# World Energy Outlook

2009

International Energy Agency

# *World Energy Outlook* 2009

Since *WEO-2008*, the economic downturn has led to a drop in energy use, $CO_2$ emissions and energy investment. Is this an opportunity to arrest climate change or a threat that any economic upturn might be stifled at birth?

What package of commitments and measures should the climate negotiators at the UN Climate Change Conference (COP 15) in Copenhagen put together if they really want to stop global temperatures rising? How much would it cost? And how much might the developed world have to pay to finance action elsewhere?

How big is the gas resource base and what is the typical pattern of production from a gas field? What does the unconventional gas boom in the United States mean for the rest of the world? Are we headed for a global gas glut? What role will gas play in the future energy mix? And how might the way gas is priced change?

All these questions and many others are answered in *WEO-2009*. The data are extensive, the projections more detailed than ever and the analyses compelling.

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# INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme.

It carries out a comprehensive programme of energy co-operation among twenty-eight of the thirty OECD member countries. The basic aims of the IEA are:

- To maintain and improve systems for coping with oil supply disruptions.
- To promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations.
- To operate a permanent information system on international oil markets.
- To provide data on other aspects of international energy markets.
- To improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use.
- To promote international collaboration on energy technology.
- To assist in the integration of environmental and energy policies, including relating to climate change.

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

## ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

The OECD is a unique forum where the governments of thirty democracies work together to address the economic, social and environmental challenges of globalisation. The OECD is also at the forefront of efforts to understand and to help governments respond to new developments and concerns, such as corporate governance, the information economy and the challenges of an ageing population. The Organisation provides a setting where governments can compare policy experiences, seek answers to common problems, identify good practice and work to co-ordinate domestic and international policies.



**International Energy Agency (IEA)**
9 rue de la Fédération, 75739 Paris Cedex 15, France

The Executive Director of the International Energy Agency (IEA) is not a climate negotiator. It is for national and regional governments, not international secretariats, to decide how far nations need to go in curbing greenhouse-gas emissions and what commitments they are prepared to make to attain the goal. The answer to that will emerge at the 15th Conference of the Parties (COP 15) to the United Nations Framework Convention on Climate Change (UNFCCC) in December 2009 in Copenhagen.

But negotiators need hard, quantified information. And the IEA is well placed to provide that. In detail, sector by sector and region by region, the *World Energy Outlook 2009* (*WEO-2009)* lays out the commitments and measures in the energy sector that could underpin a just international agreement on climate change.

My chief economist, Fatih Birol, has again directed the team responsible for this analysis. Their work details the components of an ambitious, but realisable, package. The full *WEO-2009* is published only one month before the climax of the UNFCCC negotiations, but the key results on the issue of climate change have been made available in advance.

*WEO-2009* has many other riches. As the world struggles to emerge from the financial crisis, it quantifies the impact of the crisis on energy investment and shows what the implications could be, once the global economy recovers. In one sense, the sudden halt to new investment is an important opportunity: the new investment, when it comes, can make the most of the best available technologies, guided by any evidence from Copenhagen that the international community is serious about climate change. But in another sense, it is a threat: under-investment, if prolonged, could constrain energy supply, pushing up the price of energy and even stifling the economic recovery.

In the short term, far from being short of supply, we could be heading for a glut in natural gas supply. The economic slowdown has slashed demand for gas, but investment in the gas-supply infrastructure is long term in nature and, once committed, tends to be carried through. Coupled with a boom in supplies in the United States from unconventional sources, this situation has transformed the gas market. Gas demand is set to rebound, as the global economy recovers and as governments act to drive power generators away from use of the most polluting fossil fuels. But it could then stutter again, as growth in demand for electricity slows down under pressure from action on climate change, and even gas finds it has to give way to renewables and nuclear power in power generation. On the supply side, gas resources are ample: this year's study of their extent and of patterns in gas production is comparable in depth to the study of oil resources in *WEO-2008*.

Collective action to tackle climate change calls for the wholesale transformation of the global energy system. We show here that limiting the global average temperature increase to 2°Celsius, which a growing number of world leaders now accept as the ultimate goal, would require fossil-energy consumption to peak by around 2020 and then decline.

Consistent with past practice, we also offer in this year's *WEO* an expanded survey of energy production and use in a particular region of the world, this time Southeast Asia. This region has growing influence in the global energy market.

Enthusiastic support and financial backing from IEA member countries, as well as from others who rely on *WEO*, make it possible to provide analysis of the quality and scope found here. I am confident that our supporters are getting good value for their money and that our global readership will again derive significant benefit from the insights offered from this volume.

**Nobuo Tanaka**
**Executive Director**

*This publication has been produced under the authority of the Executive Director of the International Energy Agency. The views expressed do not necessarily reflect the views or policies of individual IEA member countries.*

This study was prepared by the Office of the Chief Economist (OCE) of the International Energy Agency (IEA) in co-operation with other offices of the Agency. The study was designed and directed by **Fatih Birol**, Chief Economist of the IEA. **Laura Cozzi** co-ordinated the analysis of climate policy scenarios; **Trevor Morgan** co-ordinated the analysis of natural gas prospects; **Amos Bromhead** co-ordinated the analysis of Southeast Asia; **Marco Baroni** and **Pawel Olejarnik** led the modelling work. **Maria Argiri**, **Raffaella Centurelli**, **Michael-Xiaobao Chen**, **John Corben**, **Tim Gould**, **Timur Gül**, **Paul Dowling**, **Bertrand Magné**, **Chris Mullin**, **Uğur Öcal**, **Sho Siam Poh**, **Olivier Rech**, **Shigeaki Shiraishi**, **David Wilkinson**, **Akira Yanagisawa** and **Tatiana Zhitenko** also authored different chapters of the book and were instrumental in delivering the study. **Sandra Mooney** provided essential support. For more information on the members of the OCE and their contribution to the *WEO*, please visit www.worldenergyoutlook.org.

**Robert Priddle** carried editorial responsibility.

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# EXECUTIVE SUMMARY

**The past 12 months have seen enormous upheavals in energy markets around the world, yet the challenges of transforming the global energy system remain urgent and daunting.** The global financial crisis and ensuing recession have had a dramatic impact on the outlook for energy markets, particularly in the next few years. World energy demand in aggregate has already plunged with the economic contraction; how quickly it rebounds depends largely on how quickly the global economy recovers. Countries have responded to the threat of economic melt-down as a result of the financial crisis with prompt and co-ordinated fiscal and monetary stimuli on an unprecedented scale. In many cases, stimulus packages have included measures to promote clean energy with the aim of tackling an even bigger, and just as real, long-term threat — that of disastrous climate change.

**How we rise to that challenge will have far-reaching consequences for energy markets.** As the leading source of greenhouse-gas emissions, energy is at the heart of the problem and so must be integral to the solution. The time to act has arrived: the 15$^{th}$ Conference of the Parties (COP) to the United Nations Framework Convention on Climate Change (UNFCCC) in Copenhagen (December 2009) presents a decisive opportunity to negotiate a successor treaty to the Kyoto Protocol — one that puts the world onto a truly sustainable energy path. The *World Energy Outlook 2009* (WEO-2009) quantifies the challenge and shows what is required to overcome it.

**The scale and breadth of the energy challenge is enormous — far greater than many people realise. But it can and must be met.** The recession, by curbing the growth in greenhouse-gas emissions, has made the task of transforming the energy sector easier by giving us an unprecedented, yet relatively narrow, window of opportunity to take action to concentrate investment on low-carbon technology. Energy-related carbon-dioxide ($CO_2$) emissions in 2009 will be well below what they would have been had the recession not occurred. But this saving will count for nothing if a robust deal is not reached in Copenhagen — and emissions resume their upward path.

**Households and businesses are largely responsible for making the required investments, but governments hold the key to changing the mix of energy investment.** The policy and regulatory frameworks established at national and international levels will determine whether investment and consumption decisions are steered towards low-carbon options. Accordingly, this *Outlook* presents the results of two scenarios: a *Reference Scenario*, which provides a baseline picture of how global energy markets would evolve if governments make no changes to their existing policies and measures; and a *450 Scenario*, which depicts a world in which collective policy action is taken to limit the long-term concentration of greenhouse gases in the atmosphere to 450 parts per million of $CO_2$-equivalent (ppm $CO_2$-eq), an objective that is gaining widespread support around the world.

## The financial crisis brings a temporary reprieve from rising fossil-energy use

**Global energy use is set to fall in 2009 – for the first time since 1981 on any significant scale – as a result of the financial and economic crisis; but, on current policies, it would quickly resume its long-term upward trend once economic recovery is underway.** In our Reference Scenario, world primary energy demand is projected to increase by 1.5% per year between 2007 and 2030, from just over 12 000 million tonnes of oil equivalent (Mtoe) to 16 800 Mtoe – an overall increase of 40%. Developing Asian countries are the main drivers of this growth, followed by the Middle East. Projected demand growth is slower than in *WEO-2008*, reflecting mainly the impact of the crisis in the early part of the projection period, as well as of new government policies introduced during the past year. On average, demand declines marginally in 2007-2010, as a result of a sharp drop in 2009 – preliminary data point to a fall in that year of up to 2%. Demand growth rebounds thereafter, averaging 2.5% per year in 2010-2015. The pace of demand growth slackens progressively after 2015, as emerging economies mature and global population growth slows.

**Fossil fuels remain the dominant sources of primary energy worldwide in the Reference Scenario, accounting for more than three-quarters of the overall increase in energy use between 2007 and 2030.** In absolute terms, coal sees by far the biggest increase in demand over the projection period, followed by gas and oil. Yet oil remains the single largest fuel in the primary fuel mix in 2030, even though its share drops, from 34% now to 30%. Oil demand (excluding biofuels) is projected to grow by 1% per year on average over the projection period, from 85 million barrels per day in 2008 to 105 mb/d in 2030. All the growth comes from non-OECD countries: OECD demand actually falls. The transport sector accounts for 97% of the increase in oil use. As conventional oil production in countries not belonging to the Organization of the Petroleum Exporting Countries (OPEC) peaks around 2010, most of the increase in output would need to come from OPEC countries, which hold the bulk of remaining recoverable conventional oil resources.

**The main driver of demand for coal and gas is the inexorable growth in energy needs for power generation.** World electricity demand is projected to grow at an annual rate of 2.5% to 2030. Over 80% of the growth takes place in non-OECD countries. Globally, additions to power-generation capacity total 4 800 gigawatts (GW) by 2030 – almost five times the existing capacity of the United States. The largest additions (around 28% of the total) occur in China. Coal remains the backbone fuel of the power sector, its share of the global generation mix rising by three percentage points to 44% in 2030. Nuclear power output grows in all major regions bar Europe, but its share in total generation falls.

**The use of non-hydro modern renewable energy technologies (including wind, solar, geothermal, tide and wave energy, and bio-energy) sees the fastest rate of increase in the Reference Scenario.** Most of the increase is in power generation: the share of non-hydro renewables in total power output rises from 2.5% in 2007 to 8.6% in 2030, with wind power seeing the biggest absolute increase. The consumption of biofuels for transport also rises strongly. The share of hydropower, by contrast, drops from 16% to 14%.

## Falling energy investment will have far-reaching consequences

**Energy investment worldwide has plunged over the past year in the face of a tougher financing environment, weakening final demand for energy and lower cash flow.** All these factors stem from the financial and economic crisis. Energy companies are drilling fewer oil and gas wells, and cutting back spending on refineries, pipelines and power stations. Many ongoing projects have been slowed and a number of planned projects have been postponed or cancelled. Businesses and households are spending less on new, more efficient energy-using appliances, equipment and vehicles, with important knock-on effects for the efficiency of energy use in the long term.

**In the oil and gas sector, most companies have announced cutbacks in capital spending, as well as project delays and cancellations, mainly as a result of lower cash flow.** We estimate that global upstream oil and gas investment budgets for 2009 have been cut by around 19% compared with 2008 – a reduction of over $90 billion. Oil sands projects in Canada account for the bulk of the suspended oil capacity. Power-sector investment is also being severely affected by financing difficulties, as well as by weak demand, which is reducing the immediate need for new capacity additions. In late 2008 and early 2009, investment in renewables fell proportionately more than that in other types of generating capacity; for 2009 as a whole, it could drop by close to one-fifth. Without the stimulus provided by government fiscal packages, renewables investment would have fallen by almost 30%.

**Falling energy investment will have far-reaching and, depending on how governments respond, potentially serious consequences for energy security, climate change and energy poverty.** Any prolonged downturn in investment threatens to constrain capacity growth in the medium term, particularly for long lead-time projects, eventually risking a shortfall in supply. This could lead to a renewed surge in prices a few years down the line, when demand is likely to be recovering, and become a constraint on global economic growth. These concerns are most acute for oil and electricity supplies. Any such shortfalls could, in turn, undermine the sustainability of the economic recovery. Weaker fossil-fuel prices are also undermining the attractiveness of investments in clean energy technology (though recent government moves to encourage such investment, as part of their economic stimulus packages, are helping to counter this effect). Cutbacks in energy-infrastructure investments also threaten to impede access by poor households to electricity and other forms of modern energy.

**The financial crisis has cast a shadow over whether all the energy investment needed to meet growing energy needs can be mobilised.** The capital required to meet projected energy demand through to 2030 in the Reference Scenario is huge, amounting in cumulative terms to $26 trillion (in year-2008 dollars) – equal to $1.1 trillion (or 1.4% of global gross domestic product [GDP]) per year on average. The power sector requires 53% of total investment. Over half of all energy investment worldwide is needed in developing countries, where demand and production are projected to increase fastest. With little prospect of a quick return to the days of cheap and easy credit, financing energy investment will, in most cases, be more difficult and costly in the medium term than it was before the crisis took hold.

## *Current policies put us on an alarming fossil-energy path*

**Continuing on today's energy path, without any change in government policy, would mean rapidly increasing dependence on fossil fuels, with alarming consequences for climate change and energy security.** The Reference Scenario sees a continued rapid rise in energy-related $CO_2$ emissions through to 2030, resulting from increased global demand for fossil energy. Having already increased from 20.9 gigatonnes (Gt) in 1990 to 28.8 Gt in 2007, $CO_2$ emissions are projected to reach 34.5 Gt in 2020 and 40.2 Gt in 2030 – an average rate of growth of 1.5% per year over the full projection period. In 2020, global emissions are 1.9 Gt or 5% lower than in the Reference Scenario of *WEO-2008*. The economic crisis and resulting lower fossil-energy demand growth account for three-quarters of this improvement, while government stimulus spending to promote low-carbon investments and other new energy and climate policies account for the remainder. Preliminary data suggest that global energy-related emissions of $CO_2$ may *decline* in 2009 – possibly by around 3% – although they are expected to resume an upward trajectory from 2010.

**Non-OECD countries account for all of the projected growth in energy-related $CO_2$ emissions to 2030.** Three-quarters of the 11-Gt increase comes from China (where emissions rise by 6 Gt), India (2 Gt) and the Middle East (1 Gt). OECD emissions are projected to fall slightly, due to a slowdown in energy demand (resulting from the crisis in the near term and from big improvements in energy efficiency in the longer term) and the increased reliance on nuclear power and renewables, in large part due to the policies already adopted to mitigate climate change and enhance energy security. By contrast, all major non-OECD countries see their emissions rise. However, while non-OECD countries today account for 52% of the world's annual emissions of energy-related $CO_2$, they are responsible for only 42% of the world's cumulative emissions since 1890.

**These trends would lead to a rapid increase in the concentration of greenhouse gases in the atmosphere.** The rate of growth of fossil-energy consumption projected in the Reference Scenario takes us inexorably towards a long-term concentration of greenhouse gases in the atmosphere in excess of 1 000 ppm $CO_2$-eq. The $CO_2$ concentration implied by the Reference Scenario would result in the global average temperature rising by up to 6°C. This would lead almost certainly to massive climatic change and irreparable damage to the planet.

**The Reference Scenario trends also heighten concerns about the security of energy supplies.** While the OECD imports less oil in 2030 than today in the Reference Scenario, some non-OECD countries, notably China and India, see big increases in their imports. Most gas-importing regions, including Europe and developing Asia, also see their net imports rise. The Reference Scenario projections imply an increasingly high level of spending on energy imports, representing a major economic burden for importers. Oil prices are assumed to fall from the 2008 level of $97 per barrel to around $60 per barrel in 2009 (roughly the level of mid-2009), but then rebound with the economic recovery to reach $100 per barrel by 2020 and $115 per barrel by 2030 (in year-2008 dollars). As a result, OECD countries as a group are projected to spend on average close to 2% of their GDP on oil and gas imports to 2030. The burden is even higher in most importing non-OECD countries. On a country basis, China overtakes the United States soon after 2025 to become the world's biggest spender on oil and gas imports (in monetary terms) while India's spending on oil and gas imports surpasses that of Japan soon after 2020 to become the world's third-largest importer. The increasing concentration of the world's remaining conventional oil and gas reserves in a small group of countries, including Russia and resource-rich Middle East countries, would increase their market power and ability to influence prices.

**Expanding access to modern energy for the world's poor remains a pressing matter.** We estimate that 1.5 billion people still lack access to electricity – well over one-fifth of the world's population. Some 85% of those people live in rural areas, mainly in Sub-Saharan Africa and South Asia. In the Reference Scenario, the total number drops by only around 200 million by 2030, though the number actually increases in Africa. Expanding access to modern energy is a necessary condition for human development. With appropriate policies, universal electricity access could be achieved with additional annual investment worldwide of $35 billion (in year-2008 dollars) through to 2030, or just 6% of the power-sector investment projected in the Reference Scenario. The accompanying increase in primary energy demand and $CO_2$ emissions would be very modest.

## *Limiting temperature rise to 2°C requires a low-carbon energy revolution*

**Although opinion is mixed on what might be considered a sustainable, long-term level of annual $CO_2$ emissions for the energy sector, a consensus on the need to limit the global temperature increase to 2°C is emerging.** To limit to 50% the probability of a global average temperature increase in excess of 2°C, the concentration of greenhouse gases in the atmosphere would need to be stabilised at a level around 450 ppm $CO_2$-eq. We show how this objective can be achieved in the 450 Scenario, through radical and co-ordinated policy action across all regions. In this scenario, global energy-related $CO_2$ emissions peak at 30.9 Gt just before 2020 and decline thereafter to 26.4 Gt in 2030 – 2.4 Gt below the 2007 level and 13.8 Gt below that in the Reference Scenario. These reductions result from a plausible combination of policy instruments – notably carbon markets, sectoral agreements and national policies and measures – tailored to the circumstances of specific sectors and groups of countries. Only by taking advantage of mitigation potential in all sectors and regions can the necessary emission reductions be achieved. OECD+ countries (a group that includes the OECD and non-OECD EU countries) are assumed to take on national emission-reduction commitments from 2013. All other countries are assumed to adopt domestic policies and measures, and to generate and sell emissions credits. After 2020, commitments are extended to Other Major Economies – a group comprising China, Russia, Brazil, South Africa and the Middle East.

**The reductions in energy-related $CO_2$ emissions required in the 450 Scenario (relative to the Reference Scenario) by 2020 – just a decade away – are formidable, but the financial crisis offers what may be a unique opportunity to take the necessary steps as the political mood shifts.** At 30.7 Gt, emissions in 2020 in the

450 Scenario are 3.8 Gt lower than in the Reference Scenario. In non-OECD countries, national policies currently under consideration, along with sectoral approaches in transport and industry, yield 1.6 Gt of emission abatement. But this abatement will not happen in the absence of an appropriate international framework. The challenge for international negotiators is to find instruments that will give the right level of additional incentive to ensure that the necessary measures are implemented. With national policies, China alone accounts for 1 Gt of emissions reductions in the 450 Scenario, placing the country at the forefront of global efforts to combat climate change. The remaining reductions in 2020 are delivered by OECD+ countries through an emissions cap in the power and industry sectors, domestic policies, and by financing, through the carbon market, additional abatement in non-OECD countries. In 2020, the OECD+ carbon price reaches $50 per tonne of $CO_2$. The financial and economic crisis has temporarily slowed the lock-in of high-carbon energy technologies. With the prospect of demand picking up over the next few years, it is crucial to put in place an agreement providing clear economic signals to encourage the deployment of low-carbon technologies.

**With a new international climate policy agreement, a comprehensive and rapid transformation in the way we produce, transport and use energy — a veritable low-carbon revolution — could put the world onto this 450-ppm trajectory.** Energy needs to be used more efficiently and the carbon content of the energy we consume must be reduced, by switching to low- or zero-carbon sources. In the 450 Scenario, primary energy demand grows by 20% between 2007 and 2030. This corresponds to an average annual growth rate of 0.8%, compared with 1.5% in the Reference Scenario. Increased energy efficiency in buildings and industry reduces the demand for electricity and, to a lesser extent, fossil fuels. The average emissions intensity of new cars is reduced by more than half, cutting oil needs. The share of non-fossil fuels in the overall primary energy mix increases from 19% in 2007 to 32% in 2030, when $CO_2$ emissions per unit of GDP are less than half their 2007 level. Yet, with the exception of coal, demand for all fuels is higher in 2030 than in 2007, and fossil fuels remain the dominant energy sources in 2030.

## *Energy efficiency offers the biggest scope for cutting emissions*

**End-use efficiency is the largest contributor to $CO_2$ emissions abatement in 2030, accounting for more than half of total savings in the 450 Scenario, compared with the Reference Scenario.** Energy-efficiency investments in buildings, industry and transport usually have short pay-back periods and negative net abatement costs, as the fuel-cost savings over the lifetime of the capital stock often outweigh the additional capital cost of the efficiency measure, even when future savings are discounted. Decarbonisation of the power sector also plays a central role in reducing emissions. Power generation accounts for more than two-thirds of the savings in the 450 Scenario (of which 40% results from lower electricity demand). There is a big shift in the mix of fuels and technologies in power generation: coal-based generation is reduced by half, compared with the Reference Scenario in 2030, while nuclear power and renewables make much bigger contributions. The United States and China together contribute about half of the reduction in global power-sector emissions. Carbon capture and storage (CCS) in the power sector and in industry represents 10% of total emissions savings in 2030, relative to the Reference Scenario.

**Measures in the transport sector to improve fuel economy, expand biofuels and promote the uptake of new vehicle technologies — notably hybrid and electric vehicles — lead to a big reduction in oil demand.** By 2030, transport demand for oil is cut by 12 mb/d, equal to more than 70% of all the oil savings in the 450 Scenario. Road transport accounts for the vast majority of these transport-related oil savings. A dramatic shift in car sales occurs; by 2030, conventional internal combustion engines represent only about 40% of sales, down from more than 90% in the Reference Scenario, as hybrids take up 30% of sales and plug-in hybrids and electric vehicles account for the remainder. Efficiency improvements in new aircraft and the use of biofuels in aviation save 1.6 mb/d of oil demand by 2030.

## *New financing mechanisms will be critical to achieving low-carbon growth*

**The 450 Scenario entails $10.5 trillion *more* investment in energy infrastructure and energy-related capital stock globally than in the Reference Scenario through to the end of the projection period.** Around 45% of incremental investment needs, or $4.7 trillion, are in transport. Additional investment (which includes the purchase of energy-related equipment by households in this analysis) amounts to $2.5 trillion in buildings (including domestic and commercial equipment and appliances), $1.7 trillion in power plants, $1.1 trillion in industry and $0.4 trillion in biofuels production (mostly second-generation technologies, which become more widespread after 2020). More than three-quarters of the total additional investment, which is geographically distributed almost equally between OECD+ countries and the rest of the world, is needed in the 2020s. On an annual basis, global additional investment needs reach $430 billion (0.5% of GDP) in 2020 and $1.2 trillion (1.1% of GDP) in 2030. Most of this would need to be made by the private sector; households alone are responsible for around 40% of the additional investments in the 450 Scenario, with most of their extra expenditure directed towards low-carbon vehicle purchases. In the short term, the maintenance of government stimulus efforts is crucial to this investment.

**The cost of the additional investments needed to put the world onto a 450-ppm path is at least partly offset by economic, health and energy-security benefits.** Energy bills in transport, buildings and industry are reduced by $8.6 trillion globally over the period 2010-2030. Fuel-cost savings in the transport sector amount to $6.2 trillion over the projection period. Oil and gas imports, and their associated bills, in the OECD and developing Asia are much lower than in the Reference Scenario and are lower than in 2008 in OECD countries. Cumulative OPEC oil-export revenues in 2008-2030 are 16% less than in the Reference Scenario, but are still four times their level in real terms of the previous 23 years. Other implications include a big reduction in emissions of air pollutants, particularly in China and India, and in the cost of installing pollution-control equipment.

**It is widely agreed that developed countries must provide more financial support to developing countries in reducing their emissions; but the level of support, the mechanisms for providing it and the relative burden across countries are matters for negotiation.** There is a wide range of potential funding outcomes. In the 450 Scenario, $197 billion of additional investment is required in 2020 in non-OECD countries; what part of this is contributed by OECD+ is entirely a matter for negotiation. There are various channels through which funds can flow to developing countries. The international carbon market will undoubtedly play an important role. Depending on how the market is structured, primary trading of $CO_2$ emission reductions between OECD+ and other regions ranges between 0.5 Gt and 1.7 Gt in 2020. A central case sees a carbon price of around $30 per tonne of $CO_2$ and annual primary trading of around $40 billion. The current Clean Development Mechanism would need extensive reform to cope efficiently and robustly with a substantially increased level of activity. International funding pools are another important channel that could provide a means of increasing financial transfers to developing countries.

## Natural gas will play a key role whatever the policy landscape

**With the assumed resumption of global economic growth from 2010, demand for natural gas worldwide is set to resume its long-term upwards trend, though the *pace* of demand growth hinges critically on the strength of climate policy action.** Constraints on the rate at which low-carbon technologies can be deployed, and the low carbon content of gas relative to coal and oil, mean that gas demand will continue to expand, even in the 450 Scenario. In the Reference Scenario, global gas demand rises from 3.0 trillion cubic metres (tcm) in 2007 to 4.3 tcm in 2030 — an average rate of increase of 1.5% per year. The share of gas in the global primary energy mix increases marginally, from 20.9% in 2007 to 21.2% in 2030. Over 80% of the increase in gas use between 2007 and 2030 occurs in non-OECD countries, with the biggest rise occurring in the Middle East. India and China see the most rapid *rates* of increase. The power sector is expected to remain the largest driver of gas demand in all regions.

**The outlook to 2015 differs markedly from the longer-term picture.** Although only partial and preliminary data on gas demand are available for 2008 and early 2009, it is likely that, worldwide, primary gas demand will fall in 2009 — perhaps by as much as 3% — as a result of the economic contraction. On the assumption that the economy begins to recover by 2010, global demand is projected to rebound. On average, it grows by 2.5% per year between 2010 and 2015. Supply capacity is set to grow faster.

**In the 450 Scenario, world primary gas demand grows by 17% between 2007 and 2030, but is 17% lower in 2030 compared with the Reference Scenario.** Demand continues to grow in most non-OECD regions through to 2030, but some regions see a decline after 2020. Measures to encourage energy savings, by improving the efficiency of gas use and encouraging low-carbon technologies, reduce gas demand. This more than offsets the enhanced competitiveness of gas against coal and oil in power generation and end-use applications that results from higher carbon prices and regulatory instruments. Gas demand in OECD countries generally peaks by around the middle of the projection period in this scenario and then declines through to 2030, as generators switch investment mainly to renewables and nuclear power capacity. The United States sees higher gas use than in the Reference Scenario in the last decade of the *Outlook* period, largely because gas becomes more competitive against coal.

## Gas resources are huge but exploiting them will be challenging

**The world's remaining resources of natural gas are easily large enough to cover any conceivable rate of increase in demand through to 2030 and well beyond, though the cost of developing new resources is set to rise over the long term.** Proven gas reserves at the end of 2008 totalled more than 180 tcm globally – equal to about 60 years of production at current rates. Over half of these reserves are located in just three countries: Russia, Iran and Qatar. Estimated remaining recoverable gas resources are much larger. The long-term global recoverable gas resource base is estimated at more than 850 tcm (including only those categories of resource with currently demonstrated commercial production). Unconventional gas resources – mainly coalbed methane, tight gas (from low-permeability reservoirs) and shale gas – make up about 45% of this total. To date, only 66 tcm of gas has been produced (or flared).

**The non-OECD countries as a whole are projected to account for almost all of the projected increase in global natural gas production between 2007 and 2030.** The Middle East sees the biggest increase in output (and in exports) in absolute terms: that region holds the largest reserves and has the lowest production costs, especially when the gas is produced in association with oil. Iran and Qatar account for much of the growth in output. Africa, Central Asia (notably Turkmenistan), Latin America and Russia also see significant growth in production. Inter-regional gas trade is projected to grow substantially over the projection period, from 677 bcm in 2007 to around 1 070 bcm in 2030 in the Reference Scenario and just over 900 bcm in the 450 Scenario. OECD Europe and Asia-Pacific see their imports rise in volume terms in both scenarios.

**The rate of decline in production from existing gas fields is the prime factor determining the amount of new capacity and investment needed to meet projected demand.** A detailed, field-by-field analysis of the historical gas-production trends of nearly 600 fields (accounting for 55% of global production) indicates that close to half of the world's existing production capacity will need to be replaced by 2030 as a result of depletion. This is the equivalent of twice current Russian production. By then, only about one-third of total output comes from currently producing fields in the Reference Scenario, despite continuing investment in them. Decline rates for gas fields once they have passed their peak are lower for the largest fields and higher for offshore fields than for onshore fields of similar size. The observed average post-peak decline rate of the world's largest gas fields, weighted by production, is 5.3%. Based on these figures and estimates of the size and age distribution of gas fields worldwide, the global production-weighted decline rate is 7.5% for all fields beyond their peak – a similar rate to oilfields.

## *Unconventional gas changes the game in North America and elsewhere*

**The recent rapid development of unconventional gas resources in the United States and Canada, particularly in the last three years, has transformed the gas-market outlook, both in North America and in other parts of the world.** New technology, especially horizontal-well drilling combined with hydraulic fracturing, has increased productivity per well from unconventional sources — notably shale gas — and cut production costs. This supplement to supply, combined with weak demand following the economic crisis and higher than usual storage levels, has led to a steep drop in US gas prices from an average of almost $9 per million British thermal units (MBtu) in 2008 to below $3/MBtu in early September 2009, cutting liquefied natural gas (LNG) import needs and putting downward pressure on prices in other regions. The fall in North American prices has inevitably reduced drilling activity, but production has held up remarkably well, indicating that marginal production costs have fallen steeply. Our analysis shows that new unconventional sources of supply have the potential to increase overall North American production at a wellhead cost of between $3/MBtu and $5/MBtu (in year-2008 dollars and drilling and completion costs) for the coming several decades, though rising material costs and rig rates are expected to exert upward pressure on unit costs over time. The high decline rates of unconventional gas will also require constant drilling and completion of new wells to maintain output.

**The extent to which the boom in unconventional gas production in North America can be replicated in other parts of the world endowed with such resources remains highly uncertain.** Outside North America, unconventional resources have not yet been appraised in detail and gas production is still small. Some regions, including China, India, Australia and Europe, are thought to hold large resources, but there are major potential obstacles to their development in some cases. These include limitations on physical access to resources, the requirement for large volumes of water for completing wells, the environmental impact and the distance of resources from the existing pipeline infrastructure. In addition, the geological characteristics of resources that have not yet been appraised may present serious technical and economic challenges to their development. In the Reference Scenario, unconventional gas output worldwide rises from 367 bcm in 2007 to 629 bcm in 2030, with much of the increase coming from the United States and Canada. The share of unconventional gas in total US gas production rises from over 50% in 2008 to nearly 60% in 2030. In Asia-Pacific (outside Australia) and Europe, output is projected to take off in the second half of the projection period, though the share of unconventional gas in total production in those regions remains small. Globally, the share of unconventional gas rises from 12% in 2007 to 15% in 2030. This projection is subject to considerable uncertainty, especially after 2020; there is potential for output to increase much more.

## *A glut of gas is looming*

**The unexpected boom in North American unconventional gas production, together with the current recession's depressive impact on demand, is expected to contribute to an acute glut of gas supply in the next few years.** Our analysis of trends in gas demand and capacity, based on a bottom-up assessment of ongoing investment and capacity additions from upstream, pipeline and LNG projects, points to a big increase in spare inter-regional gas transportation capacity. We estimate that the under-utilisation of pipeline capacity between the main regions and global LNG liquefaction capacity combined rises from around 60 bcm in 2007 to close to 200 bcm in the period 2012-2015. The utilisation rate of this capacity drops from 88% to less than three-quarters. The fall in capacity utilisation is likely to be most marked for pipelines; the owners of new LNG capacity are likely to be more willing to offer uncontracted supplies onto spot markets at whatever price is needed to find buyers, backing out gas that would otherwise have been traded internationally by pipeline (though the volume guarantees in long-term, take-or-pay contracts will limit somewhat the extent to which buyers will be able to reduce their offtake of piped gas).

**The looming gas glut could have far-reaching consequences for the structure of gas markets and for the way gas is priced in Europe and Asia-Pacific.** The much-reduced need for imports into the United States (due to improved prospects for domestic production and weaker-than-expected demand) could lead to less connectivity between the major regional markets (North America, Europe and Asia-Pacific) in the coming years. Relatively low North American gas prices are expected to discourage imports of LNG. Assuming that oil prices rise in the coming years – and that there is no major change in pricing arrangements – gas prices will tend to rise in Europe and Asia-Pacific because of the predominance of oil-indexation in their long-term supply contracts, diverging from those in North America. However, sliding spot prices for LNG could increase the pressure on gas exporters and marketers in Europe and Asia-Pacific to move away from, or to adjust, the formal linkage between gas and oil prices in long-term contracts. If the major exporting countries bend to pressure from importers to modify the pricing terms in their long-term contracts and make available uncontracted supplies to the spot market, lower prices would result. This would help to boost demand, especially in power generation (in which some short-term switching capability exists and new gas-fired capacity could be brought on stream within three to four years) and reduce the overhang in supply capacity in the medium term.

## ASEAN countries will become a key energy market

**The ten countries of the Association of Southeast Asian Nations (ASEAN) are set to play an increasingly important role in global energy markets in the decades ahead.** Brunei Darussalam, Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Thailand and Vietnam collectively make up one of the world's most dynamic and diverse regions, with an economy as large as Canada and Mexico combined, and a population that exceeds that of the European Union. Their energy consumption is already comparable to that of the Middle East and is set to continue to grow rapidly from a comparatively low per-capita level, fuelled by rapid economic and population growth, and by continuing urbanisation and industrialisation. In the Reference Scenario, ASEAN primary energy demand expands by 76% between 2007 and 2030, an average annual rate of growth of 2.5% – much faster than the average rate in the rest of the world. Reflecting the current economic weakness, demand is projected to grow modestly in the near term, before quickening. Even in the 450 Scenario, demand grows at 2.1% per year. Coupled with the emergence of China and India on the global energy scene, these trends point to a refocusing of global energy activity towards Asia.

**Many hurdles will need to be overcome if Southeast Asia is to secure access to the energy required to meet its growing needs at affordable prices and in a sustainable manner.** The energy sector in most parts of the region is struggling to keep pace with the rapid growth in demand experienced since the region's recovery from the Asian Financial Crisis of 1997/1998. With only about 1% of the world's proven reserves of oil, the region is heavily dependent on imports and is set to become even more so in the future. It also faces possible natural gas-supply shortages in the decades ahead, despite rapidly growing reliance on coal-fired power generation. While parts of Southeast Asia have relatively abundant renewable sources of energy, various physical and economic factors have left a significant share of it untapped. A total of $1.1 trillion needs to be invested in energy infrastructure in the ASEAN region in 2008-2030 in the Reference Scenario, more than half in the power sector. In the 450 Scenario, total investment needs are $390 billion higher. Financing is a major challenge, exacerbated by the recent global financial crisis, which has forced energy companies to cut back on capital spending and delay or cancel projects. At the same time, access to modern energy services still remains limited in some pockets of the region: it is estimated that 160 million people have no access to electricity today, though this number drops to 63 million by 2030 in the Reference Scenario.

## *Turning promises into results*

**The upcoming UN Climate Change Conference in Copenhagen will provide important pointers to the kind of energy future that awaits us.** Whatever the outcome, implementation of the commitments that are made – then or later – will remain key. The road from Copenhagen will undoubtedly be as bumpy as the road leading up to it. It will need to be paved with more than good intentions. The IEA has already called on all countries to take action on a large scale – a *Clean Energy New Deal* – to exploit the opportunity the financial and economic crisis presents to effect the permanent shift in investment to low-carbon technologies that will be required to curb the growth of energy-related greenhouse-gas emissions. Recent initiatives by a number of countries within the framework of economic stimulus packages are an important step in this direction. But much more needs to be done to get anywhere near an emissions path consistent with stabilisation of the concentration of greenhouse gases in the atmosphere at 450 ppm and limiting the rise in global temperature to 2°C.

**A critical ingredient in the success of efforts to prevent climate change will be the speed with which governments act on their commitments.** Saving the planet cannot wait. For every year that passes, the window for action on emissions over a given period becomes narrower – and the costs of transforming the energy sector increase. We calculate that each year of delay before moving onto the emissions path consistent with a 2°C temperature increase would add approximately $500 billion to the global incremental investment cost of $10.5 trillion for the period 2010-2030. A delay of just a few years would probably render that goal completely out of reach. If this were the case, the additional adaptation costs would be many times this figure. Countries attending the UN Climate Change Conference must not lose sight of this. The time has come to make the hard choices needed to turn promises into action.

## Scope and methodology

Past *Outlooks* have highlighted the unsustainability of current energy trends – environmentally, economically and socially – and the urgent need for action to bring about a wholesale global shift to low-carbon technologies. The issue is particularly pertinent this year, as countries around the world negotiate a new global deal on action to address climate change. Energy is at the heart of the problem – it accounts for 65% of the world's greenhouse-gas emissions – and so must be at the heart of the solution. The wild gyrations of energy prices over the last couple of years have also drawn attention to the importance of energy to economic activity everywhere and to our vulnerability to imbalances in fuel supplies. The surge in prices through to mid-2008 probably helped tip the world economy into the worst recession since the Second World War.

The results of the analysis presented here aim to provide policy makers, investors and energy consumers alike with a rigorous, quantitative framework for assessing likely future trends in energy markets and the cost-effectiveness of new policies to tackle climate change, energy insecurity and other pressing energy-related policy challenges. More specifically, this report is intended to inform the climate negotiations by providing an analytical basis for the adoption and implementation of commitments and plans to reduce greenhouse-gas emissions.

It would be almost an understatement to say that a lot has changed in the last 12 months. The first part of this year's *World Energy Outlook* (WEO) accordingly provides a comprehensive update of our long-term energy demand and supply projections in the Reference Scenario, fuel by fuel, region by region and (in some cases) country by country. This takes account of the dramatic economic downturn that has hit every region of the world; new measures that governments have adopted in response to and in pursuit of energy and environmental policies; and changes in expectations about energy prices in the near term. As always, this update makes no attempt to guess at future government policies, and takes no account of intentions or targets that may have been expressed by governments or other parties but which are not backed up by specific implementing measures. On this basis, it assesses the implications of global trends for energy security, the environment, the economy and energy poverty in the developing world, including a detailed review of the impact of the financial and economic crisis on energy investment along each of the energy supply chains. This analysis is set out in Part A.

Part B sets out the detailed results of a post-2012 scenario, which assumes governments adopt commitments to limit the long-term concentration of greenhouse gases in the atmosphere to 450 parts per million of carbon-dioxide-equivalent (ppm $CO_2$-eq), an objective that is gaining widespread support around the world.[1] We have called this

1. For this reason, the results of the 550 Policy Scenario, first presented in *WEO-2008*, are not described in detail in this report.

the 450 Scenario. It takes a close look at the period through to 2020 that is so crucial to the climate negotiation process and projects trends beyond that to 2030, based on the trajectory of emissions required ultimately to reach the stabilisation goal. This scenario builds on the "hybrid" climate policy framework introduced in *WEO-2008*. Without attempting to prescribe an ideal outcome to the negotiations, the 450 Scenario reflects a plausible set of policies that could emerge — a realistic combination of a cap-and-trade system, sectoral agreements and national policies tailored to each country's circumstances. The possible national and international implications of a global climate deal for the energy mix, greenhouse-gas emissions, investment and costs are described sector by sector and region by region. The aim is not to predict the commitments that countries may sign up to at the 15th Conference of the Parties (COP) of the United Nations Framework Convention on Climate Change (UNFCCC) in Copenhagen (December 2009) or beyond, but rather to illustrate how emissions would evolve under a given set of assumptions consistent with the overall stabilisation goal. Part B also includes a comprehensive analysis of the energy-related costs and investments necessary to achieve the higher level of energy efficiency and to deploy, on an adequate scale, the new energy technologies that would be needed to realise the outcomes described in the 450 Scenario, and explores some financing options. The financial flows and requirements, including carbon-trading flows, are quantified nationally and internationally.

Part C contains the results of an in-depth assessment of the prospects for global gas markets, focusing on the critical factors that will drive gas demand, production and trade in the medium to long term. It gives results for both the Reference and the 450 Scenarios. The analysis is intended to provide insights into the economics of gas demand and supply at the country and regional level, the technical and economic feasibility of continuing expansion of global gas production through to at least 2030, and the prospects for changes in the way gas is traded and priced along the supply chain. It complements and updates the study of oil and gas production prospects in last year's *Outlook*. The analysis of gas demand includes an assessment of the competitiveness of gas against other fuels and of the drivers of gas demand by sector, including the economics of fuel choice in power generation. On the supply side, the review quantifies global gas resources and examines recent trends in reserves, discoveries and exploration drilling, and the prospects for technological developments in the upstream gas industry. This assessment includes a special focus on developments in unconventional gas — particularly the sudden emergence of shale gas as an abundant and potentially low-cost source of supply in North America — and provides a quantitative analysis, on a field-by-field basis, of the production profiles of the world's biggest gas fields. Production and trade projections, as well as their implications for investment, are presented, with special focus on the most significant energy markets.

The final section of the book, Part D, analyses in detail the prospects for energy markets in Southeast Asia — one of the fastest-growing energy-consuming regions in the world. Projections are given of regional energy demand and supply by fuel and sector, energy investment and energy-related $CO_2$ emissions in the two scenarios. The implications of these trends for global energy markets and the prospects for regional multilateral co-operation to address Southeast Asia's environmental and energy-security challenges are also assessed. The energy situation of four of the region's nations are examined in some depth.

As indicated above, the *WEO-2009* continues past practice in using a scenario approach to examine future energy trends: this year, the Reference Scenario and the 450 Scenario. The projection period currently runs to 2030; 2007 is the last year for which comprehensive historical data are available but, in many cases, preliminary data are available for 2008 and have been incorporated. The projections are derived from a large-scale mathematical model, the World Energy Model,[2] which has been updated, drawing on the most recent historical data and revised assumptions. The power-generation and gas-supply modules have been completely overhauled, and a new water desalination/power module has been incorporated for the Middle East and North Africa. We have also enhanced our transport and carbon-finance models.

As in previous years, the Reference Scenario describes what would happen if, among other things, governments were to take no new initiatives bearing on the energy sector, beyond those already adopted by mid-2009. Most recent policy action bearing on the energy sector has been designed to contribute to emergence from the economic recession, to improve energy security, or to combat climate change and simultaneously address other environmental problems by improving energy efficiency and encouraging switching to lower-carbon fuels. Examples of major new policies adopted over the 12 months to mid-2009 are shown in Table 1. Importantly, the Reference Scenario does not include possible, potential or even likely future policy initiatives, thus it cannot be considered a forecast of what is *likely* to happen. Rather, it is a baseline picture of how global energy markets would evolve if the underlying trends in energy demand and supply are not changed. This allows us to test quantitatively the possible effects of new government policies, as in the 450 Scenario. We have also carried out sensitivity analyses, using alternative assumptions about gross domestic product (GDP) growth and energy prices, to reflect the enormous uncertainty surrounding both factors (see Annex B).

The 450 Scenario describes the implications for energy markets of a co-ordinated global effort to achieve a trajectory of greenhouse-gas emissions that would ensure the stabilisation of the concentration of those gases in the atmosphere at 450 ppm $CO_2$-eq. According to the Intergovernmental Panel on Climate Change (IPCC), stabilisation at that concentration creates a 50% chance of restricting to around 2°C the eventual increase in global average temperature (IPCC, 2007). By comparison, the Reference Scenario is consistent with an increase in temperature of up to 6°C. Because greenhouse gases remain in the atmosphere for a long time, stabilisation at 450 ppm would require annual emissions of greenhouse gases to peak within the next few years, followed by reductions of 3% or more each year. According to the IPCC, even a 2°C temperature increase would lead to a significant rise in sea level, species loss and increased frequency of extreme weather events. The emission reductions from energy use in the 450 Scenario are assumed to result from a structured international

2. A detailed description of the World Energy Model can be found at www.worldenergyoutlook.org/model.asp.

agreement on the adoption and implementation of a framework of effective policy mechanisms, including a cap-and-trade system and sectoral agreements. The detailed assumptions are described in Chapter 5.

**Table 1 • *Selected major new energy-related government policies taken into account in the Reference Scenario***

| Country/region | Policy | Detail |
|---|---|---|
| United States | New Corporate Average Fuel Economy (CAFE) standards | Sales-weighted fuel economy for light-duty vehicles capped at 39 mpg in 2016, 35.5 mpg for cars. |
| China | Golden Sun Programme | Subsidises 50% of investment cost for on-grid solar-power projects (over 500 MW) and 70% for off-grid projects, 2009-2011. |
| | Feed-in tariff for wind power plants | Four categories of on-grid tariffs for new wind projects, based on regions of varying wind conditions. |
| | Nuclear programme | Planned expansion of nuclear capacity to 2020. |
| European Union | 20-20-20 Package | Cap on overall greenhouse-gas emissions of 20% below 1990 levels by 2020. National renewable energy targets for emission reductions and to reduce energy imports. Include a minimum 10% share for alternative fuels in gasoline and diesel by 2020. Revised guidelines on state aid for environmental protection to support development and safe use of carbon capture and storage (CCS). |
| Japan | Photovoltaic (PV) subsidy and feed-in tariff for households | Subsidy: JPY 70 000/kW with a total budget of JPY 20 billion (April 2009 to January 2010). Feed-in tariff: surplus electricity to be purchased by electric utilities at twice retail price (JPY 48/kWh). |

## Principal assumptions

The projections in each scenario are underpinned by assumptions about a range of factors that drive energy demand and supply. Chief among these are population growth, macroeconomic trends, energy prices, technological developments and government policies. These assumptions are described below. The population and economic growth assumptions are the same for both the Reference and 450 Scenarios (see Chapter 5 for a discussion of the economic effects in the latter scenario). The principal difference between the scenarios is that new policies are assumed in the 450 Scenario (see above), along with some differences in technology. Prices are also assumed to be affected by these changes.

### Population

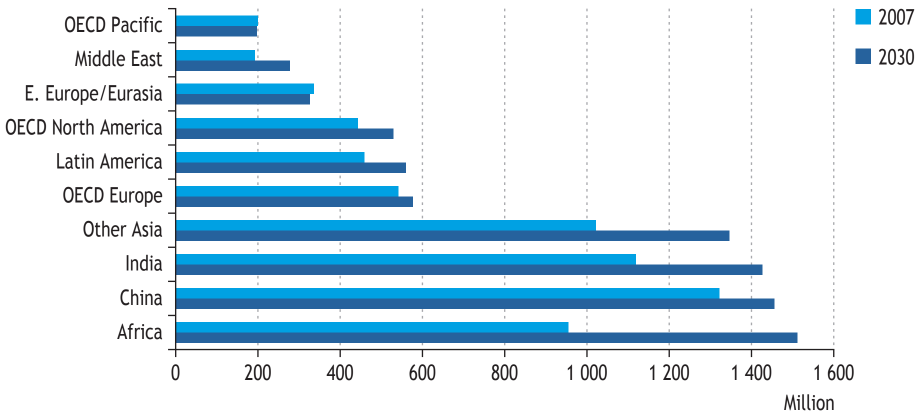
Demography affects the size and pattern of energy demand, directly and through its impact on economic growth and development. The rates of population growth assumed for each region in this *WEO* are based, as usual, on the most recent projections produced by the United Nations (UNPD, 2009). Global population is projected to grow by 1% per year on average, from an estimated 6.6 billion in 2007 to 8.2 billion in 2030. Population growth slows progressively over the projection period, as it did in the last two decades or so, from 1.1% per year in 2007-2015 to 0.9% in 2015-2030 (Table 2). Population expanded by 1.5% per year from 1980 to 2007.

**Table 2 • Population growth by region** (compound average annual growth rates)

| | 1980-1990 | 1990-2007 | 2007-2015 | 2015-2030 | 2007-2030 |
|---|---|---|---|---|---|
| **OECD** | **0.8%** | **0.8%** | **0.6%** | **0.3%** | **0.4%** |
| North America | 1.2% | 1.2% | 0.9% | 0.7% | 0.8% |
| *United States* | *0.9%* | *1.1%* | *0.9%* | *0.7%* | *0.8%* |
| Europe | 0.5% | 0.5% | 0.4% | 0.2% | 0.3% |
| Pacific | 0.8% | 0.4% | 0.1% | -0.2% | -0.1% |
| *Japan* | *0.6%* | *0.2%* | *-0.2%* | *-0.5%* | *-0.4%* |
| **Non-OECD** | **2.0%** | **1.5%** | **1.3%** | **1.0%** | **1.1%** |
| E. Europe/Eurasia | 0.8% | -0.2% | -0.1% | -0.2% | -0.1% |
| *Russia* | *n.a.* | *-0.3%* | *-0.4%* | *-0.5%* | *-0.4%* |
| Asia | 1.8% | 1.4% | 1.1% | 0.8% | 0.9% |
| *China* | *1.5%* | *0.9%* | *0.6%* | *0.3%* | *0.4%* |
| *India* | *2.1%* | *1.7%* | *1.3%* | *0.9%* | *1.1%* |
| Middle East | 3.6% | 2.3% | 1.9% | 1.5% | 1.6% |
| Africa | 2.9% | 2.5% | 2.3% | 1.9% | 2.0% |
| Latin America | 2.0% | 1.5% | 1.1% | 0.8% | 0.9% |
| *Brazil* | *2.1%* | *1.5%* | *0.8%* | *0.5%* | *0.6%* |
| **World** | **1.7%** | **1.4%** | **1.1%** | **0.9%** | **1.0%** |
| *European Union* | *n.a.* | *0.3%* | *0.2%* | *0.0%* | *0.1%* |

Most of the increase in global population will occur in non-OECD countries, mainly in Asia and Africa (Figure 1). Non-OECD population grows by 1.1% per year from 2007 to 2030, reaching 6.9 billion – equal to 84% of the world total. The only major non-OECD country that experiences a decrease in population is Russia, where the population falls from 142 million in 2007 to 129 million in 2030. Africa sees the fastest rate of growth. In absolute terms, the biggest increase occurs in non-OECD Asia, though its share of world population falls by one percentage point to 52% by 2030. China remains the world's most heavily populated country, with 1.46 billion people in 2030, while India's population, growing faster, almost reaches that of China by then. The population of the OECD increases by only 0.4% per year on average in 2007-2030, its share of global population falling further, from 18% in 2007 to less than 16% in 2030. Most of the increase in the OECD occurs in North America; Europe's population increases slightly, while the Pacific's actually falls marginally. The projected global population trends depend on achieving a major increase in the proportion of AIDS patients who get anti-retroviral therapy to treat the disease and on the success of efforts to control the further spread of HIV.

**Figure 1** • **Population by major region**




All of the increase in world population in aggregate will occur in urban areas. In 2009, for the first time in history, the world's urban population overtook the rural population. Continuing rapid urbanisation in non-OECD countries will tend to push up demand for modern energy, the bulk of which is consumed in or close to towns and cities.[3] The population will continue to age in all regions as fertility and mortality rates decline. Worldwide, the proportion of people over 60 years old is projected to rise from 10% in 2007 to about 15% by 2030. This will have far-reaching economic and social consequences, which will inevitably affect both the level and pattern of energy use. Older people, for example, tend to travel less for work and leisure. On the other hand, the average size of households will tend to fall, which might push up per-capita demand for residential space heating and cooling.

## Economic growth

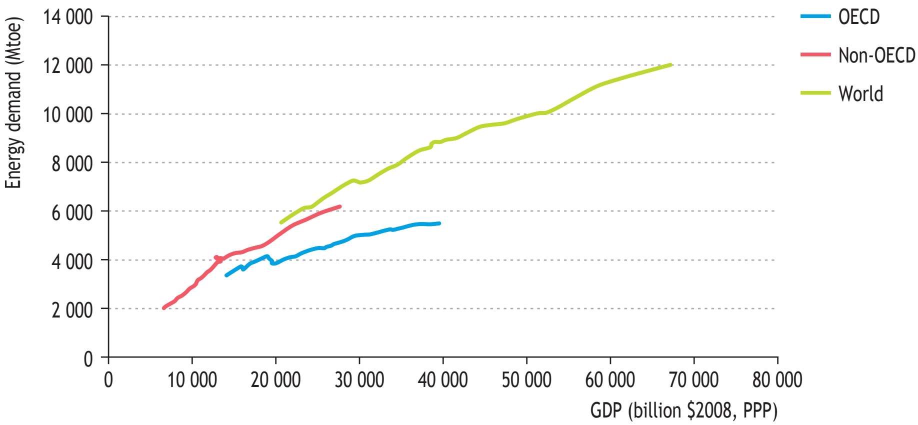
The energy projections in the *Outlook* are highly sensitive to underlying assumptions about GDP growth – the principal driver of demand for energy services. The pattern of economic development, notably the relative contributions of manufacturing industry and services, also affects overall energy demand and the fuel mix. Since the 1970s, primary energy demand has risen in a broadly linear fashion along with GDP: between 1971 and 2007, each 1% increase in global GDP (expressed in real purchasing power parity, or PPP, terms[4]) was accompanied by a 0.7% increase in primary energy consumption (Figure 2). Demand for electricity and transport fuels has been particularly closely aligned with GDP. However, the so-called income

3. IEA (2008) contains a detailed analysis of trends in energy use in cities.

4. PPPs compare the costs in different currencies of a fixed basket of traded and non-traded goods and services, and yield a widely based measure of standard of living. This helps in analysing the main drivers of energy demand or comparing energy intensities among countries.

elasticity of primary energy demand – the increase in demand relative to GDP – has changed over time. It fell sharply from 0.8 in the 1970s to 0.5 in the 1990s, but then rebounded to 0.7 in 2000-2007, mainly because of a surge in energy-intensive manufacturing in China.

**Figure 2 • *Primary energy demand and GDP, 1971-2007***




The projections in *WEO-2009* are strongly affected by the global economic recession. The economies of most OECD countries and many non-OECD countries have already contracted sharply and economic growth rates have slowed abruptly everywhere else. According to preliminary data, global GDP fell by an unprecedented 6.5% in the fourth quarter of 2008 (on an annualised basis), with the advanced economies contracting by around 8% and the emerging economies by 4%. GDP fell almost as fast in the first quarter of 2009, with the US economy contracting by 6.4% and the Japanese economy by 11.7%. Although the US economy may have suffered most from intensified financial strains and the continued fall in the housing sector, western Europe and OECD Asia have been hit hard by the collapse in global trade, as well as by rising financial problems of their own and housing corrections in some national markets. There are signs that the world economy is now beginning to pull out of recession, helped by unprecedented macroeconomic and financial policy support. However, the exact path of recovery is very uncertain, and could be sluggish and uneven.

The global economic crisis was triggered by the financial crisis, which began in mid-2007 and took a dramatic turn for the worse in the second half of 2008. Financial difficulties caused by plunging asset values curtailed sharply the ability and willingness of banks to lend money; this impeded investment, undermining consumption and paralysing economic activity. The deteriorating economic climate, in turn, aggravated the financial crisis, sending the world's financial and economic systems into a sharp downward spiral. Inflation has been declining rapidly in response to economic contraction and the collapse of commodity prices since mid-2008. The precise role of other factors in causing the initial economic downturn is unclear, though it appears that high oil prices may have played a significant role (Box 1).

**Box 1 • *To what extent are high oil prices to blame for the economic crisis?***

Although it is generally considered that the financial crisis was the principal immediate cause of the sudden, deep and synchronised global economic downturn that took hold in 2008, other factors – including the run-up in oil prices in the period 2003 to mid-2008 – arguably played an important, albeit secondary, role. High oil prices certainly helped to render the economies of oil-importing industrialised countries more vulnerable to the financial crisis, by damaging their trade balances, reducing household and business income, putting upward pressure on inflation and interest rates, and dampening economic growth. Such concerns prompted the Kingdom of Saudi Arabia to convene the Jeddah Energy Meeting on 22 June 2008 and the United Kingdom to host the follow-up London Energy Meeting on 19 December 2008. Both meetings were aimed at enhancing dialogue between oil producers and consumers during a time of extremely volatile prices.

Action was clearly needed. The share of energy bills in, for example, US household spending more than doubled to about 8% over the five years to 2008, reducing spending on other goods and services, and increasing household indebtedness. The rise in oil and other energy prices contributed significantly to the surge in flows of capital from oil-rich countries to the advanced economies, notably the United States, which helped temporarily to sustain consumption and imports.

Analysis carried out by the IEA in 2006 concluded that the rise in oil prices over the previous four years had lowered world GDP growth by an average of 0.3 percentage points per year. It also drew attention to the fact that not all of the effects of higher prices had fully worked their way through the economic system and that any further price increases would pose a significant threat to the world economy, by causing a worsening of current account imbalances and by triggering abrupt exchange rate realignments, a rise in interest rates and a slump in property and other asset prices. Nonetheless, the speed and depth of the resulting economic and financial crisis took almost everyone by surprise. It follows that if there were any sharp upward surge in oil prices in the months to come, this would risk causing the nascent economic recovery to stall.

Sources: IEA (2006); IMF (2009a).

There is enormous uncertainty about near-term economic prospects worldwide as the ramifications of the credit crunch and the full effects of the economic slump unfold. The leading forecasting bodies – private and public – have revised downwards repeatedly over the past year their projections for 2009 and beyond. In mid-July 2009, the International Monetary Fund (IMF) updated its global GDP estimates and forecasts: GDP is now estimated to have grown by 5.1% in 2007 and 3.1% in 2008, and is expected to fall by 1.4% in 2009 (IMF, 2009b). The downturn is being led by the advanced economies, which are now forecast to contract in aggregate by 3.8% in 2009. This would be the first annual contraction since the Second World War. The IMF still expects the world economy to stage a modest recovery in 2010, conditional on continued success in stabilising financial conditions, sizeable fiscal support, a gradual improvement in credit conditions, a bottoming of the US housing market and the cushioning effect from sharply lower oil and other major commodity prices. Global GDP is projected to grow by 2.5% in 2010, though the advanced economies are expected to see no growth.

The problems that have beset global financial and credit markets since mid-2007 were both a cause and an effect of the broader slump in the real economy. Concerns about the stability of the financial system first appeared in mid-2007, as large losses on mortgage-backed securities caused by defaults in the United States came to light. The crisis intensified with the collapse of the US securities firm, Bear Stearns, in March 2008, and the investment bank, Lehman Brothers, in September, and the subsequent intervention of the monetary authorities to bail out several institutions in the United States and Europe. The crisis spread rapidly across the financial markets in the OECD and to emerging markets, as falling asset values damaged the balance sheets of banks and other financial institutions, forcing them to rein in lending and tighten the terms of new loans, including raising interest rates sharply. Growing concerns about counterparty risk also disrupted credit markets, especially the interbank and commercial paper markets. This made it much harder – and more expensive – for businesses of all types to borrow money whether on a short-term or long-term basis. The credit crunch both caused and fed on the sharp downturn in economic growth, as the value of physical and financial assets spiralled lower, liquidity and credit diminished and economic activity contracted.

Governments in the advanced economies, through their central banks, responded forcefully to the financial crisis with extraordinary measures. These included large injections of liquidity (more recently by introducing or printing "new" money, a tactic known as quantitative easing), co-ordinated cuts in interest rates (to almost zero in all OECD countries), the full or part nationalisation of major financial institutions and direct interventions in commercial paper markets. These moves sought to shore up the financial system and sustain lending to businesses and households. Governments also launched programmes to provide economic stimuli to sustain demand and combat recession, involving big increases in public spending (often to support sectors that have been particularly badly hit by the economic slump and the credit crunch, notably the car industry) and tax cuts. In mid-February 2009, US President Obama signed into law a $787-billion package of measures to be introduced over ten years, including about $50 billion of incentives to develop and deploy clean energy technologies (see Chapter 4). Most European countries, Japan, Korea and Australia also introduced or proposed strong measures to stimulate their economies, complementing the EU Economic Recovery Plan announced in November 2008. China introduced, in late 2008, a sweeping stimulus package worth $585 billion over two years, which is already beginning to bear fruit. China and other emerging economies could provide the motor of economic recovery for the rest of the world.

This *Outlook* takes on board the latest GDP growth projections from the IMF (2009b) and the OECD (2009). We assume that the rate of growth recovers to 4.1% by 2015 and then turns down progressively through to 2030. World GDP is assumed to grow by an average of 3.1% per year over the period 2007-2030, compared with 3.3% from 1990-2007 (Table 3). This average is distorted by the impact of the economic recession in 2008 and 2009. GDP growth is assumed to average 3.3% per year in 2007-2015 and 3.0% per year in 2015-2030.

**Table 3 • *Real GDP growth by region*** (compound average annual growth rates)

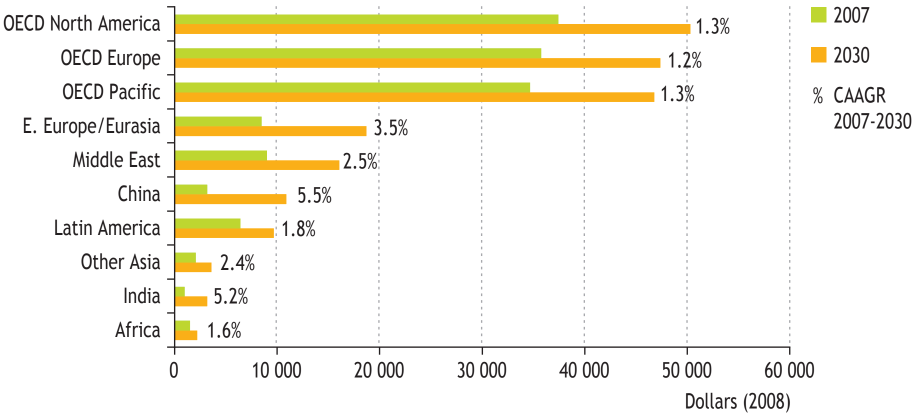
| | 1980-1990 | 1990-2007 | 2007-2015 | 2015-2030 | 2007-2030 |
|---|---|---|---|---|---|
| **OECD** | **3.0%** | **2.5%** | **1.4%** | **1.9%** | **1.8%** |
| North America | 3.1% | 2.9% | 1.8% | 2.3% | 2.1% |
| *United States* | *3.3%* | *2.9%* | *1.8%* | *2.2%* | *2.0%* |
| Europe | 2.4% | 2.3% | 1.0% | 1.8% | 1.5% |
| Pacific | 4.3% | 2.3% | 1.3% | 1.3% | 1.3% |
| *Japan* | *3.9%* | *1.4%* | *0.7%* | *1.1%* | *1.0%* |
| **Non-OECD** | **2.1%** | **4.6%** | **5.7%** | **4.1%** | **4.6%** |
| E. Europe/Eurasia | -0.2% | 0.5% | 3.3% | 3.3% | 3.3% |
| *Russia* | *n.a.* | *0.3%* | *3.3%* | *3.4%* | *3.4%* |
| Asia | 6.6% | 7.4% | 7.2% | 4.6% | 5.5% |
| *China* | *8.9%* | *10.0%* | *8.8%* | *4.4%* | *5.9%* |
| *India* | *5.8%* | *6.3%* | *7.0%* | *5.9%* | *6.3%* |
| Middle East | -1.3% | 3.8% | 4.5% | 4.0% | 4.2% |
| Africa | 2.3% | 3.7% | 4.7% | 3.1% | 3.7% |
| Latin America | 1.2% | 3.4% | 3.1% | 2.5% | 2.7% |
| *Brazil* | *1.5%* | *2.9%* | *3.1%* | *2.5%* | *2.7%* |
| **World** | **2.7%** | **3.3%** | **3.3%** | **3.0%** | **3.1%** |
| *European Union* | *n.a.* | *2.2%* | *1.1%* | *1.8%* | *1.5%* |

Note: Calculated based on GDP expressed in year-2008 dollars at purchasing power parity (PPP) terms.

India and China are expected to continue to grow faster than other regions, followed by the Middle East. India grows fastest, at 6.3% per year on average, and overtakes China as the fastest-growing major country before 2020, because its population grows quicker and because India is at an earlier stage in the development process. The growth rates of the economies of all the emerging economies are expected to slow as they mature. Growth in the Middle East is buoyed by rising oil revenues. GDP growth is assumed to slow gradually in all three OECD regions as their populations and labour forces stagnate, and they face increased competition from the emerging economies. North America is expected to remain the fastest-growing OECD region, partly due to its more rapidly expanding and relatively young population, though the rate of GDP growth is assumed to drop from an annual average of 2.9% in 1990-2007 to 2.1% per year over the *Outlook* period (partly because of the effect of the current recession). Europe and the Pacific see the lowest GDP growth. Based on our population and GDP growth assumptions, per-capita incomes grow most rapidly in China and India, but remain well below OECD levels when calculated using market exchange rates (Figure 3).[5]

5. Exchange rates in real terms are assumed to remain constant at 2008 levels (EUR 0.68 and JPY 103.39) over the projection period.

**Figure 3 • Per-capita income by region**




Notes: Calculated on the basis of GDP at market exchange rates. CAAGR is compound average annual growth rate.

## Energy prices

Energy prices are an exogenous determinant of energy demand and supply in the World Energy Model. The assumed trajectories for international fossil-energy prices in the Reference Scenario, summarised in Table 4, are based on a top-down assessment of the prices that would be needed to encourage sufficient investment in supply to meet projected demand over the *Outlook* period. In other words, they are derived iteratively to ensure their consistency with the overall global balance of supply and demand. These trajectories should not be seen as forecasts. Although the price paths follow smooth trends, this should not be interpreted as a prediction of stable energy markets: prices will, in reality, certainly deviate from these assumed trends, widely at times, in response to short-term fluctuations in demand and supply, and to geopolitical events.

International prices are used to derive average end-user pre-tax prices for oil products, gas and coal in each region and for each sector analysed in WEO-2009. Final electricity prices are derived from changes in marginal power-generation costs and non-generation costs of supply. Tax rates and subsidies are taken into account in calculating final post-tax prices, which help to determine final energy demand. In all cases, the rates of value-added taxes and excise duties on fuels are assumed to remain unchanged. Current policies on pricing and other market reforms are also taken into account in the Reference Scenario. In most non-OECD countries, at least one fuel or form of energy continues to be subsidised, usually through price controls that hold the retail or wholesale price below the level that would prevail in a truly competitive market.[6] Most of these countries have policies to reform subsidies, though often the intended timing is vague and the commitment is half-hearted. We assume that these subsidies

6. Energy-related consumption subsidies in 20 non-OECD countries (accounting for over 80% of total non-OECD primary energy demand) amounted to about $310 billion in 2007 (IEA, 2008).

are gradually reduced, but at varying rates across regions. In the 450 Scenario, final prices also take into account carbon prices under the cap-and-trade systems that are assumed to be introduced in many parts of the world.

**Table 4 • Fossil-fuel price assumptions in the Reference Scenario**
(dollars per unit)

| | Unit | 2000 | 2008 | 2015 | 2020 | 2025 | 2030 |
|---|---|---|---|---|---|---|---|
| **Real terms (2008 prices)** | | | | | | | |
| IEA crude oil imports | barrel | 34.30 | 97.19 | 86.67 | 100.00 | 107.50 | 115.00 |
| Natural gas imports | | | | | | | |
| *United States* | *MBtu* | *4.74* | *8.25* | *7.29* | *8.87* | *10.04* | *11.36* |
| *Europe* | *MBtu* | *3.46* | *10.32* | *10.46* | *12.10* | *13.09* | *14.02* |
| *Japan LNG* | *MBtu* | *5.79* | *12.64* | *11.91* | *13.75* | *14.83* | *15.87* |
| OECD steam coal imports | tonne | 41.22 | 120.59 | 91.05 | 104.16 | 107.12 | 109.40 |
| **Nominal terms** | | | | | | | |
| IEA crude oil imports | barrel | 28.00 | 97.19 | 101.62 | 131.37 | 158.23 | 189.65 |
| Natural gas imports | | | | | | | |
| *United States* | *MBtu* | *3.87* | *8.25* | *8.55* | *11.66* | *14.78* | *18.73* |
| *Europe* | *MBtu* | *2.82* | *10.32* | *12.27* | *15.89* | *19.27* | *23.11* |
| *Japan LNG* | *MBtu* | *4.73* | *12.64* | *13.96* | *18.07* | *21.83* | *26.17* |
| OECD steam coal imports | tonne | 33.65 | 120.59 | 106.77 | 136.84 | 157.67 | 180.42 |

Notes: Gas prices are expressed on a gross calorific-value basis. All prices are for bulk supplies exclusive of tax. Nominal prices assume inflation of 2.3% per year from 2008. Detailed price assumptions for the 450 Scenario can be found in Chapter 5.

## Oil prices

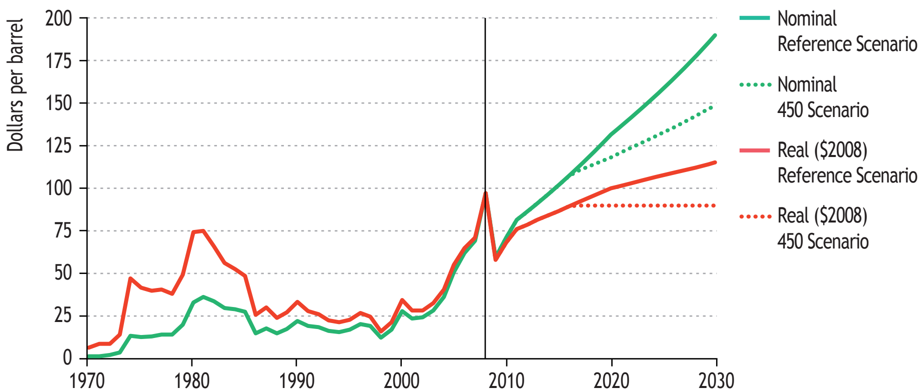
The average IEA crude oil import price, a proxy for international prices, is assumed in the Reference Scenario to fall from the 2008 level of $97 per barrel to around $60 per barrel in 2009 (roughly the level of mid-2009) and then recover with the economic recovery to reach $100 per barrel by 2020 and $115 per barrel by 2030 in year-2008 dollars (Figure 4).[7] In nominal terms, prices roughly triple between 2009 and 2030, reaching almost $190 per barrel. The price assumptions are sharply lower in the near-to-medium term compared with last year's *Outlook*, reflecting the collapse in prices in the second half of 2008.[8] For the end of the projection period, prices are only slightly lower than assumed last year, as the prospective marginal cost of oil supply and the

7. In 2008, the average IEA crude oil import price was $3 per barrel lower than first-month forward West Texas Intermediate (WTI) and $0.20 higher than dated Brent.

8. The assumed oil prices are slightly below those assumed by the US Energy Information Administration (EIA), but are significantly higher than those assumed by the Organization of the Petroleum Exporting Countries (OPEC). For its most recent long-term energy projections, the EIA assumes an average world oil price of around $130 per barrel in year-2007 prices for 2030 (DOE/EIA, 2009). In its most recent *World Oil Outlook*, OPEC has retained its previous assumption of nominal prices in the range of $70 to $90 per barrel over the next decade for the reference basket of crude oils (OPEC, 2009).

outlook for demand in the long term have not changed radically (see Chapter 1). In the 450 Scenario, prices are assumed to follow the same trajectory as in the Reference Scenario to 2015 and then remain flat to 2030, due to weaker demand. Prices are 10% lower than in the Reference Scenario in 2020 and 22% lower in 2030 (Figure 4).

**Figure 4 • Average IEA crude oil import price** *(annual data)*




Oil prices have ridden a veritable roller-coaster over the past year or so. From highs near $150 per barrel in July 2008, crude prices plunged to around $35 per barrel in February 2009 before recovering to $65 to $70 per barrel by mid-year. Explaining price movements is never simple and the experience of 2008 has inevitably prompted a lively debate about the causes of the dramatic market turnaround (IEA, 2009a). Oil market fundamentals certainly played a central role in driving prices up and down: tight distillate supply and highly price-inelastic demand combined to push up prices through to mid-2008, while the sudden weakening of demand in belated response to higher prices and, more importantly, the sudden deterioration in global economic conditions pushed prices back down through the rest of the year.

The magnitude of the price swings can be explained by the very low price elasticities of demand and supply, which mean that big and sudden changes in prices are necessary to balance the market in the event of even relatively small changes in either supply or demand. Expectations about future market tightness undoubtedly contributed to stronger demand and prices, while subsequent fears about the impact of the financial and economic crisis on oil demand in the medium term helped to drive prices lower. The extent to which speculative financial flows into and out of futures markets contributed to the swings in prices remains a topic of animated discussion, but it is reasonable to conclude that those flows may well have played a part in amplifying the impact of shifting fundamentals on prices, both upwards and downwards. Yet recent analyses have been unable to prove a direct price-making role for non-commercial operators on futures exchanges (IEA, 2009a).

The assumption of a steady recovery in prices to at least 2015 is based on our expectation of gradually tightening international oil markets in the medium term (on the assumption of global economic recovery). Global oil demand is expected to recover as the economy pulls out of recession, outpacing the growth in capacity, while recent large cutbacks in upstream and downstream investment will have a big impact on supply in the next three to five years as a result of the long lead times in bringing new projects on stream. In addition, the Organization of Petroleum Exporting Countries (OPEC) is likely to seek to push up prices in the near term by ensuring that production quotas rise more slowly than demand. Although the underlying trend may be upwards, prices are likely to remain highly volatile. In the longer term, we assume in the Reference Scenario that rising marginal costs of supply, together with demand growth in non-OECD countries, will continue to exert upward pressure on prices. By contrast, in the 450 Scenario, lower oil demand means there is less need to produce oil from costly fields higher up the supply curve in non-OPEC countries (see Chapter 5). As always, there are acute risks to these assumptions on both sides: the timing and pace of economic recovery and, therefore, the rebound in oil demand remain highly uncertain, as do the levels of investment in oil production and refining capacity, and of dollar exchange rates.

