordos basins.

⁴ In some countries tight gas is considered as a "continuation" of conventional gas and is not separated in official statistics. This section discusses principally shale gas and CBM.

Exploration of unconventional resources has started in Europe, with a focus primarily on shale gas. The leading country is Poland (Box 2.2), but activities are under way in Germany, Spain, the United Kingdom, Ukraine and elsewhere. However, a moratorium was placed on shale gas activities in France before drilling started, mainly due to concerns about water management. Significant production is not expected in Europe before 2020, due to the time needed for resource appraisal and development and associated technical, environmental and regulatory issues. Gaining access to land could prove difficult due to concerns about population density and the need for, and treatment of, large volumes of water, especially in agricultural areas.

Box 2.2 ▶ Poland leads the way for shale gas in Europe

Interest in European unconventional gas production has been growing over the past few years, with many countries involved in surveying and analysis of shale gas, tight gas and CBM prospects. Shale gas in Poland has attracted the most interest. The Ministry of Environment in Poland had granted 86 concessions for exploration for unconventional gas as of mid-2011 and some five exploratory wells had been completed, with a further 15 to follow in 2011. Several major international oil and gas companies, as well as some smaller independent companies, are active in the country. Exploration activity is concentrated in the north of Poland, with drilling to depths of 3 500 to 4 500 metres. While work is focussing on shale gas, tight gas is also being explored for in the Poznań region. CBM results have been less promising.

Preliminary estimates by industry consultants and the US Energy Information Administration (US DOE/EIA, 2011) suggest that Poland could have as much as 1.4 to 5.3 tcm of shale gas; the Polish Institute of Geology plans to publish its updated estimates of unconventional (or shale) gas resources in the second half of 2011. Studies are also ongoing concerning the costs of exploitation, including the availability of drilling rigs and manpower. Early work indicates production costs substantially above those in North America, but still potentially competitive in the European gas market.

Should the resource be confirmed, a number of hurdles to speedy development will remain. Because of the relatively large numbers of wells needed to be drilled, obtaining approval from local authorities and communities may not be straightforward. The treatment and disposal of large quantities of waste-water may also complicate projects. In addition, development and third party access to pipeline infrastructure will require domestic policy reform, as the Polish market is still effectively monopolised, although the reform process is underway.

Notwithstanding the technical, environmental and regulatory barriers, shale gas has the potential to radically change the Polish energy landscape. Poland currently depends on Russia for two-thirds of its gas consumption; in addition, the Polish power-sector is dominated by coal (92%), with only a small role for gas (2%). Domestic shale gas could provide the means to reduce greenhouse-gas emissions and other pollution in the power sector and elsewhere and improve security of supply.

India is promoting its unconventional gas potential, with a fifth CBM licensing round and a shale gas licensing round scheduled for 2012. Despite this activity, Indian CBM production began only in 2007 and is still very small, at less than 1 bcm annually. However the last unconventional gas licensing round attracted more interest than the most recent conventional gas licensing round. Future increases in domestic gas production have been hindered by the low prices set by the Administrative Price Mechanism (APM) which discouraged investment by NOCs, but the increase of APM prices in mid-2010, from \$1.8/MBtu to \$4.2/MBtu, will provide more incentive. The role of government in pricing and allocation and the problem of insufficient domestic transport infrastructure still need to be tackled (IEA, 2010c).

Indonesia hopes that its large CBM resources will enable it to supplement its conventional gas output. Over 20 CBM Production Sharing Contracts have been signed and the government is organising new tenders. Small scale production of CBM should start in mid-2011. First production is planned from the West Sangatta deposit in East Kalimantan province and total CBM production could reach 5 bcm by 2020. Development of shale gas is clearly lagging, with the regulatory framework still being developed and contracts expected to be signed in 2012 at the earliest.

There is significant potential for producing tight gas in several Middle East and North African countries, including Saudi Arabia, Oman, Jordan, Algeria and Tunisia. Development of resources in these countries will depend on the level of each country's conventional gas output, the need for additional resources to meet demand and relative production costs. Two countries – Oman and Jordan – are currently focusing their exploration on tight gas fields. South Africa had issued exploration licenses for shale gas, but has recently announced a moratorium on hydraulic fracturing, so it is unclear if projects will proceed. Argentina has been focusing more on tight gas rather than shale gas. The government has taken measures to encourage investment in unconventional gas production under its Gas Plus program, which allows companies to sell gas at up to \$6/MBtu (compared to a set wellhead price of \$2.5/MBtu for conventional gas), to allow for the higher production costs.

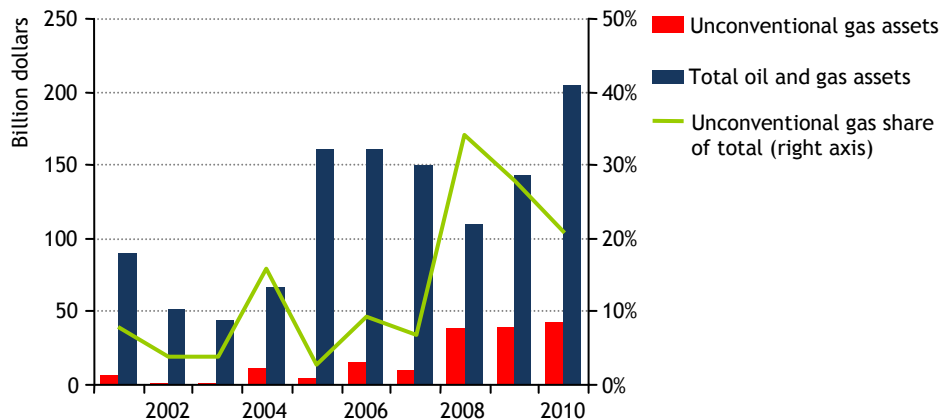
Ownership of unconventional gas and the spread of expertise

Merger and acquisition activity is serving to facilitate the spread of expertise in unconventional gas production beyond North America. While small independent companies pioneered the technologies that made shale gas extraction profitable there, many of the largest international companies were slow to realise its potential. Companies that have entered into the unconventional gas arena later have often grown their positions rapidly through mergers and acquisitions, enabling them to acquire in single transactions material resources and production together with knowledge and experience.

The precipitous fall in North American natural gas prices from the second half of 2008 did little to deter significant mergers and acquisition activity aimed at obtaining access to unconventional gas assets (Figure 2.6). The buy-out of XTO by ExxonMobil in 2009 – for a total of \$41 billion – reinforced the view of many that increasing gas production in North America was a secure prospect. In 2010, seven further shale gas transactions, with values of between \$1 billion and \$5 billion, were completed in North America. Purchasers of these assets include both international and state-owned oil and gas companies, seeking to add North American gas resources to their portfolios and to acquire operational experience that can be applied elsewhere. Asian companies, particularly those based in China, are

increasingly active. In 2010, China National Offshore Oil Corporation (CNOOC) acquired unconventional assets costing \$2.4 billion and in early 2011 PetroChina acquired assets for \$5.6 billion.

Figure 2.6 ▶ Transaction values of oil and gas acquisitions



Source: IEA databases and analysis.

The desire to develop unconventional gas resources in regions outside North America is strong. China has auctioned exploration rights for shale gas blocks, but with dominant participation limited to Chinese companies. International companies wishing to participate have therefore sought to enter into partnerships with Chinese companies; Shell and Statoil are working with PetroChina, Hess with Sinochem, and BP with Sinopec. China is also participating in CBM developments through partnerships with foreign companies and acquisitions in North America. PetroChina has entered partnerships with Shell and BP, while China United Coalbed Methane (CUCBM) has entered three partnerships with Sino Gas and Energy, Dart Energy and Far East Energy. PetroChina acquired Arrow Energy jointly with Shell in 2010, giving it access to one of the CBM-based LNG projects in Australia.

Environmental impact of gas production and transport

Natural gas mainly consists of methane (CH₄), a greenhouse-gas with a global warming potential (GWP) significantly higher than that of CO₂.⁵ While gas is the cleanest burning fossil fuel, some greenhouse-gas emissions arise during its production and transportation, through venting, leakages or accidents. Leakage appears to be a more important source of CH₄ than venting. The US Environmental Protection Agency (EPA) estimated that worldwide leakage and venting volumes would reach around 95 bcm in 2010 (US EPA, 2006); it estimates that this figure is still valid. The production of gas (and oil) also gives rise to CO₂ emissions, including through flaring. In 2010, 134 bcm of gas were flared globally⁶, equal to

⁵ The global warming potential of CH₄ is 72 times greater than CO₂ over a 20-year period, 25 times over a 100-year period and 7.6 times over a 500-year period (IPCC, 2007).

⁶ Estimate based on satellite data measurements from World Bank Global Gas Flaring Reduction public-private partnership data (GGFR, 2010). Other data sources give different estimates for certain countries.

about 4% of marketed gas output. The volume of flared gas has been falling over the past few years, as regulations have improved. Though more gas is flared than is vented, on a CO₂ equivalent (CO₂-eq) basis, total emissions from leaked and vented gas are significantly higher than emissions from flaring, by a factor of six.

Emissions data related to the production and transport of gas are hard to collect and are often less reliable than those for marketed energy. The available data shows that such emissions are substantially lower than the CO₂ emissions produced from gas combustion. Table 2.2 shows CO₂ and CH₄ emissions arising from the production of gas in selected countries. Emissions related to gas production include those from gas flared or vented during oil production, as emissions from oil and gas production are reported together. A large part of flaring actually comes from oil production, so emissions from gas production and transport as presented in this report are somewhat overstated. These emissions average 0.37 million tonnes (Mt) CO₂-eq per bcm of gas produced, versus 1.9 Mt CO₂-eq per bcm when this gas is burned, *i.e.* about five times less. Potentially, emissions from gas production can be reduced further. Some of the CO₂ coming from the reservoir can be captured using CCS. There are a few such projects around the world, but widespread uptake of the technology will depend on future regulation to reduce greenhouse-gas emissions. CH₄ and CO₂ emissions can also be reduced by applying specific techniques during the production phase.

Environmental impact of unconventional gas production

Hydraulic fracturing – a technique developed by the oil and gas industry over the past 70 years – is essential to stimulate the flow of gas in shale gas wells. Increased fracturing requirements in recent years have been accompanied by increased water requirements per well. Rapidly increasing shale gas production in the United States and exploration in countries with strong supply prospects have sparked public concerns about the environmental impact of hydraulic fracturing. Some of these concerns centre on the large volume of water required to fracture the rock and on the potential contamination of fresh water aquifers by the fluid injected into shale formations.

Hydraulic fracturing involves pumping large volumes of fluid mixed with sand (or other granular products, collectively called proppants) and chemicals to aid the process (US DOE, 2009).⁷ The total volume of water injected ranges from 7 500 to 20 000 cubic metres per well. Until recently, for proprietary reasons, the detailed composition of the fluids was not disclosed, which has caused some public concern. In the United States, some companies have now started providing more data on the fluids used. Recovered water from shale gas wells may also contain materials from the surrounding rock, such as naturally occurring radioactive materials and heavy metals. If not treated or disposed of properly, these pose another potential risk of contamination of water supplies.

⁷ In hydraulic fracturing fluid, water is typically 98 to 99.5% by volume.

Table 2.2 ▶ Gas production and associated emissions in selected countries, 2008

	Fugitive emissions (Mt)*					Gas production (bcm)	Specific fugitive emissions (Mt CO ₂ -eq per bcm)
	Production/ transport		Venting/ flaring		Total CO ₂ -eq		
	CO ₂	CH ₄	CO ₂	CH ₄			
Russia	0.08	13.61	29.88	0.97	395	662	0.596
United States	21.77	4.59	8.20	-	145	571	0.253
Canada	0.07	1.02	15.95	0.97	66	176	0.372
Norway	0.09	0.03	2.12	0.02	3	102	0.034
Netherlands	0.00	0.02	0.07	0.02	1	84	0.012
United Kingdom	0.01	0.21	3.67	0.04	10	74	0.133
Australia	0.01	0.16	5.82	0.06	11	45	0.253
Sub-total	22.04	19.64	65.71	2.07	631	1 713	0.368
World	n.a.	n.a.	n.a.	n.a.	n.a.	3 161	n.a.

*Includes exploration and leakage.

Note: UNFCCC data are available only for Annex-I parties. The countries listed in the table accounted for 54% of global gas production in 2008. Venting and flaring includes emissions from both oil and gas production. CH₄ emissions on a CO₂-eq. basis have been calculated over a 100-year period, using a global warming potential of 25 (following the IPCC greenhouse gas reporting convention). Mt is million tonnes; bcm is billion cubic metres; CO₂-eq is carbon-dioxide equivalent; n.a. is not available.

Sources: UNFCCC greenhouse gas inventories, available at www.unfccc.int (fugitive emissions) and IEA databases (gas production).

The life-cycle emissions of shale gas production have also come under scrutiny, with some commentators calling into question the potential contribution of shale gas in reducing greenhouse-gas emissions, as there is evidence that shale gas production can release significantly higher amounts of CH₄ into the atmosphere than conventional gas during the well completion process. The EPA has recently revised CH₄ emission factors related to unconventional gas production, with the result that the emission factors of some of the steps in the production process are now many times higher than for conventional gas and much higher than previously reported (US EPA, 2010). These figures stem largely from operations in which all produced gas is vented. Despite this, total emissions from production are only slightly higher than for conventional gas; and both the water and climate impacts can be mitigated using existing techniques (Box 2.3).

Box 2.3 ▶ Mitigation of the environmental impact of shale gas production

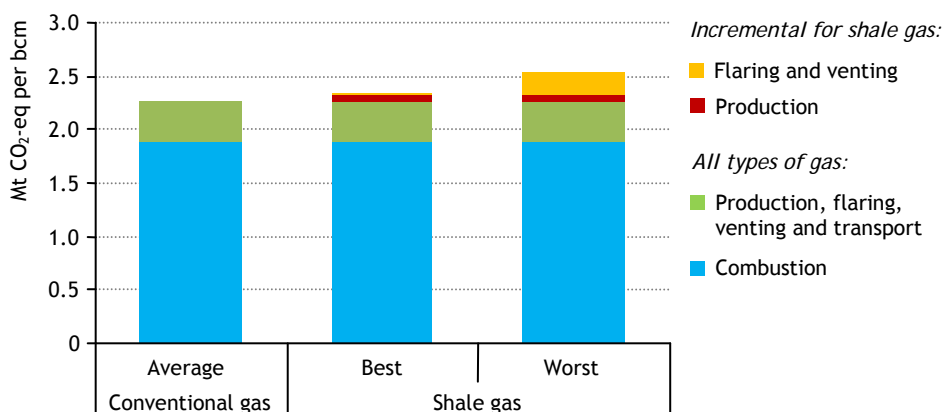
For geologic reasons, producing shale gas requires intensive drilling of wells (a number at least an order of magnitude greater than for conventional gas) and the use of hydraulic fracturing on a large scale. As the scale of operations and production expands, the number of wells increases significantly. As a result, even limited effects per well on local water resources and greenhouse-gas emissions could have sweeping implications for the acceptability of the development of shale gas resources. All shale gas operations need consistently to follow a clear set of well-formulated regulations and apply best available practices in order to mitigate potential environmental risks. For example, the voluntary Natural Gas Star Program in the United States encourages best practices for reducing CH₄ emissions in the oil and gas industry, including in shale gas production. The following are key practices:

- Ensure that the well and the shale formation remain hydraulically isolated from all other strata penetrated by the well. This means ensuring both the physical integrity of barriers between the well and those other strata, and that no communication is opened between the shale formation and surrounding strata. To prevent contamination of water supplies, gas wells and the shale formation itself need to remain hydraulically isolated from other geological formations, especially freshwater aquifers. This must be ensured both in design and well construction (which includes hydraulic fracturing) and the long-term production process during the life of the well.
- Limit gas venting. Venting can occur during shale gas development and is a source of waste and additional greenhouse-gas emissions. Using specialised equipment, the fracturing fluids which return from the well together with gas, can be separated from the gas in temporary facilities during the completion phase. The separated gas can be fed into a gathering system so that it can be used. Alternatively, if the gas cannot be used, flaring it is preferable to venting.
- Minimise water use. Improving the efficiency of water use in water-intensive operations through reuse and recycling reduces the burden on local water resources. Given that some of the fracturing fluid injected into wells returns to the surface contaminated by naturally occurring substances that leach from the rocks, minimising water use can also reduce treatment and disposal needs.
- Dispose of produced water appropriately. Because of the sheer volumes involved, enforcing stringent and consistent regulations requiring appropriate treatment before water disposal is the most effective means of minimising water contamination. Complete disclosure of the chemicals used in the fracturing process would improve the quality of the environmental debate.

Successful implementation of these practices requires a combination of good regulation, operational competence and development and adoption of some new technologies. There is a slight increase in costs, but best practice can make more gas available for sale, thus increasing revenues.

Figure 2.7 compares greenhouse-gas emissions of conventional and unconventional gas.⁸ The conventional gas values represent the average emissions values arising across the entire gas production and transport industry (including emissions from gas flared or vented during the production of oil, as gas and oil figures are reported collectively, see Table 2.2). The emissions from shale gas are incremental to those from conventional gas and reflect activities specific to shale gas production, in particular emissions from the volume of gas that is produced when completing wells, which vary according to whether this gas is captured, flared or vented. In this analysis, in the best case we assume that the gas is flared, and in the worst case that it is vented. We assume that a typical unconventional shale gas well produces 45 million cubic metres (mcm) over its lifetime and 0.57 mcm during the completion phase. This latter figure equates to 1.3% of the well's total production being produced during the completion phase, a figure which lies between lower industry estimates and higher academic estimates (Howarth *et al.*, 2011).

Figure 2.7 ▶ Well-to-burner greenhouse-gas emissions of natural gas



Notes: The average value for conventional gas fugitive emissions has been calculated using UNFCCC data from Table 2.2. CH₄ emissions have been converted to a CO₂-eq basis assuming a global warming potential of 25 over a 100-year period.

Sources: IEA databases and analysis; UNFCCC greenhouse gas inventories, available at www.unfccc.int (fugitive emissions); US EPA (2006 and 2010); Wood *et al.* (2011); NYS (2009).

Emissions from shale gas extraction are higher than those for conventional gas extraction. However, total emissions from shale gas from production through to use (well-to-burner) are only 3.5% higher in the best case (flaring the gas) than the equivalent figure for conventional gas and around 12% higher in the worst case (venting the gas). Avoiding venting is already recognised as best practice (Box 2.3) and is mandated in some jurisdictions and voluntarily pursued in other areas. In the GAS Scenario, if all shale gas production in 2035 were produced following the best case rather than the worst case (of venting the gas), 106 million tonnes (Mt) CO₂-eq of emissions would be avoided. This is

⁸ The figure presents well-to-burner emissions. There is no universally accepted method of accounting for the full range of emissions of a given fuel.

equivalent to 10% of the emissions from the combustion of this volume of shale gas, which would be 1.06 gigatonnes (Gt) CO₂-eq. Gas produced during the completion process can also be captured and sold, further reducing emissions to below the best case presented here.

Concerns about unconventional gas development are not yet fully reflected in environmental legislation because they are recent and not yet fully evaluated. More studies are necessary to determine precisely the environmental footprint of shale gas production.⁹ In response to public concern, a number of countries around the world – including certain states in the United States and provinces in Canada – have placed a moratorium on shale gas exploration (Table 2.3) and in May 2010 the lower house of the French parliament voted to ban hydraulic fracturing. The situation regarding rules and regulations is rapidly evolving.

Table 2.3 ▶ **Restrictions on shale gas exploration in selected countries**

	Observation
France	The prime minister has imposed a temporary moratorium on shale gas drilling through to June 2011 while awaiting two government-commissioned reports on the impact of shale gas and oil drilling. In May 2011, the lower house of parliament voted to ban hydraulic fracturing – the bill is expected to be debated in the senate in June 2011.
India	In March 2011, the government deferred the auction of shale gas blocks for exploration by a year.
South Africa	In April 2011, the government placed an indefinite moratorium on hydraulic fracturing in the development of shale gas in the Karoo basin.
Canada (Quebec)	In March 2011, the provincial government put shale gas exploration on hold until an environmental evaluation is conducted.
United States (New York)	In December 2010, the governor of New York imposed a moratorium on high-volume horizontal fracturing until July 2011. The state government is reviewing the environmental impact of drilling in the Marcellus Shale.
United States (Maryland)	In March 2011, Maryland's house of representatives decided to place a moratorium on hydraulic fracturing until 2013.

Note: As of May 2011.

The environmental implications of coalbed methane production are similar to those associated with shale gas: one of the principal environmental challenges is the treatment and disposal of large volumes of produced water (water extracted prior to gas extraction and together with the gas). Produced water is managed according to its composition and volumes; local site characteristics may dictate that it is reinjected into aquifers, dispersed on the surface, held in impoundments or evaporation ponds, or discharged into local streams. Over the next decade, CBM production is expected to increase significantly in Australia, where public concerns centre on the treatment and disposal of produced water, the risk of contaminating freshwater aquifers (used extensively for agriculture in some areas) and the intensity of land use. Monitoring of adjacent aquifers, as well as the integrity of well construction, is planned to alleviate these concerns.

⁹ Obtaining more accurate emissions data from shale gas production will also help. For example, the United States Mandatory Reporting of Greenhouse Gases Rule, effective as of 2011, requires reporting of greenhouse-gas data from large sources and suppliers, including from the oil and gas industry.

Expanding inter-regional transportation capacity

Expanding inter-regional transportation infrastructure will be essential if the role of natural gas in the energy mix is to increase. Trade between major regions more than doubles over the projection period in the GAS Scenario. Increased trade will be needed to facilitate higher gas consumption in many regions, notably in Asia. Inter-regional transport will involve both LNG terminals and pipelines. While both long-distance pipelines and LNG projects are under development in Asia and Europe, LNG regasification terminals are making faster progress. New technologies are expected to be deployed during the *Outlook* period that facilitate greater use (and hence less wastage) of gas as well as lowering unit transportation costs, particularly of smaller volumes (Box 2.5).