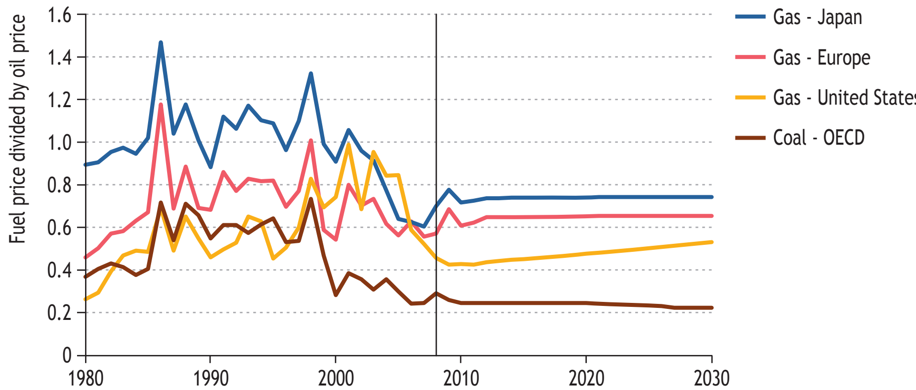
### *Natural gas prices*[9]

Natural gas prices have followed divergent paths in different parts of the world, largely according to the degree of contractual linkage to oil prices and of government price controls. In Europe and the Pacific, where most gas is traded under long-term contracts with oil-price indexation, prices peaked in late-2008, reflecting the impact of high oil prices in the second quarter of the year (most contracts adjust gas prices with a lag of six to nine months). They have since fallen back with lower oil prices, reaching about $7 per million British thermal units (MBtu) in Europe and $7.50/MBtu to $8.00/MBtu in the Pacific in mid-2009. In North America, where gas-to-gas competition is the dominant price-setting mechanism, prices peaked in the middle of 2008 and then started falling briskly with plunging demand, caused by the recession and rising stocks, while production held up much more (thanks to a boom in shale gas drilling). By mid-2009, spot prices at Henry Hub (the leading North American benchmark) had fallen to little more than $3/MBtu — the lowest level since 2002.

In the Reference Scenario, gas prices in Europe and the Pacific are assumed to fall back in 2009 from their mid-2008 peaks in lagged response to the fall in oil prices. Prices then begin to rise after 2015, in line with rising demand and oil prices (Figure 5). Although the expected development of gas-to-gas competition in both regions is likely to weaken the contractual links between oil and gas prices over the projection period, gas prices are not assumed to fall relative to oil prices. Competition would exert some downward pressure on the prices of gas relative to those of oil, but this effect is assumed to be offset by rising marginal supply costs for gas as the distances over which gas has to be transported by pipeline or as liquefied natural gas (LNG) increase. Growing LNG trade is expected to contribute to some convergence in European and Pacific prices over the projection period.

9. A detailed discussion of the outlook for gas pricing can be found in Chapter 14.

**Figure 5 • *Ratio of natural gas and coal prices to crude oil in the Reference Scenario****




* Calculated on an energy-equivalent basis using real-2008 dollars.

By contrast, in North America, gas prices are expected to follow a path much more independent from oil prices. The abundance of relatively low-cost shale gas in the United States is expected to continue to exert downward pressure on US gas prices in the near term, making LNG imports generally uncompetitive and causing the North American market largely to disconnect from Europe. Prices are nonetheless assumed to rise moderately through to 2030 with higher prices of oil (which increases the market value of gas against competing oil products and raises the price of gas in other regional markets) and the rising marginal cost of unconventional gas supply as reserves are depleted. The price reaches $7/MBtu by 2015 and just over $11/MBtu in 2030. Prices would not rise so steeply if domestic supply costs turn out to be lower and/or LNG imports become available at lower prices.

Natural gas prices in the 450 Scenario are lower than in the Reference Scenario in all regions as a result of both lower oil prices (in Europe and the Pacific only) and weaker gas demand (everywhere). In Europe and the Pacific, gas prices are 9% lower in 2020 and 21% lower in 2030 than in the Reference Scenario. In North America, where prices are largely determined by the domestic supply and demand balance, prices fall much less, by 8% in 2020 and 10% in 2030, mainly because gas demand in that region drops less steeply than in other parts of the world.

### *Steam coal prices*

International steam coal prices have tended broadly to follow oil and gas prices in recent years, reflecting the dynamics of inter-fuel competition and the importance of oil in the cost of transporting coal. The average price of steam coal imported by OECD countries jumped from $74 per tonne in 2007 (in year-2008 dollars) to $121 per tonne in 2008.[10] By mid-2009, the price had dropped back to around $90 per tonne. The abrupt turnaround in coal demand in industry and power generation resulting from the economic slowdown, together with plunging prices of gas (which has led some generators to switch from coal) largely explains the drop in prices.

In the Reference Scenario, coal prices are assumed to bottom out at less than $65 per tonne in real terms on average in 2009, before recovering gradually to over $100 per tonne by 2020 and almost $110 per tonne by 2030. Rising oil and gas prices make coal increasingly competitive. In reality, however, the possibility of a carbon price being introduced or increasing where it already exists – though not assumed in this scenario – will affect the use of coal, counterbalancing to some degree the impact on coal demand of relatively lower prices.

In the 450 Scenario, coal prices are assumed to be markedly lower, especially towards the end of the *Outlook* period, as a result of a widespread and large-scale shift away from coal to cleaner fuels. In fact, coal prices are the most affected by the lower supply-demand equilibrium in the 450 Scenario. Coal prices are assumed to drop to $80 per tonne in 2020 and $65 per tonne in 2030 – $45 per tonne below the Reference Scenario level.

## $CO_2$ prices

At present, only the European Union has adopted a formal cap-and-trade system that sets prices for $CO_2$ – the EU Emissions Trading System. Thus, in the Reference Scenario, carbon pricing is limited to the power and industry sectors in EU countries. The price of $CO_2$ under that system is projected to reach $43 per tonne in 2020 and $54 per tonne in 2030. In the 450 Scenario, the cap-and-trade system is assumed to be extended to the power and industry sectors in OECD+ (a group that includes all the OECD countries plus non-OECD EU countries) as of 2013 and to Other Major Economies (which includes China, Russia, Brazil, South Africa and the Middle East) as of 2021. We assume that $CO_2$ is traded in two separate markets: the OECD+ and Other Major Economies. To contain emissions at the levels required in the 450 Scenario, we estimate that the $CO_2$ price reaches $50 per tonne in OECD+ in 2020; it rises to $110 per tonne in OECD+ and $65 per tonne in the Other Major Economies in 2030. The prices are set by the most expensive abatement option (for example, carbon capture and storage in industry in the OECD+ in 2030). Full details of carbon pricing and how it is modelled in the 450 Scenario can be found in Chapters 5 and 8.

## Technology

The status and efficiency of different energy-sector technologies, both long-standing technologies and novel technologies, will be a key factor in determining the world's energy demand, fuel use, $CO_2$ emissions and investment choices in the years to come. Our projections are therefore very sensitive to assumptions about rates of technological development, of improvements in energy and cost efficiencies, and of commercialisation and accessibility.

10. In mid-2008, prices approached $200 per tonne for certain qualities of coal in some European markets and $150 per tonne in the United States.

In general, it is assumed in the Reference Scenario that the performance of currently available technologies improves, particularly in terms of efficiency, over the projection period. This reflects historic experience of technological learning over time, but is also stimulated by higher energy prices. Our assumptions about the pace of technological advance vary markedly by fuel, by sector and by technology, taking into account the current status of technologies, the potential for further improvements, current research and development (R&D) investment, policy support and other sector-specific factors. Such factors include, notably, the rate of retirement and replacement of capital stock. This varies markedly by technology, ranging from around one year for an incandescent lightbulb to 40 to 50 years for a nuclear power station and over 100 years in the case of some buildings and infrastructure. Typically, the lifetimes of energy sector investment are relatively long, which limits capital turnover and the rate at which average efficiency can improve. However, rising demand for energy counteracts this effect to some degree, as the need for additional capacity increases the potential for improving the mix and efficiency of technologies over the next 20 years.

A number of major new technologies that are approaching commercialisation are assumed to be deployed at various points over the projection period. These include:

- *Carbon capture and storage (CCS):* CCS is a crucial, but relatively costly, form of emissions abatement in the 450 Scenario. It is also assumed, at very small scale, from 2020 in the power generation sector in the Reference Scenario — in countries with sufficiently large incentives or subsidies in place. While the basic technology already exists to capture $CO_2$ emissions, and to transport and permanently store the gas in geological formations, it has yet to be deployed at significant scale in an integrated way in the power sector. Nevertheless, 2009 has seen some very important steps forward, with a number of demonstration projects now underway or planned (see Chapter 7). Challenges to successful full-scale demonstration and commercial deployment include: the financing of large-scale demonstration projects and integration of CCS into greenhouse-gas policies; the higher cost and efficiency penalty of CCS technology relative to coal-fired power plants without CCS; the development and financing of adequate $CO_2$ transport infrastructure; and the development of legal and regulatory frameworks to ensure safe and permanent $CO_2$ storage (IEA, 2009b). Another important challenge is to make CCS available and cost-effective in the industry sector, as well as in power generation.
- *Concentrating solar power (CSP):* Solar power is a long-established technology but in the past it has been constrained by technical difficulties in producing power on a sufficiently large scale, for a given area of land and at sufficiently low cost. However, there has been significant technological progress in recent years and this is set to continue over the projection period. In particular, solar power is likely to become much more cost-effective in a world of higher energy prices, giving a large boost to deployment in areas such as the United States, North Africa and southern Europe.
- *Electric and plug-in hybrids vehicles:* Major progress has been made in recent years in respect to electric vehicles and there are now a few vehicles available in niche markets. Plug-in hybrids, which run on electric power with an additional

conventional engine to allow for driving over longer distances than is possible with current battery technology, are a potential intermediate step towards full electric vehicles. Plug-in hybrids and electric cars have recently seen their first commercial applications. However, challenges to the mass adoption of these technologies still remain, particularly improvements in battery technology to provide sufficient range and to reduce costs, and the build-up of adequate battery-manufacturing capacities and recharging infrastructure. A number of countries have announced subsidies and/or sales targets for electric vehicles, including the United Kingdom, Spain, Ireland and China, which are taken into account in the Reference Scenario. Meanwhile, overall fleet efficiency targets in many regions, including Japan, the European Union and the United States, are likely to stimulate the adoption of more efficient conventional cars and hybrid vehicles. In the Reference Scenario, in the absence of stronger targets and more directed policy support, electric cars and plug-in hybrids remain only niche markets. They feature much more prominently in the 450 Scenario, which takes into account the impact of a global sectoral agreement on the efficiency of passenger light-duty vehicles (PLDVs).

- *Advanced biofuels:* Despite increasing research efforts, second-generation biofuels are still a long way from commercialisation and are not deployed until 2020 in the Reference Scenario. Even then, this is on a small scale and mainly in the United States, in part driven by the US Renewable Fuel Standard, which mandates the use of second-generation ligno-cellulosic biofuels. The 450 Scenario assumes a rapid increase in the production of second-generation biofuels, accounting for all the biofuels growth between 2020 and 2030. This will require concerted R&D efforts to be stepped up immediately and bringing demonstration plants on line in the next few years. The last year has seen something of a global shift in biofuels policy, with greater caution with regard to the overall sustainability of some first-generation biofuels. For example, Germany has scaled back its 2009 blending target, which will mainly be met by first-generation biofuels, and is increasing its R&D focus on second-generation biofuels.

While some technologies that can be considered novel at the time of writing are expected to reach commercialisation and widespread deployment over the projection period, no altogether new technologies (beyond those known about and to some extent demonstrated today) are assumed to be deployed in either the Reference Scenario or the 450 Scenario. This is because there is no way of knowing whether or when such breakthroughs may occur. Consequently, potential exists to "improve upon" the scenarios presented here in the event of radical, unforeseen technological breakthroughs.

PART A
# GLOBAL ENERGY TRENDS TO 2030

## PREFACE

Part A of this *WEO* presents a comprehensive update of the energy projections in the Reference Scenario, which shows how the future might look on the basis of the policies so far adopted by governments. These projections – which form the basis of all the discussion in Part A – are not a forecast: there is no implication that policy making has been brought to a sudden halt. But examination of future trends on the basis of today's policies is a necessary starting point for deciding in what way and by what measures the future might be changed.

Chapter 1 sets out the results of this Reference Scenario. The numbers are down on the projections in *WEO-2008*, reflecting mainly the impact of the financial and economic crisis that has gripped the world since those projections were produced last year.

Chapter 2 draws out some implications for what are known as the "three Es" of sound energy-policy making: environmental sensitivity, energy security and economic development.

Chapter 3 takes a special look at the consequences of the financial and economic crisis. Investment commitments have plunged. This could threaten the adequacy of supply when the economy recovers. But it could also be an opportunity: when investment resumes, it could be directed towards new technologies that are better adapted to the priorities of tackling climate change.

# GLOBAL ENERGY TRENDS IN THE REFERENCE SCENARIO

## Where do existing policies take us?

### H I G H L I G H T S

- The Reference Scenario is most definitely not a forecast of what will happen but a baseline picture of how global energy markets would evolve if governments make no changes to their existing policies and measures. It sees global primary energy demand rising by 1.5% per year on average between 2007 and 2030 – an overall increase of 40%. China and India are the main drivers of growth, followed closely by the Middle East. Projected demand growth is slower than in last year's *Outlook*, reflecting the impact of the financial and economic crisis.
- Oil demand is projected to grow by 1% per year on average over the projection period, from 85 million barrels per day in 2008 to 105 mb/d in 2030. All the growth comes from non-OECD countries; OECD demand falls. The transport sector accounts for 97% of the increase. As non-OPEC conventional oil production peaks around 2010, most of the increase in output comes from OPEC countries, which hold the bulk of remaining recoverable resources.
- World primary demand for natural gas expands on average by 1.5% per year in 2007-2030, reaching 4.3 trillion cubic metres. The biggest increases occur in the Middle East, China and India, but North America, Russia and Europe remain the leading consumers in 2030. New power stations absorb 45% of the increase. The Middle East sees the biggest increase in production while output also increases markedly in Russia, the Caspian and Africa.
- Demand for coal grows more strongly than demand for any other energy sources except non-hydro modern renewables – at an average annual rate of 1.9% – reaching almost 7 000 Mtce in 2030. Growth in production in all other regions is dwarfed by China's 61% share of incremental global production, as it strives to satisfy a near-doubling of domestic demand.
- World electricity demand is projected to grow at an annual rate of 2.5% to 2030. Over 80% of the growth takes place in non-OECD countries. Globally, additions to power-generation capacity total 4 800 GW by 2030. The largest additions occur in China. Coal remains the backbone fuel of the power sector worldwide, its share of the generation mix rising by three percentage points to 44% in 2030. The share of renewables rises from 18% in 2007 to 22% in 2030, with most of the growth coming from non-hydro sources. Nuclear power grows in all major regions bar Europe, but its share in total generation falls.
- Cumulative energy investment needs amount to $26 trillion (in year-2008 dollars) in 2008-2030, equal to $1.1 trillion (or 1.4% of global GDP) per year on average. The power sector requires 53% of total investment, followed by oil (23%), gas (20%) and coal (3%). Over half of all investment worldwide is needed in non-OECD countries, where demand and production are projected to increase fastest.

# World energy trends to 2030

## Primary energy mix

Global primary energy demand[1] in the Reference Scenario is projected to increase by 1.5% per year between 2007 and 2030, reaching 16.8 billion tonnes of oil equivalent (toe) – an overall increase of 40% (Table 1.1). This increase is, nonetheless, significantly smaller than projected in last year's *Outlook*, mainly because of the impact of the financial and economic crisis on demand growth in the early years of the projection period.[2] On average, demand actually declines by 0.2% per year in 2007-2010, as a result of a pronounced drop in 2009: preliminary data point to a fall of up to 2%. This would be the first fall in global energy use since 1981. Demand growth rebounds after 2010, averaging 2.5% per year in 2010-2015. The pace of demand growth slackens progressively after 2015, averaging 1.5% per year in the period to 2030.

Fossil fuels remain the dominant sources of primary energy worldwide, accounting for almost 77% of the overall increase in energy demand between 2007 and 2030. Their share of world demand, nonetheless, falls marginally, from 81% to 80%. In volume terms, coal sees by far the biggest increase in demand over the projection period, followed by gas and oil (Figure 1.1). Yet oil is still the single largest fuel in the primary fuel mix in 2030, even though its share drops, from 34% now to 30%. Coal remains the second-largest fuel, its share increasing by two percentage points to 29%. Non-hydro modern renewable energy technologies (including wind, solar, geothermal, tide and wave energy) see the fastest rate of increase in demand, but their share of total energy use still only nudges above 2% in 2030 – up from less than 1% today. The shares of all the other primary energy sources remain almost constant over the *Outlook* period.

**Table 1.1 • World primary energy demand by fuel in the Reference Scenario** (Mtoe)

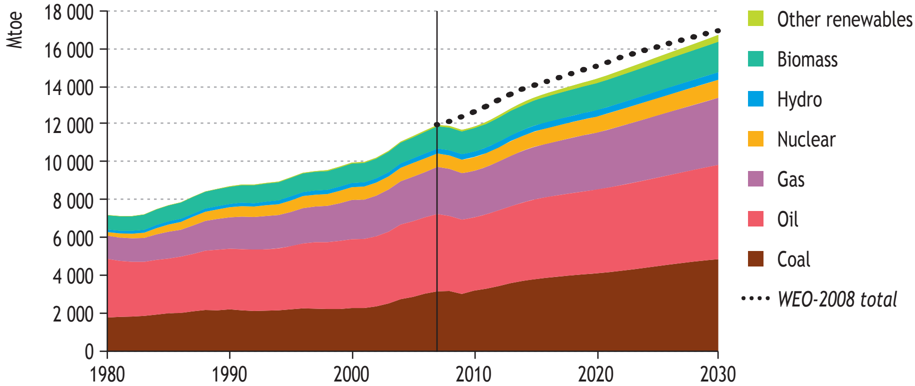
| | 1980 | 2000 | 2007 | 2015 | 2030 | 2007-2030* |
|---|---|---|---|---|---|---|
| Coal | 1 792 | 2 292 | 3 184 | 3 828 | 4 887 | 1.9% |
| Oil | 3 107 | 3 655 | 4 093 | 4 234 | 5 009 | 0.9% |
| Gas | 1 234 | 2 085 | 2 512 | 2 801 | 3 561 | 1.5% |
| Nuclear | 186 | 676 | 709 | 810 | 956 | 1.3% |
| Hydro | 148 | 225 | 265 | 317 | 402 | 1.8% |
| Biomass and waste** | 749 | 1 031 | 1 176 | 1 338 | 1 604 | 1.4% |
| Other renewables | 12 | 55 | 74 | 160 | 370 | 7.3% |
| **Total** | **7 228** | **10 018** | **12 013** | **13 488** | **16 790** | **1.5%** |

* Compound average annual growth rate.
** Includes traditional and modern uses.

1. World total primary energy demand, which is equivalent to total primary energy supply, includes international marine and aviation bunkers, which are excluded from the regional totals. Primary energy refers to energy in its initial form, after production or importation. Some energy is transformed, mainly in refineries, power stations and heat plants. Final consumption refers to consumption in end-use sectors, net of losses in transformation and distribution. In all regions, total primary and final demand include traditional biomass and waste, such as fuel wood, charcoal, dung and crop residues, some of which are not traded commercially. For details of statistical conventions and conversion factors, please go to www.iea.org.

2. See the Introduction for details of the assumptions underlying the Reference Scenario. Relative to the projections in *WEO-2008*, demand is revised down 4.5% in 2015 and 1.3% in 2030.

**Figure 1.1 • World primary energy demand by fuel in the Reference Scenario**




**Box 1.1 • Interpreting the Reference Scenario results**

As explained in the Introduction, the Reference Scenario describes a future in which governments are assumed to make no changes to their existing policies and measures insofar as they affect the energy sector. The projections in this scenario are most definitely not a forecast of what will happen: we do not expect governments to do nothing. On the contrary, it is becoming increasingly likely that governments around the world will take rigorous action to address the central energy challenges that we have identified in past *Outlooks* – climate change, energy security and energy poverty – and put the global energy system onto a more sustainable path. Climate change could become the main driver of policy in the coming decades. A critical factor will be the outcome of the climate negotiations in Copenhagen in December 2009 and how the commitments adopted there are implemented. But we cannot know exactly what governments will decide to do.

The virtue of the Reference Scenario is that it provides a baseline picture of how global energy markets would evolve if the underlying trends in energy demand and supply are not changed. It both illustrates the consequences of inaction and allows us to test alternative assumptions about future government policies. This is precisely the aim of the 450 Scenario, the results of which are set out in Part B. There are, of course, an infinite number of permutations of different policies that could be introduced, each leading to a different set of outcomes for energy markets. We have chosen a scenario and a set of policies designed to stabilise the global concentration of greenhouse gases in the atmosphere at 450 parts per million of carbon dioxide equivalent (ppm $CO_2$-eq), a level that climate experts judge would give us a 50% chance of limiting global temperature increase to 2°C. G8 leaders and the Major Economies Forum, both meeting in L'Aquila, Italy, in July 2009, recognised that the temperature increase ought not exceed this level.

## Regional trends

Just over 90% of the increase in world primary energy demand between 2007 and 2030 is projected to come from non-OECD countries (Table 1.2).[3] As a result, their share of world demand grows from 52% to 63%. Non-OECD countries collectively overtook the OECD in 2005 as the biggest energy consumers. The increase in the share of the non-OECD regions in world demand results from their more rapid economic and population growth, and comes despite the increases in real prices to final consumers that result from rising international prices and assumed reductions in subsidies. Industrialisation and urbanisation boost demand for modern commercial fuels.

**Table 1.2 • Primary energy demand by region in the Reference Scenario** (Mtoe)

| | 1980 | 2000 | 2007 | 2015 | 2030 | 2007-2030* |
|---|---|---|---|---|---|---|
| **OECD** | **4 050** | **5 249** | **5 496** | **5 458** | **5 811** | **0.2%** |
| North America | 2 092 | 2 682 | 2 793 | 2 778 | 2 974 | 0.3% |
| *United States* | *1 802* | *2 280* | *2 337* | *2 291* | *2 396* | *0.1%* |
| Europe | 1 493 | 1 735 | 1 826 | 1 788 | 1 894 | 0.2% |
| Pacific | 464 | 832 | 877 | 892 | 943 | 0.3% |
| *Japan* | *345* | *518* | *514* | *489* | *488* | *-0.2%* |
| **Non-OECD** | **3 003** | **4 507** | **6 187** | **7 679** | **10 529** | **2.3%** |
| E. Europe/Eurasia | 1 242 | 1 008 | 1 114 | 1 161 | 1 354 | 0.9% |
| *Russia* | *n.a.* | *611* | *665* | *700* | *812* | *0.9%* |
| Asia | 1 068 | 2 164 | 3 346 | 4 468 | 6 456 | 2.9% |
| *China* | *603* | *1 105* | *1 970* | *2 783* | *3 827* | *2.9%* |
| *India* | *207* | *457* | *595* | *764* | *1 287* | *3.4%* |
| *ASEAN* | *149* | *389* | *513* | *612* | *903* | *2.5%* |
| Middle East | 128 | 378 | 546 | 702 | 1 030 | 2.8% |
| Africa | 274 | 499 | 630 | 716 | 873 | 1.4% |
| Latin America | 292 | 457 | 551 | 633 | 816 | 1.7% |
| **World**** | **7 228** | **10 018** | **12 013** | **13 488** | **16 790** | **1.5%** |
| *European Union* | *n.a.* | *1 684* | *1 757* | *1 711* | *1 781* | *0.1%* |

* Compound average annual growth rate.

** World includes international marine and aviation bunkers (not included in regional totals).

China and India are the main drivers of non-OECD demand growth. China accounts for 39% of the global increase in primary energy use, its share of total demand jumping from 16% in 2007 to 23% in 2030. India accounts for 15% of the global increase, with its share of the total expanding from 5% to 8%. Outside of Asia, the Middle East sees the fastest rate of increase in demand. China's primary energy demand almost doubles between 2007 and 2030 to 3.8 billion toe – a far bigger increase than that of any other country or region (Figure 1.2). The bulk of the increase is in the form of coal, which remains the leading fuel for power generation.

3. Most of the downward revision to primary demand in 2030 in this year's *Outlook* comes from the OECD (-369 Mtoe), with non-OECD demand dropping by only 75 Mtoe.

SPOTLIGHT

**How do the energy demand projections compare with *WEO-2008*?**

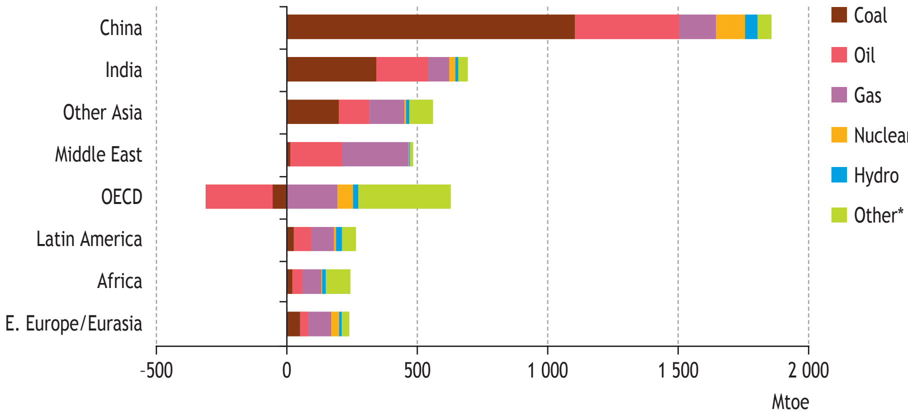
The energy demand projections in the Reference Scenario in this year's *Outlook* differ markedly from those of *WEO-2008*. These revisions result from the impact of the financial and economic crisis (which is expected to depress demand in the period 2007-2010) the effect of new policies enacted between mid-2008 and mid-2009 (which have been taken into account in the Reference Scenario this year), and adjustments to the assumptions about energy prices and in gross domestic product (GDP) growth rates in the longer term.

Overall, these changes lead to lower world primary energy demand: it is revised down by 4.5% (632 million tonnes of oil equivalent [Mtoe]) in 2015 and 1.3% (224 Mtoe) in 2030 compared with last year's projections. OECD countries see the biggest revisions, with demand down 5.7% in 2015 and 4.2% in 2030. Demand in non-OECD countries is only marginally lower, by 0.3 % in 2030, mainly as a result of faster GDP growth over the whole projection period. Among fuels, gas sees the biggest downwards revision in absolute terms in 2030, with demand 120 billion cubic metres (bcm) lower than last year's projection. World oil demand is 6.4% (or 6 million barrels per day [mb/d]) lower in 2015 and 2% (or 2.1 mb/d) lower in 2030.

As compared with *WEO-2008*, final energy demand is lower in the first half of the projection period, but is little different in 2030. This is mainly because faster projected growth in electricity use offsets slower growth in all other final fuels. Among sectors, demand in industry, residential, services, agriculture and non-energy uses is, in each case, lower by 2030, but transport is revised upwards – by 5% – mainly because of faster growth in non-OECD countries than was projected last year. Compared with the projections in *WEO-2008*, this year's electricity generation is lower in the short term (until 2011-2013) in most countries, as a result of the economic and financial crisis, but higher globally in 2030. Coal-fired, nuclear power and renewables-based generation increase most.

The non-OECD countries contribute the bulk of the increase in global demand for all primary energy sources except non-hydro renewables. China accounts for close to 65% of the global increase in coal use over the projection period. Most of the rest of the growth in coal demand comes from India and other non-OECD Asian countries; coal use falls in the OECD overall, despite modest growth in North America. Non-OECD countries account for all of the increase in oil demand in 2007-2030, with demand dropping significantly in all three OECD regions, due to major efficiency gains in the transport sector (which offset a further modest expansion of the car fleet) and continued switching away from oil in non-transport sectors. After China, India and the Middle East see the strongest rise in oil demand, the consequence of rapid economic growth and persistent (though declining) subsidies on oil products. Non-OECD Asia overtakes North America to become the world's largest oil consumer. Natural gas demand increases most in the Middle East, which holds the majority of the world's proven reserves. OECD countries account for 43% of the global increase in the use of renewables.

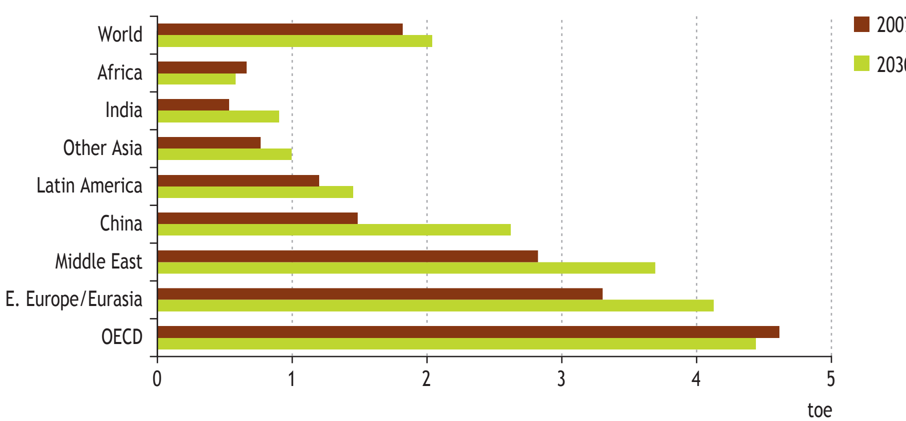
**Figure 1.2 • Incremental primary energy demand by fuel and region in the Reference Scenario, 2007-2030**




* Includes biomass and waste, wind, geothermal, solar, and tide and wave.

Although non-OECD regions account for the overwhelming bulk of the increase in energy demand to 2030, their per-capita consumption remains much lower than that in the rest of the world. By 2030, it averages just 1.5 toe, compared with 4.4 toe in the OECD. There are big differences across regions (Figure 1.3). Per-capita demand in Eastern Europe/Eurasia and the Middle East approaches that of the OECD; but it remains far lower in Africa, Latin America and Asia. In addition, much of the energy consumed in 2030 in Africa is traditional biomass, which is typically used in inefficient and polluting ways (though it is carbon-neutral). In sub-Saharan Africa, each person uses on average 0.38 toe of primary energy in 2030 – *down* 17% on 2007 and still only about one-quarter of the level in Latin America and a twelfth of that in OECD countries. This trend results from sub-Saharan Africa's rapid population growth and switching from traditional to modern energy, which is used more efficiently.

**Figure 1.3 • Per-capita primary energy demand by region in the Reference Scenario**

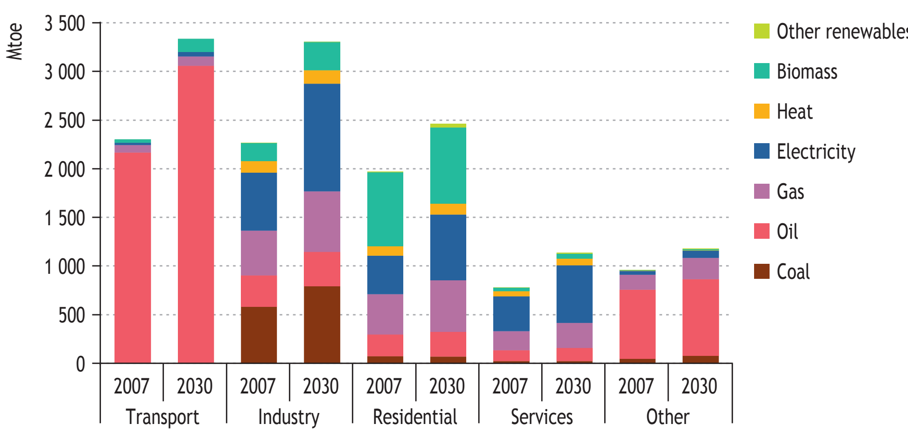


## Sectoral trends

The power and heat generation, and transport sectors account for nearly three-fourths of the global increase in primary energy use in absolute terms over the projection period, in line with past trends. Their combined share of global demand rises from 57% in 2007 to 62% in 2030. Inputs to power stations and heat plants worldwide grow by 1.9% per year between 2007 and 2030, while energy use in transport rises at an annual rate of 1.6%. Demand for mobility and electricity-related services will continue to grow broadly in line with GDP, but at a slower rate than in the past, thanks to a policy- and price-driven acceleration in efficiency gains.

Energy use in final sectors – transport, industry, households, services, agriculture and non-energy uses – in aggregate is projected to grow by 1.4% per year through to 2030, approximately the same rate as for primary energy demand. Industry demand grows most rapidly, at 1.7% per annum. Industry demand climbs in most regions, with the fastest growth occurring in the Middle East. Transport nonetheless remains the single largest final sector, just ahead of industry (Figure 1.4). Demand in the residential sector grows by only 1% per year on average, as efficiency gains largely offset the effects of rising population, urbanisation and growing wealth.

**Figure 1.4 • *World final energy consumption by fuel and sector in the Reference Scenario***

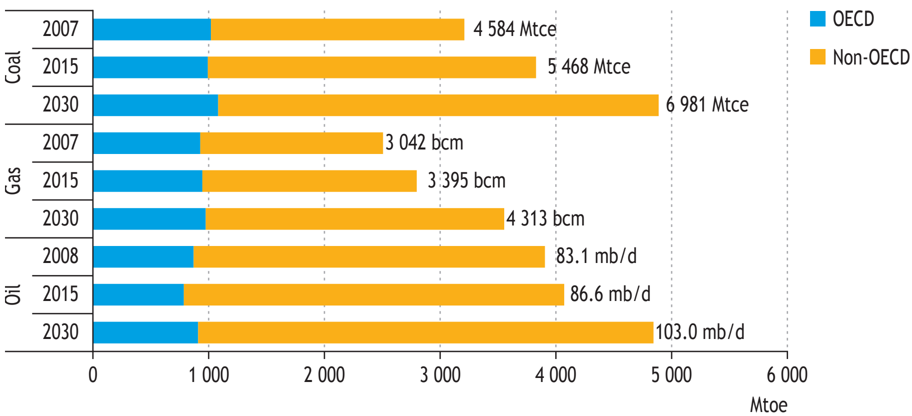



Among final forms of energy, after other renewables, electricity consumption continues to expand most rapidly over the projection period as a result of increased demand for household appliances, and industrial and commercial electrical equipment, in line with rising prosperity. Worldwide, electricity use grows by 2.5% per year on average, and its share in final energy consumption rises from 17% in 2007 to 22% in 2030. The shares of all the other fuels either remain flat or fall. The share of oil drops most, from 43% in 2007 to 40% in 2030, as demand grows only very slowly in non-transport sectors (see below: Oil market outlook).

## Energy production and trade

In aggregate, the world's energy resources are adequate to meet the projected increase in energy demand through to 2030 and well beyond. But geographic disparities in resource endowment and demand prospects imply a significant expansion in inter-regional trade. The projected expansion of supply is contingent on adequate investment in production and transportation infrastructure. There is little change in the geographical sources of incremental fossil-energy supplies: more than 95% of the increase in production, in energy-value terms, comes from non-OECD regions (where most low-cost resources are located), compared to about 94% over the previous quarter of a century (Figure 1.5).

**Figure 1.5 ● World fossil-energy production by region in the Reference Scenario**




Proven reserves of gas and coal far exceed the cumulative amounts of both fuels that are projected to be consumed in the Reference Scenario over the *Outlook* period. Coal reserves are particularly large. Reserve additions in the coming years could, in principle, sustain continued demand growth for many years after 2030. The outlook for oil is less rosy, though not immediately alarming: the share of the world's ultimately recoverable conventional oil resources left to be produced is projected to fall from about two-thirds today to around one-half by 2030. Reserves of unconventional oil (notably Canada's oil sands) are large and, on the assumption that environmental and logistical constraints can be overcome, are expected to play an increasing role in meeting global oil demand. Other sources of oil supply include coal- and gas-to-liquids plants. But the costs of supply will undoubtedly be higher than in the past, which is one reason why we assume a progressive increase in international oil prices. Uranium resources to fuel nuclear-power production are abundant, as are renewable energy sources, though their availability varies across regions.

International trade in energy expands substantially over the projection period to accommodate the growing mismatch between the location of demand and that of production. Some net importing regions see an increase in their import needs, while current exporters mostly increase their exports. Net flows to OECD countries as a whole fall by 12%, from 1 650 Mtoe in 2007 to 1 450 Mtoe in 2030. Trade between countries within the non-OECD grouping is also expected to grow: China and India, in particular, become more dependent on imports of all three fossil fuels. Oil trade between *WEO* regions as a share of primary demand is projected to grow by three percentage points between 2007 and 2030, as production becomes increasingly concentrated in a small number of resource-rich countries. Natural gas trade grows by 60% and coal trade by two-thirds, mainly driven by rising Asian demand, which outpaces indigenous production. Growing fossil-energy trade has important implications for energy security (see Chapter 2).

## Oil market outlook

Oil demand in the Reference Scenario is projected to grow by 1% per year on average over the full projection period, from 85.2 million barrels per day (mb/d) in 2007 (and 84.7 mb/d in 2008) to 88.4 mb/d in 2015 and 105.2 mb/d in 2030 (Table 1.3).[4] Demand in 2030 is just over 1 mb/d lower than projected in *WEO-2008*. Demand is now expected

**Table 1.3 • Primary oil demand* by region in the Reference Scenario** (mb/d)

| | 1980 | 2000 | 2008 | 2015 | 2030 | 2008-2030** |
|---|---|---|---|---|---|---|
| **OECD** | **41.3** | **44.7** | **43.2** | **41.2** | **40.1** | **-0.3%** |
| North America | 20.8 | 22.9 | 22.8 | 22.2 | 21.8 | -0.2% |
| *United States* | *17.4* | *19.0* | *18.5* | *17.9* | *17.2* | *-0.3%* |
| Europe | 14.4 | 13.6 | 13.0 | 12.2 | 12.0 | -0.4% |
| Pacific | 6.1 | 8.2 | 7.4 | 6.8 | 6.2 | -0.8% |
| *Japan* | *4.8* | *5.3* | *4.5* | *3.8* | *3.1* | *-1.6%* |
| **Non-OECD** | **20.0** | **26.6** | **35.0** | **40.2** | **56.2** | **2.2%** |
| E. Europe/Eurasia | 9.0 | 4.2 | 4.6 | 4.7 | 5.3 | 0.6% |
| *Russia* | *n.a.* | *2.6* | *2.8* | *2.8* | *3.1* | *0.5%* |
| Asia | 4.4 | 11.2 | 15.8 | 19.6 | 30.7 | 3.0% |
| *China* | *1.9* | *4.6* | *7.7* | *10.4* | *16.3* | *3.5%* |
| *India* | *0.7* | *2.3* | *3.0* | *3.8* | *6.9* | *3.9%* |
| *ASEAN* | *1.1* | *3.0* | *3.5* | *3.8* | *5.3* | *1.8%* |
| Middle East | 1.9 | 4.5 | 6.4 | 7.6 | 9.9 | 2.1% |
| Africa | 1.2 | 2.2 | 2.9 | 2.9 | 3.7 | 1.1% |
| Latin America | 3.4 | 4.5 | 5.3 | 5.4 | 6.6 | 1.0% |
| *Brazil* | *1.3* | *1.9* | *2.0* | *2.1* | *2.8* | *1.4%* |
| **International bunkers*** ** | **3.4** | **5.2** | **6.5** | **7.0** | **8.9** | **1.5%** |
| **World** | **64.8** | **76.5** | **84.7** | **88.4** | **105.2** | **1.0%** |
| *European Union* | *n.a.* | *12.9* | *12.4* | *11.7* | *11.3* | *-0.4%* |

* Excludes biofuels demand, which is projected to rise from 0.8 mb/d in 2008 to 1.6 mb/d in 2015 and to 2.7 mb/d in 2030.

** Compound average annual growth rate.

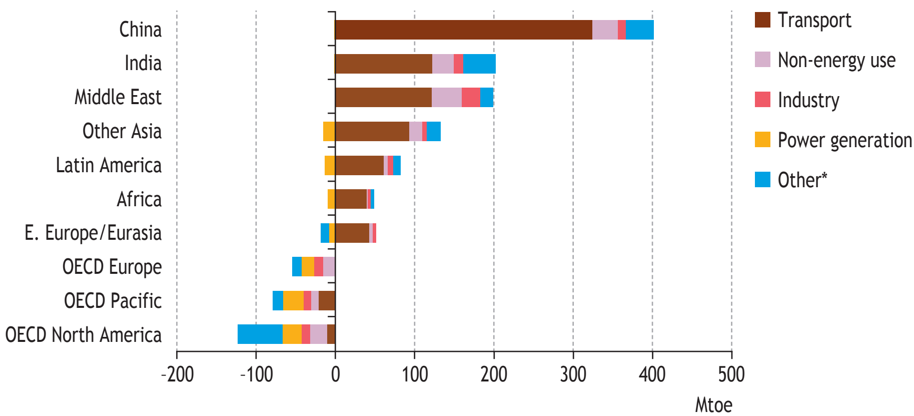
*** Includes international marine and aviation fuel. In previous *WEOs*, international aviation fuel was included at the regional level.

4. Preliminary data on total oil demand only are available for 2008 by region (the sectoral breakdown is available for 2007). Oil does not include biofuels derived from biomass. For this reason, and because of methodological differences, the oil projections in this report are not directly comparable with those published in the IEA's *Oil Market Report*.

to drop sharply in 2009, but then recover progressively from 2010 as the world economy pulls out of recession.[5] The non-OECD regions – especially Asia and the Middle East – account for all of the demand growth over the *Outlook* period; some 42% of the overall increase comes from China alone (close to three-quarters to 2015).

The transport sector is the main driver of oil demand in every region where demand grows (Figure 1.6). Transport accounts for 97% of the increase in world primary oil use between 2007 and 2030. Although biofuels take an increasing share of the market for road-transport fuels (see below: Biofuels outlook), oil-based fuels continue to dominate transport energy demand, their share falling only slightly from 94% to 92% over the projection period. Virtually all the growth in transport demand comes from non-OECD regions; it barely increases in Europe and North America, and actually declines in the Pacific region. Total non-transport oil demand falls in all three OECD regions, but increases everywhere else – especially in non-OECD Asia and the Middle East.

**Figure 1.6 • Change in primary oil demand by region and sector in the Reference Scenario, 2007-2030**

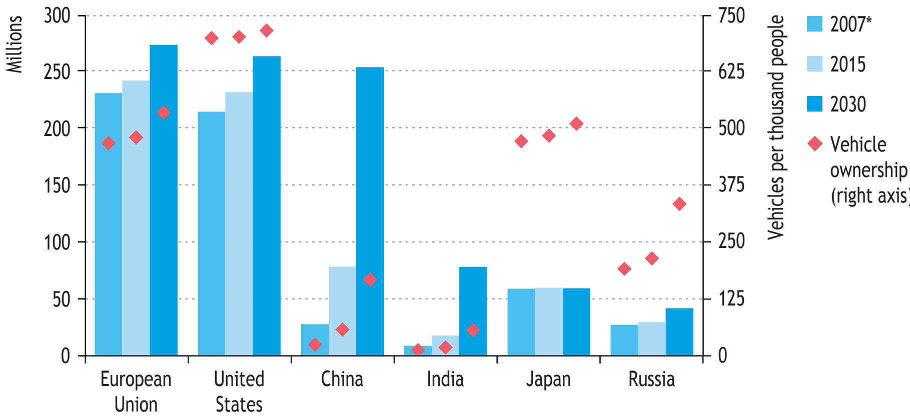



* Includes residential, services, agriculture and other energy sectors.

Continued increases in vehicle ownership in non-OECD regions push up the global fleet of passenger light-duty vehicles (PLDVs) from an estimated 770 million in 2007 to 1.4 billion in 2030 (Figure 1.7). This increase is counter-balanced to some degree by significant improvements in vehicle efficiencies throughout the world, as new, more efficient cars are commercialised (boosted in the near term by the scrapping incentives that form part of economic stimulus packages in several countries). Higher fuel prices (in part due to the assumption of subsidy removal in some countries) and recently introduced government measures contribute to this trend. In the United States,

5. The September 2009 edition of the IEA's *Oil Market Report* projects a fall in demand of 2.2% in 2009 and a rebound of 1.5% in 2010.

**Figure 1.7 • *Passenger light-duty vehicle fleet and ownership rates in key regions in the Reference Scenario***




* IEA estimate.

Corporate Average Fuel Economy (CAFE) standards were recently tightened markedly, requiring the sales-weighted average of fuel economy for new cars, SUVs and light trucks to rise from 27.5 miles per gallon (8.6 litres per 100 kilometres) today to 39 mpg (6.0 l/100km) by 2016. China has announced tax exemptions for vehicles with engines smaller than 1.6 litres. The European Union has set an objective of reducing the average $CO_2$ emissions of new vehicles to 120 grammes per kilometre[6] phased in between 2012 and 2016, from around 160 g/km today, which will entail significant efficiency gains. These measures are likely to bring about a sharp improvement in the efficiency of energy consumption in road transport in the long run.[7]

**Table 1.4 • Oil production and supply by region/country in the Reference Scenario** (mb/d)

| | 1980 | 2000 | 2008 | 2015 | 2030 | 2008-2030* |
|---|---|---|---|---|---|---|
| **Non-OPEC production** | **36.8** | **44.3** | **46.8** | **46.3** | **49.2** | **0.2%** |
| ***Crude oil*** ** | ***33.6*** | ***38.2*** | ***39.3*** | ***36.6*** | ***35.3*** | ***-0.5%*** |
| OECD | 15.0 | 17.2 | 13.5 | 10.5 | 9.5 | -1.6% |
| North America | 11.8 | 10.2 | 9.1 | 7.7 | 7.9 | -0.6% |
| *Canada* | *1.2* | *1.4* | *1.3* | *1.0* | *0.8* | -2.2% |
| *Mexico* | *1.9* | *3.0* | *2.8* | *2.0* | *2.6* | -0.4% |
| *United States* | *8.7* | *5.8* | *5.0* | *4.7* | *4.5* | -0.4% |
| Europe | 2.4 | 6.2 | 3.9 | 2.4 | 1.5 | -4.2% |
| Pacific | 0.8 | 0.8 | 0.5 | 0.4 | 0.1 | -6.1% |

6. This target can be met by a combination of efficiency improvements and alternative measures such as biofuels.

7. See Chapter 4 for a discussion of the $CO_2$ implications of these trends.

**Table 1.4 • Oil production and supply by region/country in the Reference Scenario** (mb/d) (continued)

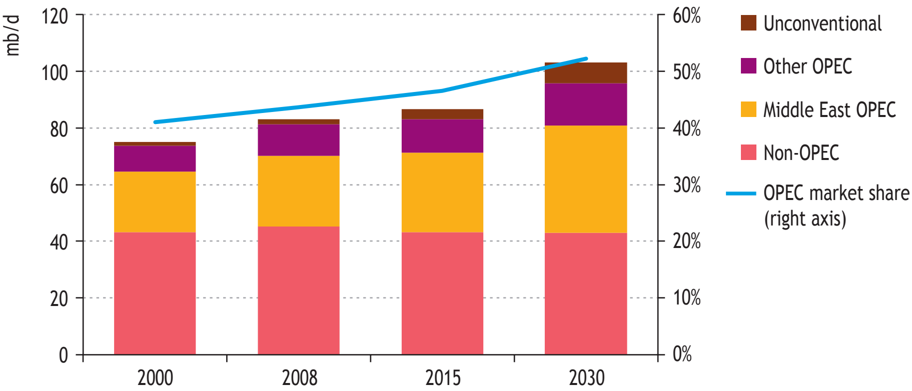
| | 1980 | 2000 | 2008 | 2015 | 2030 | 2008-2030* |
|---|---|---|---|---|---|---|
| E. Europe/Eurasia | 11.5 | 7.7 | 12.0 | 12.4 | 14.9 | 1.0% |
| *Russia* | *10.7* | *6.3* | *9.5* | *9.2* | *9.0* | *-0.3%* |
| Asia | 4.3 | 6.5 | 6.9 | 6.3 | 4.6 | -1.8% |
| *China* | *2.1* | *3.2* | *3.8* | *3.8* | *3.2* | *-0.8%* |
| *India* | *0.2* | *0.7* | *0.7* | *0.6* | *0.3* | *-3.3%* |
| *ASEAN* | *1.8* | *2.4* | *2.2* | *1.8* | *1.0* | *-3.7%* |
| Latin America | 1.2 | 3.0 | 3.3 | 4.3 | 3.9 | 0.7% |
| *Brazil* | *0.2* | *1.2* | *1.8* | *3.1* | *3.4* | *2.9%* |
| Africa | 1.0 | 1.8 | 2.2 | 2.0 | 1.6 | -1.4% |
| Middle East | 0.5 | 2.0 | 1.5 | 1.1 | 0.8 | -2.6% |
| ***Natural gas liquids*** | ***2.8*** | ***5.0*** | ***5.8*** | ***6.6*** | ***7.6*** | ***1.2%*** |
| ***Unconventional oil**** | ***0.4*** | ***1.1*** | ***1.7*** | ***3.2*** | ***6.3*** | ***6.2%*** |
| *of which Canada* | *0.2* | *0.6* | *1.2* | *2.1* | *3.9* | *5.4%* |
| **OPEC** | **26.7** | **30.8** | **36.3** | **40.3** | **53.8** | **1.8%** |
| ***Crude oil**** | ***25.1*** | ***27.8*** | ***31.2*** | ***32.6*** | ***41.4*** | ***1.3%*** |
| Middle East | 17.9 | 19.5 | 21.5 | 22.6 | 29.2 | 1.4% |
| *Iran* | *1.5* | *3.7* | *3.9* | *3.3* | *4.0* | *0.1%* |
| *Iraq* | *2.6* | *2.6* | *2.4* | *3.0* | *6.7* | *4.8%* |
| *Kuwait* | *1.7* | *2.0* | *2.6* | *2.3* | *3.1* | *0.8%* |
| *Qatar* | *0.5* | *0.7* | *0.8* | *0.6* | *0.5* | *-2.0%* |
| *Saudi Arabia* | *9.8* | *8.3* | *9.2* | *10.9* | *12.0* | *1.2%* |
| *United Arab Emirates* | *1.8* | *2.2* | *2.6* | *2.5* | *3.0* | *0.7%* |
| Non-Middle East | 7.2 | 8.3 | 9.7 | 10.0 | 12.2 | 1.0% |
| *Algeria* | *0.9* | *0.8* | *1.4* | *1.2* | *1.6* | *0.7%* |
| *Angola* | *0.2* | *0.7* | *1.8* | *2.1* | *2.5* | *1.4%* |
| *Libya* | *1.8* | *1.4* | *1.7* | *1.7* | *2.3* | *1.3%* |
| *Nigeria* | *2.1* | *2.0* | *1.9* | *2.3* | *2.3* | *0.8%* |
| *Venezuela* | *2.0* | *2.9* | *2.4* | *2.4* | *3.2* | *1.4%* |
| ***Natural gas liquids*** | ***1.6*** | ***2.8*** | ***4.9*** | ***7.3*** | ***11.3*** | ***3.9%*** |
| ***Unconventional oil**** | ***0.0*** | ***0.2*** | ***0.1*** | ***0.3*** | ***1.1*** | ***10.7%*** |
| **World production** | **63.5** | **75.0** | **83.1** | **86.6** | **103.0** | **1.0%** |
| Processing gains | 1.7 | 1.7 | 1.5 | 1.8 | 2.2 | 1.7% |
| **World oil supply** | **65.2** | **76.8** | **84.6** | **88.4** | **105.2** | **1.0%** |
| Crude oil | 58.6 | 66.0 | 70.5 | 69.2 | 76.7 | 0.4% |
| Natural gas liquids | 4.4 | 7.8 | 10.8 | 13.9 | 18.9 | 2.6% |
| Unconventional oil *** | 0.4 | 1.2 | 1.8 | 3.5 | 7.4 | 6.6% |
| *OPEC market share* | *42%* | *41%* | *44%* | *47%* | *52%* | *n.a.* |

* Compound average annual growth rate.
** Includes condensates.
*** Extra heavy oil (excluding Venezuela), natural bitumen (oil sands), chemical additives, gas-to-liquids and coal-to-liquids. Biofuels are not included.

Alternative vehicles such as hybrid cars, plug-in hybrids and electric cars have received widespread public attention recently. However, this public attention has not yet led to significant policy support directed specifically towards the adoption of such technologies aside from recently announced subsidies for hybrids, electric cars and fuel cells in China, and a similar policy in the United Kingdom (both of which have been incorporated into the Reference Scenario). In the absence of more direct policy support, the combination of high costs and the slow rate of vehicle-stock turnover sees the share of hybrids (excluding plug-ins) in the global fleet reach 5.3% by 2020 and 6.1% by 2030, up from just 0.15% in 2007. Plug-in hybrids and electric cars remain marginal in the Reference Scenario, accounting for only 0.3% of the global fleet in 2030.

Net of processing gains in refining, oil production rises from 83.1 mb/d in 2008 to 86.6 mb/d in 2015 and 103 mb/d in 2030 (Table 1.4). Most of the projected increase in output comes from members of the Organization of the Petroleum Exporting Countries (OPEC), which hold the bulk of remaining proven oil reserves and ultimately recoverable resources. Their collective output of conventional crude oil, natural gas liquids (NGLs) and unconventional oil (mainly gas-to-liquids) rises from 36.3 mb/d in 2008 to just over 40 mb/d in 2015 and almost 54 mb/d in 2030. As a result, OPEC's share of world oil production jumps from 44% now to 52% in 2030 (Figure 1.8). In principle, OPEC's recoverable resources are big enough and development costs low enough for output to grow faster than this, but investment is assumed to be constrained by several factors, including conservative depletion policies.

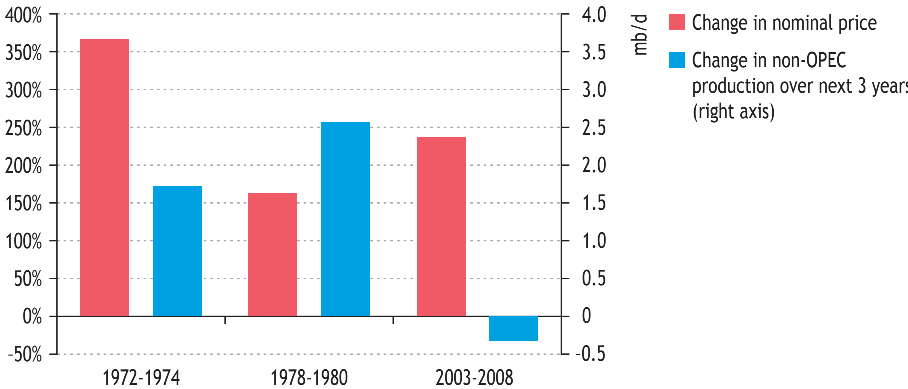
**Figure 1.8 • *Oil production by source in the Reference Scenario***




Note: Excludes processing gains. Conventional oil includes crude oil, natural gas liquids (NGLs), extra heavy oil from Venezuela and chemical additives.

Non-OPEC conventional production (crude oil and NGLs) is projected to peak around 2010 and then begin to decline slowly through to the end of the projection period. A continued decline in the number and size of new discoveries is expected to drive up marginal development costs. Production has already peaked in most non-OPEC countries and is expected to peak in most of the others before 2030 – despite an assumed steady increase in oil prices. Kazakhstan, Azerbaijan and Brazil are the only non-OPEC producing countries to see any significant increase in output. Non-OPEC conventional oil production is expected to drop by 330 thousand barrels per day (kb/d) between 2008 and 2011; by contrast, after the first two oil-price shocks, production surged (Figure 1.9).

**Figure 1.9 • Non-OPEC oil production and the oil price in the three oil shocks**




Note: The change in production is the average over the three years beginning the year immediately after the end of the period of oil-price increase. Production does not include unconventional oil or biofuels.

**Box 1.2 • Impact of falling investment on oilfield decline rates**

Initial soundings among industry participants suggest that upstream capital spending cuts will affect new field developments more than ongoing development of fields already in production (see Chapter 3). In recent years, more than half of total development spending has gone to existing fields. Yet some cutbacks in spending on existing fields have occurred. Chevron actually announced in late January 2009 that it was focusing its spending cutbacks on programmes aimed at mitigating decline at existing fields, which is expected to push up observed decline rates from a typical level of 4-5% to 7% in 2009, though it expects to reinstate that spending when market conditions improve. Some other companies are thought to have followed suit.

For the industry as a whole, decline rates could rise significantly as a result of capital spending cuts. Based on the analysis of decline rates set out in Chapter 10 of last year's *Outlook*, were capital spending on developing existing fields to be reduced by the same proportionate amount as total upstream spending in 2009 and 2010 (*i.e.* by 19% compared with 2008), the production-weighted post-peak year-on-year decline rate of existing fields globally would rise by about 0.5 percentage points within two years or so – assuming that the investment cutbacks are the same across all types of field and all regions (IEA, 2008). This implies that an additional 350 kb/d of capacity would be lost each year. The increase would be much greater for non-OPEC countries – roughly 0.6 percentage points, compared with 0.3 for OPEC countries. Worldwide, decline rates are currently lowest in the Middle East and highest in the OECD.

This difference is explained partly by the more limited opportunities for boosting production, compared with previous oil shocks, the surge in upstream costs over the last few years, the steep decline rates in non-OPEC countries (IEA, 2008) and the recent sharp drop in prices. But the decline in overall non-OPEC conventional production is more than offset by rising unconventional output, which tempers the decline in total output in the period to 2015 and then increases output overall in the second half of the projection period. Progressively higher prices are expected to stimulate renewed interest in Canadian oil sands and other unconventional sources. Although global oil production is not expected to peak before 2030, conventional oil production is projected to approach a plateau towards the end of the projection period. Unconventional sources, mainly Canadian oil sands, extra-heavy oil, gas-to-liquids and coal-to-liquids, take a growing share of world production. Global unconventional output rises from 1.8 mb/d in 2008 to 7.4 mb/d in 2030.

## Biofuels outlook

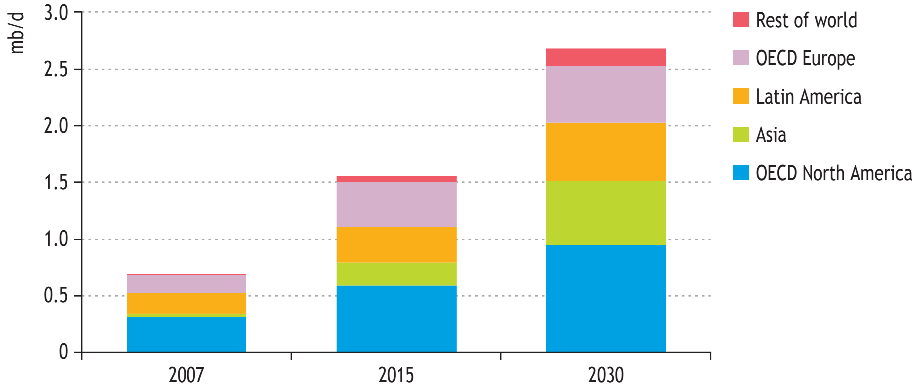
Global biofuels supply reached 0.7 mb/d[8] (34.1 Mtoe) in 2007, an impressive 37% increase on 2006, yet still accounted for only 1.5% of total road-transport fuel. According to preliminary data, supply reached 0.8 mb/d in 2008. Most of the increase in the use of biofuels in 2007 and 2008 occurred in the OECD, mainly in North America and Europe.

The recent surge in biofuels production is not expected to continue in the near term. Concerns about the effects on food prices of diverting crops to biofuels, questions about the magnitude of the greenhouse-gas emissions savings associated with switching to biofuels and doubts about their environmental sustainability have seen many countries rethinking biofuels blending targets. For example, Germany has just revised downwards its blending target for 2009 from 6.25% to 5.25%. In addition, lower oil prices have cut the profitability of biofuel production and placed enormous financial strain on many bio-refineries. Investment in new plants has all but dried up (see Chapter 3) and many existing plants are running at well below capacity.

Despite the recent downturn, world use of biofuels is projected to recover in the longer term, reaching 1.6 mb/d in 2015 and 2.7 mb/d in 2030 in the Reference Scenario (Figure 1.10). By 2030, the fuels meet 5% of total world road-transport energy demand, up from about 2% today. Close to one-quarter of this increase comes from second-generation technologies (see Introduction). Second-generation biofuels for aviation also enter the market around 2020, but economic problems and problems of scaling up facilities see production reaching only about 80 kb/d by 2030, equal to a mere 1% of aviation energy demand.

8. Calculated from an energy-equivalent basis.

**Figure 1.10 • Biofuels demand by region in the Reference Scenario**

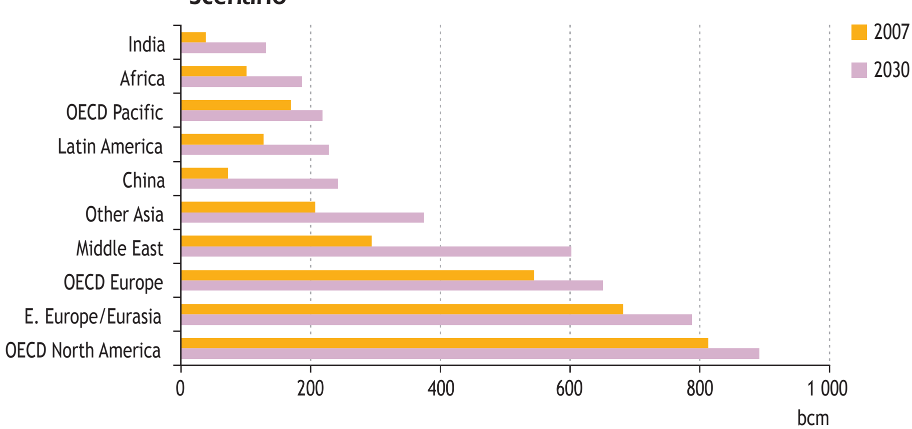



Note: On an energy-equivalent basis.

## Gas market outlook[9]

Demand for natural gas grows on average by 1.5% per year in the Reference Scenario, from 3 049 bcm in 2007 (and 3 149 bcm in 2008 according to preliminary data) to just under 3 400 bcm in 2015 and 4 310 bcm in 2030. The biggest increase in absolute terms occurs in the Middle East, where the bulk of world's gas reserves are to be found, and non-OECD Asia (Figure 1.11). North America and Eastern Europe/Eurasia remain the leading gas consumers in 2030, even though their demand rises less in percentage terms than almost anywhere else. These regions account for more than one-third of world consumption in 2030, compared with just under half today.

**Figure 1.11 • Primary natural gas demand by region in the Reference Scenario**




9. This section briefly summarises the Reference Scenario projections for natural gas. Detailed results for the gas market in this scenario together with the 450 Scenario can be found in Part C (Chapters 10-14).

New power stations, mostly using combined-cycle gas turbine technology, are projected to account for 45% of the increase in gas demand over the projection period. In many parts of the world, gas remains the preferred generating fuel for economic and environmental reasons. Gas-fired generating plants are very efficient at converting primary energy into electricity, and are cheap and fast to build, compared with coal-based and nuclear power technologies. Gas is also favoured over coal and oil for its lower emissions, especially of $CO_2$. However, the choice of fuel and technology for new power plants hinges on the price of gas relative to other fuels for generation: higher gas prices are projected to temper investment in new gas-fired plants from the middle of the next decade.

Worldwide, gas resources are more than sufficient to meet projected demand to 2030, though there are doubts about whether sufficient investment can be mobilised in all regions. Gas production rises in all major *WEO* regions except OECD Europe, where output from the North Sea is expected to decline steadily over the projection period. In line with demand, the Middle East sees the biggest increase in production in volume terms over the projection period, its output more than doubling from an estimated 379 bcm in 2008 to close to 800 bcm in 2030. Output also increases markedly in Russia, the Caspian region and Africa. Unconventional sources, including tight gas, coalbed methane and shale gas, account for an increasing share of gas supply in North America and grow in absolute terms in some other regions.

## Coal market outlook

After enjoying a number of years of strong demand and high prices, the coal industry had to adjust to a dramatic fall in demand during the second half of 2008 – a consequence of the financial crisis (see Chapter 3). The unprecedented surge in prices in 2004-2008, with average OECD steam coal import costs hitting a peak of $137 per tonne in the fourth quarter of 2008, boosted investment in coal mining and transport infrastructure. Now, with weakening demand and prices, coal producers face lower proceeds, exacerbated by a weakened dollar in the case of exporters.

Coal accounts for 27% of world primary energy demand, making it the second most important fuel after oil. Spurred mainly by demand in the power sector of non-OECD countries, coal's share in the global fuel mix reaches 29% at the end of the projection period in the Reference Scenario. Coal demand grows more strongly than all other energy sources except modern non-hydro renewables – at an average annual rate of 1.9% – from a level of 4 548 million tonnes of coal equivalent (Mtce) in 2007 to 6 980 Mtce in 2030 (Table 1.5). The share of OECD in global coal use has declined significantly, from 54% in 1980 to 36% in 2007, and is projected to decline further, to 23% by 2030, as the decrease in consumption in OECD Europe and Pacific exceeds the modest growth in OECD North America.

Most of the projected increase in global coal demand occurs in non-OECD countries, mainly in Asia, which accounts for 97% of incremental demand. China and India, which in 1980 consumed one-fifth of world coal, now account for nearly half of global demand and their share is set to rise to nearly two-thirds. Driven by strong economic expansion and urbanisation, as well as by the availability of coal resources, China's coal demand nearly doubles, while India's demand more than doubles. By 2030, India overtakes the United States as the world's second-largest coal consumer behind China, leading to a quadrupling of imports and a rise in import dependency (see below). With four-fifths of total OECD coal demand now coming from the power sector, current policies geared toward developing and investing in less carbon-intensive power-generation technologies, together with the introduction of more efficient state-of-the-art coal plants, lead OECD coal consumption to decline at an average annual rate of 0.2% over the *Outlook* period.

**Table 1.5 • Primary coal* demand by region in the Reference Scenario** (Mtce)

| | 1980 | 2000 | 2007 | 2015 | 2030 | 2007-2030** |
|---|---|---|---|---|---|---|
| **OECD** | **1 379** | **1 563** | **1 654** | **1 588** | **1 576** | **-0.2%** |
| North America | 571 | 832 | 848 | 843 | 888 | 0.2% |
| *United States* | *537* | *777* | *792* | *784* | *830* | *0.2%* |
| Europe | 663 | 467 | 482 | 420 | 378 | -1.0% |
| Pacific | 145 | 264 | 325 | 325 | 310 | -0.2% |
| *Japan* | *85* | *137* | *164* | *155* | *139* | *-0.7%* |
| **Non-OECD** | **1 181** | **1 711** | **2 895** | **3 880** | **5 405** | **2.8%** |
| E. Europe/Eurasia | 517 | 292 | 301 | 306 | 373 | 0.9% |
| *Russia* | *n.a.* | *158* | *146* | *166* | *227* | *1.9%* |
| Asia | 572 | 1 250 | 2 396 | 3 351 | 4 748 | 3.0% |
| *China* | *446* | *899* | *1 847* | *2 633* | *3 424* | *2.7%* |
| *India* | *75* | *235* | *346* | *436* | *837* | *3.9%* |
| *ASEAN* | *5* | *42* | *109* | *173* | *314* | *4.7%* |
| Middle East | 2 | 12 | 14 | 16 | 32 | 3.7% |
| Africa | 74 | 129 | 151 | 158 | 182 | 0.8% |
| Latin America | 16 | 29 | 32 | 49 | 70 | 3.4% |
| **World** | **2 560** | **3 275** | **4 548** | **5 468** | **6 981** | **1.9%** |
| *European Union* | *n.a.* | *459* | *472* | *401* | *334* | *-1.5%* |

* Includes hard coal (steam and coking coal), brown coal (lignite) and peat.

** Compound average annual growth rate.

Globally, more than three-quarters of the increase in coal demand between 2007 and 2030 comes from the power generation sector and 12% from the industrial sector. Due to fuel switching in the industrial sector in favour of electricity, the share of coal use in industry declines by two percentage points from today's share of 26%, despite a 1.3% average annual rate of demand growth. Coal as an input into electricity and heat production grows at 2.1% per annum and coal's share in the world's electricity generation mix (fuel inputs) rises from 48% now to 49% in 2030.

Global hard coal resources are very significant. Latest figures from the German Federal Institute for Geosciences and Natural Resources (BGR) suggest that total potential resources are around 16 000 billion tonnes, in addition to economically recoverable reserves of 729 billion tonnes (BGR, 2009). As recently as 2006, BGR reported potential resources of just 8 818 billion tonnes. The large upward revision is due mainly to the incorporation of previously unaccounted resources in the United States following a comprehensive study of Alaskan coal resources by the US Geological Survey. Brown coal resources total over 4 000 billion tonnes and reserves 269 billion tonnes. The overall reserve-to-production ratio approaches 1:150. Limits to the use of coal come not from any lack of reserves, but from logistical factors and – above all – from the environmental effects of its use.

In 2007 and on an energy basis, 86% of global coal was produced by seven countries: China, the United States, Australia, India, Indonesia, Russia and South Africa. China accounted for 41% of global production and the United States for another 18%. Over the projection period, world production rises by 52% (or by 2 400 Mtce) an amount almost equal to today's combined production from China, India and Indonesia (Table 1.6).

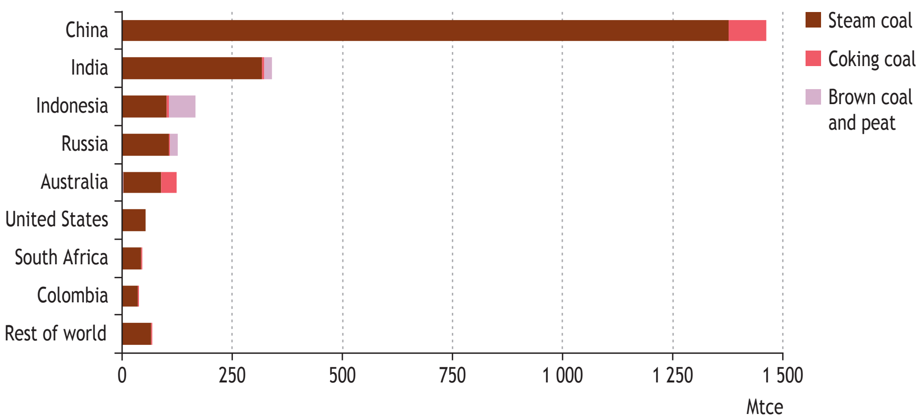
**Table 1.6 • Coal production by region in the Reference Scenario** (Mtce)

| | 1980 | 2000 | 2007 | 2015 | 2030 | 2007-2030* |
|---|---|---|---|---|---|---|
| **OECD** | **1 384** | **1 385** | **1 456** | **1 417** | **1 545** | **0.3%** |
| North America | 672 | 835 | 868 | 862 | 918 | 0.2% |
| *United States* | *640* | *778* | *811* | *801* | *857* | *0.2%* |
| Europe | 609 | 306 | 270 | 215 | 189 | -1.5% |
| Pacific | 103 | 244 | 318 | 340 | 438 | 1.4% |
| *Oceania* | *76* | *240* | *316* | *339* | *438* | *1.4%* |
| **Non-OECD** | **1 196** | **1 792** | **3 128** | **4 051** | **5 436** | **2.4%** |
| E. Europe/Eurasia | 519 | 306 | 361 | 375 | 477 | 1.2% |
| *Russia* | *n.a.* | *167* | *209* | *232* | *334* | *2.1%* |
| Asia | 568 | 1 250 | 2 484 | 3 324 | 4 546 | 2.7% |
| *China* | *444* | *928* | *1 875* | *2 575* | *3 336* | *2.5%* |
| *India* | *77* | *209* | *300* | *348* | *640* | *3.3%* |
| *Indonesia* | *0* | *66* | *230* | *282* | *397* | *2.4%* |
| Middle East | 1 | 1 | 2 | 2 | 3 | 2.8% |
| Africa | 100 | 187 | 205 | 241 | 279 | 1.4% |
| *South Africa* | *95* | *181* | *200* | *221* | *243* | *0.9%* |
| Latin America | 9 | 48 | 77 | 109 | 130 | 2.3% |
| *Colombia* | *4* | *36* | *65* | *81* | *99* | *1.9%* |
| **World**** | **2 579** | **3 177** | **4 584** | **5 468** | **6 981** | **1.8%** |
| *European Union* | *n.a.* | *306* | *268* | *207* | *162* | *-2.2%* |

* Compound average annual growth rate. ** Includes stock changes.

Increases in production in all regions between 2007 and 2030 are dwarfed by China's 61% share of incremental global production as it strives to satisfy a near-doubling of domestic demand (Figure 1.12). By 2015, India is projected to overtake Australia as the third-largest coal producer, while China and the United States remain the world's top two producers. In OECD Europe, hard coal production in Germany and Poland fell sharply in 2008, a trend that is projected to continue over the *Outlook* period, although not as steeply. Overall, production in the European Union fell from 144 million tonnes (Mt) in 2007 to 134 Mt in 2008. The growth in United Kingdom production in 2008, following the reopening of the Hatfield colliery, reversed the general trend of falling output seen since 1913. Elsewhere, hard coal production in many European countries is not competitive. In contrast, European brown coal production provides a competitive source of fuel for power generation in Germany (the world's largest producer), Turkey, Greece, Poland and the Czech Republic. Indonesia is projected to become the world's largest brown coal producer by around 2025, driven by a 5.9% average annual demand growth for coal in its power generation sector (see Chapter 15).

**Figure 1.12 • Incremental coal production by type and region in the Reference Scenario, 2007-2030**



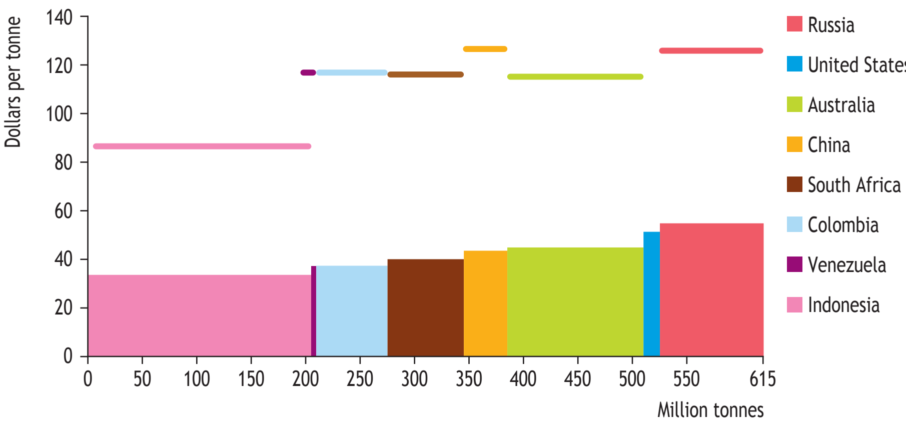

Note: Minor declines in production levels not shown due to graph scale.

Steam coal, which today accounts for three-quarters of global coal production, increases from 3 504 Mtce to 5 691 Mtce, raising its share to 82% in 2030. At the world level, the shares of coking coal and brown coal and peat combined decline from 16% and 8% respectively today to 12% and 6% by 2030. China accounts for nearly two-thirds of the growth in steam and coking coal production, while 71% of the increase in brown coal and peat production comes from Indonesia.

The rate of growth of international hard coal trade fell below 2% in 2008 from its 25-year average of 5.5%. China is expected to remain a dominant influence on the world coal market as it swings from being a net coal exporter to a net importer. Acrimonious negotiations between China and its main coking coal suppliers in 2009 resulted in prices falling back from the high levels seen in 2008. Producers in the United States and Canada are likely to compete increasingly with Australian producers, who accounted in 2008 for more than half of global trade in coking coal of all qualities. The steam coal market is more diverse, with no dominant supply country. Even in countries, such as China and Indonesia, where steam coal production is dominated by big producers, there are few barriers to new entrants. Moreover, coal companies in most countries are mainly privately owned and resource nationalism is rarely an issue.