Pipeline projects

Relatively few inter-regional pipelines are under construction (Table 2.4). Only two new major connections have been commissioned since late-2009: the first string of the Central Asia Gas Pipeline (CAGP), linking Turkmenistan to China, and the Medgaz pipeline between Algeria and Spain. Asia remains the most prospective area for further pipeline interconnections. The capacity of the Central Asia Gas Pipeline is being expanded to 40 bcm per year, with work expected to be complete by 2012, and further expansion to 60 bcm per year is under discussion. Construction of the 12 bcm per year Myanmar-China pipeline began in mid-2010 and is expected to be finished by 2013. Discussions on pipeline imports from Russia to China are continuing. Some progress is being made, especially on the crucial pricing issue, but the route remains unspecified and the pipeline is not likely to be completed before 2015 at the earliest.

Table 2.4 ► Major inter-regional natural gas pipeline projects

	Name	Delivery Point	Capacity (bcm)	Status	Start date
Russia	Altai	China	30	Planned	2015
	Russia-Asia Pacific	Korea	10	Planned	2015-17
	Nord Stream	N.W. Europe	27.5	Under construction	2011 end
	Nord Stream 2	N.W. Europe	27.5	Planned	2012
	South Stream	S.E. Europe	63	Planned	2015 end
Caspian / Middle East	Nabucco	S.E. Europe	26-31	Planned	2017
	ITGI	S.E. Europe	12	Planned	2017
	TAP	Italy	10+10	Planned	2017
	IGAT 9	Europe	37	Planned	2020+
Caspian	CAGP	China	+30	Under construction	2012
	CAGP expansion	China	+20	Planned	Post CAGP
	TAPI	Pakistan	30	Planned	2015+
Middle East / Turkey	IPI	India	8	Planned	2015+
	Arab Gas Pipeline	Middle East/ Turkey	10	Partially Built	n.a.
Asia Pacific	Myanmar-China	China	12	Under construction	2013
Africa	GALSI	Europe	8	Planned	2015

Note: Start dates are as reported by pipeline sponsors. Abbreviations: Central Asian Gas Pipeline (CAGP), Trans-Afghanistan Pipeline (TAPI), Iran Pakistan India (IPI), Interconnection Turkey Greece Italy (ITGI), Trans Adriatic Pipeline (TAP), Iranian Gas Trunkline (IGAT), (in Italian) Gasdotto Algeria Sardegna Italia (GALSI).

In Europe, the only pipeline under construction is the 27.5 bcm per year Nord Stream line, expected to start operation at the end of 2011. Financing has been secured to double the capacity and construction of the second phase is planned to start in mid-2011, for end-2012 completion. It is unclear whether this project will bring incremental volumes or transfer existing supplies that currently flow through Ukraine/Slovakia and Belarus/Poland. Other projects in Europe have stalled. The final investment decision on Galsi, from Algeria to Italy, has been postponed once more and there has been no decision yet on the future of South Corridor pipelines – Nabucco, the Interconnector Greece Italy (IGI) or the Trans-Adriatic Pipeline (TAP) – proposed for connecting European markets to supplies in the Caspian (Shah Deniz in Azerbaijan) and Middle East. The Arab Gas Pipeline, linking Egypt to Israel, Jordan, Syria and Lebanon, is one of few projects progressing in the Middle East, but further expansion to Turkey may be threatened by the availability of export volumes and recent unrest in the region. Indeed the existing Egypt-Jordan-Israel link was interrupted twice in early 2011.

Elsewhere, pipeline projects are intra-regional for geographic reasons. Significant interconnections already exist in North America, where capacity continues to expand. In the United States, soaring shale gas production has promoted new south-north links to transport the gas from the areas of supply to the principal markets. Realisation of intra-regional projects in Latin America depends highly on incremental production growth, which cannot be counted on at present, in Argentina, Bolivia or Venezuela. In southeast Asia, the bulk of regional trade is expected to be in the form of LNG and few further pipeline interconnections are likely to be built (Box 2.6).

Prospects for LNG

The LNG industry is in the midst of rapid expansion, which is boosting significantly the share of LNG in global gas trade. Since early 2009, 100 bcm per year of liquefaction capacity has come on-line, of which more than 60 bcm is located in Qatar; this country now accounts for more than a quarter of world liquefaction capacity. As of mid-2011, total liquefaction capacity is estimated to be 370 bcm. Total LNG trade grew 25% in 2010, to nearly 300 bcm, as most new plants reached their plateau production rates (some encountered technical hitches). Over the coming years, China, India and several countries in the Middle East and Latin America are set to become increasingly reliant on LNG imports.

LNG capacity additions will slow slightly in the next few years: there are nine projects under construction, with a total capacity of 80 bcm per year, most of which is due to be on stream by around 2014 and all by 2016 (Table 2.5). Three-quarters of this additional capacity is in the Pacific region, with Australia contributing nearly 50 bcm. The last plants to be approved are focussed on Asian markets, with supply contracts signed with buyers in China, Japan, Korea and India. For the first time, two LNG projects, Queensland Curtis and Gladstone LNG, will be based on CBM.

Given lower demand in 2009 and uncertainties about future prices, the fact that five final investment decisions were taken between late 2009 and early 2011 might be considered surprising; by comparison, in the 2005 to 2008 period, only one to two projects were sanctioned annually. But the projects to be commissioned in 2014 to 2016 differ from those recently commissioned in that they will compensate to some degree for the expected decline in throughput at some existing facilities, mainly in Indonesia, Malaysia and Oman, as well as provide for incremental demand. This is particularly important for Japan, which

sees more than one-third of its contracts (around 35 bcm) ending in the 2011 to 2016 period. The volumes in question have not yet been fully replaced through new supply contracts and extensions.

Table 2.5 ▸ LNG liquefaction plants under construction by country

	Plant	Capacity		Start date
		(bcm)	(mtpa)	
Algeria	Skikda (rebuild)	6.1	4.5	2013
	Gassi Touil	6.4	4.7	2013
Angola	Angola	7.1	5.2	2012
Australia	Pluto	6.5	4.8	2011
	Gorgon	20.4	15.0	2014
	Gladstone LNG	10.6	7.8	2014
	Queensland Curtis	11.6	8.5	2015
Indonesia	Donggi Senoro	2.7	2.0	2014
Papua New Guinea	PNG LNG	9.0	6.6	2014

Note: Start dates are as reported by project sponsors. Mtpa is million tonnes per annum.

Looking further ahead to the period between 2015 and 2020, projects totalling over 500 bcm of additional liquefaction capacity are being evaluated. Four countries account for three-quarters of this capacity – Australia, Russia, Nigeria and Iran (Figure 2.8). However, closer inspection reveals that no final investment decision is imminent for any project outside Australia (Box 2.4) and few are expected to be operational before 2020. Russia is looking at possibilities both in the Yamal Peninsula and the Far East (Vladivostok), in addition to the expansion of Sakhalin. Nigeria is expecting to move forward one of the most advanced of its planned projects – Brass LNG, OK LNG or SevenPlus. Despite huge reserves, Iran is struggling to meet its own rising demand. In any case, international sanctions make the possibility of technology transfer to Iran for rapid LNG development unlikely.

In the Middle East, in the medium term, only Qatar could be in a position to increase its capacity through debottlenecking,¹⁰ which is thought unlikely to happen before 2015; new plants could be added beyond 2020 if the country's moratorium on new developments were lifted. Meanwhile, other countries, such as Brazil, Venezuela or Cameroon, could enter the club of LNG exporters. Elsewhere, projects in Canada and the United States are looking increasingly possible, provided that they secure markets and regulatory approval. The notion that Canada or the United States could export LNG no longer looks far-fetched. In May 2011, the US DOE approved exports from the US Gulf Coast, construction of liquefaction facilities could start as soon as 2012 for exports in 2015. Two other projects are also seeking approval. These facilities will most likely be incorporated into an existing regasification terminal in order to take advantage of mooring facilities and tankage). Exports from the west coast of Canada to Asian markets are looking increasingly likely.

¹⁰ Debottlenecking is the act of removing constraints within a process to increase throughput.

Box 2.4 ▶ Australia: the emerging LNG giant?

Australia is well endowed with recoverable resources of conventional gas and CBM, currently estimated at 4.6 tcm and 420 bcm, respectively. The potential CBM resource is considerably larger, possibly ten times this amount; and the US EIA recently put Australian technically recoverable shale gas resources at 11 tcm. Moreover, much of the land mass and large offshore areas have yet to be fully explored. Most of the conventional gas, however, is located offshore and in remote areas, making the task of bringing it to market difficult. For export markets, LNG is the key enabling technology.

Australia entered the export market in 1989, shipping LNG produced from fields off the coast of Western Australia to Japan. In 2006, a second export project started from Darwin in the Northern Territory, sourcing gas from the Timor Sea. Drawing on expansions to the original North West Shelf project, exports totalled 26 bcm in 2009, with about two thirds shipped to Japan and the remainder to other Asian markets, including China and Korea. This made Australia the fourth-largest LNG exporter globally based on 2010 estimates, behind Indonesia and Malaysia, but well behind Qatar.

A new project, Pluto, with annual output of 6 bcm, also located near the North West Shelf production area, is scheduled to start up in late 2011, with strong prospects for expansion. Late in 2009, the giant Gorgon project in Western Australia received the go-ahead. Two Queensland based LNG projects utilising CBM were sanctioned in late 2010 and early 2011. The world's first floating LNG project, Prelude, will be moored off of Western Australia and was sanctioned in May 2011. Based on currently operating and sanctioned projects, Australian LNG export capacity could exceed 70 bcm by mid decade, making it the second-largest global LNG exporter behind Qatar.

Yet further expansion of LNG exports seems highly likely, with two projects planned in Western Australia. Other conventional gas projects are planned in the Northern Territory and the Timor Sea (although the latter has been delayed by lack of agreement with the East Timorese government) and two more CBM based projects in Queensland are at an advanced stage of planning. Expansion of existing facilities at the Gorgon project is already being considered. By 2020, total capacity could approach 120 bcm.

Australia's conventional gas projects are mainly situated in remote locations where little or no infrastructure exists, so labour costs, fuelled by the continent's natural resource boom, can be more than double those in major cities. The CBM projects are more favourably located: they will pipe gas from inland coal basins to LNG facilities near the town of Gladstone in Queensland, closer to Australia's major labour markets. However, given that each project will typically employ 5 000 construction workers, with a local population of only 50 000, inflationary pressures are likely.

Australia is set to become a key global LNG supplier in the next decade, but controlling costs will be a major ongoing challenge. Large projects like Gorgon, based on Barrow Island in Western Australia and producing around 20 bcm per year with a capital investment of some \$40 billion, will be the backbone of Australian supply. Estimated costs for LNG delivered to Asia from these projects range from \$6/MBtu to \$8/MBtu, figures which will tend to put upward pressure on the price in the Pacific basin.

Box 2.5 ▶ Emerging technologies for natural gas transportation and use

The main obstacle to developing a gas resource is often getting the gas to market. Large gas discoveries can justify dedicated pipelines or integrated LNG projects, but smaller discoveries often do not. New technologies are expected to be deployed during the *Outlook* period which will lower the unit cost of transportation of smaller volumes and hence speed up development of smaller gas deposits. These include:

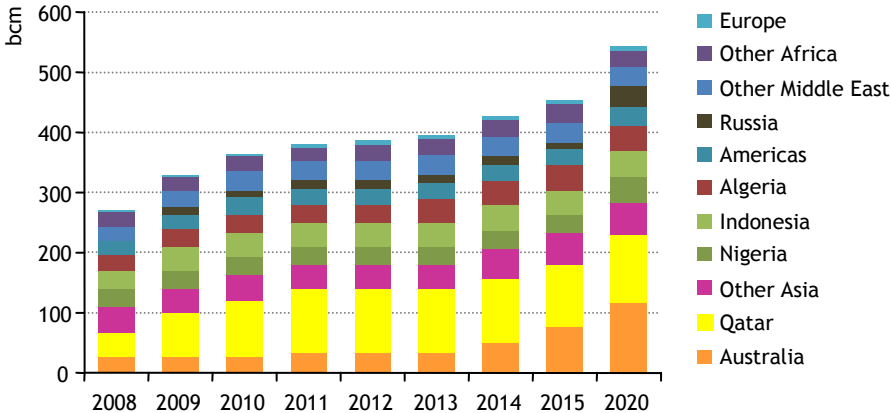
- Floating LNG (FLNG), whereby facilities on a large boat which is anchored over the field liquefy the gas and then offload it to LNG carriers for export to market. This technology eliminates the need for pipelines to shore and the risk of a land-based LNG plant running out of gas reserves: the boat can simply sail to another gas field when the first one is depleted. The world's first FLNG project was sanctioned in May 2011. It will be moored 200 km off of Western Australia with plans to deliver 4.7 bcm/year from 2017. Other projects are being planned and could contribute up to 15 bcm of supply by 2020.
- Compressed natural gas (CNG) transporters, either land or ship borne, use a large number of gas cylinders to store gas at high pressure during transportation. This eliminates the need for costly liquefaction plants. However, CNG has a lower energy density than LNG, leading to correspondingly higher unit transportation costs, particularly over long distances. CNG has so far found only limited applications, mainly in local distribution systems.
- Small scale LNG liquefaction and transport technologies are being developed and deployed in some markets (Box 2.6).

GTL technologies use chemical processes to convert natural gas to liquid hydrocarbon fuels. Although the first processes were developed in the 1920s, production has remained small due to technical complexities and the high cost of facilities. In 2009, global GTL production used only some 10 bcm of gas as feedstock. Two new plants are under construction in Qatar and Nigeria that could bring annual GTL gas consumption to about 25 bcm before 2015, still less than 1% of world marketed gas volume. Sustained differences between oil and gas prices could create opportunities for additional plants and advances in technology suitable for small-scale application would also be important, particularly in the use of gas that is currently flared. If one-half of the estimated 134 bcm of gas flared in 2010 were used as GTL feedstock this could produce some 0.7 million barrels per day of additional liquid hydrocarbon fuel.

Other technologies with potential, but with only limited deployment to date, include the generation of electricity or the manufacture of chemicals at sites close to gas fields. The product (either electricity or chemicals) is then exported, instead of gas. This is advantageous in cases where power grids or road transport infrastructure exist but gas pipelines do not.

In 2010, global annual regasification capacity increased by 42 bcm, reaching 830 bcm. This is twice the level of liquefaction capacity. Korea and Japan account for 44% of regasification capacity (well in excess of their demand), North America has 25% and Europe 22%. This mismatch between regasification and liquefaction is to a certain degree intentional, driven by security of supply or seasonal load-balancing considerations. Such surplus capacity can, in the case of a country such as Japan, provide very important flexibility to move LNG cargoes around the country and allow extra spot supplies to reach power plants, of great value in the recent crisis in supplying Japan's power needs.

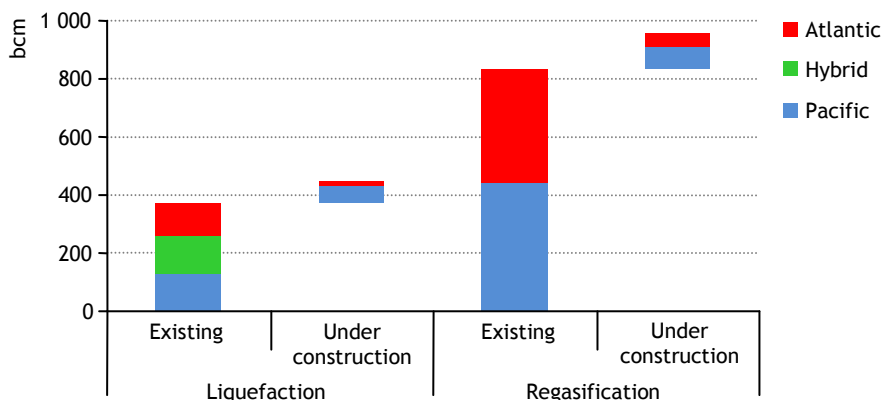
Figure 2.8 ▶ Projected LNG liquefaction capacity by country



Note: Projects up to 2015 are under construction; 2020 projections are IEA estimates taking account of projects currently planned or awaiting final investment decision.

Over the last decade, some trading and marketing companies have invested in LNG terminals in different regions in order to arbitrage between them (Figure 2.9). But excess capacity can also be the result of overestimation of import needs. The United States, which has well over 180 bcm of regasification (most of it built in the last few years) but which imported only 12 bcm in 2010, is an obvious example. Looking ahead, supply capacity from regasification terminals is set to advance faster than pipeline import capacity. 2011 will see 69 bcm of new regasification capacity coming on-line, almost 40% of it in Asia. Thailand will inaugurate its first LNG terminal, while six LNG terminals are under construction in China and two in India, three of which are planned to come on-stream in 2011. In Europe, an additional 25 bcm is under construction and expected to start operation over 2011 to 2015, including an LNG import terminal which is due to open in 2011 in the Netherlands, where production is expected to decline.

Figure 2.9 ▶ LNG capacity by type and region, December-2010



Source: IEA databases and analysis.

Pricing mechanisms and prices

The way that gas is priced has a significant influence on the *level* of prices (both in absolute terms and relative to the prices of competing fuels) and, therefore, on the level of demand, supply and trade. Lower prices encourage demand, but may discourage investment in supply infrastructure, especially at greenfield, remote or technically complex sites. Price uncertainty and volatility may also undermine investment, if price risks cannot be hedged. The long-term prospects for gas supply hinge to some degree on how trading and pricing mechanisms evolve and the consequent effects on the level of prices and investment risk. Price mechanisms must balance the needs and interests of suppliers and users. In practice, there are big differences across countries and regions in the way gas prices are set and the way gas is purchased at the various stages of the supply chain.

Much of the gas traded across borders in Europe and in OECD Asia is sold under long-term contracts, with linkages to the price of oil or refined products. However, there are important variations in these mechanisms, including the time lags (from 3 to 9 months), averaging or smoothing provisions to reduce oil-induced price volatility, and the ratio of gas to oil prices (often below 1:1 on an energy basis). In LNG contracts, it is common to find provisions protecting producers at low oil prices and buyers (and hence ultimate consumers) at high oil prices. However, the appropriateness of the oil-linked index in the Pacific may be questioned in the future, in particular for the fast growing power sector, where oil is disappearing rapidly as an energy source. Globally, around one-fifth of gas supply is priced by oil-linkage: around 500 bcm in the OECD region (continental Europe, Japan and Korea) and 150 bcm in the non-OECD region.¹¹

In a growing number of markets, gas prices are set freely in the market, an approach known as gas-to-gas competition (usually as spot trading or as gas-price indexation in term contracts). Prices are set this way in North America, the United Kingdom and Australia and increasingly in continental Europe. As much as one-quarter by volume of continental European gas supply is priced in this fashion (IEA, 2011b), and approximately one-third of

¹¹ IEA analysis based on International Gas Union data (IGU, 2009).

the world's gas supply. In practice, a variety of detailed arrangements can be encompassed under this heading, depending on the needs of buyers and sellers. For example, gas prices indexed to power prices have advantages for power sector buyers.

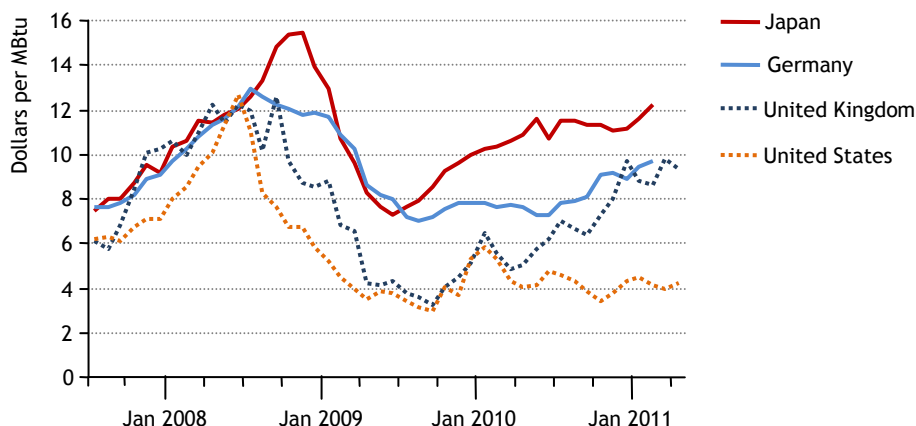
Other pricing mechanisms include bilateral monopoly¹² and direct regulation by the authorities. About one-third of the world's gas supply is still based on regulated prices, which may take the cost of supply or the level of international prices into account. In many cases, regulated prices are set at levels below the full cost of supply, *i.e.* are subsidised or imposed on the basis of cost of service or on a social/political basis. Although regulated prices are not directly affected by oil prices, a rise in the latter will tend to put upward pressure on the former, as the burden of financing subsidies increases.

Differences in pricing mechanisms inevitably lead to differences in the actual level of prices. When oil prices are high, as they are today, oil-indexed gas prices will tend to be high. The level of gas prices that results under gas-to-gas competition depends on the supply/demand balance in each regional market, including the prices of all competing fuels. Gas prices set this way have been significantly lower than oil-indexed prices in the past two to three years both in the United States and continental Europe, though differentials have narrowed in Europe as spot prices have risen with the rebound in demand and increases in alternative fuel prices (especially coal). Regulated prices tend to be lower, in particular when they are subsidised, a widespread practice in many non-OECD countries. Prices based on bilateral monopoly vary substantially depending on the relationship between the two countries: geopolitical factors can play an important role in the price that is agreed under such conditions. Within a given country or region, several different pricing mechanisms often co-exist. How these affect end-user prices differs. Averaged prices ensure that all users are affected when the price increases, but also that all benefit when prices fall. In other regions large users, such as the power sector, tend to gain from falling prices before smaller users.

Big differences in prices between regional and national markets emerged in 2009, as a result of the slump in global gas demand and market-related prices (Figure 2.10). Spot prices in the United Kingdom and the United States differed widely from oil-linked gas prices in continental Europe and Asia. In 2010, the situation changed again. The close correlation between prices at Henry Hub (HH) in the United States (where a floor of around \$4/MBtu has been established) and the National Balancing Point (NBP) in the mainland United Kingdom ended in April 2010; since then NBP prices have converged towards the higher prices in continental Europe, due to stronger demand across Europe (largely due to the weather), worries about imports from key suppliers, tightening of the global LNG market and the influence of higher coal prices in the power-generation sector. In continental Europe, contract renegotiations and additional inflows of cheaper spot gas in early 2010 had weakened the link between gas and oil, but prices remained relatively high over 2010 at \$8/MBtu on average. With NBP prices increasing throughout 2010, due to the increasing quantities of gas transiting the United Kingdom into the continental market, the benefit of spot indexation became less obvious. Meanwhile, average prices in Asia remained high at \$11/MBtu, reflecting oil indexation, albeit with certain limits. In North America, oil and gas prices remain disconnected, due to the continuing abundance of shale gas.

¹² Bilateral monopoly is a pricing mechanism between one supplier and one or a few buyers, usually involving state-owned companies.

Figure 2.10 ▶ Natural gas prices in major markets, July 2007 to April 2011



As oil prices have risen in most areas over the last two years, the oil-indexation pricing mechanism has come under pressure from buyers and governments that have sought greater use of spot indexation. Companies in Europe also sought more flexibility on the volume of their off-takes. External suppliers responded in different ways, with Norwegian producers offering more pricing flexibility. Russia's Gazprom also granted some important concessions on pricing in early 2010, accepting the partial use of indexation to spot gas prices for a period of three years. By contrast, there has been little change in pricing long-term gas supplies into the Asia-Pacific region.

Continuing evolution in the way gas is priced could have a major impact on future demand and supply of gas in some regions, but how quickly these mechanisms will change across countries and regions remains uncertain. The remainder of this section considers the possibilities.

How could price mechanisms evolve in continental Europe?

Despite successful efforts to open up markets to gas-to-gas competition over the past decade or so, which has led to the rapid growth of spot trade, and the recent pricing concessions by some of Europe's main external suppliers, we estimate that around three-quarters of gas consumed in continental Europe is still bought wholesale under long-term contracts with oil-price indexation. This pricing mechanism continues to be used for new supplies,¹³ especially where spot gas is physically unavailable (*e.g.* in eastern and central Europe), even though gas ultimately has to compete against electricity in industry and in the residential and commercial sectors, and against coal, renewables and nuclear in the power sector, where the share of oil rarely amounts to more than a few percent of demand. This continued reliance on oil indexation in continental Europe contrasts with the dominant role played by gas-to-gas competition in the mainland United Kingdom market (as in North America), following the establishment of a third-party access regime and other market reforms in the 1980s and 1990s. A key difference between the evolution of the markets in the United States and the mainland United Kingdom on the one hand and those

¹³ For example, the Polish gas company, PGNiG signed a deal with Gazprom in January 2010 extending and expanding an existing supply contract to 2045, with prices continuing to be set by indexation to oil prices.

in continental Europe on the other is that the former had important domestic production, with a large number of producers, while much of continental European gas supply has come from a small number of external suppliers.

Some observers expect there to be a permanent and large-scale shift away from oil indexation and towards the use of spot gas price indexation (hub-based pricing) in existing and new long-term contracts in continental Europe. The main gas importers are becoming more insistent in demanding such a transition, having experienced over the past two years a situation in which they have been contractually obliged to buy minimum volumes of gas under their long-term contracts at high oil-linked prices (albeit with some flexibility to lift certain volumes later) while selling some of that gas to large-volume consumers at spot-related prices, engendering significant losses. A rebound in demand and hence spot prices in late 2010 helped to relieve that pressure, but the risk of future exposure to hub prices at a discount to contract prices remains. European gas utilities and their shareholders are adopting more of a commercial trading culture and are becoming increasingly reluctant to accept such risk in the face of growing competitive pressures. Captive or smaller volume customers in Europe also object to price increases, often in double digit percentage terms annually, even as they observe a fall in at least some wholesale prices.

Surges in demand or increases in the prices of competing fuels can also increase spot gas prices. For example, cold weather can rapidly increase peak electricity demand which is frequently met by gas-fired plant, requiring a rapid ramp-up in gas supply which in turn pushes up spot gas prices sharply. Such price signals provide important incentives for investment in additional gas supply, fuel switching to other sources both in the short-term and in the longer term and improved storage capable of responding physically to rapid changes in demand. Gas prices based on oil prices six or nine months previously will be unlikely to deliver this behavioural or investment change.

Demands from the European gas utilities for wholesale pricing reform are meeting considerable resistance from major import suppliers, notably Gazprom (despite the limited duration concessions by Gazprom mentioned above) and Sonatrach, who remain adamant that there is no acceptable long-term alternative to oil indexation and that the commercial pressures faced by their European customers will quickly dissipate as markets tighten in the coming years. Their argument rests in large part on the lack of liquidity and depth of the existing trading hubs in continental Europe, with implications for possible manipulation of prices and excessive volatility, particularly in view of the limited number of buyers and sellers in most markets across the continent. They observe that oil indexed prices constrain volatility through averaging provisions. Spot trading in Europe continues to grow rapidly; physical trading in 2010 on the seven¹⁴ leading continental hubs increased from 100 bcm to 140 bcm, while traded volumes were about three times that figure, so the churn ratio¹⁵ is still well below that of the highly liquid figure of about twelve at NBP (IEA, 2011b). Nonetheless prices across hubs are converging. Steady reduction of the technical and market barriers has been a major spur to this growth, for example, reducing the number of balancing zones in Germany in recent years. Continued progress in this regard will be important in encouraging hub trade and more accurate price discovery. Investment in gas storage will also be important to address rapidly changing user needs and reduce volatility.

¹⁴ The seven spot markets are: Zeebrugge (Belgium), TTF (Netherlands), NCG (Germany), Gaspool (Germany), PEG (France), PSV (Italy) and CEGH (Austria).

¹⁵ Churn ratio is the ratio of contractual volumes sold to the physically delivered amounts.

The extent and timing of the expansion of gas-to-gas competition, supplanting oil indexation, and the impact on consumers, remain uncertain. The majority of long-term contracts in continental Europe contain clauses that provide for periodic renegotiation of the base price and indexation terms (plus off-take arrangements in some cases) under certain conditions, so-called price review and re-opener clauses (Frisch, 2010). In practice, there is no guarantee that the buyer and seller in each case will even agree that there are grounds for opening negotiations or, if they do, that they will subsequently reach agreement on changing the pricing terms. In the event that the parties are unable to agree, the contracts provide for a decision to be taken by an arbitrator, an appointed expert or tribunal. Historically, arbitrations have been quite rare, but many have been reported in recent years. One possibility is a landmark ruling that hub-based prices should be regarded as the best available reflection of current market conditions, paving the way for a wholesale move towards hub-based pricing, albeit over a transitional period (Stern and Rogers, 2011). Alternatively, high volume users with switching opportunities, such as power producers, may secure access to cheaper gas at the expense of smaller users who typically lack bargaining power.

If a general and durable transition to more spot indexed prices were to occur, the result is likely to be lower gas prices on average in Europe in the near to medium term, (at least for some types of consumers) while spare supply capacity exists in the European market. But in the long term, gas prices could actually turn out to be higher at certain times than they would otherwise have been; for example, strong demand during cold winters or through a surge in gas-fired power demand could see prices rise steeply. Moreover, a degree of correlation between gas and oil prices could persist in Europe, largely as a result of indirect linkages with the Asia-Pacific markets (for as long as gas prices there remain more closely linked to oil prices).

What will drive prices in Asia?

The outlook for pricing arrangements for international gas supplies in Asian markets is somewhat different, given the dominance of relatively high cost LNG in the supply mix, particularly in Japan and Korea. To date, the LNG industry has been built on long-term contracts and crude oil linked prices, though spot supplies are growing. Japanese LNG importers had been taking a tougher stance on pricing with their suppliers in the face of increasing competitive pressures, seeking at least some degree of price relief on the basis of spot gas prices. But they are now faced with two difficulties. First, any new surge in gas demand will have to be met by LNG, where costs are high, while at the same time a number of existing LNG contracts must be renewed or replaced. Second, no Asian reference spot price exists as yet (see Box 2.6). In Korea, there is little incentive to push for a move away from oil indexation in LNG import contracts, as the state company, Kogas, still holds a monopoly on imports of LNG for onward sale (three other companies import LNG only for their own use) and end-user gas prices in Korea are regulated on a cost-plus basis, enabling Kogas to pass through commodity costs. This creates little incentive to strive for lower priced wholesale gas supplies.

Box 2.6 ▶ Development of regional trade in southeast Asia

ASEAN has significant gas reserves (7.3 tcm). Historically a gas exporting region, in the form of LNG from Indonesia, Malaysia and Brunei, the region as a whole is expected to remain a net exporter for the coming decades. However, rapidly growing demand and dwindling supplies in key producing countries mean that some countries will have to turn to a combination of pipeline and LNG imports, unless they review their energy policy so as to dampen gas demand growth (such as reducing subsidies) or encourage new exploration and production. So far, intraregional connections have been based on pipelines: between Indonesia, Malaysia, Myanmar, Thailand, Singapore and Vietnam. There are currently no LNG importers in southeast Asia.

Looking forward, LNG options are expected to be taken up faster than additional intraregional pipeline connections. The most ambitious intraregional pipeline project, the Trans ASEAN Gas Pipeline (TAGP), largely based on the proposed exploitation of Indonesia's challenging East Natuna field, has made little progress. Meanwhile, Thailand is expected to start its 6.8 bcm Map Ta Phut LNG terminal in July 2011 and Singapore its 4.6 bcm terminal in 2013. Indonesia has proposed swapping pipeline gas delivered from Sumatra to Singapore with LNG coming from East Kalimantan or Papua, allowing Sumatran gas to make-up for supply shortfalls on nearby Java, demonstrating how flexible LNG supplies can complement pipelines.

Several countries are considering a total of eight new LNG terminals (or 23 bcm of import capacity): Indonesia (three), Vietnam (one), the Philippines (two), and Malaysia (two). Indonesia and Malaysia are actually planning to continue to export LNG, albeit in declining volumes, as newer projects, such as Tangguh, succeed old ones, such as Arun. All eight planned terminals could start before 2015 if floating regasification, storage and offloading facilities were to be adopted, which is the current plan for both Indonesia and Vietnam.

The region is also looking at small scale intra-regional LNG trade as a way to supply remote areas, based on small LNG vessels. LNG might be used to complement intermittent power sources, such as hydropower, in isolated communities not connected to wider electricity grids. Meanwhile floating LNG could be a solution to develop smaller remote fields. Singapore intends to become a regional LNG hub for southeast Asia, based on its future LNG terminal and LNG storage capacity that could be used by third parties. Another objective of such a hub is to develop a spot reference price, similar to that at the National Balancing Point in the United Kingdom or at Henry Hub in the United States, as no such marker yet exists in Asia.

Pricing terms for LNG imports into China and India differ to some degree from those in most Japanese and Korean contracts, though they typically also incorporate a degree of oil indexation. LNG import volumes into these countries are currently small, but they are growing rapidly, with more recent contracts tending to command higher prices. The price paid by China for imports of gas by pipeline from Turkmenistan is linked to the oil price and to the high capital costs of development and transport. No major change in these arrangements is expected in the near term, whether for existing long-term contracts or new contracts to be signed in the next few years. However, reliance on spot or short-term deals involving spot gas price indexation could increase: a number of cargoes of LNG were

imported into India in 2010 at prices linked to the Henry Hub spot price. Pakistan has also been looking to import LNG under a six-year contract, with prices indexed to a mixture of oil and Henry Hub prices. The trend towards charging more market-reflective prices to end-users in the domestic market in China, India and other developing Asian countries is likely to continue, leading to higher retail prices. For now, indigenous supplies are typically priced below the cost of imports because of low, controlled or subsidised prices as well as lower transport costs. As demand in China and India grows, LNG imports are likely to grow quickly, raising the prospect of competition between European and Asian buyers and linking prices in the two regions.

More market-based gas pricing in the rest of the world?

The outlook for pricing in other regions, including the former Soviet Union, the Middle East and Africa, where contractual arrangements and actual prices vary widely, is mixed. In some countries, steps are being taken or are planned to reform pricing, in order to ensure that prices better reflect supply costs or market values. But few countries are planning to introduce gas-to-gas competition along the lines of the North American or mainland United Kingdom markets. The pace of change, particularly where it involves raising prices to end-users and eliminating subsidies, remains highly uncertain, given political sensitivities and resistance from consumers.

Russia, which has the second-largest gas market in the world, for a long time has subsidised gas prices on the internal market. Its subsidies are some of the biggest in the world, amounting to almost \$19 billion in 2009 (IEA, 2010e). The federal government has begun to remove these subsidies by gradually raising the prices charged to Russian consumers towards the same levels, in netback terms, as the prices charged to European importers. This process is due to be completed in 2014. Many Middle East and North African countries also continue to subsidise gas heavily. In 2009, the value of gas subsidies in Iran alone amounted to about \$25 billion. Many countries are likely to continue to hold down domestic prices for political reasons, but pressures to cut subsidies are set to grow in those countries, such as Kuwait, Oman, Saudi Arabia and the United Arab Emirates, that are facing growing shortages and a consequent need to import gas or accelerate development of their own gas resources. Domestic gas prices in major producing countries in the Middle East are likely to remain regulated at below-cost levels, but a move, at least, towards cost-of-service based pricing is possible, especially as the cost of developing new fields is set to rise.

Global implications for supply

Pricing mechanisms are likely to become more reflective of market conditions, including the prices of competing energy sources, such as coal, other gas supplies and in some cases oil. The expansion of inter-regional trade is likely to be based on a combination of oil linked and spot gas pricing, so pricing systems in countries needing imports to supplement indigenous supplies which are subject to price controls or are subsidised will come under increased pressure. Many former Soviet Union countries are moving away from bilateral monopoly pricing and towards European netback pricing, which is currently still strongly influenced by oil indexation. How rapidly and to what extent the role of spot gas pricing grows will hinge to some degree on how long the overcapacity in global gas supply persists, how it develops regionally and how long spot gas prices remain below the price of oil-

indexed gas in long-term contracts. The broad trend towards more cost-reflective gas pricing within domestic markets is likely to continue, driven by the need to finance the construction of new infrastructure and, in some countries, by budgetary pressures.

In principle, a move towards more widespread gas-to-gas competition and gas price indexation would be expected to result in lower international gas prices than would otherwise be the case. This is likely over the next few years, as supply capacity remains ample, though there may be times when supply shortages or demand surges lead to spikes in prices. However, the removal of subsidies in some major markets might offset any short-term benefit to end-users from a fall in international prices. Over a longer timescale, growing demand can be expected to ease prices upwards and encourage more exploration and development, thus boosting supplies in the longer term.

Will demand for gas keep pace with supply?

Highlights

- The factors that drive natural gas demand point to a future that favours a more significant role for gas in the global energy mix. These drivers include access to supply, the competitiveness of gas versus other energy sources, the environmental impacts of using different forms of energy, changes in technology and government policies.
- Gas is a particularly attractive fuel for countries, such as China and India, and the Middle East region that are seeking to satisfy rapid growth in fast-growing cities. These emerging economies will largely determine the extent to which gas use expands over the next quarter of a century.
- There is huge potential for additional gas use in China and its recently adopted 12th Five-Year Plan strongly favours gas consumption. Gas use in China today accounts for just 3% of total energy demand, compared with 21% globally. There is significant scope for using more gas in China's quickly expanding power sector, where today the share of gas-fired electricity generation is estimated to have provided less than 2%, compared with about 22% worldwide.
- The extent of the expansion of gas use hinges on the interaction between economic and environmental factors and policy interventions in the market. In the absence of a price for CO₂, coal is likely to remain cheaper than gas for generating electricity in many regions. However, a cost comparison alone does not reflect the full range of benefits that gas can provide, such as diversifying energy supply, providing flexibility and back-up capacity as more renewable capacity comes online and reducing emissions (when substituting for coal).
- When used in place of other fossil-fuels, natural gas reduces emissions of greenhouse gases and local pollutants. In power generation, the largest gas-consuming sector, a new combined-cycle gas turbine plant in 2020 is projected to emit 330 kg CO₂ per MWh of electricity produced, or about half the emissions of a new coal-fired power plant using the latest technology.
- Gas does not currently compete strongly in all markets or sectors, but additional opportunities are rapidly emerging. Easier access to supply, facilitated by the construction of new infrastructure, is stimulating greater gas consumption in previously underdeveloped markets. In the oil-dominated road-transport sector, natural gas vehicles (NGVs), though making inroads in only a handful of countries, typically bring considerable fuel cost savings and emission reductions. The strongest case for NGVs is often for those commercial fleets that do not require widespread refuelling infrastructure.

The promising outlook for natural gas supply described in Section 2 prompts the question whether or not gas demand growth will match the potential growth in supply. Increasingly, the factors that drive gas demand point to a positive answer. This section reviews the key drivers of natural gas demand and the nature and strength of their relationships and explores the relative advantages and disadvantages of gas versus the alternatives. It presents an analysis of the economics and environmental impacts of gas use in power generation, the sector which will have the most influence on overall gas demand. It also examines the potential place of natural gas in the transport sector and, more briefly, in other sectors. These analyses show how fuel choice is likely to be determined in different regions, particularly China, the European Union and the United States. This section concludes with a brief review of recent events and emerging trends which illustrate how the theoretical interactions of the forces described here are being manifest in practice.

Factors driving demand for natural gas

Natural gas demand is determined by a range of factors, the most important of which are the level of economic activity, the competitiveness of gas versus other energy sources, environmental considerations, changes in technology, the ease of access to supply and government policies (Table 3.1). There are many uncertainties. Any projection of gas demand, such as that made in the GAS Scenario (see Section 1), depends critically on assumptions about these drivers. How quickly will economies grow? Where and at what price will gas compete with coal in power generation? What actions will governments take to reduce local pollution or carbon-dioxide (CO₂) emissions?

Economic activity

Economic activity is the most important determinant of natural gas demand in markets where its use is established. The relationship between the two is strong: rapid economic growth typically drives up gas consumption, just as downturns cause gas use to stagnate or contract (Figure 3.1). Whether in mature markets with well-developed gas-supply infrastructure or in less developed markets that are investing in infrastructure, economic growth can spur additional demand via:

- rising household incomes and increased commercial activity, which boost space and water heating requirements in buildings;
- higher industrial production, which raises the need for gas-fuelled process heat and power and demand for petrochemical feedstock; and
- increased electricity demand, which results in additional demand for gas for power generation.

Power generation is the largest gas-using sector today and is expected to be the biggest driver of gas demand growth in the coming decades. Gas demand in power generation is more sensitive to changes in the rate of GDP growth than is gas use in any other sector. Averaged globally over 1990 to 2008, each 1% increase in GDP led to a 1% increase in gas use in the power sector, *i.e.* the elasticity of demand to GDP growth was 1. The average elasticity of demand for gas in both buildings and in industry was markedly lower during the same period, at 0.6 and 0.4, respectively. These relationships are steady and persistent over time (although there was an unaccustomed blip in 2010).

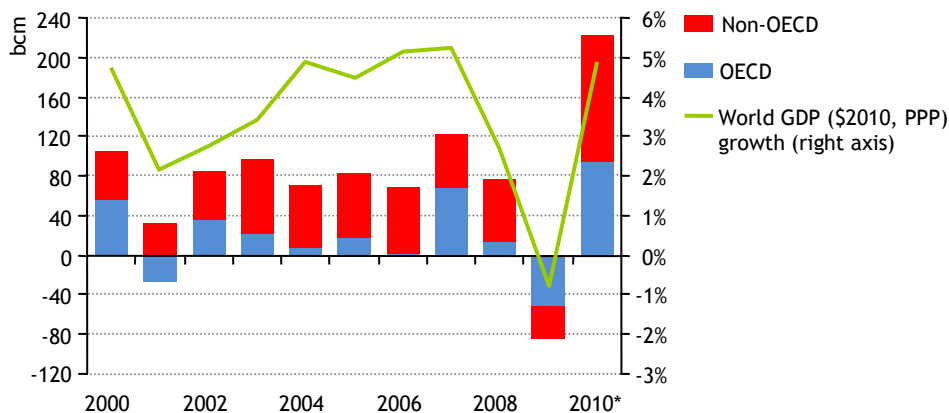
Table 3.1 ▾ **Principal drivers of natural gas demand by sector**

	Economic activity	Competitiveness	Environmental impact	Technology	Access/infrastructure	Government policies
Power generation	(+/-)* Industrial output and household income levels, which rise and fall with economic activity, are strong determinants of electricity demand.	(+/-) Gas-fired generation is sensitive to changes in relative fuel prices and CO ₂ prices; (+) Short lead times for construction; low capital costs.	(+) Less emissions intensive than other fossil-fuels (local pollution/climate); increase flexibility of the system with more renewables capacity.	(+) Best available CCGTs have a sizeable efficiency advantage over coal-fired plants; an electric vehicle breakthrough could raise electricity needs.	Not significant in most regions as power plants are typically built close to major infrastructure.	(+/-) Regulation of CO ₂ emissions; (+) Policy uncertainty favours gas-fired plants to reduce risk; (-) Support for renewables and nuclear power.
Buildings	(+/-) Household income levels strongly correlate with residential space and water heating needs.	(+/-) Changes in relative fuel prices could cause switching in the long term.	(+) Gas-fired boilers produce fewer emissions than most fossil-fuel based alternatives.	(-) Potential to raise average boiler efficiency by replacing old stock.	(+) Construction of gas distribution networks enables potential end-users to connect to supply.	(-) Standards, subsidies and labels to promote higher efficiency buildings and equipment.
Industry	(+/-) Industrial output strongly correlates with gas demand for process heat and steam-raising.	(+) Gas is usually the preferred fuel for new equipment; (-) High gas prices encourage use of more efficient boilers.	(+) Reduced impact of gas use on air quality compared to other fossil-fuels; no need for management of waste products.	(-) Potential to raise boiler efficiency by installing new units; increased use of combined heat and power (CHP) plants.	Not significant in most regions as factories are typically built close to major infrastructure.	(+) Government-subsidised gas pricing to protect domestic industry; (-) Efficiency standards for industry equipment.
Transport	Not significant because penetration of natural gas vehicles (NGVs) is small.	(+) Payback period for purchasing an NGV shortens with higher oil prices.	(+) In road transport, gas is less emissions intensive than oil and able to improve local air quality.	(+) Potential to improve gas storage technology to extend NGV range.	(+) NGVs require large network of refuelling stations; pipeline gas transport raises power needs in compressors.	(+) Policies promoting use of NGVs (personal and fleets) to improve energy security and/or air quality.
Other	(+/-) Demand for gas for feedstock use is closely tied to industrial production and GDP.	(+/-) Petrochemicals feedstock demand is very sensitive to price of gas relative to naphtha.	Relatively insensitive.	(+) Technical advances in GTL or other technologies could greatly boost use of stranded gas.	Not significant in most regions as industries using feedstocks are typically built close to major infrastructure.	(+) Policies to support domestic industries that utilise natural gas inputs (fertilisers, GTL and petrochemicals).