Due to higher diesel, labour, steel, spare parts and other operational costs, the cost of producing steam coal for the international market has shifted upwards by around $10 per tonne across almost all regions, compared with the analysis published in *WEO-2008*. Costs range from an average of $34 per tonne in Indonesia, the world's largest steam coal exporter, to $55 in Russia, the third-largest steam coal exporter today (Figure 1.13). In Russia and China, more than half of the supply cost is due to the long distances coal has to be transported by rail from mines to ports and consumers, while in South Africa, Australia and Colombia more than 60% of the costs relate to mining. By mid-2008, the cost of shipping coal by sea had risen remarkably. For example, rates of over $50 per tonne were quoted from Richards Bay in South Africa to the ports of Antwerp, Rotterdam and Amsterdam in northwest Europe. By the end of the year, rates had collapsed by over 90% and then recovered to about one-third of the peak by mid-2009. In the long run, shipping rates are assumed to reflect marginal costs, despite the recent period of extreme price volatility.

**Figure 1.13 • *Coal supply cash-cost curve for internationally traded steam coal for 2008 and average FOB prices for 2008 and first-half 2009***




Note: Boxes represent costs and bars show FOB (free on board) prices. Values adjusted to 6 000 kcal/kg.
Source: IEA Clean Coal Centre citing data from Marston and IHS Global Insight.

Global inter-regional trade[10] in coal among *WEO* regions is projected to rise by more than two-thirds, from 654 Mtce in 2007 to over 1 080 Mtce in 2030. Trade as a share of total hard coal output rises from 15% to 17% (Table 1.7). While total coal trade is projected to grow at an average annual rate of 2.2%, compared to 5.1% over the past seven years, steam coal trade growth at 2.3% is stronger than the projected growth in coking coal trade of 1.7%, due to the underlying trends in end use. In 2007, seven countries (Australia, Indonesia, Russia, South Africa, Colombia, the United States and

10. All the trade figures cited in this section exclude brown coal and peat, but include coke. Inter-regional trade is less than international trade.

China) accounted for 91% of global net exports. Their share is projected to decline to 87% by 2030, as China becomes a net importer and other exporters, including Venezuela, Mongolia and other Africa, make a greater contribution. By 2030, Australia and Indonesia remain the top two exporters with a combined share of global trade of 57% compared to 60% in 2007. Russia, South Africa and Colombia each continue to account for around 10% of global trade.

OECD Asia and Europe, other non-OECD Asian countries, India and the Middle East today account for 91% of world net coal imports. A strong appetite for coal in the power generation and industrial sectors, coupled with a decline in demand of around 1% per year in the import-dependent regions of OECD Europe and Asia, means that India is projected to overtake OECD Europe as the second-largest net importer by 2030. The country's dependence on coal imports rises from 14% at present to 24% by 2030. With production declining faster than demand, largely due to the relative economics of production, OECD Europe's reliance on imports of hard coal rises from 60% at present to 75% by 2030.

**Table 1.7 • Net inter-regional hard coal* trade by region in the Reference Scenario** (Mtce)

| | 1980 | 2000 | 2007 | 2015 | 2030 |
|---|---|---|---|---|---|
| **OECD** | **- 20** | **- 119** | **- 194** | **- 171** | **- 31** |
| North America | 80 | 45 | 23 | 20 | 30 |
| *United States* | *81* | *39* | *17* | *18* | *27* |
| Europe | - 67 | - 150 | - 203 | - 205 | - 189 |
| Pacific | - 33 | - 14 | - 14 | 14 | 127 |
| *Asia* | *- 73* | *- 189* | *- 241* | *- 242* | *- 229* |
| *Oceania* | *40* | *175* | *228* | *256* | *357* |
| **Non-OECD** | **16** | **126** | **218** | **171** | **31** |
| E. Europe/Eurasia | 0 | 16 | 57 | 69 | 105 |
| *Russia* | *n.a.* | *10* | *61* | *66* | *107* |
| Asia | - 2 | 39 | 78 | - 27 | - 202 |
| *China* | *5* | *58* | *15* | *- 58* | *- 89* |
| *India* | *0* | *- 20* | *- 48* | *- 87* | *- 197* |
| *Indonesia* | *0* | *51* | *176* | *200* | *262* |
| Middle East | - 1 | - 10 | - 13 | - 14 | - 29 |
| Africa | 26 | 60 | 53 | 83 | 97 |
| *South Africa* | *27* | *66* | *61* | *78* | *94* |
| Latin America | - 8 | 21 | 42 | 60 | 61 |
| *Colombia* | *0* | *33* | *60* | *77* | *92* |
| **World** | **158** | **461** | **654** | **801** | **1 085** |
| *European Union* | *n.a.* | *- 141* | *- 193* | *- 193* | *- 171* |

* Steam and coking coal (including coke).

Note: Trade between *WEO* regions only. Positive figures denote exports; negative figures imports. Inter-regional trade between *WEO* regions differs from total international trade, which includes trade within regions.

In North America, the United States has fulfilled its traditional role of swing supplier to the international coal market, with steam coal exports to Europe reaching 13 Mt in 2008 compared with 2.2 Mt in 2005. Its increased exports of steam and coking coal in 2008 were an important response to a period of unprecedented high prices and production difficulties in Australia. Given the country's significant coal reserves, rail infrastructure and port capacity, the United States is expected to continue to play this balancing role in the Atlantic market, with net exports reaching 27 Mtce by 2030. Canada has the potential to increase coking coal exports as prices recover.

With declining indigenous hard coal production, the dependence of many European countries on high-quality Russian coal has increased. Long rail transport distances mean that this source will always tend to be relatively expensive. The recent fall in coal prices has hurt Russian producers more than others, despite shipping increased volumes into Europe and, through new loading capacity at Pacific ports, to the Far East. At the prices assumed in this *Outlook*, Russian exports remain competitive and net exports reach 107 Mtce in 2030. This outcome depends on additional rail and port investments, and perhaps on making greater use of existing capacity in the Baltic countries.

Over the *Outlook* period, OECD Oceania (essentially Australia) remains the world's largest net exporter, with almost 190 Mtce of steam coal net exports and 170 Mtce of coking coal net exports in 2030. Despite serious weather-related production problems early in 2008, Australian hard coal production rose by 0.5% to 325 Mt, in addition to the 72 Mt of brown coal production in Victoria. Recent investments in port and rail expansion projects have brought an end to the bottlenecks seen in 2007 and 2008 that led to long delays for vessels wishing to load coal. Given the country's substantial coal reserves of 77 billion tonnes (close to 8% of global reserves), there is considerable potential to expand exports, with the necessary investments in infrastructure.

China, which in 2007 accounted for 41% of global coal demand, is projected to become a net importer over the projection period. Since peaking at 101 Mtce in 2003, coal exports from China have fallen to 61 Mtce, based on preliminary 2008 data. The government closely controls exports through quotas and taxes to ensure that domestic demand is met; however, exports to Korea and Japan remain economically attractive and are projected to continue. As domestic coal demand grows, China's net imports reach 60 Mtce by 2015 and around 90 Mtce by 2030. Indonesia expands production to meet both increasing domestic demand and export demand, including from Europe. Net exports reach 262 Mtce in 2030, up from 176 Mtce in 2007 (see Chapter 15).

Coal exports from South Africa have stagnated in recent years, falling in 2008 to 59 Mtce. They are projected to rise in the long term, to 95 Mtce by 2030, on the assumption that investment in rail infrastructure is forthcoming. Elsewhere in Africa, projects in Mozambique and Botswana are moving ahead, and there is further interest in developing prospects in Zimbabwe and Madagascar. The Moatize project in Mozambique is expected to deliver 11 Mt of mainly coking coal each year from 2011. Overall, Africa is projected to remain a significant net exporter, at 97 Mtce by 2030, with growing exports to India.

Coal exports from Latin America grew in 2008, with Colombia overtaking South Africa to become the world's fourth-largest coal exporter. The low-cost structure in Colombia and its significant reserves, amounting to 67 years at current production levels, mean exports are projected to reach 92 Mtce by the end of *Outlook* period. Despite short-term labour relations problems, Drummond and El Cerrejón (a joint venture between BHP, Anglo American and Xstrata) both plan to double their production to 40 Mt, while Vale has acquired mining licences in Colombia. The situation in Venezuela is less clear. Exports fell in 2008 by 2 Mt as a consequence of strikes. However, earlier calls by President Chavez to limit annual coal production to 10 Mt have been forgotten as the country moves to attract foreign direct investment in the coal sector; as a result, exports are projected to triple compared to current levels, reaching 22 Mtce by 2030.

# Power and renewables

## Electricity demand

World electricity demand in the Reference Scenario is projected to grow at an annual rate of 2.7% in the period 2007-2015, slowing to 2.4% per year on average in the period 2015-2030 as economies mature and as electricity use becomes more efficient (Table 1.8). Over 80% of the growth between 2007 and 2030 is in non-OECD countries. In the OECD, electricity demand is projected to rise by 0.7% per year on average between 2007 and 2015, which takes into account the impact of the current

**Table 1.8 • Final electricity consumption by region in the Reference Scenario** (TWh)

| | 1980 | 2000 | 2007 | 2015 | 2030 | 2007-2030* |
|---|---|---|---|---|---|---|
| **OECD** | **4 740** | **8 253** | **9 245** | **9 792** | **11 596** | **1.0%** |
| North America | 2 386 | 4 144 | 4 530 | 4 773 | 5 679 | 1.0% |
| *United States* | *2 026* | *3 500* | *3 826* | *3 986* | *4 676* | *0.9%* |
| Europe | 1 709 | 2 696 | 3 062 | 3 222 | 3 855 | 1.0% |
| Pacific | 645 | 1 413 | 1 653 | 1 797 | 2 062 | 1.0% |
| *Japan* | *513* | *944* | *1 009* | *1 057* | *1 178* | *0.7%* |
| **Non-OECD** | **2 059** | **4 390** | **7 183** | **10 589** | **17 334** | **3.9%** |
| E. Europe/Eurasia | 1 101 | 1 023 | 1 189 | 1 354 | 1 805 | 1.8% |
| *Russia* | *n.a* | *609* | *701* | *813* | *1 066* | *1.8%* |
| Asia | 477 | 2 023 | 4 108 | 6 777 | 11 696 | 4.7% |
| *China* | *259* | *1 081* | *2 717* | *4 723* | *7 513* | *4.5%* |
| *India* | *90* | *369* | *544* | *892* | *1 966* | *5.7%* |
| *ASEAN* | *55* | *321* | *497* | *701* | *1 383* | *4.5%* |
| Middle East | 75 | 371 | 575 | 790 | 1 382 | 3.9% |
| Africa | 158 | 346 | 505 | 662 | 1 012 | 3.1% |
| Latin America | 248 | 627 | 806 | 1 006 | 1 438 | 2.6% |
| *Brazil* | *119* | *319* | *395* | *492* | *654* | *2.2%* |
| **World** | **6 799** | **12 642** | **16 429** | **20 381** | **28 930** | **2.5%** |
| *European Union* | *n.a.* | *2 520* | *2 840* | *2 973* | *3 485* | *0.9%* |

* Compound average annual growth rate.

financial and economic crisis, discussed in Chapter 3. Growth in the period 2015-2030 is somewhat higher, averaging 1.1% per year. Demand in non-OECD countries grows by 5% per year over 2007-2015, slowing to 3.3% per year in 2015-2030. In contrast to all other final forms of energy, projected electricity demand in 2030 is slightly higher than in last year's *Outlook*.

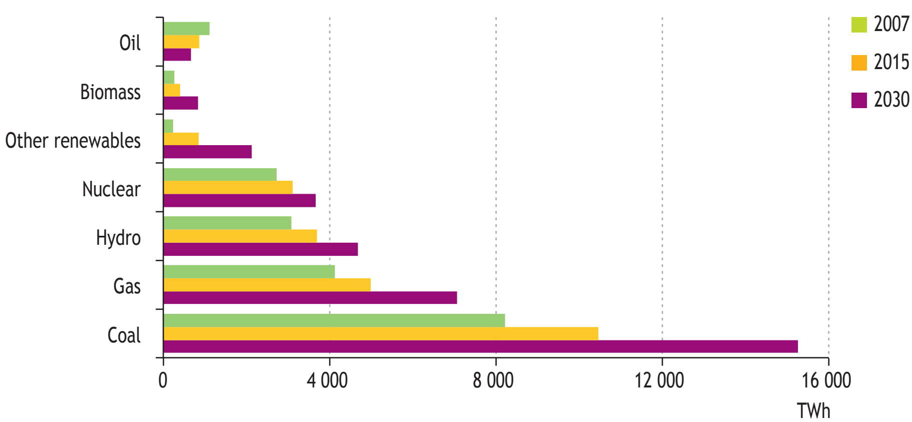
Electricity demand grows the most rapidly in non-OECD Asia. China's electricity demand, which grew by over 14% per year between 2000 and 2007, continues to increase but at a slower rate, primarily reflecting the shift in the economic structure from heavy industry towards less energy-intensive lighter industry and services. Nonetheless, demand increases by 75% between 2007 and 2015, and almost triples by 2030. The projected slowdown results primarily from a shift in the economic structure from heavy industry to less energy-intensive lighter industry and services. India's growth in electricity demand, at 5.7% annually between 2007 and 2030, is the highest in the world. Demand in ASEAN countries also grows rapidly, at 4.5% annually.

Despite the projected strong growth in electricity demand in non-OECD countries, per-capita demand remains low, even in 2030, in several regions. Per-capita electricity consumption is lowest in sub-Saharan Africa and although it is projected to increase from 140 kWh per person per year now to 230 kWh by 2030, it will still be almost 40 times lower than the current OECD average. This is because a large number of people living in sub-Saharan Africa are not expected to have access to electricity even in 2030 (see Chapter 2).

## Electricity supply

In the Reference Scenario, global electricity generation rises from 19 756 TWh in 2007 to 24 350 TWh by 2015 and to 34 290 TWh by 2030.[11] The share of coal in total electricity generation increases from 42% now to 44% in 2030 (Figure 1.14). Non-hydro

**Figure 1.14 • World electricity generation by fuel in the Reference Scenario**




11. Electricity generation includes final consumption of electricity, network losses, own use of electricity at power plants and "other energy sector".

renewable energy sources – biomass, wind, solar, geothermal, wave and tidal energy – continue to increase their share of the market, accounting for almost 9% of the total in 2030, up from 2.5% now. The share of gas-fired generation remains flat at about 21%. Oil use in power generation, already marginal in most countries, drops to 2% by 2030. Hydropower accounts for a slightly smaller share in 2030 than now. The share of nuclear power, which has been falling since the mid-1990s, drops from 14% in 2007 to 11% in 2030.

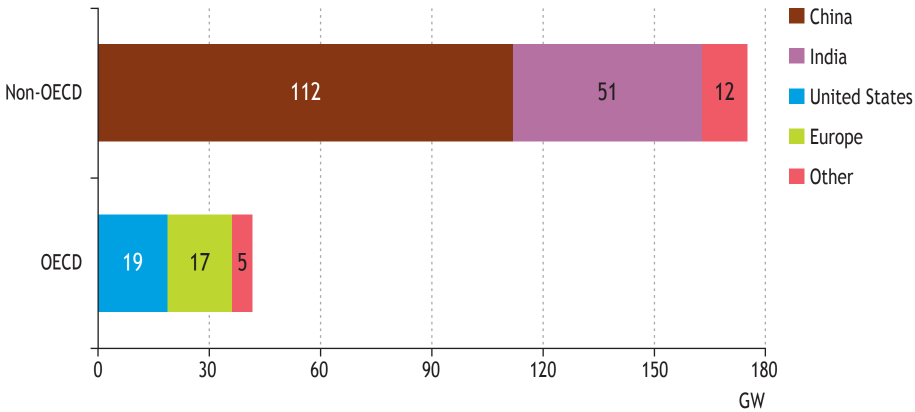
**Box 1.3 ● *Changes in power-generation projections in this year's Outlook***

Compared with *WEO-2008*, this year's projections for electricity generation is lower in the short term (until 2011-2013) in most countries, as a result of the economic and financial crisis, but higher globally in 2030. The most important other revisions are:

- Electricity demand in 2030 is lower in the OECD (-2%), Russia (-1%) and Latin America (-4%). Long-term demand has been revised upward in Africa (+1% in 2030), Middle East (+2%) and non-OECD Asia (+10%), including China and India. Consequently, global electricity demand in 2030 is 3% higher than *WEO-2008*.
- Coal-based generation is 5% higher globally in 2030, with OECD reduced by 8% and non-OECD Asia increased by 10%. Gas is higher by 5% globally, spread among OECD, non-OECD Asia and the Middle East. Gas-fired generation is higher in the United States, at the expense of coal, because of assumed lower gas prices there.
- Nuclear capacity in 2030 is 42 gigawatts (GW) or 10% higher in 2030 compared with *WEO-2008*, mainly because of a reassessment of China's nuclear power plan.
- Total non-hydro renewables generation in 2030 has been revised up by 2%. Wind and solar power are higher by 3% and 14% respectively (mainly due to new policies), but biomass prospects have been revised downward by 3%. The share of non-hydro renewables in total generation in the OECD is higher, but globally the share is very slightly lower (8.6% in 2030 against 8.7% in *WEO-2008*) because of the greater weight of non-OECD countries (which make less use of renewables than the OECD) in world demand.

Coal-fired generation nearly doubles between 2007 and 2030, with coal remaining the main fuel for power generation worldwide. The bulk of the increase comes from non-OECD countries. A total of 217 GW of coal-fired capacity is now under construction in the world; over 80% of it is in non-OECD countries (Figure 1.15). In the OECD, coal-fired generation increases modestly, at 0.3% per annum between 2007 and 2030. It falls significantly in the European Union because of policies to reduce greenhouse-gas emissions. Coal-fired generation grows by 2.5 times in China and by 3.5 times in India during this period.

**Figure 1.15 • Coal-fired power-generation capacity under construction by country**




Note: Includes power plants considered as under construction in 2008.

Source: Platt's World Electric Power Plants Database, December 2008 version.

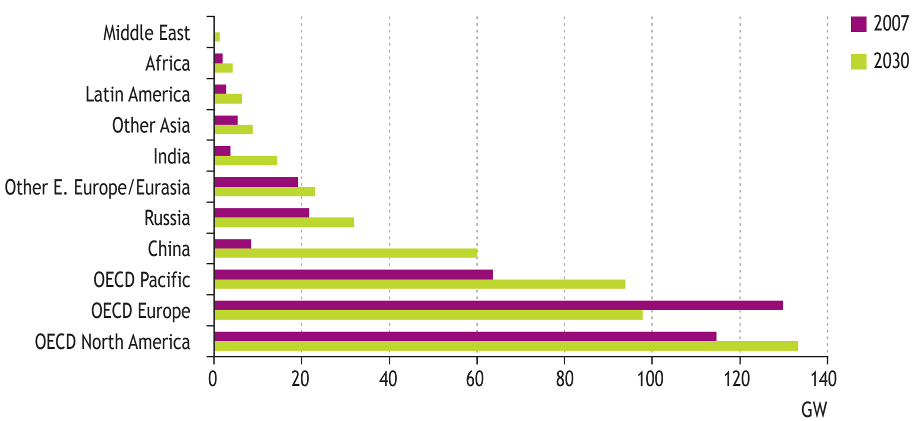
The average gross efficiency of coal-fired generation (excluding combined heat and power) is projected to increase from 35% in 2007 to 36% in 2015 and to 40% in 2030, as new power plants are based increasingly on more advanced technologies. Supercritical technology is expected to become more widely used in the mid-term, while ultra-supercritical technology and integrated gasification combined-cycle plants are projected to become more widespread after 2020.

Natural gas-fired electricity generation is projected to increase from 4 126 TWh in 2007 to 6 910 TWh in 2030. The increase in gas-fired generation is more equally distributed across regions than coal. The most substantial increase is in the Middle East, as a result of strong growth in electricity demand and a gradual switch from oil to gas, in order to free up oil for export. Gas-fired generation is expected to continue to grow in the OECD, although much more slowly than over the past decade. Although high natural gas prices are expected to constrain demand for new gas-fired generation, it still has advantages that make it attractive to investors, notably lower capital costs and a shorter construction time than most other generation technologies. It also has lower $CO_2$ emissions per unit of electricity produced, compared with coal, helping generators to comply with requirements to reduce these emissions.

Oil products have a marginal role in power generation. They were used to produce only 6% of total electricity generation worldwide in 2007. This share has been declining slowly for many years, due to government policies to diversify away from oil and, more recently, to high oil prices. Electricity generation based on oil is projected to fall from 1 117 TWh in 2007 to 665 TWh by 2030, less than 2% of the total.

Electricity generation from nuclear power plants rises from 2 719 TWh in 2007 to 3 670 TWh in 2030. Nuclear power generation capacity reached 371 GW in 2007 and is projected to rise to 410 GW by 2015 and to 475 GW by 2030. Over the past few years, a large number of countries have expressed renewed interest in building nuclear power plants, driven by concerns over energy security, surging fossil-fuel prices and rising $CO_2$ emissions. Few governments, however, have taken concrete steps to promote the construction of new reactors, other than in those countries that have had active nuclear power construction programmes in place for a long time. The exception is China, where the government has announced ambitious targets to develop nuclear power plants. Consequently, most of the projected increase in nuclear power is in China, where nuclear power expands from 8 GW in 2007 to 60 GW in 2030 and its share in electricity output increases from 2% to 6% (Figure 1.16). Nuclear power also increases in other Asian countries, notably in Japan, Korea and India. In the United States, installed nuclear power capacity increases from 101 GW in 2007 to 115 GW in 2030, an increase initially supported by financial incentives to power producers.[12] By contrast, nuclear power capacity falls from 132 GW to 103 GW in the European Union, as a result of policies to phase out nuclear power plants and widespread retirements of existing reactors, notably after 2020. The share of nuclear power in total electricity in the European Union drops sharply, from 28% in 2007 to 19% in 2030. However, there is growing interest in nuclear power in many European countries, which could change these prospects.

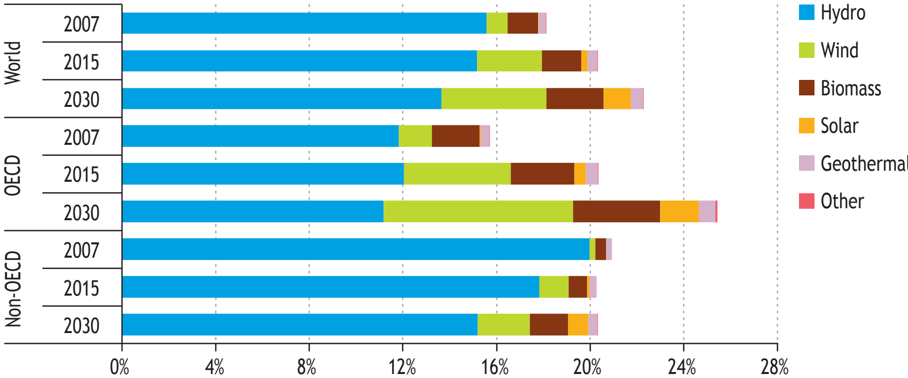
**Figure 1.16 • Nuclear power-generation capacity by region in the Reference Scenario**




Higher fossil-fuel prices, as well as increasing concerns over energy security and climate change, are boosting the development of renewable energy for electricity production in many parts of the world. World renewables-based electricity generation (including hydropower) is projected to increase from 3 577 TWh in 2007 to 7 640 TWh in 2030. Its share in total electricity generation rises from 18% in 2007 to 22% in 2030 (Figure 1.17). In the OECD, the share of renewables reaches one-quarter of total electricity production by 2030, up from 16% now. This increase is largely driven by incentives to encourage new renewable technologies, particularly wind and solar power. Increased reliance on intermittent renewables, such as wind power, would increase the need for firm back-up capacity.

12. Detailed projections of generating capacity by region for all fuels can be found in Annex A.

**Figure 1.17 • Share of renewables in electricity generation by region in the Reference Scenario**




Hydropower increases from 3 078 TWh in 2007 to 4 680 TWh in 2030. Most new hydropower capacity is added in non-OECD countries, where the remaining potential is high. In the OECD, the best sites have already been exploited and environmental regulations constrain new development. Some 160 GW of hydropower capacity is under construction, about half of it in China. India is constructing 13 GW. Russia and Brazil each have about 5 GW under construction. Interest and support for hydropower projects in non-OECD countries are growing among international lenders and the private sector.

Wind power has been growing rapidly in the OECD and, increasingly, in non-OECD countries, notably in China and India. Electricity generation from wind power is projected to reach 4.5% of total electricity generation in 2030 worldwide, compared with less than 1% in 2007. In the OECD, this share reaches 8% in 2030. Wind power is projected to soon become the most significant source of renewables-based electricity after hydropower, ahead of biomass.

Biomass for power increases from 259 TWh in 2007 to 840 TWh in 2030. Most of this comes from combined heat and power plants. Other growing areas of biomass use in power generation include co-firing in coal-based power plants and landfill gas.

Electricity generation from solar photovoltaics (PV) is currently tiny, but is growing fast. It reaches almost 280 TWh in 2030, up from just 4 TWh in 2007.[13] Installed PV capacity rose to 13 GW in 2008, up from 8 GW in 2007, owing mostly to a dramatic increase in Spain. PV capacity is projected to rise to 200 GW by 2030, with two-thirds of it installed in OECD countries. Most PV systems are installed in buildings rather than in central-grid power plants and this is likely to remain the case in the future. Central-grid based generation from PV is expected to remain costly, despite falling costs. The economics of PV in buildings are much more favourable, as PV competes against grid electricity prices, which are expected to increase over time. In the past few years, there has been a surge in projects using concentrating solar power (CSP)

13. This figure is likely to be understated because of a lack of good data (see IEA, 2009).

technologies and this trend is set to continue, particularly in sunny areas, where CSP better competes with conventional technologies. Electricity generation from CSP plants is projected to increase from less than 1 TWh in 2007 to almost 124 TWh by 2030.

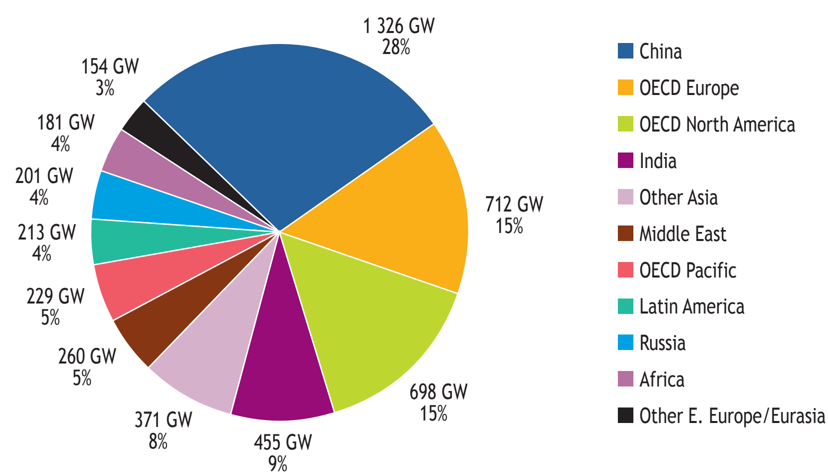
Geothermal power increases in a number of regions, but its expansion is constrained by the distribution of resources and by the fact that resources are often located far from demand centres. Most of the increase is along the countries of the Pacific Rim. The United States accounts for one-quarter of the global increase in geothermal power between 2007 and 2030.

Tide and wave energy is still in its infancy, producing just 0.6 TWh of electricity in 2007. This rises to almost 13 TWh by 2030, a small fraction of its technical potential. Wave power and ocean current technologies are at an early stage of commercialisation, but there is strong interest on the part of several governments in developing them further.

## New capacity and investment in infrastructure

World installed power-generation capacity in the Reference Scenario is projected to rise from 4 509 GW in 2007 to 7 820 GW in 2030. Total gross capacity additions amount to 4 800 GW over the period, with 30% of this installed by 2015. On average, capacity additions amount to 190 GW per year in 2008-2015, rising to almost 220 GW per year in 2016-2030. The largest capacity additions are in China, nearly 30% of the world total (Figure 1.18).

**Figure 1.18 • Power-generation capacity additions by region, 2008-2030**




Cumulative power-sector investment over 2008-2030 amounts to $13.7 trillion in year-2008 dollars. Just over half of this amount, around $7.2 trillion, is needed in generating plants. The remainder is needed in networks, with transmission requiring $2 trillion and distribution $4.5 trillion. The largest investment requirements, exceeding $3 trillion, arise in China. Investment needs are also very large in the United States and Europe (Table 1.9).

**Table 1.9 • Projected capacity additions and investment in power infrastructure by region in the Reference Scenario**

| | Investment, 2008-2015 ($2008 billion) | | | | Investment, 2016-2030 ($2008 billion) | | | |
|---|---|---|---|---|---|---|---|---|
| | Capacity additions (GW) | Power generation | Trans-mission | Distri-bution | Capacity additions (GW) | Power generation | Trans-mission | Distri-bution |
| **OECD** | **481** | **906** | **237** | **550** | **1 158** | **2 386** | **480** | **1 135** |
| North America | 184 | 304 | 111 | 240 | 514 | 1 014 | 243 | 524 |
| *United States* | *148* | *261* | *93* | *200* | *420* | *880* | *201* | *434* |
| Europe | 220 | 477 | 71 | 214 | 492 | 1 047 | 155 | 470 |
| Pacific | 77 | 126 | 55 | 96 | 153 | 325 | 82 | 142 |
| *Japan* | *47* | *72* | *35* | *58* | *90* | *200* | *50* | *83* |
| **Non-OECD** | **1 041** | **1 106** | **429** | **925** | **2 119** | **2 798** | **859** | **1 853** |
| E. Europe/ Eurasia | 100 | 131 | 31 | 104 | 255 | 427 | 62 | 207 |
| *Russia* | *59* | *79* | *14* | *45* | *142* | *249* | *24* | *78* |
| Asia | 736 | 792 | 323 | 666 | 1 415 | 1 795 | 626 | 1 292 |
| *China* | *530* | *542* | *218* | *449* | *795* | *981* | *304* | *627* |
| *India* | *117* | *145* | *61* | *126* | *338* | *459* | *182* | *375* |
| *ASEAN* | *56* | *61* | *28* | *58* | *187* | *219* | *88* | *181* |
| Middle East | 85 | 50 | 25 | 52 | 175 | 165 | 61 | 126 |
| Africa | 57 | 58 | 21 | 42 | 124 | 188 | 47 | 98 |
| Latin America | 64 | 74 | 29 | 61 | 150 | 222 | 63 | 130 |
| **World** | **1 522** | **2 012** | **666** | **1 475** | **3 277** | **5 183** | **1 339** | **2 988** |
| *European Union* | *213* | *467* | *69* | *206* | *460* | *996* | *140* | *417* |

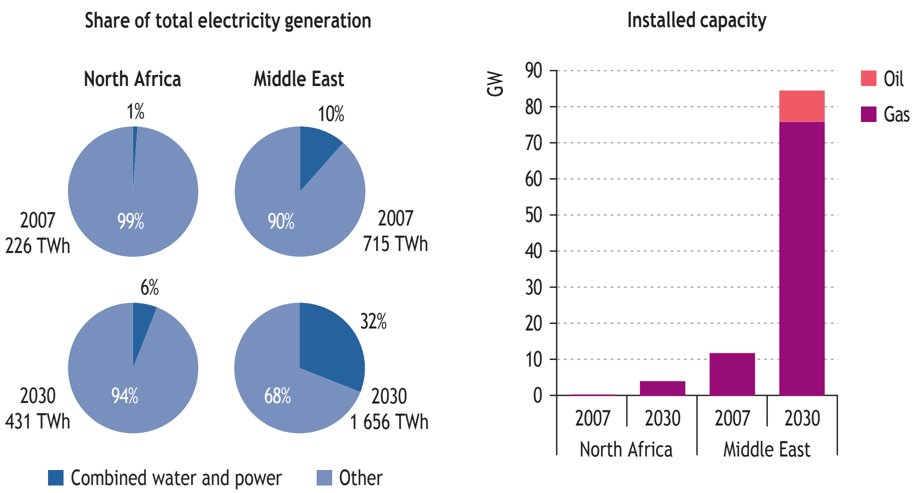
## Water desalination

Water desalination is used in several parts of the world where access to fresh water is scarce. It is an energy-intensive process, using electricity or steam. It is used primarily in the Middle East and North Africa, and these two regions hold around half of the world's total desalination capacity. Demand for desalinated water there is growing rapidly. Our analysis shows that desalination capacity in these two regions alone is expected to grow from 21 million cubic metres (mcm) of water per day in 2007 to nearly 110 mcm per day by 2030 (of which 70% is in Saudi Arabia, the United Arab Emirates, Kuwait, Algeria and Libya), contributing to the surge in energy use in the region.

One efficient way to reduce the energy needs of the thermal water desalination process is to couple it with electricity generation to provide more efficient use of the inputs (fossil fuel or renewable such as concentrated solar power). In combined water and power plants, steam is used to drive a turbine to generate electricity and the resulting low-grade heat output may then be used for distillation. Approximately 5% of the electricity is required for operating the desalination plant, with the remainder available for export to the transmission network.

In 2009, the world's largest combined desalination and power plant was officially opened in Saudi Arabia, with the plant capable of producing 800 000 cubic metres ($m^3$) of water per day and a total generating capacity of 2 750 megawatts (MW). We estimate that by 2030 almost one-third of electricity production (Figure 1.19) and capacity additions in the Middle East will come from combined water and power plants. In other words, 54% of the additional generation between 2007 and 2030 will be met by these types of plants.

**Figure 1.19 • Electricity generation from combined water and power plants in North Africa and the Middle East**




Sources: GWI (2009); IEA analysis.

Membrane distillation though reverse osmosis (RO) is the other common desalination technique typically employed, for which the principal energy input is electricity. Historically, RO plants were smaller in scale and limited in output capacity. However, new plants are now rivalling their thermal distillation counterparts, such as the 500 000 $m^3$ per day RO plant under construction in Oran, Algeria. Through innovation and technology advancement, the energy requirement per unit of water output for RO has been steadily dropping and is now less than 4 kWh/$m^3$ for new plant. By 2030, total electricity requirements for desalination in the Middle East and North Africa are expected to have tripled compared with 2007, rising to 122 TWh.

## Energy investment

The Reference Scenario projections in this *Outlook* call for cumulative investment in energy-supply infrastructure of $25.6 trillion (in year-2008 dollars) for the period

2008-2030 (Table 1.10).[14] Projected investment will be needed to expand supply capacity, and to replace existing and future supply facilities that will be closed during the projection period as they become obsolete or resources are exhausted.

Energy investment requirements to 2030 are slightly lower than projected in *WEO-2008*. In addition to the period being one year shorter, the reduction is due to the downward revision in projected total primary energy demand, which has slightly reduced the need to bring on additional supply capacity and the recent wave of cost deflation, resulting in a modest reduction in assumed unit costs – particularly in the upstream oil and gas industry. These factors have been offset to some extent by a slight rise in projected power-sector investment, due to marginally higher electricity demand in 2030 and a shift in the generating mix towards more capital-intensive options, such as nuclear, wind and solar.

**Table 1.10 • Cumulative investment in energy-supply infrastructure by region in the Reference Scenario, 2008-2030**
*($ billion in year-2008 dollars)*

| | Coal | Oil | Gas | Power | Total |
|---|---|---|---|---|---|
| **OECD** | **133** | **1 262** | **2 262** | **5 695** | **9 460** |
| North America | 72 | 882 | 1 389 | 2 435 | 4 857 |
| Europe | 24 | 293 | 611 | 2 435 | 3 391 |
| Pacific | 37 | 88 | 262 | 825 | 1 212 |
| **Non-OECD** | **464** | **4 444** | **2 824** | **7 969** | **15 748** |
| E. Europe/Eurasia | 43 | 1 001 | 870 | 962 | 2 878 |
| *Russia* | *25* | *521* | *592* | *487* | *1 626* |
| Asia | 384 | 872 | 769 | 5 494 | 7 547 |
| *China* | *280* | *482* | *233* | *3 119* | *4 132* |
| *India* | *58* | *170* | *165* | *1 347* | *1 745* |
| *ASEAN* | *38* | *206* | *263* | *635* | *1 146* |
| Middle East | 1 | 903 | 577 | 479 | 1 960 |
| Africa | 22 | 1 018 | 361 | 454 | 1 855 |
| Latin America | 15 | 650 | 248 | 579 | 1 508 |
| Inter-regional transport | 64 | 213 | 63 | n.a. | 346 |
| **World** | **661** | **5 919** | **5 149** | **13 664** | **25 555** |

Note: Regional totals include a total of $163 billion investment in biofuels production facilities.

The power sector requires around $13.7 trillion of capital expenditure over the *Outlook* period, accounting for more than half of total energy-supply investments (Figure 1.20).

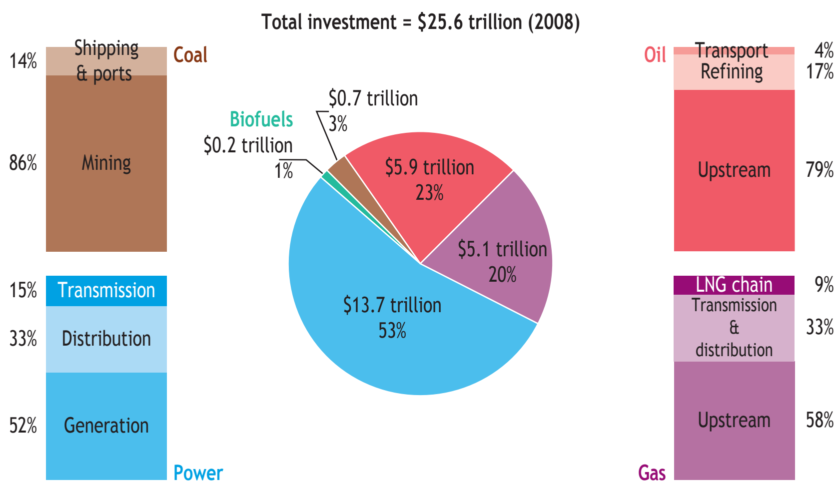
14. The projections of investment in both scenarios presented in this *WEO* for the period 2008-2030 derive from the projections of energy supply for each fuel and each region. The methodology involves estimating new-build capacity needs for production, transportation and (where appropriate) transformation, as well as unit capital costs for each component in the supply chain. Incremental capacity needs are multiplied by unit costs to yield the amount of investment needed. Capital spending is attributed to the year in which the plant in question becomes operational. It does not include spending that is usually classified as operating costs.

The share is closer to about 70% if investment in the oil, gas and coal supply chains to meet the fuel needs for power generation is included. Almost half of the investment in the electricity industry is needed for transmission and distribution networks, and the rest for power plants.

Investment in the oil sector, mostly for upstream developments and mainly to replace capacity that will become obsolete over the projection period, amounts to \$5.9 trillion. Of this, investment in oil refining amounts to almost \$1.0 trillion. Investment in bio-refineries is projected to total \$163 billion, most of which occurs in the United States, the European Union and China. Investment totals \$5.1 trillion in the gas sector and \$660 billion in the coal industry.

As world primary energy production continues to shift toward non-OECD regions, 50% of the total energy investment is required in developing countries, and another 11% in Russia and other countries in Eastern Europe/Eurasia. China alone needs to invest \$4.1 trillion – 16% of the world total – while India needs to invest \$1.7 trillion. The Middle East requires about \$2 trillion, of which half is for upstream oil and gas projects. ASEAN countries need \$1.1 trillion in investments in the energy sector to 2030. OECD countries account for 37% of global investment, with OECD North America requiring a higher level of investment in dollar terms than any other region or country.

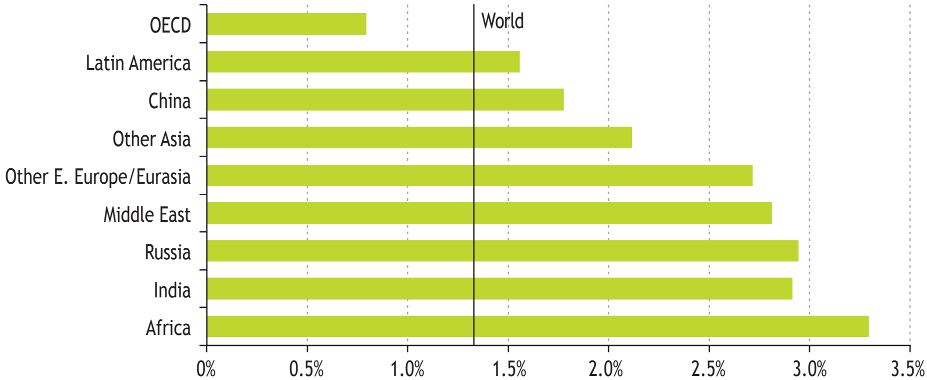
**Figure 1.20 • *Cumulative investment in energy-supply infrastructure in the Reference Scenario, 2008-2030*** (in year-2008 dollars)




Projected global energy investment of \$25.6 trillion equates to 1.4% of global GDP on average through to 2030.[15] The share of energy investment in GDP varies across regions. The share is highest (around 3% on average) in India, Africa, the Middle East and Russia. In contrast, in the OECD it is only 0.8% of GDP (Figure 1.21).

15. Total cumulative investment divided by cumulative world GDP (in year-2008 dollars at market exchange rates) between 2008 and 2030.

**Figure 1.21 • *Share of energy investment in GDP by region in the Reference Scenario, 2008-2030***




Note: GDP expressed in year-2008 dollars at market exchange rates.

The credit crunch and economic downturn have dramatically altered the landscape for financing energy investment. Overall investment in energy supply, including oil and gas wells, refineries, pipelines and power stations, is expected to be reduced substantially over the next year or two, and the allocation of capital across the different energy sectors to be markedly changed. Raising funds is expected to be more challenging until a recovery takes hold, particularly in liberalised markets, where private capital flows are very sensitive to macroeconomic conditions (see Chapter 3). Some countries have allocated funding to the energy sector as part of their economic stimulus packages.

# IMPLICATIONS OF CURRENT ENERGY POLICIES

## Why is the Reference Scenario unsustainable?

### H I G H L I G H T S

- The Reference Scenario projections have profound implications for each of the "three Es" of sound energy policy making: energy security, environmental protection and economic development.
- In the absence of new initiatives to tackle climate change, rising global fossil-fuel use continues to drive up energy-related $CO_2$ emissions, from 29 Gt in 2007 to 40 Gt in 2030 — an increase of 40%. Although the financial crisis has slowed the growth in emissions, current trends put us on a path to a global average temperature increase of up to 6°C. The projected rise in energy demand also has implications for ambient air quality, with serious public health and environmental effects, particularly in developing countries.
- While the OECD will be importing less oil in 2030 than today, some non-OECD countries, notably China and India, will see big increases. Most gas-importing regions also see their net imports rise. China overtakes the United States, soon after 2025, to become the world's biggest spender on oil and gas imports, while India's spending surpasses that of Japan soon after 2020 to become the world's third-largest importer.
- Cumulative OPEC revenues from oil and gas exports increase to $30 trillion between 2008 and 2030, almost a five-fold increase on earnings over the past 23 years. Even in the event of a global commitment to curb greenhouse-gas emissions, as assumed in the 450 Scenario, OPEC countries would be called upon to produce 11.4 mb/d more oil in 2030 than they produce today. In both scenarios, the market power of OPEC increases.
- In some respects, energy supplies become more flexible, diverse and robust to interruptions in the years to come, for example as global LNG trade grows. Growing dependence on international trade, in some cases dependent on vulnerable transit routes, pulls in the other direction. Uncertainties about the adequacy of supply-side investment are an important component of long-term risk. The security of electricity supply is as much an issue for governments as the security of oil and gas supply.
- 1.3 billion people lack access to electricity in 2030, compared with 1.5 billion people today. Universal electricity access could be achieved with additional power-sector investment of $35 billion per year in 2008-2030, or just 6% of the annual average investment in the power sector in the Reference Scenario. Furthermore, the resulting increase in primary energy demand and $CO_2$ emissions would be modest.

## Introduction

The Reference Scenario provides a baseline vision of how global energy markets are likely to evolve if no new government policies are introduced during the projection period. This chapter draws out the implications of the results in this scenario for each of the "three Es" of balanced energy policy making: environmental protection, energy security and economic development.

The projected rate of growth in fossil-fuel consumption in the Reference Scenario would drive up energy-related carbon-dioxide ($CO_2$) emissions over the next two decades. Although the economic downturn, along with a range of government policies, including those intended to address climate change and enhance energy security, has slowed the rate of growth in emissions, in most countries, emissions are still rising fast. Moreover, the environmental consequences of the Reference Scenario go beyond climate change. Increasing reliance on fossil fuels would also intensify problems of local air pollution, particularly in countries that do not have advanced emissions-control systems in their power plants, industry and vehicles. Noxious and toxic emissions contribute directly to health problems, urban smog and acid rain.

Rising fossil-energy use also has energy security implications. The risks of disruptions to oil and natural gas supplies increase, as much of the incremental production is set to come from politically unstable parts of the world and to be shipped along vulnerable maritime and pipeline routes. In addition, because of the concentration of resources in a small group of countries, the market dominance of these countries increases.

The continuation of current trends in energy demand and supply would also have significant implications for economic and human development. The Reference Scenario projections, combined with our price assumptions, imply an increasing transfer of wealth from consuming countries to producing countries to pay for oil and gas imports. Energy poverty is already a major problem in the world's least-developed regions, holding back much-needed improvements in productivity, employment, communication, health-care and education.[1]

## Implications for the environment

### Global trends in energy-related $CO_2$ emissions[2]

The Reference Scenario sees a continued rapid rise in energy-related $CO_2$ emissions through to 2030, resulting from increased global demand for fossil energy. Having already increased from 20.9 Gt in 1990 to 28.8 Gt in 2007, energy-related $CO_2$ emissions are projected to reach 34.5 Gt in 2020 and 40.2 Gt in 2030 – an average

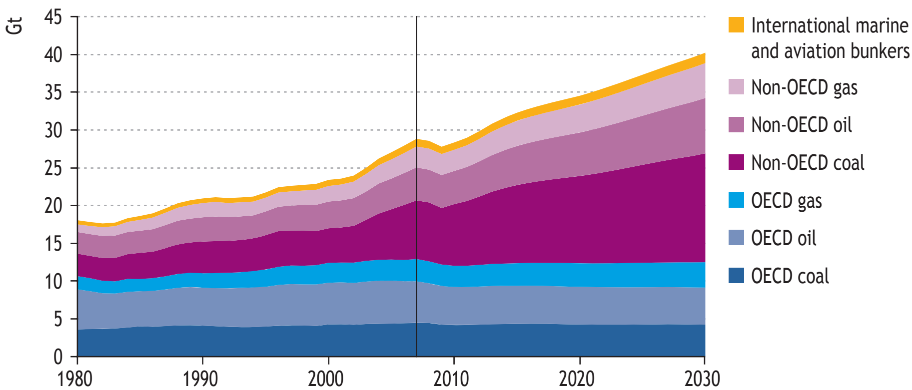
1. *WEO-2010* will include detailed analysis of policy measures to improve rural electrification and to promote the sustainable use of biomass.

2. See Part B for a detailed analysis of trends in energy-related $CO_2$ emissions in both the Reference and 450 Scenarios.

rate of growth of 1.5% per year over the full projection period (Figure 2.1). Non-OECD countries account for all of this emissions growth: OECD emissions are projected to dip slightly over the period, due to a slowdown in energy demand (resulting mainly from big improvements in energy efficiency) and the increased use of nuclear and renewables, in large part due to the policies already adopted to mitigate climate change and boost energy security.

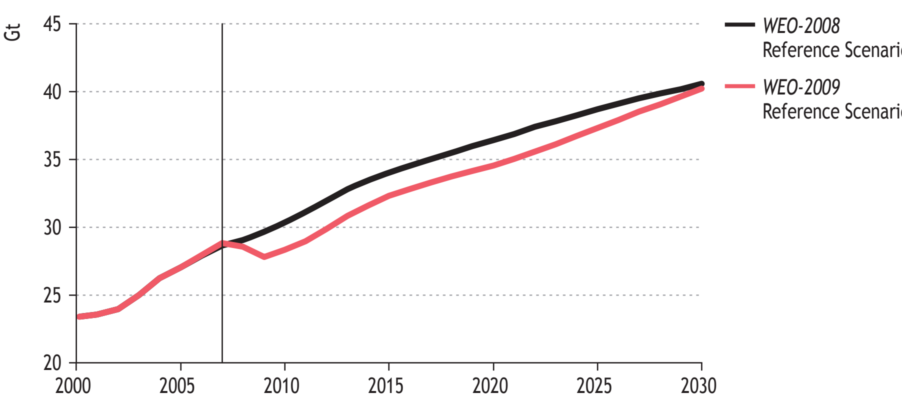


**Figure 2.1 • Energy-related $CO_2$ emissions by fuel and region in the Reference Scenario**




The rate of increase in $CO_2$ emissions over the projection period in this year's Reference Scenario is less than that projected in *WEO-2008* (Figure 2.2). For the period to 2020, this is partly explained by the current global recession, which has dramatically slowed the growth in energy demand and $CO_2$ emissions in the short term.

**Figure 2.2 • World energy-related $CO_2$ emissions in *WEO-2009* and *WEO-2008***



In 2009, global emissions of energy-related $CO_2$ are set to decline for the first time since 1992. Even so, emissions in 2020 in this year's Reference Scenario are 2 Gt below those in *WEO-2008*, largely on account of the persistent effects of the recent set-back to economic activity. But by 2030, despite lower assumptions for global gross domestic product (GDP), emissions are only 0.3 Gt lower than last year's Reference Scenario. This is due to upward revisions of GDP for several non-OECD countries that are heavily dependent on coal. In cumulative terms, between 2007 and 2030, world energy-related $CO_2$ emissions are 35.1 Gt lower than in *WEO-2008*.

### *Consequences for global climate*

While greenhouse-gas emissions in this year's Reference Scenario are lower than in *WEO-2008*, current policies are insufficient to prevent a rapid increase in the concentration of greenhouse gases in the atmosphere, with very serious consequences for climate change. As a general rule, higher greenhouse-gas emissions lead to higher greenhouse-gas concentrations, leading to higher global temperatures and more severe climatic consequences.[3] However, the links between emissions of greenhouse gases and climate change are complex and factors such as carbon sinks, solar heat reflection, cloud cover, land-use change and aerosols might partially neutralise – or compound – these effects (IPCC, 2007). Nonetheless, it is clear that the rapid growth of greenhouse-gas emissions projected in the Reference Scenario would lead to a substantial long-term increase in the concentration of greenhouse gases in the atmosphere, as well as a large increase in global temperatures.

The atmosphere currently contains long-lived greenhouse gases at a concentration of around 455 parts per million of carbon-dioxide equivalent (ppm $CO_2$-eq)[4], which is roughly 60% above pre-industrial levels (see Chapter 4). This level far exceeds the natural range over the last 650 000 years. Average global temperatures are currently around 0.76°C higher than pre-industrial levels and are rising at an increasing rate. The world is already experiencing the adverse effects of rising levels of greenhouse gases in the atmosphere. For example, the Greenland ice sheet has been losing mass at a rate of 179 billion tonnes per year since 2003 (Wouters *et al.*, 2008), while global sea levels are on course to rise by around one metre over the remainder of the century. Developing countries and island states are particularly vulnerable to the impacts of global warming.

3. 1 ppm of atmospheric $CO_2$ concentration today equates to around 7.7 Gt $CO_2$. In the past 50 years, around 58% of all the $CO_2$ emitted has stayed in the atmosphere – the rest has been removed over different timescales by various processes, including absorption by oceans and the biosphere, or has been broken down (Hansen, 2006). Consequently, at the present levels of atmospheric concentration, each additional 13.3 Gt of $CO_2$-eq gases released corresponds to an approximate increase in concentration of around 1 ppm. This may change in the future as some of the removal processes reach saturation.

4. The concentrations of greenhouse gases other than $CO_2$ in the atmosphere can be measured in terms of the equivalent $CO_2$ concentration that would result in the same level of radiative forcing. Today, their additional warming effect is partly offset by the cooling effect of anthropogenic aerosols and tropospheric ozone – but this is unlikely to remain the case in future (IPCC, 2007).

We estimate that the trajectory of energy-related $CO_2$ emissions in the Reference Scenario, when projected out to 2050 and beyond and taking into account emissions of all greenhouse gases from all sources, would result in a concentration of greenhouse gases in the atmosphere of around 1 000 ppm of $CO_2$-eq over the long term.[5] Our projected increase in energy-related $CO_2$ emissions to 2030 lies in the middle of the range of emissions and concentration scenarios that have been assessed by the Intergovernmental Panel on Climate Change (IPCC) in its *Fourth Assessment Report*, assuming an absence of new climate policies (IPCC, 2007).[6]

According to our analysis, the greenhouse-gas concentration implied by the Reference Scenario would result in an eventual global mean temperature rise of up to 6°C. According to the studies summarised by the IPCC, this could lead to hundreds of millions of people being displaced from their homes, massive water and food shortages, widespread mortality of ecosystems and species, and substantial human health risks. Even long before this stage is reached, there is a risk that the world would reach significant tipping points that could propel the climate into a vicious cycle of deterioration. For example, melting ice caps could reduce the earth's reflection of solar energy, leading to higher temperatures. In turn, rising Arctic temperatures could precipitate the melting of permafrost across northern regions, leading to a massive release of methane and further temperature increases. Studies published since the IPCC report suggest that the risks associated with global warming are even more severe than previously thought.

Although opinion is mixed on what might be considered a sustainable long-term level of annual emissions for the energy sector (and total emissions depend on emissions in other sectors), a consensus on the need to limit the global temperature increase to 2°C is emerging. This increase is consistent with a greenhouse-gas concentration of around 450 ppm $CO_2$-eq (as in the 450 Scenario). To achieve this would entail a complete and rapid transformation of the energy sector, relative to the Reference Scenario. None of the scenarios assessed by the IPCC with a concentration of greenhouse gases in the 445 ppm to 490 ppm $CO_2$-eq range (corresponding to a temperature increase of around 2°C) had annual energy $CO_2$ emissions above 5 Gt over the long term – whereas the Reference Scenario has emissions of 40.2 Gt in 2030.

### *Local and regional air pollution*[7]

The negative environmental consequences of the Reference Scenario extend beyond climate change. Rising energy consumption and increasing reliance on fossil fuels have already led to a deterioration in ambient air quality in many parts of the world, particularly in the least-developed countries. Emissions of sulphur dioxide ($SO_2$),

5. These projected emissions are consistent with model outputs of concentrations from the Model for the Assessment of Greenhouse-gas Induced Climate Change (MAGICC) (Version 5.3).

6. The atmospheric $CO_2$ concentration by around the end of the next century implied by the Reference Scenario is in line with the range of 855 ppm to 1 130 ppm $CO_2$-eq (660 ppm to 790 ppm $CO_2$) in five scenarios assessed by the IPCC.

7. This section discusses emissions of sulphur dioxide ($SO_2$), nitrogen oxides ($NO_X$) and particulate matter with an aerodynamic diameter of less than 2.5 µm (PM2.5).

nitrogen oxides ($NO_x$) and particulate matter (PM), in particular, are directly harmful to human health and are also in part responsible for other environmental problems, such as acid rain and urban haze.

In 2007, world emissions of $SO_2$ were about 90 million tonnes (Mt). OECD countries contributed just over a quarter to this total (Table 2.1). The main sources are power plants and industry. In the Reference Scenario, the implementation of current policies on air-pollution control result in a 4% decline in world emissions of $SO_2$ between 2007 and 2030. This leads to a 48% decline in emissions in the OECD and a 11% increase in the rest of the world.

**Table 2.1 • Emissions of major air pollutants by region in the Reference Scenario** (Mt)

| | 2007 | 2015 | 2030 | 2007-2030* |
|---|---|---|---|---|
| | | Sulphur dioxide ($SO_2$) | | |
| **OECD** | **23.7** | **14.3** | **12.2** | **-2.8%** |
| **Non-OECD** | **66.6** | **69.2** | **74.2** | **0.5%** |
| E. Europe/Eurasia | 11.3 | 9.9 | 10.2 | -0.5% |
| Asia | 42.5 | 48.2 | 52.6 | 0.9% |
| *China* | *31.5* | *34.6* | *29.0* | *-0.4%* |
| *India* | *6.3* | *8.5* | *14.8* | *3.8%* |
| *ASEAN* | *2.6* | *2.3* | *3.0* | *0.5%* |
| Middle East | 4.6 | 4.1 | 4.0 | -0.6% |
| Africa | 4.7 | 3.7 | 3.7 | -1.0% |
| Latin America | 3.4 | 3.4 | 3.6 | 0.3% |
| **World** | **90.3** | **83.6** | **86.4** | **-0.2%** |
| | | Nitrogen oxides ($NO_x$) | | |
| **OECD** | **32.7** | **22.1** | **16.6** | **-2.9%** |
| **Non-OECD** | **49.1** | **53.6** | **67.1** | **1.4%** |
| E. Europe/Eurasia | 7.8 | 7.0 | 6.9 | -0.6% |
| Asia | 27.3 | 32.5 | 42.7 | 2.0% |
| *China* | *16.9* | *21.3* | *24.3* | *1.6%* |
| *India* | *4.1* | *5.0* | *9.5* | *3.7%* |
| *ASEAN* | *4.5* | *4.3* | *5.9* | *1.2%* |
| Middle East | 4.0 | 4.2 | 5.6 | 1.4% |
| Africa | 4.4 | 4.5 | 5.8 | 1.2% |
| Latin America | 5.5 | 5.5 | 6.2 | 0.5% |
| **World** | **81.8** | **75.7** | **83.7** | **0.1%** |
| | | Particulate matter (PM2.5) | | |
| **OECD** | **3.7** | **3.2** | **3.1** | **-0.8%** |
| **Non-OECD** | **35.4** | **36.9** | **36.8** | **0.2%** |
| E. Europe/Eurasia | 2.0 | 1.3 | 2.2 | 0.4% |
| Asia | 23.4 | 24.0 | 23.1 | -0.1% |
| *China* | *13.1* | *13.2* | *10.9* | *-0.8%* |
| *India* | *5.1* | *5.4* | *6.3* | *0.9%* |
| *ASEAN* | *3.5* | *3.7* | *3.8* | *0.3%* |
| Middle East | 0.7 | 0.7 | 0.6 | -0.2% |
| Africa | 7.3 | 8.1 | 9.0 | 0.9% |
| Latin America | 2.0 | 2.0 | 2.0 | -0.2% |
| **World** | **39.1** | **40.1** | **40.0** | **0.1%** |

* Compound average annual growth rate.
Note: The base year of these projections 2005; 2007 is estimated by IIASA.
Source: IIASA (2009).

World emissions of $NO_x$ were 82 Mt in 2007, of which 40% originated from OECD countries. Road transport was responsible for about one-third of $NO_x$ emissions. In the Reference Scenario, $NO_x$ emissions increase by 2% by 2030, the combined effect of a near-50% fall in emissions in the OECD and a 37% increase in the rest of the world. The majority of non-OECD countries are currently implementing emission standards for vehicles, which slows down the pace of increase of $NO_x$ emissions.



Some 90% of global emissions of fine particulate matter (PM2.5), which amounted to 35 Mt in 2007, come from non-OECD countries. The biggest sectoral contributors are the residential and commercial sector, and industry. In 2030, emissions are 2% above 2007 levels. This relatively small increase in emissions is due to changes in fuel use patterns by households (replacement of solid fuels with other energy forms) and better controls on sources in power plants, industry and road transport.

# Implications for energy security

Concerns about energy security – defined as access to adequate, affordable and reliable supplies of energy – have evolved over time, with changes in the global energy system, and new perceptions about the risks and potential costs of supply disruptions. In the 1970s and 1980s, the focus was on oil and the risks associated with over-dependence on oil imports. Today, worries about energy security extend to natural gas, which is increasingly traded internationally, and to the reliability of electricity supply. While the focus of energy security is generally on the near-term threat to supply, there are also concerns about the adequacy of investment and of supply in the longer term. Furthermore, energy security is increasingly being discussed as an aspect of climate change and of national security.

The perceived risk of a serious disruption to energy supplies for any given country or at any given time depends on a large array of different factors, some of which are inherently difficult to measure. The most important indicators of energy security are the extent of imports (especially from politically unstable regions), the distance from production to consumption, the vulnerability of physical supply chains to disruption, the degree of fuel substitutability, the diversity of the fuel mix and the degree of concentration of market power.

## Oil security

### *Rising trade and import dependence*

Net inter-regional trade in oil is set to increase sharply through the *Outlook* period in the Reference Scenario, from 38 million barrels per day (mb/d) in 2008 to over 51 mb/d in 2030 – almost half of global oil production at that time (Table 2.2). Total non-OPEC (Organization of the Petroleum Exporting Countries) output is set to remain broadly flat over the projection period, while production in OPEC countries, especially in the Middle East, increases, reflecting their much larger resource base and their generally lower production costs. OPEC's market share consequently rises from 44% in 2008 to 52% in 2030, above its historical peak in 1973. Increased international trade in oil will bring economic benefits to exporting countries and will underpin economic development in importing countries, but it will also heighten concerns about OPEC pricing and production policies, as OPEC market power increases.

In the Reference Scenario, net exports from the Middle East, already the biggest exporting region, rise from 20.2 mb/d in 2008 to 29.3 mb/d in 2030. The region's exports represent more than 57% of global oil trade in 2030, up from 54% today. Net exports from Africa and Eastern Europe/Eurasia also continue to expand steadily. Brazil contributes most to the increase in net exports from Latin America in the early part of the *Outlook* period and Venezuela thereafter.

**Table 2.2 • Net inter-regional oil trade in the Reference Scenario** (mb/d)

| | 1980 | 2000 | 2008 | 2015 | 2030 |
|---|---|---|---|---|---|
| **Net importers** | | | | | |
| OECD | -24.0 | -22.9 | -24.6 | -24.4 | -20.5 |
| *North America* | *-6.6* | *-8.8* | *-9.5* | *-9.1* | *-5.2* |
| *United States* | *-7.1* | *-11.0* | *-11.6* | *-11.1* | *-10.0* |
| *Europe* | *-11.8* | *-6.8* | *-8.3* | *-9.0* | *-9.8* |
| *Pacific* | *-5.6* | *-7.3* | *-6.8* | *-6.3* | *-5.5* |
| *Japan* | *-4.8* | *-5.3* | *-4.5* | *-3.8* | *-3.1* |
| Non-OECD Asia | 0.1 | -4.3 | -8.4 | -13.0 | -24.5 |
| *China* | *0.2* | *-1.4* | *-3.9* | *-7.0* | *-12.1* |
| *India* | *-0.4* | *-1.5* | *-2.2* | *-3.0* | *-6.3* |
| **Net exporters** | | | | | |
| Middle East | 17.8 | 19.0 | 20.2 | 23.0 | 29.3 |
| Africa | 5.0 | 5.7 | 7.9 | 8.4 | 9.2 |
| Latin America | 0.3 | 2.3 | 1.5 | 2.3 | 1.9 |
| *Brazil* | *-1.1* | *-0.7* | *-0.1* | *1.2* | *0.7* |
| E. Europe/Eurasia | 3.0 | 4.1 | 8.3 | 8.8 | 11.5 |
| *Russia* | *n.a.* | *3.9* | *7.2* | *6.9* | *6.6* |
| **Total trade** | **27.3** | **33.5** | **37.8** | **41.6** | **51.5** |
| *European Union (imports)* | *n.a.* | *-9.4* | *-10.1* | *-10.3* | *-10.3* |

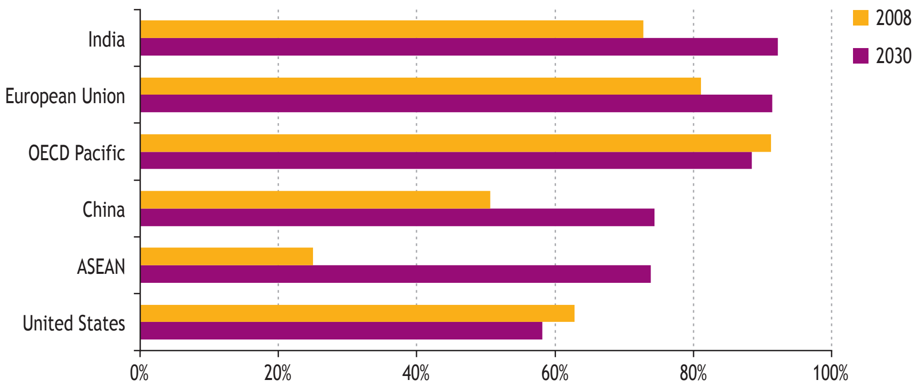
Note: Trade between *WEO* regions only. Positive figures denote exports; negative figures imports.

Trends in import dependence vary across regions. In the OECD as a whole, net imports as a share of total oil demand fall from 57% in 2008 to 51% in 2030, largely as a result of a sharp drop in imports into North America. Canadian output from oil sands displaces oil that would otherwise have been imported from outside the region, primarily from the Middle East. The import dependence of the United States alone declines from 63%

to 58%, mainly because of a decline in demand (Figure 2.3). The OECD Pacific's oil-import dependence remains high, at 88% in 2030, compared with 91% currently. The European Union sees a sharp rise in net import dependence, from 81% to 91%, as North Sea oilfields continue their rapid decline, having already passed their peak.



**Figure 2.3 • Dependence on net imports of oil by major country/region in the Reference Scenario**




Developing Asia becomes much more reliant on imports, both in absolute terms and as a share of demand. In 2008, China passed a milestone with its oil imports exceeding domestic production for the first time. By 2030, China's net imports are projected to reach 12 mb/d, comparable in volume to the current imports of the United States, and accounting for 74% of China's demand. The increase in dependence is also dramatic in India, where imports are projected to rise from today's level of around three-quarters of the total oil consumed domestically to 92% by 2030.

### *Fuel substitutability*

In the Reference Scenario, the transport sector is responsible for 97% of the growth in oil demand to 2030. By that time, oil-based fuels account for 92% of all transport fuel consumption, a modest fall from the level of 94% in 2007, resulting from the wider deployment of biofuels and, to a lesser extent, the uptake of plug-in hybrids and electric vehicles. The growing concentration of oil demand in the transport sector is set to magnify the vulnerability of importing countries to price spikes. Opportunities for substituting oil-based fuels in existing vehicles are limited and fuel demand tends to change very little in the near term in response to price increases. For a given supply reduction, the price adjustment needed to bring global demand back into equilibrium is expected to increase. In other words, oil-price volatility will tend to rise with the increased rigidity of oil demand.

### *Vulnerability to oil supply disruptions*

The prevalence and seriousness of major oil-supply disruptions could grow as the world becomes increasingly dependent on supply sourced from a small group of countries and transported along vulnerable supply routes. In the Reference Scenario, a growing share of oil supplies is transported by pipeline or along maritime routes, some of which have narrow sections that are susceptible to piracy, terrorist attacks or accidents (Table 2.3). These choke points are typically in places that cannot easily be bypassed.

**Table 2.3 • *Key global oil transit choke points***

| Choke point | Main destination | Description |
|---|---|---|
| Straits of Hormuz | Europe, Japan, United States | Most important oil-shipping route. Tankers divide into two lanes just 3 km wide. Few alternative export routes for Persian Gulf oil. |
| Malacca Strait | Japan, China, ASEAN | Principal oil route in Asia. Only 2.7 km wide at narrowest. Rising demand in Asia will increase traffic. |
| Suez Canal | Europe, United States | Connects Red Sea with Mediterranean. Closure would force tankers to transit around the southern tip of Africa. |
| Bab el-Mandab passage | Europe, United States | Links Red Sea with the Gulf of Aden. |
| Sumed pipeline | Europe, United States | Links Red Sea with the Mediterranean. |
| Bosphorus/Turkish Straits | Europe | 30-km waterway linking the Black Sea with the Mediterranean, less than 1 km wide at the narrowest point. |
| Druzhba pipeline | Europe | Transits Russian crude oil to Europe. |
| Baltic Pipeline System | Europe | Carries Russian crude to Baltic Sea ports. |

Worries about the threat of disruptions to energy supplies are based on the experience of the last few decades. Since 1970, there have been 17 serious disruptions in the supply of crude oil that have involved an initial loss of 0.5 mb/d or more. Thirteen of these have involved countries in the Middle East. Oil supply disruptions can happen at any point from where the crude oil is extracted from the ground to where it is sold as refined product to end users – and the repercussions are sometimes global. The most recent major disruptions both occurred in the Gulf of Mexico: firstly in the summer of 2005, when Hurricanes Katrina and Rita removed some 1.5 mb/d of oil supply from the market; and then in August/September 2008, when Hurricanes Gustav and Ike caused comparable damage. Historically, there have been a number of interruptions stemming from incidents at key choke points. The most serious remains the Suez Canal crisis in 1956/1957, which blocked the passage of approximately half the oil reliant on transit through the canal. The estimated gross peak supply loss was around 2 mb/d.

### *Investment risks*

High rates of investment in oil production, refining and transportation infrastructure are essential to maintaining security of supply over the longer term. The oil sector, like all other economic sectors, has been affected by the recent financial and economic crisis (see Chapter 3). Planned global investment in oil and gas production in 2009 has been reduced by about one-fifth. Unless quickly reversed, such investment cut-backs could have severely negative consequences for energy security by leading to a shortage of capacity and another spike in prices when the economy is back on the road to recovery.

**Box 2.1 ● *The future of the IEA oil emergency response mechanisms***



The IEA's emergency response mechanisms were created pursuant to the 1974 Agreement on an International Energy Program (IEP). The Agreement requires IEA countries to hold strategic oil stocks and, in the event of a major oil supply disruption, to release stocks, restrain demand, switch to other fuels or increase domestic production. Experience has demonstrated that the most effective of these measures is the holding of emergency stocks and releasing them in a co-ordinated manner. IEA member countries currently hold 4.2 billion barrels of oil stocks, of which 1.5 billion are held by public organisations. Based solely on those public stocks, the IEA could replace a supply disruption of 4 mb/d - about the size of the current production of Iran — for one year. This is a relatively comfortable situation, especially as it is backed by other tools available under the IEP and elsewhere. The spare oil production capacity that some key producers, most notably Saudi Arabia, have historically maintained represents a valuable element of preparedness for many forms of emergencies (*e.g.* accidental loss of supply) and illustrates the importance attached by suppliers to the reputation of oil as a fuel on which customers can rely. This spare capacity has enabled important volumes of additional supplies to be made available in times of shortage, thereby stabilising the market.

Experience has demonstrated that the IEA's emergency response system works and that its member countries are ready to use it. Most recently, when Hurricane Katrina hit the Gulf of Mexico in 2005, the region's oil production and refining infrastructure was devastated and world energy markets were disrupted. The IEA member countries decided in a matter of days to bring 60 million barrels of additional oil to the market and acted promptly to implement their commitments. The market quickly stabilised.

To maintain a similar level of emergency preparedness the IEA will continue to adapt its polices and procedures to changing market conditions. Most important of these changes is the falling share of IEA member countries in global oil consumption. This is set to fall to just 36% by 2030 — from 68% when the Agency was established in 1974. International oil markets are closely inter-connected and no country can stand immune to an oil shock elsewhere. For example, despite a projected fall in the United States in dependence on oil imports, increasing import dependency in another major consuming region — notably Asia — means that a severe oil supply shock there would have rapid knock-on effects for the United States.

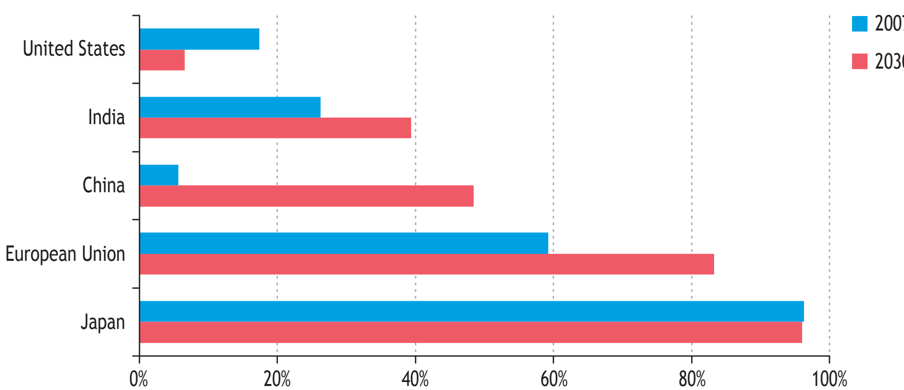
In view of these changing dynamics, the IEA is increasing its engagement on energy security issues with non-member countries. China, India, Thailand and other countries in Southeast Asia are building emergency oil stocks and the IEA is actively seeking to deepen its dialogue and exchanges with these countries, with the goal of improving co-ordination among all market players during an emergency. IEA non-member countries have started to participate in regular Emergency Response Exercises at IEA headquarters in Paris. In addition, the IEA has held Emergency Response Exercises in countries that are not IEA members. The first such exercise was held in Thailand in May 2009 and similar exercises are planned elsewhere in the region.

In the Reference Scenario, $6 trillion (in 2008 dollars) of investment is needed in the oil sector through to 2030. The share of the Middle East in total upstream oil spending, at around 15%, is small relative to the region's contribution to the increase in global supply, because exploration and development costs are low. Nonetheless, there is considerable uncertainty about the pace at which investment in the region's upstream industry will occur, how quickly production capacity will expand and, given rising domestic energy needs, how much of the expected increase in supply will be available for export. Reductions in investment may reflect government decisions to limit budget allocations to the industry or constraints on the industry's ability or willingness to invest in upstream projects.

## Natural gas security

A number of market developments are currently affecting natural gas security, including rising import dependence in some of the key consuming and emerging markets, and the globalisation of the gas market. In the Reference Scenario, gas trade between *WEO* regions is projected to increase by 58% over the projection period, from 677 billion cubic metres (bcm) in 2007 to around 1 070 bcm in 2030. The European Union is expected to require the biggest increase in import volumes through the *Outlook* period, due to declining indigenous production, particularly in the Netherlands and the United Kingdom, coupled with a modest increase in demand. By 2030, imports into the European Union meet 83% of its gas needs, compared with 59% at present (Figure 2.4). Developing Asia also becomes much more reliant on imports of gas. Both China and India have modest proven reserves of gas and limited potential for raising production. In the absence of large new discoveries, they will become increasingly reliant on imports. Imports as a share of total gas consumption reach 48% in 2030 in China and 39% in India, in the Reference Scenario.

**Figure 2.4 • Dependence on net imports of natural gas by country/region in the Reference Scenario**




In the Reference Scenario, the bulk of the increase in natural gas exports comes from Russia, Iran and Qatar, with lesser volumes provided by other Middle Eastern producers, Africa and the Caspian/Central Asian region. As with oil, increasing reliance on natural gas imports from a limited number of countries will increase the market dominance of producers and increase vulnerability to supply disruptions at major choke points.

Although gas supply disruptions caused by external events typically receive much publicity, the vast majority of gas supply disruptions are domestic in nature. The list of actual and potential causes of disruptions is long and includes weather-related catastrophes (*e.g.* hurricanes), accidents (*e.g.* fires, explosions), contractual disputes, transit disputes and political decisions. The risks associated with political control of strategic pipeline routes were highlighted in early 2009 with the most severe supply disruption in history, as Russia and Ukraine disputed the continuation of their supply and transit contracts (Box 2.2). This followed numerous other high-impact disruptions in recent years, in the United States (2005 and 2008), the United Kingdom, Italy and Ukraine (2006), Turkey (2008), Australia (2000 and 2008) and elsewhere.