* (+/-) Indicates drivers with the potential to cause either higher or lower gas demand; (+) for drivers that can raise demand; (-) for drivers that can lower demand.

Because future economic growth will have a major influence on gas demand growth, uncertainty about the prospects for the global economy translates into a comparable degree of uncertainty about future gas demand. The recent global economic recovery has been fragile among the advanced economies (though gas demand in OECD countries in 2010 bounced back very strongly, probably in large part due to weather extremes) and the short-term prospects remain very uncertain. The outlook for economic growth in non-OECD countries is much brighter, but there too, small changes in GDP assumptions over the medium and long term have significant effects on gas demand.

Figure 3.1 ▶ **Year-on-year change in world primary gas demand versus changes in world GDP**



*Based on preliminary data.

Note: Purchasing power parity (PPP) measures the amount of a given currency needed to buy the same basket of goods and services, traded and non-traded, as one unit of the reference currency.

Competitiveness versus other energy sources

As might be expected, the competitiveness of gas versus other energy sources is a key determinant of natural gas use. Alternative fuels can substitute for gas in most applications, so gas is strongly exposed to inter-fuel competition. In power generation, gas competes against coal, nuclear, renewables-based technologies, oil and oil products. In many countries, demand for renewables and nuclear is greatly influenced by government policy, limiting the significance of market factors in the competition with gas. Oil-fired power in the OECD is very small and declining, although it is still used in some non-OECD regions. In industry, the main alternatives to gas are coal, heavy fuel oil and electricity. In the commercial and residential sectors, gas competes with heating oil, liquefied petroleum gas (LPG) and electricity. In most uses, short-term flexibility to switch between gas and other fuels is constrained because of sunk costs in physical equipment (for example, boilers and heating systems). The power sector is a partial exception, especially during off-peak demand periods, as utilities may have operational capacity to switch between different plants and fuel inputs, depending, for example, on relative fuel and CO₂ prices.

All energy consumers, but power generators in particular, evaluate the economics of gas versus other options by comparing relative fuel prices, equipment costs, operational factors, policy and regulatory risks, which may be influenced by social acceptability

regarding environmental or safety issues, and other market risks. Investment decisions hinge strongly on the expectation of future gas prices, while the actual short-term price of gas relative to competing fuels determines operational decisions. Unlike oil, gas prices vary markedly across regions, depending on proximity to the sources of supply, pricing mechanisms, and subsidy and tax policies (see Section 2). Inter-fuel competition in the power generation and industrial sectors may also be affected by regulations relating to greenhouse-gas and other emissions, particularly in the case of a high price for emitting CO₂. In those countries that have introduced such a mechanism, CO₂ prices give gas a cost advantage over more carbon-intensive coal, but boost the competitiveness of lower-carbon sources of power generation, such as renewables and nuclear, relative to gas. However, other considerations may favour gas use, such as the lower capital costs and shorter lead times for construction.

Environmental impacts of energy use

Policies related to local pollution and climate change considerations increasingly influence fuel and technology selection. Due to its favourable environmental profile compared with coal and oil combustion, natural gas has increasingly become the preferred fossil fuel in end-use sectors and power generation (Section 2 discusses the environmental impacts of gas production and transport). This trend is likely to continue, particularly as developing countries' thirst for energy to support economic growth puts added pressure on local air, soil and water quality. Moreover, the role of gas-fired generation as a complement to variable renewables-based generation (flexibility in operation) supports the prospect for growth in gas-fired generation as a component of action to limit climate change.

Compared with coal and oil, gas avoids or reduces much of the local environmental damage arising from fossil-fuel use. Gas gives off fewer pollutants when burned, including the nitrogen oxide (NO_x) that contributes to acidification and ground-level ozone formation; the sulphur dioxide (SO₂) that (with NO_x) causes acid rain; and the particulate matter that (again with NO_x) causes smog and poor air quality. Consequently, using gas instead of other fossil fuels in electricity generation, in industrial and household boilers and vehicles offers the opportunity to improve air quality, especially in and around cities, where this problem is most acute. Since gas is moved mostly by pipeline and often stored underground, the visual intrusion on the landscape of the transport and storage of gas is much smaller than that of coal, which requires extensive use of rail and road networks. Gas use also produces no waste products that require management, such as coal ash or spent nuclear fuel.

Combusted natural gas emits less CO₂ than other fossil fuels, about 40% less CO₂ than coal and about 20% less than oil per unit of energy used.¹ In the power sector, which produces 40% of global energy-related CO₂ emissions, modern combined-cycle gas turbines (CCGTs) produce about half the CO₂ emissions per unit of electricity generated compared with coal-fired plants. The only mandatory CO₂ emissions trading systems in operation are in the European Union and New Zealand, where companies take CO₂ prices directly into account in operation and investment decisions. Even in regions where the cost of CO₂ emissions is not presently so explicit or binding, power companies and industries are considering the prospect of future government action to deal with climate change.

¹ Based on IPCC values (IEA, 2010a).

Changes in technology

Fuel choice and the efficiency of gas consumption are strongly affected by technology developments both across energy types and in end-use equipment and appliances. Past technical advances have been driven largely by efforts to raise efficiency so as to lower costs, but reducing CO₂ emissions is now a complementary objective.

Technology changes in power generation hold the greatest potential for influencing future fuel choice. The thermal efficiency of CCGTs already gives gas a distinct advantage over coal, with the best available CCGT units now reaching efficiencies exceeding 59%, compared with around 47% in ultra-supercritical coal-fired plants.² Further advances in two technologies in particular could alter the dynamics of gas demand in the power sector: carbon capture and storage (CCS) could change the competitiveness of gas (and coal) versus other energy sources (if CO₂ prices are taken into account), while sufficiently cost-effective batteries would stimulate deployment of plug-in hybrid electric and full-electric vehicles, resulting in a shift in road transport energy use from liquid fuels to electricity.

In other sectors, it is more probable that improvements in the efficiency of gas-consuming equipment will lower gas consumption or reduce its rate of growth. There remains considerable scope for lowering gas intensity across the manufacturing industry, especially in non-OECD countries, by more rapidly adopting commercially available technologies. In the commercial and residential sectors, government standards and incentives can encourage the adoption of more efficient technologies at a faster rate, notably condensing boilers. Similarly, more stringent building codes and better enforcement could lead to lower energy (and gas) use, or substituting electricity in place of gas.

Access to supply

Gas can be consumed only if the production and transport infrastructure is developed sufficiently to make supplies available (see Section 2). For new markets, the introduction of gas typically requires large, capital-intensive investment in infrastructure along the supply chain. This can include investment in production and processing facilities, LNG liquefaction and regasification terminals, long-distance high-pressure transmission pipelines, storage facilities and local distribution networks. For this to happen, investors need to be confident of sufficient future gas demand and that expected returns justify the upfront costs after accounting for risk. In mature markets, where gas infrastructure is well-established, the unit cost of incremental supply capacity is normally lower.

Transporting gas by pipeline or liquefied natural gas (LNG) is relatively expensive, notably more so than oil, because of the additional capital-intensive equipment needed to overcome the lower energy density of gas. In addition, long-distance gas pipelines that need to traverse multiple countries involve the reconciliation of political and economic interests. Consequently, the proximity of resources has been a key influence on the development of regional gas markets. The recent massive expansion of global LNG supply capacity is increasing opportunities for markets, new or existing, to secure LNG supplies, even if located far from gas resources.

² Efficiencies are based on gross capacity and low heating value. Ultra-supercritical coal is the most efficient coal-fired technology currently being deployed at a commercial scale.

Natural gas use in the residential, commercial and transport sectors requires the construction of distribution networks. The cost of building these networks is very high, so the delivered cost of gas per unit is considerably higher than the cost to large users supplied directly from the transmission network. Income levels must be high enough to cover these costs (unless governments are willing to subsidise the supply of gas to these markets). Rising incomes are making the establishment of local distribution networks economically viable in a growing number of cities and towns in non-OECD countries, particularly in Asia and Latin America.

Government policies

Government policies and the types of instruments used to implement those policies affect gas consumption and fuel choices – directly and indirectly – by deliberate design and, in some cases, unintentionally. For example, energy and environmental policies may encourage greater gas use through favourable taxation or subsidies to end-use prices and the development of infrastructure; but they can also constrain demand, for example, by mandating or promoting alternative technologies, such as renewables and nuclear power.

The uncertainty surrounding future energy policy choices is high in many countries. The biggest source of uncertainty concerns the strength and type of action that will be taken in the longer term to address climate change, whether in the form of financial incentives, production targets and capacity mandates to support the deployment of low-carbon power-generation technologies. Pricing reform and the removal of fossil-fuel subsidies, whether motivated by environmental or economic concerns, will also be important. Regulations to reduce local pollution could also have a major impact on the share of gas in the energy mix, especially in the least developed countries that are coping with the environmental impacts of more intensive energy use. By and large, natural gas is likely to benefit from more stringent environmental policy action, particularly where it is aimed at dealing with local pollution.

Determination of fuel choices in key sectors

Power generation and transport stand out as having potentially significant implications for future gas demand; power generation because of an established preference for gas and transport because of the scope of the potential new market for natural gas. Gas-fired plants met one-third of global incremental electricity demand between 2000 and 2008 (almost 80% in OECD countries) and prospects for further growth are high. Transport is the only major end-use sector not widely penetrated by natural gas, despite the existence of viable natural gas vehicle technologies. This analysis examines how fuel choices are determined in these two key sectors and looks briefly at other sectors.

Electricity generation

The most important factors driving the growth of gas-fired electricity generation and decisions to invest in CCGTs will be the price of gas relative to other fuels, environmental considerations (local pollution and climate change) and the perceived lower risk of building gas-fired plants. Analysed here in some detail are the impacts of different gas and CO₂ prices on the cost of gas-fired electricity generation and the emissions characteristics of various fuels and technologies in the power sector. Strong consideration is also given by

investors to other competitive factors that tend to lower the risk of investing in gas-fired plants relative to alternatives, namely their low initial capital cost, short lead time for construction, high efficiency and operational flexibility. This is particularly the case in OECD countries, where electricity demand has grown slowly, peak electricity demand has risen, economic recovery continues to be difficult to predict and more variable renewables have been added to the mix.

Future gas price assumptions are a strong influence on investment decisions in new gas-fired capacity. In contrast, operational decisions are impacted more by the actual short-term price of gas relative to competing fuels. Investors' interest has shifted towards renewables in many regions, due to the strength of government policy incentives, but strong growth in gas-fired generation is expected, supported by competitive gas prices and the other factors described above (see sensitivity analysis of gas and other fuel prices in Section 4). In the GAS Scenario, gas prices are assumed to rise steadily in all regions, but to be lower than the prices assumed in the *WEO-2010* New Policies Scenario. Low or slowly rising gas prices (relative to those of other fuels) would boost the competitiveness of gas in the power sector in the following ways:

- existing gas-fired plants would become more competitive against some existing coal-fired plants (especially older and less efficient ones where coal costs are high), resulting in increased gas-fired generation where available capacity is under-utilised;
- the competitive position of new CCGTs would be improved relative to new nuclear power, renewables and coal-fired generation;
- electricity prices would be lower, resulting in higher electricity demand. This effect is likely to be small, as the main driver of electricity demand is economic activity.

The generating costs discussed here are levelised costs (*i.e.* the cost of producing electricity from a plant over its lifetime) for plants expected to be built over 2015 to 2035 in the European Union, the United States and China, the largest energy consuming regions (see Table 3.2 for assumptions).³ The notion of levelised costs of electricity is a useful tool for comparing the unit costs of technologies over their economic life (IEA, 2009a), but power companies also use portfolio investment-valuation methodologies to evaluate risks over their entire plant portfolio, rather than focusing on the technology with the lowest stand-alone generating cost. Depending on the project, different risk profiles may be acceptable for different technologies. Key factors affecting investment decisions are expected fuel prices, required rate of return, level of upfront investment, construction time, maximum acceptable payback period, flexibility and, increasingly, the regulatory risk relating to environmental protection.

³ The assumptions in Table 3.2 are considered representative averages for each region. In reality, the figures vary within regions according to different fuel costs (*e.g.* generating costs for a coal-fired plant near the mine are lower) and capacity factors (*e.g.* wind capacity factors vary based on wind availability).

Table 3.2 ▶ Assumptions used to calculate electricity generating costs, 2015-2035

	CCGT	Coal	Coal CCS	Nuclear	Wind
European Union					
Capacity factor	60%	75%	80%	90%	24%
Thermal efficiency (gross, LHV)	61%	50%	41%	33%	n.a.
Capital cost (\$2009 per kW)	900	2 100	3 550	4 200	1 480
Construction lead time (years)	3	5	5	7	1.5
Economic plant life (years)	25	35	35	40	20
Unit cost of fuel (various*)	9.8	105	105	3	n.a.
Non-fuel O&M costs (\$2009 per kW)	23	63	105	125	22
United States					
Capacity factor	55%	80%	80%	90%	28%
Thermal efficiency (gross, LHV)	61%	51%	42%	33%	n.a.
Capital cost (\$2009 per kW)	900	2 550	3 800	4 600	1 550
Construction lead time (years)	3	5	5	7	1.5
Economic plant life (years)	25	35	35	40	20
Unit cost of fuel (various*)	6.6	55	55	3	n.a.
Non-fuel O&M costs (\$2009 per kW)	23	89	130	125	23
China					
Capacity factor	60%	80%	80%	90%	25%
Thermal efficiency (gross, LHV)	60%	49%	40%	33%	n.a.
Capital cost (\$2009 per kW)	650	1 200	2 100	3 000	1 320
Construction lead time (years)	2	4	4	6	1.5
Economic plant life (years)	25	35	35	40	20
Unit cost of fuel (various*)	10	70	70	3	n.a.
Non-fuel O&M costs (\$2009 per kW)	20	48	85	110	20

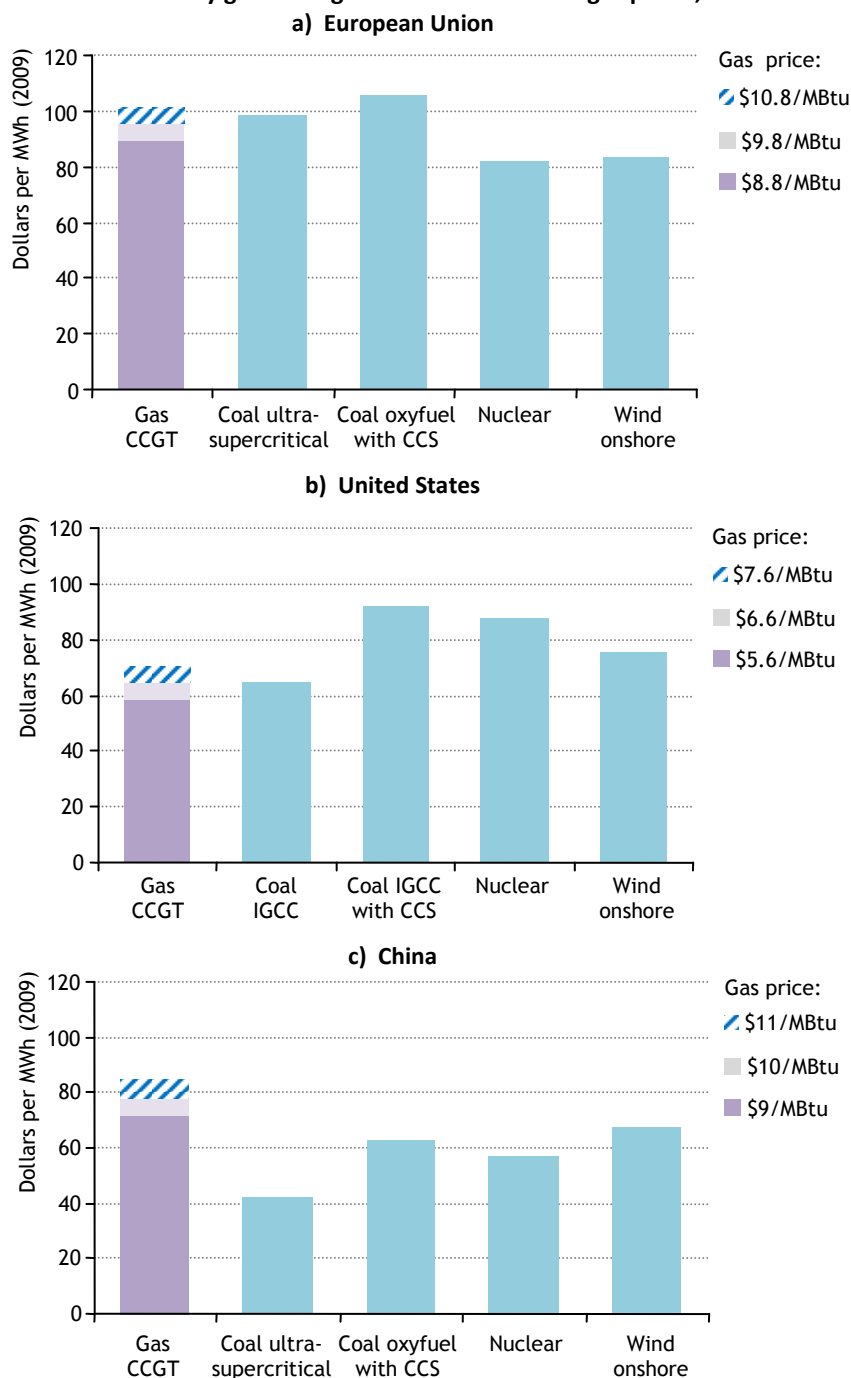
*Fuel cost units: gas is in \$/MBtu; coal is in \$/tonne; nuclear is in \$/MWh. All costs in year-2009 dollars.

Notes: O&M is operation and maintenance. LHV is lower heating value. Assumptions correspond to those in the GAS Scenario. For the European Union and China, the coal-fired technology is ultra-supercritical (with CCS, using oxyfuel combustion); for the United States it is integrated-gasification-combined-cycle (IGCC) technology. Wind refers to onshore wind power. Unit fuel costs do not include CO₂ prices. The weighted-average cost of capital is 8% for the European Union and the United States, and 7% for China. Investment costs are overnight costs. For coal and nuclear, capacity factors are estimated averages for base-load operation, with mid-load operation for gas. The IEA is currently doing a peer review of these assumptions: any revisions will be published in *WEO-2011*.

Source: IEA databases.

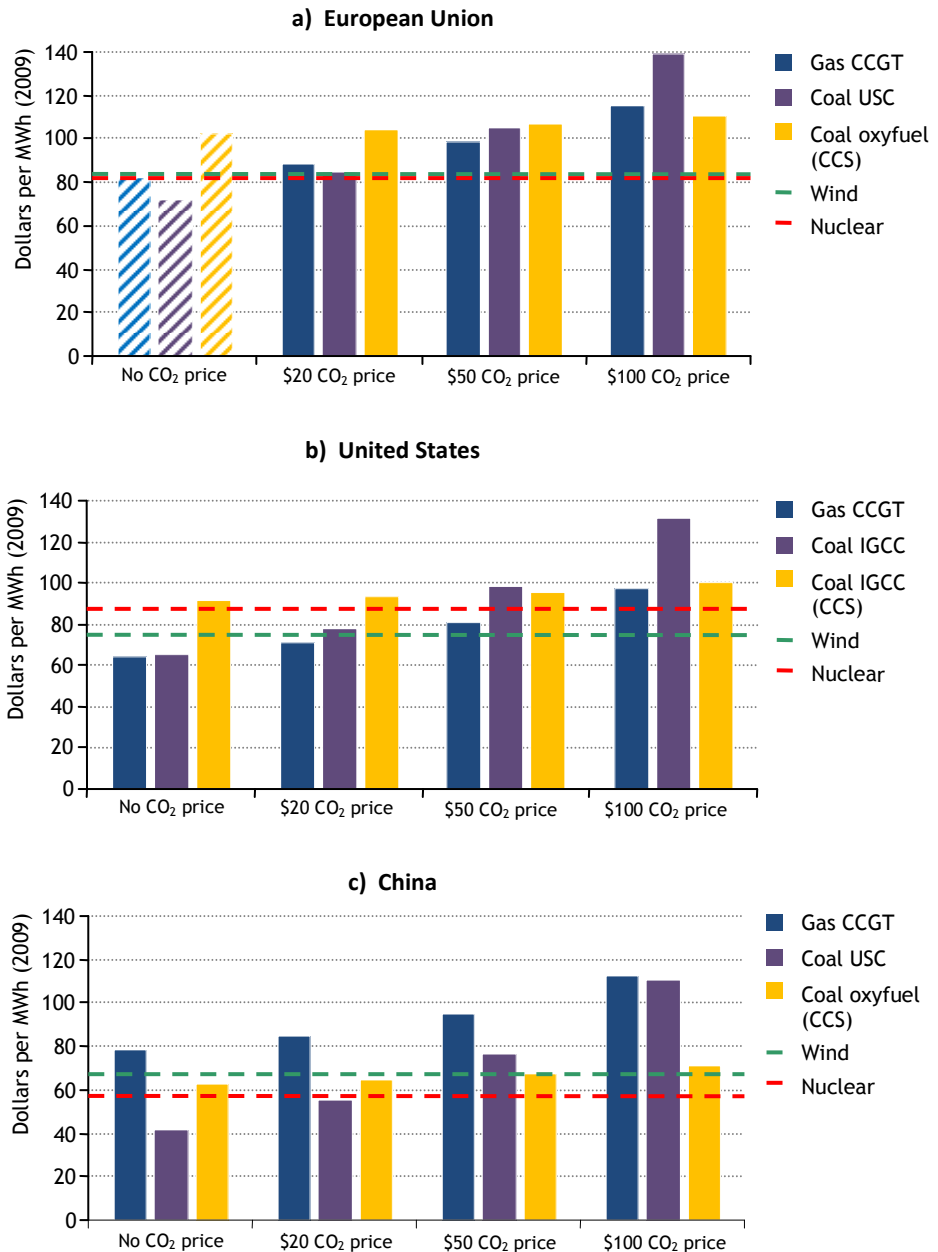
Electricity generating costs for mid- to base-load operation are compared by region for different gas prices and competing technologies in Figure 3.2. CCGT generating costs are based on three gas prices for each region that represent averages over the period 2015 to 2035, with the central price reflecting the assumptions in the GAS Scenario. The range of gas prices is chosen to show the effect on the competitiveness of gas-fired power generation, although it is important to note that gas prices (and prices for coal) can vary significantly within the large regions analysed. Assumptions about CO₂ prices in the different regions match those in the GAS Scenario (see Section 1).

Figure 3.2 ▶ Electricity generating costs under different gas prices, 2015-2035



Note: Assumptions are in Table 3.2. Electricity generating costs in the European Union include a CO₂ price of \$40 per tonne. The central gas price reflects the average price in the GAS Scenario.

Figure 3.3 ▶ Electricity generating costs under different CO₂ prices, 2015-2035



Note: Assumptions are in Table 3.2. Electricity generating costs are evaluated for new plants to be built over 2015 to 2035. A CO₂ price has existed in the European Union since 2005; generating costs excluding a CO₂ price in the European Union are shown for illustrative purposes.

In the European Union, the generating cost of a new CCGT is about \$95 per megawatt-hour (MWh) over 2015 to 2035, based on an average gas price of \$9.8 per million British thermal units (MBtu) (consistent with the average price assumed in the GAS Scenario and a CO₂ price of \$40/tonne) (Figure 3.2a). For this gas price, CCGT generating costs are close to those of ultra-supercritical coal plants. Varying the gas price assumptions shows that the relative competitiveness of gas to coal (without CCS) changes somewhat, with the low gas price favouring CCGTs and the higher gas price favouring ultra-supercritical coal. At a cost of capital higher than 8%, gas generally becomes more attractive because of lower and more certain capital costs. Coal oxyfuel plants with CCS are the most expensive option in the European Union with a gas price of \$10.8/MBtu. Across the range of gas price assumptions and as averages over 2015-2035, generating costs are lowest for nuclear and onshore wind, at \$82/MWh and \$84/MWh, respectively. While the analysis shows the economics of nuclear power to be favourable, policies in the European Union, as elsewhere, often dictate whether generators are allowed to build new plants.

A lower range of gas price assumptions in the United States demonstrates gas and coal to be competitive and the cheapest options for electricity generation (Figure 3.2b). At a gas price of \$6.6/MBtu, generating costs for CCGTs are about \$65/MWh, equal to those of coal-fired generation (without CCS). Because the United States is a large country, coal prices can vary substantially and alter this picture. The construction of coal-fired plants is strongly influenced by environmental concerns and local opposition has made it very difficult to advance projects and uncertainty regarding future regulations has contributed to project cancellations. Given an assumed gas price of \$7.6/MBtu, generating costs for CCGTs are still lower than those for onshore wind, nuclear and coal IGCC with CCS.

In China, ultra-supercritical coal is shown to be the cheapest source of electricity generation, at \$42/MWh. The availability of coal at low prices in most regions in China makes it the lowest cost option. Furthermore, coal plant equipment is produced locally and costs significantly less than in OECD countries. For gas price assumptions between \$9/MBtu and \$11/MBtu, generating costs for CCGTs are about twice those of ultra-supercritical coal (without CCS), and higher than coal fitted with CCS equipment (Figure 3.2c). If economics were the only consideration in choosing the fuel and technology for deployment, gas would have little impact on China's electricity generation mix (except in regions where transport costs raise coal prices considerably). Increasing use of gas-fired generation in China is largely driven by government policy, which is influenced by concerns about local pollution and diversity of the energy mix.

Assumptions about CO₂ prices can alter significantly the generating costs of competing fuels and technologies in power generation (Figure 3.3). In the European Union, the levelised cost of electricity generation from CCGTs is shown to be more expensive than that from nuclear power and onshore wind whenever CO₂ prices are above \$20/tonne in the period 2015 to 2035. Generation from ultra-supercritical coal is cheaper than CCGTs with a CO₂ price below \$20/tonne, but becomes more expensive at \$50/tonne. In the United States, electricity generating costs for CCGTs are generally the cheapest up to \$50/tonne, where onshore wind then becomes the least-cost option and nuclear power is much more competitive. At a CO₂ price of \$100/tonne, electricity from coal IGCC plants with CCS is still more expensive than from CCGTs. CO₂ prices would have little effect on the economic competitiveness of CCGTs in China, as they would remain the most expensive source of electricity even with an assumed CO₂ price of \$100/tonne.

Natural gas can help countries that depend heavily on coal, such as the United States and China, to reduce their CO₂ emissions. This is obviously more likely to happen if gas-fired generation is competitive against coal, which is more probable with relatively low gas prices or the imposition of a CO₂ price. In the United States, new gas-fired generation is already competitive against new coal-fired plants due to low gas prices, all else being equal, but it would take an average gas price of less than \$3.6/MBtu (with no price for CO₂), or a CO₂ price of about \$30/tonne CO₂ (with a gas price of \$6.6/MBtu), to make even the most inefficient existing coal-fired plants less economic than new CCGTs. It is more difficult for new gas-fired plants to replace existing coal-fired plants because capital costs have already been sunk. The expectation that gas prices in the United States will remain low for some time, and the possibility of future action to reduce greenhouse-gas emissions (even though no mandatory CO₂ pricing is in place), are likely to contribute to continued growth in new gas-fired capacity. Furthermore, gas could benefit from tightening controls over the pollutants arising from coal-fired power plants, such as the new standards proposed by the US Environmental Protection Administration (EPA) for hazardous air pollutants from coal- and oil-fired power plants.⁴

In China, for new gas-fired plants to compete with existing coal-fired plants, gas prices would have to fall below \$4.5/MBtu (with no price for CO₂) or CO₂ prices would need to reach \$55/tonne (with a gas price of \$10/MBtu). The economics of CCGTs versus new coal-fired generation are less attractive with break-even gas or CO₂ prices of \$4.3/MBtu (with no price for CO₂) or \$105/tonne CO₂ (with a gas price of \$10/MBtu), respectively. Based on these broad estimates, coal plants are considerably cheaper than gas plants in China, although the prices for both fuels can vary significantly within the region.

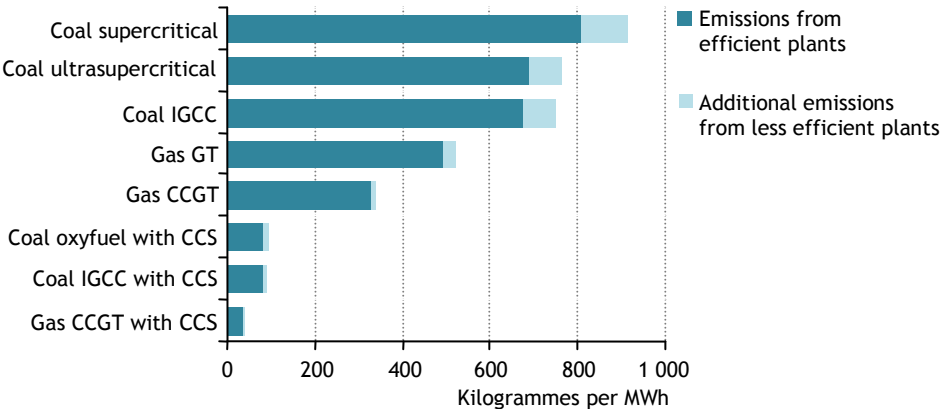
Power sector investment decisions are increasingly taking account of environmental factors such as local pollution and climate change. In the timescale of this analysis (to 2035), this is likely to mean that gas will play a growing role in the fuel mix. Some argue that, in a severely carbon-constrained world, renewables will be fully competitive on a level playing field and there will be little place for fossil fuels in electricity generation. Their vision is of gas as a transitional fuel to a world of low-carbon power generation. Others see carbon-efficient gas generation not only as a major element in the expansion of electricity generation over the next 25 years but also as a strong, lasting component of electricity supply beyond that. This study does not attempt to address that longer-term issue.

Gas can lower carbon emissions by displacing coal in power generation and other sectors. Moreover, flexible CCGT technology can be used to complement variable renewables (such as wind and solar power, the share of which is likely to increase considerably in the future) that require backup capacity. In many markets, gas-fired power plants are already being increasingly used to balance demand loads. The need for the type of flexibility provided by gas might diminish in the long term, as developments occur in electricity storage, smart grids and demand response.

⁴ According to the US EPA, some 44% of coal-fired power plants in the United States lack advanced pollution control equipment.

In addition to offering flexibility to complement growing generation from renewables, gas-fired generation reduces local air pollution and greenhouse-gas emissions when compared to other fossil fuels. A CCGT plant starting operation in 2020 is likely to emit, on average, about 330 kilogrammes (kg) of CO₂ per MWh of electricity produced (Figure 3.4). This is about half the level of a new coal-fired power plant using ultra-supercritical or IGCC technology (the technologies expected to be used in OECD countries) and less than half the emissions of a coal-fired power plant using supercritical technology (the prevailing technology in non-OECD countries by 2020). Emissions of gas-fired plants per unit of output are even lower in combined heat and power (CHP) production. CCGT plants equipped with CCS equipment have the lowest emissions of all power plants burning fossil fuels, but suffer an efficiency penalty. Should CCS technology advance, their competitiveness versus coal plants with CCS and other options will depend primarily on the level of gas prices.

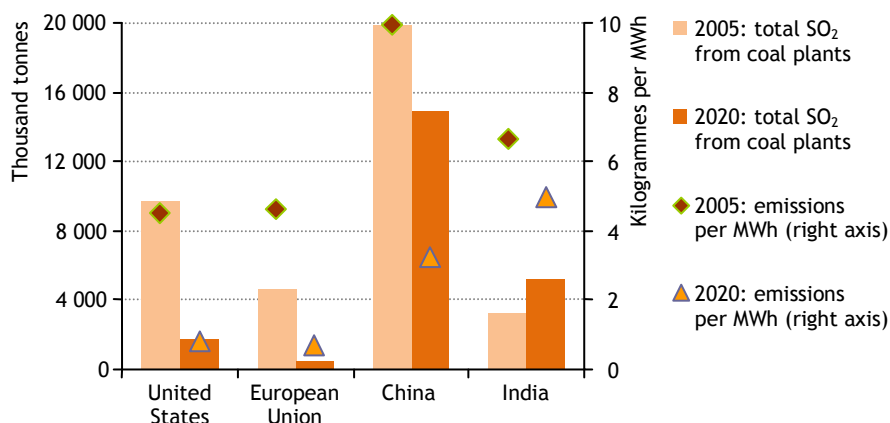
Figure 3.4 ▶ CO₂ emissions produced by new power plants in the GAS Scenario, 2020



Note: GT is gas turbines. The year 2020 is chosen as a mid-point for the outlook period. Emissions from CCS plants are not zero as part of the CO₂ in the exhaust gases of the power plant is not captured. A 90% capture rate has been used and underlying efficiency assumptions are shown in Table 3.2.

SO₂ emissions are particularly high in countries that rely heavily on coal to produce electricity but have limited pollution controls. China and India have the highest levels of SO₂ emissions from coal-fired power plants, as well as the highest SO₂ emissions per unit of coal-fired electricity produced. Although their emissions per MWh of electricity produced are expected to fall in the future, they are likely to remain significantly higher than in OECD countries. In the GAS Scenario, India’s emissions per MWh in 2020 are seven times higher than the level expected in the European Union (Figure 3.5). China’s emissions per MWh are lower than India’s due to greater use of flue gas desulphurisation technology, but still significantly higher than in the OECD.

Figure 3.5 ▶ SO₂ emissions from coal-fired power plants in selected countries in the GAS Scenario



Note: The year 2020 is chosen for comparison as a mid-point for the outlook period.

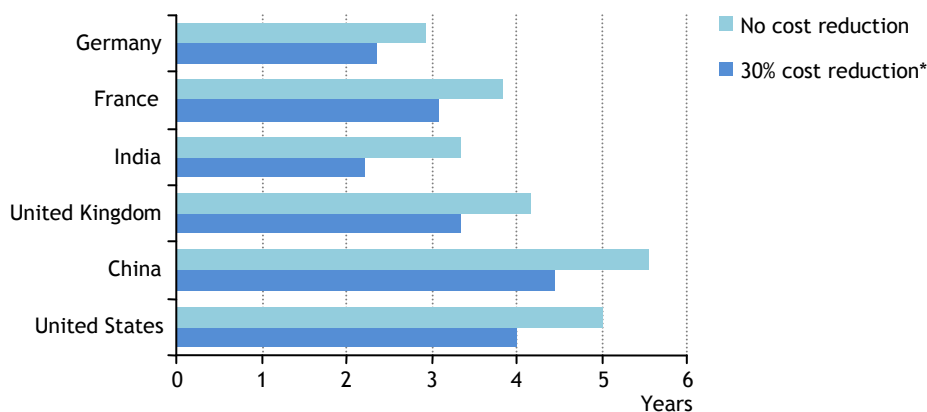
Source: IIASA (2011) for the IEA.

Transportation

Natural gas vehicles (NGVs) are fuelled commonly by compressed natural gas (CNG) or LNG. Their construction features and average fuel consumption are similar to those of conventional cars that use an internal combustion engine (ICE), but there are differences in the fuel injection system and the size of fuel storage tanks. These changes lead to somewhat higher purchase prices, with additional costs ranging between \$2 000 and \$10 000 for a new CNG vehicle (compared with a similar gasoline-fuelled vehicle). This wide range covers prices that vary by country, vehicle model and fuel storage capacity. While fuel costs for NGVs are often cheaper than for conventional vehicles (allowing for lower taxes on natural gas), higher upfront costs lead to payback periods of about three to five years. These payback periods vary, depending on the amount of distance driven and the differential between retail gasoline and gas prices, which is influenced by the costs of product treatment, refining, distribution, sales, taxes and local circumstances (Figure 3.6).

For potential buyers of a CNG vehicle, the higher purchase price and the payback period are key decision criteria. The first owner of a car typically keeps it for four to six years in industrialised countries, which emphasises the importance of shorter payback periods. In some countries, natural gas vehicles are supported through regulated fuel prices and other incentives. Irrespective of economics, a shortage of refuelling infrastructure is a major limitation to the growth of NGVs (IEA, 2010d). This suggests that, while the case for a switch to NGVs is not easily made for private consumers, it is more readily made for commercial fleets. Buses or municipal vehicles using central depots for refuelling are less vulnerable to any lack of infrastructure and can potentially secure more advantageous commercial prices for natural gas. In addition, commercial vehicles typically consume more fuel per year than private cars (driving more vehicle-kilometres), so the cheaper price of gas as a fuel can shorten the payback period.

Figure 3.6 ▶ Payback periods for CNG light-duty vehicles in selected countries in the GAS Scenario, 2020



*Assumes a fall of 30% in the premium over the cost of a conventional car.

Note: The figure is based on the assumption of a cost premium of \$4 000 for a CNG light-duty vehicle relative to a similar gasoline-fuelled internal combustion engine vehicle, excluding costs for infrastructure build-up. In the absence of data for natural gas prices for transport, prices have been constructed by taking the primary fuel price and adding a distribution cost and a retail margin. Under our assumptions, natural gas is cheaper than gasoline both at end-use level and on a primary fuel basis (gas against crude oil). The year 2020 is chosen as a mid-point for the outlook period.

Source: IEA databases and analysis.

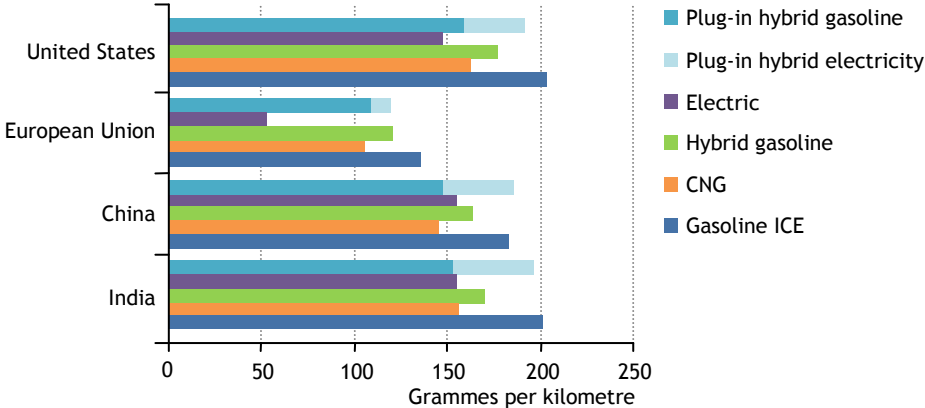
NGVs emit less CO₂ per kilometre (km) than conventional vehicles using gasoline. With engine performance optimised for CNG, the CO₂ emissions savings over a gasoline ICE vehicle are of the order of 20% to 25%. In the GAS Scenario, CNG vehicles in which natural gas replaces gasoline produce 22% less CO₂/km than gasoline vehicles in 2020 in India, 21% less in China, 22% less in the United States and 20% less in the European Union. Accounting for liquid biofuels use in conventional cars would yield slightly different results.⁵ Well-to-wheel greenhouse-gas emissions from biofuels vary considerably across regions and according to the fuel produced and technology used, with the savings *vis-à-vis* conventional gasoline being minimal or non-existent in some cases.

CNG vehicles may emit less CO₂ per km than electric vehicles (EV) and plug-in hybrid vehicles (PHEV), depending on the fuels used to produce electricity. In 2020, CNG cars are expected to emit less CO₂ per km than PHEVs in all the regions shown in Figure 3.7, assuming 10% of the vehicle-kilometres of PHEVs is electrically driven. They also emit less CO₂ per km than EVs in China, because of heavy reliance there on coal to produce electricity. In India, CNG vehicles and EVs emit about the same amount of CO₂/km, while in the United States EVs emit slightly less CO₂/km on average than CNG vehicles. By contrast, CNG vehicles in the European Union emit twice as much CO₂/km as electric vehicles. This is because of the low carbon intensity of electricity generation in that region, which is

⁵ The United States, European Union and China each have policies to increase the use of biofuels in transport.

projected to fall to 235 kg CO₂ per MWh by 2020 in the GAS Scenario, driven by the European Union’s efforts to curb CO₂ emissions. This compares with electricity generation carbon intensities of 480 kg CO₂/MWh in the United States, 605 kg CO₂/MWh in China and 675 kg CO₂/MWh in India.⁶

Figure 3.7 ▶ CO₂ emissions from new vehicles in the GAS Scenario, 2020

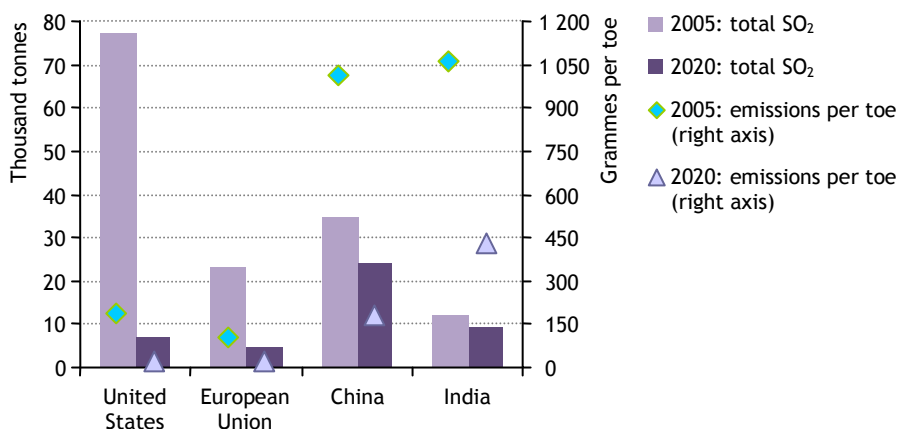


Note: Using on-road efficiency. ICE is internal combustion engine. ICE CO₂ emissions reflect the vehicle’s combustion emissions. Emissions from electric vehicles have been calculated using average CO₂ emission rates from electricity generation in 2020, adjusted for network losses. For PHEVs, we assume a 10% electric drive share. The year 2020 is chosen as a mid-point for the outlook period.

Gasoline and diesel use may also release SO₂. Most OECD countries have stringent fuel-quality standards, resulting in low emissions per unit of fuel consumed. In the GAS Scenario, India’s fuel quality standards are assumed to remain less stringent than those in OECD countries. In 2020, a vehicle in India emits over twenty-times more sulphur per tonne of oil equivalent (toe) consumed than a car in the European Union (Figure 3.8). China’s emissions per toe are lower than India’s, but in volumetric terms are the highest in the world.

⁶ The carbon intensity of electricity generation is defined as the ratio of total emissions from power plants to total electricity generated.

Figure 3.8 ▶ SO₂ emissions from light-duty vehicles in selected countries in the GAS Scenario



Note: The year 2020 is chosen for comparison as a mid-point for the outlook period.

Source: IIASA (2011) for the IEA.