2

### Box 2.2 • The 2009 Russia-Ukraine gas dispute

Interruption of Russian gas flows through Ukraine in January 2009, at a time of very high demand, triggered Europe's worst-ever gas-supply crisis. A dispute between Russia and Ukraine over the price of gas sold to Ukraine, payment of outstanding debt and transit fees resulted in the interruption of some 110 million cubic metres per day (mcm/d) of supply to Ukraine from 1 January, along with smaller volumes of supply to countries further west. On 5 January, supplies were further reduced and, on 7 January, all transit through the Ukrainian network was halted, causing the loss of 300 mcm/d to 350 mcm/d of supply to the rest of Europe. This came at a time of very high peak gas demand in Western and Central Europe, with the coldest weather in two decades.

European gas companies responded by drawing down gas from commercial storage, implementing demand-side measures and securing alternative supplies via other pipeline routes from Russia, other producers and as liquefied natural gas (LNG). Except for flows from the United Kingdom, cross-border flows within Europe were severely reduced and deliveries were slow to arrive, so that countries poorly equipped with storage and other emergency arrangements (notably in Eastern Europe) were heavily affected. When flows were restored on 20 January, following new deals on gas sales and transit, some 5 bcm of transit gas supplies had not been delivered over a two-week period, in addition to around 2 bcm of Ukrainian supplies.

The new agreements on gas sales and transit should put the gas relationship between Russia and Ukraine on a more solid commercial basis, but the risk of a renewed interruption to supply has not disappeared in the short term. As of September 2009, Ukraine has made its monthly payments for gas imports promptly, but it will take time for Ukrainian domestic prices and industry to adjust to the new European pricing mechanism for gas import. In the meantime, state-owned Naftogaz remains heavily in debt. Pricing reform, greater efficiency and broader energy-market restructuring in Ukraine will be vital to the medium-term health of the gas relationship with Russia.

A growing share of world trade is expected to take the form of liquefied natural gas (LNG). On the one hand, the growing LNG market offers greater supply flexibility, as cargoes can be diverted at short notice to offset a sudden loss of supply from another source. Nonetheless, recent events have also demonstrated that long-term LNG contracts do not guarantee security of supply. For the last several years, Japan has struggled with the inability of Indonesia to produce the quantities of LNG stipulated under long-term contracts, due to declining output and rising domestic demand.

Gas-importing countries have some concerns that the Gas Exporting Countries Forum (GECF) — which was established in 2001 and has a Secretariat based in Qatar — could one day evolve into a cartel intent on influencing world prices in the same manner as OPEC, which itself had existed for over a decade before exerting its collective influence during the first oil shock in 1973.[8] The global economic crisis, which has sent spot prices plummeting and is expected to result in the first global contraction in natural gas demand in more than half a century, may well add impetus to such a development. But several market factors also stand in the way, including the prevalence of long-term contracts, the regionalised nature of gas markets, the scope to substitute other fuels for gas and the growing number of competing suppliers, such as those responsible for the recent surge in gas production from non-conventional sources in the United States. Nonetheless, the possibility of eventual formal co-ordination of investment, production and pricing policies by gas importers will be a risk taken into account by the purchasers of gas (see Chapter 10).

## Electricity security

The reliability of electricity supply is a growing concern in both OECD and non-OECD countries. Most power systems in most OECD countries were conceived and constructed some 40 to 50 years ago. Many generation units are well in excess of 25 years old, especially nuclear and coal-fired plants. The demands on electricity-supply infrastructure are growing, with increasingly distributed and variable sources of generation, including wind and solar power. Furthermore, electricity demand still does not respond quickly to price changes when supply conditions change. Yet, in certain regions there appears to be a lack of timely, diverse electricity-generation investment, or investment in expanded and enhanced transmission interconnections. Public opposition to siting of new generation and transmission infrastructure sometimes causes delays and increases risks and costs for investors, and may totally prevent new investment. Regulatory complexity and uncertainty, especially as markets integrate over larger geographic areas, is a further inhibition. Greater reliance on natural gas for power generation in many markets has contributed to supply diversification, but gas-supply interruptions have been demonstrated to be a real threat.

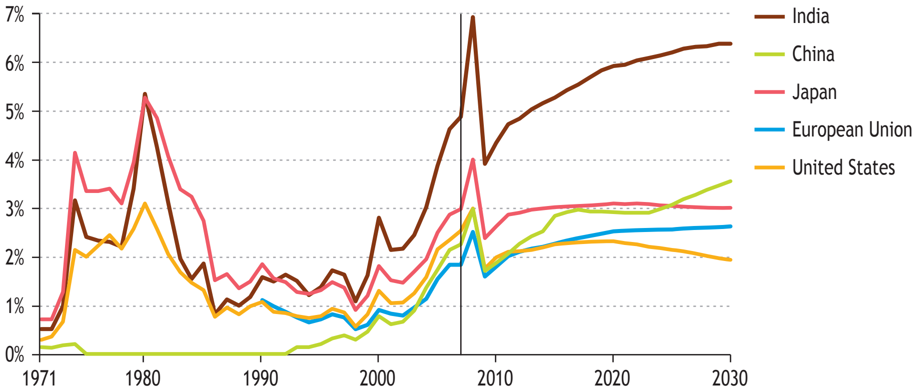
8. See Chapter 14 Spotlight: Is the Gas Exporting Countries Forum the new "Gas-OPEC"?

# Selected economic implications

## Spending on imports

The Reference Scenario projections imply a persistently high level of spending on oil and gas imports by almost all importing countries (Figure 2.5). As a share of GDP at market exchange rates, spending on oil and gas imports spiked in 2008, in line with the run-up in prices. For the OECD as a whole, the level reached 2.3%, which approached the peaks seen during the second oil shock in 1979. For many emerging economies, a new record level of spending was reached, as they have typically become more dependent on energy imports over the last several decades due to a sharp increase in demand and/or shrinking domestic production. Two examples illustrate the case: in 2008 spending on oil and gas imports reached 6.9% of GDP in India and 3.0% in China.

**Figure 2.5 • Expenditure on net imports of oil and gas as a share of GDP at market exchange rates in the Reference Scenario**



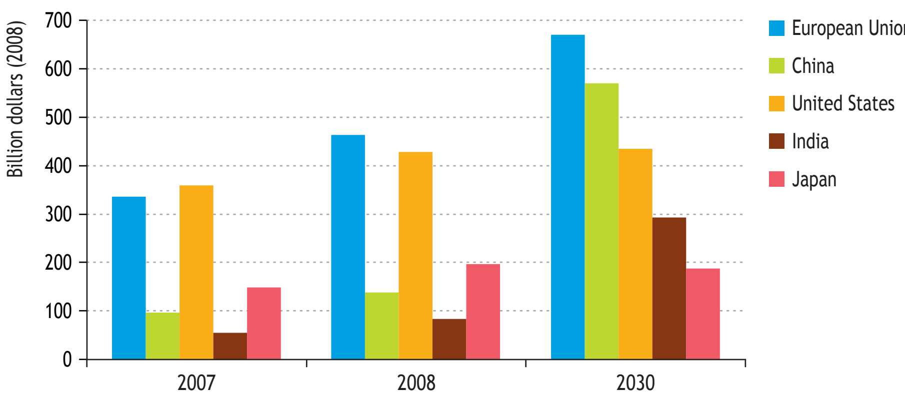

Note: Calculated as the value of net imports at prevailing average international prices. The split between crude/refined products and LNG/piped gas is not taken into account.

Based on current trends, spending on oil and gas imports in the OECD, as a share of GDP, is set to stabilise at around 1.8% over much of the *Outlook* period. Japan and Korea are expected to be slightly worse off, due to their near-total dependence on imports. In most cases, in developing countries the share of imports in GDP is significantly higher than in the OECD, as they tend to be more dependent on imports and consume more energy to generate one unit of economic output. In India, for example, although spending on oil and gas imports as a share of GDP has fallen back from the peak in 2008, it is projected to rise progressively through the *Outlook* period, reaching 6.4% in 2030.

These projections are based on the price assumptions that underpin the Reference Scenario. However, market tightness or significant geopolitical tensions could lead to price spikes or even sustained higher prices over the *Outlook* period, increasing the financial burden on countries dependent on oil and gas imports. Recent experience suggests that any such development could have important implications for the global economy: it is generally considered that the run-up in oil prices in the period 2003 to mid-2008 played a significant, albeit secondary, role in the current global economic downturn. On the other hand, short-lived bouts of over-supply could alleviate the burden on importing countries.

In the Reference Scenario, in real-dollar terms, annual expenditure on oil and gas imports continues to increase in most importing countries, even compared to the record levels experienced in 2008 (Figure 2.6). For example, the spending on oil and gas imports in the European Union is expected to reach $671 billion (in year-2008 dollars) in 2030, up from $463 billion in 2008 (and $336 billion in 2007). On a country basis, China overtakes the United States soon after 2025 to become the world's biggest spender on oil and gas imports, in monetary terms, while India's spending on oil and gas imports surpasses that of Japan soon after 2020 to become the world's third-largest importer.

**Figure 2.6 • *Annual expenditure on net imports of oil and gas in the Reference Scenario***




Note: Calculated as the value of net imports at prevailing average international prices. The split between crude/refined products and LNG/piped gas is not taken into account.

Reducing imports of oil and gas would lower the economic burden on oil importers, as well as bringing environmental and energy-security benefits. Such a reduction can be achieved through efforts to stimulate indigenous production of hydrocarbons and alternative sources of energy, such as biofuels, other renewable energy technologies and nuclear power, as well as through measures to improve energy efficiency. More importantly still, subsidies on oil and gas consumption can be removed (Box 2.3). Most countries are considering stronger policies and measures to reduce oil-import intensity for economic, security and/or climate change reasons (see Chapter 4).

### Box 2.3 ● *The implications of phasing out energy subsidies*

Large subsidies to the consumption of fossil fuels still exist in many non-OECD countries. As inferred from the gap between domestic and international fossil-fuel prices, they are currently highest in percentage terms in the Middle East, Russia, other non-EU Eastern European countries and India. In many cases, price controls prevent the full cost of higher imported energy from being passed through to end users, thereby dampening the responsiveness of consumption to increases in prices. Subsidies can also place a heavy direct burden on government finances and thereby weaken the potential for economic growth. In addition, by encouraging higher consumption and waste, subsidies exacerbate the harmful effects of energy use on the environment, while also impeding the development of more environmentally benign energy technologies. Although usually meant to help the poor, subsidies often benefit better-off households.

Energy subsidies take many different forms, some of which are not transparent. Some subsidies aim at making fossil fuels more affordable, while others aim to support domestic production. Closing the gap between domestic and international fossil-fuel prices is an important, albeit politically difficult, step towards improving all three central objectives of energy policy. Subsidy removal also frees up budgetary resources that can be used to target social objectives more directly.

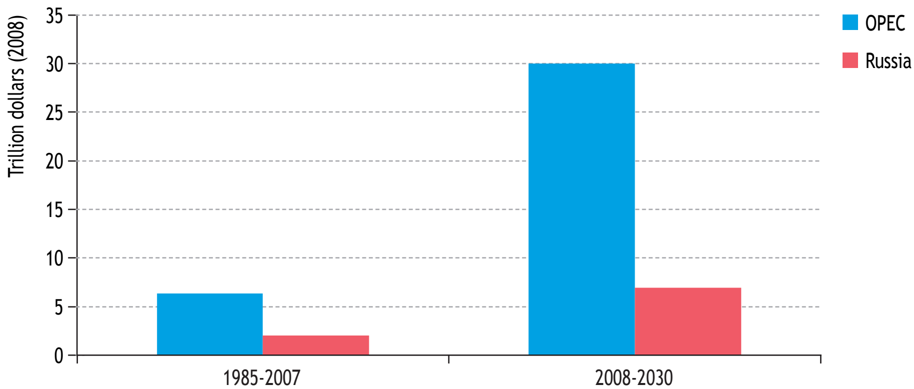
The *WEO-2008* found that subsidies on fossil fuel in 20 non-OECD countries (accounting for over 80% of total non-OECD primary energy demand) amounted to about $310 billion in 2007 (IEA, 2008).[9] A further study by the OECD in collaboration with the IEA, using IEA estimates of the gap between actual prices and the estimated true market prices of a range of fuels, found that if energy subsidies were phased out gradually between 2013 and 2020, total primary energy demand at the global level would be cut by slightly more than 5% by 2030, compared to a baseline in which subsidy levels remain unchanged. It was found that removing subsidies would also raise per-capita GDP in most countries concerned.

## Export revenues

In the Reference Scenario, OPEC countries and Russia continue to earn substantial revenues from oil and gas exports, even after taking into account that more of their production is needed to satisfy rising domestic demand. On an undiscounted basis, cumulative OPEC country revenues from oil and gas exports between 2008 and 2030 amount to almost $30 trillion — a near five-fold increase on earnings over the past 23 years (Figure 2.7). Russia's cumulative earnings to 2030 amount to $7 trillion, some 3.5 times larger than over the previous 23 years.

9. *WEO-2010* will include an in-depth analysis of the impact subsidy removal would have on global energy trends, economic efficiency, $CO_2$ emissions and local pollution.

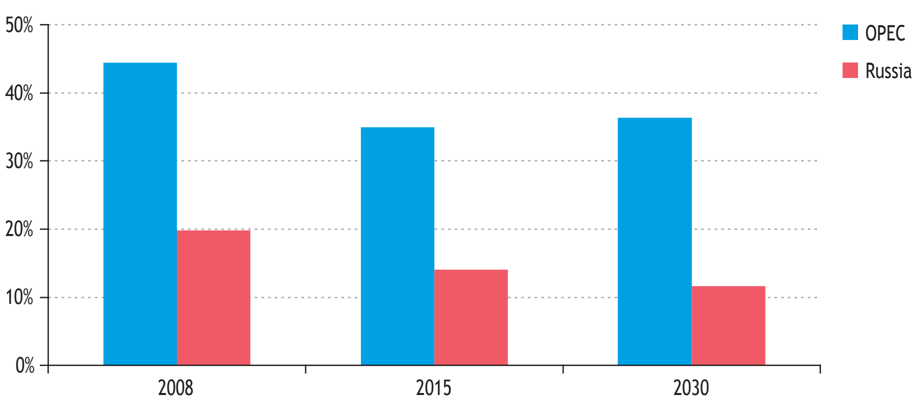
**Figure 2.7 • Cumulative oil and gas export revenues in the Reference Scenario for selected key exporters**




Note: Calculated as the value of net exports at prevailing average international prices. The split between crude/refined products and LNG/piped gas is not taken into account.

Existing and planned efforts in OPEC countries to implement structural economic reforms aimed at accelerating economic diversification are set to reduce gradually reliance on hydrocarbon export revenues. Nonetheless, revenues from oil and gas exports are still projected to represent 36% of the combined GDP of the OPEC countries in 2030, down from 44% in 2008 (Figure 2.8). On a per-capita basis, in real-dollar terms, in 2030 OPEC countries are set to earn around $3 600 from exports of oil and gas compared to just under $2 800 in 2008.

**Figure 2.8 • Oil and gas export revenues as a share of GDP at market exchange rates for selected producers in the Reference Scenario**




Note: Calculated as the value of net exports at prevailing average international prices. The split between crude/refined products and LNG/piped gas is not taken into account.

SPOTLIGHT

**Do energy producers need greater security of demand?**

With the economic weakness of 2008/2009 prompting the sharpest decline in oil demand in a quarter of a century, and with the prospect that an agreement may be brokered at the UN Climate Change Conference (COP 15) that could kick-start a transition to a low-carbon economy, it is important and timely to consider the other side of the energy security coin – security of demand. After all, in the same way that energy-importing countries seek security of supply, energy-exporting countries seek security of energy demand as they invest billions of dollars in production infrastructure.

The fall in global oil demand in 2009, which could exceed 2%, will almost certainly be the steepest since the early-1980s. It is understandable that resource holders may hesitate to commit new capital to increase upstream production capacity or to maintain spare capacity when they are unsure how long it will take before they see a return on their investment. Yet, even taking into account the current uncertainty, there is still widespread agreement that sustained investment will be needed to meet rising demand in the medium and longer term. In the Reference Scenario of this *Outlook*, global oil demand is projected to reach 105 mb/d in 2030, while in OPEC's *World Oil Outlook 2009* (OPEC, 2009), released in July 2009, it is slightly higher at 106 mb/d.

Naturally, these projections would not hold true if the UN Framework Convention on Climate Change (UNFCCC) process leads to a successful climate deal, as they are predicated on the assumption that there will be no major shift in government polices. But even in the 450 Scenario of this *Outlook* – in which the concentration of greenhouse gases is stabilised at 450 ppm $CO_2$-eq – oil demand in 2030 is projected to be slightly higher in 2030 than today, at 88.5 mb/d. Given that OPEC countries possess the world's largest and least-cost reserves, even in this scenario they would be called upon to produce 11.4 mb/d more oil in 2030 than they do today. In fact, the growth in OPEC production in this scenario over 2008-2030 is faster than the increase in output over the period 1980-2008 (see Chapter 5).

Our analysis suggests that investment by low-cost producers in new supplies will pay off, even if highly ambitious efficiency measures and alternative fuel and vehicle technology programmes are put in place in consuming countries. It therefore bodes well for economic prospects in the major producing countries, particularly when coupled with the ongoing efforts in countries such as the United Arab Emirates and Saudi Arabia to diversify their economies.

Russia's economy has become heavily dependent on earnings from oil and natural gas exports. For a brief period in mid-2008, earnings approached $1 billion per day but by July 2009 they had halved, in line with the decline in energy prices and the fall in demand for exports. In the Reference Scenario, Russia's earnings from oil and gas exports, predominately to European customers, amount to 12% of the country's GDP in 2030, down from 19% in 2008. Russian earnings on a per-capita basis increase steadily through the *Outlook* period, from around $2 300 in 2008 to $3 100 in 2030.

Oil and gas export revenues continue to make up an important part of the national budgets of producing countries. This is true even if stringent steps are taken by the international community to cut greenhouse-gas emissions (see Spotlight). This underscores the persistence of genuine interdependence between producers and consumers. But attempts by producers to actively manage the market to protect their revenue base can damage trust. Fears that producers may constrain investment in order to safeguard against possible future over-supply or exploit their growing market domination (by actively limiting short-term production in order to manipulate prices) can drive importers to adopt more stringent measures to reduce dependence on oil and gas.

## Implications for energy poverty[10]

### *Current status of electricity access by region*

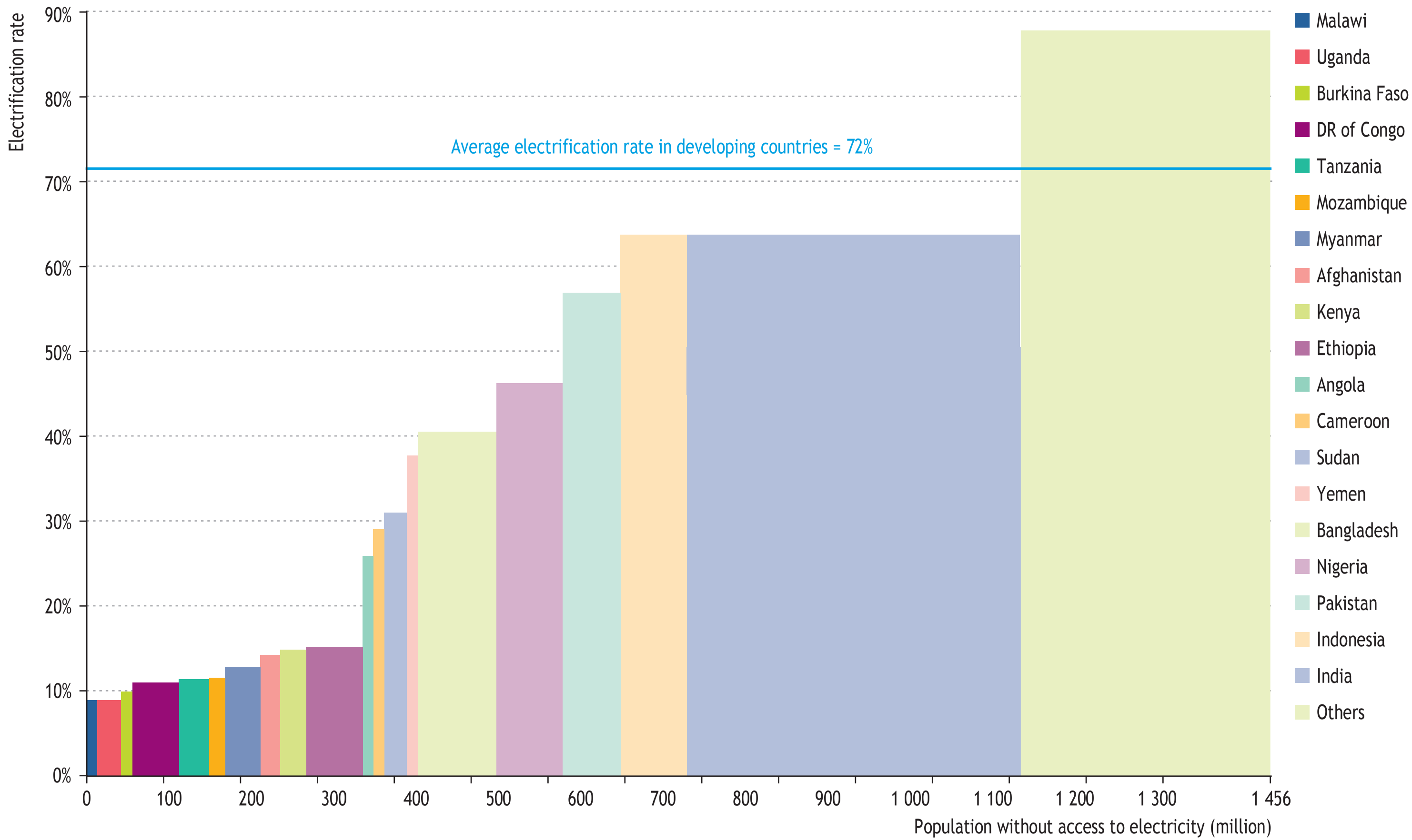
Based on a detailed country-by-country database updated for this *Outlook*, we estimate that in 2008 the number of people without access to electricity was 1.5 billion – or 22% of the world's population. Some 85% of those people live in rural areas. Expanding access to modern energy is a necessary condition for each of the economic, social and environmental dimensions of human development. The UN Millennium Project has emphasised the close links between energy use and the eight Millennium Development Goals (UN, 2009). Modern energy services help to reduce poverty, improve educational opportunities for children and promote gender equality.

Since the issue of energy poverty was first analysed in the *World Energy Outlook 2002*, the number of people without access to electricity has decreased by an estimated 188 million, despite the growth in world population of more than 500 million. Increased urbanisation and the successful implementation of electrification programmes have contributed to the improvement in these figures, but it is also partly due to revisions as data quality has improved.

*South Asia* currently accounts for 42% of the total number of people in the world without access to electricity, even though the percentage of the population with access to electricity in South Asia increased by around 8% over the last three years (Figure 2.9). Bangladesh, India and Pakistan in total have 570 million people without electricity, 92% of whom live in rural areas. The Indian government has declared reducing poverty and enhancing social and economic development a key priority, and has introduced a new

10. See www.worldenergyoutlook.org for the definitions and methodology utilised in the energy poverty analysis as well as disaggregated results.

**Figure 2.9 • Electrification rates and population without access to electricity, 2008**



remote village electrification programme. In Pakistan, nearly 133 000 villages have been electrified by the Water Resources and Power Development Authority and its rural electrification programme.

In *Sub-Saharan Africa* only 29% of the population has access to electricity today. Despite slightly increasing electrification rates, the total number of people in the region without access to electricity has grown by 78 million since 2001 — mainly due to rapid population growth, which has outpaced electrification.

The overall number of people without access to electricity in *East Asia* and *China* has fallen to 195 million, from 241 million in 2001. Myanmar has the lowest electrification rate in the region, at 13%, followed by East Timor (22%) and Cambodia (24%). China has achieved impressive results in electrification, providing electricity access to more than 1.3 billion people. The National Development and Reform Commission has introduced national renewable energy programmes, including the Riding the Wind Plan and the Brightness Project to provide electricity to people in remote areas through renewable technologies such as wind and solar (Zhang *et al.*, 2009).

Although the average electrification rate in *Latin America* was 93% in 2008, some countries in the region with large populations have much lower rates, including Peru, Nicaragua and Bolivia. While almost the entire urban population in Latin America has access to electricity, the rate in rural areas is just 70%.

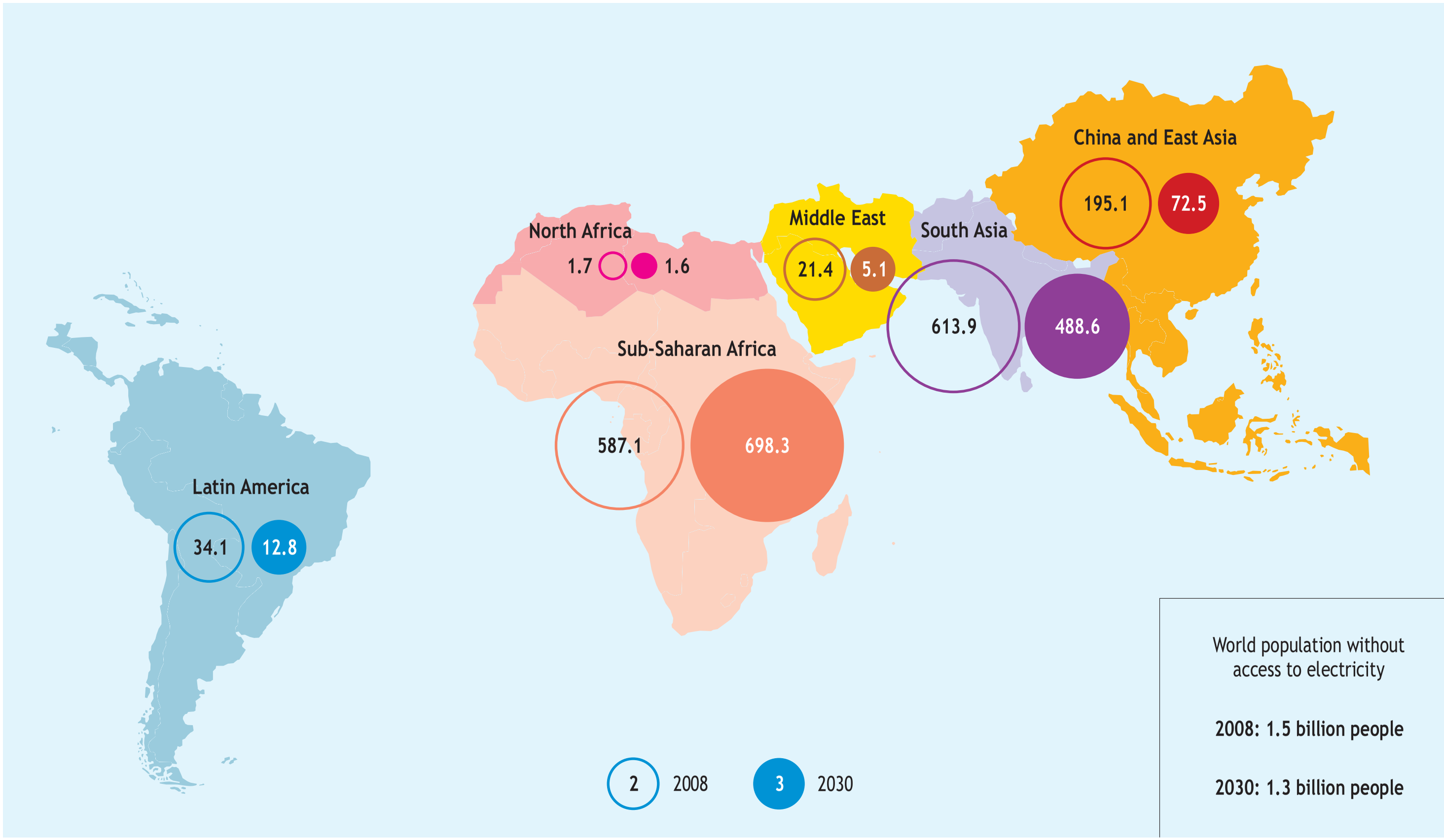
### *Prospects for electricity access*

In the Reference Scenario, 1.3 billion people, or 16% of the world's population, still lack access to electricity in 2030, despite more widespread prosperity and more advanced technology (Figure 2.10). Though the Reference Scenario takes into account the effects of the current economic crisis, there is a risk that its consequences for the ongoing electrification process in developing countries could be understated: financing programmes to connect new customers, whether carried out by public-private partnerships or by local electric utilities, could be particularly severely affected.

On the Reference Scenario figures, the electrification rate at the global level reaches 84% in 2030, from 78% in 2008. This represents a reduction in the number of people without access to electricity of 176 million compared to today, despite the substantial projected rise in global population.

Most of the people without access to electricity in 2030 are in Sub-Saharan Africa (698 million) and South Asia (489 million). Four out of five of them live in rural areas (Table 2.4). In Sub-Saharan Africa, despite a projected increase in the electrification rate from 29% in 2008 to 47% in 2030, the number of people without access to electricity increases by 111 million by 2030. These projections are highly dependent on assumptions about incomes and electricity pricing; higher electrification rates could be achieved in 2030 if new policies to alleviate energy poverty were introduced.

**Figure 2.10 • Number of people without access to electricity in the Reference Scenario** (millions)




The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

**Table 2.4 • Electricity access in the Reference Scenario**

| | 2008 | | | | Projections | | | |
|---|---|---|---|---|---|---|---|---|
| | Population without access (millions) | Electrification rate (%) | | | Population without access (millions) | | Electrification rate (%) | |
| | | Overall | Urban | Rural | 2015 | 2030 | 2015 | 2030 |
| Africa | 589 | 40 | 67 | 23 | 627 | 700 | 45 | 54 |
| *North Africa* | *2* | *99* | *100* | *98* | *2* | *2* | *99* | *99* |
| *Sub-Saharan Africa* | *587* | *29* | *57* | *12* | *625* | *698* | *36* | *47* |
| Non-OECD Asia | 809 | 77 | 94 | 67 | 765 | 561 | 80 | 87 |
| *China* | *8* | *99* | *100* | *99* | *5* | *0* | *100* | *100* |
| *India* | *405* | *65* | *93* | *53* | *385* | *294* | *69* | *79* |
| *Other* | *396* | *63* | *85* | *48* | *374* | *267* | *68* | *81* |
| Latin America | 34 | 93 | 99 | 70 | 18 | 13 | 96 | 98 |
| Middle East | 21 | 89 | 98 | 71 | 11 | 5 | 95 | 98 |
| **Sub-total** | **1 453** | **72** | **90** | **58** | **1 420** | **1 279** | **75** | **81** |
| E. Europe/Eurasia and OECD | 3 | 100 | 100 | 100 | 2 | 2 | 100 | 100 |
| *Sub-total* | *3* | *100* | *100* | *100* | *2* | *2* | *100* | *100* |
| **World** | **1 456** | **78** | **93** | **63** | **1 422** | **1 281** | **80** | **84** |

**Box 2.4 • The Universal Electricity Access Case**

Achieving universal access to electricity by 2030 would result in higher global energy demand than projected in the Reference Scenario. It would also have implications for energy investment and for emissions of energy-related $CO_2$ emissions. The Universal Electricity Access Case (UEAC) seeks to quantify these increments. It is based on the assumption that new policies are introduced that result in a progressive increase in electrification rates to 100% of the world's population by 2030.

It is assumed that each person gaining access is at first going to use electricity only as a substitute for the traditional fuels used to cover basic needs (*e.g.* candles, liquefied petroleum gas [LPG], kerosene). Basic electricity consumption in rural areas is assumed to be 50 kWh per person per year, while the minimum urban consumption is set at 100 kWh per person per year. It is assumed that the consumption levels of the newly connected areas increase over time to reach the regional (rural and urban specific) average after 10 years, reflecting the income-generating effects of modern energy services. It is also assumed that the electricity is generated using the fuel mix set out in the Reference Scenario for the country or region in question.

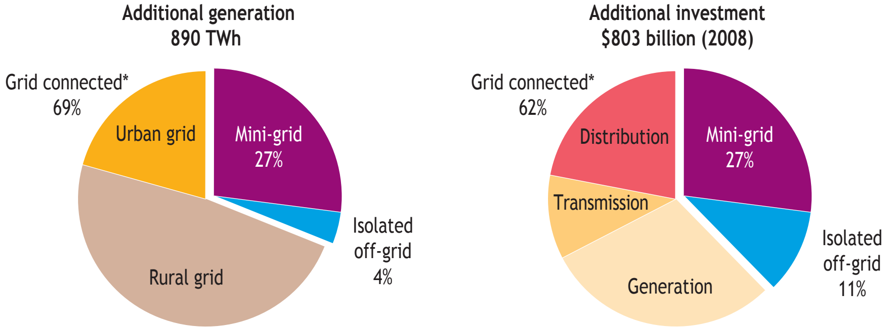
Relative to the Reference Scenario, global electricity generation in the UEAC is less than 3% higher in 2030, an increase of 890 TWh. Around 70% of the additional supply is projected to be based on grid extensions, which remain the cheapest option in all countries, while development of mini-grids accounts for 27% and isolated off-grid generation for 4% (Figure 2.11). Almost 90% of the incremental supply is required in just two regions, Sub-Saharan Africa (448 TWh) and South Asia (316 TWh).

Additional power-sector investment worldwide of $35 billion per year on average is required in the UEAC in 2008-2030. This increase is equivalent to just 6% of the annual average global investment in the power sector in the Reference Scenario, or around one-quarter of the annual investment required in China's power sector in the *Outlook* period. Almost 85% of the incremental investment to meet the UEAC is needed in Sub-Saharan Africa and South Asia.

The task of achieving universal access to electricity is, clearly, formidable but it would contribute substantially to the alleviation of poverty. The required investment is most unlikely to be driven by the private sector, as in those countries in which electricity access is the lowest there is often no market and there are no guarantees. Urban circumstances are more favourable to prospective private finance, but there are still formidable obstacles. Providing full access means providing electricity to those who are so poor that they have no means to pay. For these people, the only solution is for the service to be provided by governments or the international community as an investment in future social and income benefits.

Compared to the Reference Scenario, in the UEAC there is an increase in global energy-related $CO_2$ emissions of just 1.3% by 2030 – less than the current emissions of the United Kingdom. This increase is disproportionately modest compared with the number of people affected, as initial consumption levels are less than 1% of the global per-capita average. Similarly, providing universal electricity access is unlikely to lead to a deterioration in other forms of energy security, as global oil and gas balances remain essentially unchanged. If the generation fuel mix to supply the additional demand were that of the 450 Scenario (see Introduction and Part B), the increase in energy-related global $CO_2$ emissions would be a mere 0.9% by 2030.

**Figure 2.11** ● *Incremental electricity generation and investment in the Universal Electricity Access Case, 2008-2030*




* Covers generation, transmission and distribution for both urban and rural grids.

### *Reliance on traditional biomass*

Cooking a meal, a daily and routine task, can be a difficult chore and a danger to human health in some parts of the world. Today 2.5 billion people, or 37% of the world's population rely on biomass[11] as their primary fuel for cooking. Over half of those people live either in India or Sub-Saharan Africa.

Reliance on biomass often results in regular exposure to harmful emissions of carbon monoxide, hydrocarbons and particulate matter. The World Health Organization (WHO) estimates that 1.5 million premature deaths occur each year due to indoor air pollution from the use of solid fuels: it is estimated that indoor air pollution causes about 36% of lower respiratory infections and 22% of chronic respiratory disease (WHO, 2006). Women and children suffer most from indoor air pollution, because traditionally they are responsible for household chores. Also in regions reliant on biomass, women and children are typically responsible for fuel collection, an exhausting task that can result in long-term physical damage.

As incomes increase, fuel switching occurs from biomass to modern forms of energy, such as LPG or kerosene, and then gas and electricity. Nonetheless, higher income does not guarantee access to modern fuels. Limited availability and reliability of supply of alternative fuels can prevent or limit the transition.

In the Reference Scenario, the number of people depending on biomass for cooking is expected to rise to around 2.7 billion in 2020, before stabilising close to that level for the remainder of the *Outlook* period. However, these global trends mask significant changes at the country/regional level. The number of people depending on biomass increases steadily in Sub-Saharan Africa, from 608 million today to 765 million in 2030, by which time 30% of the people using biomass worldwide live in the region. In developing Asia, the number of people using biomass increases from 678 million today to 731 million in 2030. In contrast, in China the number of people reliant on biomass has already peaked and continues to decline through to 2030. In India the number of people depending on biomass declines after 2020 as the country (like China) experiences a gradual transition towards modern fuels.

11. Biomass includes animal dung, roots, agriculture residues and fuel wood.

# IMPACT OF THE FINANCIAL CRISIS ON ENERGY INVESTMENT

## A threat or an opportunity?

### H I G H L I G H T S

- Energy investment worldwide has plunged in the face of a tougher financing environment, weakening final demand for energy and falling cash flows – the result, primarily, of the global financial and economic crisis. Energy companies are drilling fewer oil and gas wells, and cutting back spending on refineries, pipelines and power stations. Many ongoing projects have been slowed and a number of planned projects postponed or cancelled. Businesses and households are spending less on energy-using appliances, equipment and vehicles.
- In the oil and gas sector, most companies have announced cutbacks in capital spending, as well as project delays and cancellations, mainly as a result of lower prices and cash flow, and demand uncertainties. We estimate that global upstream oil and gas investment budgets for 2009 have been cut by around 19% compared with 2008 – a reduction of over $90 billion. Since October 2008, over 20 planned large-scale upstream oil and gas projects, involving around 2 mb/d of oil production capacity, have been deferred indefinitely or cancelled and a further 29 projects, involving 3.8 mb/d of oil capacity, have been delayed by at least 18 months. Oil sands projects in Canada account for the bulk of the postponed oil capacity.
- Power-sector investment is expected to be severely affected by financing difficulties, as well as by weak demand. Global electricity consumption is projected to drop by 1.6% in 2009 – the first annual contraction since the end of the Second World War. Weakening demand is reducing the immediate need for new capacity. If a recovery takes longer than expected and fossil-energy prices remain low relative to recent peaks, investment may (depending on government policies) shift to coal- and gas-fired plants at the expense of more capital-intensive options such as nuclear and renewables.
- In late 2008 and early 2009, investment in renewables-based generation fell proportionately more than that in other types of generating capacity. For 2009 as a whole, it could drop by close to one-fifth. Without the stimulus provided by government fiscal packages, it would have fallen by almost 30%. In most regions, investment in bio-refineries all but dried up in early 2009, due to lower ethanol prices and scarce finance.
- Falling energy investment will have far-reaching and, depending on how governments respond, potentially serious effects on energy security, climate change and energy poverty. Cutbacks in investment in energy infrastructure will affect capacity only with a lag; sustained lower investment could lead to a shortage of capacity and another spike in energy prices in several years' time.

# How the crisis has affected energy investment so far[1]

The financial and economic crisis has had far-reaching and widespread consequences for energy markets, the repercussions of which will be felt for several years to come. Economic contraction has led to a downturn in global demand for energy. Investment in energy infrastructure has also been hit hard, which will have lasting effects on supply capacity. Energy investment has been affected in three main ways by the crisis:

- *Tighter credit:* Energy companies have been finding it much harder than in the past to obtain credit for both ongoing operations and to raise fresh capital for new projects, because of paralysed credit markets. In addition, plunging share prices have driven up gearing ratios and obliged companies to cut absolute levels of debt. In some cases, the cost of capital has risen in absolute terms, despite very substantial across-the-board cuts in central bank lending rates – especially for the riskiest projects – making marginal investments uneconomic.
- *Lower profitability:* The slump in the prices of oil and other forms of energy during the second half of 2008 and early 2009 (resulting from weak demand) together with expectations of lower prices compared with a year ago, have made new investments in production facilities generally less profitable, as costs (while starting to fall back) generally remain high. The price collapse (and, in Europe, a big drop in carbon prices) has also shifted the relative economics of power-generating plants, to the detriment of low-carbon renewables-based generation and nuclear power.
- *Less immediate need for capacity:* Falling demand for energy, caused by the economic slowdown, has reduced the appetite and urgency for suppliers to invest now in new capacity. Spare capacity or reserve margins, in many cases, have grown over the past year and are expected to increase further in the next year or two.

The combined effect, so far, has been a scaling back of all types of energy investment along the supply chain in most countries, especially in those projects considered to be most risky and funded off the balance sheet. A number of energy companies have cut capital spending programmes for 2009 and beyond, and are seeking greater flexibility in planning and completing projects. Most projects that were already under development in mid-2008 are proceeding and are not expected to be halted, unless sponsors or financiers are directly hit or project economics sour considerably in the months ahead (for instance, if oil prices fall back again). But many ongoing projects are being slowed, and many planned or proposed projects have already been postponed or cancelled – for lack of finance and/or because of downward revisions in expected profitability.

The impact of the crisis on investment varies considerably across fuels and countries, reflecting differences in risk, market and ownership structures, the level of leverage, the state of local credit markets, changes in relative fuel prices and costs, project lead times, the economic outlook and prospects for energy demand in the near to medium term. In some cases, notably in the power sector, the main reason for cutbacks in investment has been difficulty in securing finance, both for new projects and current

1. An early version of this chapter was presented to G8 Energy Ministers at their meeting in Rome in May 2009.

operations; in the oil and gas sector, the drop in prices and the expectation of lower costs in the near future have been the main drivers of cutbacks in capital spending (see below).



**Box 3.1 ● How has the crisis affected energy demand so far?**

Comprehensive data on energy demand trends in the second half of 2008 and 2009 will not be available for many months. But partial data on consumption of specific fuels for some countries point to plunging energy demand in the face of economic contraction. The September 2009 edition of the IEA's monthly *Oil Market Report* estimates that global oil demand dipped by 3.4% in the first quarter of 2009 (year-on-year) and by 2.6% in the second quarter, based on preliminary data. The fall in demand is sharpest in the OECD. On current trends, world demand is expected to drop by 2.2% in 2009 as a whole, following a drop of 0.2% in 2008 (the sharp drop in demand in the second half of the year more than offset growth in the first half).

Partial data for other fuels and certain regions also point to much weaker demand, particularly in the industrial sector. In the United States, for example, total primary energy use in the first five months of 2009 was 6% lower than a year earlier, with consumption of oil down almost 8%, and use of natural gas and electricity both falling by over 4%. Industrial energy use in total was 13% lower. Demand for gas and electricity in Europe has also fallen heavily since mid-2008, despite the coldest winter for 20 years. Preliminary data point to a year-on-year fall of 9% in gas use in the first half of 2009, with big declines recorded in Turkey (18%), Italy (14%), Spain (13%) and the United Kingdom (11%). Electricity demand fell by an estimated 5%. In the Pacific, falling demand in industry and in the power sector translated into big falls in overall gas demand (10% in Korea and 8% in Japan).

Sources: IEA databases; US Energy Information Administration (www.eia.doe.gov); industry sources.

Investment in energy-related capital stock (equipment, buildings, vehicles and appliances), which affects the efficiency and pattern of energy use, is similarly affected by financing difficulties and lower prices, making energy savings less attractive financially. The economic crisis has affected consumer behaviour in three main ways:

- Consumers (businesses and households) are spending less on new durable goods, delaying the deployment of a more efficient generation of equipment, vehicles, buildings and appliances.
- They are less willing and able to pay the premium for more efficient goods, as their disposable income decreases and energy prices slump.
- They are making less use of new goods, once purchased.

The economic crisis has also encouraged businesses to rein in capital spending across the board as a defensive measure, while households have cut their spending on new appliances and cars in the face of worries about future income. Furthermore, equipment manufacturers – including carmakers – are expected to reduce investment in research, development and commercialisation of more energy-efficient models, unless they are able to secure financial support from governments. Governments in many countries have recognised the negative impact of the crisis on consumer spending on more efficient (and more expensive) technologies, and have put in place measures to try to counterbalance this effect, often as part of their economic stimulus programmes (see Introduction).

The crisis is affecting energy-supply industries and individual firms in different ways, mainly according to how dependent they are on external finance, the sensitivity of demand and final price to economic trends, capital intensity, and the degree of government ownership and regulation. Power-sector investment has been particularly severely affected by financing difficulties, as well as by the prospect of stagnant demand. The drop in investment in renewables-based power projects has generally been disproportionately larger as a result of the improved competitiveness of fossil-fuel generation technologies, though countervailing action by government has offset part of this effect. Oil and gas investment is already being trimmed back, largely because of lower prices. Coal investment programmes have also been cut sharply, as a result of falling coal prices and pressure on mining companies to cut debt. One likely consequence of the crisis may be consolidation across the energy sector, as small- and medium-sized firms that are struggling to meet their ongoing financial needs are taken over by or merge with competitors with stronger balance sheets. Falling share prices are likely to encourage this trend.

The medium-term ramifications of the crisis for energy investment are very uncertain, not least because of doubts about the recovery profile and, linked to that, how quickly lending to energy producers and consumers will revive. There are signs that the strong medicine administered by governments to the financial system is beginning to work, with a drop in interbank rates and an easing of credit conditions in some markets. The world economy may now be bottoming out. But the global financial system remains fragile amid fears of further losses as asset values continue to fall. There is little prospect of a quick return to the days of cheap and easy credit. In general, financing energy investment will certainly be more difficult and costly in the medium term than before the crisis took hold. Even assuming a gradual easing of credit conditions, the expected rebound in energy demand and prices, which would create new opportunities for profitable investment on both the supply and demand sides, will hinge to a large degree on economic recovery: demand in the short term for most types of energy is highly and immediately sensitive to changes in economic activity and incomes (and much less sensitive to price movements). Energy companies will seek reassurance that any upturn in energy demand and price, when it comes, is durable before committing to a significant increase in capital spending.

## Impact on oil and gas investment

### Global trends and near-term outlook

Investment has been scaled back across the oil and gas sector, largely as a result of the precipitous drop in prices since July 2008 (in large part due to weak demand) and, to a lesser extent, because of financing difficulties. The collapse in prices, which has so far outpaced that in costs, has starved companies of cash flow that could be used to finance capital spending. It has also led many companies to revise down their assumptions about future price levels and, therefore, projected cash flows, undermining the assessed profitability of new projects. Some national companies' investment programmes are being cut because dwindling revenues are needed to cover spending in other sectors. The majority of these companies have announced cuts in investment budgets (compared with 2008 spending and that originally planned for 2009), and many have postponed planned and proposed projects. Upstream investment has so far been hit hardest.



Total oil and gas investment across the industry is expected to drop significantly in 2009, both year-on-year and compared with planned capital spending a year ago. The pattern of spending cuts is by no means even. In general, the smaller the company, the bigger the cutback. We have surveyed the capital spending plans of 50 leading oil and gas companies. The results point to a drop of 16% in investment compared with 2008, from $524 billion to $442 billion (Table 3.1). In aggregate, the super-majors (ExxonMobil, Shell, BP, Chevron and Total) plan to cut spending by only about 7%. A few companies, notably Mexico's Pemex and China's CNOOC, have announced increases in spending. But most other companies are cutting spending, in some cases drastically. The top 25 companies have cut budgets by 15% and the next 25 by almost 17%. Spending cuts are even bigger when compared to the level of spending planned in mid-2008 for 2009, according to the results of a survey published in last year's *Outlook* (IEA, 2008a). On this basis, the real reductions in planned spending by the 50 leading companies are 16%. Smaller operators than those covered by our survey are more affected by the credit crunch because they tend to have higher debt-to-equity ratios and smaller cash reserves. As a result, the magnitude of the overall reduction in oil and gas investment worldwide is certainly even bigger than the reductions made by the leading companies. In general, spending is expected to fall most heavily in the upstream.

As in the power sector, almost all projects already under construction are expected to be completed, though work is being slowed in many cases to limit the need to raise fresh capital and to take advantage of an expected fall in costs. Construction and operating costs in both the upstream and downstream sectors have soared in recent years, but they are now starting to fall back (see Chapter 12). Planned projects — especially those in the early stages of design — are most heavily affected by spending cuts: most projects not yet under construction have already been pushed back, in some cases indefinitely, or cancelled outright.

## Impact of the credit crunch on oil and gas financing

The squeeze on lending has affected oil and gas companies' capital spending to varying degrees. Relative to other energy sectors, the oil industry is characterised by a high level of self financing (out of cash flow) and low debt-equity ratios. International oil companies, which currently account for around half of global oil and gas investment, have generally been the least affected among energy companies by the difficulties faced in raising capital. They typically finance the bulk of their capital needs from internal cash flows and have less need to borrow either short or long term. Their balance sheets are generally sound, so they still have little trouble in raising additional funds from financial markets. Nonetheless, in early 2009, most of the largest oil companies were unable to cover their capital spending programmes out of cash flow and have been forced to borrow, as a result of the sharp drop in prices in the second half of 2008 (though the rebound in prices in the second quarter of 2009 has improved their cash flow). The cost of borrowing has also risen with the credit crunch, though rates have been falling recently.

**Table 3.1 • *Total investment plans of 50 leading oil and gas companies***

| Company | 2008 ($ billion) | 2009 ($ billion) | Change 2009/2008 (%) | Change 2009 vs. plan of mid-2008 (%) |
|---|---|---|---|---|
| PetroChina | 34.0 | 34.1 | 0.4% | -5.9% |
| Shell | 32.0 | 31.0 | -3.1% | -8.1% |
| Petrobras | 29.1 | 28.0 | -3.7% | -6.6% |
| Gazprom | 25.6 | 14.6 | -42.8% | -47.3% |
| ExxonMobil | 23.9 | 24.9 | 4.3% | -1.4% |
| Chevron | 22.8 | 19.7 | -13.5% | -20.9% |
| BP | 22.0 | 19.0 | -13.6% | -16.7% |
| Eni | 21.4 | 17.6 | -17.7% | -11.9% |
| Total | 20.5 | 18.0 | -12.3% | -17.4% |
| ConocoPhillips | 19.9 | 12.5 | -37.4% | -22.2% |
| Pemex | 18.0 | 20.4 | 13% | 11% |
| StatoilHydro | 16.9 | 13.5 | -20.1% | -6.9% |
| Sinopec | 15.8 | 16.4 | 4.2% | -22.3% |
| Lukoil | 11.1 | 6.5 | -41.5% | -38.1% |
| Devon Energy Corp | 9.4 | 4.5 | -52.0% | -30.8% |
| Repsol YPF | 9.3 | 8.4 | -9.6% | -4.0% |
| Rosneft | 8.7 | 7.0 | -19.5% | -25.5% |
| Marathon | 7.4 | 5.5 | -25.1% | -14.7% |
| EnCana | 7.4 | 5.6 | -24.1% | -20.4% |
| Occidental | 6.8 | 3.6 | -47.1% | -20.0% |
| Canadian Natural Resources | 6.4 | 3.1 | -51.6% | -44.6% |
| Apache | 5.9 | 3.4 | -43.5% | -39.0% |
| Anadarko | 5.3 | 4.2 | -20.8% | -12.4% |
| Talisman | 5.2 | 3.2 | -39.9% | -24.9% |
| CNOOC | 5.1 | 5.7 | 11.8% | -3.4% |
| **Sub-total top 25** | **390.0** | **330.6** | **-15.2%** | **-15.7%** |
| **Next 25** | **133.5** | **111.1** | **-16.8%** | **-18.2%** |
| **Total 50 companies** | **523.6** | **441.7** | **-15.6%** | **-16.3%** |

Sources: Company reports and announcements; IEA analysis.

Wholly state-owned national companies, which account for a growing share of global crude oil production, are largely immune from tighter lending standards because of credit guarantees and favourable borrowing terms from their state owners. National companies that are part privately owned, including Brazil's Petrobras, the Chinese national companies and Russia's Gazprom, have been hit by plunging share prices, which have constrained their ability to raise private capital. Nevertheless, most of the cutbacks in capital spending by national companies are the result of a weaker outlook for demand, prices and revenues rather than of financing difficulties. Moreover, Russian companies have been protected from the full impact of the crisis by the devaluation of the rouble.



Smaller private firms, especially independent exploration and production companies, have been affected much more by the credit crunch, as they rely more on commercial debt and borrowing to cover their investment programmes. Independent companies in the United States and elsewhere – especially the least credit-worthy – have endured a sharp rise in borrowing costs. Most have cut capital spending to keep it within cash flow, borrowing from banks or issuing commercial paper only as a last resort. Some companies have disposed of non-core assets to raise funds for upstream developments. Others in severe financial difficulties have been forced to refinance debt and sell off core assets to stave off bankruptcy. In March 2009, Hallwood Energy, an independent shale gas producer, became the largest US upstream company to go bankrupt since the crisis broke. But there are signs that fresh financing has become easier in recent months.

Private downstream oil and gas companies are generally more highly leveraged than the international companies, with an average equity-to-debt ratio of around 30:70, and have, therefore, faced more difficulties and higher costs in refinancing debt and raising fresh capital for their long-term investment programmes. The longer it takes for credit markets to return to normal, the more likely it is that their investment programmes will be reined in.

One area that has been hit hard is project finance, which is commonly used for large-scale and high-risk oil refining and mid-stream activities, such as liquefied natural gas (LNG) chains and oil and gas pipeline projects. Project finance on a non-recourse or limited-recourse basis, which keeps debt off a participating company's balance sheet, has become much more costly and much harder to secure, as a result of diminishing liquidity and increased risk aversion among lenders.

## Upstream investment

In late 2008 and early 2009, a number of delays to and cancellations of high-cost oil and gas projects, and cutbacks in capital spending budgets, were announced. Many of the project delays are the direct result of the financial crisis and lower oil prices, though attributing all the delays to the crisis would be misleading: some of the delays would no doubt have occurred regardless of the crisis as a result of "normal" project slippage, which has been running at up to one year on average over the past couple of years. Between October 2008 and September 2009, over 20 planned large-scale upstream oil and gas projects, involving around 2 million barrels per day (mb/d) of peak oil capacity and around 9 billion cubic metres (bcm) per year of peak gas capacity, were deferred indefinitely or cancelled (Table 3.2). The total value of these delayed investments, mainly involving oil, is over $170 billion. Oil sands projects, which are among the most expensive of all upstream developments on a per barrel basis, account for the bulk of

**Table 3.2 ● Major upstream oil *and gas* projects deferred by at least 18 months, suspended or cancelled** (October 2008 to September 2009)

| Project | Country | Type | Operator | Original start date of first production | New completion date (estimated) | Peak capacity addition oil (kb/d) | Gas (mcf/d*) |
|---|---|---|---|---|---|---|---|
| Jackpine 1B | Canada | Oil sands | Shell | 2012 | Suspended | 100 | |
| Carmon Creek 1 | Canada | Oil sands | Shell | 2008 | Suspended | 50 | |
| BA Phase 1 | Canada | Oil sands | Value Creation Group | 2009 | Suspended | 70 | |
| BA Phase 2 | Canada | Oil sands | Value Creation Group | 2010 | Suspended | 70 | |
| BA Phase 3 | Canada | Oil sands | Value Creation Group | 2011 | Suspended | 70 | |
| Firebag 5 | Canada | Oil sands | Suncor | 2012 | Suspended | 68 | |
| Firebag 6 | Canada | Oil sands | Suncor | 2012 | Suspended | 68 | |
| Fort Hills 1 (with upgrader) | Canada | Oil sands | Petro-Canada | 2012 | Suspended | 140 | |
| Fort Hills 2 | Canada | Oil sands | Petro-Canada | 2014 | Suspended | 130 | |
| Surmont expansion | Canada | Oil sands | ConocoPhilips | 2012 | Suspended | 65 | |
| Horizon 2nd phase | Canada | Oil sands | CNRL | 2010 | Suspended | 45 | |
| Voyageur expansion upgrader | Canada | Oil sands | Suncor | 2010 | Suspended | 200 | |
| Kai Kos Dehseh upgrader | Canada | Oil sands | StatoilHydro | 2016 | Suspended | 200 | |
| Heartland upgrader | Canada | Oil sands | Value Creation Group | 2009 | Suspended | 250 | |
| Sunrise | Canada | Oil sands | Husky/BP | 2012 | Suspended | 200 | |
| Karachaganak Phase III | Kazakhstan | Gas condensate | BG Group | 2012 | Suspended | 27 | 650 |
| Forties | UK | Offshore oil | Kessog | 2009 | Suspended | 25 | |
| Shenhua 2 | China | Coal-to-liquids | Shell | 2011 | Suspended | 60 | |
| Ivanhoe | Egypt | Gas-to-liquids | Ivanhoe Energy | 2010 | Suspended | 95 | |
| Reindeer | Australia | Offshore gas | Santos | 2010 | Suspended | | 210 |
| Entrada | US Gulf of Mexico | Offshore oil | Callon Petroleum | 2009 | Cancelled | 14 | |
| Trebs & Titov | Russia | Onshore oil | Lukoil | 2008 | Cancelled | 80 | |
| **Total suspension/cancellations** | | | | | | **2 027** | **860** |

* Million cubic feet per day.

**Table 3.2 • Major upstream oil and gas projects deferred by at least 18 months, suspended or cancelled** (October 2008 to September 2009) (continued)

| Project | Country | Type | Operator | Original start date of first production | New completion date (estimated) | Peak capacity addition oil (kb/d) | Gas (mcf/d*) |
|---|---|---|---|---|---|---|---|
| Puma | US Gulf of Mexico | Offshore oil | BP | 2010 | 2013 | 40 | |
| Kearl 1 | Canada | Oil sands | Imperial | 2012 | 2014 | 100 | |
| Goliat (FPSO) | Norway | Offshore oil | ENI | Apr-12 | End-2013 | 100 | |
| Cheviot (former Emerald) | UK | Offshore oil | ATP | Oct-08 | Oct-10 | 30 | |
| Lochnagar | UK | Offshore oil | Chevron | Aug-10 | 2015 | 90 | |
| Kuyumbinskoye | Russia - E.Siberia | Onshore oil | Slavneft | 2010 | 2013 | 60 | |
| Vankor | Russia - E.Siberia | Onshore oil | Rosneft | 2008 | Aug-09 | 380 | |
| Vladimir Filanovsky | Russia - N.Caspian | Offshore oil | Lukoil | 2012 | 2014 | 120 | |
| Shah Deniz Phase 2 | Azerbaijan | Offshore gas | BP | 2014 | 2016 | 40 | 1070 |
| Jidong Nanpu | China | Offshore oil | PetroChina | Feb-10 | End-2011 | 300 | |
| Bhagyama | India | Onshore oil | Cairn | 2009 | Mar-11 | 30 | |
| Calauit | Philippines | Offshore oil | Otto Energy | Apr-08 | 2011 | 12 | |
| Menzel Ledjmet East (Block 405b) | Algeria | Onshore oil | Sonatrach/First Calgary | 2010 | 2012 | 8 | |
| Jufeyr I | Iran | Onshore oil | INOC | 2009 | 2010 | 25 | |
| Darkhovin III | Iran | Onshore oil | INOC | 2012 | 2014+ | 120 | |
| Kharg NGL | Iran | Onshore NGL | INOC | 2012 | 2014+ | 85 | |

**Table 3.2 • Major upstream oil and gas projects deferred by at least 18 months, suspended or cancelled** (October 2008 to September 2009) (continued)

| Project | Country | Type | Operator | Original start date of first production | New completion date (estimated) | Peak capacity addition oil (kb/d) | Gas (mcf/d*) |
|---|---|---|---|---|---|---|---|
| Burgan water treatment | Kuwait | Onshore oil | KPC | 2009 | 2013 | 120 | |
| Sabriya GC-24 | Kuwait | Onshore oil | KPC | 2010 | 2013 | 160 | |
| NC186 expansion | Libya | Onshore oil | LNOC | 2008 | 2012 | 35 | |
| Zuetina expansion | Libya | Onshore oil | LNOC | 2010 | 2013 | 50 | |
| Nafoora expansion | Libya | Onshore oil | LNOC | 2010 | 2013 | 150 | |
| Verenex Ghadames Basin Area 47 | Libya | Onshore oil | LNOC | 2010 | 2012 | 50 | |
| Bonga SW/Aparo | Nigeria | Offshore oil | Shell | 2012 | 2014 | 150 | |
| Egina | Nigeria | Offshore oil | Total | 2012 | 2014 | 150 | |
| Gbaran/Ubie | Nigeria | Offshore oil | Shell | 2009 | 2011 | 160 | |
| Al Shaheen increments | Qatar | Offshore oil | Maersk | 2008 | 2010 | 80 | |
| Manifa crude | Saudi Arabia | Onshore oil | Saudi Aramco | 2012 | 2014 | 900 | 1 240 |
| Lower Zakum expansion | UAE | Offshore oil | ADNOC | 2011 | 2013 | 75 | |
| Upper Zakum expansion | UAE | Offshore oil | Zadco/ExxonMobil | 2012 | 2014 | 150 | |
| **Total postponed (>18 months)** | | | | | | **3 770** | **2 310** |
| **Total** | | | | | | **5 797** | **3 170** |

* Million cubic feet per day.

the postponed oil capacity (See Spotlight). In addition, 29 projects, involving 3.8 mb/d of peak oil capacity and close to 25 bcm/year of peak gas capacity (involving more than $70 billion of investment), were delayed by at least 18 months. The largest of these projects is the 900 thousand barrels per day (kb/d) Manifa oilfield in Saudi Arabia, which was originally due to be brought on stream by 2012. Saudi Aramco is now looking to extend the duration of the project by up to 18 months in order to reap the benefit of falling costs industry-wide.



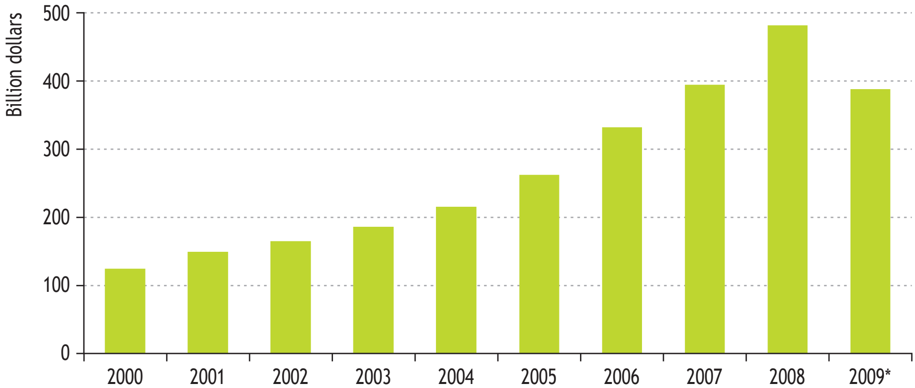
Many other projects have been delayed for a year or more, in many cases at least in part due to efforts to negotiate lower costs with contractors or because the project developer is short of cash to cover development costs. The Organization of the Petroleum Exporting Countries (OPEC) announced in February 2009 that the collapse of oil prices had led its members to delay completion of 35 out of a total of 150 upstream projects, resulting in the planned addition of 5 mb/d of gross capacity being delayed from 2012 to some time after 2013. OPEC has provided no details of which projects have been affected.[2] Upstream oil projects have been affected much more than gas projects so far. As yet, only four major gas projects – Manifa in Saudi Arabia (oil and gas), Karachaganak Phase 3 in Kazakhstan, Shah Deniz in Azerbaijan and the smaller Reindeer field in Australia – have been suspended or delayed for 18 months or more.

Global upstream budgets are set to fall this year for the first time this decade. Excluding acquisitions, we estimate that budgeted spending on exploration and production in aggregate worldwide for 2009 currently totals around $388 billion, down by more than $90 billion, or 19%, on 2008 (Figure 3.1). This includes spending by national and international companies. The budget cuts are sharpest among the independent exploration and production companies, especially in North America (in some cases, due to postponements of high-cost oil sands projects). US independents with a strong focus on natural gas production are among the companies expected to cut budgets the most, on average by more than half. Russian companies are also cutting spending sharply. Trends vary considerably by the type of company: the super-majors plan to keep upstream spending broadly flat, while the national companies have reduced spending by 7% and other international companies by around 33% (Figure 3.2).

The drop in upstream spending is most pronounced in the regions with the highest development costs, and where the industry is dominated by small players and small developments. For these reasons, investment in non-OPEC countries is expected to drop the most. The spending slump in 2009 is expected to be strongest in North America, Russia and the North Sea. Drilling activity in the United States and Canada has already fallen precipitously: rig counts – a measure of drilling activity – plunged to a three-year low in mid-2009 to a level less than half that of a year earlier. In response to a fall-off in drilling, the Alberta government announced in March 2009 a new royalty and drilling incentives programme, aimed at lowering charges and improving the economics of new upstream projects. Russian investment is particularly vulnerable to lower prices because of high development costs and an unattractive fiscal regime, despite attempts to improve it. In the North Sea, another high-cost region, drilling has already fallen sharply.

2. Earlier IEA analysis of medium-term supply prospects had already discounted some of this new capacity on the basis of over-ambitious target dates and offsetting decline at other fields.

**Figure 3.1 ● Worldwide upstream capital expenditures**

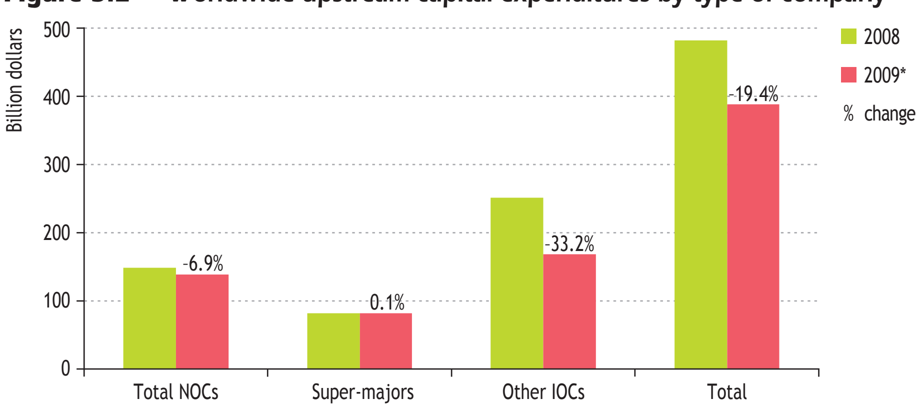



* Based on company plans.

Source: IEA databases and analysis.

The Middle East and North Africa have been less prone to spending cuts, notwithstanding the decision by the Saudi government to delay work temporarily on the Manifa and Karan fields. Saudi Aramco may scale back its investment programme for the five-year period to 2014, if it can negotiate lower project costs. Elsewhere, the picture is mixed. West Africa is characterised by large-scale projects with long lead times, so spending there is likely to hold up better in the near term. But investment may fall in the longer term, unless prices rebound sharply. Significant cuts in spending are likely in Venezuela, where central government revenue needs will constrain the amount of revenue that the national companies will be allowed to retain to cover capital spending. Petroleos de Venezuela SA (PDVSA) is already struggling to find cash to pay suppliers and partners, and may delay plans to help Nicaragua build a refinery, while similar promises to Ecuador and Cuba may well suffer the same fate. The Ecuadorian state oil company, Petroecuador, has almost halved its 2009 upstream capital spending budget to under $1 billion.

**Figure 3.2 ● Worldwide upstream capital expenditures by type of company**




* Based on company plans.

Source: IEA databases and analysis.

SPOTLIGHT

### Canadian oil sands: is the boom over or taking a breather?

Canada's once booming oil sands industry has been hit extremely hard by the oil price slump and the global credit crisis, mainly because such projects are very capital-intensive and much of their output is destined for the United States, where demand is waning. Canada ranks second only to Saudi Arabia in terms of proven oil reserves, with 178 billion barrels that can be recovered using current technology. The vast bulk is in the form of oil sands — a thick, viscous mixture of sand, water, clay and bitumen, concentrated in three major deposits in northern Alberta. Oil sands projects require much greater capital expenditure than conventional oil to extract the oil-rich bitumen and then refine it into oil. Nonetheless, because of high oil prices and a lack of opportunities to increase production in those parts of the world that are open to foreign investment, oil companies flocked to Alberta over the past decade; output from the oil sands rose from 600 kb/d in 2000 to 1.2 mb/d in 2008. This rapid growth led to shortages in skilled labour and rapid cost inflation, prompting concerns that the pace of development was not sustainable.

The outlook has changed dramatically since mid-2008. Projects involving around 1.7 mb/d of peak capacity and worth around $150 billion of investment have been suspended or cancelled (Table 3.2).[3] The new economic challenges come on top of fresh worries about the environmental impact of the oil sands industry. In addition to needing huge amounts of water and natural gas, oil sands generate about 20% higher $CO_2$ emissions than conventional oil on a "well-to-wheel" basis. In today's uncertain regulatory framework, this is creating worries for investors — a carbon price of $50 per tonne of $CO_2$ could increase the cost of producing oil sands by up to $5 per barrel.

Providing that current challenges can be overcome, Canadian oil sands have the potential to make a significantly greater contribution to global energy security for decades ahead by increasing the diversity of supply. As Canadian oil sands represent one of the few growth areas among non-OPEC countries, many countries — particularly the United States and China — will be looking for a bigger share of oil sands output in order to reduce their dependence on Persian Gulf oil. For example, PetroChina agreed to buy a 60% stake in two planned oil sands projects from Canadian firm Athabasca Oil Sands in September 2009. However, as an industry whose profitability currently relies on oil prices of around $75 to $80 per barrel,[4] the outlook for oil sands in the medium term is much less certain. While existing projects will continue to produce, as current crude prices are more than adequate to cover operating costs, new investment will hinge on an improvement in overall project economics — either through a rise in the oil price or a significant reduction in production costs. On the assumption of rising oil prices, we project Canadian oil sands production to reach 2.1 mb/d in 2015 and 3.9 mb/d in 2030 (see Chapter 1).

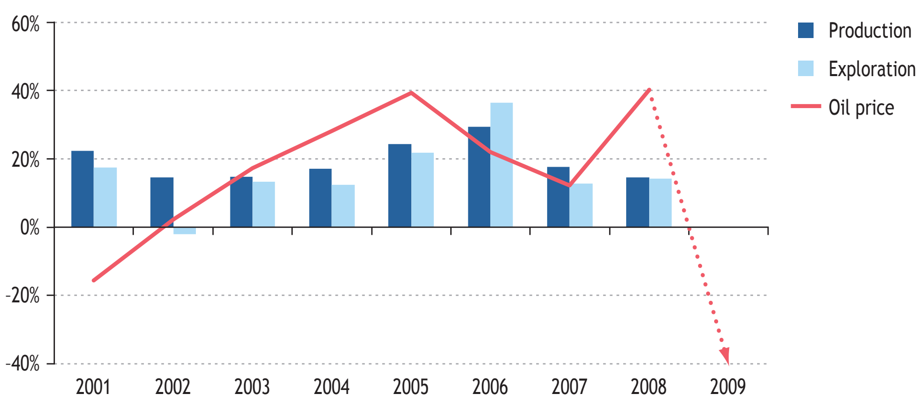
3. Not all planned oil sands projects have been postponed. The first 110-kb/d phase of the 300-kb/d Kearl project, a joint venture of ExxonMobil and Imperial, received the green light in May 2009.

4. Falling costs will probably lower this hurdle price in the medium term. Reductions of 15% to 20% in capital costs for some planned oil sands projects, including Kearl have been reported.

Investment in deepwater developments has been generally less affected than onshore drilling, largely because deepwater projects tend to be much larger in scale and to be undertaken by the largest international and national companies, which rely to only a limited degree on corporate borrowing. These projects are mostly based on hurdle prices of $40 to $50 per barrel, yielding an internal rate of return of 8% to 9%. Most companies are unlikely to cancel such projects, even if prices were to remain below that range for several months, on the assumption that they would eventually rebound (as they did in the second quarter of 2009). Despite the fall in prices since mid-2008, Petrobras is pressing ahead with ambitious plans to develop its pre-salt deepwater finds in the Santos Basin, with pilot production beginning in 2009. Initial soundings among industry participants suggest that upstream capital spending cuts will affect new field developments more than ongoing development of fields already in production, which will push up decline rates (see oil security sub-section in Chapter 2).

Although little hard data is yet at hand, it is likely that the upstream industry will reduce spending on exploration more sharply than on field developments in 2009 – largely because the bulk of spending on development projects is associated with completing projects that had already been launched before the slump in prices. In the United Kingdom, for example, exploration drilling fell by 78% in the first quarter of 2009 – almost twice as fast as the overall drop in drilling. Exploration spending has historically been affected more than development spending by swings in oil prices and cash flow, typically with a lag of about one year (Figure 3.3). Upstream companies can usually cut spending on exploration more quickly, especially onshore, where drilling is faster and rigs are hired for shorter periods. Moreover, the impact of reduced spending on exploration will be felt only several years later, whereas delaying the completion of a current development project can undermine cash flow within a short period.

**Figure 3.3 • Exploration and development capital spending and average nominal IEA crude oil import price** (year-on-year change)




Source: IEA databases and analysis.

## Downstream investment

A number of downstream oil projects have also been delayed as a result of the financial crisis and the weaker outlook for oil-product demand. Since September 2008, five refining projects have been postponed indefinitely and another three cancelled. The combined capacity of these projects is almost 1.5 mb/d (Table 3.3). They include four grassroots refineries, including the planned 615 kb/d Al Zour refinery in Kuwait. In addition, a number of other refinery projects – with a combined capacity of almost 550 kb/d – have been delayed by 18 months or more. In total, refiners are expected to reduce capital spending in 2009 by 10 to 20%, as the prospective returns are balanced against continued problems for some refiners in accessing debt markets and the overall level of profitability achievable under the current conditions.

**Table 3.3 • Major oil refinery projects deferred by at least 18 months, suspended or cancelled** (October 2008 to September 2009)

| Project/location | Country | Type | Operator | Original start date of first production | New completion date (estimated) | Peak capacity addition (kb/d) |
|---|---|---|---|---|---|---|
| Toledo | US | HOE* | BP/Husky | 1Q2011 | Suspended | 15 |
| Wilhelmshaven | Germany | HOE | ConocoPhilllips | 3Q2012 | Suspended | 50 |
| Yeosu | South Korea | HOE | GS-Caltex | 4Q2011 | Suspended | 55 |
| Al Zour | Kuwait | New refinery | KPC | 4Q2012 | Suspended | 615 |
| Al Shaheen | Qatar | New refinery | QPC | 3Q2013 | Suspended | 250 |
| St Johns | Canada | New refinery | BP/Irving Oil | 2014 | Cancelled | 300 |
| Porto Marghera | Italy | HOE | ENI | 2Q2011 | Cancelled | 50 |
| Ras Laffan | Qatar | New refinery | Qatar Petroleum | 1Q2011 | Cancelled | 140 |
| **Total suspension/cancellations** | | | | | | **1 475** |
| Detroit | US | HOE | Marathon | 1Q2011 | 4Q2012 | 15 |
| Port Arthur | US | Refinery expansion | Motiva | 1Q2011 | 3Q2012 | 325 |
| Thessaloniki | Greece | Refinery expansion | Hellenic Petroleum | 1Q2009 | 1Q2011 | 10 |
| Sines | Portugal | HOE | Galp Energia | 1Q2011 | 1Q2013 | 45 |
| Cartegena Murcia | Spain | Refinery expansion | Repsol YPF | 2Q2011 | 1Q2013 | 110 |
| Incheon | South Korea | HOE | SK Energy | 3Q2011 | 2016 | 40 |
| **Total postponed (>18 months)** | | | | | | **545** |
| **Total** | | | | | | **2 020** |

* Heavy oil expansion.