Determination of fuel choice in other sectors

In *industry*, depending on the sub-sector, gas competes against coal, oil products, electricity or renewables, such as biomass or solar. In 2008, coal and oil accounted for over 40% of energy demand in industry and almost 80% of the sector's direct CO₂ emissions (Table 3.3). In the GAS Scenario, the share of coal and oil combined in industrial energy demand falls over time, but still remains high in 2020 (37%) and even in 2035 (30%).

Relative pricing is a critical factor in determining the preferred industrial fuel input. Other considerations can be equally important, depending on the sub-sector and the location (which determines the framework of regulations). In general, gas is easier to handle, more efficient and associated with fewer environmental problems than other fuels. No on-site fuel storage or disposal of by-products (such as coal ash) is necessary. Gas is ideal for some industries that require cleaner-burning fuels, such as food processing, glass and paint manufacturing. Other advantages of gas in industrial applications are lower capital costs, shorter lead times for equipment and a smaller physical footprint.

Gas is used mainly for producing steam for mechanical energy and process heat. By far the biggest gas-consuming industrial sector is chemicals (not including feedstock use in petrochemicals). Gas can be substituted by other fuels when new fuel-burning equipment is being installed, but this is often only economic at relatively high gas prices. In other sub-sectors, gas competes with fuel oil and coal, especially in boilers, with the choice of fuel determined by price and environmental regulations (which may favour gas use). Lower capital costs reduce risk and therefore tend to amplify the advantage of gas-fired equipment. The competitive position of gas in industrial applications is less clear in non-OECD countries, where coal is often cheap, gas markets are immature and environmental regulations are not as stringent as those in the OECD.

Table 3.3 ► Global energy consumption, CO₂ emissions and CO₂ emissions intensity in industry and buildings sectors in the GAS Scenario

	Energy consumption (Mtoe)			CO ₂ emissions (Mt)			CO ₂ emissions intensity (tonnes CO ₂ per toe)		
	2008	2020	2035	2008	2020	2035	2008	2020	2035
Industry									
Total	2 351	3 087	3 426	5 056	6 304	6 212	2.2	2.0	1.8
<i>Coal</i>	646	794	728	2 947	3 642	3 312			
<i>Oil</i>	332	354	316	1 035	1 107	988			
<i>Gas</i>	466	666	819	1 074	1 555	1 913			
Buildings									
Total	2 850	3 288	3 782	2 946	3 177	3 254	1.0	1.0	0.9
<i>Coal</i>	125	123	86	482	476	333			
<i>Oil</i>	344	350	318	998	1 010	914			
<i>Gas</i>	617	724	859	1 467	1 692	2 007			

Notes: Total energy consumption includes electricity, heat and direct use of renewables. Emissions intensity refers to direct emissions only, *i.e.* excluding CO₂ emissions from electricity generation.

Natural gas is used as a *feedstock* primarily for making petrochemicals, methanol and ammonia (a critical ingredient in fertiliser production). It is readily substituted by oil products such as naphtha in petrochemicals, but less easily in making methanol and ammonia. Price is a key factor in each use. Variations in relative fuel prices can cause gas use in petrochemicals to fluctuate markedly in the short term. Since 2000, natural gas has been growing more quickly than oil products (which include gas liquids) in feedstock use. The use of gas as a feedstock is likely to continue to increase in the long term as economies grow, boosting the demand for fertiliser in the agriculture sector, for example in India. Yet the rate of growth will vary across regions according to local market conditions and the abundance of gas *vis-à-vis* other feedstocks. China has a large coal-to-chemicals sector, which is unlikely to change over the medium term.

In *buildings*, natural gas is usually the preferred fuel in OECD countries for space and water heating (residential, commercial and public sectors). The principal competition to gas in these sectors is light heating oil, which is generally more expensive on a heating value basis and involves higher installation and maintenance costs. Gas-fired condensing boilers are very thermally efficient, with an average efficiency of around 90%, compared with around 70% to 80% for conventional boilers that use either natural gas or heating oil. Gas boilers also have practical advantages over oil (and coal) boilers, given that no fuel storage is required.

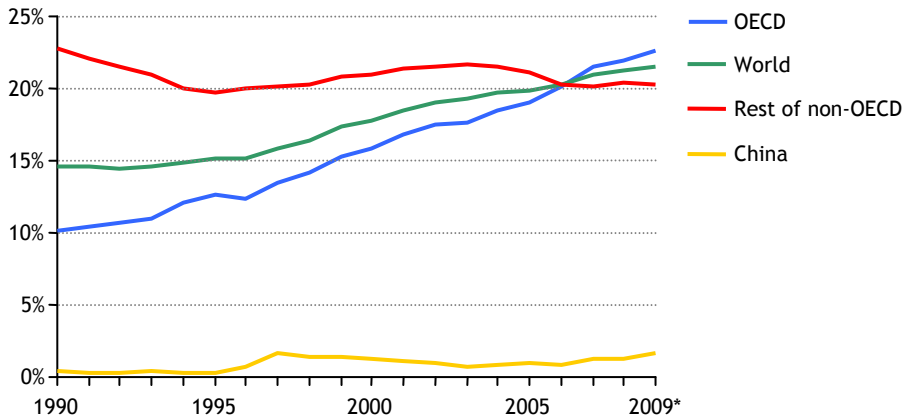
The steady introduction of condensing boilers, as households replace older equipment, will reduce the amount of gas required to heat a given amount of occupied space and curb the rate of future demand growth in buildings. The next generation of space heating equipment, heat pumps and micro-cogeneration, has recently become commercially available. In large buildings, there is some potential for applying micro-cogeneration, which involves small combined heat and power units with overall efficiencies above 90%. An added benefit of these distributed systems is their ability to reduce peak electricity demand.

There is some opportunity for reducing CO₂ emissions from buildings, as coal and oil accounted for 16% of total energy demand in 2008 and for 50% of direct CO₂ emissions. In most countries, use of gas in buildings produces less CO₂ than use of electricity for the same applications. Substituting gas for coal or oil in a boiler used for space heating can reduce its CO₂ emissions by between 20% and 60%. Similarly, 10% of the emissions from using LPG in cooking (a common fuel in some non-OECD regions) can be avoided by switching to gas.

Emerging trends as an indicator of future gas demand

In the last decade, globally the most striking change in the power sector was the surge in coal-fired generation that arose in response to booming electricity needs in China to support economic growth and urbanisation. Somewhat overshadowed by this, but nonetheless very significant, was that global gas-fired power generation grew by almost 60% during that time and raised its share of the global electricity mix from 18% to 22% (Figure 3.9).

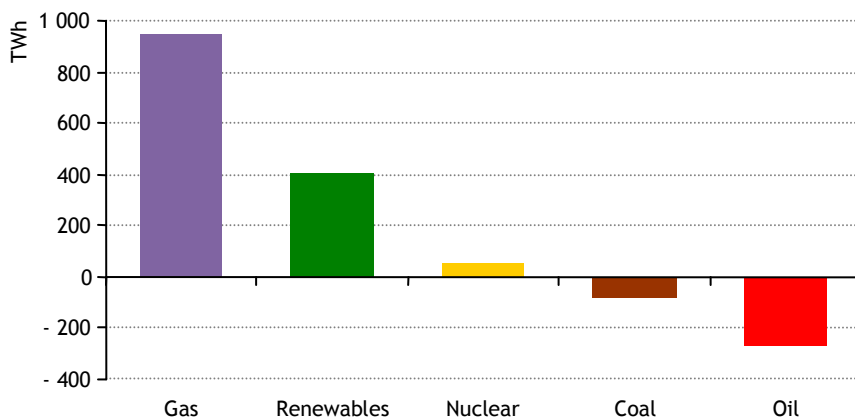
Figure 3.9 ▶ Share of gas-fired electricity generation in the power sector



*Based on estimated data for 2009.

In OECD countries, gas-fired plants were the predominant choice for new generation (Figure 3.10), with about 90% of net additional electricity output coming from gas in the period 2000 to 2010. Among the particular factors influencing power utilities in OECD countries during the last decade were slow and uncertain growth in electricity demand, rising peak electricity demand, economic uncertainty and the addition of more variable renewables. These drove utilities' investment in CCGTs, which were perceived to mitigate risks, primarily because of their lower capital cost and the shorter lead time for construction. An added consideration for investors was the expectation of new regulations to reduce greenhouse-gas emissions. While mandatory systems have not materialised in many countries, utilities view gas-fired generation as a lower risk option in this context (compared with coal).

Figure 3.10 ▶ **OECD incremental power generation, 2000-2010***

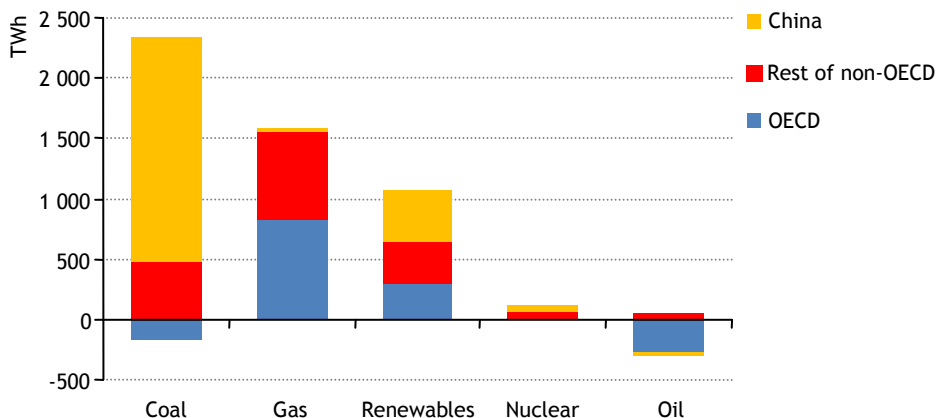


*Based on estimated data for 2010.

There was substantial growth in gas-fired generation in non-OECD countries over 2000 to 2009, though the conditions that underpinned that growth were very different from those in the OECD (Figure 3.11). Whereas electricity demand in OECD countries increased only slowly, it outstripped the growth in supply in many non-OECD countries. In the Middle East, increasing oil and gas (much of it associated gas) production led to gas becoming the preferred fuel for power generation, since it could free up more valuable oil for export. This remains a key driver in the Middle East, particularly as many of these countries depend significantly on oil-fired electricity generation, face pressure to maintain oil exports, and seek to develop value-added industries for oil, such as petrochemicals. Electricity demand also rose very quickly in ASEAN countries over 2000 to 2009, where gas-fired plants met one-half of new demand. While electricity demand did not grow as quickly in Russia as in other non-OECD countries, gas-fired power plants, which form the backbone of its power sector, are relatively inefficient and future electricity needs could be achieved with considerably less gas use.

Despite minimal growth in gas-fired power generation in China over 2000 to 2009, its 12th Five-Year Plan (FYP) reflects a major policy shift which aims to give gas a much more important role in the broader energy system. Policy choices made by China and other emerging economies will determine the future fuel mix and the trajectory of gas demand globally to a much greater extent than choices elsewhere. The focus of China’s 12th FYP, for 2011 to 2015, is on more sustainable growth through energy efficiency and use of cleaner energy sources. It entails the upward revision of China’s target gas consumption: from 5.3% of total primary energy consumption in the previous Plan to 8.3% by 2015 in the new Plan, corresponding to an expected tripling of gas use over 2008 to 2015.

Figure 3.11 ▶ World incremental power generation, 2000-2009*



*Based on estimated data for 2009.

Recent government actions and priorities in other regions are influencing the prospects for gas demand. Many countries continue to support expanded use of renewable energy in the power sector, increasing the need for system flexibility in a manner which favours additional gas use. In India, gas transmission and distribution infrastructure are presently being expanded, driven by rising domestic supply and robust demand across end-use sectors. The Indian government plans to facilitate increased penetration of gas in its energy mix (Dhar, 2010). In addition, the recent disaster at the Fukushima nuclear facility in Japan has called into question the future role of nuclear power and prompted re-evaluation of related policies in many countries. To the extent that future nuclear power capacity is lower than previously expected, demand for gas in power generation is likely to increase.

The increasing economic burden of subsidised energy pricing has caused several large gas consuming countries to pursue price reforms, which may curtail gas use somewhat. The adverse consequences of regulated energy prices in Russia, which have led to deep inefficiencies and under-investment in the energy sector, have stimulated actions to raise domestic gas and electricity prices during the last decade and there are plans eventually to bring these prices into line with international levels. In Iran, sweeping cuts were made to all energy subsidies at the end of 2010, including gas and electricity, to curb fuel imports and alleviate budget pressure.

Taking stock of future uncertainties

Highlights

- Future gas demand is most sensitive to the level of gas prices relative to those of other fuels and to the rate of economic growth. Sensitivity analysis on these variables within the framework of the New Policies Scenario of *WEO-2010* shows that world gas demand could rise from 3.2 trillion cubic metres (tcm) in 2008 to between 4.2 tcm and 4.9 tcm per year in 2035. Across the range of sensitivities, the share of gas in world total primary energy demand in 2035 varies between 21.9% and 23.8% compared with 22.4% in the *WEO-2010* New Policies Scenario and 25.3% in the GAS Scenario.
- The level of global energy-related CO₂ emissions is influenced most by the level of GDP. Changes in CO₂ emissions correlate with changes in GDP growth, and result primarily from differences in overall energy use, as the energy mix varies only slightly. In the sensitivity analysis, total CO₂ emissions range from less than 32 Gt to over 39 gigatonnes (Gt) in 2035, compared with 35.4 Gt in the New Policies Scenario and 35.3 Gt in the GAS Scenario.
- What if the United States were to stop building new coal-fired power plants after 2015 and installed gas-fired plants instead? This would increase gas demand in the United States by one-quarter and reduce greenhouse-gas emissions by 270 million tonnes (Mt) in 2035.
- What if relatively simple energy efficiency improvements were widely adopted in countries in Eastern Europe and Central Asia? This could reduce gas use there by at least 15% by 2035, saving more than 100 bcm of gas and reducing CO₂ emissions by nearly 200 Mt. Removal of subsidies would be necessary to achieve these savings, which could free up gas for export.
- What if there was a surge in global demand for natural gas vehicles (NGVs)? Vehicles in urban areas are well-placed to use gas at relatively low infrastructure cost, which also brings air quality improvements. If 10% of total vehicle sales by 2035 were NGVs, the global stock of NGVs would rise to 190 million. This would reduce oil demand by nearly 6 mb/d, 12% of total road-transport fuel demand. Annual gas demand would rise by 320 billion cubic metres (bcm) and greenhouse-gas emissions would fall by 165 Mt.
- What if carbon capture and storage (CCS) does not prove to be viable before 2035? If, in that event, all anticipated CCS-fitted gas- and coal-fired plants were replaced by gas-fired plants (without CCS), gas use would increase by around 65 bcm and greenhouse-gas emissions would rise by 140 Mt annually.

Some factors driving gas demand and the broader energy mix may change markedly, especially given the high level of uncertainty pervading many aspects of energy markets. This section begins by describing the main projections for gas demand between 2008 and 2035 in the *WEO-2010* New Policies Scenario in order to establish a baseline from which to test changes in its underlying assumptions. A sensitivity analysis is carried out to examine what happens to demand for gas and other energy sources if assumptions are changed about the rate of economic growth, gas prices, coal prices and other variables. While these are key factors that will determine future gas demand, the future can deviate from projections also because of unforeseen events. The final part of this section asks, what if some such events were to occur? It offers an analysis of how several illustrative *high-impact low-probability (HILP)* events, might reshape gas demand trends.

Projected gas demand in *WEO-2010* New Policies Scenario

The New Policies Scenario of the *WEO-2010* provides a useful point of reference against which to measure the impact of various alternative assumptions: those underpinning the Golden Age of Gas Scenario (GAS Scenario), other sensitivities elaborated here and possible events described here as *HILP* events. This section opens by recalling the main features of the New Policies Scenario.

Table 4.1 ▶ **Primary natural gas demand by region in the *WEO-2010* New Policies Scenario (bcm)**

	2008	2015	2020	2025	2030	2035	2008-2035*
OECD	1 541	1 568	1 625	1 666	1 713	1 758	0.5%
North America	815	817	844	864	886	913	0.4%
Europe	555	562	582	601	620	628	0.5%
Pacific	170	189	199	200	206	216	0.9%
Non-OECD	1 608	1 969	2 169	2 367	2 584	2 777	2.0%
E. Europe/Eurasia	701	744	771	802	826	838	0.7%
Asia	341	497	585	676	800	934	3.8%
<i>China</i>	85	169	216	266	331	395	5.9%
<i>India</i>	42	80	97	117	143	177	5.4%
Middle East	335	424	466	523	573	608	2.2%
Africa	100	136	149	155	161	164	1.9%
Latin America	131	168	197	212	223	232	2.1%
World	3 149	3 536	3 794	4 033	4 297	4 535	1.4%
<i>European Union</i>	536	540	558	574	591	598	0.4%

* Compound average annual growth rate.

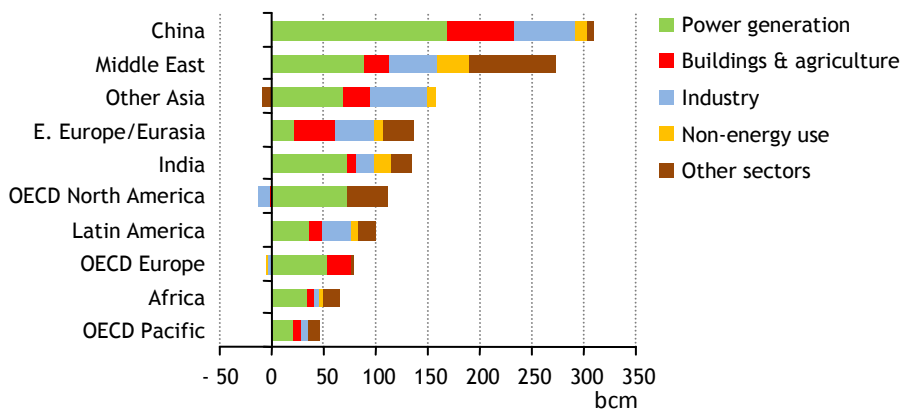
World economic growth in that scenario averages 3.2% per year between 2008 and 2035, with the brightest prospects in non-OECD countries.¹ Gas prices were assumed to rise steadily in all regions (see Table 1.1). With regard to government policies, the New Policies Scenario assumed that action would be taken to implement the broad commitments and plans announced by countries around the world to tackle either environmental or energy-security concerns, even where the relevant measures remained to be identified. These commitments included the national pledges to reduce greenhouse-gas emissions, communicated formally under the Copenhagen Accord and plans to phase out fossil-energy subsidies.

The New Policies Scenario showed world gas demand rising from 3.1 trillion cubic metres (tcm) in 2008 to 4.5 tcm in 2035 – a total increase of 44%, equivalent to an average annual growth rate of 1.4% (Table 4.1). The share of gas in overall primary energy demand increased marginally during the *Outlook* period, from 21% to 22%, as demand for other energy sources rose.

Regional trends

In the New Policies Scenario, gas demand grows in almost all regions over the next 25 years (Figure 4.1). Non-OECD countries are the primary drivers of demand, accounting for 80% of the increase. Their economies and populations grow much faster, and the scope for expanding gas use is much greater, than in the OECD. Globally, China sees the highest rate of growth in gas demand; it also accounts for the largest increment of growth in absolute terms.² All sectors support impressive demand increases. These are met by the opening up of new sources of supply, a mixture of indigenous production of conventional and unconventional gas and imports via pipeline and liquefied natural gas (LNG). In India, demand growth is strong, but starts from a smaller base. Demand there rises to meet power and industrial sector needs and requirements for petrochemical feedstock.

Figure 4.1 ▶ Incremental primary gas demand by region and sector in the *WEO-2010* New Policies Scenario, 2008-2035



¹ GDP growth in the OECD and non-OECD was assumed to average 1.8% and 4.6% per year, respectively.

² The *WEO-2010* New Policies Scenario did not take account of China's 12th Five-Year Plan, as its details emerged after the analysis.

Gas demand also surges in the Middle East, driven mainly by the power sector. Gas-fired plants are brought online to replace oil-fired units and free up oil for export or value-added uses, such as petrochemical. Development of large, indigenous resources facilitates rising gas use. Strong demand in other non-OECD countries is matched by hydrocarbon developments. Brazil is expected to tap recently discovered offshore resources; in the Caspian region, gas use soars as production from new projects starts to flow. It is anticipated that gas use in Russia will grow only modestly over 2008 to 2035, as a result of continued improvements in energy efficiency (the replacement of older equipment, notably in the power sector) and the gradual elimination of subsidised gas prices.

In the New Policies Scenario, projected gas-demand growth in the mature OECD markets is considerably slower than in the non-OECD. Even though the United States and Europe remain two of the largest blocs through 2035, additional OECD gas demand amounts to just 19% of that in non-OECD countries. Limited scope exists for increased gas use in the residential sector in the OECD because of saturation effects. Although modest economic growth in the OECD lifts industrial output, more efficient gas use in the sector leads to a marginal drop in gas demand. Growing electricity production from gas-fired units continues to account for the lion's share of additional gas demand in OECD countries.

Sectoral trends

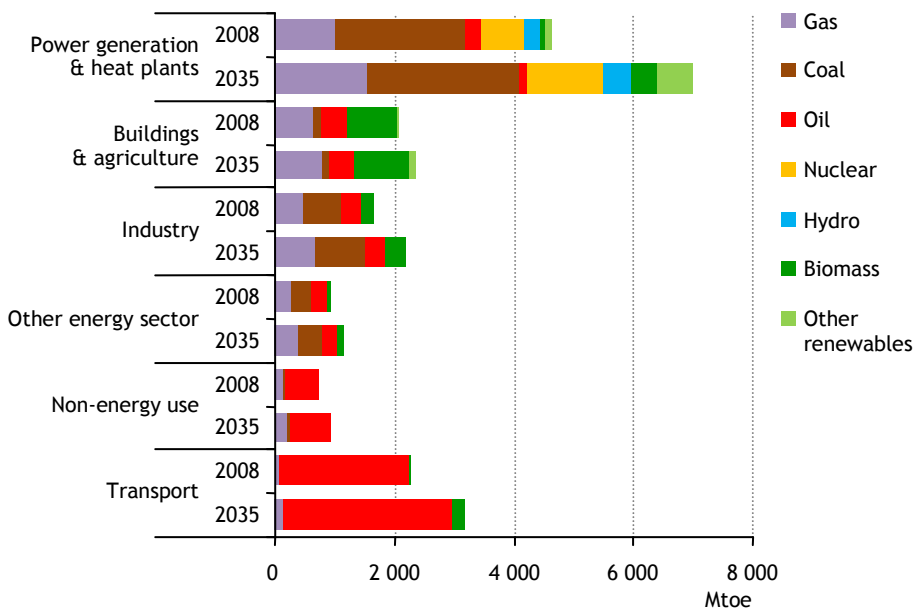
In the New Policies Scenario, power generation is the principal driver of natural gas demand in most regions to 2035, accounting for nearly half of incremental growth. Despite slowly rising gas prices, combined-cycle gas turbines (CCGTs) are expected to remain the preferred choice for new power plants in many regions. With an array of risks confronting new power generation capacity, gas is a relatively low-risk option. Non-OECD electricity demand rises rapidly, increasing the need for all sources of power generation, including gas. The competitiveness of gas-fired generation relative to coal is boosted in OECD countries by CO₂ prices, which are assumed to rise throughout the projection period. Continued support for renewables in regions where environmental or energy security concerns are high constrains the growth of gas use in the power sector, notwithstanding its ability to provide back-up for variable renewables-based capacity.

The buildings sector is responsible for 15% of additional gas demand during the *Outlook* period. Economic and population growth lift gas consumption in the sector, to meet additional space and water heating needs. Strong demand growth in non-OECD countries overall is driven by rapidly expanding urban populations, even though gas demand in buildings changes little in some non-OECD regions where the climate is warm or personal incomes are too low to support the construction of distribution networks. Demand growth for gas in buildings in the OECD is limited, whether for space or water heating, due to market saturation, slow population growth and the adoption of more efficient technologies.

Natural gas consumption by industry accounts for 17% of new demand over 2008 to 2035, rising in response to heightened economic activity and increased output across the industrial sector to fuel additional process heat and steam-raising in factories. Nearly all new gas demand in the industrial sector arises in the non-OECD, where economic growth is strongest. Another non-OECD trend is the switching from oil to gas in industry, as gas is more economically and environmentally attractive. In contrast, in most OECD countries industrial gas demand declines as the impact of slowly increasing industrial output (due

partly to the relocation of industries to non-OECD countries) is offset by efficiency gains and the growing use of electricity.

Figure 4.2 ▶ World primary energy demand by sector and type in the WEO-2010 New Policies Scenario



Note: Non-energy use includes inputs to petrochemicals. Other energy sector includes energy consumed in oil and gas production, gas-to-liquids transformation and distribution losses.

Gas use in the transport sector is responsible for just 4% of additional demand over 2008 to 2035. While powering gas pipelines today accounts for four-fifths of gas consumed in the transport sector, nearly all new gas consumption during the *Outlook* period arises from gas use in road transport (prominently in vehicles fuelled by compressed natural gas [CNG]). Non-OECD Asia, Latin America and OECD North America are responsible for the bulk of the increase. The scope for increased demand in the transport sector depends on the future market penetration of natural gas vehicles (NGVs), which comprise a minute share of the world car fleet today (less than 1%) and face infrastructure hurdles.

Sensitivity analysis of gas demand

While the assumptions underlying the New Policies Scenario are all plausible, none is infallible. Some factors may change markedly, with far-reaching consequences for energy demand and the share of gas in the energy mix. In view of these uncertainties, we have tested the sensitivity of gas demand to certain changed assumptions, using the *WEO-2010* New Policies Scenario as the baseline.

This sensitivity analysis was carried out by re-running the World Energy Model (WEM),³ the principal tool used to produce our global energy projections, for each new assumption in isolation (*i.e.* all other assumptions were unchanged). This allowed us to quantify the sensitivity of gas demand to changes in each chosen factor: natural gas prices, oil prices, coal prices, CO₂ prices, the rate of economic growth and the share of nuclear power in the electricity mix.⁴ The assumptions were varied both positively and negatively from the levels assumed in the New Policies Scenario (Table 4.2). The sensitivity analysis was used to enhance understanding of the effects of different drivers. This helped us build the GAS Scenario (see Section 1), which accommodates the interactions between all factors.

Table 4.2 ▶ **Summary of sensitivity cases and assumptions relative to the WEO-2010 New Policies Scenario**

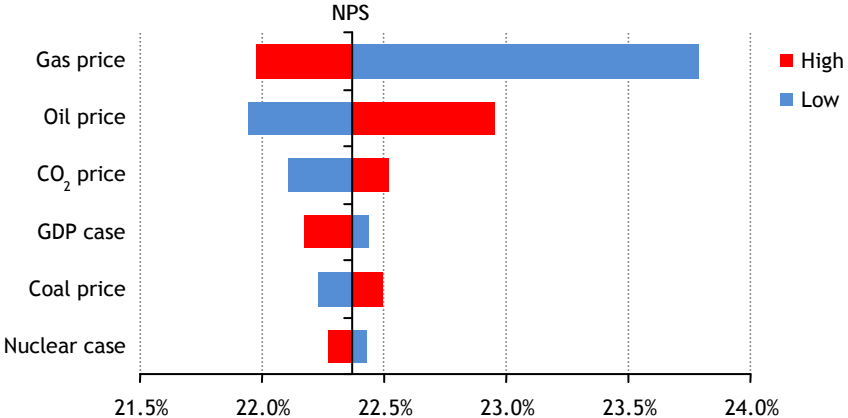
Variable	Assumptions (between 2009 and 2035)	
	Low case	High case
Gas price	The increase in prices in all regions is reduced by 67%.	The increase in prices in all regions is raised by 33%.
Oil price	The increase in the international crude oil price (average IEA crude oil imports) is reduced by 33% (resulting in lower refined product prices).	The increase in price is raised by 67%.
Coal price	The increase in the international steam coal price (OECD imports) is reduced by 67%.	The increase in price is raised by 67%.
CO ₂ price	In all regions where carbon pricing is assumed to be introduced, the increase in price to 2035 is reduced by 100% of the increase in the EU carbon price.	In all regions where carbon pricing is assumed to be introduced, the increase in price to 2035 is raised by 100% of the increase in the EU carbon price.
GDP growth	The rate of GDP growth is 0.5% per year lower in all regions.	The rate of GDP growth is 0.5% per year higher in all regions.
Nuclear power	The global gross capacity additions are reduced by 10% (no change in the assumed lifetimes of existing plants).	The global gross capacity additions are raised by 10% (no change in the assumed lifetimes of existing plants).

Across the range of these sensitivities, the share of gas in world total primary energy demand in 2035 varies between 21.9% and 23.8% compared with 22.4% in the New Policies Scenario (Figure 4.3) and 25.3% in the GAS Scenario. The largest increase in market share occurs in the low gas price case, which stimulates gas demand at the expense of a drop in demand for competing fuels. The largest drop in the share of gas occurs in the low oil price case, due to much higher oil demand (which has the effect of pushing up total primary energy demand) and a small reduction in gas use (which is a result of less switching from oil to gas).

³ A detailed description of the WEM can be found at www.worldenergyoutlook.org/model.asp.

⁴ The WEO-2011 will analyse in-depth the global implications of a low-nuclear scenario.

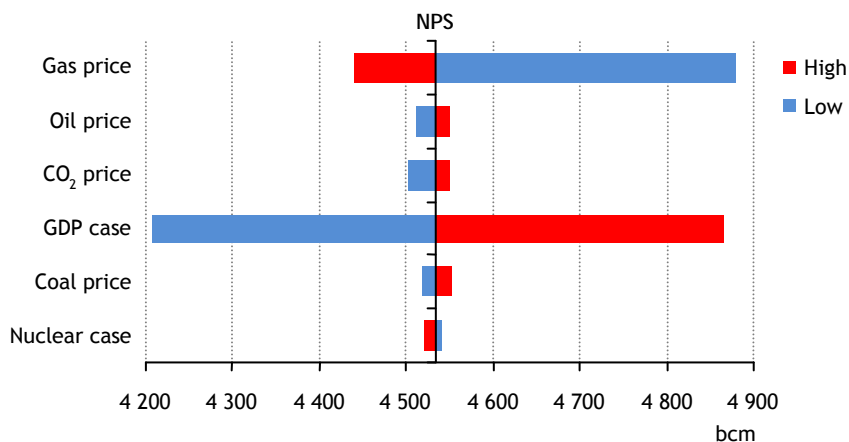
Figure 4.3 ▶ Share of gas in world primary energy demand in the sensitivity cases, 2035



Note: NPS is New Policies Scenario.

Global primary gas demand increases most in the high GDP growth case and under low gas prices. Correspondingly, gas demand falls most in the low economic growth and high gas price cases (Figure 4.4). Gas demand in 2035 ranges between 4.2 tcm (in the low GDP price case) and 4.9 tcm (in the high GDP and low gas price cases), compared with 4.5 tcm in the New Policies Scenario. Gas demand in power generation and industry reacts most to varied rates of GDP growth, reflecting the strong relationship of those sectors to the level of economic activity. The power sector proves to be the most sensitive to changes in gas prices. This is the result of two combined effects: the changing demand for electricity and the changing fuel mix used to produce this electricity. Gas prices strongly influence electricity prices, which affect electricity demand. The fuel mix is affected by changes in the merit order (the dispatching of power plants typically on an hourly basis, based on their running costs) and, in the long term, changes in investment decisions. Demand for gas is hardly affected by changes in oil, coal and carbon prices. Gas demand is also unaffected by reducing the share of nuclear power in the electricity mix. In this case, fewer new nuclear plants are built in non-OECD countries, where most of the growth in nuclear capacity is expected and cheaper coal fills the gap.

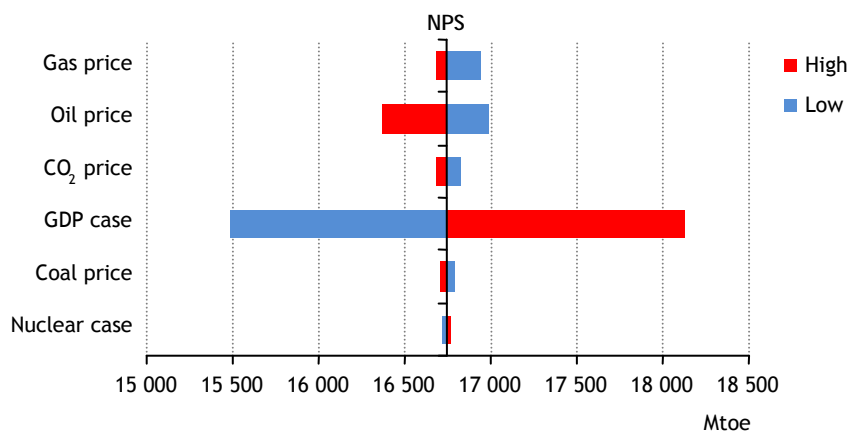
Figure 4.4 ▶ Global primary gas demand in the sensitivity cases, 2035



Note: NPS is New Policies Scenario.

Global primary energy demand is also affected most by changes in the GDP (Figure 4.5). World total primary energy demand in 2035 ranges from 15 500 million tonnes of oil equivalent (Mtoe) in the low GDP case to 18 150 Mtoe in the high GDP case – these represent a -7.5% and +8.3% change, respectively – relative to the New Policies Scenario baseline. Higher or lower levels of economic activity directly influence overall global energy needs. Oil and coal demand are most sensitive to changes in the rate of economic growth, followed by gas. The sensitivity of oil consumption arises because the transport sector accounts for the majority of oil demand and the rate of vehicle purchase and use depends highly on economic growth. Likewise, electricity demand is highly responsive to economic activity and is the primary driver of coal demand, especially in the emerging economies, where GDP growth is highest. Changes in oil prices, through their direct impact on oil demand, also have a relatively large impact on primary energy demand.

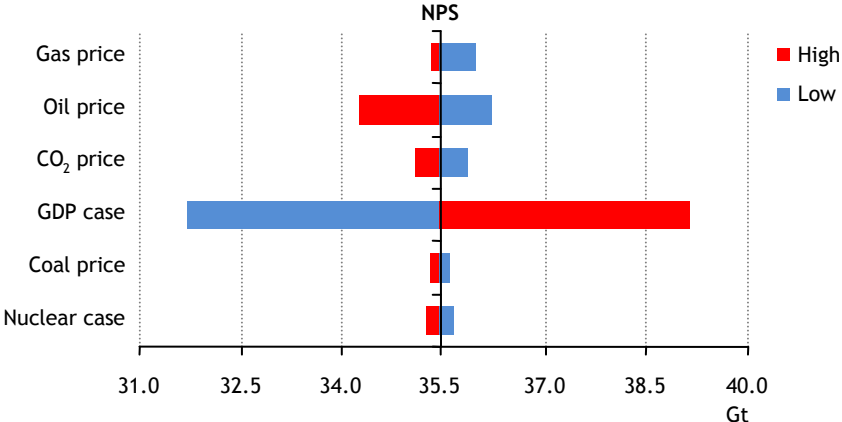
Figure 4.5 ▶ Global total primary energy demand in the sensitivity cases, 2035



Note: NPS is New Policies Scenario.

GDP is also the most important factor influencing CO₂ emissions (Figure 4.6). Changes in CO₂ emissions correlate with changes in GDP growth, and result primarily from differences in overall energy use, as the energy mix varies only slightly. Total emissions range from less than 32 gigatonnes (Gt) to over 39 Gt in 2035, against 35.4 Gt in the New Policies Scenario, and 35.3 Gt in the GAS Scenario. Oil prices also have a fairly large impact on CO₂ emissions, mainly due to the impact on oil demand. Lower gas prices have a somewhat surprising effect on CO₂ emissions, causing an increase of 530 Mt, about 1.5%, in 2035, because lower gas prices result in higher overall energy demand. CO₂ emissions barely change in the low and high coal price cases, as there is little overall change in global energy demand.

Figure 4.6 ▶ Global CO₂ emissions in the sensitivity cases, 2035



Note: NPS is New Policies Scenario.

Accounting for high-impact, low-probability events

Whereas sensitivity tests examine the effects of variations in key assumptions, unexpected events can have a sharp impact on the energy landscape and should not be disregarded. Many such events have occurred in the past, quickly altering underlying trends and the long-term outlook for energy markets generally and gas markets in particular. One example is the development of CCGT technology, which in a short span of time created a new and highly valuable market opportunity for gas in power generation. In the past few years, technological advances in shale gas production have led to a dramatic surge in supply in the United States and opened up the possibility of the development of shale gas resources in many other parts of the world (see Section 2). Other recent, potentially high-impact, events include the commitment of China’s government to expand gas use substantially, the Macondo oil spill in the US Gulf of Mexico in 2010, the disaster at the nuclear power plants in Fukushima and turmoil in North Africa and the Middle East in early 2011.

Few can predict such disruptive events or how extensive their impact on energy markets might be. For illustrative purposes only, we consider four such *high-impact low-probability (HILP)* events and analyse how they could affect gas markets, using the *WEO-2010* New Policies Scenario as the baseline. The objective is to provide insights into how individual events could alter the underlying drivers of gas demand (see Section 3) and cause

significant divergence from the path that planned policies and market forces have set. The objective is to illustrate uncertainty, not to speculate about the likelihood of the occurrence. None of the events covered here is included in the GAS Scenario.

The four chosen *HILP* events are:

- **Gas-fired power generation:** What if demand for natural gas in power generation were to be much stronger than projected due to increased substitution from coal? We consider a hypothetical development in the United States.
- **Energy efficiency:** What difference could be made by much quicker implementation of energy efficiency measures in countries where the potential for savings remains large? We consider the possible implications for selected countries in Eastern Europe and Central Asia.
- **Natural gas vehicles (NGVs):** What would be the impact of a surge in demand for natural gas vehicles? We consider a case where 10% of all vehicle sales worldwide are NGVs by 2035.
- **Carbon capture and storage (CCS):** What if CCS could not be deployed before 2035 for economic, social or technological reasons?

A larger share of gas in US power generation

As the second largest energy consumer in the world, what happens in the United States matters globally. The power-generation sector accounts for over 40% of total primary energy demand in the United States and this share increases to nearly 45% by 2035 in the *WEO-2010* New Policies Scenario. Natural gas is the second most important fuel (after coal) for electricity generation in the United States.

In the New Policies Scenario, planned policy incentives for low-carbon energy, including the pricing of CO₂, support a major shift towards a lower-carbon electricity generation mix in the United States. Electricity generation from coal falls, while the shares of renewables, nuclear power and coal- and gas-fired plants fitted with CCS increase. The share of natural gas is projected to remain broadly flat at about 21% in that scenario. Yet, gas could, under certain conditions, play a much bigger role. For example, in the GAS Scenario the share of gas in electricity generation in the United States reaches 27% in 2035.

The future role of natural gas in the US power sector is sensitive to several factors. These include the price of gas, which in turn depends in large part on the durability of the shale gas boom, regulation of shale gas production, the evolution of coal prices in the United States, the stringency and pace of actions to reduce CO₂ emissions, the need to replace ageing coal power plants, the rate of penetration by renewable energy sources and the economic viability and public acceptance of nuclear power.

Future policies in the United States on climate change will be of critical importance. While coal accounted for around half of the electricity generated in the United States in 2008, it produced about 80% of total CO₂ emissions in the power sector. As in the rest of the world, natural gas could play a central role in the transition to a low-carbon power sector since, on a per unit basis, gas produces about one-half the CO₂ level of coal and can be quickly generated to meet peaks in electricity demand (see Section 3). Gas also provides back-up capacity to support and balance electricity markets, which is particularly valuable to incorporate the increasing levels of variable renewable sources such as wind power.

HILP event analysis: A larger share of gas in US power generation

For the purpose of this analysis, it is assumed that policies in the United States do not allow construction of any new coal-fired power generation plants after 2015. We also assume that all of the coal-fired capacity that would have been built is replaced by CCGT power plants. As a result, an additional 126 GW of gas-fired capacity is built by 2035, equivalent to replacing more than 40% of the coal-fired electricity generating capacity that would have been in operation in 2035 with natural gas.

In this case, US total primary demand for natural gas increases by around 160 bcm in 2035, an increase of 24% relative to the New Policies Scenario (Table 4.3). In contrast, total primary coal demand falls by around 170 Mtoe, or 43%. CO₂ emissions fall by 270 Mt CO₂ in 2035, a 6% reduction from the New Policies Scenario. The net investment required in power plants in 2015 to 2035 is lower, but fuel costs are higher (for simplicity, other costs are assumed not to change). US gas production is assumed to rise in line with the increase in demand, implying that the break-even cost of incremental gas production is lower than in the New Policies Scenario.

Table 4.3 ▶ The impact of gas taking a larger share of US power generation

	2008	NPS (2035)	HILP (2035)	Change
Coal power demand (Mtoe)	495	361	188	-173
Natural gas power demand (bcm)	205	230	388	158
Gas-fired electrical capacity (GW)	409	420	546	126
CO ₂ emissions from power (Mt)	2 385	1 759	1 488	-271
Cumulative investment (\$ billion), from 2015	n.a.	419	250	-169
Cumulative fuel cost (\$ billion), from 2015	n.a.	2 164	2 491	327

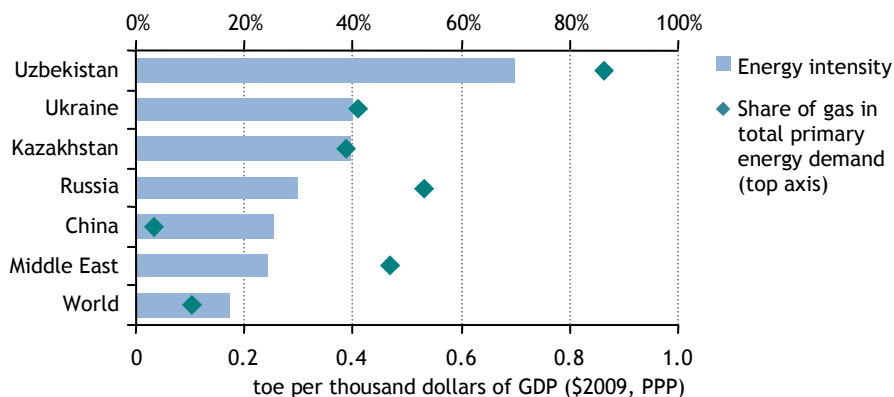
Note: NPS is New Policies Scenario. All of the coal-fired capacity that is built in 2015 to 2035 in the New Policies Scenario is replaced by gas-fired CCGT power plants in the HILP event case.

More efficient gas use in Eastern Europe and Central Asia

The scope for more efficient consumption of natural gas globally remains large but the opportunities for savings are not distributed evenly around the world. A large part of the efficiency potential lies in the former Soviet Union countries that make up the Eastern Europe and Central Asia region. A concerted effort to realise this potential would have major implications for the global gas balance.

The largest gas consumers in Eastern Europe and Central Asia are Russia, Ukraine, Uzbekistan and Kazakhstan. Although these countries together represent only 3.5% of the global population, they account for almost 20% of global gas demand. In 2008, they consumed collectively more gas than the whole of OECD Europe and nearly five times as much gas as China and India combined. They are also among the most energy-intensive economies in the world, *i.e.* they consume large amounts of energy per dollar of GDP (Figure 4.7). This is partly explained by climatic factors that boost heating needs. But it is also because of the inefficient industrial and municipal infrastructure inherited from the Soviet era and the slow pace of efforts since 1991 to tackle these inefficiencies. This includes the persistence of heavy subsidies on fuel prices, which undermine the financial attractiveness of spending on and investing in more efficient equipment and appliances.