Source: IEA databases.

Investment in LNG supply is set to fall back significantly once the current wave of construction has passed. Only a handful of new projects have received the green light in the last four years. In view of the impact of economic recession on demand and financing problems, there are formidable barriers to new projects being sanctioned in 2009 and even 2010. Investment in transmission pipelines and local distribution networks is likely to be much less affected. Large-scale, cross-border and inter-regional pipeline projects were already facing difficulties in obtaining approvals and financing even before the crisis took hold for a number of reasons, including local resistance to routing, geopolitical factors, and regulatory and market risks. The crisis has undoubtedly added to these hurdles. Certainly, few major projects have been given the green light in recent months. In Europe, for example, final investment decisions have yet to be taken on several major projects that have been under discussion for some time, including the Nabucco pipeline from the Caspian region through Turkey and southeast Europe, and South Stream from Russia to southern Europe. Nord Stream from Russia to Germany continues to be delayed by planning and environmental issues, though the proponents are confident that these can be resolved to allow the laying of pipe to begin in early 2010 (see Chapter 13). In most regions, plunging gas demand has removed any urgency in pressing ahead with pipeline projects. The planned Skanled project, a pipeline running from western Norway to Denmark and eastern Sweden, was suspended in April 2009. Nonetheless, the European Union has set aside EUR 1.4 billion for gas-pipeline projects as part of its economic stimulus package.

## *Implications for capacity — are we heading for a mid-term supply crunch?*

The consequences of investment cutbacks for the adequacy of oil and gas supply capacity in the medium term are very uncertain. Lower investment and project postponements or cancellations will inevitably reduce the gross and net additions to capacity in crude oil and natural gas production, refining and processing, and transportation. But the long lead times of many projects mean that recently announced delays will only affect capacity additions fully after several years.

The risk of a tightening of capacity in the medium term appears greatest for oil, though spare capacity is set to rise in the near term. Both OPEC and non-OPEC capacity is also now expected to grow more slowly than previously thought, in part because of project postponements and delays prompted by the financial and economic crisis. In aggregate, gross capacity of around 1 mb/d has been deferred beyond 2009 and 2010, though much of this will enter production later on. This leaves a rather anaemic profile for world capacity growth through 2014, after a short-term surge in 2010. In the latest *IEA Medium-Term Oil Market Report*, released in June 2009, total capacity is now projected to grow by 4.2 mb/d between 2008 and 2014 (IEA, 2009), compared with 5.5 mb/d in the mid-2008 edition (IEA, 2008b). Nonetheless, the downward shift in supply has been much smaller than that in demand: According to the September 2009 edition of the IEA monthly *Oil Market Report* demand is projected to drop to 84.4 mb/d – 1.9 mb/d less than in 2008 and 3.3 mb/d less than projected in the 2008 *Medium-Term Oil Market Report*, before the recession hit (IEA, 2008b). As a result, spare crude oil production capacity has risen sharply, to around 5.5 mb/d (excluding Iraq, Nigeria and Venezuela) in September 2009 and could rise further to 6 mb/d in 2010. Around 2.7 mb/d of new refining capacity is expected to be added globally during 2009, almost three-quarters of it in Asia, outstripping global demand.



The outlook for spare crude oil production and refining capacity in the longer term hinges on how quickly demand rebounds once the global economy is back on the road to recovery, how much further investment is scaled back in the coming months and how quickly investment rebounds in the coming years. The faster the rebound in demand, the more likely it is that capacity will be squeezed in the medium term: the latest GDP projections from the International Monetary Fund (IMF) imply that oil demand could indeed recover rapidly (IMF, 2009). Even if investment recovers strongly and quickly with economic recovery and higher oil prices, gross oil-production capacity additions would taper off after 2011, as the impact of extending project completions takes effect and because relatively few major projects have been sanctioned in the last two to three years. On the other hand, were the global economy and – thus oil demand – to recover more slowly, spare capacity could remain at current levels until around the middle of the next decade (IEA, 2009).

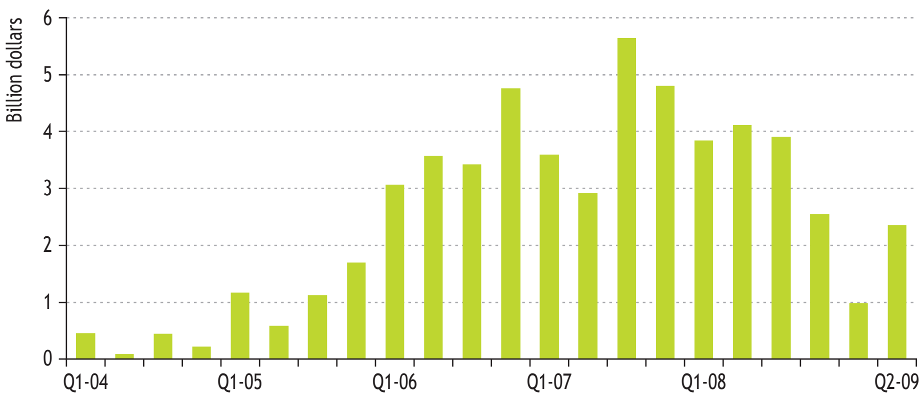
The near-term outlook for LNG supply has eased considerably in the past year as a result, with the slowdown in demand growth and more than 15 new liquefaction trains due to come on stream within the next few years (see Chapter 12). The final investment decisions for most of these projects were taken several years ago. There are around a dozen projects lined up that are facing a final investment decision before the end of 2010. The earliest any of these would come on stream would be 2014 or 2015. It is far from certain that any of them will proceed, in view of the prospect of lower prices, persistently high construction costs, scarce finance and reluctance on the part of some buyers to sign long-term purchase contracts (given the uncertainty about the outlook for demand in the medium term). As a result, global liquefaction capacity is set to plateau by 2013. The next few years are expected to see a significant fall in the utilisation rates of LNG liquefaction plants and inter-regional pipelines (see Chapter 12), which could put pressure on exporters to cut prices. But, given the long lead times in building new plants, LNG markets could tighten once again beyond the middle of next decade, depending on how quickly economic activity and gas demand revives in the main consuming markets. Faster demand growth than projected in the Reference Scenario could eat up most of the spare capacity and drive prices up.

## Impact on biofuels investment

Investment in conventional biofuels production has fallen heavily over the past year or so. The biofuels industry is particularly susceptible to lower oil prices because of the high cost of production and limits on the amount of fuel that can be absorbed by gasoline and diesel blending pools. A wave of construction of new bio-refineries across the world is dissipating and many plants that were brought into operation in recent years have recently been standing idle because of a worsening of economics: biofuel prices, in many cases, have been too low to cover the cost of the feedstock and operating the plant. The higher cost of credit and restricted access to new finance, in addition to regulatory uncertainties related to the environmental sustainability of first-generation biofuels technology, is also deterring new investment.

Worldwide, asset financing of bio-refineries – now almost the sole source of physical biofuels investment – fell almost 50% in the last quarter of 2008, compared with the last quarter of 2007. Financing dropped 74% in the first quarter of 2009 (year-on-year) and by 43% in the second quarter, though it more than doubled in the second quarter compared the first (Figure 3.4). Though never a large share of total investment, public investment and venture capital funding (part of which normally goes to physical assets), have also collapsed. Lower investment, together with lower utilisation rates of existing plants, will reduce incremental biofuels supply: in the five years to 2008, biofuels met 13% of the increase in world demand for oil products and 15% of the increase in demand for liquid transport fuels.

**Figure 3.4 ● *Global asset financing of bio-refineries***



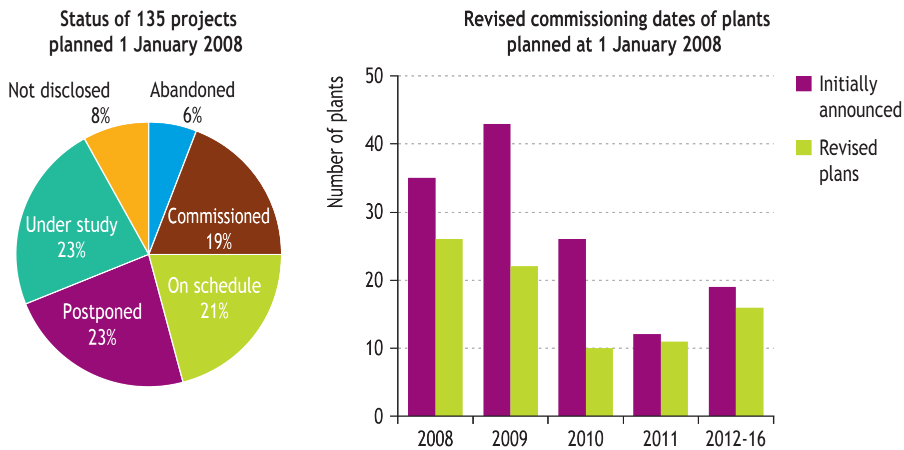

Source: New Energy Finance databases.

New investment in bio-refineries has fallen sharply in the United States with the axing of a number of proposed corn-based ethanol projects due to financing problems, lower ethanol prices or a combination of the two. A growing number of biofuels producers have encountered severe financial difficulties. At the end of 2008, the country's second-largest ethanol producer, Verasun, filed for Chapter 11 bankruptcy protection, along with Greater Ohio Ethanol and Gateway Ethanol. Since the start of the year, Renew Energy, Northeast Biofuels and – most recently – Aventine Renewable Energy have also filed, while a number of other companies have been struggling to avoid the same fate. It is worth noting, however, that some of these assets will be bought and operated by other, more financially robust owners. Reportedly, about one-fifth of US ethanol production capacity was idle in early 2009 because of low crush spreads – the gap in price between the corn feedstock and ethanol. However, market conditions have improved somewhat in recent months, with improved crush spreads as a result of lower corn prices, which has helped to push up utilisation rates and bolster the finances of ethanol refiners.

Many ethanol producers in Brazil have been also struggling, because the sector is highly leveraged. High sugar prices, in part due to poor growing conditions, have added to the industry's woes. New projects that have already secured funding will continue, but many of those that have not are likely to be cancelled. Of 135 projects that were under development at the start of 2008, 29% have been postponed or abandoned and another 23% have stalled (Figure 3.5). Only 85 plants are now expected to be commissioned by 2016. The Brazilian government is considering a bail-out plan for ethanol producers.



**Figure 3.5** ● ***Status of ethanol plants in Brazil***




Source: New Energy Finance databases.

The European Union is also seeing a slowdown in biofuel capacity additions, due to both lower diesel prices (most of the biofuels produced are methyl esters blended into diesel) and financing problems. Uncertainty about forthcoming policy on sustainability criteria for EU member states, to meet the target for renewable energy sources (mainly biofuels) to provide at least 10% of transport energy use by 2020, have also undermined interest in new plants.

The slowdown in global investment will inevitably lead to a levelling off of biofuel production capacity in the near to medium term. At present, ethanol and biodiesel capacity in total stands at 2.2 mb/d – up from 1.8 mb/d in mid-2008 – though more than 0.2 mb/d is currently idle or mothballed (Table 3.4). A further 400 kb/d of capacity is under construction and an additional 500 kb/d is planned. It is likely that, unless crush spreads improve significantly in the coming months, many of the planned plants will be cancelled.

Although investment in conventional biofuels plants has dropped significantly, funding to second-generation biofuels – notably ligno-cellulosic ethanol – is likely to grow, with large amounts of stimulus package funds being directed to research and development of these technologies. A number of companies are pursuing investments in demonstration plants. For example, BP and Verenium recently committed $45 million to a joint venture to develop a ligno-cellulosic ethanol plant. In the United States, part of the $16.8 billion allocated to the Department of Energy's Office of Energy Efficiency & Renewable Energy is expected to be devoted to advanced biofuels.

**Table 3.4 • *Status of biofuel-production capacity worldwide*** (kb/d)

| | Mid-2008 | September 2009 | New listings | Baseline difference |
|---|---|---|---|---|
| In operation | 1 784 | 2 174 | 36 | 355 |
| Idle | 5 | 158 | 9 | 145 |
| Shut | 0 | 55 | 9 | 46 |
| Under construction | 820 | 395 | 51 | -476 |
| Project | 864 | 485 | 28 | -407 |
| Cancelled | 23 | 98 | 0 | 74 |
| Unknown | 0 | 137 | 0 | 137 |

Source: IEA databases and analysis.

## Impact on coal investment

### Overview

Coal-sector investment is expected to turn out to be significantly lower in 2009 than in 2008, falling by perhaps half. Nonetheless, the drop in spending is from the very high levels reached in 2007 and 2008, which were exceptionally profitable years: coal companies increased their investments sharply then, in part to absorb some of their free cash flows, and paid out large dividends to shareholders. Expected reductions in capital spending in 2009 are most marked among high-cost producers, especially those supplying the export market, such as coal mining companies in the United States and Russia. In contrast, Indonesian coal producers continue to enjoy high margins, with little apparent disruption to planned expansions.

The large multinational mining companies are taking steps to address a sharp drop in cash flow. High debt-to-equity ratios following earlier acquisitions and their exposure to the steep downturn in demand for commodities, such as iron ore and other minerals, mean that many new projects have been cancelled or delayed. For other mining companies, the picture is mixed. Those with single customers, such as Sasol in South Africa (which produces mainly for its Secunda chemical plant) and RWE (which produces mainly for its lignite power plants in Germany) have not made any significant changes to capital investment plans at their coal business units. Low-cost suppliers, such as those in Indonesia, anticipate continued strong demand and aim to continue raising production through new investment. State-owned companies, such as those in China and Coal India, can be expected to direct their investments toward government objectives to promote economic growth (as outlined in China's economic stimulus package and in India's 11th Five-Year Plan).

The industry euphoria that flowed from rising coal prices during 2007 and 2008 came to an abrupt end with the steep fall in prices after July 2008. By the end of 2008, international prices had fallen over 70% from their peak and returned to 2006 levels. For some companies, remaining solvent became the priority. This was particularly the case with the Anglo-Australian company, Rio Tinto, which had taken on massive borrowings to fund its expansion. In early 2009, it entered into an agreement whereby state-owned Chinalco, China's largest aluminium conglomerate, would double its equity stake in Rio Tinto to 18%, but the deal subsequently collapsed. In a related move, BHP Billiton abandoned its ambitious attempt to take over Rio Tinto in a deal that would have been worth around $150 billion. Both companies were able to raise significant amounts of capital in mid-2009 through bond and rights issues, with the proceeds being used to cover short-term debt. All mining companies have moved to bolster their cash flows by divesting non-core assets (Anglo American, for example, has sold its stake in China Shenhua Energy), issuing bonds and reducing or eliminating non-essential expenses.



## Impact on major coal producers

Investment by 25 leading coal companies around the world, which account for around 35% of total global coal production (hard coal and brown coal) and over 60% of global coal trade, rose 20% in 2008 (Table 3.5). Privately owned companies (such as Drummond, whose shares are not publicly traded or listed) have limited reporting requirements and publish very little information about their business activities. In these instances and others where companies are state-owned (Coal India, Datong Coal Mining Group and Shanxi Coking Coal Group), capital investments are less reliably reported.

**Table 3.5 • *Production, exports and investment of 25 leading coal companies***

| Company | Corporate base | Production in 2008 (Mt) | Exports in 2008 (Mt) | Investment ($ million) | |
|---|---|---|---|---|---|
| | | | | 2007 | 2008 |
| BHP Billiton | UK-Australia | 116.1 | 76.7 | 873 | 938 |
| Xstrata | UK-Switzerland | 85.5 | 74.8 | 807 | 1 204 |
| Anglo American | UK-South Africa | 99.5 | 50.4 | 1 052 | 933 |
| Rio Tinto | UK-Australia | 160.5 | 31.8 | 452 | 653 |
| Peabody Energy | United States | 231.8 | 22.6 | 439 | 266 |
| Arch Coal | United States | 126.6 | 6.4 | 488 | 497 |
| Consol Energy | United States | 59.0 | 3.3 | 681 | 446 |
| Massey Energy | United States | 37.3 | 7.3 | 271 | 737 |
| Drummond | United States | 35.0 | 35.0 | n.a. | n.a. |
| Teck Cominco | Canada | 23.0 | 16.9 | 532 | 880 |
| SUEK | Russia | 96.2 | 28.2 | 357 | 449 |
| Kuzbassrazrezugol | Russia | 46.0 | 23.0 | n.a. | n.a. |
| RWE Power | Germany | 103.8 | 0.9 | 263 | 331 |
| Kompania Węglowa | Poland | 44.6 | 6.6 | 234 | 371 |

**Table 3.5 • Production, exports and investment of 25 leading coal companies** (continued)

| Company | Corporate base | Production in 2008 (Mt) | Exports in 2008 (Mt) | Investment ($ million) | |
|---|---|---|---|---|---|
| | | | | 2007 | 2008 |
| Sasol | South Africa | 40.4 | 2.5 | 131 | 121 |
| Coal India | India | 403.5 | 1.4 | 863 | 863 |
| Shenhua Group | China | 232.7 | 21.2 | 2 080 | 2 090 |
| China National Coal Group | China | 100.4 | 16.0 | 761 | 1 142 |
| Datong Coal Mining Group | China | 122.0 | 5.0 | n.a. | n.a. |
| Shanxi Coking Coal Group | China | 80.3 | 3.2 | n.a. | n.a. |
| Banpu | Thailand | 18.5 | 16.3 | 92 | 120 |
| Mitsubishi Development | Japan | 33.1 | 33.1 | n.a. | n.a. |
| PT Bumi Resources | Indonesia | 52.8 | 41.0 | 210 | 567 |
| PT Adaro Indonesia | Indonesia | 38.5 | 27.0 | 71 | 151 |
| PT Kideco Jaya Agung | Indonesia | 21.7 | 15.0 | n.a. | n.a. |
| **Total** | | **2 408.8** | **565.6** | **10 657** | **12 759** |

Sources: Company reports; IEA analysis.

Uniquely among the companies listed above, Shenhua has published its revised capital spending plan for 2009, cutting coal-mining investment by 35%. Other companies have given new guidance on capital expenditure during 2009, without issuing precise numbers on coal-mining investment plans. Xstrata has announced that it will slash spending by 45% across all its activities, which include coal mining; Anglo American expects a year-on-year fall in capital expenditure of 50% in 2009 and has abandoned its earlier plan to raise coking coal production by 10%. In the United States, following a third revision statement, Arch Coal's 2009 production target is now 17% lower than 2008 production. In contrast, PT Bumi Resources intends to raise production by 10% in 2009. More broadly, a survey of media reports during the first half of 2009 indicates that the number of new export coal-mine and mine-expansion projects announced has declined by 40%, compared with the same period in 2008. The aggregate production capacity of these projects is 18% lower, suggesting that investment in 2009 is going to a smaller number of larger projects.

### *Implications for capacity*

The recent scaling back of investment in coal mining will undoubtedly slow the growth in production capacity, but probably not to the extent that coal will be in short supply in the near future. When demand and prices recover, most of the mining projects that have recently been postponed will be revived. In most case, projects can be producing within two to five years of an investment decision. There is likely to be an acceleration of the trend, seen now over many decades, of a shift in production to those regions with large, easily accessible resources, such as Indonesia, Australia and west of the Mississippi River in the United States.



## Impact on power-sector investment

### Electricity demand

As in the oil and gas sectors, the first, most immediate effect of the financial and economic crisis on the power sector has been a lowering of electricity demand, particularly in industrial applications, in almost all countries. This is despite a sharp fall in wholesale electricity prices – linked to the drop in fossil fuel prices – and cold winter temperatures in the Northern Hemisphere, which would normally support growth in consumption. In the OECD, electricity demand in the fourth quarter of 2008 fell by 2.6% compared to the corresponding quarter of 2007, according to preliminary data (Table 3.6). The drop-off accelerated in the first quarter of 2009, with electricity consumption falling by 4.7% compared to the first quarter of 2008. OECD electricity demand fell by an estimated 2.7% in the second quarter. Non-OECD regions have also seen weaker demand: electricity demand in China fell by a staggering 7.1% in the fourth quarter of 2008, by 4% in the first quarter of 2009 and by an estimated 0.6% in the second quarter. Electricity consumption has also fallen heavily in Russia; the second quarter of 2009 registered a year-on-year fall of 6.4%.

**Table 3.6 • Electricity demand growth rates for selected countries**

| | Quarterly growth rates (year-on-year)* | | | | | | Annual growth rates | | |
|---|---|---|---|---|---|---|---|---|---|
| | Q1-08 | Q2-08 | Q3-08 | Q4-08 | Q1-09 | Q2-09 | 2007* | 2008* | 2009** |
| Canada | -0.1 | -0.5 | -1.1 | -1.9 | -3.5 | -5.5 | 1.0 | -0.9 | *n.a.* |
| France | 5.1 | 6.3 | 1.4 | -1.4 | 2.6 | -4.7 | 0.4 | 2.7 | *n.a.* |
| Germany | 2.0 | 4.8 | 2.6 | -1.8 | 2.1 | -6.5 | -0.5 | 1.8 | *n.a.* |
| Italy | 1.2 | -0.8 | 2.4 | -5.4 | -8.0 | -3.4 | 0.4 | -0.7 | *n.a.* |
| Japan | 8.5 | 1.0 | -1.1 | -4.6 | -12.5 | -1.3 | 2.9 | 0.9 | *n.a.* |
| Korea | 8.8 | 4.3 | 5.9 | 2.5 | -0.4 | 5.7 | 5.8 | 5.4 | *n.a.* |
| United Kingdom | 1.8 | 1.1 | 0.5 | -3.0 | 2.4 | -2.0 | -0.9 | 0.0 | *n.a.* |
| United States | 2.1 | 0.4 | -3.2 | -2.2 | -5.2 | -1.6 | 2.4 | -0.8 | *n.a.* |
| Russia | 6.6 | 4.3 | 5.1 | 0.5 | -3.7 | -6.4 | 4.0 | 4.0 | *n.a.* |
| China | 13.1 | 10.4 | 6.2 | -7.1 | -4.0 | -0.6 | 14.8 | 5.2 | *n.a.* |
| India | 8.8 | 4.8 | 8.8 | 4.0 | 1.7 | 8.4 | 7.0 | 6.5 | *n.a.* |
| OECD | 3.3 | 1.5 | -0.9 | -2.6 | -4.7 | -2.7 | 2.0 | 0.3 | *n.a.* |
| **World** | **n.a.** | **n.a.** | **n.a.** | **n.a .** | **n.a.** | **n.a.** | **6.8** | **2.6** | **-1.6** |

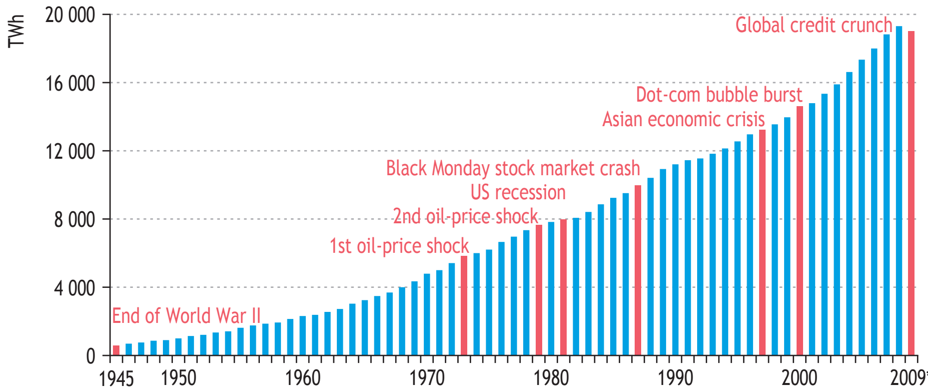
*Actual data.

**IEA estimate.

Source: IEA databases and analysis.

Based on the IMF's latest GDP growth forecast for 2009 (IMF, 2009), we estimate that global electricity demand could drop by as much as 1.6% in 2009. This would represent the first contraction in global electricity demand since the end of the Second World War; even during the first and second oil shocks, and the US recession in the early 1980s, global electricity demand continued on its upward trend (Figure 3.6). Our analysis suggests demand will fall the most in Russia, where the economy has been hit by the slump in oil and gas export earnings, followed by the OECD.

**Figure 3.6 • *Historical world electricity consumption***




* IEA estimate.

Source: IEA databases and analysis.

## Power-sector investment trends and outlook

The economic crisis has changed the outlook for power-sector investment, both in terms of the amount of new capacity that is expected to come on line and the generation fuel mix. Low or negative rates of electricity demand growth are reducing the immediate need for new capacity. In addition, the crisis, by helping to drive down fossil-fuel prices, has led to much lower power prices, which, all other things being equal, typically favour less capital-intensive generation options (such as natural gas and coal) over costlier option (such as nuclear and renewables). At the same time, commercial borrowing has become more difficult, and venture capital and private-equity investment has fallen sharply. The extent to which these factors influence the evolution of the electricity generation mix will depend largely on the duration of the economic downturn. If a recovery takes longer than expected and fossil-fuel prices remain at depressed levels relative to recent peaks, we would expect to see a shift to coal- and gas-fired plants in the longer term.

While construction work is continuing on most new power projects already underway, market commentators have suggested that new power plant orders worldwide could fall by as much as 50% in 2009, although large equipment manufacturers have quoted figures closer to 30%. Many power companies across Europe have been slashing their investment programmes. For example, Spanish utilities have announced cuts totalling €30 billion, or about 44% of planned spending, while E.On, a German utility, announced in February 2009 a downward revision of their investment plan for 2009-2011 from €36 billion to €30 billion, with most of the cut expected to be in fossil fuel-fired power generation. Enel, an Italian company, announced cuts in investment in excess of 20%. In contrast, several other large European utilities, including GDF Suez, RWE and EnBW, have each stated their intent to keep previous investment plans intact. Reduced costs for raw materials and intense competition in the power sector in the face of dwindling orders have contributed to a drop in unit investment and equipment costs by 20% to 30% from the record highs reached in 2008, which should lead to lower investment needs in the coming years.



Although there have been a number of postponements to new coal-fired power plants, these have been linked in significant part to climate and environmental policy, rather than problems stemming from the financial crisis. For example, in the United States, plans for 8.6 GW of new coal capacity were cancelled during the first quarter of 2009, primarily as a result of regulatory uncertainty over climate change legislation. Similarly, in the Netherlands, plans to build three new coal plants have been shelved for approximately 18 months while an interpretation of EU rules on emissions of oxides of nitrogen and sulphur dioxide is handed down. Nonetheless, as it can take between four to six years to build new coal-fired capacity (which is longer than other generating options with the exception of nuclear), investment in new coal plants will be affected by the rising cost of debt.

In contrast, natural gas plants, which have much shorter lead times, could benefit in this respect although their proponents face the heightened uncertainty over the near-term outlook for electricity demand. However, several gas projects are facing difficulty, including the $2.2 billion Al Dur power and water project in Bahrain – a joint venture between the Gulf Investment Corp and France's GDF Suez – which has been delayed by several months as the project proponents seek to negotiate new terms with lenders.

As yet, there have been very few delays or abandonments to transmission and distribution (T&D) projects that were already underway or announced, including key cross-country power grid interconnections. In fact, a number of countries, including France and the United States, have boosted investment in T&D as part of their economic stimulus plans. However, over time, a reduction or contraction in demand for electricity will reduce the need for network investment. In addition, there remains the possibility that projects to upgrade existing distribution lines will be delayed as price formulas used by transmission system operators are revised to take into account recent changes in credit rates.

Given the combination of comparatively stronger rates of electricity demand growth in the coming years and limited financial resources, the power sector in developing countries is likely to be disproportionately affected by the financial crisis. This will hinder efforts to tackle energy poverty (see Chapter 2). Indeed, a number of key projects have already been postponed or abandoned. For example, the 750 MW Kufue Gorge Lower hydropower station that was expected to end Zambia's power shortages has been delayed by one year as several of the international firms interested in providing capital withdrew. Similarly, in Tanzania, a 200 MW coal-fired power plant costing $400 million, which was due to start operation by 2011, has been postponed, while a $300 million 300 MW natural gas-fired plant is struggling to secure financing.

### Nuclear power investment

The financial and economic crisis could lead to delays and possibly cancellations of new nuclear power plants, and hinder efforts to revive new construction programmes, reducing the capacity that is likely to be commissioned in the period 2015-2020. Some 54 reactors are currently under construction, with a total capacity of almost 49 GW; 40 of these units are in non-OECD countries. Projects that were already well-advanced are, for the most part, proceeding. One exception is in South Africa, where the national utility, Eskom, has been forced to delay plans to build a second nuclear plant, extending the date of commissioning by two years to 2018, partly because a downgrading of its credit rating has increased the company's cost of borrowing.

Recent years have seen increased interest in building new nuclear plants in both nuclear and non-nuclear countries. Nuclear technology is the only large-scale, base-load, electricity-generation technology with a near-zero carbon footprint, apart from hydropower (potential for which is often limited). The economics of nuclear relative to fossil-fuelled generation, particularly coal, improves with carbon pricing. The cost of nuclear power is highly sensitive to its capital costs (both the absolute levels of capital expenditure and the cost of capital) because of high capital intensity (typically the cost of a new 1600 MW plant is likely to exceed $5 billion) and long lead times. However, nuclear power is significantly less sensitive to fuel cost than coal- and gas-fired generation. Third-generation nuclear reactors are being built in China, Finland and France. Such technology promises lower costs, improved safety, more efficient fuel use and less radioactive waste. A number of other countries, including the United States, China, Italy, the United Kingdom, Hungary, the Czech Republic and Poland, have recently announced plans to construct new nuclear reactors. For example, in the United States there are two dozen proposals for new reactors, but licensing approval for any of them is not expected before 2011. In the case of Italy, which invoked a complete phase-out of nuclear energy in a 1987 referendum, the government hopes to begin construction of its first new reactor by 2013. However, the recession and financial crisis may hold back moves to launch some of these programmes.

A nuclear renaissance is possible but cannot occur overnight. Nuclear projects face significant hurdles, including extended construction periods and related risks, long licensing processes and manpower shortages, plus long-standing issues related to waste disposal, proliferation and local opposition. The financing of new nuclear power plants, especially in liberalised markets, has always been difficult and the financial crisis seems almost certain to have made it even more so. The huge capital requirements, combined with risks of cost overruns and regulatory uncertainties, make investors and lenders very cautious, even when demand growth is robust. Certain financing models that might have underwritten new nuclear plant development are likely to be unavailable for some time, depending on the speed of economic recovery. These include project financing, which typically involves syndication and securitisation, and industry consortia funding (such as occurred in Finland). Only a few electricity utilities are big enough to finance nuclear plants from their balance sheets and that number has diminished in the current crisis. Governments wishing to encourage investment in nuclear may need to remove or mitigate some risks investors are facing, especially for first-of-a-kind nuclear plants and in countries where there is no existing nuclear programme or where there has been no new construction for many years. The United States provides the clearest example of state support, with federal loan guarantees, risk insurance for licensing delays and production tax credits under the *2005 Energy Act*. By contrast, the United Kingdom has stated its intention not to support nuclear projects financially, though it is taking action aimed at reducing regulatory and planning risks for investors.



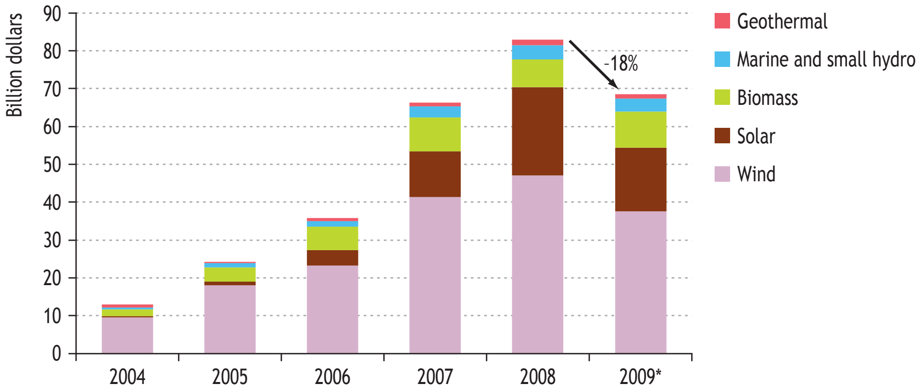
## Renewables-based power-generation investment

Investment in new-build renewable energy assets in the power sector grew tremendously in recent years, recording year-on-year growth of 85% in 2007. Activity in the renewables sector continued to grow rapidly until the third quarter of 2008, but then fell away dramatically as the financial crisis dried up sources of project finance and lower fossil-fuel prices reduced the economic incentive to invest in renewables. The latest preliminary data, covering the first half of 2009, indicate that renewables investment hit bottom in the first quarter, with spending down 47%. It recovered in the second quarter, to 21% below the level of one year previous.

Based on current investment trends in the sector, the IMF's most recent global GDP forecasts and assuming fossil-fuel prices remain close to current levels for the reminder of the year, we project worldwide investment in renewables-based power-generation technologies in 2009 as a whole to drop to under $70 billion, allowing for the effects of the clean energy components of stimulus packages. This represents a fall of 18% on 2008, taking spending back to 2007 levels (Figure 3.7). The stimulus packages make an important difference: without them, investment would have fallen by an estimated 29%. The slump in investment in renewables represents a major setback in the fight against climate change.

New investment flows from private equity and venture capital — which play an important role in funding early-stage clean energy technology companies — fell to just over $1 billion in the first quarter of 2009. This was the lowest capital inflow on a quarterly basis since the last quarter of 2006 and represented a 67% drop from the record level reached in the third quarter of 2008 (Figure 3.8). In the first quarter of 2009, only one-third of venture capital invested in US clean technology companies went to alternative energy firms. Preliminary data for the second quarter of 2009 show an even more dramatic drop. New investment flows from private equity and venture capital fell to only $680 million, a further 39% drop from first quarter of 2009 and 69% less than the level of investment in second quarter of 2008.

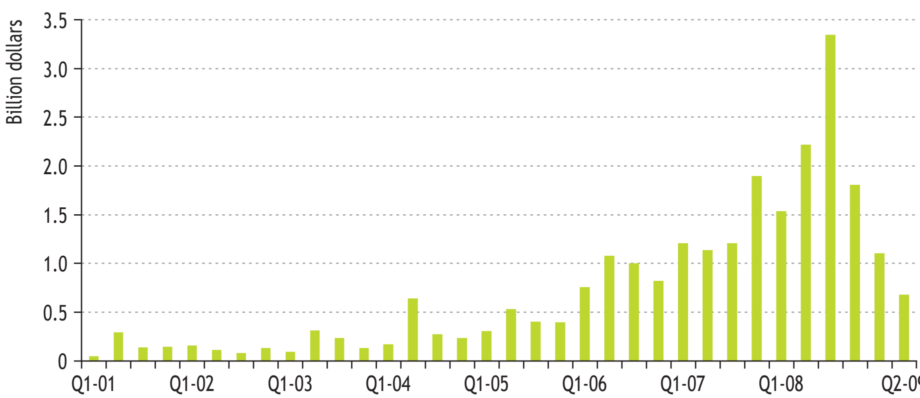
**Figure 3.7 • Global investment in new renewables-based power-generation assets**




* IEA projection taking account of preliminary data for the first half of the year and the impact of fiscal stimulus packages.

Sources: New Energy Finance databases; IEA analysis.

**Figure 3.8 • Venture capital and private equity new investment in clean energy companies, 2001-2009**



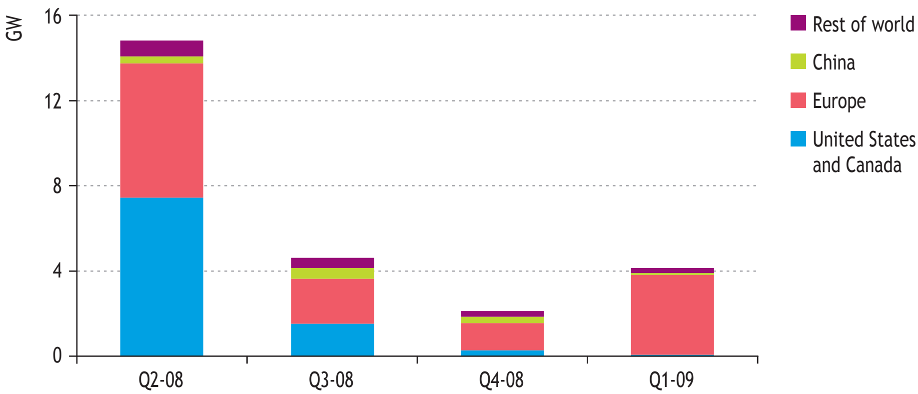

Source: New Energy Finance databases.

Globally, new orders for wind turbines dropped precipitously through 2008, from a peak of almost 15 GW in the second quarter to just 2 GW by the fourth quarter, though orders rebounded to about 4 GW in the first quarter of 2009 (Figure 3.9) and are thought to have risen further in the second quarter. The downturn was particularly severe in the United States and China, whereas spending in the European Union held up comparatively well in comparison. As is the case with most types of renewables, the extent of the impact is linked to the effectiveness and the coherence of policies and support mechanisms individual countries and regions have in place. In the United

States, a slump in funding from so-called "tax equity investors" had a significant impact on wind-power investment. These investors, typically financial services or insurance companies with large tax liabilities, had been buying into renewables projects to secure federal and state tax credits. With several important investors, including Lehman Brothers, now gone and others facing large losses (which reduce the value of the tax credits), interest in investing in renewables projects – especially mid-sized wind farms – has dropped sharply. For example, it is thought that only around half of the large investors that were active in financing wind-power projects in 2008 remained active in early 2009. As the economic outlook improves and federal government stimulus programmes begin to take effect, new sources of finance, including private equity, are likely to emerge.



**Figure 3.9 • Global orders for wind turbines**




Sources: Industry sources; IEA analysis.

Many wind energy projects rely relatively heavily on debt financing, which either has become much harder to find or more expensive, due to higher risk premiums. More risky and high-investment projects, such as offshore wind and large wind farms, are being hit the most. Centrica, a British energy company, has put three planned offshore wind farms on hold, partly because of rising financing costs and lower carbon prices under the EU Emissions Trading System – the result of a projected slowdown in electricity demand. But other projects are proceeding, albeit at a sharply slower pace than planned, in several cases, due to financing problems. For example, the Trianel Group, a German energy trading firm, has halved the size of its planned Borkum-West II offshore wind farm to 200 MW, due to problems securing project finance. Some major wind-farm developers – notably in the United States – have delayed placing orders in the hope of prices falling further and to profit from any fiscal stimuli or loan guarantees that may be introduced. Even so, with cash now at a premium, investors are reportedly demanding much higher returns on renewables projects.

Investment in solar energy held up relatively well through much of 2008, but then suffered a sharp downturn in late 2008. Preliminary data suggests that the decline deepened in the first quarter of 2009, but that investment rebounded in the second quarter. The bulk of the downturn was attributed to caps that have been placed on the very attractive feed-in tariff available to solar photovoltaic in Spain, which will limit the growth in capacity to a maximum of 500 MW in 2009, from over 2.5 GW in 2008. As with wind, the largest projects have been hit hardest.

## What role for government?

Governments are concerned about the impact of the financial and economic crisis on energy investment because of its potential consequences for energy security and climate change, as well as the longer-term effects on economic and human development. Any prolonged downturn in investment threatens to hold back capacity growth in the medium term, particularly for long lead-time projects, risking a shortfall in supply and a renewed surge in prices a few years down the line, when demand is likely to be recovering. That could, in turn, undermine the sustainability of the economic recovery. Weaker fossil-fuel prices are also reducing the attractiveness of investments in clean energy technology. And cutbacks in energy-infrastructure investments threaten to impede access by poor households to electricity and other forms of modern energy. These concerns justify government action to support investment. For such action to be cost effective, it needs to be based on a clear understanding of the reasons for falling spending, and be consistent with overall energy and economic policy goals.

Lower investment is a normal response to weaker market prospects. There is always a risk of under-investment in supply capacity because the market does not accurately predict the timing and speed of the economic upturn at the end of a recession. But that does not by itself provide grounds for government intervention. After all, there is equally a risk of over-investment because of over-optimism about economic prospects (which explains why most sectors are facing excessive spare capacity at present). However, there is strong evidence that the credit crunch is exacerbating investment cutbacks. Financing difficulties are, in some cases, impeding investment in economically viable projects that would, in the absence of the credit crunch, have gone ahead. This is a market failure that calls for government intervention, as part of a broader package of measures to stimulate lending by banks. Specific action may also be needed at the sectoral level to address funding bottlenecks to important projects.

Climate change provides an added reason for action to support energy investment of the right sort. While greenhouse-gas emissions are likely to be considerably lower in the near term than would have been the case had the crisis not occurred, there is growing concern that lower investment in low-carbon energy technologies – resulting from financing difficulties and lower fossil-energy prices – may well lead to higher emissions in the longer term (see Chapter 4). Many governments have introduced new climate change measures as part of a broader package of increased public spending and other measures to stimulate the economy. But others have already indicated that priority will be given to dealing with the economic downturn and stabilising the financial system, even if this means that action to combat climate change will be stalled for the time being on the grounds of costs.

PART B

# POST-2012 CLIMATE POLICY FRAMEWORK

## PREFACE

The climate change analysis in this year's *Outlook*, set out in this Part B, details the consequences of the energy projections for greenhouse-gas emissions and how those emissions might be curtailed.

Chapter 4 discusses the importance of the energy sector in the context of climate change. It describes the consequences of the Reference Scenario – the emissions trends and their implications on the basis of policies already enacted (including those recently announced).

The remaining chapters in Part B describe an alternative world, with an energy sector that is substantially cleaner, more efficient and more secure – in which annual energy-related $CO_2$ emissions peak just before 2020 at 30.9 Gt and decline thereafter to 26.4 Gt in 2030. This alternative scenario, the 450 Scenario, puts us on track for ultimate stabilisation of the atmospheric concentration of greenhouse gases at 450 parts per million (ppm) of $CO_2$-equivalent. This should be a sufficient change to avoid too drastic a rise in the global temperature.

Chapter 5 describes a plausible set of actions to achieve the 450 Scenario, detailing how the resulting energy mix and $CO_2$ emissions differ from the Reference Scenario.

Chapter 6 takes a closer look at the sectoral trends in the 450 Scenario.

Chapter 7 sets out the investment requirements of that scenario, and the additional costs and benefits entailed.

Chapter 8 addresses the challenge of financing the investments and identifies where the funding might come from, the extent to which OECD countries might support non-OECD countries, and the financial mechanisms that could serve to support this effort.

Finally, Chapter 9 brings together the whole analysis, describing the contribution that each of ten regions or countries might make in order to achieve the necessary transformation.

Of course, the adoption of the 450 ppm objective is just one of the possible outcomes of the negotiations at the 15th Conference of the Parties (COP) to the United Nations Framework Convention on Climate Change (UNFCCC, December 2009, Copenhagen). The 450 Scenario is just one possible configuration of the implications for the energy sector; but it is clearly indicative of the level of action that would be needed globally to put the world on a more sustainable footing.

# CLIMATE CHANGE AND THE ENERGY OUTLOOK

## An opportunity at Copenhagen?

### HIGHLIGHTS

- Energy-related $CO_2$ emissions in the Reference Scenario rise from 28.8 Gt in 2007 to 34.5 Gt in 2020 and 40.2 Gt in 2030. In 2020, global emissions are 1.9 Gt or 5% lower than in the Reference Scenario of *WEO-2008*. The impact of the economic crisis and lower growth accounts for three-quarters of this improvement, while government stimulus spending to promote low-carbon investments and other new climate policies account for the remainder.
- In the Reference Scenario, OECD emissions in 2030 are 3% lower than in 2007. By contrast, all major non-OECD countries see their emissions rise. Of the 11 Gt growth in global emissions, China accounts for 6 Gt, India for 2 Gt and the Middle East for 1 Gt. However, while non-OECD countries today account for 52% of the world's annual emissions of energy-related $CO_2$, they are responsible for only 42% of the world's cumulative emissions since 1890.
- All sectors see growth in energy-related $CO_2$ emissions over the *Outlook* period in the Reference Scenario, with aviation and power generation being the fastest-growing sectors. The power sector accounts for over half the increase in emissions between 2007 and 2030, with a 60% increase from coal-fired generation.
- Despite the short-term improvement in $CO_2$ emissions trends compared to *WEO-2008*, the Reference Scenario still leaves the world on course for a concentration of greenhouse gases in the atmosphere of around 1 000 parts per million, implying a global temperature rise of around 6°C. If the world wishes to limit to 25% the probability that a temperature rise in excess of 2°C will occur, $CO_2$ emissions over the period 2000-2049 must not exceed 1 trillion tonnes. Between 2000 and 2009, the world emitted 313 billion tonnes of $CO_2$.
- If all the most ambitious 2020 emissions aspirations of OECD countries were met (including Japan's new 25% target, a 30% cut for the European Union and a 25% reduction in Australia), their total reduction, compared with 2007, would be 2.7 Gt. If policies were put in place in OECD and non-OECD countries to maintain through to 2030 the global emissions level that would be reached in 2020, and sharp cuts were achieved after 2030, global abatement would be broadly in line with the 550 Policy Scenario modelled in *WEO-2008*.
- Copenhagen provides an opportunity to take prompt action. Each year of delay before moving to a more sustainable emissions path would add around $500 billion to the global investment cost of delivering the required energy revolution (some $10.5 trillion for the period 2010-2030 in the 450 Scenario). A delay of just a few years would render a 450 Scenario completely out of reach.

# Introduction

The world is entering a new era in addressing the challenge of climate change. In December 2009, heads of state, ministers and negotiators from nearly all of the world's countries will gather in Copenhagen at the 15th Conference of the Parties (COP) of the United Nations Framework Convention of Climate Change (UNFCCC). Their objective there is to put in place a comprehensive programme of robust, collective actions to reduce greenhouse-gas emissions – a challenge that will dominate the energy sector for the foreseeable future.

Continuing on today's path, without new policies, would mean rapidly increasing dependence on fossil fuels and continuing wasteful use of energy, taking us towards a concentration of greenhouse gases in the atmosphere in excess of 1 000 parts per million (ppm) of $CO_2$-equivalent ($CO_2$-eq).[1] This, the outcome of the Reference Scenario, would almost certainly lead to massive climatic change and irreparable damage to the planet.

Many countries have called for the world to move urgently onto a completely different trajectory. Some have suggested stabilisation of the greenhouse-gas concentration at 450 ppm. To meet this target would require a number of challenging conditions to be met:

- All countries would need to participate, while respecting the principle of common but differentiated responsibilities. Only by taking advantage of mitigation potential in all regions could a change of the required magnitude be achieved.
- To make the transformation feasible and equitable, sustainable transfers of finance and technology to non-OECD countries need to occur. These countries account for over half the world's emissions and much of the abatement must happen there.
- Strong action must be taken now. Delay of just a few years would drastically reduce the likelihood of stabilisation at 450 ppm ever being achieved.

The energy sector, which accounts for 84% of global $CO_2$ emissions and 64% of the world's greenhouse-gas emissions, must be at the heart of this transformation. It is not simply a case of reducing emissions at the margins: meeting a 450 Scenario (or a 550 Scenario) requires a fundamental change in our approach to producing and consuming energy. Whether it is re-orientating our power generation mix away from fossil fuels and towards nuclear and renewables, maximising the efficiency of our vehicles, appliances, homes and industries, or developing revolutionary technologies for the future, almost all potential sources of lower emissions will need to be tapped.

This year's financial crisis and global recession has bought the world a little time to change track to this very different energy future. In 2009, for the first time since the early-1980s, global emissions of energy-related $CO_2$ are set to decline significantly. Meanwhile, many countries have taken the opportunity to put in place green energy packages as part of their action to rejuvenate their economies.

In the months leading up to the UN Climate Change Conference (COP 15), many countries have introduced unilateral emissions targets and policies that lead to a

1. Carbon dioxide equivalent ($CO_2$-eq) is a measure used to compare and combine the emissions from various greenhouse gases, and is calculated according to global-warming potential of each gas.

lower-emissions future. While these steps often fall short of what would be required to achieve a 450 Scenario, they show some momentum going into the Conference. Many countries have already pledged to go further as part of a strong global deal.

## Greenhouse-gas emissions in the Reference Scenario

### Trends across all sectors

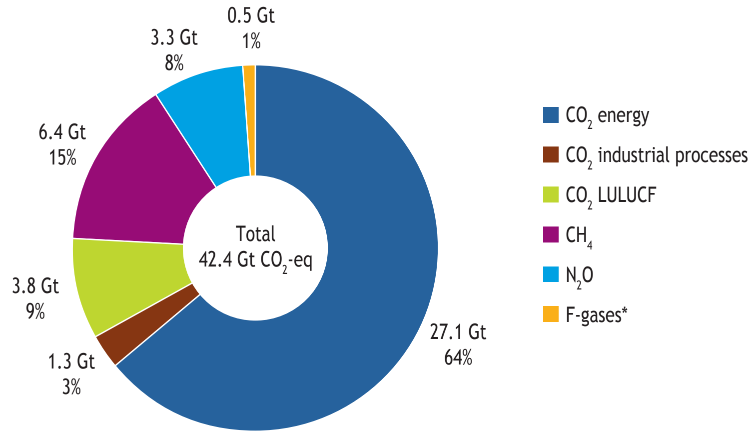
Global greenhouse-gas emissions have risen rapidly over the last few decades, and they continue to increase to 2030 and beyond in the Reference Scenario, which quantifies the impact of existing trends and policies. The Reference Scenario incorporates all relevant policies (related to climate, energy security and economic recovery) enacted as of September 2009; but it does not include the impact of policies under consideration, potential future policies (which differ from current policies) or "targets" that are not backed up by commensurate policy measures. An additional important assumption in the Reference Scenario is that energy subsidies on fossil fuels will be gradually reduced globally, such that end-use prices reflect more closely the real cost of production, transformation and transportation of fossil fuels.

The analysis and presentation of trends in this *Outlook* focus primarily on the energy sector, particularly in terms of emissions of energy-related $CO_2$. In addition, our climate policy analysis – including the trajectories of the Reference Scenario and the 450 Scenario – take full account of trends and mitigation potential in non-$CO_2$ greenhouse gases, including methane ($CH_4$), nitrous oxide ($N_2O$) and F-gases (see footnote to Figure 4.1), as well as emissions outside the energy sector.[2]

Total emissions of greenhouse gases, across all sectors, were 42.4 gigatonnes (Gt) of $CO_2$-eq in 2005 (Figure 4.1). In the Reference Scenario, they reach 50.7 Gt in 2020 and 56.5 Gt in 2030 (Figure 4.2). Within this total, energy-related $CO_2$ is the major component. $CO_2$ and other greenhouse gases have their source in both energy-related and non energy-related activities. Emissions of greenhouse gases other than energy-related $CO_2$ are projected to increase by around 6% between 2005 and 2020, and to stabilise between 2020 and 2030. Within this category, methane emissions increase the most by volume – from 6.4 Gt $CO_2$-eq in 2005 to 7.2 Gt in 2020 and 7.6 Gt in 2030. Most of this increase comes from to wastewater, coal mining and the increased pipeline leakage associated with higher global gas demand, although there has recently been a reduction in gas leakages in OECD countries and several producing countries are taking measures to reduce flaring and venting. Nitrous oxide emissions grow by around 10% between 2005 and 2030, while F-gases more than double. $CO_2$ emissions from land use, around 3.8 Gt in 2005, fall by around one-third in the Reference Scenario, to 3.2 Gt in 2020 and 2.6 Gt in 2030, due to a deceleration in the rate of land-use change – in part a result of international policy action. Between 2030 and 2050, total greenhouse-gas emissions continue to rise in the Reference Scenario (despite a slight reduction in $N_2O$ and in land-use $CO_2$), reaching 68.4 Gt in 2050.

2. This work has been carried out in conjunction with the OECD Environment Directorate. Drawing on the results of ENV-Linkages (Burniaux and Chateau, 2008), we have ensured that our scenarios are fully consistent in terms of these trends and abatement across all gases and all sectors.

**Figure 4.1 • World anthropogenic greenhouse-gas emissions by source, 2005**

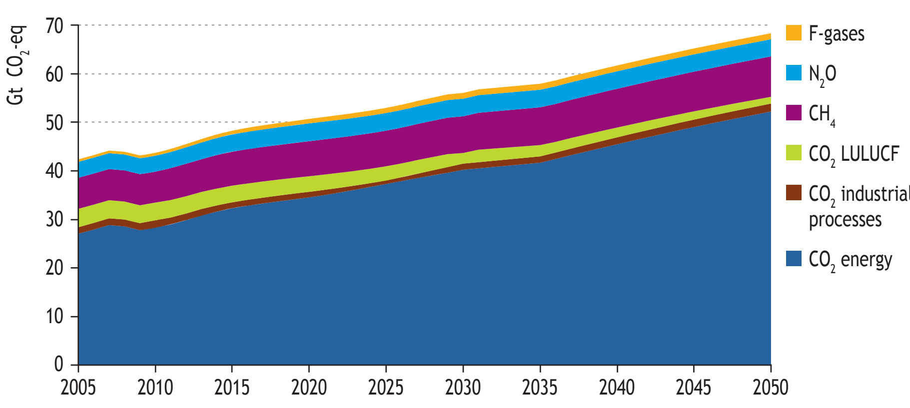



* F-gases include hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride ($SF_6$) from several sectors, mainly industry.

Note: Industry $CO_2$ includes non-energy uses of fossil fuels, gas flaring and process emissions. Energy methane includes coal mines, gas leakages and fugitive emissions. $N_2O$ from industry and waste amounts to 0.12 Gt $CO_2$-eq. LULUCF is land use, land-use change and forestry.

Sources: OECD and IEA databases and modelling; IPCC (2007a); OECD (2009); EPA (2006).

**Figure 4.2 • World anthropogenic greenhouse-gas emissions by source in the Reference Scenario**




Sources: IEA analysis using the World Energy Model and the OECD's ENV-Linkages model.

## Global trends in energy-related $CO_2$ emissions

Energy-related $CO_2$ continues to dominate global greenhouse-gas emissions over the projection period. The Reference Scenario sees a continued rapid rise in energy-related $CO_2$ emissions by 2030, resulting from the growth in global demand for fossil energy. Having already increased from 20.9 Gt in 1990 to 28.8 Gt in 2007, emissions are projected to rise further to 34.5 Gt in 2020 and 40.2 Gt in 2030, an average rate of growth of 1.5% per year over the projection period (see Chapter 2). This is much faster than the growth rate of other greenhouse gases, which increase on average by 0.3% per year.

Energy-related $CO_2$ emissions in this year's Reference Scenario are below those in *World Energy Outlook 2008* (*WEO-2008*). In 2020, emissions are 1.9 Gt lower, while 2030 emissions are 0.3 Gt lower. In cumulative terms, between 2007 and 2030, emissions are 35.1 Gt below the *WEO-2008* Reference Scenario. The primary reason for this, accounting for 75% of the reduction, is the lower level of economic activity, resulting from the global recession. A sharp downturn in economic demand has led to a contraction in energy demand and $CO_2$ emissions. Provided the right investment choices are made in a timely manner, the global recession provides an opportunity to move onto a lower emissions trajectory (see Spotlight).



SPOTLIGHT

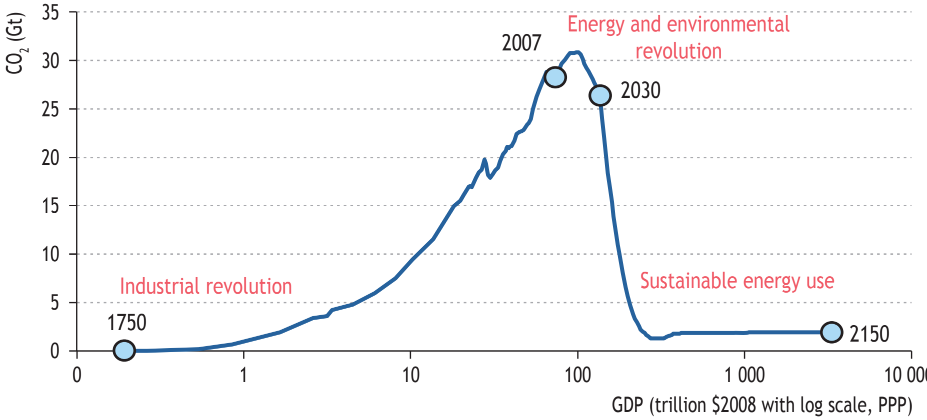
### Is the financial crisis an unexpected opportunity to step up the climate change effort?

In the near term, slower economic growth will curb the growth in emissions. Our preliminary estimates point to a sharp decline in 2008 in the rate of growth of $CO_2$ emissions and an absolute fall in emissions – more pronounced than any in the last 40 years – in 2009. As emitted greenhouse gases largely stay in the atmosphere, the environmental benefit of this downward blip in emissions will be long-lasting. The reduction in emissions growth in the immediate future is opportune, as the upward trajectory would otherwise continue to 2012, the date at which any agreement reached at the UN Climate Change Conference (COP 15) would be likely to take effect. The recession is delaying some investment decisions that may otherwise have locked-in carbon-intensive technologies for many years. But investments in low-carbon technologies are also being deferred.

In this situation, well-focused government policy at the national level is particularly important, to free up finance for investment and provide incentives to sustain investment despite weaker fossil-fuel prices. Strong financial incentives and tough regulatory interventions may be needed. Table 5.3 in Chapter 5 sets out some examples of new sustainable energy policies matched to today's circumstances.

Governments have announced nearly $250 billion of stimulus funding for green energy projects. But further efforts will be needed to ensure that, when economies rebound, the historical link between $CO_2$ emissions and economic output (Figure 4.3) can finally be broken. A recent IEA paper analysing the response to the financial crisis indicates that existing government commitments would need to be increased four-fold to meet a 450 Scenario (IEA, 2009). An energy and environmental revolution is needed, and action to address the financial and economic crisis, coupled with positive steps at the UN Climate Change Conference (COP 15), can support that objective.

**Figure 4.3** • **Historical link between energy-related $CO_2$ emissions and economic output, and the pathway to achieving a 450 Scenario**




Note: The projected trend approximates that required to achieve long-term stabilisation of the total greenhouse-gas concentration in the atmosphere at 450 ppm $CO_2$-eq, corresponding to a global average temperature increase of around 2°C. World GDP is assumed to grow at a rate of 2.7% per year after 2030.

Source: IEA databases and analysis.

In addition to the impact of the financial crisis on economic growth, a significant factor in the prolonged lower emissions in the Reference Scenario of this *Outlook* compared to *WEO-2008* is the implementation in 2008-2009 of new policies to promote low-carbon energy and improve energy efficiency, in OECD and non-OECD countries alike (Table 4.1). These policies will result in lower emissions than would otherwise have been the case. The relevant policies include the ratification of the EU 20-20-20 Package at the end of 2008, strengthened Corporate Average Fuel Economy (CAFE) standards in the United States and various national economic stimulus packages, many of which have a substantial low-carbon component. Combined, these policies deliver cumulative $CO_2$ emissions savings of around 9 Gt between today and 2030, relative to the policies in the *WEO-2008* Reference Scenario. They account for around one-quarter of the overall emissions reduction in this year's Reference Scenario.

The financial crisis has provided an occasion for countries to take further actions prior to the UN Climate Change Conference (COP 15). In heeding calls to launch a "Clean Energy New Deal", countries have recognised that government spending can simultaneously rejuvenate the economy, create new jobs[3] and put in place a more sustainable energy system. Some $242 billion of additional low-carbon funding has been committed by G20 governments alone as part of their national stimulus packages (Figure 4.4). Much of this helps to stimulate additional investment by the private sector: for example, our analysis suggests that for every $1 of public money spent on supporting renewables, $3.6 of private investment will result. These packages go some way towards offsetting the shortfall in low-carbon investments resulting from the sharp, temporary downturn in global energy demand and global energy prices

3. Macroeconomic studies, most of which have been carried out in the United States and the European Union, show that these energy-efficiency measures lead to an overall net increase in jobs (UNEP *et al.*, 2008).

(which would make low-carbon investments less cost-effective). However, some 45% of the low-carbon funds have been allocated to rail projects, leaving sectors such as renewables less adequately supported.

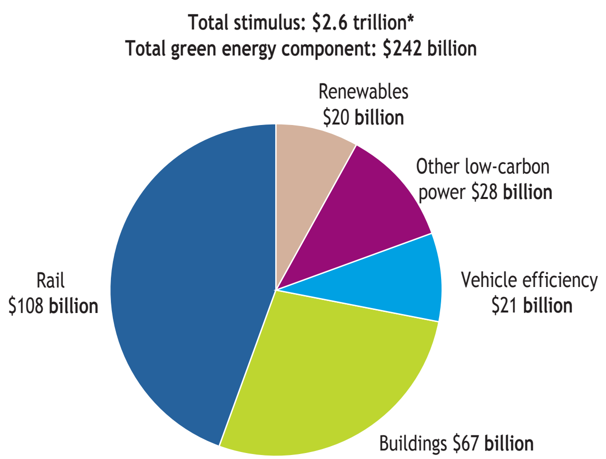
**Table 4.1 • Examples of new policies incorporated in the Reference Scenario**

| Country/region | Policy | Detail |
|---|---|---|
| United States | Strengthened CAFE standards* | Sales-weighted fuel economy for LDVs capped at 39 mpg in 2016, 35.5 mpg for cars |
| China | Nuclear programme | Planned expansion of nuclear capacity over the period to 2020 |
| European Union | 20-20-20 Package | EU ETS capped at 21% below 1990 levels and inclusion of aviation emissions; renewables and energy efficiency commitments |
| G20 | Financial stimulus packages | Low-carbon energy components amount to $242 billion, covering power generation and efficiency |
| Canada | National vehicle scrappage programme | CAD 92 million package over four years to promote new, cleaner vehicles |
| Japan | Reintroduction of subsidies for solar power | JPY 70 000 per kW offered to households that install solar panels |

* CAFE standards for fuel economy are in the process of being harmonised with greenhouse-gas emissions standards relating to clean air, set by the US Environmental Protection Agency.

Note: Includes policies enacted by mid-2009.

**Figure 4.4 • Green energy components of the G20 stimulus packages, 2009-2018**




* Year-2009 dollars.

Note: Components are based on definitions comparable to those used in the *WEO* categorisation of investments required to realise the 450 Scenario and values are based on IEA analysis of publicly available documents. Only additional commitments to stimulate investment, newly announced in 2009, have been included. Science spending is not included. In some cases, values as presented are lower than those headlined in official announcements or analyses that assume a broader definition of "low-carbon" or "green".

### *National emissions targets*

In the months leading up to the UN Climate Change Conference (COP 15), a number of countries, particularly in the OECD, have moved to set their own national emissions targets and start to put in place policies for meeting them (Table 4.2). Where targets have been decided and commensurate policies are in place to deliver them, they are assumed to be met in the Reference Scenario. Among the most advanced and ambitious commitments is the European Union's 20-20-20 Package, which aims to reduce EU emissions by 20% by 2020, relative to 1990 levels (although this reduction is likely to include some use of "banked" credits and international offsets, so the domestic reduction may be less – see Box 4.2). This target has been backed up by a range of policies, including a 21% cap on the EU Emissions Trading System (EU ETS), caps for non-EU ETS sectors, incentives for renewables, targets for vehicle manufacturers and substantial financial resources for green energy programmes, including carbon capture and storage (CCS) demonstration.

A number of countries are considering new national emissions targets, or have announced targets but not yet (as at September 2009) put in place the policies needed to ensure that they are met. These targets are not assumed to be fully met in the Reference Scenario, although they indicate potential for lower emissions in the future. In September 2009, the new Japan administration announced a new target to reduce greenhouse-gas emissions by 25% by 2020, relative to 1990 levels. Many commensurate policies have already been implemented and, while Japan's emissions in the Reference Scenario are only 1.8% below 1990 levels, they are 13.8% below 2005 levels. However, achieving the 25% target will require substantial additional domestic measures (likely to entail a higher abatement cost than those faced by some other developed countries[4]) and possibly some credits from supporting mitigation activities abroad. In the United States, the world's largest economy and second-largest emitter, the Waxman-Markey bill (the *American Clean Energy and Security Act of 2009*) was approved by the US House of Representatives but has not been enacted at the time of writing. This bill[5] aims to reduce US emissions by 17% by 2020 compared with 2005 levels, albeit with a generous provision for offsets. On 30 September 2009, a separate Boxer-Kerry bill, proposing a 20% cut in US emissions, was put forward. Canada has set an objective of reducing its emissions by 20% by 2020 from 2006 levels, but it has yet to introduce the policies to ensure this happens. Korea is also planning to set a mid-term emissions target.

While most OECD countries have set or are considering their own domestic emissions targets for 2020 and beyond, a number of non-OECD countries are similarly engaged, including relatively low emitters, such as Liechtenstein and Monaco. This year, Russia announced an intended reduction in emissions relative to 1990 of 10% to 15% by 2020; this, in fact, represents a substantial increase in emissions relative to today's level and, in light of the global recession, is comfortably met in the Reference Scenario, along with the proposed targets in Belarus and Ukraine. Over 75 other countries have set themselves targets in terms of energy efficiency or power generation through renewables. China's energy plans are a prominent example.

4. According to *WEO* analysis. A study by the Japanese government indicates that Japan could face a domestic marginal abatement cost as high as $150 per tonne of $CO_2$ (Akimoto, 2009).

5. As placed on the US Senate Legislative Calendar on 7 July 2009.

**Table 4.2 • National greenhouse-gas emissions goals in OECD countries**

| Country / region | 2020 target | 2020 target relative to 1990 emissions* | Long-term ambition |
|---|---|---|---|
| **2020 targets with commensurate policy enacted, met in Reference Scenario**** | | | |
| Australia | -5% of 2000 | -3% | n.a. |
| European Union*** | -20% of 1990 | -20% | -60% to -80% by 2050 |
| Norway | -30% | reference year not specified | -100% by 2050 |
| **Targets not yet enacted or not fully supported by additional policy, partially met in Reference Scenario**** | | | |
| Canada | -20% of 2006 | +24% | n.a. |
| Iceland | -15% of 1990 | -15% | -50% to -75% by 2050 |
| Japan | -25% of 1990 | -25% | -60% by 2050 |
| Mexico | n.a. | n.a. | -50% by 2050 |
| New Zealand | -10% to -20% of 1990 | -10% to -20% | -50% by 2050 |
| Switzerland | -20% of 1990 | -20% | n.a. |
| United States**** | -17% of 2005 | -4% | n.a. |

* On the basis of national greenhouse-gas inventory data for all gases and from all sources, including emissions from land use and deforestation.
** In most cases, the targets may be met through a combination of domestic emissions reductions and use of offsets, such that actual emissions in any country may be above the target level. In some cases, land-use and deforestation emissions are excluded from national targets, such that actual targets relative to 1990 may vary from those stated.
*** The European Union has announced that it will adopt a target of up to 30% in the context of a global agreement; this is not enacted or fully met in the Reference Scenario.
**** The recently announced Boxer-Kerry bill proposes a 20% reduction compared to 2005.

Sources: UNFCCC (2009); IEA databases and analysis.

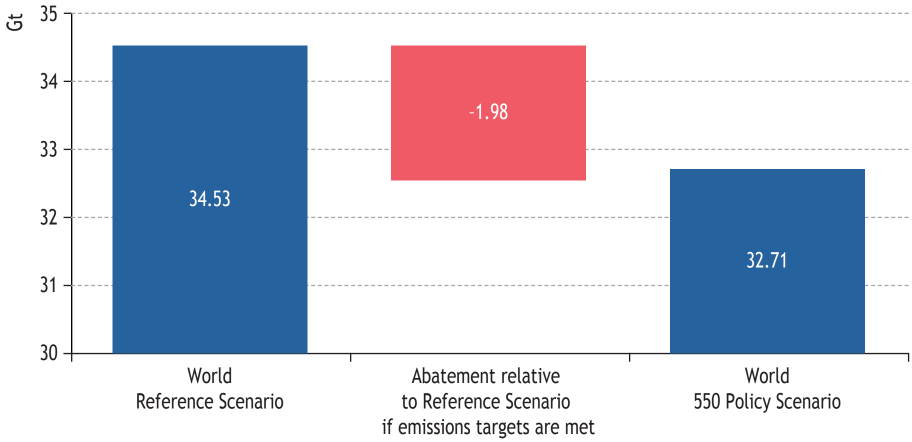
Although policies are not yet fully in place to realise these targets, if all the 2020 emissions goals in Table 4.2 were met, the reduction in energy-related $CO_2$ emissions in those countries, compared to the Reference Scenario, would be 1.50 Gt in 2020[6] (although part of this would be met through offsets). If OECD countries were to meet the more stringent targets under consideration (the European Union's 30% target, which it would pursue in the event of an ambitious global deal, a 25% reduction in Australia and a 10% reduction in New Zealand), the total reduction in 2020, relative to the Reference Scenario, would be 1.98 Gt.[7] Global abatement on this scale would put the world in line with the 2020 emissions level in the 550 Policy Scenario, modelled in *WEO-2008* (Figure 4.5).[8] However, even if these targets were met, being on track for 550 ppm would also require emissions in the years leading up to 2020 to be in line with the 550 Policy Scenario, while further, more substantial measures would be needed after 2020 to remain on course.

6. Emissions of non-energy $CO_2$ and other greenhouse gases would be expected to decline by more in percentage terms given the relative costs of abatement.

7. This corresponds to a reduction in OECD+ emissions of 2.73 Gt compared to 2007 levels (if all reductions were achieved domestically). See Annex C for definitions.

8. Emissions in 2020 would be 0.2 Gt below the level in the 550 Policy Scenario.

**Figure 4.5** • **Emissions of energy-related $CO_2$ in 2020 in the Reference Scenario and reductions if OECD countries meet their emissions targets**




Notes: Reduction targets are as follows: United States (17% relative to 2005), Japan (25% relative to 1990), European Union (30% relative to 1990), Australia (25% relative to 2005), New Zealand (10% relative to 1990) and Canada (20% relative to 2006). The inclusion of non-OECD countries would not change the chart significantly as all large non-OECD countries with targets meet these targets, through policies already in place, in the Reference Scenario.

Emissions reductions assume that the targeted percentage emissions reduction is achieved in respect of energy $CO_2$. In reality, targets encompass multiple gases and sectors – and may also contain provisions for banking credits – such that the energy $CO_2$ reduction in 2020 could differ from that indicated.

While the targets announced to date fall short of what would be needed to achieve a 450 ppm outcome and are, in any case, not yet fully backed up by policy actions, it is important to emphasise that they have essentially been adopted unilaterally. The policy developments in 2009 and the lower demand due to the global recession together provide strong momentum going into the UN Climate Change Conference (COP 15).

## *Per-capita trends*

Despite a dip due to the financial crisis, global per-capita emissions of energy-related $CO_2$ in the Reference Scenario show a steady increase over the remainder of the *Outlook* period, from 4.4 tonnes in 2007 to 4.8 tonnes in 2030 (Figure 4.6).[9] Per-capita emissions in OECD countries currently outstrip those in non-OECD countries by a factor of four, but this gap is closing rapidly. Of the world's largest countries, the United States is the biggest per-capita emitter (18.7 tonnes in 2007), although the level falls to 14.9 tonnes by 2030.

While attention often falls on the world's largest emitters in absolute terms, it is important not to overlook countries that are the highest emitters per capita, many of which are relatively wealthy and can more easily afford to make emissions reductions.

9. The world's population increases by 25% over the same period, to 8.2 billion in 2030.

The world's four largest per-capita emitters are in the Middle East, in large part due to the oil industry (Table 4.3). Qatar emits over ten times the global average per person. The United Arab Emirates, with a population of fewer than 5 million, has over three times the annual emissions of New Zealand, a similarly sized OECD country. In contrast, some countries with much lower per-capita emissions and incomes – such as Romania and Latvia – have signed up to emissions caps under the Kyoto Protocol and as part of the EU ETS.



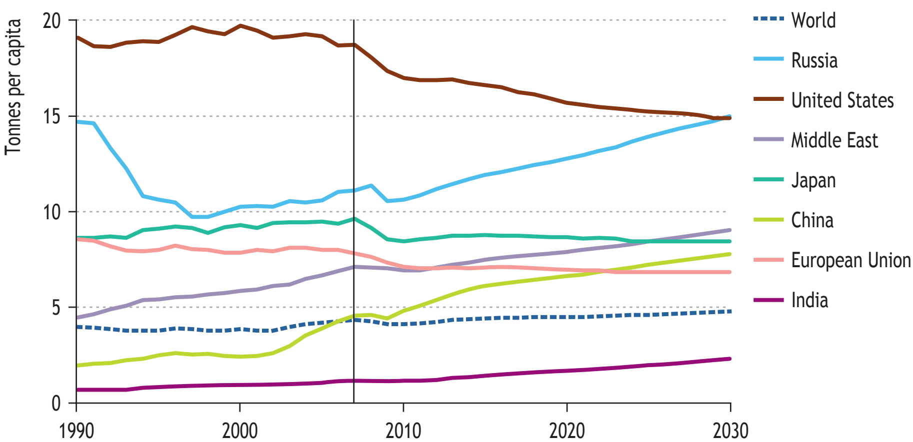
**Table 4.3 • World's 40 biggest emitters of energy $CO_2$ per capita, 2007**

| Rank | Country | $ GDP per capita | $CO_2$ per capita (t) | Rank | Country | $ GDP per capita | $CO_2$ per capita (t) |
|---|---|---|---|---|---|---|---|
| 1 | Qatar | 96 858 | 58.0 | 21 | Singapore | 51 437 | 9.8 |
| 2 | United Arab Emirates | 39 455 | 29.9 | 22 | Belgium | 36 285 | 9.7 |
| 3 | Bahrain | 33 751 | 28.2 | 23 | Japan | 34 303 | 9.6 |
| 4 | Kuwait | 48 452 | 25.1 | 24 | Germany | 34 930 | 9.6 |
| 5 | Luxembourg | 82 821 | 22.1 | 25 | Cyprus | 27 830 | 9.3 |
| 6 | Trinidad and Tobago | 19 617 | 21.9 | 26 | Israel | 26 916 | 9.2 |
| 7 | United States | 46 701 | 19.0 | 27 | Turkmenistan | 5 522 | 9.1 |
| 8 | Australia | 36 870 | 18.7 | 28 | Denmark | 37 805 | 9.1 |
| 9 | Canada | 39 341 | 17.4 | 29 | Greece | 29 609 | 8.7 |
| 10 | Brunei Darussalam | 51 376 | 15.0 | 30 | United Kingdom | 36 439 | 8.6 |
| 11 | Saudi Arabia | 23 439 | 14.8 | 31 | New Zealand | 27 575 | 8.5 |
| 12 | Oman | 24 230 | 13.8 | 32 | Austria | 38 831 | 8.0 |
| 13 | Estonia | 21 038 | 13.4 | 33 | Poland | 16 680 | 7.9 |
| 14 | Kazakhstan | 11 113 | 12.3 | 34 | Slovenia | 28 388 | 7.9 |
| 15 | Finland | 35 765 | 12.1 | 35 | Norway | 53 434 | 7.7 |
| 16 | Czech Republic | 24 606 | 11.8 | 36 | Spain | 30 773 | 7.7 |
| 17 | Russia | 15 116 | 11.1 | 37 | Iceland | 40 584 | 7.5 |
| 18 | Netherlands | 40 426 | 10.9 | 38 | Italy | 30 911 | 7.3 |
| 19 | Ireland | 44 175 | 10.1 | 39 | South Africa | 10 046 | 7.3 |
| 20 | Korea | 27 100 | 9.9 | 40 | Ukraine | 7 113 | 6.8 |
| | | | Selected other countries | | | | |
| 41 | Serbia | 10 230 | 6.7 | 67 | Mexico | 14 454 | 4.1 |
| 49 | France | 33 273 | 5.7 | 70 | Turkey | 12 254 | 3.6 |
| 53 | Portugal | 22 239 | 5.2 | 96 | Brazil | 9 841 | 1.8 |
| 56 | Sweden | 37 457 | 4.9 | 108 | India | 2 728 | 1.2 |
| 59 | China | 5 500 | 4.6 | 117 | Pakistan | 2 555 | 0.9 |
| World average | | 10 156 | 4.4 | 143 | Ethiopia | 804 | 0.1 |
| 64 | Lithuania | 18 294 | 4.3 | | | | |

Note: White shading denotes OECD+, violet Other Major Economies and green Other Countries (see Chapter 5 for definitions).