Figure 4.7 ▶ Energy intensity and share of gas in total primary energy demand in selected countries and regions, 2008



In 2010, both Russia and Ukraine approved new programmes that include specific medium-term targets for energy saving (Government of Russia, 2010; Government of Ukraine, 2010). There are also signs in Uzbekistan and Kazakhstan that energy efficiency is becoming a higher policy priority. Kazakhstan, for example, is assessing what would be required to meet a national target to reduce energy intensity by 25% by 2020. Each of these countries has strong reasons to realise their energy-saving potential. Greater efficiency represents a cheap source of incremental energy “supply”,⁵ freeing up resources either for export or – notably in the case of Ukraine – as a means to reduce dependence on imports. To a greater or lesser extent, this potential has been recognised and integrated into national policy objectives. In Russia, for example, the technical potential for energy saving has been estimated at more than 40% of total primary energy supply, or around 300 Mtoe, based on 2007 energy use (Government of Russia, 2010). This provides the basis for the official target to improve the energy intensity of the national economy by 40% between 2007 and 2020.

If there is a strong economic case for making these energy savings, why then are they not happening? There is some evidence of efficiency improvements in recent years, as the private sector undertakes profitable investments in new industrial processes and in upgrading the capital stock. But the pace of this change is still relatively slow. From 2000 to 2008, the overall energy intensity of the Russian economy improved by around 5% per year, yet efficiency gains accounted for only one-fifth of this improvement, with the rest coming from structural changes in the economy, *i.e.* a shift in the economic structure away from energy-intensive products and processes. Numerous barriers to greater efficiency still remain across the four countries examined here. These include:

- weak price signals because of low, subsidised energy prices;
- incomplete information, whereby households and companies are either unaware of the potential gains or underestimate their value;
- poorly performing capital markets that may not be geared to lend to energy efficiency projects;

⁵ It has been estimated that every additional \$1 invested in energy efficiency may avoid \$2 to \$3 in investment in future gas supply (McKinsey & Co, 2009; World Bank, 2010).

- difficulties with gaining access to energy-efficient technology; and
- inadequate policy mechanisms and inducements.

The existence of these barriers to improved energy efficiency means that the potential for gas saving is not assumed to be exploited to any great degree in the projections for gas consumption in the New Policies Scenario. Total primary gas demand in Russia, Ukraine, Uzbekistan and Kazakhstan together is projected to rise to over 660 bcm in 2020 and 720 bcm in 2035, reflecting only a marginal improvement in energy efficiency compared to today.

HILP event analysis: More efficient gas use in Eastern Europe/Central Asia

In this case, Russia, Ukraine, Uzbekistan and Kazakhstan are all assumed to adopt and fully achieve ambitious targets for natural gas savings, as follows:

- In Russia, the gas savings target included in the new programme for energy saving and increased energy efficiency to 2020 is assumed to be fully met, *i.e.* the additional savings necessary to meet the targeted 40% decrease in overall energy intensity to 2020 are achieved.
- In Ukraine, it is assumed that, by 2016, 15 bcm of imported gas is displaced by other fuels and that the efficiency of gas consumption is improved by 20% (the rate of efficiency improvement thereafter to 2020 is assumed to be 1% per year).
- In Kazakhstan and Uzbekistan, it is assumed that savings equal to 20% of 2010 consumption are achieved by 2020.
- After 2020, all four countries are assumed to consolidate these efficiency gains through to 2035.

The result is that total gas consumption in 2035 declines by 105 bcm (15%) in these countries (collectively) compared with the New Policies Scenario (Table 4.4). The cumulative volume of gas saved relative to the New Policies Scenario is about 600 bcm over the period 2011 to 2020, an amount larger than a full year's consumption of gas in OECD Europe. The cumulative gas savings from 2011 to 2035 surpass 2 tcm, equal to the estimated gas reserves at the giant Kovykta gas field in Eastern Siberia.

The four countries highlighted here are not alone in having the scope to achieve material gains in energy efficiency, but they are among the countries with the greatest potential for gas saving. Moreover, these efficiencies would by no means exhaust their technical potential for additional gas savings.

Table 4.4 ▶ The impact of more efficient gas use in Eastern Europe/Central Asia

	2008	NPS (2035)	HILP (2035)	Change
Total natural gas consumption (bcm)	610	719	614	-105
Total natural gas CO ₂ emissions (Mt)	1 106	1 304	1 113	-191

Note: NPS is New Policies Scenario. See text above for details of the assumptions in the *HILP* event case.

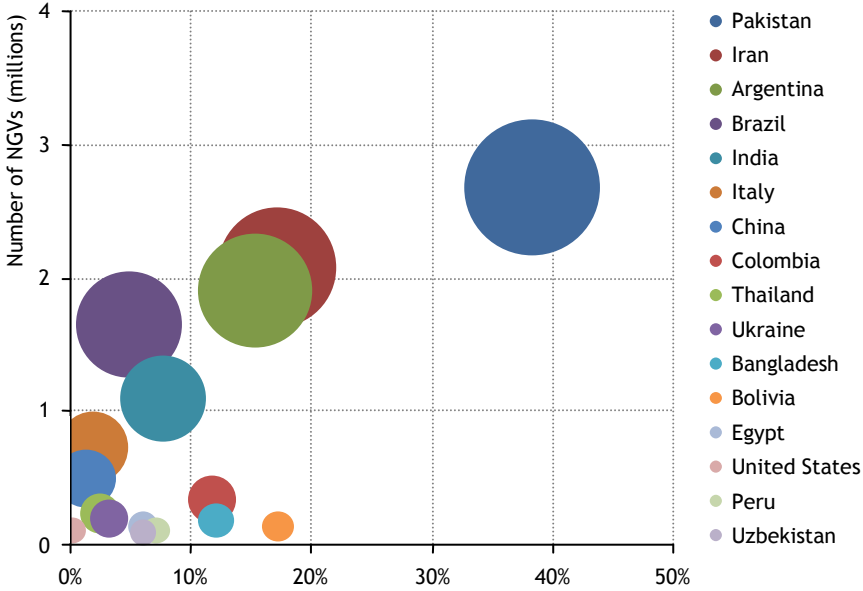
Increased use of natural gas vehicles

Natural gas vehicles (NGVs) presently account for less than 1% of total world road-fuel consumption and less than 1% of total world gas demand. More than 70% of all NGVs and – one-half of all fuelling stations can be found in just five countries: Pakistan, Iran, Argentina, Brazil and India. The technology is long established: it is most commonly used as CNG, but it can also be used in a liquid state as LNG. It can be used across the road transport spectrum, from two-wheelers and cars to buses and trucks. Despite strong growth in the number of NGVs on the road in recent years they remain a niche market in global terms, with an estimated 12 million vehicles in use (Figure 4.8).

NGVs offer several benefits, typically including fuel-cost savings, reduced greenhouse-gas emissions and local air-quality improvements, noise reduction and, in some cases, improved energy security. Specific benefits, and their value, depend on the national or local circumstances. There are important barriers limiting the growth of NGVs, of which the lack of refuelling infrastructure is probably the most significant. To put this in perspective, there are around 17 000 fuelling stations for NGVs worldwide, but more than 100 000 gasoline stations in the United States alone (US DOE, 2010). While the relatively small existing NGV market discourages investment in refuelling infrastructure, the lack of refuelling stations discourages NGV uptake, a classic chicken-and-egg problem. Another barrier is the higher purchase price or conversion costs of NGVs relative to conventional vehicles (even though this is typically compensated for over a relatively short period by lower fuel costs). And the on-board fuel tank is bigger and has less capacity than for gasoline or diesel, requiring more frequent refuelling. Some manufacturers seek to overcome this problem by offering bi-fuel vehicles that run on natural gas and gasoline or diesel, but this reduces the cost and emission benefits. With transport, as with other energy sectors, it is uncertain whether natural gas might form part of an interim solution en route to low-carbon technologies – driven by emissions standards – or be a permanent part of the transport fuel mix.

The uptake of NGVs is expected to remain limited unless there is a significant increase in the availability of refuelling infrastructure. In geographic terms, the most likely source of demand growth is within established markets, notably in non-OECD Asia and Latin America. In North America, where abundant supplies of unconventional gas are expected to hold gas prices down in the coming years, natural gas is seen as a potentially viable alternative to gasoline and diesel. In the United States, the New Alternative Transportation to Give Americans Solutions (NAT GAS Act), currently under debate in Congress, would provide incentives for passenger cars and trucks to run on natural gas as well as for home refuelling stations. In addition, the federal government is discussing a plan for newly purchased federal government vehicles to run on alternative fuels, starting in 2015. This could help build the market for NGVs. More stringent emissions standards could also encourage faster deployment of NGVs, as could adoption by some cities or regions that are seeking to improve local air quality. However, in such cases NGVs are in competition with other technologies, such as electric and hybrid cars, and local circumstances will determine whether they offer an advantage (see Section 3). The scope for deployment of NGVs is greatest for commercial, freight and public vehicle fleets, since provision of the necessary refuelling infrastructure can be more easily accommodated for fleets such as urban buses. Furthermore, the higher usage of fleet vehicles improves the economics of ownership of an NGV, provided that a pricing differential exists between gas and gasoline or diesel.

Figure 4.8 ▶ Largest natural gas vehicle markets and estimated market share, 2009*



* Size of bubble represents number of NGVs.

Sources: IEA databases; NGVA Europe (2010); BRTA (2011); and the World Bank databases.

In the *WEO-2010* New Policies Scenario, the global stock of NGVs increases from around 12 million to 31 million in 2035, with annual vehicle sales reaching just under 3 million. Natural gas use for road transport triples to over 60 bcm by 2035. The amount of oil saved as a result increases from about 300 thousand barrels per day in 2008 to just over 1 million barrels per day (mb/d) in 2035. Most of the increase in oil savings comes from non-OECD countries, but North America, where wholesale gas prices are lowest, also makes a contribution. However, in 2035 NGVs are still projected to represent only around 1.7% of the global vehicle fleet and 1.3% of overall global gas demand. In comparison, the GAS Scenario assumes that governments in some countries act to encourage the introduction of greater numbers of NGVs, and that lower wholesale gas prices than in the New Policies Scenario serve to increase their competitiveness, resulting in around 70 million NGVs in 2035.

Box 4.1 ► Experience of natural gas vehicle penetration in selected markets

In the early 1990s, the government of *Pakistan* recognised the benefits of domestic gas supplies in displacing imported oil in road transport. Today Pakistan is the largest market for NGVs in the world, with over 2.5 million vehicles. While keeping CNG prices deregulated, the government consistently placed emphasis on CNG as a substitute road fuel and introduced a number of supportive policies. These included a liberal licensing policy for CNG refuelling infrastructure, simplified procedures to support private investment, and tax and duty exemptions for equipment import and sale. Meanwhile, Pakistan's gas distribution pipeline network grew substantially. While the availability of financing for refuelling infrastructure may constrain faster growth, a domestic NGV industry has developed and there are plans to replace more diesel vehicles by NGVs.

In *Brazil*, NGVs represent almost 5% of the total vehicle stock, 4% of road fuel consumption and 10% of natural gas demand (IEA, 2010d). Market growth has been attributed to a combination of relatively low gas prices, a lower tax on the ownership of NGVs and government loans for taxi conversion kits. In contrast with some other markets, most NGV refuelling is integrated with other refuelling stations. However, the government's commitment to sugar-cane biofuels means that, notwithstanding increasing domestic gas output, future growth of the NGV market in Brazil is uncertain.

Regulatory changes have been central to NGV development in *India*. Markets have been nurtured at the city level, for example through policies linking NGV programmes to improving public transport. In Delhi, with its nearly 300 000 NGVs, the adoption of a mandate to convert all public transport buses to CNG was the key to success. This stimulated the build up of the initial infrastructure, which had spill-over benefits in terms of supporting an increasing shift of passenger vehicles to CNG (especially taxis). Studies have shown the conversion of buses from diesel to CNG in Delhi has helped significantly to reduce concentrations of pollutants such as sulphur dioxide (SO₂), particulates (PM₁₀) and carbon monoxide (CO) (Narain and Krupnick, 2007).

In *Argentina*, the policy of maintaining CNG prices lower than gasoline has been the largest factor driving market adoption (Collantes and Melaina, 2011). The government's role in promoting investment in refuelling infrastructure was limited to a small number of prominent early cases. Instead the focus has been on developing codes and standards to send clear signals of commitment to CNG, resulting in a market penetration of more than 15% of all vehicles in 2010.

By 1985, NGVs had more than 10% of the market share in *New Zealand*. This was a result of government incentives, loan programmes and targets to promote their adoption. However, after a new government rescinded favourable CNG loan conditions, the NGV market quickly declined and essentially disappeared (Yeh, 2007).

HILP event analysis: Increased use of natural gas vehicles

For this analysis, we assume that NGVs account for 10% of total vehicle sales worldwide by 2035, up from only 1.1% today and 1.9% in 2035 in the New Policies Scenario. This would equate to an increase in NGV vehicle sales from an estimated 1.3 million in 2008 to around 17 million in 2035 (Table 4.5). As a result, the global stock of all NGVs would reach around 186 million vehicles in 2035, up from 31 million in the New Policies Scenario.

The change in NGV penetration has a significant impact on fossil-fuel demand and a lesser impact on emissions. Demand for natural gas increases by around 320 bcm in 2035, compared with the New Policies Scenario, and oil demand decreases by 5.7 mb/d, more than 12% of global oil demand in the road-transport sector in 2035. As a result, CO₂ emissions from that sector would drop by 165 Mt in 2035.

Some studies, such as scenarios produced by the International Gas Union, see higher oil prices as the main driver of a 100 million-plus NGV market by 2035, with most growth occurring in the Non-OECD Asia region (IGU, 2009). The potential opportunity for gas in the road transport sector is large, but uptake so far is weak in all but a handful of countries due to a lack of a supporting regulatory framework (Box 4.1), albeit not solely. In addition, competing technologies, such as plug-in hybrid electric vehicles and electric vehicles, mean that the future of NGVs remains uncertain.

Table 4.5 ▶ The impact of scaling up natural gas vehicles

	2008	NPS (2035)	HILP (2035)	Change
Sales of NGVs (million)	1.3	3	17	14
Stock of NGVs (million)	12	31	186	155
Share of NGVs in total vehicle sales	1.1%	2%	10%	n.a.
Total road natural gas demand (bcm)	18	60	381	320
Total road oil demand (mb/d)	35	45	40	-5.7
Total road CO ₂ emissions (Mt)	4 849	6 444	6 279	-165

Note: NPS is New Policies Scenario. *HILP* event case assumes that NGV sales reach 10% of the total vehicle sales worldwide by 2035, up from only 1.1% today and 1.9% in 2035 in the New Policies Scenario.

Delayed carbon capture and storage

While the technology exists to capture CO₂ emissions, and to transport and permanently store the gas in geological formations, it has yet to be deployed on a large scale in the power and industrial sectors and costs remain uncertain. Critical to the deployment of CCS is the experience to be gained from the operation of large-scale demonstration projects. This demonstration phase is likely to last for over a decade. At the end of 2010, a total of 234 active or planned CCS projects have been identified across a range of technologies, project types and sectors, but only eight projects are currently operating (GCCSI, 2011a). The challenges to successful full-scale demonstration and commercial deployment include (IEA, 2009b):

- cost (typically around \$1 billion) and financing of large-scale demonstration projects and integration of CCS into greenhouse-gas policies;
- higher cost and lower efficiency of CCS technology relative to similar coal-fired power plants without CCS;
- development and financing of adequate CO₂ transport infrastructure; and
- development of legal and regulatory frameworks to ensure safe and permanent CO₂ storage.

The unproven nature of CCS technology for power generation means that many of the data on costs are based on feasibility studies and pilot projects (IEA, 2011a). At present, it is estimated that incorporating CCS into a power plant increases the levelised cost of electricity production by between 37% and 76%, depending on the technology and fuel source (GCCSI, 2011b). As well as deploying CCS in power generation, another important challenge is to make it available as a cost-effective technology in the industry sector.

CCS raises many legal, regulatory and economic issues that must be resolved before it can be widely deployed. Several initiatives have been taken by the IEA and other bodies, such as the Global CCS Institute and the Carbon Sequestration Leadership Forum, to develop the policy and regulatory framework to enable commercial deployment of CCS on a large scale, but much remains to be done.

CCS technology is deployed on a limited scale in the New Policies Scenario, with its share of total power generation rising from zero today to 1.5% in 2035. Most of the projected generation from power plants fitted with CCS equipment is in OECD countries. It is driven by government initiatives to build demonstration facilities that prove the technology as a large-scale CO₂ mitigation option. By 2035, 55 GW of CCS coal plants (roughly equivalent to 40 to 80 full-sized plants) and 24 GW of CCS gas plants (roughly equivalent to 25 to 50 full-sized plants) are commissioned. Coal-based CCS capacity is in place primarily in the United States, China and Europe. Gas-based CCS is located mainly in Europe, the Middle East, the United States, China and Russia. The New Policies Scenario does not assume any operational CCS in the industry sector during the *Outlook* period. Stronger CO₂ price signals than those in the New Policies Scenario or faster cost reductions would be needed to stimulate wider adoption of CCS technology.

HILP event analysis: Delayed carbon capture and storage

In this case, we make the pessimistic assumption that CCS technology does not progress beyond the early demonstration phase for either coal or gas within the *Outlook* period. We assume that the CCS-fitted power-generation capacity in the New Policies Scenario (both coal- and gas-fired) is replaced entirely with CCGT plants. This is a simplified assumption; in practice, of course, one would expect the capacity to be redistributed across a broader range of technologies, but it is likely that gas-fired capacity would benefit most.

As a result, demand for natural gas increases by 65 bcm compared with the New Policies Scenario (Table 4.6). Coal use drops by around 80 Mtoe in 2035, equivalent to over 70% of primary demand in Japan in 2008, but only a very small fraction of global demand. The absence of CCS leads to an increase in CO₂ emissions of over 140 Mt in 2035 – equivalent to the annual emissions of around 65 million cars in Europe today – and a cumulative increase occurs of around 1 Gt of CO₂ emissions over the *Outlook* period. The total investment required over the Outlook period is reduced by \$130 billion, but fuel costs increase – due to switching from coal to more expensive gas – by a similar amount. This analysis demonstrates that increased use of gas, while bringing some environmental benefits in some circumstances, can also work against climate goals when weighed against low- or zero-emission alternatives. In a scenario consistent with keeping the global average temperature increase below 2°C, CCS technology would need to be deployed on a much larger scale than considered here, reaching several hundred GW of gas- and coal-fired capacity by 2035 and, if CCS was not available before that time, the scenario might well become unachievable.

Table 4.6 ► The global impact of delayed carbon capture and storage in power generation

	NPS (2035)	HILP (2035)	Change
Coal power demand (Mtoe)	2 531	2 450	-81
Natural gas power demand (bcm)	1 858	1 924	65
Electricity-generation capacity with CCS (GW)	79	0	-79
CO ₂ emission from power (Mt)	13 756	13 898	142
Cumulative investment (\$ billion), from 2010	9 634	9 505	-129

Note: NPS is New Policies Scenario. *HILP* event case assumes that CCS technology is not deployed commercially at all before 2035, and that the power generation capacity that is associated with CCS in the New Policies Scenario is replaced entirely with CCGT plants.

Units and conversion factors

This annex provides general information on units and conversion factors. Further details may be found at www.worldenergyoutlook.org/docs/weo2010/World_Energy_Model.pdf.

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
	gCO ₂ /km	grammes of carbon dioxide per kilometre
Energy	gCO ₂ /kWh	grammes of carbon dioxide per kilowatt-hour
	toe	tonne of oil equivalent
	Mtoe	million tonnes of oil equivalent
	Mt LNG	million tonnes of liquefied natural gas
	MBtu	million British thermal units
	MJ	megajoule (1 joule x 10 ⁶)
	GJ	gigajoule (1 joule x 10 ⁹)
	TJ	terajoule (1 joule x 10 ¹²)
	EJ	exajoule (1 joule x 10 ¹⁸)
	kWh	kilowatt-hour
	MWh	megawatt-hour
	GWh	gigawatt-hour
	TWh	terawatt-hour
Gas	cm	cubic metres
	mcm	million cubic metres
	bcm	billion cubic metres
	tcm	trillion cubic metres
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)
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
	mpg	miles per gallon

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)
	GWth	gigawatt thermal (1 Watt x 10 ⁹)
	TW	terawatt (1 Watt x 10 ¹²)

General conversion factors for energy

	bcm	Mt LNG	TJ	GWh	MBtu	GCal	Mtoe
1 bcm =	1	0.7350	4.000 x 10 ⁴	11.11 x 10 ³	3.79 x 10 ⁷	9.552 x 10 ⁶	0.9554
1 Mt LNG =	1.360	1	54 400	15 110	5.16 x 10 ⁷	1.299 x 10 ⁷	1.299
1 TJ =	2.5 x 10 ⁻⁵	1.838 x 10 ⁻⁵	1	0.2778	947.8	238.8	2.388 x 10 ⁻⁵
1 GWh =	9.0 x 10 ⁻⁵	6.615 x 10 ⁻⁵	3.6	1	3412	860	8.6 x 10 ⁻⁵
1 MBtu =	2.638 x 10 ⁻⁸	1.939 x 10 ⁻⁸	1.0551 x 10 ⁻³	2.931 x 10 ⁻⁴	1	0.252	2.52 x 10 ⁻⁸
1 GCal =	1.047 x 10 ⁻⁷	7.698 x 10 ⁻⁸	4.1868 x 10 ⁻³	1.163 x 10 ⁻³	3.968	1	1 x 10 ⁻⁷
1 Mtoe =	1.047	0.7693	4.1868 x 10 ⁴	11 630	3.968 x 10 ⁷	1.00 x 10 ⁷	1

Other notes

- Gas volumes are measured at a temperature of 15°C and a pressure of 101.325 kilopascals.
- The Gross Calorific Value (GCV) of gas is defined as 40.0 MJ/cm for conversion purposes in the table above.
- The global average GCV varies with the mix of production over time, in 2009 it was 38.4 MJ/cm.

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PRINTED IN FRANCE BY SOREGRAPH, June 2011

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