While per-capita emissions in OECD countries are falling, they are increasing in many non-OECD countries. China already emits marginally more per capita than the global average and is set to overtake the European Union soon after 2020 in the Reference Scenario. Russia and the Middle East are among the regions showing the fastest growth, both in terms of their absolute and their per-capita emissions.

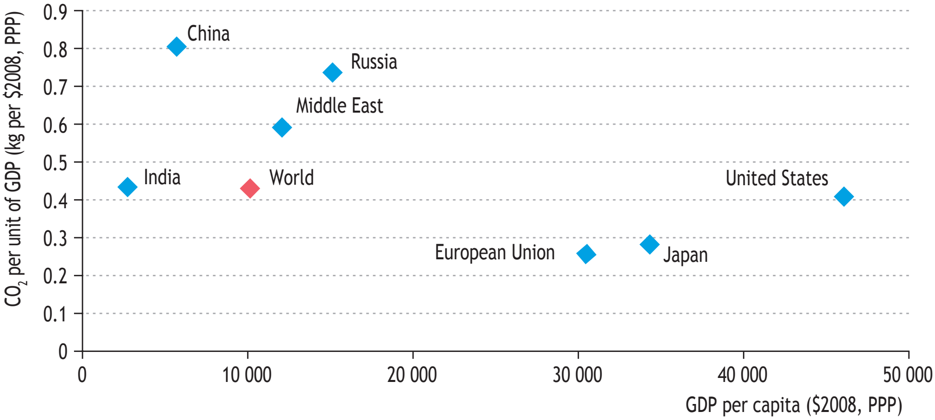
**Figure 4.6 • Per-capita energy-related $CO_2$ emissions in the Reference Scenario**




## *$CO_2$ intensity*

Between 2007 and 2030, the Reference Scenario sees a substantial reduction in global energy $CO_2$ emissions per unit of GDP. The average rate of improvement, when GDP is calculated on a purchasing power parity (PPP) basis, is 1.6% per year over the period. While non-OECD countries emit less per capita, their emissions per unit of GDP are significantly higher than non-OECD countries: in 2007, non-OECD emissions of energy-related $CO_2$ were 65% higher per unit of GDP. There is generally an inverse relationship between per-capita incomes and emissions intensity, but countries' economic structure, geography and energy choices are also important factors in their emissions intensity (Figure 4.7). The Middle East has historically gone against this trend and is the only region with higher emissions per unit of GDP today than in 1990. China is currently one of the world's leading emitters per unit of GDP, at just below double the global average. This can partly be explained by the fact that it produces a large proportion of the world's manufactured goods (Box 4.1), but it is also the region that sees the fastest improvement in emissions intensity (3% per year) over the projection period.

**Figure 4.7** • **Energy-related $CO_2$ intensity and GDP per-capita, 2007**




Note: In calculating $CO_2$ intensity it is also relevant to consider GDP on the basis of market exchange rates. In general, using market exchange rates increases the variation in $CO_2$ intensity across countries.

**Box 4.1** • **Embedded energy**

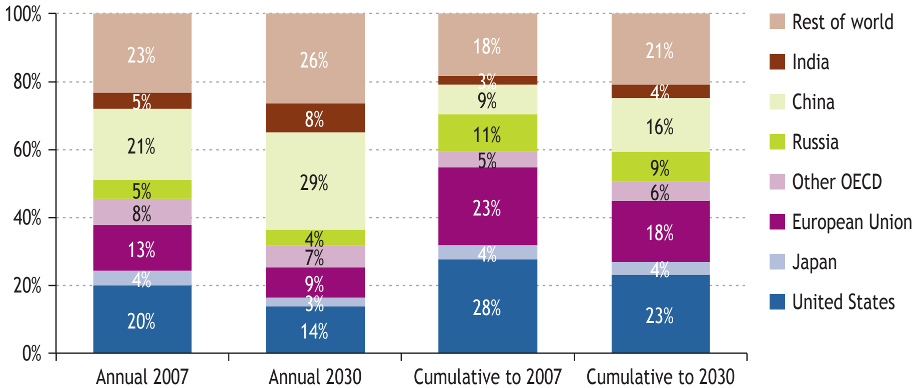
In the *WEO*, $CO_2$ emissions are attributed to the country or region in which the fossil fuel from which the emissions arise is consumed, in accordance with inventory-reporting guidelines of the UNFCCC (for the same reason, emissions from international aviation and shipping are reported only at the global level). Yet the consumption benefits from goods and services produced are often realised in a country other than that in which the emissions arise. This is an important issue for many emerging economies, which tend to be more export orientated and whose exports tend to consist of more energy-intensive manufactured goods.

A reliable consumption-based accounting system would be extremely difficult, if not impossible, to design, while the current system, based on emissions within national borders, has the important advantage of simplicity. *WEO-2008* provides some indicative values for the magnitude of embedded energy flows: our estimate of the share of emissions embedded in exports in 2006 ranges from 15% for North America to 48% for the Middle East. The share of total energy use and carbon emissions embedded in international trade would fall over the projection period if emerging economies, such as China, become more orientated towards their domestic markets.

### *Cumulative emissions since 1890*

In considering countries' emissions today and in the future, particularly in the context of equitably sharing the burden of future climate change interventions, an important perspective can be provided by looking at regions' historical contributions to global emissions. While non-OECD countries today account for 55% of the world's annual emissions of energy-related $CO_2$, over the period since 1890 as a whole, their responsibility was lower: 42% of the world's cumulative emissions. The United States alone accounts for 28% of the world's historical emissions on this basis (Figure 4.8).

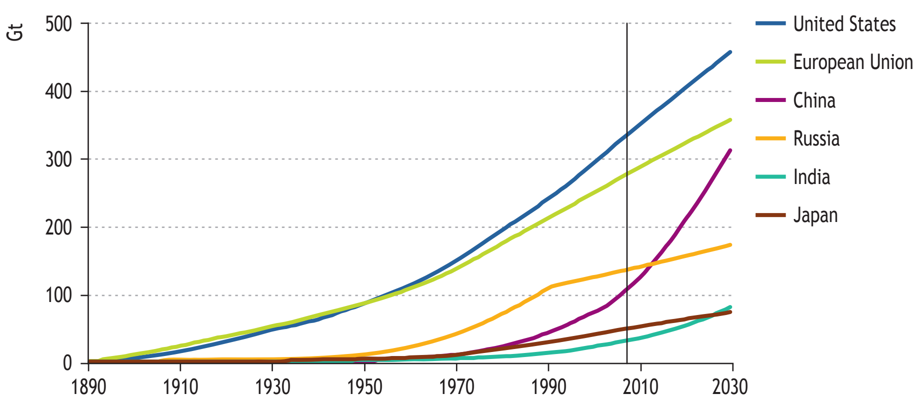
**Figure 4.8 • *Share of global annual and cumulative energy-related $CO_2$ emissions since 1890 in the Reference Scenario***




Sources: IEA databases and analysis; Marland *et al*. (2006).

However, the rapid growth in emissions in non-OECD countries, both in recent years and in the projections in the Reference Scenario, sees them accounting for an increasing share of cumulative emissions of energy-related $CO_2$. By 2030, non-OECD countries account for just over half the world's cumulative emissions since 1890. The share of historical emissions accounted for by China, now the world's highest-emitting economy, is growing particularly rapidly (Figure 4.9), closing the gap on the European Union and the United States over the *Outlook* period. However, in terms of cumulative emissions per capita, the gap between the United States and China continues to widen. India's share of cumulative emissions is also growing fast; by the end of the *Outlook* period, its cumulative emissions since 1890 overtake those of Japan.

**Figure 4.9 • *Cumulative energy-related $CO_2$ emissions since 1890 in the Reference Scenario***

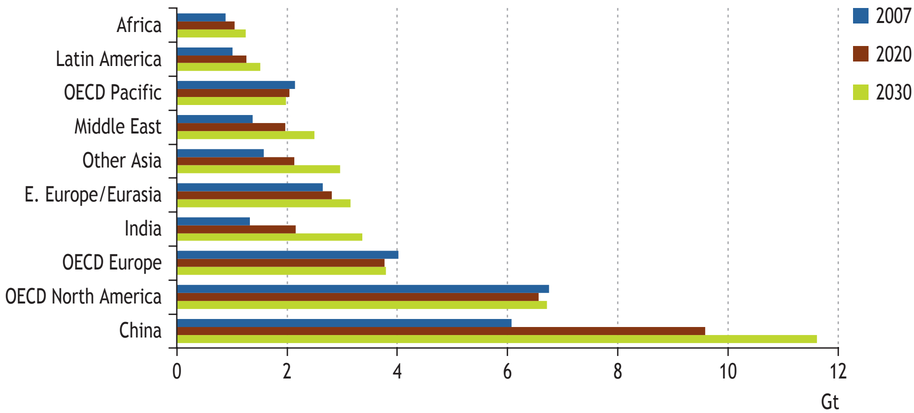



Sources: IEA databases and analysis; Marland *et al*. (2006).

## Trends in energy-related $CO_2$ emissions in key regions

Across the OECD, emissions fall in all major regions between 2007 and 2030 in the Reference Scenario. In contrast, there is sharp growth in many non-OECD regions, particularly in India, where emissions in 2030 are 2.5 times the level in 2007, and in China, the world's biggest emitter, which sees an increase in absolute terms of 5.5 Gt over the projection period (Figure 4.10).

**Figure 4.10 • Energy-related $CO_2$ emissions by region in the Reference Scenario**




### *United States*

In the United States, energy-related $CO_2$ emissions dip from a peak of 5.7 Gt in 2007 to 5.4 Gt in 2010, a result of lower energy demand resulting from the financial crisis. They subsequently remain broadly flat for the remainder of the projection period, amounting to 5.5 Gt in 2020 and 2030. $CO_2$ emissions from power generation are marginally higher in 2030 than in 2007, but the Reference Scenario does not take full account of the implications of the Waxman-Markey or Boxer-Kerry bills, neither of which had been enacted at the time of writing. Nevertheless, 2009 has seen a marked – and important – change of emphasis in the United States, with new policies aimed specifically at tackling climate change. The *American Recovery and Reinvestment Act of 2009* contains $787 billion of economic stimulus money, much of which will be directed to low-carbon energy projects. Measures include the long-term extension of the renewable energy production tax credit, as well as tax credits for efficient vehicles and efficiency measures in buildings. $CO_2$ emissions from road transport fall by 7.8% between 2007 and 2020, in large part due to strengthened CAFE standards to ensure improved vehicle efficiency and the adoption by a number of states of California's more stringent efficiency standards.

### *European Union*

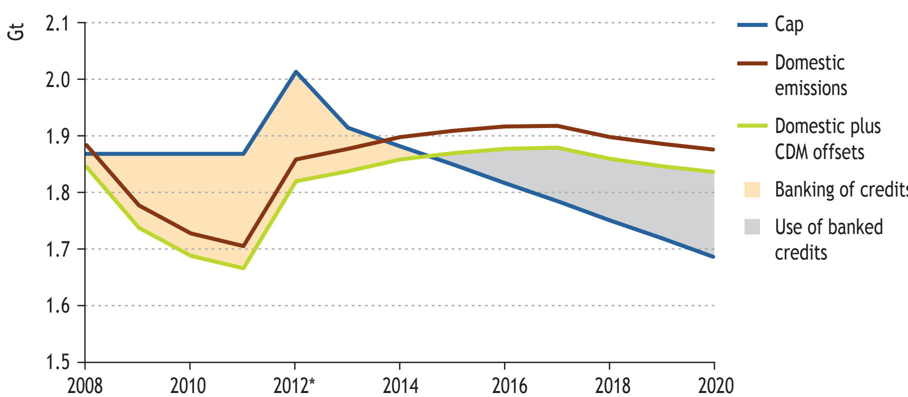
In the European Union, energy-related $CO_2$ emissions fall in the Reference Scenario, from 3.9 Gt in 2007 to 3.5 Gt in 2030. Emissions are held in check by ambitious new policies, agreed in December 2008 (the 20-20-20 Package), which put in place measures to keep greenhouse-gas emissions in 2020 to 20% below 1990 levels. These measures include a 20% target for the share of renewables in the energy mix and a cap for the EU ETS equivalent to a reduction of emissions in power generation, industry and aviation of 21% relative to 2005 levels (Box 4.2).

**Box 4.2 • *Analysis of the EU ETS in the Reference Scenario***

It is interesting to note how the European Union would meet its Emissions Trading System (EU ETS) cap of 21% below 2005 levels under the Reference Scenario (Figure 4.11). Although emissions in 2020 would meet the cap, domestic EU emissions in those sectors covered by the cap are actually only 13% below 2005 levels. The remainder of the target is met through uptake of Clean Development Mechanism (CDM) credits and use of the EU ETS banking provision. Given the global recession, the cap in Phase II of EU ETS (2008-2012) now looks relatively loose, so countries will be able to bank surplus allowances, enabling them to have higher emissions in Phase III than the cap would suggest.

Our analysis is limited to energy-related $CO_2$ emissions and we have considered the cap relative to 2005 data as published in this *Outlook*. This implies an annual cap of 1.87 Gt between 2008 and 2011, rising to 2.01 Gt in 2012, when aviation is included, and tapering down to 1.69 Gt by 2020. Between 2009 and 2013, domestic emissions in the Reference Scenario are significantly below the cap. Combined with CDM credits, this generates a cumulative surplus of credits amounting to 0.5 Gt by 2013. Banking allows these to be used in Phase III of the EU ETS, from 2013 onwards, such that in 2020 domestic emissions could be similar to today's level. This analysis does not take account of the fact that additional abatement may occur in the period to 2020 in anticipation of emissions caps in the period beyond 2020.

**Figure 4.11 • How the European Union complies with its EU ETS cap in the Reference Scenario**




* Aviation is to be included in EU ETS from 2012, hence the shift in the baseline.

## *Japan*

In Japan, energy-related $CO_2$ emissions, 1.23 Gt in 2007, fall by over 15% between 2007 and 2020 in the Reference Scenario. This is driven by policies that include a substantial increase in nuclear power, the reintroduction of subsidies for photovoltaic power, programmes to make transport more efficient and spending to promote efficiency in buildings. In 2009, Japan announced a major stimulus package, with almost $30 billion of new funds devoted to low-carbon investments.

Having seen power generation from coal rise seven-fold over the last 30 years, Japan is now looking to other technologies to deliver a cleaner future. Coal-fired power generation falls by 3% between 2007 and 2020, while non-hydro renewables generation more than doubles over the same period. Emissions in the transport sector, growing fast in many parts of the world, are declining in Japan. They fall by 23% between 2007 and 2020 in the Reference Scenario.



## *China*

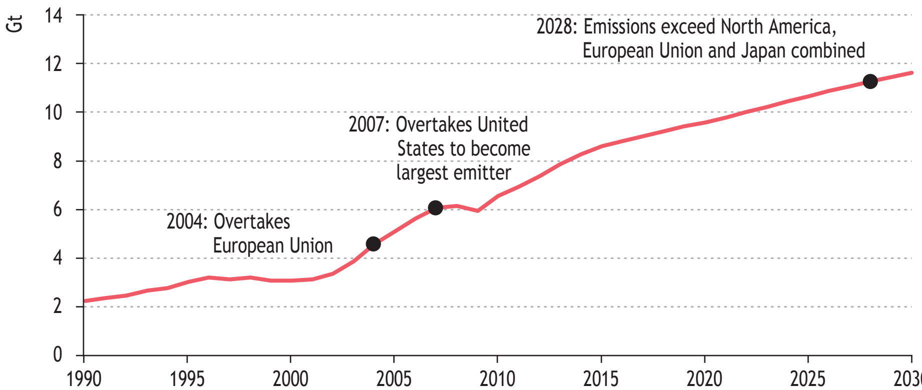
China has put in place a national climate plan, which targets a cut in energy consumption per unit of GDP of 20% between 2005 and 2010, and a 10% cut in emissions from pollutants such as sulphur dioxide ($SO_2$). Over the same period, it aims to increase the proportion of renewable energies in primary energy resources to 10% (which it achieves in the Reference Scenario).[10] In response to the global recession, China has put in place one of the largest national stimulus packages in the world. Of a total stimulus of over $600 billion, much of which is new money, around 10% is directed towards low-carbon projects (rail projects make up most of the low-carbon spending).

Nevertheless, as the world's most populous country, and given its rapid economic development, China has seen its emissions grow very quickly over recent decades and they now exceed the global average in per-capita terms. Between 2000 and 2007 alone, China's total emissions of energy-related $CO_2$ doubled, to 6.1 Gt in 2007. China's emissions continue to grow rapidly in the Reference Scenario, to 9.6 Gt in 2020 and 11.6 Gt in 2030 – an increase of over 90% during the projection period. By 2030, China accounts for 29% of the world's emissions – more than North America, Japan and the European Union combined (Figure 4.12). But China's fast emissions growth is in large part due to its rapidly growing economy, with Chinese GDP in 2020 assumed to be around 2.5 times its 2007 level. China's energy $CO_2$ emissions per unit of GDP decline by 37% between 2007 and 2020 in the Reference Scenario.

Emissions from power generation alone in China increase by more than 3 Gt over the projection period. With rapidly expanding car ownership, China's road-transport emissions increase more than four-fold between 2007 and 2030. Given the way in which China's trends dominate the global Reference Scenario, its actions, appropriately supported, will be central to efforts to reduce global emissions.

10. On 22 September 2009, China announced plans to extend this renewables target to 15% by 2015, which would go beyond Reference Scenario levels.

**Figure 4.12** • **China's energy-related $CO_2$ emissions in the Reference Scenario**




## *India*

Emissions of energy-related $CO_2$ in India grow at an even faster rate than in China, albeit from a much lower base, both in absolute and per-capita terms. India's emissions in 2007 were 1.3 Gt, and they rise to 2.2 Gt in 2020 and 3.4 Gt in 2030 in the Reference Scenario – taking them to around the level of the European Union in 2030. Emissions from industry grow by 180% over the period to 2030, with iron and steel accounting for 40% of this increase. India is one of the countries leading the uptake of wind power and it sees a six-fold increase between 2007 and 2030. This growth is in part due to a government-imposed renewable portfolio standard, which starts at 5% in 2010 and increases to 15% by 2020. Although India has not announced a low-carbon financial stimulus package, the National Plan on Climate Change (launched in 2008) focuses on promoting solar energy and other renewables, as well as other climate initiatives. With per-capita income only one-quarter of the world average, India will be looking to other countries to help support its clean energy revolution, as well as its wider development objectives.

## *Russia*

Russia saw its emissions fall by around 35% in the early 1990s, although they have been growing steadily since 1998 and amounted to 1.6 Gt in 2007. After the financial crisis, this steady growth is expected to resume, but more slowly than in other countries as we expect the financial crisis to affect domestic energy demand over the full period to 2020. Emissions in Russia reach 1.7 Gt in 2020 and 1.9 Gt in 2030 in the Reference Scenario. This is slightly lower than in the *WEO-2008* Reference Scenario, due to the impact of the recession.

## Sectoral trends in energy-related $CO_2$ emissions

Growth in energy-related $CO_2$ emissions between today and 2030 is common to all major sectors (Table 4.4). International aviation and power generation are the fastest-growing sectors, with power generation accounting for over half the increase in $CO_2$ emissions over the projection period.

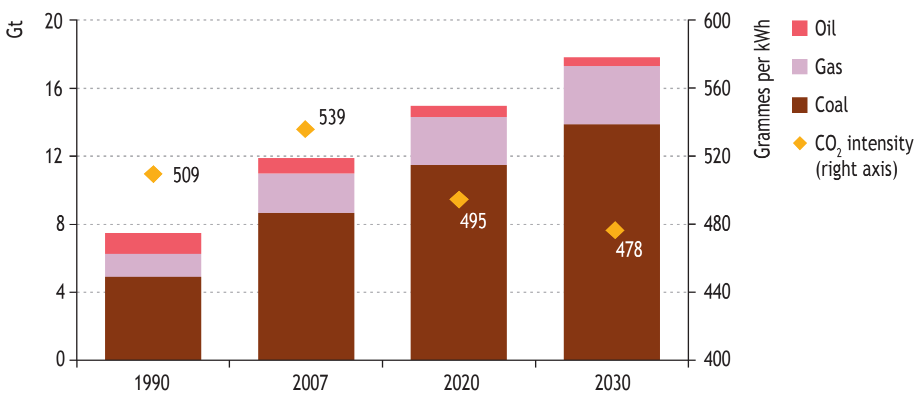
**Table 4.4 • Energy-related $CO_2$ emissions by sector in the Reference Scenario** (Mt)

| | 1990 | 2007 | 2020 | 2030 |
|---|---|---|---|---|
| Power generation | 7 471 | 11 896 | 14 953 | 17 824 |
| Other energy sector | 1 016 | 1 437 | 1 755 | 1 993 |
| Industry | 3 937 | 4 781 | 5 571 | 6 152 |
| *Iron and steel* | *938* | *1 470* | *1 702* | *1 796* |
| *Non-metallic minerals* | *505* | *818* | *822* | *810* |
| *Other industry* | *2 493* | *2 493* | *3 047* | *3 546* |
| Transport | 4 574 | 6 623 | 7 733 | 9 332 |
| *Road* | *3 291* | *4 835* | *5 646* | *6 920* |
| *Aviation* | *538* | *742* | *884* | *1 067* |
| *International shipping* | *358* | *613* | *685* | *780* |
| *Other transport* | *387* | *433* | *518* | *564* |
| Residential | 1 891 | 1 877 | 2 031 | 2 198 |
| Services | 1 066 | 878 | 972 | 1 096 |
| Agriculture | 405 | 433 | 423 | 437 |
| Non-energy use | 581 | 900 | 1 087 | 1 195 |
| **Total** | **20 941** | **28 826** | **34 526** | **40 226** |

## *Power generation*

In the power-generation sector, $CO_2$ emissions increase by 26% between 2007 and 2020, while in 2030 they reach 50% above today's level. These higher emissions are driven by the rapid growth in demand for electricity and the consequent increased use of fossil fuels, particularly coal (see Chapter 1). Emissions from coal-fired plants are projected to grow by 60% between 2007 and 2030, by which time they comprise over three-quarters of power-sector emissions (Figure 4.13).

**Figure 4.13 • World energy-related $CO_2$ emissions from the power sector and $CO_2$ intensity of power plants in the Reference Scenario**



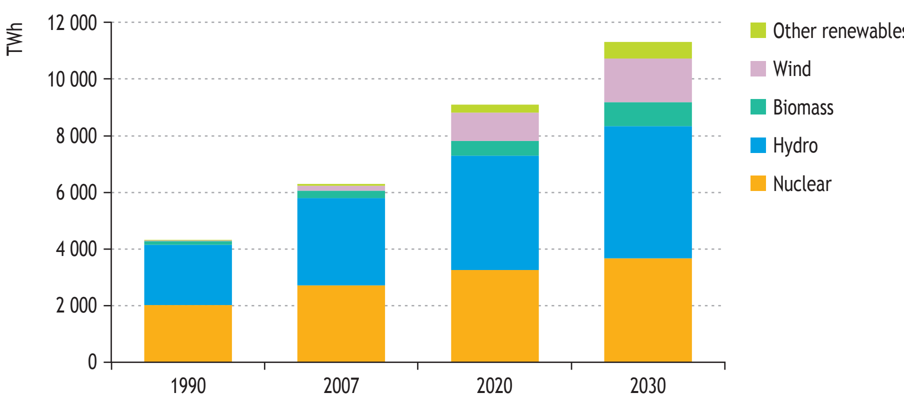

Note: $CO_2$ intensity is calculated across all power plants including nuclear, hydropower and other renewables, but excluding combined heat and power.

In the OECD, $CO_2$ emissions from power generation dip around 8% below 2007 levels by 2011 – a consequence of the global financial crisis – before recovering to around 5 Gt in 2015 and stabilising over the remainder of the projection period. OECD emissions in 2030 are slightly below 2007 levels, which means that non-OECD countries account for the entire global emissions growth in this sector in the Reference Scenario. Non-OECD countries make up over two-thirds of total power-sector emissions in 2030.

Globally, power generation becomes more efficient in the Reference Scenario, with the $CO_2$ intensity of power generation falling slightly, from 539 grammes of $CO_2$ per kWh in 2007 to 478 $gCO_2$/kWh in 2030 (Figure 4.13).[11] While this has a downward effect on emissions, it is far from sufficient to offset the increase in electricity demand. In the OECD, energy intensity improves from 456 $gCO_2$/kWh in 2007 to 362 $gCO_2$/kWh in 2030. In non-OECD countries, power generation is around 50% more carbon-intensive than in OECD countries, falling from 636 $gCO_2$/kWh to 551 $gCO_2$/kWh over the projection period. China's power sector, which relies heavily on coal, is highly emissions-intensive, but improves from 807 $gCO_2$/kWh in 2007 to 668 $gCO_2$/kWh in 2030. Given their greater carbon intensity, and the high absolute level of their power-sector emissions, non-OECD countries (and particularly China) offer substantial potential for $CO_2$ abatement relative to the Reference Scenario, in the context of a global climate change deal.

In the Reference Scenario, fossil fuels continue to account for around two-thirds of world power-generation output, a share that changes little over the projection period. However, given that overall energy use increases rapidly, this also implies a significant expansion in low-carbon power generation (Figure 4.14). Between 2007 and 2020, power generation from renewables and other low-carbon sources (large hydro, nuclear and biomass) increases by 44%.

**Figure 4.14 • *World low-carbon electricity generation in the Reference Scenario***




Note: Generation with carbon capture and storage (CCS) is not included in this chart as it totals less than 100 TWh in 2030 in the Reference Scenario.

11. Power generation intensity is calculated on the basis of electricity-only power plants; combined heat and power and heat plants are excluded from these calculations.

Non-hydro renewables-based power generation is expanding most rapidly, with output in the Reference Scenario increasing five-fold between 2007 and 2020, and continuing to grow fast throughout the projection period. Wind power is the dominant component of this, with the largest increases in the United States and China, where capacity has been doubling every year for the last three years. Solar power is the fastest-growing source of power in the Reference Scenario.

Since the publication of last year's *Outlook*, there have been some important developments in nuclear power: global installed capacity in 2020 in the Reference Scenario is now 427 GW, an increase of 56 GW relative to 2007 capacity and 21 GW higher than the equivalent value in the *WEO-2008* Reference Scenario (Table 4.5). China is an important source of growth in nuclear power, with a five-fold increase in capacity between 2007 and 2020. Recent announcements suggest that China could aim for as much as 70 GW of nuclear capacity by 2020; if plans for this are put in place, it will be reflected in the Reference Scenario of future *Outlooks*.



**Table 4.5 • *Installed nuclear capacity by region in the Reference Scenario*** (GW)

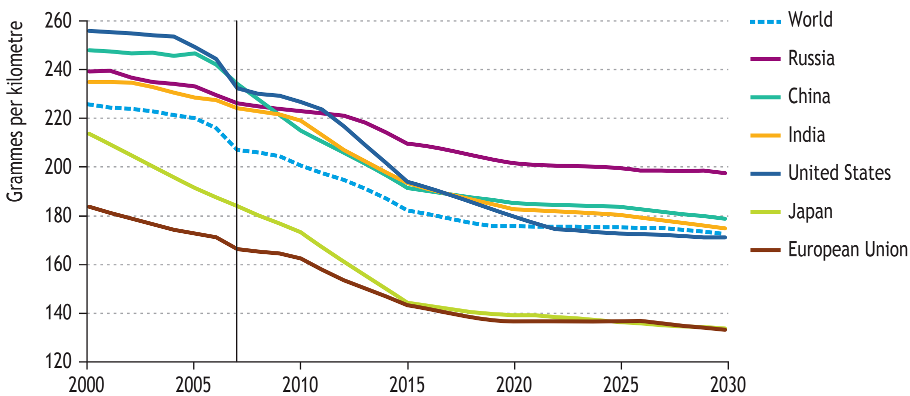
| | Installed nuclear capacity | | Change 2007-2020 | Change in 2020 compared to *WEO-2008* |
|---|---|---|---|---|
| | 2007 | 2020 | | |
| **OECD** | **308** | **307** | -1 | -0 |
| OECD North America | 115 | 123 | +9 | +3 |
| OECD Pacific | 64 | 80 | +17 | -2 |
| OECD Europe | 130 | 103 | -27 | -1 |
| **Non-OECD** | **63** | **121** | **+58** | **+21** |
| China | 8 | 40 | +31 | +14 |
| India | 4 | 11 | +7 | +0 |
| E. Europe/Eurasia | 41 | 53 | +12 | +5 |
| Other non-OECD | 10 | 17 | +7 | +1 |
| **World** | **371** | **427** | **+56** | **+21** |

## *Transport*

Transport-related $CO_2$ emissions increase by 41% from 2007 to 9.3 Gt in 2030. The bulk of the emissions growth is from road transport, which, over the *Outlook* period, remains responsible for around three-quarters of all transport-related $CO_2$ emissions. The increase in $CO_2$ emissions is largely a result of increasing demand for individual mobility in developing countries, where increases in vehicle ownership are expected to increase substantially the global fleet of passenger light-duty vehicles (PLDVs) (see Chapter 1).

The Reference Scenario of this year's *Outlook* nevertheless assumes significant improvements in vehicle efficiencies across world regions (Figure 4.15). Together with higher fuel prices and subsidy reform, policies implemented in the last year will help in this respect. CAFE standards, currently being harmonised with clean-air standards, encourage the sales-weighted average fuel economy of LDVs in the United States to rise to 39 miles per gallon (mpg) by 2016. China has announced tax exemptions for vehicles with engines smaller than 1.6 litres. The European Union has set an objective of reducing the average $CO_2$ emissions of new sales to 120 grammes per kilometre (g/km), phased in between 2012 and 2015. These measures are likely to drive a sharp improvement in the efficiency of energy consumption in LDV transport in the long run. However, the efficiency gains only partly offset the global increase in vehicle stocks, leading to the overall increase in transport $CO_2$ emissions.

**Figure 4.15 • Average $CO_2$ intensity of new LDVs by region in the Reference Scenario**




Note: Based on on-road performance (the average efficiency in use), which is typically around 20% lower than test-cycle efficiency, to which targets usually relate.

Alternative, low-carbon vehicles, such as hybrid cars, plug-in hybrids and electric cars, have received widespread public attention recently. However, this has so far led to only limited policy support: examples include subsidies for hybrids, electric cars and fuel cell vehicles in China, the United States and some European countries, all of which are taken into account in the Reference Scenario. In the absence of more direct policy support, the combination of high costs and the slow rate of vehicle stock turnover sees the share of hybrids in the global fleet reach about 5% by 2020 and almost 8% by 2030, up from just 0.15% in 2007. Plug-in hybrids and electric cars remain marginal in the Reference Scenario, accounting for only 0.2% of the global fleet in 2030.

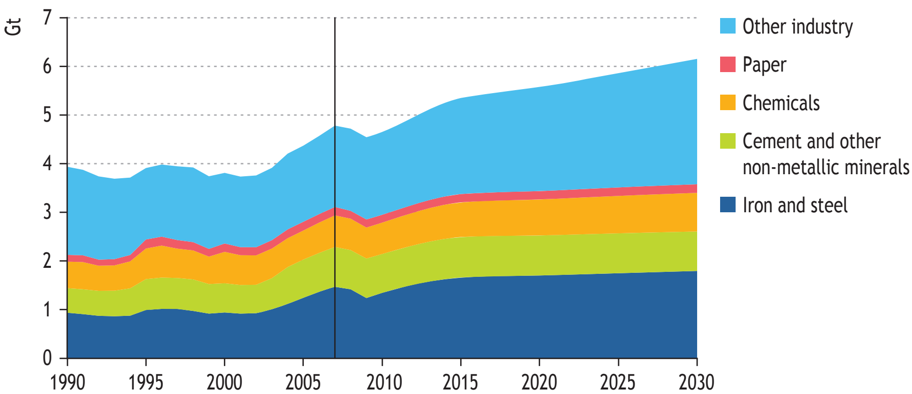
Aviation emissions increase by 44% over the projection period, growing from 742 million tonnes (Mt) in 2007 to 884 Mt in 2020 and 1067 Mt in 2030. International aviation is the largest and fastest-growing component of this, increasing from 405 Mt in 2007 to 494 Mt in 2020 and 600 Mt in 2030. Fleet turnover and the penetration of more efficient aircraft over the projection period, together with further improvements in air-traffic management and the roll-out of performance-based navigation systems (including NextGen in the United States and Single European Sky), result in a 38% improvement in average fleet efficiency, which reaches 2.8 litres per 100 revenue passenger kilometres[12] in 2030. However, this is offset by strong growth in demand for air transport, which increases at 4% per year through to 2030. The global fleet of large planes (with a capacity of over 100 seats) is set to double from almost 20 000 today to almost 40 000 in 2030. Emissions from marine transport, both domestic and international, are set to rise quickly, from a combined 737 Mt today to 954 Mt in 2030.



### *Industry*

The industrial sector, comprising manufacturing such as iron and steel, chemicals, non-metallic minerals and paper, as well as related products and processes, accounts for 17% of today's world energy-related $CO_2$ emissions. In 2007, $CO_2$ emissions from fossil fuel combustion in industry totalled 4.8 Gt, an increase of 21% since 1990. In the Reference Scenario, these emissions reach 5.6 Gt in 2020 and 6.2 Gt in 2030 (Figure 4.16), with this growth driven entirely by non-OECD countries. In China, emissions rise by 480 Mt between 2007 and 2020 (comprising over 60% of the global increase), while India's annual emissions almost double over the same period. Almost half the emissions growth between 2007 and 2020 is due to the expansion of the iron and steel, and cement industries, involving increased use of coal. In the OECD, $CO_2$ emissions from industry decline by 10% between 2007 and 2020, mainly due to efficiency improvements. The average energy intensity of steel production in the OECD falls from 0.20 tonnes of oil equivalent (toe) per tonne of steel in 2007 to 0.18 toe in 2020, while steel production outside the OECD is almost twice as energy-intensive.

**Figure 4.16 • Industry energy-related $CO_2$ emissions by sub-sector in the Reference Scenario**




12. Defined as the number of passengers multiplied by the number of kilometres flown on the respective flights (a common measure of air transport activity).

### *Residential, services and agriculture*

In the residential sector, which accounts for around 7% of today's global energy-related $CO_2$ emissions, emissions increase from 1.9 Gt in 2007 to 2.2 Gt in 2030, with all the growth accounted for by the non-OECD group. In the services sector, OECD emissions in 2030 are very close to their 2007 level, while globally emissions increase from 0.9 Gt to 1.1 Gt over the projection period. In agriculture, world $CO_2$ emissions from energy use are expected to remain close to the current level of 0.4 Gt. In all these sectors, global $CO_2$ intensity falls only slightly in the Reference Scenario.

## *The implications of the Reference Scenario for climate change*

While greenhouse-gas emissions projected in this year's Reference Scenario are lower than in the *WEO-2008* Reference Scenario, this is only partially good news. Emissions remain several times greater than what could be considered a sustainable level in the long term[13] and currently enacted policies are insufficient to prevent a rapid increase in the concentration of greenhouse gases in the atmosphere, with very severe climate-change consequences.

### *Greenhouse-gas concentration*

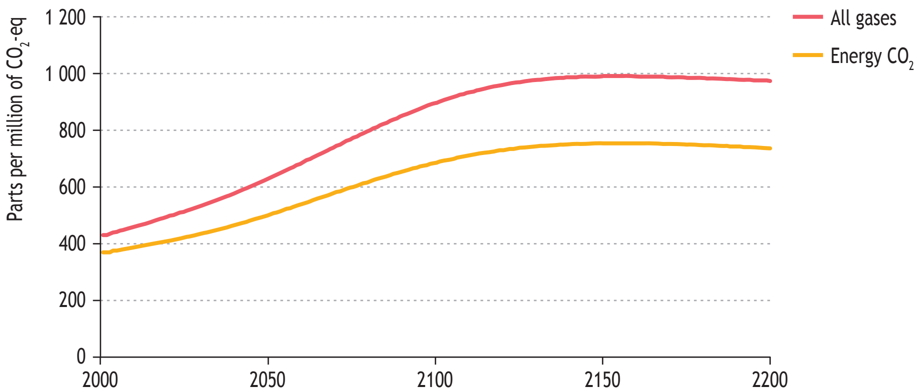
The rapid growth of global greenhouse-gas emissions, as projected in the Reference Scenario, would lead to a substantial long-term increase in the concentration of greenhouse gases in the atmosphere, and a consequent large increase in global temperatures. Our Reference Scenario projections for energy-related $CO_2$ emissions to 2030 lie within the range modelled in other scenarios assessed by the Intergovernmental Panel on Climate Change (IPCC) that assume an absence of new climate policies (IPCC, 2007a, 2007b). While our Reference Scenario analysis of the energy sector is detailed up to 2030, we have also made global projections for energy $CO_2$ and other greenhouse gases, from all sources, up to 2050 (Figure 4.2). We have further extrapolated these trends to 2100, based on long-term economic growth forecasts and energy elasticities. In conjunction with the OECD Environment Directorate, this has allowed us to project the long-term concentration of greenhouse gases in the atmosphere that is consistent with the Reference Scenario trend. Taking into account emissions of all greenhouse gases from all sources, the Reference Scenario corresponds to a long-term concentration of around 1 000 ppm $CO_2$-eq (Figure 4.17).[14]

13. Although opinion is mixed on what might be considered a sustainable long-term level of annual emissions for the energy sector, and this depends on emissions levels in other sectors, none of the scenarios assessed in the *Fourth Assessment Report of the IPCC* in the 445 to 490 ppm $CO_2$-eq range had annual energy $CO_2$ emissions above 5 Gt in the long term – well below 2007's level of almost 29 Gt.

14. These projected emissions are consistent with model outputs of concentrations from MAGICC (Version 5.3).

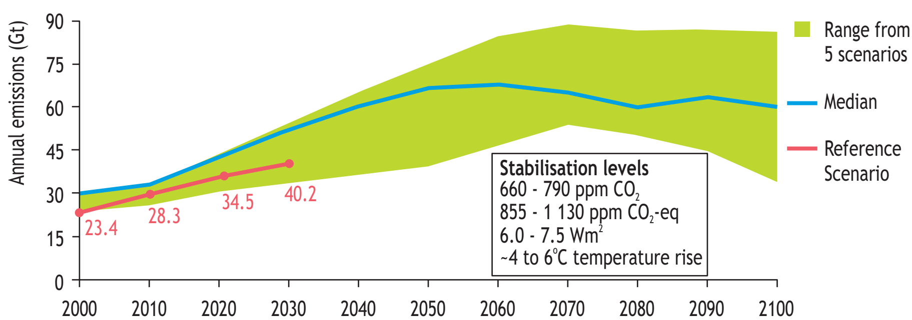
In our long-term projections, atmospheric $CO_2$ concentrations by around the end of the next century are in line with the 855 to 1 130 ppm $CO_2$-eq (660 to 790 ppm $CO_2$) from five independent scenarios (IPCC, 2007a, 2007b) (Figure 4.18).

**Figure 4.17 • *Long-term concentration of atmospheric greenhouse gases resulting from the Reference Scenario***




Sources: IEA analysis using the MAGICC (version 5.3) and ENV-Linkages models.

**Figure 4.18 • *Comparison of the Reference Scenario emissions trajectory with relevant studies assessed by the IPCC***




Sources: IPCC (2007a, 2007b); IEA analysis.

## Climatic consequences

The consequences of the world following the 1 000 ppm trajectory implied by following the Reference Scenario to 2030 and beyond, would, based on central estimates, result in a global mean temperature rise of around 6 °C. At this level, studies indicate that the environmental impacts would be severe (Box 4.3).

**Box 4.3 ● Environmental impacts of a 6°C temperature rise**

As discussed in Chapter 17 of *WEO-2008*, the expected impacts of global temperature rise of around 6°C, as implied by the Reference Scenario, are:

- Sea level rise of up to 3.7 metres, with 50% loss of coastal wetlands, the loss of several islands and millions of people experiencing flooding each year.
- Increased malnutrition, cardio-respiratory and infectious diseases, and increased mortality from heatwaves, droughts and floods.
- Damage to ecosystems, with extinction of over 40% of the world's species and widespread coral mortality.
- Water droughts in mid-to-low latitudes and disappearance of glaciers.
- Food shortages and decreased productivity of all cereal crops.
- High risk of dangerous feedbacks and an irreversible vicious cycle of environmental destruction.

Since the publication of *WEO-2008*, substantial new knowledge has emerged that advances our knowledge of the causes and impacts of climate change. The latest evidence suggests that the situation is even more grave than previously understood. A study by Smith *et al.* (2009) shows that deleterious climate change impacts now appear at significantly lower levels of global average temperature rise and that, even for a temperature rise of 2°C, there are very high risks of extreme weather events and destruction of many ecosystems. Even at 2°C, there is now considered to be a moderate likelihood of a major tipping point having been reached. The impacts of climate change can already be seen to be increasing. For example, current surveys (such as Church *et al.*, 2009) suggest that ocean warming is about 50% greater than had previously been reported by the IPCC. The recent research merely increases the importance of taking urgent action to reduce greenhouse-gas emissions.

# The cost of delayed action

## *A global carbon budget to last a generation?*

Given that emissions have broadly the same impact on the concentration of atmospheric greenhouse gases wherever and whenever they occur, it is informative to consider a given climate change goal in terms of the global "budget" of emissions that society has available over a period of time – and cannot surpass – if it is to meet that goal. Meinshausen *et al.* (2009) have shown that if the world wishes to limit to 25% the probability that a temperature rise in excess of 2°C will occur, it can allocate itself a budget of only 1 trillion tonnes (Tt) of $CO_2$ emissions over the entire period between 2000 and 2049. Of course, the same principle applies for different objectives: for example, Meinshausen states that a budget of 1.44 Tt $CO_2$ (which, taking account of $CO_2$ emissions from land use and industrial processes is broadly consistent with the *WEO-2009* 450 Scenario) would give roughly a 50% chance of keeping the temperature rise below 2°C. The 550 Policy Scenario in *WEO-2008* has cumulative $CO_2$ emissions of 1.55 Tt between 2000 and 2049, while the cumulative $CO_2$ emissions associated with this year's Reference Scenario are 2.1 Tt – more than twice the 1 Tt budget that Meinshausen has suggested (Table 4.6).

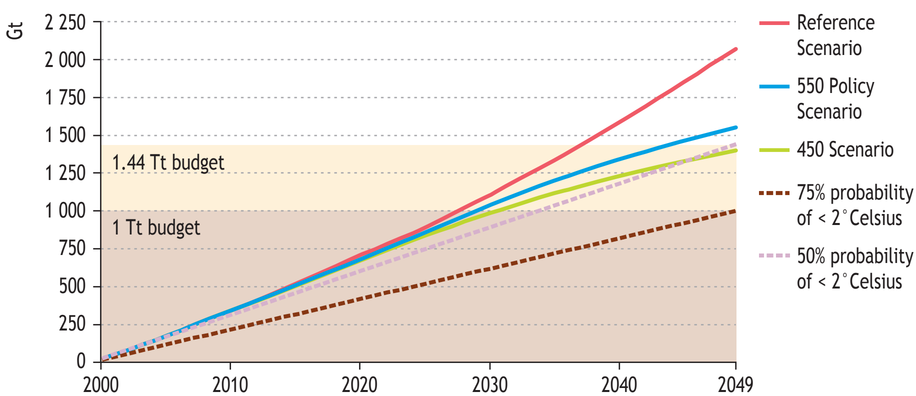
**Table 4.6 • Cumulative $CO_2$ "budgets" for 2000-2049 corresponding with probabilities of keeping the global temperature increase below 2° Celsius**

| Probability of keeping global temperature increase below 2°C | $CO_2$ budget (all sectors) 2000-2049 | Corresponding *WEO* Scenario |
|---|---|---|
| Likely (75%) | 1 trillion tonnes | - |
| Moderate (50%) | 1.4 trillion tonnes | 450 Scenario |
| Unlikely (25%) | 1.6 trillion tonnes | 550 Policy Scenario |
| Extremely unlikely (<5%) | 2.1 trillion tonnes | Reference Scenario |

Sources: Meinshausen *et al*. (2009); IEA analysis.

We are currently eating into these $CO_2$ budgets at a disproportionate rate (Figure 4.19). Between 2000 and 2009, the world emitted a total of 313 Gt of $CO_2$ – or some 31% of the budget of 1 Tt for the period to 2050. The Reference Scenario sees cumulative emissions since 2000 pass the 1 Tt level as early as 2028 and by 2049 they exceed 2 Tt. Even in the 450 Scenario, cumulative emissions to 2030 are substantially above the level that would distribute an emissions budget of 1.44 Tt (corresponding to a 50% probability of exceeding 2°C) evenly over time – an indication of the effort the scenario implies for getting back on track.

**Figure 4.19 • Cumulative $CO_2$ emissions by scenario compared to various "budgets"**



Meinshausen's $CO_2$ budget concept highlights one fundamental fact: the range of achievable stabilisation levels for the concentration of greenhouse gases in the atmosphere is diminishing rapidly. Emissions in the first decade of this century have probably already rendered a 75% probability of limiting temperature rise to 2°C out of reach, though a 450 Scenario is still achievable with urgent action and a strong deal at the UN Climate Change Conference (COP 15). Delay carries the cost of needing to achieve even tighter annual emissions levels in the future.

We have estimated the energy-sector cost of delaying action on climate change. If the world decides to pursue a 450 ppm trajectory, every year of delay relative to the 450 Scenario means subsequently catching up on abatement, at a time when the world is already achieving substantial abatement and the costs of further mitigation efforts are likely to be substantial. An indicative guide, based on our results, is that for every year of delay before moving to a 450 ppm trajectory, an extra $500 billion is added to the global bill of $10.5 trillion (Chapter 7) for mitigating climate change. This figure applies only to delays of one to three years; if further delay means that a 450 ppm trajectory becomes unattainable, the additional adaptation costs would be several times this figure. This result is highly sensitive to assumptions about marginal abatement costs at different points in time, although it is broadly consistent with the results in the limited literature available.[15]

## Energy sector lock-in

The costs of delay are in large part due to the inertia of the energy sector, resulting from the long life of costly capital assets. In the power sector, a coal-fired plant or nuclear reactor has a typical lifetime of 40 to 60 years: the plants that are built today determine the $CO_2$ emissions for a generation. Since they also involve such substantial up-front investments, scrapping these plants before the end of their lifetime is usually economically costly. Consequently, these investments – and their associated emissions (whether high or low) – are effectively "locked-in". For example, in the Reference Scenario, three-quarters of the projected output of electricity worldwide in 2020 (and more than half in 2030) comes from power stations that are already operating today (see Chapter 6). As a result, even if all power plants built from now onwards were carbon-free, $CO_2$ emissions from the power sector in 2020 would be lower by only 25%, or 4 Gt, relative to the Reference Scenario.[16] A similar barrier exists in the industrial sector. In the steel sector, where a capital plant typically has a lifetime in excess of 25 years, around 60% of all the plants in the world will be less than ten years old in 2010, leaving little scope for replacing them with more efficient ones over the following decade. The picture is similar in the cement industry (where plants last 25 to 35 years), while infrastructure and buildings also have very long lifetimes.

The issue of lock-in in the energy sector highlights the importance of ensuring that capital expenditure, whether to expand or to replace capacity, takes the form of low-carbon investments, so that it is these that become locked into the system. For every year that passes, the window for action on emissions over a given period becomes narrower – and the costs of transforming the energy sector to deliver a 450 Scenario increase.

15. Relevant papers include Vliet *et al.* (2009), Keppo and Rao (2007), and Richels *et al.* (2007).

16. OECD countries would account for just one-third of this reduction.

# ENERGY AND $CO_2$ IMPLICATIONS OF THE 450 SCENARIO

## *Is there a plausible route to an alternative energy future?*

### HIGHLIGHTS

- The 450 Scenario analyses how global energy markets could evolve if countries take co-ordinated action to restrict the global temperature increase to 2°C. OECD+ countries are assumed to take on national emissions-reduction commitments for 2020. All other countries are assumed to adopt domestic policies and measures, and to generate and sell emissions credits. After 2020, commitments are extended to Other Major Economies, including China, Russia and the Middle East.
- In this scenario, global energy-related $CO_2$ emissions peak just before 2020 at 30.9 Gt and decline thereafter to 26.4 Gt in 2030. OECD+ emissions decline steadily, from 13.1 Gt in 2007 to 7.7 Gt in 2030. Emissions in Other Major Economies peak at 12.6 Gt in 2020 and then decline to 11.1 Gt in 2030, still 14% above 2007 levels. Emissions in Other Countries increase steadily. We estimate that national policies and measures, and sectoral agreements in transport and industry, could generate 2.1 Gt of the 3.8 Gt reduction needed, relative to the Reference Scenario, to meet the 2020 emission target.
- National policies under consideration in China would bring about some 1 Gt of reductions by 2020, placing that country at the forefront of global efforts to combat climate change. Key measures include the target for nuclear and renewables in power generation (which cut emissions by 400 Mt), rebalancing the Chinese economy towards services (210 Mt) and standards for buildings efficiency (140 Mt).
- The remaining 1.8 Gt of reductions in 2020 are achieved through a combination of domestic reductions in the power and industry sectors in OECD+ countries (at a $CO_2$ price of $50 per tonne) and through carbon-market mechanisms in non-OECD countries (at a $CO_2$ price of $30 per tonne).
- In this 450 Scenario, primary energy demand grows by 20% between 2007 and 2030. Except for coal, demand for all fuels is higher in 2030 than in 2007. Fossil fuels comprise 68% of global primary demand in 2030, down from over 80% in 2007. In contrast, the share of zero-carbon fuels increases from 19% to 32% in 2030.
- Demand for oil grows on average by 0.2% per year, reaching 89 mb/d in 2030. Oil imports to the United States, the European Union and Japan are significantly lower than in 2007; imports into China and India continue to grow, but much less quickly than in the Reference Scenario. OPEC production reaches 48 mb/d in 2030, an increase of 11 mb/d over 2008 levels. Cumulative OPEC oil revenues amount to $23 trillion over the *Outlook* period, 16% less than in the Reference Scenario but a four-fold increase compared to the period 1985-2007.

# Methodology and assumptions

## Overview

The 450 Scenario, discussed in this chapter and the rest of Part B, describes the potential implications for the energy sector of one possible outcome to the negotiations at the 15th Conference of the Parties (COP) of the United Nations Framework Convention on Climate Change (UNFCCC) (December 2009, Copenhagen). Building on the analysis in *World Energy Outlook 2008* (*WEO-2008*), it analyses the implications of the measures in the energy sector that might be taken in order to fulfil a co-ordinated global commitment ultimately to stabilise the concentration of greenhouse-gas emissions in the atmosphere at 450 parts per million (ppm) of $CO_2$-equivalent ($CO_2$-eq). It describes, by region, the profile for energy $CO_2$ emissions between today and 2030 (with reference to the trajectory required after 2030), the corresponding fuel mix, the energy investments involved, their costs and benefits, and how that investment might be financed. There are several new features to this analysis. For both the Reference Scenario and the 450 Scenario, detailed country-by-country projections are provided, zooming in on 2020 — an important focal point for UNFCCC negotiations. In addition, we have carried out a more detailed analysis of investment costs and have, for the first time, quantified the financing options for these investments (Box 5.1).

## Greenhouse-gas emissions trajectory

As in last year's *Outlook*, the 450 Scenario corresponds to the long-term stabilisation of the atmospheric concentration of greenhouse gases at 450 ppm $CO_2$-eq. This is a trajectory that is achievable with very strong co-ordinated action in the energy sector and other emitting sectors. Stabilisation at 450 ppm $CO_2$-eq corresponds to around a 50% chance of restricting the increase in the global average temperature to 2°C (see Figure 4.19 in Chapter 4).[1] According to the *Fourth Assessment Report of the Intergovernmental Panel on Climate Change* (IPCC), to be consistent with the 450 to 490 ppm $CO_2$-eq range of scenarios, $CO_2$ emissions would need to fall to 50% to 85% below 2000 levels by 2050 (IPCC, 2007a). Even with stabilisation at 450 ppm $CO_2$-eq, the IPCC projects that this level of change in the average global temperature would lead to a significant rise in sea level, species loss and increased frequency of extreme weather events.

1. Stabilisation levels of between 445 and 490 ppm $CO_2$-eq (between 350 and 400 ppm $CO_2$) correspond to temperature rises of between 2.0° and 2.4°C. At 550 ppm $CO_2$-eq, there would be a 24% probability of exceeding a 4°C temperature rise. The wide range reflects the uncertainty associated with different emission pathways and the sensitivity of climate to those emissions (IPCC, 2007a).

**Box 5.1 ● Key new features of *WEO-2009* climate change analysis**

The 450 Scenario in this year's *Outlook* builds on the climate policy scenarios modelled in *WEO-2008*, but is fully updated to reflect the latest trends and incorporate a number of improved analyses, in order to provide important energy-sector insights for the UNFCCC 2009 negotiations:

- The 450 Scenario takes full account of the updated trends and new policies in the Reference Scenario, including the impact of the financial crisis and recently adopted policies to address climate change. These policies influence the additional policies and measures, as well as the costs that would be necessary to achieve a 450 ppm $CO_2$-eq trajectory.
- This year's *Outlook* provides substantially more detail at the country level than previous editions, particularly for the period to 2020, in order to provide additional information for decision makers and investors (see Chapter 9).
- A comprehensive analysis of investment costs is being undertaken, assessing, on a region-by-region basis, the costs of low-carbon energy-sector investments for different technologies and sectors (see Chapter 7).
- The World Energy Model's carbon-flow sub-model has been rebuilt in order to take on board more refined data on national costs and the latest analysis of potential barriers and restrictions to international trading of emissions allowances. This enables a clear distinction to be drawn between abatement actions that are undertaken domestically and the potential flows of allowances and credits.
- This *Outlook* dedicates a chapter to the key issue of how to finance a post-2012 agreement (see Chapter 8). Since finance will often need to come from outside the country in which the abatement takes place, our analysis sets out potential levels of funding support from OECD countries to non-OECD countries by sub-sector and in relation to our climate policy framework. It also considers how international financing mechanisms might evolve in the 450 Scenario.
- The OECD's ENV-Linkages model has been used to provide the macroeconomic context and implications of the 450 Scenario, and for the projections of greenhouse-gas emissions other than energy-related $CO_2$. ENV-Linkages projects economic and environmental developments, including emissions of all major greenhouse gases, for 12 world regions and calculates the economic consequences of emission-reduction scenarios (Burniaux and Chateau, 2008).



In developing the 450 Scenario, we have assumed that the international community adopts the objective of stabilising the long-term concentration of greenhouse gases at 450 ppm $CO_2$-eq, less than half the level reached in the Reference Scenario (Figure 5.1). Using the OECD ENV-Linkages model, we have estimated the greenhouse-gas emissions trajectory to 2050 compatible with this long-term concentration target (OECD, 2009). The Model for the Assessment of Greenhouse-gas Induced Climate

S P O T L I G H T

**Other possible stabilisation targets — where does the current debate stand?**

While 450 ppm $CO_2$-eq is arguably the most discussed stabilisation level, since it offers around a 50% probability of keeping the global temperature increase below 2°C – a temperature regarded by many (including the IPCC and G20) as likely to avoid the worst effects of climate change – the negotiations leading up to the UN Climate Change Conference (COP 15) are seeing discussion of other possible targets, such as 550 ppm $CO_2$-eq and 350 ppm $CO_2$-eq.

The implementation of the most stringent versions of the current national pledges announced by a number of countries would bring global energy-related $CO_2$ emissions in 2020 to 32.6 gigatonnes (Gt) (see Figure 4.5 in Chapter 4).[2] If policies were put in place in OECD and non-OECD countries to stabilise global emissions at this level until 2030 (a substantial departure from the 40 Gt emitted in the Reference Scenario), the world could be on track for a 550 ppm stabilisation trajectory (Chapter 4). A detailed analysis of the implications for the energy sector of delivering stabilisation at 550 ppm was conducted in *WEO-2008* in the 550 Policy Scenario. This scenario would be a major improvement on the Reference Scenario, in terms of its environmental consequences, but would still yield a temperature rise of around 3°C (compared with 1 000 ppm and up to 6°C in the Reference Scenario). This level of temperature increase would entail significant adaptation costs, as the global community came to terms with the rise in sea levels consequent upon the melting ice caps and a considerable increase in arid land in many parts of the world.

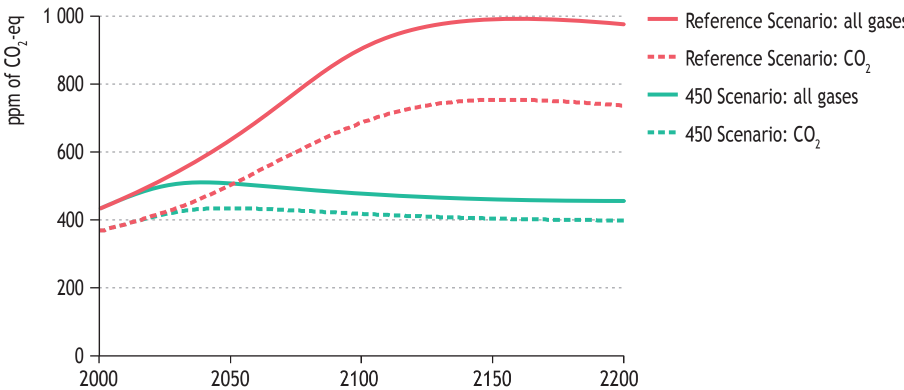
While some countries advocate a 550 ppm target, others, particularly those most vulnerable to climate change, are proposing to move to a much lower stabilisation level, such as 350 ppm (Hansen *et al.*, 2008). For the purposes of this *Outlook*, given that the concentration of all long-lived greenhouse gases in the atmosphere (taking account of all anthropogenic forcing agents, including aerosols) was already around 455 ppm in 2005 (IPCC, 2007b) and greenhouse-gas emissions continue to mount, it would not be meaningful to analyse a scenario for stabilisation at substantially below 450 ppm as a basis for considering the evolution of the energy sector to 2030. Achieving such an outcome would be a long-term scientific challenge requiring breakthroughs in technology to remove greenhouse gases from the atmosphere; changes in the energy sector alone over the next two decades would not be sufficient. Nevertheless, by following a trajectory now that is consistent with 450 ppm, the energy sector can help position the world for a yet more stringent target, should such technological breakthroughs occur.

2. Includes the following reductions: United States (17% relative to 2005); Japan (25% relative to 1990); European Union (30% relative to 1990); Australia (25% relative to 2005); New Zealand (10% relative to 1990); Canada (20% relative to 2006); Russia (15% relative to 1990); Belarus (10% relative to 1990) and Ukraine (20% relative to 1990).

Change (MAGICC) was used to confirm this result.[3] We focused on the energy-related $CO_2$ emissions trajectory to 2030, in order to understand the milestones for the energy sector – particularly for 2020 and 2030 – on the path to attaining such a target.[4] The 450 trajectory is (as in *WEO-2008*) an overshoot trajectory, *i.e.* the concentration of greenhouse gases peaks at 510 ppm in 2035, remains flat for around ten years and then finally declines to 450 ppm – the long-term concentration target. The overshoot happens despite the downward revision of emissions in this year's Reference Scenario, due to the financial crisis. As less capital stock is locked-in over the next few years because of the lower economic activity, energy-related $CO_2$ emissions in the 450 Scenario peak at a lower level than in *WEO-2008* and cumulative energy-related $CO_2$ emissions between 2007 and 2030 are 3% lower. However, those revisions have little effect on the long-term path to stabilisation, because, although greenhouse-gas emissions reach an earlier peak in 2020, $CO_2$ remains in the atmosphere for about 100 years.



**Figure 5.1 • *Greenhouse-gas concentration trajectories by scenario***




Source: IEA analysis using the MAGICC (version 5.3) and ENV-Linkages models.

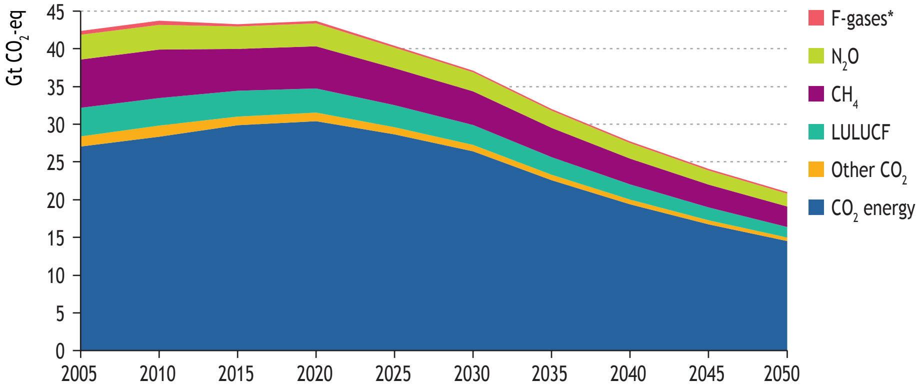
In the 450 Scenario, global greenhouse-gas emissions peak in 2020 at 44 Gt of $CO_2$-eq and decline to 21 Gt in 2050, around half 2005 levels. Emissions from land use, land-use change and forestry (LULUCF), exogenous to ENV-Linkages, are assumed to decline from 3.8 Gt in 2005 to 3.2 Gt in 2020 and 1.4 Gt in 2050, the same trajectory as in the Reference Scenario. This assumption reflects the large uncertainty surrounding estimates of these emissions, their reduction potential and the costs of action in this sector. Combined emissions from methane ($CH_4$), nitrous oxide ($N_2O$), F-gases and $CO_2$ from industrial processes peak soon after 2010 at 11.7 Gt and decline to 5.1 Gt in 2050. Steps to reduce methane leakage, lower levels of gas flaring, improve process efficiencies and better agricultural management are the key measures that are assumed

3. http://www.cgd.ucar.edu/cas/wigley/magicc/

4. The emissions profile for the energy sector – especially to 2020 – takes into account the existing capital stock, the likely growth of the capital stock from now to 2012, and a realistic path for technology development and deployment for the energy sector.

to bring about those savings. Because of the lower abatement cost of these measures, relative to those aimed at reducing energy-related $CO_2$ emissions, abatement from these gases accounts for more than 40% of global greenhouse-gas abatement by 2020, compared with the Reference Scenario. In 2050, these gases account for just 20% of total abatement, as their abatement potential is almost fully utilised.

**Figure 5.2 • World greenhouse-gas emissions by type in the 450 Scenario**




F-gases include hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride ($SF_6$) from several sectors, mainly industry.

Source: IEA analysis using the MAGICC (version 5.3) and ENV-Linkages models.

Energy-related $CO_2$ emissions peak just before 2020 at 30.9 Gt and decline steadily thereafter, reaching 26.4 Gt in 2030 and 15 Gt in 2050.[5] The pace of the decline in energy-related $CO_2$ emissions is about 1.5% per year in the period 2020-2030. Reductions are faster in the period 2030-2050 (around 3% per year). This trend is in line with the BLUE MAP Scenario presented in the IEA's *Energy Technology Perspectives 2008*, which leads to global energy-related $CO_2$ emissions of 14 Gt in 2050 (IEA, 2008). Our analysis focuses on the policy framework needed to achieve these emission levels between today and 2030, and analyses the implications for energy prices, investment and technology deployment. In 2020, emissions are more than 6% higher than today's levels, while in 2030 they are 8% lower. Compared with the Reference Scenario, these figures represent a reduction of almost 4 Gt in 2020 and about 14 Gt in 2030.

**Table 5.1 • World greenhouse-gas emissions trajectories in the 450 Scenario** (Gt $CO_2$-eq)

| | 1990 | 2005 | 2020 | 2030 | 2050 |
|---|---|---|---|---|---|
| All gases | n.a. | 42.4 | 43.7 | 37.1 | 21.0 |
| Energy-related $CO_2$ | 20.9 | 27.0 | 30.7 | 26.4 | 14.5 |

5. This trajectory is similar to the one analysed in *WEO-2008*. However, lower $CO_2$ emissions in the Reference Scenario through to 2020, due to the financial crisis, allow emissions to peak at a lower level than in last year's *Outlook*.

## Policy framework

Emission reductions in the energy sector on the scale and at the pace described in the 450 Scenario would require an international agreement on a structured framework of effective international policy mechanisms and their implementation. Such an agreement could take many forms but, for modelling purposes, the 450 Scenario assumes that different groups of countries adopt binding economy-wide emissions targets in successive steps, reflecting their different stages of economic development and their respective responsibility for past emissions.

Three regional groups are considered:

- OECD+: OECD countries and those countries that are members of the European Union but not of the OECD.
- Other Major Economies (OME): The largest emitting countries outside OECD+ (based on their total emissions of energy-related $CO_2$ in 2007), with gross domestic product (GDP) per capita that is expected to exceed $13 000 in 2020. The countries belonging to this group are China, Russia, Brazil, South Africa and the countries of the Middle East.
- Other Countries (OC): This group comprises all other countries, including India, Indonesia, the African countries (excluding South Africa), the countries of Latin America (excluding Brazil), and the countries of Other Asia and Eastern Europe/Eurasia.[6]

We assume that in 2013 only OECD+ countries adopt economy-wide emission-reduction targets to be met in 2020. In that year, Other Major Economies also adopt economy-wide targets to be met in 2030. Other Countries are not assumed to adopt economy-wide targets before 2030.

We assume a plausible combination of policy instruments, notably:

- carbon markets,
- sectoral approaches, and
- national policies and measures.

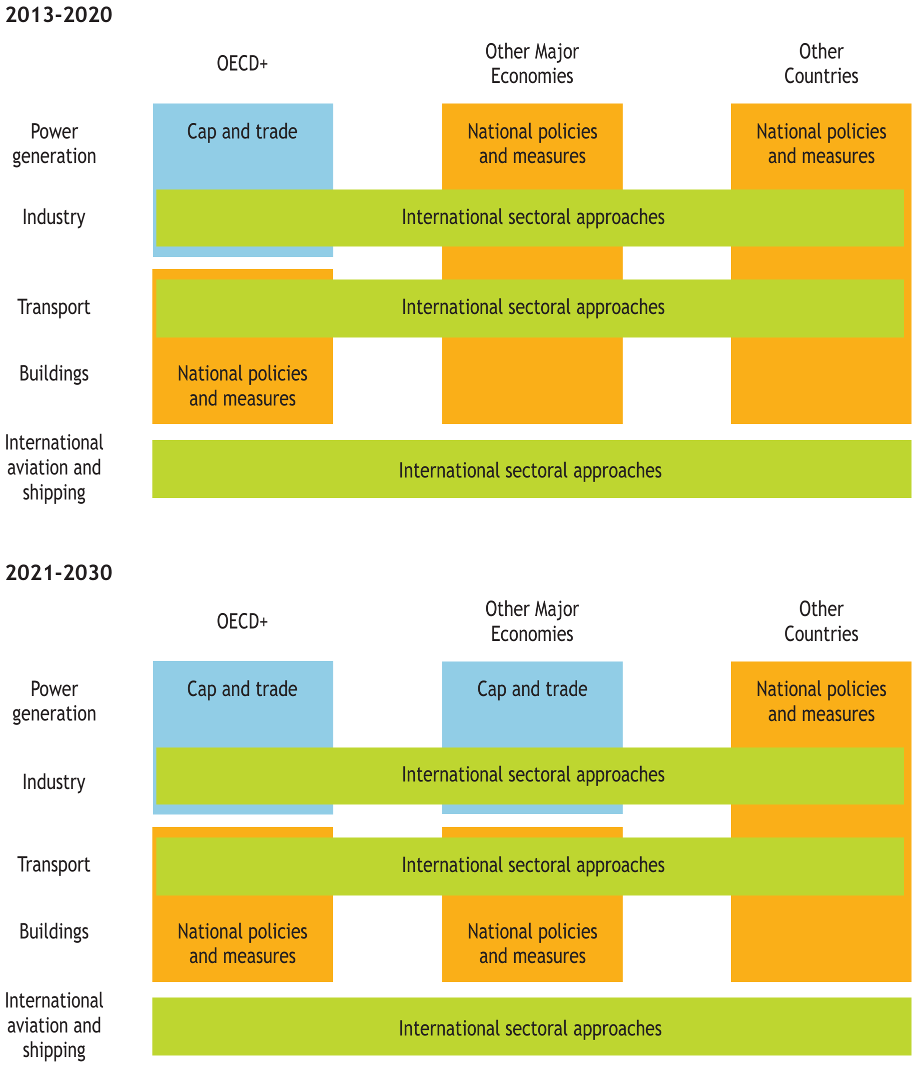
These measures and their applications are tailored to the circumstances of specific sectors and groups of countries (Figure 5.3). They are discussed in detail in *WEO-2008*. Our assumptions about the measures adopted by the respective groups of countries may be summarised as follows (sectoral details are provided in Chapter 6):

- *Carbon market:* OECD+ countries introduce in 2013 a cap-and-trade scheme covering the power-generation and industry sectors. The emission cap is a binding collective cap for all the OECD+ countries, thereby linking emission reductions in each country through a single market. From 2021 onwards, Other Major Economies institute a cap-and-trade regime, also for power generation and industry. The binding emission cap, like that for the OECD+, is a collective cap for these countries. The two carbon-trading schemes are not assumed to be linked. Other Major Economies (through 2020) and Other Countries (through 2030) have the opportunity to generate and trade emissions credits through carbon-market mechanisms.[7]

6. See Annex C for the regional definitions.

7. Note that this is specific to this *WEO*'s 450 Scenario. In the 550 Policy Scenario modelled in *WEO-2008* (IEA, 2008), Other Major Economies do not face any binding commitments in the period to 2030.

**Figure 5.3 • Policy framework in the 450 Scenario**




- *Sectoral agreements:* We assume that international agreements with particular sectoral commitments are adopted in the iron and steel and cement industries, and cover all countries with effect from 2013.[8] Iron and steel and cement are also part of the cap-and-trade scheme in OECD+ countries and are, therefore, subject to a carbon price that incentivises the uptake of more efficient technologies. The highest efficiency levels, *i.e.* "best available technology", are used to set sectoral targets (see Box 6.4

8. The power sector is not covered by a formal sectoral approach in the scenarios, though countries may, in reality, decide to pursue other forms of collaboration in this sector in order to facilitate technology transfer (IEA, 2009).

in Chapter 6). In the transport sector, international agreements that set international standards are assumed to apply to passenger light-duty vehicles (PLDVs), aviation and shipping (see Box 6.2 in Chapter 6), with common effect from 2013.

- *National policies and measures:* These measures are assumed to be adopted at the national level in pursuit of national policy and not in discharge of any international commitment. In the buildings sector, all countries adopt national policies and measures such as buildings standards, labelling of appliances, and minimum energy-performance standards. Other Countries and Other Major Economies are assumed to undertake national policies and measures, in line with their development objectives, across all sectors not covered by international sectoral agreements. From 2020, the cap-and-trade scheme in Other Major Economies subsumes domestic policies and measures in the power and industry sectors.



Other Major Economies and Other Countries could be given financial and technological incentives to achieve quantified emissions reduction or sectoral standards. One way this could be achieved is through a crediting mechanism applying to specified sectors, enabling these countries to receive funds from OECD+ countries in return for undertaking abatement activities — an enhanced version of the existing Clean Development Mechanism (see Chapter 8).

## Macroeconomic impact

Putting the world onto a 450 ppm trajectory requires a deep and rapid transformation of the way we produce and consume energy, and a similar transformation of industrial processes and agricultural and forestry practices. Innovation would be required across all sectors. Meanwhile, a new equilibrium between supply and demand would change the relative prices of a number of goods. Taking all these factors into consideration, together with the financial transfers across countries attributable to $CO_2$ permit allocation, we estimate that global GDP would be reduced in 2020 by between 0.1% to 0.2%, and in 2030 by between 0.9% and 1.6% compared with the Reference Scenario.[9] As the global economy is assumed to double between 2007 and 2030, a 1.6% fall in GDP in 2030 is equivalent to losing a few months of growth over 23 years. Energy demand would be lower than in the Reference Scenario because of this change in economic activity, thereby decreasing the cost of climate change mitigation. By contrast, including in the model the impact of an accompanying rise in global temperature on energy use, such as increased use of air conditioning or lower water availability for hydropower, would have the opposite effect of increasing the cost of mitigation. The net effect of these opposing forces is difficult to quantify, and for modelling purposes GDP is assumed not change in the 450 Scenario *vis-à-vis* the Reference Scenario.[10]

The particular policies and measures adopted within the 450 Scenario have considerable impact on energy demand, notably for fossil fuels. We assume that fossil-

9. The estimated changes to GDP have been calculated by using the ENV-Linkages model under the assumption of a single global carbon price. The impact on GDP grows over time and could become substantial in the period to 2050. The OECD estimates that stabilisation at 550 ppm would lead to a GDP loss of 4% in 2050 (OECD, 2009).

10. Moreover, there is convincing evidence that over the longer term, the cost of inaction would far out-weigh the cost of mitigation action (Stern, 2007).

fuel prices would change broadly in line with the Reference Scenario until 2015. After that, demand for oil, gas and coal starts to diverge from the figures in the Reference Scenario, due to the introduction of additional policies to improve energy efficiency and increase the shares of nuclear and renewable energies, with consequent divergent effect on prices. Lower oil demand means there is less need to produce oil from costly fields higher up the supply curve in non-OPEC countries. As a result, the oil price is assumed to reach $90 per barrel in 2020 – a fall of 10% compared with the Reference Scenario – and remains at this level through to 2030 (Table 5.2).

**Table 5.2 • *Fossil-fuel price assumptions in the 450 Scenario***
(year-2008 dollars per unit)

| | | | | | | | | % difference from Reference Scenario | |
|---|---|---|---|---|---|---|---|---|---|
| | Price | Unit | 2008 | 2015 | 2020 | 2025 | 2030 | 2020 | 2030 |
| Crude oil | IEA import price | barrel | 97.19 | 86.67 | 90.00 | 90.00 | 90.00 | -10 | -22 |
| Natural gas imports | | | | | | | | | |
| | United States | MBtu | 8.25 | 7.29 | 8.15 | 9.11 | 10.18 | -8 | -10 |
| | Europe | MBtu | 10.32 | 10.46 | 11.04 | 11.04 | 11.04 | -9 | -21 |
| | Japan | MBtu | 12.64 | 11.91 | 12.46 | 12.46 | 12.46 | -9 | -21 |
| Steam coal | OECD imports | tonne | 120.59 | 85.55 | 80.09 | 72.46 | 64.83 | -23 | -41 |

Widespread use of oil-price indexation in long-term gas-supply contracts is assumed to continue in European and Asia-Pacific markets,[11] resulting in gas prices that are 9% lower in 2020 and 21% lower in 2030 than in the Reference Scenario. In North America, the gas price is primarily determined by the domestic supply and demand balance. As gas demand in North America declines less steeply than in other parts of the world, the US gas price is assumed to fall by 8% in 2020 and 10% in 2030 compared to the Reference Scenario.

Coal import prices are affected the most in the 450 Scenario. The massive shift away from coal to cleaner fuels drives down prices relative to the Reference Scenario, especially towards the end of the *Outlook* period when coal demand falls most heavily. Coal prices decline from $121 per tonne in 2008 to $80 in 2020 and $65 in 2030 (around 2006 levels).

## Implications for energy-related $CO_2$ emissions

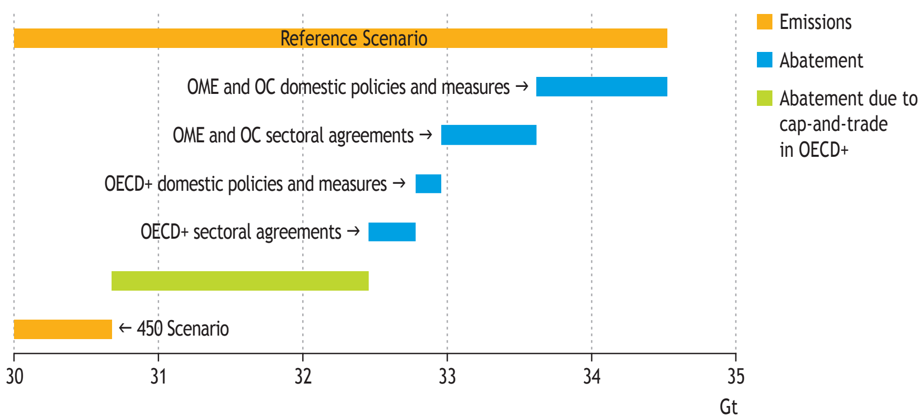
In order to be on the 450 ppm concentration path in the 450 Scenario, energy-related $CO_2$ emissions need to be 30.7 Gt in 2020 and 26.4 Gt in 2030. Compared with the Reference Scenario, 3.85 Gt of $CO_2$ savings are required globally in 2020 (Figure 5.4). Abatement in OECD+ countries arising from sectoral approaches in the transport

11. See discussion in Chapter 14.

sector and national policies and measures is 500 million tonnes (Mt) (Table 5.3). National policies and sectoral approaches in non-OECD countries deliver 1 570 Mt. The sectoral agreement in aviation delivers 28 Mt. A further 1 750 Mt of abatement is realised through the emissions caps in OECD+ countries. Those reductions are achieved in OECD+ countries through a combination of domestic reductions in the power and industry sectors, and through credits obtained as a result of financing additional emission reductions in non-OECD countries. For reasons of efficiency and equity, we have imposed the constraint that two-thirds of the additional reductions required to meet the 450 Scenario are achieved through domestic abatement in OECD+ countries. Therefore, the power and industry sectors in OECD+ limit their combined domestic emissions to 5.2 Gt in 2020 – 21%, or 1.4 Gt, lower than in 2005 and 18%, or 1.2 Gt, lower than in the Reference Scenario. Some 600 Mt is achieved in non-OECD countries as a result of OECD financial support and credited to the OECD. After 2020, a similar framework is adopted, extending the cap-and-trade system to Other Major Economies.



**Figure 5.4 • Abatement by policy type in the 450 Scenario relative to the Reference Scenario, 2020**




Under this framework, domestic emission reductions in OECD+ countries account for 43% of total world reductions achieved in 2020, compared to the level in the Reference Scenario. Reductions in China account for 31%, those in the rest of the Other Major Economies for 10% and those in Other Countries for 16%. However, the financial burden is expected to differ from this (see Chapter 8). In the OECD+ countries, emission reductions from the power and industry sector account for more than two-thirds of the savings, as the $CO_2$ price drives a transformation to lower-carbon technologies (Box 5.2). Sectoral agreements on passenger vehicle emissions standards are also very important in delivering savings. Standards a little more stringent than that for new cars currently proposed by the European Union, 95 grammes of $CO_2$ per kilometre ($gCO_2$/km), deliver more than 110 Mt of savings by

**Table 5.3 • $CO_2$ savings due to national policies and measures and sectoral approaches, 2020**

| Region | Country | Sector | Policy target in 2020 | Savings in 2020 vs Reference Scenario (Mt) |
|---|---|---|---|---|
| **OECD+** | US | Transport* | PLDV sales fuel-economy standard at 110 $gCO_2$/km** | -129 |
| | | Buildings | Standards on new buildings efficiency and refurbishment | -45 |
| | Japan | Transport | PLDV sales fuel-economy standard at 90 $gCO_2$/km | -21 |
| | | Buildings | Standards on new buildings efficiency and refurbishment | -4 |
| | EU | Transport | PLDV sales fuel-economy standard at 90 $gCO_2$/km | -111 |
| | | Buildings | Standards on new buildings efficiency and refurbishment | -30 |
| | Other OECD+ | Transport | PLDV sales fuel-economy standard at 105 $gCO_2$/km | -66 |
| | | Buildings | Standards on new buildings efficiency and refurbishment | -18 |
| | OECD+ | Other energy sector | Savings due to reduced throughput and increased efficiency | -58 |
| | | Other savings | | -21 |
| *Sub-total* | | | | *-503* |
| **Other Major Economies** | China | Power generation | 16% of installed capacity of nuclear, wind and solar, 300 GW of hydro | -398 |
| | | Industry | Rebalancing towards services (+47% of GDP in 2020) | -211 |
| | | Industry | Sectoral standards for iron and steel and cement | -230 |
| | | Transport | PLDV sales fuel-economy standard at 110 $gCO_2$/km | -60 |
| | | Buildings | Standards on new buildings efficiency, appliances and lighting | -144 |
| | Russia | Power | Nuclear generation at 31 GW | -31 |
| | South Africa | Power | More efficient coal | -16 |
| | Middle East | Electricity demand | Efficiency standards for air conditioning and lighting, and industrial motors | -33 |
| | All OME excluding China | Transport | PLDV sales fuel-economy standard at 110 $gCO_2$/km | -100 |
| | | Industry | Sectoral standards for iron and steel and cement | -34 |
| *Sub-total* | | | | *-1 255* |
| **Other Countries** | India | Power generation | Renewables capacity at 110 GW | -76 |
| | Other Countries | Transport | PLDV sales fuel-economy standard at 120 $gCO_2$/km | -126 |
| | | Industry | Sectoral standards for iron and steel and cement | -111 |
| *Sub-total* | | | | *-312* |
| *International aviation* | | | | *-28* |
| **Total** | | | | **-2 098** |

* In this table all transport targets for PLDV sales fuel-economy standards are for test cycle. The savings correspond to road transport.
** Grammes of $CO_2$ per kilometre.

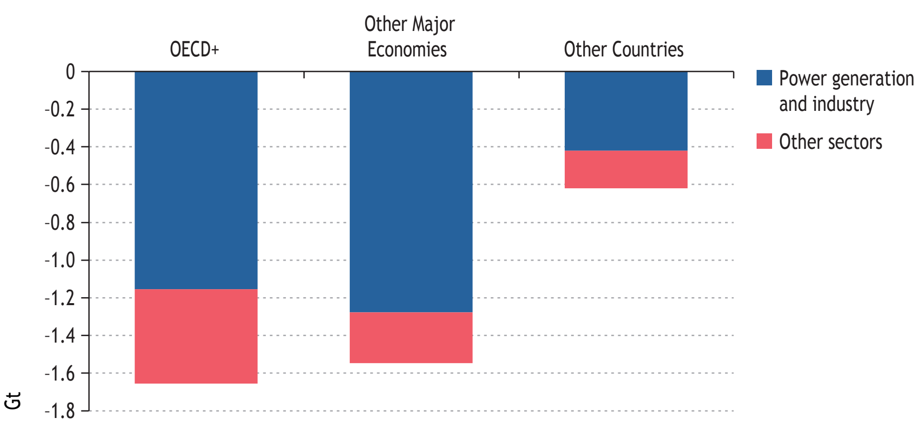
2020 in this region. In the case of the United States, achieving standards 20% more ambitious than the current fuel economy standards and renewables fuel standards would bring about 130 Mt of savings.

In non-OECD countries, measures currently under discussion in China account for some 1 Gt of abatement. Implementing the target now under consideration by the Chinese government to increase the share of zero-carbon generating capacity to 16% by 2020 would, alone, save close to 400 Mt in 2020. Rebalancing the Chinese economy towards services – another key measure included in the 11th Five-Year plan, (which is likely to be further extended because of its benefits in terms of employment, local pollution and the sustainability of Chinese economic growth) could bring about an additional 200 Mt of savings. The magnitude of these savings highlights China's key role in achieving efficient and effective global emission reductions by 2020.



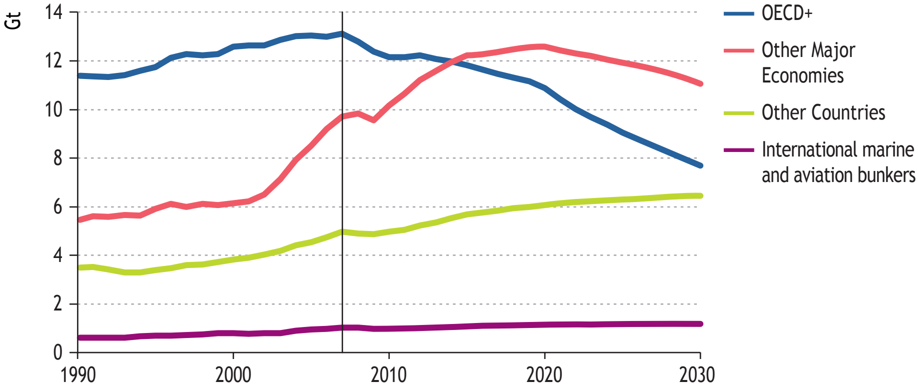
The case of China highlights the utmost importance of national policies and measures, also known as nationally appropriate mitigation actions (NAMAs), in delivering emission reductions. Fortunately, it is in the direct interest of most non-OECD countries that these reductions take place: Chapter 7 demonstrates some important co-benefits arising from the implementation of climate change mitigation policies, including reduced fuel bills for consumers and the lower cost of pollution control and health expenditures that result from local pollution. The challenge for international negotiators is to find the instruments that will give the right level of additional incentive to achieve the implementation of those reductions.

**Figure 5.5 • Energy-related $CO_2$ emission reductions by region and sector in the 450 Scenario compared with the Reference Scenario, 2020**




As a result of this framework, global emissions peak just before 2020 at 30.9 Gt and decline thereafter to reach 26.4 Gt in 2030, 26% above 1990 levels but 8.5% below 2007. Emissions from OECD+ decrease steadily from 13.1 Gt in 2007 to 7.7 Gt in 2030, 40% or 5.0 Gt lower than in the Reference Scenario. After dipping in 2009, as a result of the effects of the financial crisis, emissions in Other Major Economies rebound, peaking at 12.6 Gt in 2020 and declining to 11.1 Gt in 2030, still 14% higher than 2007 levels. Emissions in Other Countries increase steadily, from 5 Gt in 2007 to 6.4 Gt in 2030, but are 30% below the Reference Scenario by then.

## Figure 5.6 • Energy-related $CO_2$ emissions by region in the 450 Scenario




## Box 5.2 • Carbon markets and carbon prices in the 450 Scenario

From 2013 onwards, the power and industry sectors in OECD+ are assumed to take part in an emission-trading scheme that results in combined domestic emissions across both sectors of 5.2 Gt in 2020 and 2.7 Gt in 2030. We assume that this market operates as a unique market with one price and a single cap. To contain emissions at those levels, we estimate that $CO_2$ price in this market reaches $50 per tonne in 2020 and $110 in 2030. The price is set by the most expensive abatement option, for example, carbon capture and storage (CCS) in industry in 2030.

The establishment of such a market would not be easy, and it is not likely that one single OECD+ $CO_2$ market would in reality emerge as early as 2013. For example, discussions have taken place about linking the EU Emissions Trading System (EU ETS) with schemes elsewhere, which have revealed a number of difficult practical issues, ranging from legal issues to the problem of keeping the market reasonably stable (Jaffe and Stavins, 2008). From an economic standpoint, linking regional or national markets to create a larger carbon market would improve the efficiency of emissions trading, as a larger market is more liquid and competitive. More importantly, a larger market provides a deeper pool and greater variety of abatement measures, tending to minimise overall abatement costs.

In the event that domestic emissions in OECD+ countries exceed the imposed emission limits (a matter for negotiation at the UN Climate Change Conference (COP 15) – see Chapter 8), emissions trading system participants in OECD+ countries would be able, within certain defined limits, to buy a quantity of credits from non-OECD regions to achieve compliance. If, in 2020, OECD+ countries were to purchase additional credits amounting to 600 Mt, the credit price of $CO_2$ in the 450 Scenario would be around $30 per tonne (see Chapter 8). The price in this market is lower than the allowance price in the trading scheme within OECD+, as we assume that access to this market for credits would be limited.

From 2021 onwards, the power and industry sectors in Other Major Economies are assumed to be part of an emission-trading scheme that caps their combined emissions at 6.7 Gt in 2030. As linking markets is very complex and in recognition of the structural differences between the Other Major Economies and OECD+, we assume that those two markets run in parallel at first, though with a view to bringing them together at a later date, for example when prices in the two markets converge. In 2030, the resulting $CO_2$ price in the market is $65 per tonne. While convergence of prices is expected in the longer term, we assume Other Major Economies would face gradually the introduction of a $CO_2$ price.[12]

By comparison, it is interesting to note that under the assumption of a global carbon market with a unique price, reaching the 450 trajectory would lead to global $CO_2$ price of $8 per tonne in 2020 and around $70 in 2030 (according to the results of a modelling exercise using the OECD ENV-Linkages model).

5

In the 450 Scenario, all countries achieve substantial levels of abatement relative to the Reference Scenario (Table 5.4). The United States realises the highest rate of abatement, both in 2020 and 2030; this reflects partly the fact that the Waxman-Markey bill on climate change is not taken into account in the Reference Scenario (as at the time of writing it had not been enacted). US emissions in 2020 are 3% below 1990 levels. While Russia achieves the largest cut in emissions relative to 1990, this is largely a result of the sharp drop in emissions that occurred during the 1990s rather than a large reduction, relative to the Reference Scenario, due to the measures taken in the 450 Scenario. China reduces its emissions by 12% in 2020, relative to the Reference Scenario, but its share of global emissions still increases from 21% in 2007 to 28% in 2020. After 2020, China's share of global emissions stabilises, on the assumption that it adopts an economy-wide emissions cap. India's share of global emissions in the 450 Scenario increases from 4.6% in 2007 to 6.2% in 2020 and 8.3% in 2030.

Per-capita $CO_2$ emissions in OECD+ countries decline steeply over the *Outlook* period. On average they halve between 2007 and 2030, to 5.7 tonnes of energy-related $CO_2$ per person. Per-capita emissions in Other Major Economies peak in 2020 and decline thereafter to close to the level of OECD+ countries by 2030. Large differences between countries still persist by 2030 in the 450 Scenario, but they are less marked than today. For example, China in 2030 emits slightly more than the European Union on a per-capita basis, but still much less than the United States, the Middle East or Russia (Figure 5.7). In 2030, India's per-capita emissions are still less than half the world average, but they have increased in comparison to their 2007 level of 1.2 tonnes per person (one-quarter of the world average).

12. Enlarging the OECD+ market as of 2021 would lower prices, creating instability and sending the wrong long-term signals to investors. In addition, markets in Other Major Economies would face, from the start, relatively high prices and a sudden high cost for investors.

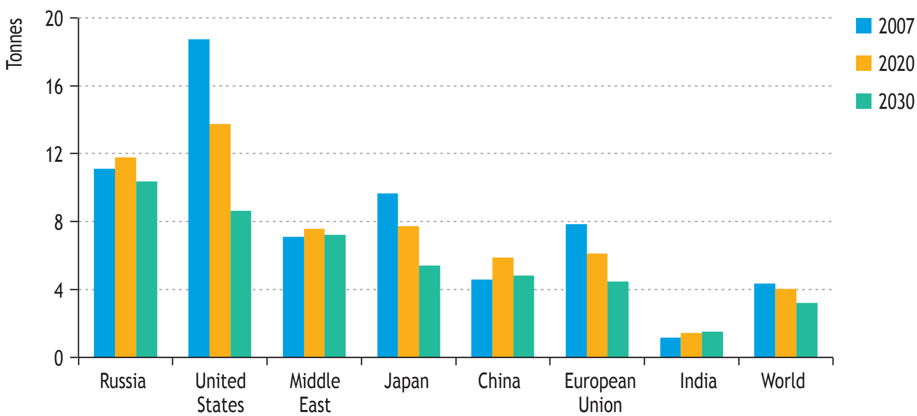
**Table 5.4 • Domestic $CO_2$ emissions by region in the 450 Scenario** (Mt)

| | 1990 | 2007 | 2020 | 2030 | % difference in 2020 from 1990 | % difference from Reference Scenario 2020 | % difference from Reference Scenario 2030 |
|---|---|---|---|---|---|---|---|
| **OECD+** | **11 381** | **13 124** | **10 878** | **7 691** | **-4** | **-13** | **-39** |
| *United States* | *4 845* | *5 742* | *4 717* | *3 171* | *-3* | *-14* | *-43* |
| *European Union* | *4 042* | *3 886* | *3 109* | *2 270* | *-23* | *-13* | *-35* |
| *Japan* | *1 064* | *1 232* | *961* | *636* | *-10* | *-8* | *-35* |
| **Other Major Economies** | **5 460** | **9 713** | **12 585** | **11 066** | **131** | **-11** | **-35** |
| *Russia* | *2 180* | *1 574* | *1 592* | *1 335* | *-27* | *-8* | *-31* |
| *China* | *2 244* | *6 071* | *8 405* | *7 062* | *275* | *-12* | *-39* |
| **Other Countries** | **3 489** | **4 970** | **6 062** | **6 445** | **74** | **-9** | **-29** |
| *India* | *589* | *1 327* | *1 911* | *2 194* | *224* | *-12* | *-35* |
| **World** | **20 941** | **28 825** | **30 676** | **26 386** | **46** | **-11** | **-34** |

Note: World includes international aviation and shipping.

Global carbon intensity per unit of GDP falls on average by 3.4% per year through the *Outlook* period in the 450 Scenario, double the rate in the Reference Scenario. As a historical comparison, intensity fell by 1.4% per year over the period 1990-2007. In 2030, the global economy emits 55% less $CO_2$ per unit of GDP in the 450 Scenario than in 2007. The carbon intensity of the US economy in 2030 is just one-third of today's level, while in India it is 40% of the current rate. The improvement in carbon intensity in the 450 Scenario is more pronounced in OECD+ and Other Major Economies than in Other Countries.

**Figure 5.7 • Per-capita energy-related $CO_2$ emissions in selected countries in the 450 Scenario**

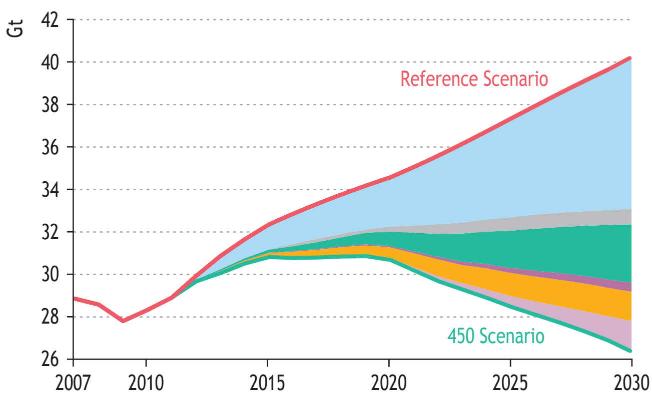



## Contribution of different abatement measures to the 450 Scenario

End-use efficiency is the largest contributor to $CO_2$ emissions abatement in 2030 compared with the Reference Scenario, accounting for more than half of total savings (Figure 5.8). Energy-efficiency measures in buildings, industry and transport usually have short pay-back periods and negative net abatement costs, as the fuel-cost savings over the lifetime of the capital stock often outweigh the additional capital cost of the efficiency measure, even when future savings are discounted (see Chapter 7). Early retirement of old, inefficient coal plants and their replacement by more efficient coal-fired power plants, mainly in China, accounts for an additional 5% of the global emissions reduction. The increased use of biofuels in the transport sector accounts for 3% of $CO_2$ savings, while increased deployment of renewables in power generation and heat production accounts for 20%. Finally, additional nuclear power and CCS in power and industry each represent 10% of the savings in 2030, relative to the Reference Scenario.



**Figure 5.8 • World energy-related $CO_2$ emission savings by policy measure in the 450 Scenario**




| | Abatement ($Mt\ CO_2$) 2020 | 2030 |
|---|---|---|
| Efficiency | 2 517 | 7 880 |
| End-use | 2 284 | 7 145 |
| Power plants | 233 | 735 |
| Renewables | 680 | 2 741 |
| Biofuels | 57 | 429 |
| Nuclear | 493 | 1 380 |
| CCS | 102 | 1 410 |

## Implications for energy demand

In the 450 Scenario, the implementation of more aggressive policies and measures curbs significantly the growth in primary and final energy demand. World primary energy demand reaches nearly 14 400 million tonnes of oil equivalent (Mtoe) in 2030 – a reduction of about 14% relative to the Reference Scenario (Table 5.5). Demand still grows, by 20%, between 2007 and 2030, but at an average annual rate of 0.8%, compared with 1.5% in the Reference Scenario. The energy savings are less marked in the period to 2020, but far from negligible: in 2020, the difference between the two scenarios is about 6%, or 850 Mtoe – a volume close to the current total consumption of OECD Pacific (Japan, Korea, Australia and New Zealand). Demand for all fuels, with the exception of coal, is higher than today's levels. Throughout the projection period, fossil fuels continue to account for the lion's share of primary demand, though by 2030 their share will have declined by more than 13 percentage points compared to 2007. In contrast, the share of zero-carbon fuels in global primary demand increases from 19% in 2007 to 32% by 2030.

Demand for oil grows in the 450 Scenario, on average by just 0.2% per year, reaching 4 250 Mtoe (or 88.5 mb/d) in 2030. In 2030, the share of oil in total primary energy demand is 30%, five percentage points less than in 2007. By 2020, the sectoral agreement on carbon intensity in new PLDVs is responsible for two-thirds of global oil savings. After 2020, the development of second-generation biofuels achieves additional savings in oil consumption in road transport and, to a lesser extent, in aviation, backed by the more widespread use of electric vehicles and plug-in hybrids. The road-transport and aviation sectors combined account for about 70% of the reductions of oil demand in 2030, while the share of oil in the transport sector declines from 94% in 2007 to 84% in 2030.

The biggest savings in oil consumption, relative to the Reference Scenario, occur in the United States, China, the European Union and the Middle East, which together contribute over half of the global oil savings by 2030. By 2030, consumption in China (665 Mtoe) exceeds that in the United States (625 Mtoe). US demand and demand in all OECD+ countries declines steadily through 2030, while oil demand in China continues to grow steadily, averaging 2.7% per year over the projection period. Demand in other developing regions continues to grow, but at a more moderate pace than in the Reference Scenario.

**Table 5.5 • World primary energy demand by fuel in the 450 Scenario** (Mtoe)

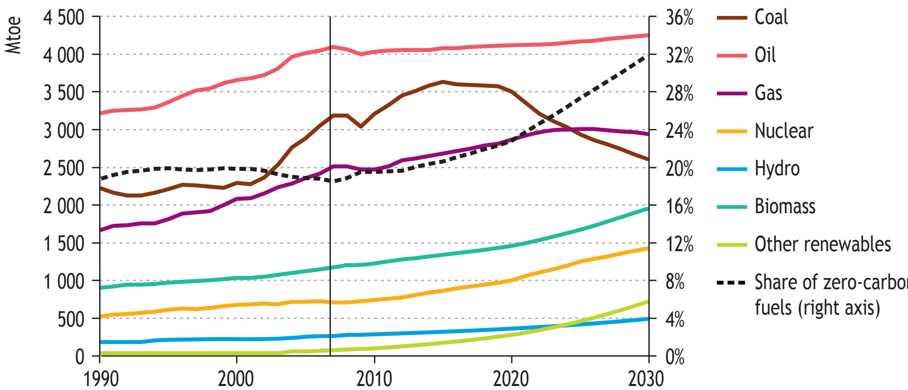
| | | | | | % difference from Reference Scenario | | |
|---|---|---|---|---|---|---|---|
| | **1990** | **2007** | **2020** | **2030** | **2020** | **2030** | **2007-2030*** |
| Coal | 2 221 | 3 184 | 3 507 | 2 614 | -15 | -47 | -0.9% |
| Oil | 3 219 | 4 093 | 4 121 | 4 250 | -7 | -15 | 0.2% |
| Gas | 1 671 | 2 512 | 2 868 | 2 941 | -6 | -17 | 0.7% |
| Nuclear | 526 | 709 | 1 003 | 1 426 | 18 | 49 | 3.1% |
| Hydro | 184 | 265 | 362 | 487 | 5 | 21 | 2.7% |
| Biomass and waste | 904 | 1 176 | 1 461 | 1 952 | 2 | 22 | 2.2% |
| Other renewables | 36 | 74 | 277 | 720 | 24 | 95 | 10.4% |
| **Total** | **8 761** | **12 013** | **13 600** | **14 389** | **-6** | **-14** | **0.8%** |

* Compound average annual growth rate.

Primary natural gas consumption is projected to climb to 3 560 billion cubic metres (bcm) in 2030, at an average annual growth rate of 0.7%. In 2030, gas demand is 750 bcm, 17% lower than in the Reference Scenario. Gas demand expands at a rate of 1% a year until 2020, and reaches a plateau thereafter. Through to 2030, gas demand growth in OECD+ countries is tempered by the introduction of a carbon price in industry and power generation. After 2020, the introduction of emissions caps in Other Major Economies slows down gas demand growth. Demand in OECD+ countries in 2030 remains more or less at its 2007 levels of around 1 554 bcm. These trends mask an increase in gas demand in the US market in the period 2021-2025, as the power sector shifts from coal to gas (see Chapter 6). Demand in non-OECD countries grows at a rate of 1.3% per year over the projection period, an increase in 2030 of 510 bcm compared with current levels. China and India together account for 220 bcm of gas demand growth in the 450 Scenario.

The share of gas in the global primary energy mix remains at around 21% throughout the *Outlook* period – similar to its share in the Reference Scenario. The power sector accounts for most of the savings in demand in 2030, mainly due to the combined effect of reduced electricity demand and a more significant role for nuclear power and renewables. Industrial and buildings demand is also lower, compared to the Reference Scenario, as more efficient processes are introduced and stricter building codes applied.

**Figure 5.9 • World primary energy demand by fuel in the 450 Scenario**



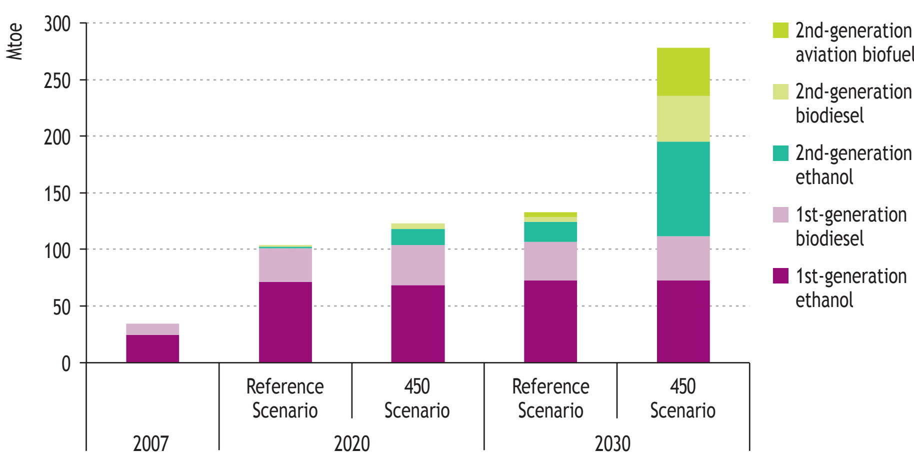

Coal demand is the most affected in volume terms in the 450 Scenario. Global coal demand reaches a plateau in 2015, at 5 190 Mtce. From 2020, it declines progressively, returning to 2003 levels by 2030. By then, global coal demand is reduced by 3 250 million tonnes of coal equivalent (Mtce), reaching a level almost 50% lower than in the Reference Scenario. This reduction is equivalent to the coal demand in 2007 of China, the United States, India and Russia combined. China accounts for almost half of the global savings in coal demand, relative to the Reference Scenario. The rebalancing of the economy towards less energy-intensive activities, the introduction of more efficient coal plants and the diversification of the power sector away from coal are the main reasons. The US coal market is also significantly affected; by 2030, coal demand in the United States is 58% lower than in 2007.

In response to carbon-price signals and policies to promote diversification of energy supplies, demand for nuclear power and renewables in 2030 in the 450 Scenario is 1 252 Mtoe, or 38%, higher than in the Reference Scenario. Non-fossil-fuel consumption more than doubles, compared with 2007 levels. China, the European Union and the United States account for nearly two-thirds of the increase in nuclear power in 2030, compared with the Reference Scenario. The level of capacity addition in China and India – a 12-fold increase versus today's installed capacity – would be particularly challenging to deliver. Hydropower in 2030 has grown by 84%, relative to 2007 levels, an increase of 21%, compared with the Reference Scenario. Non-OECD countries account for by far the greater part of the increase, as most economically viable hydro sites in OECD+ countries have already been exploited. India, with a four-fold increase in capacity compared with 2007 levels, accounts for one-fifth of the hydropower capacity additions in non-OECD countries.

Biomass consumption also increases in the 450 Scenario and in 2030 is 350 Mtoe higher than in the Reference Scenario. In non-OECD countries, the transition towards modern fuels for cooking and heating drives down demand for traditional biomass, but this reduction is almost completely offset by the increase in modern biomass use in residential sector in OECD+ countries. The use of biomass in combined heat and power production and in electricity-only power plants increases by 67% by 2030, to 172 Mtoe above the level in the Reference Scenario.

Major increases in global biofuels production are seen in the 450 Scenario, with consumption in 2030 reaching 278 Mtoe, more than double that in the Reference Scenario. Biofuels are introduced in the transport sector to help meet the $CO_2$ intensity standards set by international sectoral agreements. The deployment of second-generation biofuels occurs around 2015 – five years earlier than in the Reference Scenario. The 450 Scenario includes small amounts of second-generation biofuels by 2020, as well as constant supply of sustainably grown first-generation biofuels, with total biofuels use reaching 123 Mtoe in 2020. The last decade of the projection period sees a rapid increase in the production of second-generation biofuels, accounting for all the incremental biofuels increase after 2020. Regions that currently have strong policy support for biofuels take the largest share of the eight-fold increase over the *Outlook* period, led by the United States (where one-third of the increase occurs) and followed by the European Union, Brazil and China. To highlight the scale of the challenge, the 166 Mtoe of as yet commercially unproven second-generation biofuels required in 2030 in the 450 Scenario is greater than India's current oil consumption. To achieve this would require concerted research and development efforts to be stepped up immediately, with demonstration plants coming on-line in the next few years.

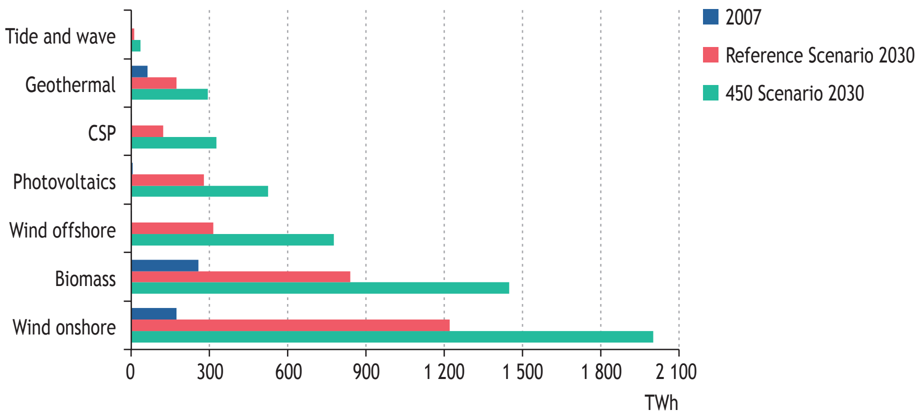
**Figure 5.10 • Biofuels demand by type and scenario**




Wind, geothermal, and solar power output grow very rapidly in the 450 Scenario, the latter by as much as 25% per year. Electricity generation from wind grows by 13% per year over the *Outlook* period, such that wind power accounts for 26%

of all the growth in power generation between 2007 and 2030 in the 450 Scenario. The share of renewables in electricity generation jumps from 18% in 2007 to 37% in 2030.

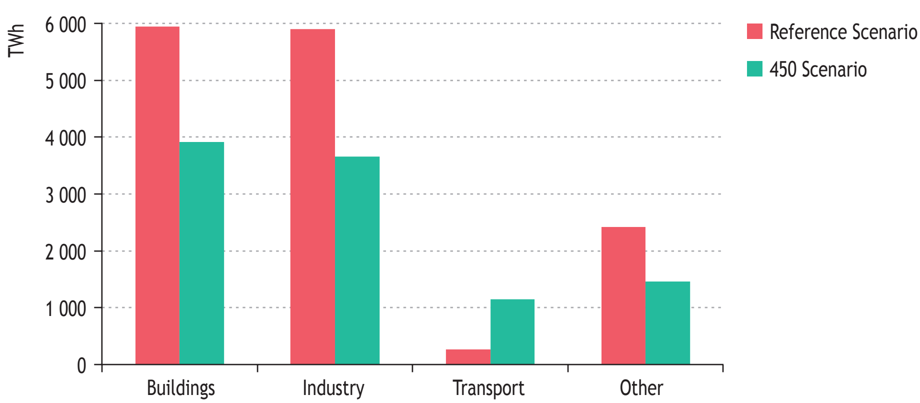
**Figure 5.11 ● *World electricity generation from non-hydro renewables by type in the 450 Scenario***




Note: CSP refers to concentrating solar power.

At the final consumption level, electricity demand reaches 25 400 TWh in 2030 – an increase of 55% compared to 2007. Relative to the Reference Scenario, demand is 3 500 TWh, or 12%, lower in 2030. Savings in Chinese electricity consumption alone account for more than 40% of the global savings but, even in the 450 Scenario, electricity demand in China more than doubles compared with 2007 levels. The electricity savings are the net result of two opposing trends: energy-efficiency measures in buildings, industry and other sectors reduce electricity demand by some 5 200 TWh, while the increased electrification of passenger transport increases electricity demand by around 900 TWh.

**Figure 5.12 ● *Incremental world electricity demand by sector and scenario, 2007-2030***

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## Implications for energy supply

### Oil

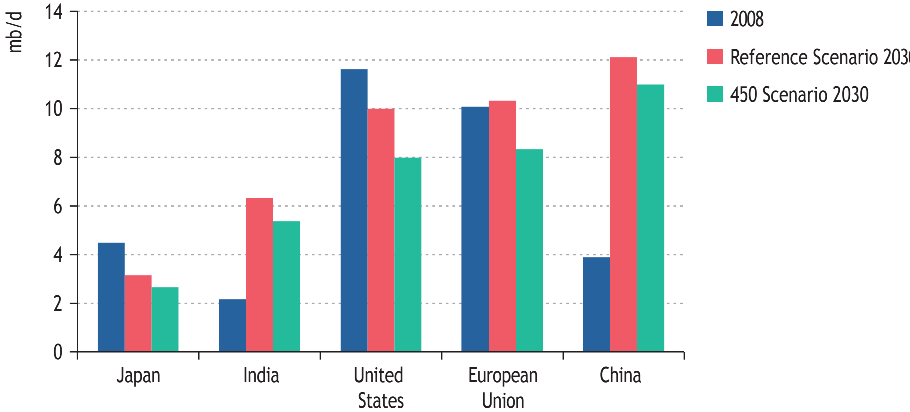
Lower global oil demand in the 450 Scenario results in a lower oil price than in the Reference Scenario. This, coupled with the introduction of $CO_2$ emissions targets in OECD+ countries, renders production in higher-cost fields uneconomic, particularly in the OECD+ region. In contrast, the economics of OPEC production are little affected by the change in oil prices. OPEC production reaches 43 mb/d in 2020 and 48 mb/d in 2030 in the 450 Scenario, an increase of 11 mb/d over 2008 levels. The required growth in production, even in this scenario, is higher than the increase in OPEC production over the period 1980-2008. OPEC's share of the global oil market rises from 44% today to 55% in 2030, similar to its market share in the Reference Scenario.

Crude oil production outside OPEC is projected to decline, from 47 mb/d in 2008 to 41 mb/d in 2020 and 39 mb/d in 2030. Unconventional oil production grows, from 1.8 mb/d today to 4.2 mb/d in 2030, but is 44% lower than in the Reference Scenario, with Canadian oil sands production particularly heavily affected. Nevertheless, the share of unconventional oil in global supply still doubles over the *Outlook* period. Overall production in OECD+ countries is expected to decline steadily, from 18.8 mb/d in 2008 to 14.4 mb/d in 2030. Production in Russian fields also declines, due to higher operational costs. Production in Africa and Latin America does not change significantly compared with the Reference Scenario.

Lower oil demand growth in the 450 Scenario has significant consequences for longer-term global oil-supply prospects. Cumulative production, up to the end of 2008, of conventional oil production (crude and natural gas liquids) stood at 1.1 trillion barrels. In the Reference Scenario, cumulative production by 2030 is projected to rise to over 1.8 trillion barrels. The produced share of currently estimated ultimately recoverable resources would, therefore, rise from around one-third today to around one-half by 2030. However, much slower growth of oil production in the 450 Scenario means that the ratio of production to ultimately recoverable resources in 2030 remains lower, deferring the peak in global conventional oil production.

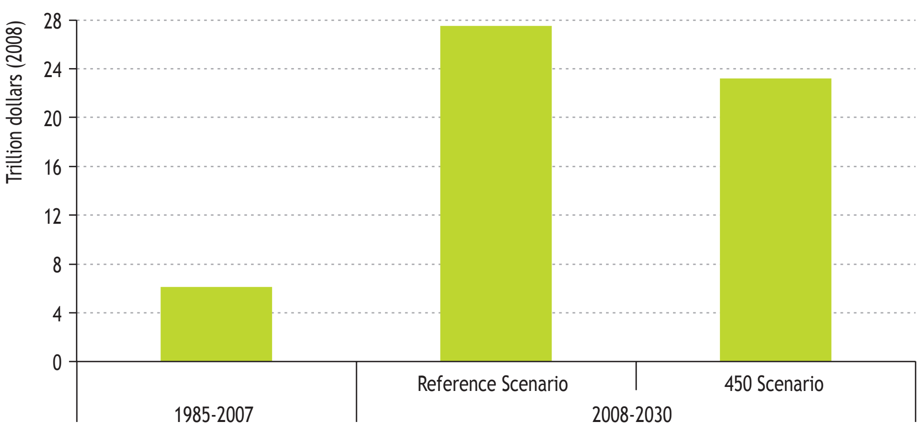
Even in the 450 Scenario, India and China – where most of the incremental oil demand is projected to arise – become more dependent on oil imports by the end of the projection period (Figure 5.13). The volume of inter-regional trade accordingly continues to expand, but by considerably less than in the Reference Scenario. Indeed, the differences between the two scenarios are significant. For example, in the 450 Scenario oil imports into the United States are less than 8 mb/d in 2030, 2 mb/d less than in the Reference Scenario and two-thirds their current level. Similar trends are seen in the European Union and Japan, bringing significant benefits in terms of security of supply and savings in oil-import bills (see Chapter 7). China and India also import less compared with the Reference Scenario, but their imports still rise significantly compared with 2008. China's imports reach 11 mb/d in 2030, while India's reach 5.4 mb/d.

**Figure 5.13 ● Net oil imports in selected regions by scenario**




Exports by OPEC producers increase in the 450 Scenario from 28 mb/d in 2008 to 37 mb/d in 2030. Export availability increases by even more than production, as domestic demand in these countries is mitigated by measures to curb fossil-fuel use, freeing up more oil for export. This has a direct consequence on revenues, which amounts to $23 trillion over the *Outlook* period – a four-fold increase compared with period 1985-2007. This is $4 trillion less than in the Reference Scenario (Figure 5.14), but this can be seen as merely a postponement of revenue, as more reserves are left under the ground to generate revenue for future generations.

**Figure 5.14 ● Cumulative OPEC oil-export revenues by scenario**




Note: Calculated as the value of net exports at prevailing average international prices.

## Natural gas

The slower increase in gas production in the 450 Scenario compared with the Reference Scenario, which results from the lower demand and prices, affects all exporting regions, but disproportionately the regions with higher price elasticities, namely those located farthest from demand centres. Production in the Middle East and Russia declines the most, both in volume and percentage terms. Production in Russia peaks at around 2020 at 650 bcm and declines to 580 bcm in 2030 – 10% lower than in 2007 and 24% below the Reference Scenario. In the Middle East, gas production expands steadily, from 357 bcm in 2007 to 645 bcm in 2030, although this is still 21% below the Reference Scenario. Gas production in North Africa, mainly derived from associated gas, declines by only 14% compared with the Reference Scenario, as a result of proximity to the European market. Although global output still increases in the 450 Scenario, with most of the growth coming from the Middle East, Africa, the Caspian and Latin America, this growth is significantly lower. Meanwhile, gas production in OECD countries declines marginally from 1 124 bcm in 2007 to 1 040 bcm in 2030 – 141 bcm lower than in the Reference Scenario (see Chapters 12 and 13).

Inter-regional gas trade grows more slowly in the 450 Scenario than in the Reference Scenario. While the European Union and China still import more than today in 2030, Japanese imports of liquefied natural gas (LNG) drop below 2007 levels in that year (Table 5.6). In the United States, the increase in gas demand around 2025, compared with the Reference Scenario, is mainly met via LNG imports. Global demand for LNG is lower than in the Reference Scenario and LNG prices are some 20% lower in 2030. These lower LNG prices mean that, in India, where natural gas demand grows at a pace similar to that in the Reference Scenario, LNG imports become more competitive than domestic supply.

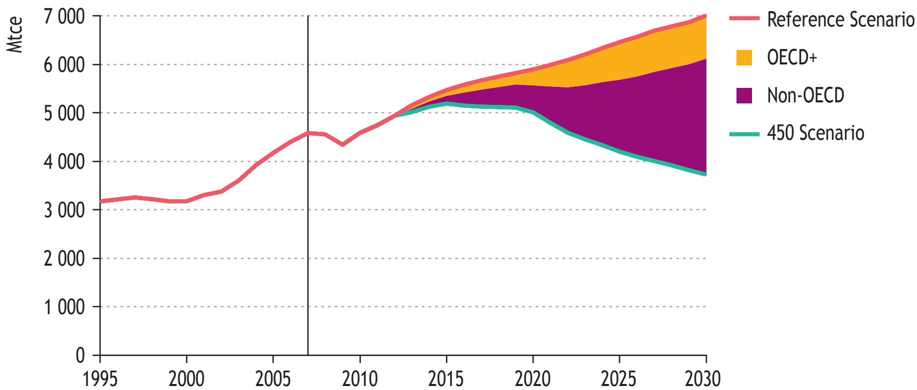
**Table 5.6 • Net natural gas imports in key importing regions by scenario** (bcm)

| | 2007 | Reference Scenario 2020 | 450 Scenario 2020 | Reference Scenario 2030 | 450 Scenario 2030 |
|---|---|---|---|---|---|
| United States | 114 | 50 | 78 | 43 | 61 |
| European Union | 312 | 425 | 391 | 516 | 428 |
| Japan | 97 | 99 | 88 | 106 | 94 |
| China | 4 | 49 | 40 | 117 | 91 |
| India | 10 | 28 | 24 | 52 | 63 |

## Coal

The fact that coal demand is sharply lower in the 450 Scenario than in the Reference Scenario has a significant impact on coal prices. In the 450 Scenario, they are 46% lower in 2030 than at their peak in 2008. Global coal production follows demand by expanding to 2015, levelling off until 2020 and then falling back to 2003 levels by 2030 (Figure 5.15). China remains the world's largest coal producer, with an output of 1 964 Mtce in 2030, but its loss of production in 2030 relative to the Reference Scenario is equivalent to the country's entire consumption in 2004. The United States remains the second-largest coal producer over the projection period, but again with production significantly lower than in the Reference Scenario. Production in exporting regions is lower, mainly due to lower demand in export markets and the adverse effects of lower international coal prices on high-cost producers, such as Russia. Overall, non-OECD countries account for almost three-quarters of the reduction in production in 2030 relative to the Reference Scenario.

**Figure 5.15 • *Change in coal production by scenario and region***




Global inter-regional trade in hard coal grows in the 450 Scenario at 0.4% per year between today and 2020, reaching almost 700 Mtce in 2020. Trade grows slightly more slowly than demand, as most coal continues to be consumed within the region in which it is produced. In 2020, trade is 16% lower than in the Reference Scenario, while by 2030, net trade is around 2002 levels at 506 Mtce, which is 53% below the Reference Scenario. In contrast with its situation in the Reference Scenario, China returns to self-sufficiency over the *Outlook* period, a major positive consequence of the 450 Scenario. India's net imports double by 2020 compared to 2007, although the level of imports is almost 60% down compared to the Reference Scenario. Australia remains the world's biggest net exporter of hard coal, exporting 216 Mtce in 2030, followed by Indonesia, which exports 103 Mtce (similar to their 2005 level). Other major net exporters, such as Colombia, South Africa and Russia, also see their net exports decline below today's levels.

# THE 450 SCENARIO AT THE SECTORAL LEVEL
## What is needed in power, transport, industry and buildings?

### H I G H L I G H T S

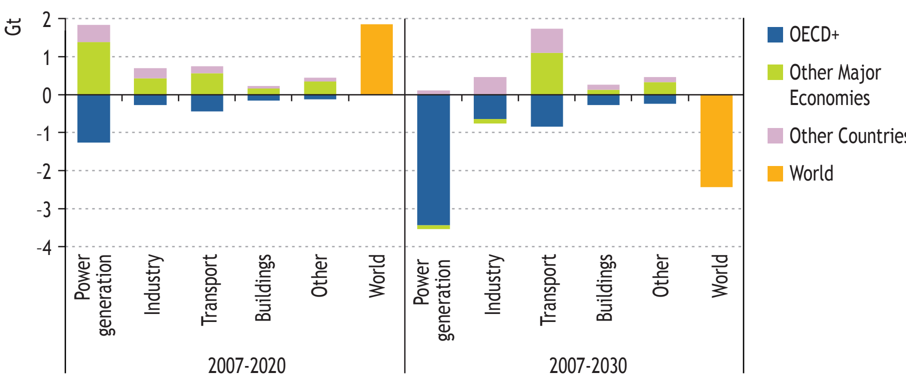
- Lower demand in the short term, due to the financial crisis, temporarily defers the urgent need for capital-stock additions in power generation and industry, opening a window of opportunity for replacing capacity with low-carbon designs. In the 450 Scenario, this opportunity is exploited with the introduction in 2013 of a carbon price in the power and industry sectors in OECD+ countries and industrial sectoral agreements in non-OECD countries.
- In this scenario, the power sector accounts for 70% (or 9 Gt) of the global emission reductions in 2030 relative to the Reference Scenario. Almost 40% of these reductions are due to lower electricity demand. Energy-efficiency measures and higher electricity prices (due to the introduction of a carbon price) curb electricity demand growth in industry and buildings. Around 20% of the savings are offset by increased demand due to the electrification of cars.
- In 2030, around 60% of global electricity production comes from renewables (37%), nuclear (18%) and CCS (5%). This represents a step-change from the Reference Scenario where fossil fuels still account for about two-thirds of generation. Coal is hit the most. In 2030, installed coal capacity reaches 1 350 GW, about 50% that of the Reference Scenario. The United States and China combined account for more than half of the reduction, due to their sheer size and large reliance on coal generation.
- Measures in the transport sector produce 12 mb/d of savings in global oil demand by 2030. They account for almost three-quarters of all the oil savings in the 450 Scenario, but only 12% of total $CO_2$ emissions savings. Road transport accounts for the vast majority of emissions savings, as a dramatic shift in car sales occurs – by 2030 conventional internal combustion engines represent some 40% of sales, down from more than 90% in the Reference Scenario, as hybrids take up 30% of sales and plug-in hybrids and electric vehicles account for the remainder. Efficiency improvements in new aircraft and in aviation biofuels save 1.6 mb/d by 2030, but cost more than savings in other transport modes.
- Global industrial energy-related direct $CO_2$ emissions are 27% (or 1.7 Gt) lower in 2030 than in the Reference Scenario. The iron and steel and cement sectors deliver more than half of those savings. China, with the largest installed industrial capacity worldwide, accounts for 0.8 Gt of reductions.

## Overview

Even in the 450 Scenario, global energy-related $CO_2$ emissions continue to grow until shortly before 2020, reaching 30.7 gigatonnes (Gt) in 2020. This represents a saving of 3.8 Gt relative to the Reference Scenario, but an increase of 1.9 Gt over 2007 levels. The economy-wide emissions cap that OECD+ countries are assumed to introduce produces domestic savings of 2.2 Gt by 2020, compared with 2007 levels. However, those savings are more than offset by the increase in emissions in all other countries. All sectors register an increase in emissions compared with 2007 levels (Figure 6.1).

In 2030, emissions drop to 26.4 Gt, 13.8 Gt less than in the Reference Scenario and 2.4 Gt lower than 2007 levels. The assumed extension of the cap-and-trade to Other Major Economies cuts emissions in the power and industry sectors to below 2007 levels. Emissions in those sectors continue to grow in Other Countries, but only by a very moderate amount. By 2030, the transport sector is the only one that still sees a major increase in emissions, compared with 2007, as the growth in car ownership and freight transport in countries outside the OECD more than offsets the introduction of stringent efficiency standards.

**Figure 6.1 • *Change in energy-related $CO_2$ emissions by sector and region in the 450 Scenario relative to 2007 levels***




## Power generation

Delivering a low-carbon future requires a major transformation of the electricity sector. Providing clear signals through policies such as a carbon price is an important driver but this alone is not sufficient to secure significant gains from low-carbon technologies. Major breakthroughs in technology development and deployment are also required, and need to be encouraged by government incentives.

The Reference Scenario already includes widespread deployment of renewable power sources as they gain competiveness with respect to fossil-based power plants. This reflects in part the action that numerous countries have taken to include clean energy measures in their economic stimulus packages, including additional support for the use of renewable energy in power generation. Carbon dioxide capture and storage (CCS) plants also receive public support in the Reference Scenario, but sizeable additional efforts are needed to reach the level of low-carbon electricity generation in 2030 required in the 450 Scenario. Lower demand in the short term, due to the financial crisis, temporarily defers the need for fossil-fuel based capacity additions that would otherwise have locked-in emissions from these plant types for decades. This opens a window of opportunity to build new and replace capacity with advanced, low-carbon plant designs.

**Box 6.1 ● *The policy framework for the power generation sector in the 450 Scenario***

Following the introduction of economy-wide emission targets in OECD+ countries, the 450 Scenario assumes the implementation of a cap-and-trade system for the power and industry sectors from 2013. Our analysis shows that to meet the domestic emissions cap of 5.2 Gt in 2020, $CO_2$ prices would reach $50 per tonne, increasing to $110 per tonne in 2030 (see Box 5.2 Chapter 5). Other Major Economies are assumed to adopt similar binding commitments in 2020 and to introduce as of 2021 a cap-and-trade system for the power and industry sectors, as carbon pricing is essential to displace the use of inefficient fossil-fuel based generating capacity during the last decade of the projection period. In these countries the $CO_2$ price reaches $65 per tonne in 2030. Other Countries introduce national policies and measures aimed at increasing energy security and reducing local pollution. Credits for emission reductions in those countries can be sold on the international carbon market (see Chapter 8). In addition, this scenario also includes strong government intervention in support of renewables, nuclear and CCS technologies.

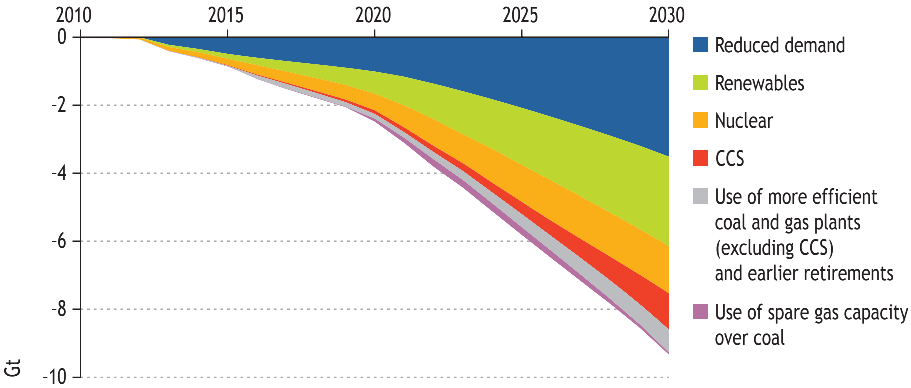
6

## Carbon intensity and $CO_2$ reductions in the power sector

Even though the Reference Scenario already sees significant increases in low-carbon power generation, particularly from nuclear, wind and biomass, the 450 Scenario necessitates even wider deployment of these technologies. In comparison with the Reference Scenario, renewables and nuclear together contribute an additional 1.1 Gt of savings by 2020, while, due to energy-efficiency measures, the reduction in electricity demand provides an equivalent saving (40% of the total) (Figure 6.2).

After 2020, the implementation of stringent climate policies in the power sector in OECD+ and Other Major Economies rapidly increases the rate of decarbonisation. Globally, additional savings in the power sector reach 9.3 Gt of $CO_2$ by the end of the projection period and account for about 70% of world $CO_2$ savings with respect to the Reference Scenario. Savings from demand reduction are 3.5 times higher in 2030 than in 2020. The next largest contribution to emission reductions comes from fuel switching to renewable sources, saving 2.6 Gt of $CO_2$ in 2030 compared with the Reference Scenario. Nuclear energy saves an additional 1.4 Gt of $CO_2$ and CCS plants a further 1.1 Gt. At the world level, the use of existing spare or new additional gas capacity and the switch to more efficient non-CCS fitted coal plant provides modest savings, of the order of 0.7 Gt of $CO_2$ by 2030.

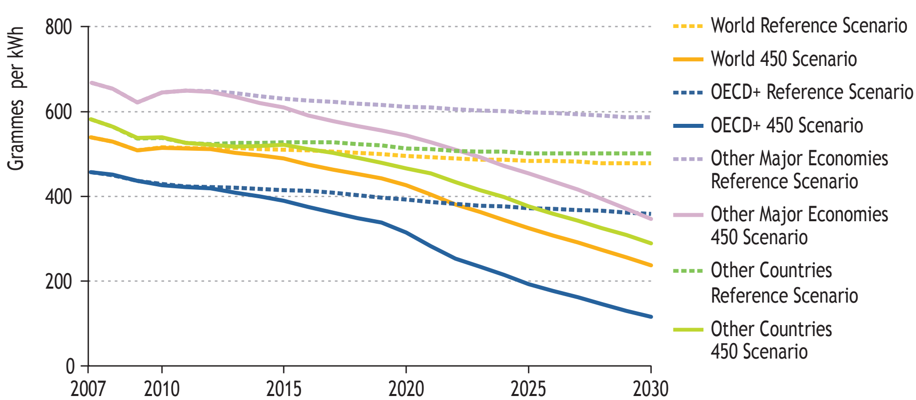
**Figure 6.2 • Change in world energy-related $CO_2$ emissions from the power generation sector in the 450 Scenario compared with the Reference Scenario**




Historically, the carbon intensity of power generation (defined as $CO_2$ emission content per unit of generation) tended to fall only gradually with improvements in technology and efficiency, and the uptake of lower or zero-carbon technologies. In 1971, carbon intensity was above 600 grammes of $CO_2$ per kWh ($gCO_2$/kWh); it fell to around 510 $gCO_2$/kWh in the 1990s and then remained fairly stable (IEA, 2008c). The reduction in carbon intensity before the 1990s was in large part due to significant expansion of nuclear capacity worldwide.

Electricity plants (excluding combined heat and power) currently account for more than 90% of total installed capacity worldwide. The carbon intensity of this category of plant improves fastest in OECD+ countries – by almost 70% relative to the Reference Scenario – to reach an average 116 $gCO_2$/kWh in 2030 (Figure 6.3). As a basis for comparison, a high pressure, high temperature ultra-supercritical coal plant typically emits around 700 $gCO_2$/kWh. This decarbonising trend accelerates after 2020, as the $CO_2$ price increases sufficiently to displace the majority of coal plants not fitted with CCS.

**Figure 6.3 • $CO_2$ intensity of electricity power plants***




*Excluding combined heat and power.

In 2007, the carbon intensity of power generation in Other Major Economies was 47% higher than in OECD+ countries, but this improves at an average of 2.8% per year, to reach 350 $gCO_2$/kWh by 2030, approximately equal to the OECD level of the Reference Scenario in 2030. The rate of improvement in Other Countries is slightly higher, as rapid demand growth provides the opportunity to build many new low-carbon generation plants. As over one-quarter of total generation in Other Countries today is hydro-based, its carbon intensity is currently moderate, *i.e.* close to the world average. Even so, this intensity is cut in half by 2030. As a result, world average carbon intensity decreases 56% compared with today's level, reaching 237 $gCO_2$/kWh in 2030.

### *Regional trends*

The options available to decarbonise the power sector vary markedly across countries. This is reflected in the distinct mix of technologies that different countries are assumed to employ to achieve the emission reductions in the 450 Scenario (Figure 6.4). This section outlines, for selected countries, the savings in $CO_2$ emissions in the power sector achieved in the 450 Scenario, relative to the emissions that would be generated if the growing electricity demand of this scenario were to be supplied using the electricity generation mix of 2007. This clearly illustrates the transformation needed in the current technology mix of the power sector in the 450 Scenario.

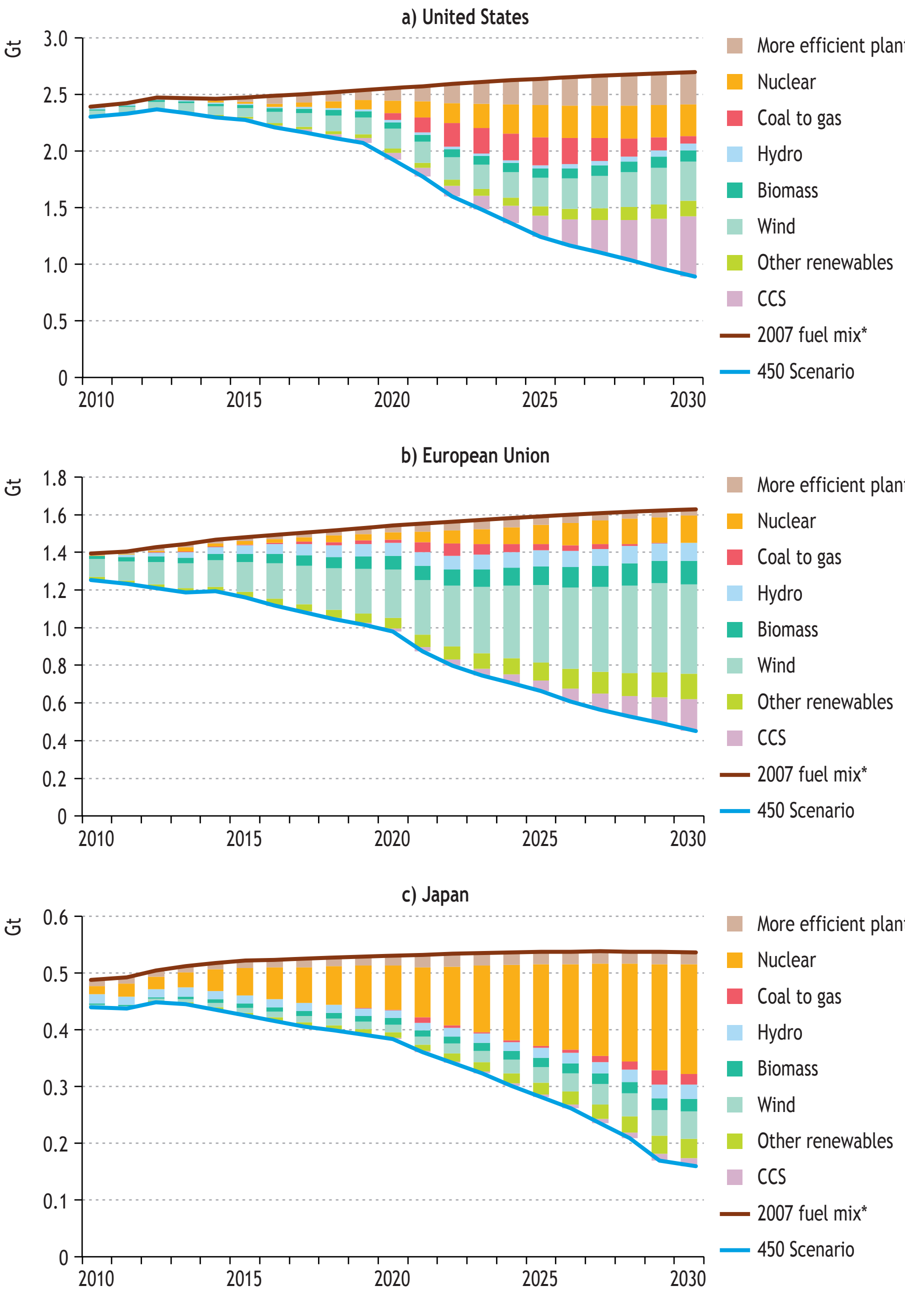
In the *United States*, about 16% of the savings (under this definition) in 2030 arise from more efficient use of coal plants, while a significant switch away from the most inefficient coal plants in favour of gas plants accounts for about 18% in 2025 (Figure 6.4a). Increased deployment of nuclear results in further savings of almost 300 million tonnes (Mt) of $CO_2$ in 2030, or 15% of the total. The biggest savings, however, come from renewable sources and CCS technology, which account respectively for 36% and 30% of the total savings by 2030. Wind alone accounts for 350 Mt of savings.

Compared with other regions, the *European Union* sees much stronger growth in wind generation, which displaces nearly 500 Mt of $CO_2$ in 2030 (Figure 6.4b). The deployment of CCS, nuclear, biomass and other renewables, each account for about 150 Mt of $CO_2$.

*Japan's* pathway to achieve the emissions reduction goal relies largely on nuclear and, to a much lesser extent, on wind energy and other renewables (Figure 6.4c). Nuclear alone contributes about half of the country's total $CO_2$ savings in 2030, or almost 200 Mt of $CO_2$. The second-biggest contributor to the savings is wind, with 13% of the reductions.

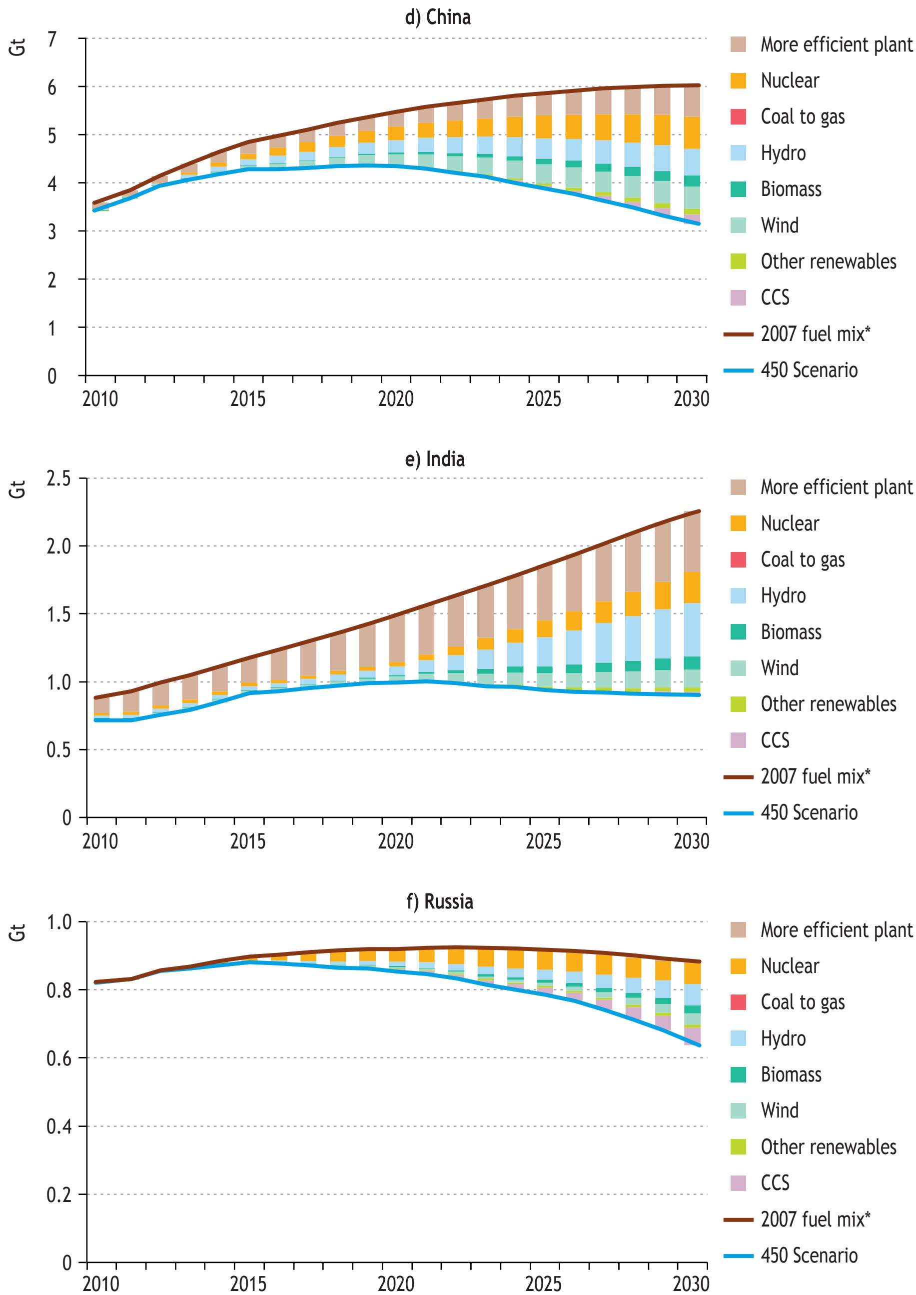
If *China* were to meet the level of electricity demand projected in the 450 Scenario in 2030 using the electricity generation structure it had in 2007, it would emit almost 3 Gt of $CO_2$ more than envisaged in the 450 Scenario (Figure 6.4d). Almost half of these savings come from renewable sources. The significant shift away from inefficient coal plants to more advanced and efficient designs saves up to 650 Mt of $CO_2$ by 2030. On top of this, CCS contributes an additional reduction of 230 Mt of $CO_2$. The large-scale deployment of nuclear power in China eliminates a further 660 Mt of $CO_2$ by 2030.

**Figure 6.4** • **$CO_2$ emission savings by type in the power generation sector in the 450 Scenario relative to the 2007 fuel mix* for selected countries**




* The total $CO_2$ emissions that would be generated in supplying the 450 Scenario electricity demand using the electricity generation mix of 2007.

**Figure 6.4** • **$CO_2$ emission savings by type in the power generation sector in the 450 Scenario relative to the 2007 fuel mix* for selected countries** (continued)




* The total $CO_2$ emissions that would be generated in supplying the 450 Scenario electricity demand using the electricity generation mix of 2007.

The assumed implementation of domestic policies and measures in *India*, along with support from foreign investments, results in more efficient use of coal resources for power generation (Figure 6.4e). This achieves one-third of the total 1.4 Gt reduction in $CO_2$ emissions in 2030. Hydropower contributes a further 30% and most of the remainder comes from increased use of nuclear and wind.

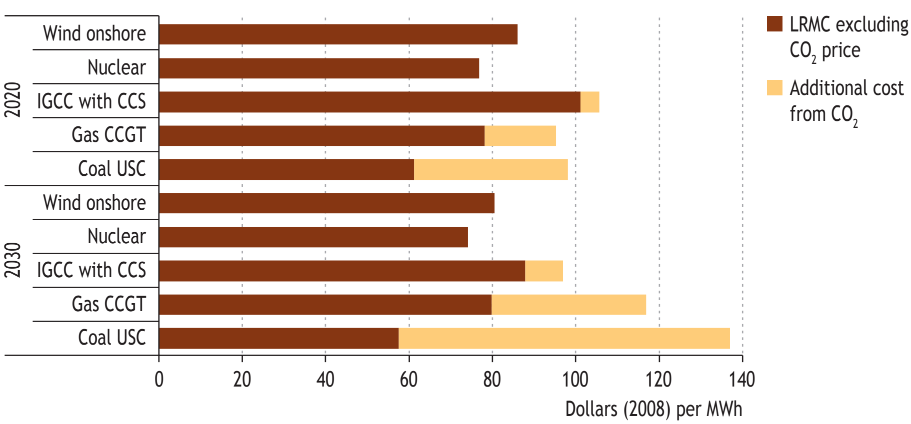
The Russian power sector experiences a more modest transformation (Figure 6.4f). It draws upon increased hydro, nuclear and other renewables in equal shares. Wind alone accounts for 13% of total savings in Russia and CCS-fitted plants for 21%.

## Evolution of the generation mix

In the 450 Scenario, global electricity demand increases from 19 756 TWh in 2007 to 26 000 TWh in 2020 and nearly 30 000 TWh in 2030, with 85% of the increase arising in Other Major Economies and Other Countries. Compared with the Reference Scenario, electricity demand decreases by 5% in 2020 and 13% in 2030, as a result of energy-efficiency measures that are put in place in most parts of the world. In 2020, OECD+ countries contribute more than one-third of this reduction, Other Major Economies almost one-half and Other Countries the remainder. In 2030, these shares change respectively to about one-quarter, one-half and one-quarter.

Lower electricity demand and additional production from newly deployed low-carbon technologies throughout the projection period radically change the fuel mix for power generation in the 450 Scenario compared with the Reference Scenario. The introduction of a carbon price changes both the merit order of existing plants (making the operation of old, inefficient plants uneconomic) and the cost-ranking of new plants (Figure 6.5).

**Figure 6.5 • Average long-run marginal cost (LRMC) of selected power-generation technologies in OECD+, with and without a $CO_2$ price**




Note: The $CO_2$ price used is $50 per tonne in 2020 and $110 per tonne in 2030, consistent with the price under cap-and-trade in OECD+. USC refers to ultra-supercritical steam conditions.

**Table 6.1 • Electricity generation by fuel and region in the 450 Scenario** (TWh)

| | 2007 | | | | 2020 | | | | 2030 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | World | OECD+ | OME | OC | World | OECD+ | OME | OC | World | OECD+ | OME | OC |
| Coal | 8 216 | 4 022 | 3 149 | 1 045 | 9 629 | 3 096 | 4 753 | 1 780 | 7 260 | 1 652 | 3 924 | 1 684 |
| *of which CCS* | 0 | 0 | 0 | 0 | *114* | *96* | *13* | *5* | *1 292* | *902* | *345* | *45* |
| Oil | 1 117 | 443 | 316 | 358 | 621 | 112 | 297 | 212 | 459 | 62 | 244 | 153 |
| Gas | 4 126 | 2 326 | 947 | 853 | 5 396 | 2 649 | 1 427 | 1 319 | 5 688 | 2 775 | 1 640 | 1 273 |
| *of which CCS* | 0 | 0 | 0 | 0 | *28* | *24* | *3* | *0* | *329* | *253* | *73* | *3* |
| Nuclear | 2 719 | 2 311 | 246 | 163 | 3 850 | 2 769 | 797 | 284 | 5 470 | 3 436 | 1 383 | 650 |
| Hydro | 3 078 | 1 284 | 1 060 | 735 | 4 215 | 1 491 | 1 586 | 1 138 | 5 659 | 1 668 | 2 076 | 1 915 |
| Biomass | 259 | 218 | 22 | 19 | 633 | 426 | 119 | 89 | 1 448 | 628 | 453 | 366 |
| Wind onshore | 173 | 150 | 10 | 14 | 1 071 | 674 | 297 | 99 | 2 001 | 1 083 | 594 | 324 |
| Wind offshore | 0 | 0 | 0 | 0 | 252 | 142 | 93 | 17 | 778 | 492 | 219 | 67 |
| Solar photovoltaics | 4 | 4 | 0 | 0 | 144 | 105 | 22 | 17 | 525 | 257 | 143 | 125 |
| Concentrating solar power | 1 | 1 | 0 | 0 | 62 | 22 | 18 | 21 | 325 | 124 | 109 | 92 |
| Geothermal | 62 | 40 | 0 | 21 | 127 | 74 | 8 | 45 | 292 | 134 | 31 | 127 |
| Tide and wave | 1 | 1 | 0 | 0 | 3 | 3 | 0 | 0 | 34 | 33 | 1 | 1 |
| **Total** | **19 756** | **10 798** | **5 750** | **3 207** | **26 003** | **11 565** | **9 418** | **5 020** | **29 939** | **12 344** | **10 817** | **6 778** |

Note: Since solar energy is difficult to monitor on a national level, historical electricity generation in 2007 is likely an underestimation. Data collection, measuring and monitoring issues for solar energy are discussed in IEA (2009a).

By 2030, global electricity production from low-carbon sources reaches around 60% of the global total (Table 6.1). This represents a step-change from the Reference Scenario, in which the ratios are one-third from low-emitting sources and two-thirds from fossil fuels. In OECD+ countries, higher $CO_2$ prices lead to about three-quarters of the total generation coming from nuclear, renewables and CCS plants.

In the 450 Scenario, electricity production from non-hydro renewable sources increases the fastest, with wind increasing at an average annual growth rate of 12.8% throughout the projection period, solar photovoltaics at 23.5%, concentrating solar power at over 30%, biomass at 7.8% and geothermal at 7%. Electricity production from hydro plants increases more, in absolute terms, than production from all other renewable sources. By 2030, 19% of the global electricity demand comes from hydro, 9% from wind, 5% from biomass and 4% from other renewable sources. Production from nuclear plants increases at an annual average growth rate of 3%, meeting 18% of global electricity demand, while CCS plants, which are deployed mainly after 2020, satisfy 5.4% of global demand for power in 2030.

### *Regional trends*

In the *United States*, lower electricity demand reduces generation from coal marginally by 2015, while generation from gas falls more, as the gradual increase of the $CO_2$ price is still insufficient to make it economically convenient to move away from coal (Figure 6.6a). After 2015, as the $CO_2$ price continues to increase, fewer coal plants are added and the least efficient coal plants are mothballed or retired. A substantial amount of coal-fired generation is replaced by gas-fired generation from existing plants, as well as by increased renewables and nuclear generation. By 2025, with $CO_2$ prices going beyond $50 per tonne, about 30 GW of nuclear plant additions have been built, replacing substantial numbers of coal plants (which are mothballed or retired) and efficient gas plants see a steady increase in their utilisation rate. Non-hydro renewable sources are widely deployed throughout the whole projection period, increasing generation from this source almost five-fold over the 2010 levels. These renewable plants, together with larger numbers of CCS plants (around 95 GW), lead to the sharp drop in $CO_2$ intensity in the power sector after 2025. By 2030, electricity generation from renewable sources accounts for 26% of the total, nuclear for 25%, gas without CCS for 24%, CCS plants for 15% (almost 90% of which is coal-based) and coal without CCS only 10%.

In the *European Union*, where the $CO_2$ price already in place gradually converges to the level for OECD+ countries as a whole by 2020, the adoption of lower carbon-emitting technologies is accelerated relative to other countries and regions (Figure 6.6b). Renewable sources account for most of the increase in electricity demand and contribute to displacing generation from coal-fired plants, which are mothballed or retired. Wind alone accounts for 20% of electricity generation by 2030. Nuclear also contributes to the shift towards low-emitting technologies, with an increase of more than 50% with respect to the Reference Scenario by 2030, and corresponding to an increase of around 20% over 2007 levels. Generation from gas-fired plants increases until 2025, as it replaces generation from coal-fired plants, before dropping back in 2030 to the levels seen in the early 2010s. Generation from CCS plants accounts for 6% of the total generation in 2030.

In *Japan*, relative to the Reference Scenario the fuel generation mix remains essentially unchanged until 2015, with small quantities of coal and gas generation displaced by nuclear and renewable sources (Figure 6.6c). Afterwards, and until shortly after 2020, wider deployment of nuclear and renewable plants reduces the use of gas in existing plants and the construction of new gas plants. There is a similar, but marginal, effect on coal units. Electricity generation from nuclear and renewables plants meets most of the increase in demand during the last decade of the projection period and accounts for about two-thirds of the total generation in 2030. This is essentially due to the increasing $CO_2$ price that brings about the swift reduction of electricity generation from coal plants to about 20% of the 2007 level, with gas generation increasing almost back to the levels of the Reference Scenario by 2030.

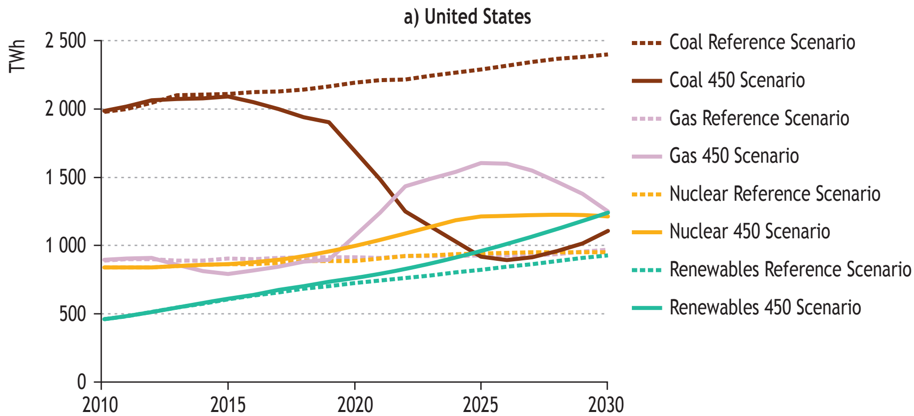
6

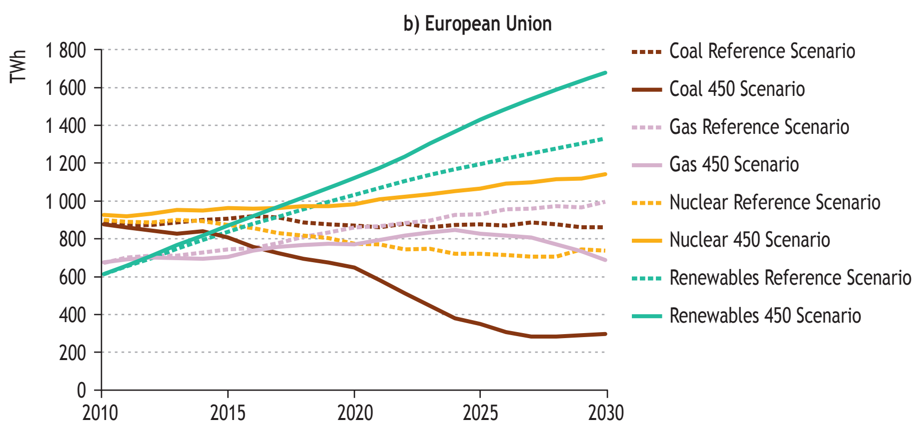
Following *China*'s 11th Five-Year National Social and Economic Development Programme and in the 12th Programme (to 2015) currently under discussion, there are two main drivers for the change in the fuel mix by 2020: a drop of 7% in electricity demand compared with the Reference Scenario and adoption of the target of ensuring that 16% of installed capacity is made up of wind, nuclear and solar (Figure 6.6d). Meeting this target, together with a growing share of hydro, brings the share of renewables and nuclear in 2020 from 21% in the Reference Scenario to 30% in the 450 Scenario, with the coal share dropping from 76% to 68%, respectively. The assumed introduction of a cap-and-trade system for $CO_2$ emissions in Other Major Economies after 2020 leads to a 20% reduction of electricity demand in China, relative to the Reference Scenario, by 2030. Coupling this lower demand with a further push towards low-carbon technologies, the share of the nuclear and renewable sources continues to increase steadily, reaching 47% of the total electricity production by 2030. At the end of the projection period, total generation from coal without CCS drops to 46% from today's 81%.

Electricity production from coal-fired plants in *India* is reduced by around 12% by 2020, compared with the Reference Scenario (Figure 6.6e). Half of the reduction results from lower electricity demand and the other half from a shift towards higher production from renewable sources, mainly hydro and wind power, which increase by 24% and 40%, respectively, relative to the Reference Scenario. By 2030, further demand-side efficiency improvements, more deployment of renewable sources and increased nuclear generation reduce coal-fired power generation to about half the level of the Reference Scenario. However, coal-fired capacity increases by three-quarters with respect to 2007. In 2030, the share of total electricity generation from hydro expands to 22%, wind to 6% and nuclear to 11%, to substitute for reduced growth in electricity production from coal-fired plants.

By 2020, coal-fired electricity generation in *Russia* decreases by about one-sixth with respect to the Reference Scenario (Figure 6.6f). This results from a 50% fall in the build of new capacity, due to energy-efficiency gains on the demand side, and slightly increased

**Figure 6.6 • Electricity generation by type for selected countries in the Reference and 450 Scenarios**



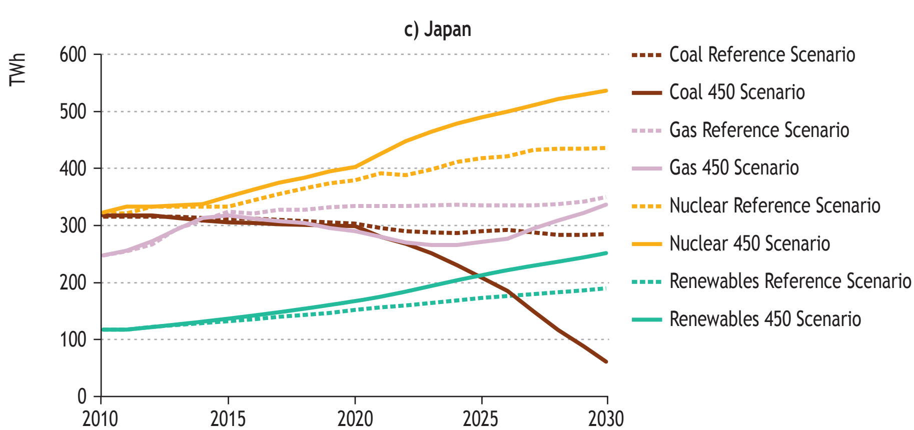
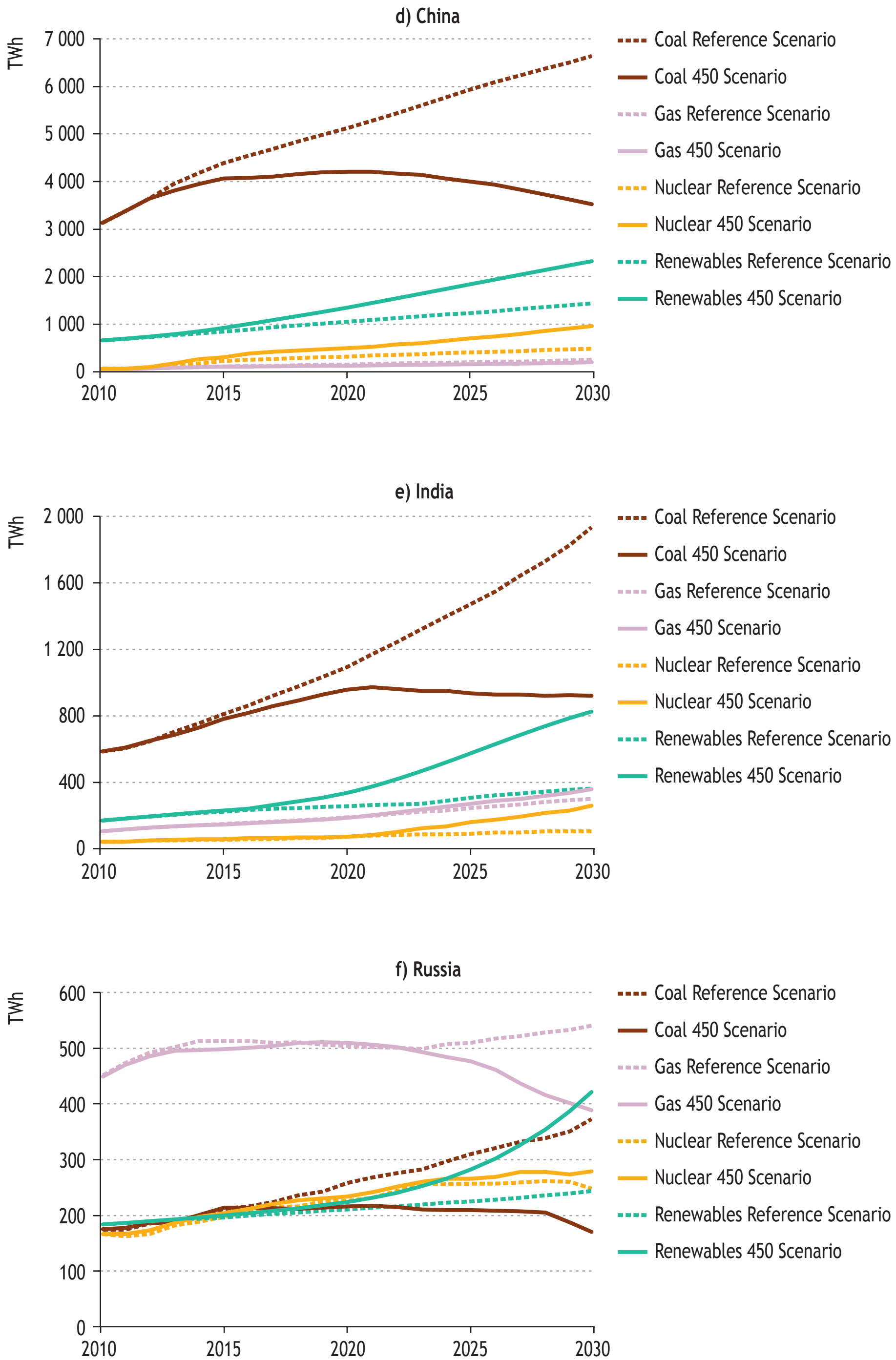



**Figure 6.6 • Electricity generation by type for selected countries in the Reference and 450 Scenarios** (continued)



generation from existing plants, principally nuclear and hydro. Following the assumed introduction of a cap-and-trade system for $CO_2$ emissions in Other Major Economies after 2020, the push to roll-out low-emitting technologies becomes more pronounced. Hydro, wind and biomass resources are then deployed at a much faster rate than in previous years, bringing the share of power generated from renewable sources to 33% by 2030, up 15 percentage points compared with 2007. Nuclear is also further developed, reaching 22% of the mix in 2030, up from the current 16%, while CCS amounts to a further 6%. These low-emitting capacity additions result in generation from coal and gas plants without CCS decreasing by 2030 to less than 40% of total generation, compared with 64% in the Reference Scenario and 65% today.

## Capacity additions

At the global level, total capacity additions in the 450 Scenario are very similar to the Reference Scenario, even though the electricity demand is 13% lower. This is mainly due to the mothballing and retirement of fossil-fuel plants and the large-scale shift to renewables, with their typically lower overall utilisation rates. Globally, renewable and nuclear additions are less than 50% of total additions through to 2020, yet in the following decade this rises to nearly 75% (Table 6.2). Much of this additional capacity is wind and solar power, in which the availability of generation is much lower than in the equivalent thermal capacity. Consequently, more capacity is needed.

**Table 6.2 • Capacity additions by fuel and region in the 450 Scenario** (GW)

| | 2008-2020 | | | | 2021-2030 | | | |
|---|---|---|---|---|---|---|---|---|
| | World | OECD+ | OME | OC | World | OECD+ | OME | OC |
| Coal | 640 | 114 | 353 | 172 | 315 | 119 | 145 | 51 |
| *of which CCS* | *15* | *13* | *2* | *0* | *167* | *112* | *48* | *7* |
| Oil | 39 | 7 | 20 | 13 | 13 | 3 | 8 | 1 |
| Gas | 517 | 178 | 193 | 146 | 347 | 134 | 123 | 90 |
| *of which CCS* | *4* | *3* | *1* | *0* | *46* | *34* | *10* | *1* |
| Nuclear | 134 | 51 | 68 | 16 | 244 | 117 | 80 | 47 |
| Hydro | 376 | 82 | 168 | 126 | 456 | 68 | 151 | 238 |
| Biomass | 84 | 53 | 19 | 12 | 153 | 48 | 60 | 46 |
| Wind onshore | 399 | 237 | 129 | 33 | 535 | 281 | 151 | 103 |
| Wind offshore | 64 | 36 | 23 | 4 | 131 | 87 | 31 | 13 |
| Solar photovoltaics | 108 | 86 | 13 | 10 | 286 | 147 | 73 | 66 |
| Concentrating solar power | 20 | 8 | 6 | 6 | 88 | 40 | 27 | 21 |
| Geothermal | 9 | 5 | 1 | 3 | 23 | 8 | 3 | 12 |
| Tidal and wave | 1 | 1 | 0 | 0 | 8 | 8 | 0 | 0 |
| **Total** | **2 391** | **858** | **992** | **541** | **2 601** | **1 060** | **853** | **688** |

Over the projection period, wind (onshore and offshore) accounts for 23% of total capacity additions, higher than coal (19%) and gas (17%). Solar photovoltaics and concentrating solar power also play an important role, with capacity additions almost doubling in the 450 Scenario compared to the Reference Scenario. Similarly, nuclear sees rapid growth, subject to means being found to finance the up-front investment required, overcoming constraints on the ability to ramp-up production of major specialised components, and increasing the production capacity of the uranium mining industry.

In OECD+, coal capacity additions are similar in both the period to 2020 and the subsequent decade, although in the latter period more than 90% of these additions incorporate CCS, compared with just over 10% in the previous period. Coal capacity additions between 2020 and 2030 in Other Major Economies and Other Countries drop to around one-third of those made during the previous decade. CCS is incorporated in around one-quarter of new coal installations completed during the last decade of the projection period.

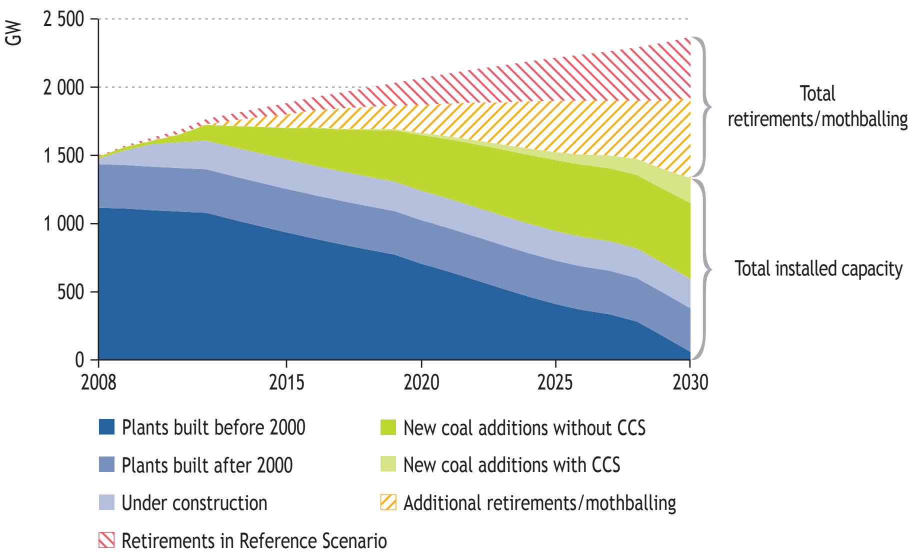
### Mothballed and decommissioned plants

In the electricity industry, the operational lifetime of assets is typically long, often over 50 years. Owners count on this period to recover their investment and an adequate return on it. But if operational costs increase faster than expected (for example, as a result of increasing fuel costs or emission charges), older, less-efficient thermal plants become uncompetitive and have to be mothballed or decommissioned sooner.



By 2030, our analysis shows that an additional 585 GW of coal plants are mothballed or retired in the 450 Scenario, over and above the 450 GW retired in the Reference Scenario (Figure 6.7). This equates to almost three-quarters of the entire installed coal plant capacity today. In addition to the plants currently under construction, plants built since 2000 remain in operation through to the end of the *Outlook* period. Older plants are mothballed or retired as they become progressively uneconomic to operate, mainly due to rising $CO_2$ prices. The majority of the plants built before 2000 that remain in operation in 2030 are in Other Countries, where only plants older than 45 years are retired.

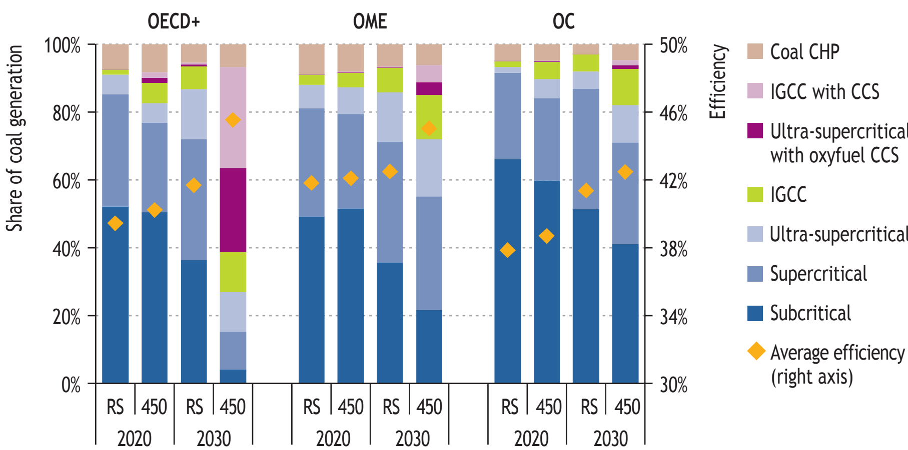
**Figure 6.7 • *World installed coal capacity and retirements/mothballing in the 450 Scenario***



Both the 450 and Reference Scenarios show an increase in overall coal plant efficiency as a result of technology improvements and the retirement of old and less-efficient plants (Figure 6.8). This is more evident in the 450 Scenario, as older plants are mothballed or decommissioned earlier and there is a greater uptake of newer, more efficient plants.

There is a marked shift away from subcritical plants in all regions, but nowhere more so than in OECD+ where subcritical plants that make up 50% of the coal-fired generation in 2020, drop to less than 5% in 2030, bringing the average efficiency of coal plants steadily higher. The subcritical plants are displaced by lower carbon-emitting technologies (such as nuclear or renewables) or by plants using more efficient coal technologies, such as high pressure and high temperature ultra-supercritical plants or integrated gasification combined cycle (IGCC) plants. By 2030, over 50% of coal-fired generation in OECD+ comes from plants fitted with CCS facilities.

**Figure 6.8 • *Regional coal-fired electricity generation by plant type and scenario***




The retirement of old, inefficient thermal plants achieves a decrease in thermal inputs per unit of generation. In the short term, stemming from the demand effect of the financial crisis, there is a temporary increase in overall efficiency of thermal plants as many older less efficient plants are shut down. However, as demand recovers and these plants return to operation, we see the efficiencies of thermal plants drop back to similar levels or slightly higher than before the crisis.

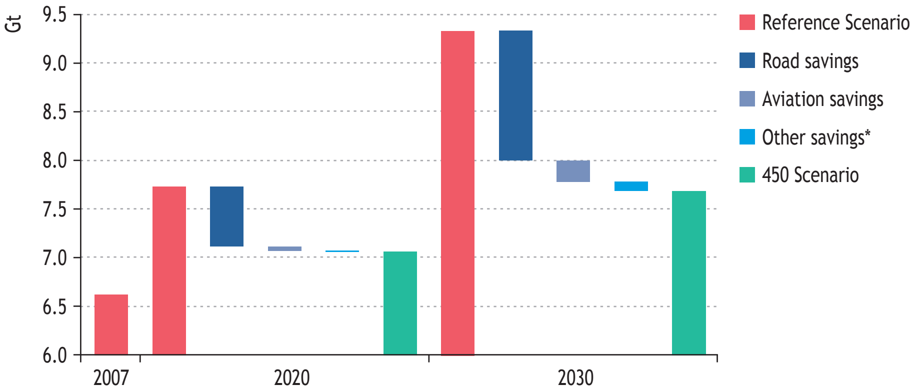
## Transport

The transport sector provides a very clear example of the complementarity between climate change policy and energy-security policy. Increasing efficiency and diversifying the fuel mix address the over-arching challenges by both cutting transportation $CO_2$ emissions and reducing oil imports (in importing countries) – and thus improving energy security.

## $CO_2$ trends

The combination of international sectoral agreements and national policies and measures sees the transportation sector reduce its $CO_2$ emissions by about 670 Mt (or 9%) by 2020 and by 1.6 Gt (or 18%) by 2030, compared with the Reference Scenario, with total emissions reaching 7.1 Gt in 2020 and 7.7 Gt in 2030 (Figure 6.9). Net savings are seen in all transport modes except rail, where the shift from road and aviation outweighs savings from rail efficiency improvements through the *Outlook* period.

**Figure 6.9 • Energy-related $CO_2$ emission reductions in transport by sub-sector in the 450 Scenario compared with the Reference Scenario**




*Includes rail, pipeline, domestic navigation, international marine bunkers and other non-specified transport.

## Road transport

Most of the $CO_2$ savings occur in road transport due to a combination of more efficient petroleum-powered vehicles, increased biofuels consumption and the penetration into the passenger car fleet of more advanced plug-in hybrid and pure electric vehicles. Globally, the average on-road $CO_2$ emissions of passenger light-duty vehicles (PLDVs) sales[1] reaches 125 grammes per kilometre ($gCO_2$/km) in 2020, a decrease of 28% from the Reference Scenario and a 40% decrease from today's level. Further improvements to the efficiency of internal combustion engine (ICE) vehicles and moving to more advanced electricity powered vehicles reduces the average $CO_2$ emissions of a vehicle sold in 2030 to 90 $gCO_2$/km.[2] Road transport accounts for 92% of total transport savings by 2020 (or 610 Mt) and 81% by 2030 (or 1.3 Gt), when PLDVs account for more than 60% of total road-transport savings. Most of these savings, however, are offset by the strong growth in transportation demand in non-OECD countries. As a result, total emissions from transport continue to rise through to 2030.

1. On-road emissions of new vehicles sold in that year, not the average of the stock of all vehicles.
2. This value includes the effect of biofuels.

**Box 6.2 ● The policy framework for the transport sector in the 450 Scenario**

As in *WEO-2008* the policy framework assumed in *WEO-2009* includes international sectoral agreements in the PLDV sector and aviation (both domestic and international), which provide for $CO_2$ emission limits to decrease year-on-year. These are complemented by national policies and measures in the other segments of the transport sector.

The assumption of a sectoral agreement was made because the PLDV and aviation sectors are dominated by several international companies using homogenous technology. The assumed approach is similar to existing regulations on PLDVs in the European Union and the United States, which obtain ongoing improvements in the efficiency of new vehicles through targets on either $CO_2$ emissions or fuel consumption.

The sectoral targets for PLDVs relate to new vehicles rather than the PLDV stock as a whole. Accounting for biofuels consumption, they are on-road efficiency targets[3] and do not assume significant consumer behavioural changes. The $CO_2$ targets in 2030 for OECD+ (80 $gCO_2$/km), Other Major Economies (90 $gCO_2$/km) and Other Countries (110 $gCO_2$/km) are averages for each region, not upper limits for each country in the region. All targets are marked improvements on the current global average of almost 210 $gCO_2$/km and take into account current fleet efficiency and region-specific factors.

In terms of heavy-duty vehicles (HDVs),[4] it is assumed that technology spillover from the PLDV fleet will result in ongoing efficiency improvements to internal combustion engines. These gains are not as pronounced as in the PLDV fleet: there is less room for improvement, given that efficiency has long been a more important purchasing criterion in the HDV segment.

It is assumed that retail fuel prices are the same in the 450 Scenario as in the Reference Scenario, on the grounds that lower international oil prices resulting from lower demand are offset by higher end-use taxes, to minimise the rebound effect. A sectoral agreement is particularly suited to aviation due to the very limited number of aircraft manufacturers present in the market and the very global nature of aircraft sales. In the 450 Scenario, we assume the global aviation fleet improves its average fuel consumption from 4.6 litres per 100 revenue passenger kilometres (RPK) to 2.6 litres per 100 RPK in 2030, a 45% increase over today's levels.[5]

Globally, the PLDV fleet increases in efficiency by 38% in 2030 relative to the Reference Scenario, as a result of further improvements to gasoline and diesel internal combustion engines, non-engine improvements to auxiliary systems (*i.e.* lighting and air conditioning) and tyres, and the increased market penetration of more advanced engine technologies, such as plug-in hybrids and electric vehicles. By 2020 only 52% of sales are of vehicles with conventional internal combustion engines and this figure declines to 42% by 2030 (Figure 6.10). Hybrid vehicles are very important for short-term emission reductions,

3. Corresponding test cycle targets would be at least 20% more stringent.

4. HDVs correspond to trucks, buses and light commercial vehicles in this analysis.

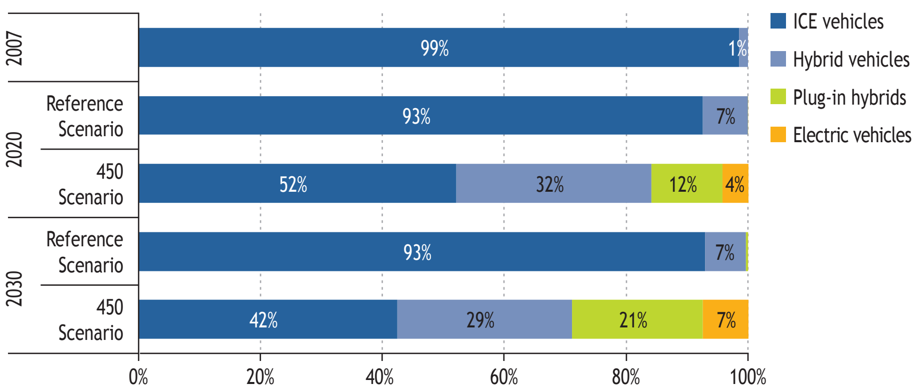
5. Revenue passenger kilometres is a common aviation industry measure of demand.

accounting for 32% of all sales by 2020 in the 450 Scenario. This share is undoubtedly ambitious: it illustrates the extent of the challenge for road transport in the 450 Scenario. In the period after 2020, as plug-in hybrids and electric cars become more available, the share of hybrids declines, reaching 29% of sales by 2030; however, this is still an increase in absolute terms of about 7 million vehicles in 2030 with respect to 2020.

Some of the technology improvements in the PLDV fleet that are driven by the assumed international sectoral agreement partially flow over to the HDV fleet and help to offset the projected increase in demand for freight through the *Outlook* period. By 2030, HDVs account for almost 40% of road-transport emission savings. The global average HDV fleet is 20% more efficient by 2020, achieving a $CO_2$ emissions reduction from an estimated 340 $gCO_2$/km in 2007 to 270 $gCO_2$/km in 2020, and 227 $gCO_2$/km in 2030 (reaching a 34% improvement in efficiency from today). Savings come from both engine and non-engine vehicle efficiency improvements, increased biofuels consumption, modal shift to rail and more efficient logistics. The latter, *e.g.* increased load factors, reduction of empty runs and better driver training, come at low or negative costs.



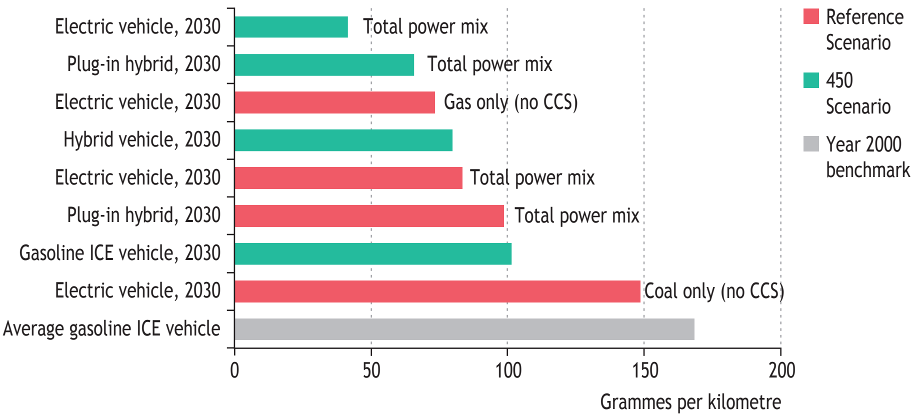
**Figure 6.10 • *Share of global passenger vehicle sales by engine technology and scenario***




Increases in electricity consumption in road transport due to rapid penetration of plug-in hybrids and electric vehicles, and to a lesser extent increased electricity-powered rail transportation, sees transport sector $CO_2$ savings partially offset by power generation emissions. An increase of 880 TWh of electricity consumption in transport in 2030, compared with the Reference Scenario, of which 90% occurs in PLDVs, results in about 250 Mt of additional $CO_2$ emissions.

The increased use of electricity in road transport is a good example of the challenges associated with the 450 Scenario. Higher market shares for electric vehicles and plug-in hybrids are desirable for reaching climate policy targets, but are insufficient if they are not accompanied by the decarbonisation of the power sector. Well-to-wheel $CO_2$ emissions per kilometre from future hybrid vehicles are lower than those of plug-in hybrids and electric cars if the electricity consumed is produced using the global power generation mix from the Reference Scenario. However, the same hybrid vehicle emits twice as much $CO_2$ per kilometre than an electric car powered by the less $CO_2$-intensive 450 Scenario power generation fuel mix (Figure 6.11). Reaching climate goals requires a holistic view of the entire energy system and cross-sectoral approaches leading to savings in every sector.

**Figure 6.11 • $CO_2$ emissions per kilometre by vehicle type and scenario**




Note: Results are indicative and may differ depending on each country fuel mix (transmission and distribution losses are not included for similar reasons).

**Box 6.3 • Fuel-pricing policy and its impact on the sectoral agreement**

Although the transport sector is recognised as being relatively more inelastic than other sectors, oil price fluctuations do impact oil demand in transport. When the oil price rises, oil consumption drops as people drive less; but when the oil price comes back down there is a tendency for people to drive more again. This rebound effect from oil price fluctuations is a well-documented phenomenon in transport. More efficient vehicles also mean it costs less to drive each kilometre, tempting drivers to drive more kilometres per year. Thus, there can be an increase in travel that partially offsets the $CO_2$ savings from efficiency improvements and the move to more advanced engine technologies.

Despite lower international oil prices, the 450 Scenario assumes end-user fuel prices are kept unchanged, compared with the Reference Scenario, as a deliberate move by governments to contain such rebound effects. A sensitivity analysis has been performed to assess the effects of a fall in the global oil price to \$90 per barrel in the 450 Scenario in 2030, down from \$115 in the Reference Scenario, if no such countervailing action were taken. This shows that global oil demand in 2030 would rebound by 3.1 mb/d, offsetting one-quarter of the oil savings achieved by the implementation of the sectoral agreements for PLDVs and aviation (described below) and, as a result, global $CO_2$ emissions would be 0.45 Gt higher. So long as conventional vehicles continue to make up a substantial part of the PLDV fleet, lower oil prices will tend in this way to counteract efforts to reduce $CO_2$ emissions from road transport and offset efficiency gains.

Setting efficiency targets and giving "feebates" (*i.e.* subsidies on the purchase of low-emission cars) are not enough to achieve climate goals in road transport. A holistic approach is required that also targets oil fuel pricing, particularly the subsidies on oil products that have persisted in some countries. China has adopted a new pricing mechanism to allow end-use prices to reflect more closely international oil prices. As a result, transport fuel prices have been adjusted six times by the first half of 2009. India increased prices by 10% in mid 2009. Several other developing countries slashed subsidies, due to the mounting fiscal burden they were creating throughout 2008, but then reversed the subsidy cuts once the oil price moved off its peak.



### Aviation and maritime

*Aviation* emissions, despite the assumption in the 450 Scenario that international sectoral agreements are reached, rise by 13% between now and 2020, and by 15% by 2030, reaching 0.85 Gt. Nonetheless, aviation is the second-largest contributor to $CO_2$ emission reductions in the transport sector, and its share in emission savings, relative to the Reference Scenario, is 6.6% by 2020 (44 Mt) and 13.2% by 2030 (217 Mt). The savings are achieved via international sectoral agreements that encourage increased biofuels consumption and additional implementation of a mixture of technical, operational and infrastructure measures. Technical and equipment measures include installation of wingtips, measures to reduce drag, early aircraft retirements, engine retrofits and upgrades. Operational measures cover fuel-management techniques, other pilot techniques and weight reductions. Savings from improvements in infrastructure come from redesigned flight paths (including the use of military airspace) and more efficient traffic control. The implementation of efficiency improvements provides half of the savings in 2030.

The other half of the savings come from second- and third-generation biofuels. The American Society for Testing and Materials (ASTM) International Aviation Fuels Sub-committee passed a new aviation fuel specification in July 2009, permitting the use of synthetic and renewable fuels in aviation. However, the remaining technical hurdles and problems of production on a sufficient scale see aviation biofuels appearing in the market only around 2020, with volumes reaching 42 million tonnes oil equivalent (Mtoe) globally by 2030 at a global blending ratio of 15%. Regions that have already supported first- and second-generation biofuels increase biofuel consumption compared with the Reference Scenario. For example, in the United States, emission savings of 15 Mt are achieved in 2030 from efficiency measures and a further 46 Mt from biofuels.

$CO_2$ emission savings in *international shipping and domestic navigation* come from improved hydrodynamics, ship hull coatings that reduce the need for cleaning, increased motor efficiency, installation of sails and speed reductions. Reducing the speed of ships can provide large $CO_2$ savings; for example, if a tanker decreases its average speed from 15.5 knots to 13.5 knots, it can reduce fuel consumption by one-third.[6] Combined technical and operational measures have been estimated to have the potential to reduce $CO_2$ emissions by up to 43% per tonne-kilometre by 2020 (Crist, 2009). Assuming partial implementation of these national measures sees emissions from shipping reduced by 4 Mt in 2020 and 84 Mt in 2030, accounting for 5% of total transport $CO_2$ savings. However, these projections are highly dependant on the historical data for $CO_2$ emissions from international shipping, which are disputed (IEA, 2009b). Activity-based measurements give vastly different results compared with fuel-based statistics, ranging from 0.8 Gt to 1.2 Gt (IMO, 2008). With the increasing prominence of international shipping in climate discussions, much work is urgently needed to improve the data to enable informed decision making.

## *Energy trends and fuel mix*

The current economic downtown has led to a significant drop in global PLDV sales, causing stagnation in the global vehicle fleet, and also a decrease in kilometres driven per vehicle and flown per aircraft. The result of this is already seen in the large drop in 2008 energy consumption. For example the United States, which was hit particularly hard by the global recession, shows decreases of 6.0% in 2008 gasoline demand relative to 2007, 8.7% for diesel and 5.6% for aviation jet fuel. The effects of the global recession are expected to persist, leaving transport energy demand below pre-recession levels for some years.

But the recession has also had a silver lining: a considerable amount of stimulus package funding for major automobile producers has been directed towards manufacturing more efficient vehicles. In both the Reference and 450 Scenarios, global PLDV fleet efficiency is projected to be higher in the long run than compared with pre-crisis projections.

Total oil consumption in the 450 Scenario is 542 Mtoe (or 12 mb/d) lower than in the Reference Scenario by 2030 (Table 6.3). Most of the oil savings occur in road vehicles, accounting for 82% of transport-sector oil savings compared with the Reference Scenario. Biofuels consumption increases to 123 Mtoe in 2020 and 278 Mtoe in 2030, an increase of 145 Mtoe in 2030 relative to the Reference Scenario. Most of the increase comes from second-generation biofuels, such as ligno-cellulosic ethanol and Fischer-Tropsch fuels, in both road and aviation sectors. Second-generation biofuels are expected to become cheaper than most first-generation biofuels in the medium-to-long term, and to be sourced from sustainably grown biomass. Biofuels represent 7% of road-transport fuel in 2020 and 11% in 2030. They make up almost 15% of aviation fuel in 2030.

6. Information provided by Gibson Shipbrokers Ltd.

The use of electricity by plug-in hybrid and electric cars increases to about 350 TWh in 2020 and 835 TWh in 2030, up from only about 40 TWh in the Reference Scenario. This projected increase in electricity consumption in transport entails significant additions to global electricity capacity. Assuming all this increase was to be covered by wind power only, it would equate to an additional 350 GW of wind turbine installations; if all the increase in demand was to be covered by nuclear power only, it would require an additional 115 GW of nuclear power plants. The additional electricity demand in transport offsets about 20% of electricity demand reductions in other end-use sectors in 2030.[7]

**Table 6.3 • World transport energy consumption by fuel and energy-related $CO_2$ emissions in the 450 Scenario**

| | | | | Change versus Reference Scenario | | |
|---|---|---|---|---|---|---|
| | 2007 | 2020 | 2030 | 2020 | 2030 | 2007-2030* |
| **Total (Mtoe)** | **2 297** | **2 574** | **2 994** | **-6%** | **-10%** | **1.2** |
| Oil | 2 161 | 2 306 | 2 510 | -9% | -18% | 0.7 |
| Gas | 75 | 77 | 82 | -11% | -15% | 0.4 |
| Electricity | 23 | 65 | 122 | 83% | 165% | 7.5 |
| Biofuels | 34 | 123 | 278 | 19% | 109% | 9.5 |
| Other | 4 | 3 | 3 | -9% | -19% | -0.9 |
| **$CO_2$ emissions (Mt)** | **6 623** | **7 066** | **7 688** | **-9%** | **-18%** | **0.7** |

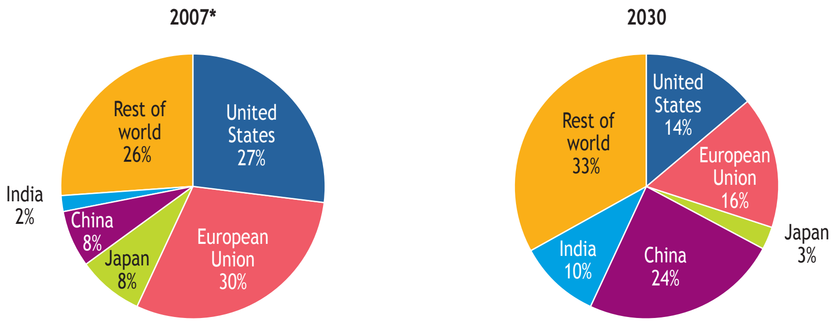
* Compound average annual growth rate.

## Regional trends

The global PLDV fleet is projected to increase to 1.4 billion vehicles by 2030. Most of this growth occurs in Other Major Economies and Other Countries. The Chinese fleet is anticipated to approach that of the United States by around 2030, at which time the Chinese market is projected to represent 24% of global sales (Figure 6.12). By the year 2030, the US and Chinese PLDV fleets combined make up 37% of the global total: in the Reference Scenario in 2030, these fleets are responsible for 36% of global road $CO_2$ emissions, despite recent policy efforts in both countries to encourage the mass uptake of fuel-efficient vehicles. Given the size of the US and Chinese fleets, it has been assumed in the 450 Scenario that these regions, along with Japan and Europe, become leaders in the adoption of advanced vehicle technologies and alternative fuels for road transport.

7. This analysis does not account for the possible savings that could be made through off-peak charging and the potential storage benefits of vehicle-to-grid systems.

**Figure 6.12** • ***Share of global PLDV sales in 2007 and 2030 in the Reference and 450 Scenarios***




* IEA estimate.

The move away from oil in transport-energy provision in the 450 Scenario varies in form according to geographical circumstances. For example, the penetration of electric vehicles in Brazil is expected to lag behind other regions, not for technological reasons but because the biofuels alternative is already cost competitive. The Brazilian PLDV fleet already meets the 2030 target for Other Major Economies and with further use of biofuels and natural fleet efficiency improvements, Brazil's emissions are significantly lower than the global average. Regions that have only limited scope for sustainably grown and affordable biomass are expected to favour the introduction of plug-in hybrids and electric vehicles rather than biofuels. Densely populated urban areas, including those in the United States, China and the European Union, could favour the introduction of electric cars in order to simultaneously reduce local pollutants.

As a result of these policy assumptions and the cost-optimisation model applied for this analysis, road-transport oil consumption is significantly reduced in OECD+ countries, to about 780 Mtoe by 2030 compared with 1 010 Mtoe in the Reference Scenario. Biofuels consumption increases to 133 Mtoe, which is an 84% increase compared with the Reference Scenario. Most of this growth comes from a four-fold increase in the use of second-generation biofuels, relative to the Reference Scenario. Electricity consumption in road transport rises to about 390 TWh, up from 4 TWh in the Reference Scenario in 2030.

In Other Major Economies and Other Countries, most of the efficiency improvements as a result of the assumed sectoral policy framework are offset by the growth of the vehicle fleet. Nevertheless, oil consumption is reduced by about 16% in both regions compared to the Reference Scenario, reaching 628 Mtoe in Other Major Economies and 467 Mtoe in Other Countries, respectively, in 2030.

The type of PLDVs sold in the 450 Scenario changes significantly from the Reference Scenario, but there are important regional differences in the changes. The United States, with its aggressive biofuels targets under the Renewable Fuel Standard, is expected to see strong growth in second-generation biofuels, which in turn reduces the need for change in other areas to meet the sectoral target. In contrast, China relies more heavily on plug-in hybrid and electric cars (Figure 6.14).

**Figure 6.13 • Regional fuel consumption in road transport by fuel type and scenario**

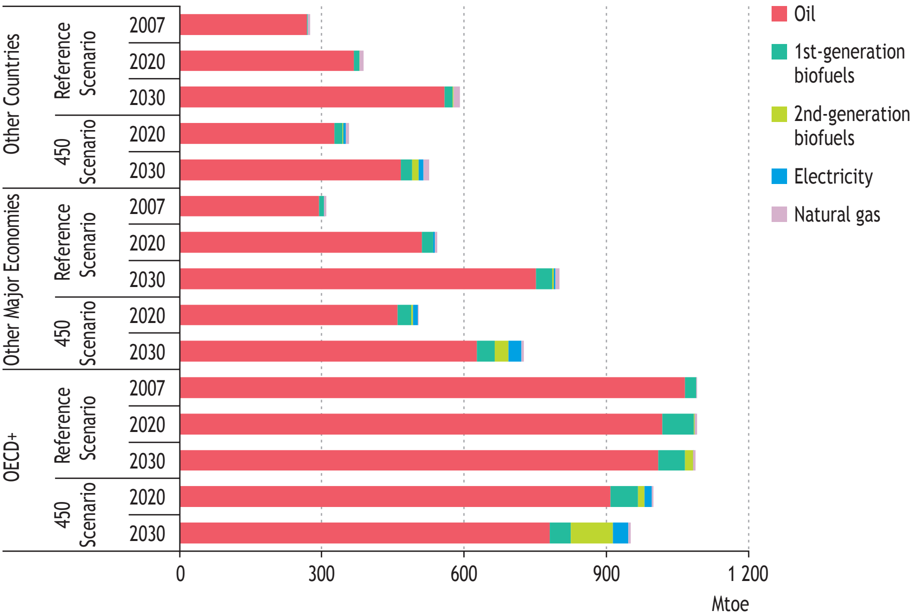
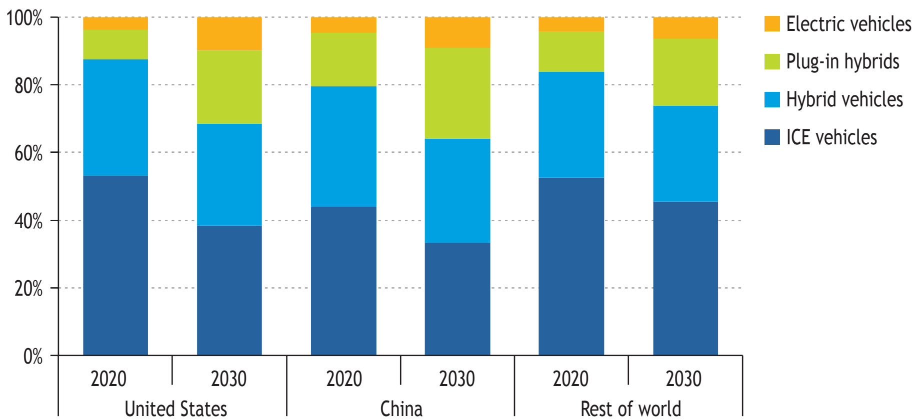



**Figure 6.14 • Share of PLDV sales by vehicle type for selected regions in the 450 Scenario**




## Implications for technology deployment

The 450 Scenario involves a shift from internal combustion engine vehicles to hybrids, then to plug-in hybrids and to electric cars. It is possible that this could be followed by a further transition to hybridised fuel cell vehicles (FCVs) after 2030. Such an evolution requires many complementary technological developments, and there is significant potential for technology spillover between PLDVs and HDVs.

Improvements to the non-engine components of PLDVs, which could increase fuel efficiency by up to 17% compared with a conventional car sold in the year 2000, would benefit all types of cars. There are further cross-benefits from efficiency improvements in internal combustion engines, which are used not only by fuel-powered vehicles, but also in hybrids and plug-in hybrids. The same applies to battery technology development for hybrids (both mild and plug-ins), electric cars and FCVs. Technology developments flow across the technology mix, making it unnecessary to pick a single, favoured technology. The scale of the challenge associated with such a fuel and engine technology transition should not be underestimated, as it represents a radical departure from historical trends and will require significant policy support and appropriate pricing signals (Box 6.3).

Increased biofuel consumption is expected to arise initially from wider adoption of first-generation biofuels, in particular sugar cane ethanol, provided dedicated energy crops can be grown in a sustainable and affordable manner. But it also requires significant research and development directed towards second-generation biofuels and their ultimate adoption on a large scale. The most promising second-generation biofuel options, such as ligno-cellulosic ethanol and Fischer-Tropsch diesel for road transport and algae-based aviation jet-fuel, are yet to be proven on a commercial scale. Remaining challenges include scaling-up production facilities and improving the economics in terms of producing and transporting the feedstock.

### *Implications for transport industry structure and policy*

The decade from 2010 to 2020 is a key period of transition for the transport sector in the 450 Scenario. The need for policy support is illustrated by the example of hybrid cars: the leading manufacturer (Toyota) has, despite much public attention, only sold about 2 million units over the last decade, well short of the 27 million required in the year 2020 in the 450 Scenario. Announcements by several car manufacturers that they will have new models on the road between 2010 and 2015 are very promising. Recent public interest in electric cars has resulted in a number of new business alliances between car manufacturers, power producers and electronics companies, and also new players entering the car market, such as BYD of China.

Market forces alone will not be sufficient to establish a market for electric cars on the scale required. Increased funding for research and development, as well as other forms of policy support, are necessary for electric cars and plug-in hybrids over the coming decade in the 450 Scenario.[8] Additionally, new and innovative solutions towards new business models could play an important role for the private sector. One such example is project Better Place[9] in which consumers purchase miles travelled in an electric vehicle and the electric battery is leased (similar to the way mobile phone users pay for minutes). To make this work requires widespread availability of battery swapping stations. The development of smart grids will aid the widespread deployment of electric cars, as they are mutually beneficial technologies.

8. More details in IEA (forthcoming).

9. www.betterplace.com/

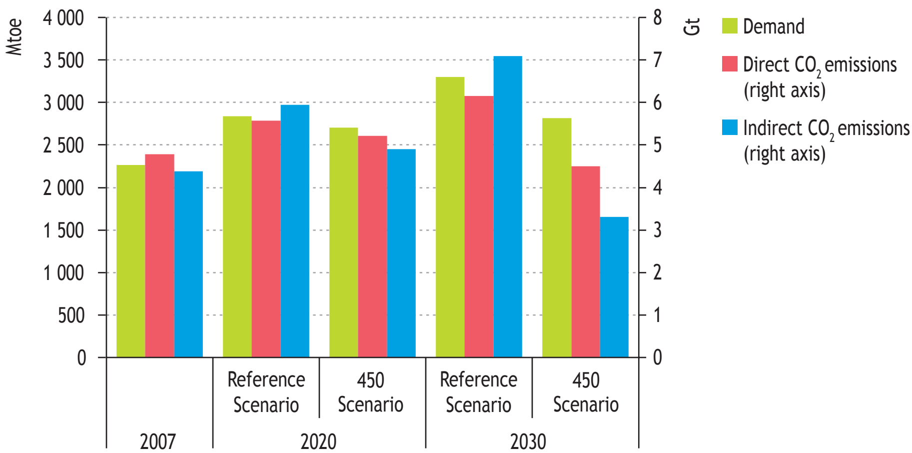
# Industry

Global final energy consumption by industry in the 450 Scenario increases at an average rate of 0.9% per year through to 2030.[10] However, energy-related $CO_2$ emissions from industry peak by 2020 and then start to decline. Compared with the Reference Scenario, the industry sector achieves a bigger energy saving and $CO_2$ reduction in 2030 than any other final energy consumption sector. Global direct $CO_2$ emissions[11] from industry reach 5.2 Gt in 2020 and decline to 4.5 Gt in 2030 – 27% lower than in the Reference Scenario (Figure 6.15).

Despite its increase in absolute terms, industrial energy demand in 2030 is lower than in the Reference Scenario by 486 Mtoe, or 15%. Demand for all fuels except renewables declines relative to the Reference Scenario. In 2030, demand for coal and oil is actually lower than in 2007. Demand for coal is reduced more sharply (28%) than demand for other fuels because the carbon price in OECD+ and Other Major Economies raises the coal price more in percentage terms. Electricity demand in 2030 declines by 17% compared with the Reference Scenario, although it is still 53% higher than in 2007. More energy-efficient motor systems and higher electricity prices lead to the second-largest reduction (after coal) relative to the Reference Scenario, in both absolute and percentage terms.



**Figure 6.15 ● *World industry energy consumption and energy-related $CO_2$ emissions by scenario***




Note: Direct $CO_2$ emissions include only emissions from fossil-fuel combustion. Emissions from coke ovens, blast furnaces and petrochemical feedstocks are included in non-energy use and other energy sector. Indirect $CO_2$ emissions are approximate estimations for electricity and heat consumption.

10. Industry sector energy demand and $CO_2$ emissions are calculated in accordance with IEA energy balance tables, *i.e.* including neither demand/emissions from coke ovens, blast furnaces and petrochemical feedstocks (which appear in the "other energy sector" or "non-energy use sector"), nor process-related $CO_2$ emissions.

11. $CO_2$ emission from fossil-fuel combustion, not including process-related emissions.

**Box 6.4 • The policy framework for the industry sector in the 450 Scenario**

Industry is part of a cap-and-trade system from 2013 in OECD+ and, as of 2021, in Other Major Economies. The carbon prices in OECD+ are \$50 per tonne of $CO_2$ and \$110 per tonne in 2020 and 2030, respectively. The carbon price leads to oil, gas and electricity end-use prices in OECD+ that are 20% to 30% higher overall in 2030, compared with the Reference Scenario. Carbon-rich coal is most affected: its price triples. The carbon price in Other Major Economies reaches \$65 per tonne of $CO_2$ in 2030, leading to higher energy prices in these countries, especially in the Middle East where energy prices today are low. As industry is a relatively price-elastic sector, the $CO_2$ price from the emissions trading scheme (ETS) leads to fast improvements in energy efficiency and to fuel switching towards low-carbon fuels. Other Countries are assumed to implement national policies and measures, but are not involved in the cap-and-trade system. They do, however, benefit from the faster deployment of technology worldwide in the 450 Scenario.

In addition to industry-wide national policies and measures, the iron and steel and cement sectors in all countries are assumed to be covered from 2013 by international sectoral agreements. Under these agreements, these industries in each region are called upon to reduce $CO_2$ intensity by at least as much as the gap between the intensity today and what could be achieved with the deployment of the currently best available technologies. The international sectoral agreements function as complement to the cap-and-trade system and national policies by limiting carbon leakage.[12]

The growth in industrial activity (activity effect) pushes global $CO_2$ emissions up by about 3% per year on average by 2030.[13] In the 450 Scenario, energy intensity[14] declines by 2.0% per year, 0.5 percentage points per year more than in the Reference Scenario. Decarbonisation of the industrial sector takes place at 1.6% per year largely because of fuel switching to renewables and the introduction of CCS. CCS is introduced in the industry sector towards the end of the *Outlook* period, mainly in OECD+. Relatively large potential for CCS implementation exists in blast furnaces in iron and steel production, and in cement kilns. By 2030, CCS reduces emissions in the industry sector by 0.3 Gt, accounting for 19% of the total reduction compared with the Reference Scenario.[15] Realisation of this objective depends on, among other things, the development of appropriate legal and regulatory frameworks, and further research and development to reduce the cost of capture, transport and storage and to improve system efficiency (IEA, 2008a).

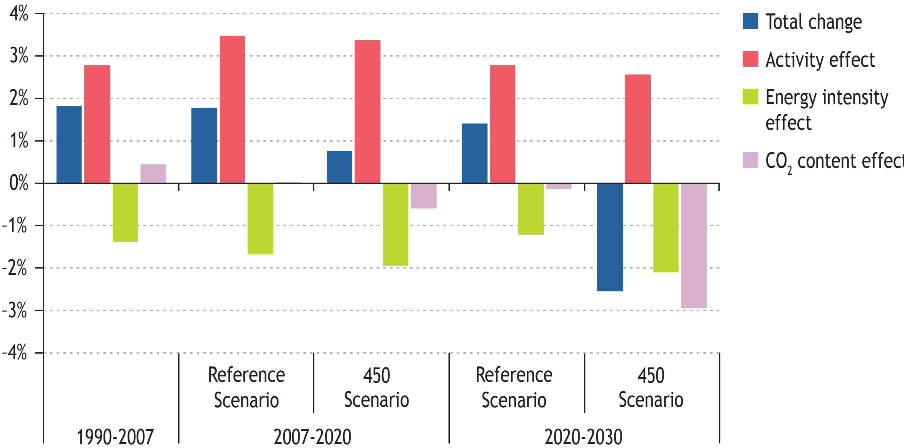
12. In regions where the cap-and-trade is in place, efficiency improvements are driven by the carbon price.

13. In the 450 Scenario, the composition of gross domestic product (GDP) is slightly different than in the Reference Scenario, as China is assumed to implement policies that increase the share of services at the expense of manufacturing sector.

14. Total final energy consumption per value added in industry sector.

15. Including process emissions and the oil and gas extraction sectors (which are not included in our definition of industry) would increase the potential for CCS in industry in 2030 to between 0.6 Gt and 0.9 Gt (IEA, 2009c).

**Figure 6.16** • *World average annual change in energy-related $CO_2$ emissions in industry by type and scenario*




Note: Final energy consumption encompasses all energy sources. $CO_2$ emissions include indirect emissions. Change in $CO_2$ emissions are decomposed into an activity effect, an energy intensity effect and a $CO_2$ content effect.

## Regional trends

In 2030, Other Major Economies contribute two-thirds (or 327 Mtoe) of the reduction in global industrial energy consumption relative to the Reference Scenario. In terms of $CO_2$ emissions, their reduction reaches nearly 1.0 Gt, or 58% of the total decrease globally. China alone accounts for 56% of the global reduction in energy demand and 49% of the reduction in global $CO_2$ emissions in 2030.

The large reductions in energy consumption and $CO_2$ emissions in Other Major Economies, relative to the Reference Scenario, result partly from a shift to a low-carbon economic structure. They are also linked to the expectation that, throughout the projection period as production increases sharply, advantage will be taken of the much greater potential that exists in these countries to improve energy efficiency and reduce $CO_2$ intensity, than in the OECD+, including through sectoral agreements. To achieve these savings, however, widespread deployment of efficient and best available technologies will be necessary.

While industrial energy consumption in Other Major Economies and Other Countries increases from current levels throughout the *Outlook* period, in OECD+ it starts to decline soon after 2010. In OECD+, energy consumption in 2030 is lower than in 2007 by 47 Mtoe and lower than in the Reference Scenario by 73 Mtoe. $CO_2$ emissions in the OECD+ decline to nearly 60% of their current level in 2030, a reduction of about one-third on the Reference Scenario. OECD+ achieves a greater percentage reduction in $CO_2$ emissions than in energy consumption, due to fuel switching and CCS.

**Table 6.4 • World industry energy consumption by fuel and energy-related $CO_2$ emissions in the 450 Scenario**

| | 2007 | 2020 | 2030 | Change versus Reference Scenario | | 2007-2030* |
|---|---|---|---|---|---|---|
| | | | | 2020 | 2030 | |
| **World (Mtoe)** | **2 266** | **2 702** | **2 816** | **-5%** | **-15%** | **0.9** |
| Coal | 581 | 653 | 572 | -7% | -28% | -0.1 |
| Oil | 320 | 323 | 314 | -4% | -12% | -0.1 |
| Gas | 460 | 517 | 543 | -5% | -13% | 0.7 |
| Electricity | 596 | 823 | 910 | -7% | -17% | 1.9 |
| Heat | 120 | 127 | 121 | -3% | -13% | 0.0 |
| Renewables | 189 | 258 | 357 | 8% | 21% | 2.8 |
| **$CO_2$ emissions (Mt)** | **4 781** | **5 214** | **4 498** | **-6%** | **-27%** | **-0.3** |

* Compound average annual growth rate.

## Sub-sectors

In the 450 Scenario, the iron and steel and cement sectors reduce their $CO_2$ intensity by as much as the best available technology permits. Although there is significant variation in production processes between regions, energy indicator work carried out by the IEA provides an estimation of current $CO_2$ reduction potentials by region (IEA, 2009c; 2008b).[16] The reduction potential in the iron and steel sector is estimated at 119 Mtoe of energy, or 0.38 Gt of $CO_2$ worldwide, equivalent to 0.096 tonnes of oil equivalent (toe) per tonne of steel produced or 300 kg of $CO_2$ per tonne, with the potential varying from 0.21 toe per tonne in Ukraine to 0.03 toe per tonne in Japan, where the process is already efficient. The potential global reduction in the cement sector is estimated at 45 Mtoe of energy, or 0.51 Gt of $CO_2$, equivalent to 0.02 toe per tonne of cement produced or 200 kg of $CO_2$ per tonne, ranging from 0.05 toe per tonne in Russia to less than 0.01 toe per tonne in Japan. China, the biggest cement-producing county, has potential of 0.02 toe per tonne and accounts for more than 40% of the global energy saving.

In some sectors, the $CO_2$ intensity of Other Major Economies and Other Countries is already lower than that of OECD+ countries. For example, in the cement industry, new and therefore relatively modern plants are usually located in emerging economies, where demand has expanded in recent years. As a result, the potential for further reductions in those countries is smaller than in some OECD+ countries.

Of all industry sub-sectors, the iron and steel sector curbs emissions most, accounting for around 40% of the reduction in industry emissions in the 450 Scenario as compared with the Reference Scenario.[17] Improvements in blast furnaces, wider use of electric

16. The definition of industry energy consumption and $CO_2$ emissions used in the paper differs from that in the *WEO*, which is based on IEA energy balances. The potentials estimated by the IEA include process emissions, as well as coke ovens and blast furnaces for iron and steel.

17. Iron and steel sector emissions do not include those from coke ovens and blast furnaces.

arc furnaces and the direct reduced iron process could support the reduction, though electric arc furnace potential is limited by the availability of scrap steel and the direct reduced iron process is not suitable for mass production. The sub-sectors making the next-greatest reductions are non-metallic minerals[18] and chemicals and petrochemicals.[19] In the cement sector, emissions decline as a result of efficiency improvements, such as replacing small-scale vertical shaft kilns with state-of-the-art dry-rotary kilns, and as a result of the deployment of CCS.

## Buildings[20]

In the 450 Scenario, energy demand in buildings grows at an average annual rate of 0.7%, from 2 752 Mtoe in 2007 to 3 232 Mtoe in 2030 (Table 6.5). The use of fossil fuels in the sector expands by 3% over the projection period, while use of modern biomass and renewables triples. Energy savings, compared with the Reference Scenario, amount to 147 Mtoe in 2020 and 363 Mtoe in 2030. With a 30% drop in 2030, relative to the Reference Scenario, coal sees the biggest reduction in share.



Direct $CO_2$ emissions from fossil-fuel combustion (mainly for water heating and space heating and cooling) in the residential and services segment are 174 Mt lower by 2020 (or 6%) and 550 Mt by 2030 (or 17%), compared with the Reference Scenario, reaching 2.83 Gt in 2020 and 2.74 Gt in 2030. OECD+ countries account for 48% of the savings in emissions in 2030, Other Major Economies for 35% and Other Countries for the remaining 17%.

**Table 6.5 • World buildings energy consumption by fuel and energy-related $CO_2$ emissions in the 450 Scenario**

| | 2007 | 2020 | 2030 | Change versus Reference Scenario | | 2007-2030* |
|---|---|---|---|---|---|---|
| | | | | 2020 | 2030 | |
| **World (Mtoe)** | **2 752** | **3 022** | **3 232** | **-5%** | **-10%** | **0.7** |
| Coal | 95 | 94 | 66 | -8% | -30% | -1.6 |
| Oil | 336 | 339 | 322 | -5% | -17% | -0.2 |
| Gas | 605 | 643 | 678 | -6% | -14% | 0.5 |
| Electricity | 754 | 937 | 1 091 | -5% | -14% | 1.6 |
| Heat | 149 | 162 | 152 | -3% | -15% | 0.1 |
| Renewables | 811 | 847 | 924 | -3% | 5% | 0.6 |
| **$CO_2$ emissions (Mt)** | **2 754** | **2 829** | **2 743** | **-6%** | **-17%** | **0.0** |

* Compound average annual growth rate.

18. Cement sector emissions in this section are energy-related and do not include process emissions.

19. Petrochemical feedstock is not included in the industry sector but rather in non-energy use sector in IEA energy balances.

20. This includes residential and services sectors.

**Box 6.5 • The policy framework for the buildings sector in the 450 Scenario**

The 450 Scenario assumes that all policies now under consideration for the building sector will be fully implemented, reinforced and extended. Many governments have included measures to improve the energy efficiency of buildings in their recent economic stimulus packages, as such measures represent an effective means of generating jobs while also promoting greener growth.

Higher electricity prices in the 450 Scenario compared with the Reference Scenario play an important role in promoting energy-efficiency measures in the building sector, and pave the way for the greater use of renewable building materials and installations. In 2030, electricity prices have increased by about 20% in OECD+ *vis-à-vis* the Reference Scenario, and by about 10% in Other Major Economies, ensuring that energy costs become a key purchasing criterion for consumers. Despite the relatively low energy-price elasticity in the building sector, especially in the short term, and limited fuel-switching options, higher energy prices are responsible for almost one-third of the total energy saving in the building sector.

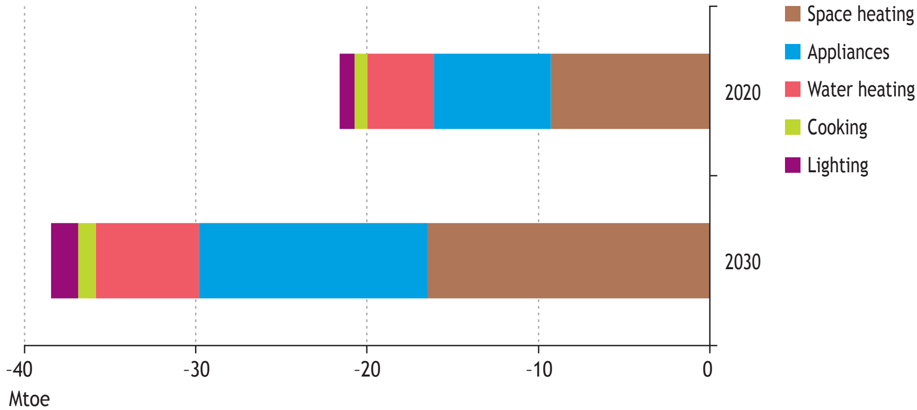
## Regional trends

OECD+ energy demand in buildings in the 450 Scenario grows at 0.5% per year on average throughout the projection period, from 1 227 Mtoe in 2007 to 1 381 Mtoe in 2030. Consumption of all fossil fuels declines, while modern biomass and other renewables grow at annual average rates of 4% and 10.5%, respectively. Demand for fossil fuels in OECD+ buildings in 2030 is 17% lower in the 450 Scenario and direct emissions from fossil fuels in the building sector are reduced by 266 Mt in 2030. Savings in energy for space heating and cooling account for more than 40% of the cumulative savings between today and 2030 in the residential sector.

For OECD+ countries, where new construction activity is estimated to be as low as 1% of the building stock per year and demolitions 0.3% to 0.5%, the biggest potential savings are in existing buildings. Most of the energy savings in the 450 Scenario in OECD+ arise through refurbishment of existing buildings, particularly in better insulated shells, thereby reducing heating and cooling needs. Recent case studies on Europe show that replacement or renovation of building openings, installation of heat control and measuring devices can improve energy efficiency by 25% to 60% (EU DGET, 2009).

In the 450 Scenario, the consumption of electricity in buildings is reduced sharply by the adoption of mandatory labelling schemes, minimum energy performance standards (MEPS) and programmes for the full replacement of incandescent lamps by more efficient alternatives, including compact fluorescent lamps (CFL). In the 450 Scenario, building electricity use reaches just over 7 000 TWh in 2030 compared with over 7 800 TWh in the Reference Scenario. Saving in appliances and lighting end-use sectors account for 39% of the total reduction in residential energy consumption in OECD+ in 2030 (Figure 6.17). The savings are particularly pronounced in Europe and OECD Pacific.

**Figure 6.17** ● **Change in OECD+ energy demand by end use in residential sector in 450 Scenario relative to the Reference Scenario**




Over the projection period, more than two-thirds of the reduction in energy consumption is attributable to energy-efficiency measures; the remaining savings are driven by the direct effect of increased electricity prices, this effect being more prominent in the mid-to-long term (2020-2030).

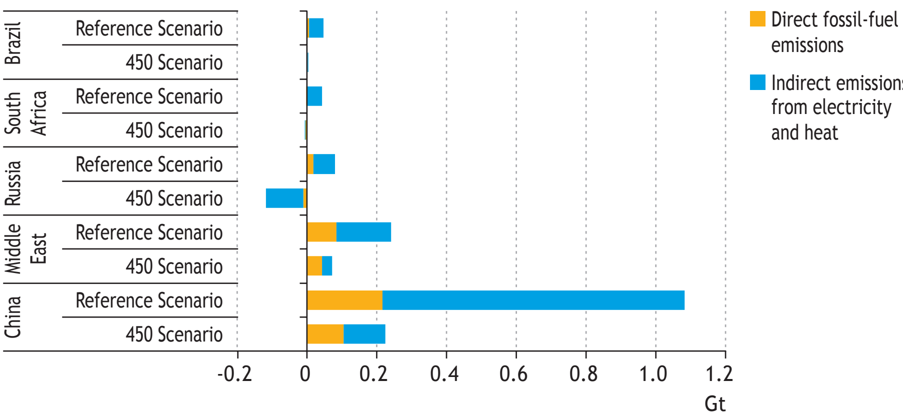
As a major result of the policies to promote renewables installations in OECD+ countries, fossil fuels are partly substituted by solar thermal and biomass for space and water heating. Biomass and other renewables will increase their share of the residential fuel mix in OECD+ from 9% today to 21% in 2030 in the 450 Scenario, nine percentage points more than in the Reference Scenario.

Energy demand in buildings in Other Major Economies rises from 696 Mtoe in 2007 to 861 Mtoe in 2030 in the 450 Scenario. Excluding the use of traditional biomass, per-capita consumption goes from 0.26 toe per capita to 0.35 toe per capita in 2030, still two-thirds less than the current per-capita consumption in OECD+. Other Major Economies see the biggest reduction in absolute and percentage terms in energy consumption in the 450 Scenario, compared with the Reference Scenario. Other Major Economies have higher demolition rates than OECD+ countries and very high construction activity, estimated at between 5% of existing stock for residential buildings and 10% for commercial buildings.

Because of this rapid expansion of the buildings stock, the biggest potential in energy saving in Other Major Economies is in new buildings. Most of the Other Major Economies are considering the introduction of national legislation defining appliance and building standards, requiring efficiency labelling, providing financial incentives and offering subsidies to low-income groups. All Other Major Economies countries are assumed to adopt or to enforce this range of measures, achieving efficiencies that gradually approach those of the OECD. International co-operation and arrangements to report best practice and cost-effective measures can actively help to create a world roadmap to transform the building sector and achieve common efficiency standard worldwide (WBCSD, 2009).

The biggest impact of the policies and measure for buildings in Other Major Economies is seen in a slowdown in growth in electricity consumption – from 3.9% per year on average in the Reference Scenario to 3.1% per year in the 450 Scenario. If the $CO_2$ emissions from upstream power generation are attributed to this sector as a whole, according to its electricity use, incremental $CO_2$ emissions from the building sector in Other Major Economies are reduced by 1.3 Gt compared with the Reference Scenario (Figure 6.18). The reduction in indirect $CO_2$ emissions achieved in the 450 Scenario results from a combination of lower demand for electricity and a less carbon-intensive power sector.

**Figure 6.18 • *Change in energy-related $CO_2$ emissions in buildings by scenario in Other Major Economies, 2007-2030***




China currently accounts for 17% of the total energy consumed in residential buildings worldwide and is constructing 2 billion square metres ($m^2$) of additional buildings each year, about 40% of the total annual global additions. There is significant potential to improve the energy efficiency of China's building stock, as currently only 4% of the country's 43 billion $m^2$ of residential buildings have implemented energy conservation measures (GIC, 2007). In the 450 Scenario, a wide range of policies and measures are assumed to be adopted in China to improve the efficiency of its buildings. These result in savings of 28 Mtoe by 2020 and of 66 Mtoe by 2030 compared with the Reference Scenario. By reducing electricity consumption, measures to promote the uptake of more efficient air conditioning and other appliances avoid emissions of 216 Mt in 2020 and 747 Mt in 2030. Additional co-benefits include lower pollution (reduction of up to 50% in the medium term) and lower energy bills (see Chapter 7). Incentives for space and water heating using renewables and targets to expand the solar collector area, increase solar and geothermal use in China by 21 Mtoe compared with the Reference Scenario.

Existing buildings in Russia have very high energy intensity, with losses estimated to be up to 40% of supplied energy. There is, accordingly, a large potential for refurbishment of existing building stock there. Policies currently under consideration show that energy efficiency is becoming a priority in Russia. The full implementation of legislation providing subsidies for energy-efficiency technologies – as well as fines for owners of buildings that fail to respect the defined standards – result in a saving of almost 25 Mtoe in 2030 compared with the Reference Scenario.

Energy demand in buildings in the 450 Scenario in Other Countries will expand 20% in the projection period, from 829 Mtoe in 2007 to 990 Mtoe in 2030. Consumption of all commercial fuels increases, while electricity consumption grows at 3.1% annually, from 102 Mtoe in 2007 to 205 Mtoe in 2030. Consumption of traditional biomass declines from 491 Mtoe today to 476 Mtoe in 2030, almost entirely because of fuel switching to modern fuels for cooking in India (see Chapter 2).

Other Countries account for 17% of the total emissions reductions for the building sector in 2030 in the 450 Scenario. Amongst this group of countries, the biggest energy savings occur in India, where total demand in buildings in 2030 is reduced by 33 Mtoe, or 13%, compared with the Reference Scenario.



India is expected to construct more buildings in the period 2008-2020 than the total stock existing in 2007. Introducing higher building standards in the short term can lock-in energy efficient solutions, avoiding more expensive building retrofits in the future. As part of the extension of existing policies and policies under consideration which is assumed in this scenario, the revised Energy Conservation Building Code (currently under discussion) provides minimum requirements for the energy-efficient design and construction of buildings that use significant amounts of energy. Full implementation of this and other measures will result in a cumulative saving of 8 Mtoe in fossil fuels and 116 TWh of electricity by 2030. The extension and reinforcement of the scheme on accelerated development and deployment of solar water – heating systems, with a goal of achieving 200 000 $m^2$ of solar collector area in the residential sector in the next two years, results in a more than three-fold increase in solar water heating in 2030 compared with the Reference Scenario.

# COSTS AND BENEFITS IN THE 450 SCENARIO

## How much additional investment is needed?

### HIGHLIGHTS

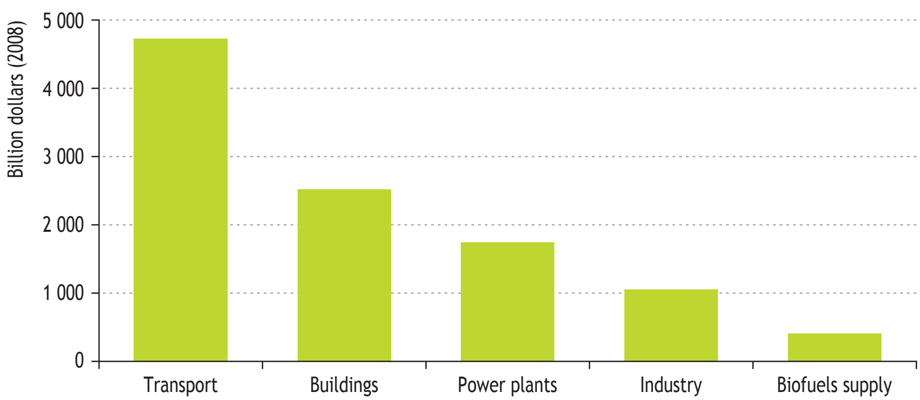
- In the 450 Scenario, additional investment of close to \$10 500 billion is needed globally in the energy sector in the period 2010-2030, relative to the Reference Scenario. This investment leads to a reduction in emissions of over 13 Gt of $CO_2$ in 2030. Over 45% of incremental investment needs, or \$4 750 billion, are in transport. Additional investment amounts to \$2 550 billion in buildings, \$1 750 billion in power plants, \$1 050 billion in industry and \$400 billion in biofuels production. More than three-quarters of the total additional cumulative investment in the 450 Scenario is needed in the 2020s.
- Most of the additional investment – \$5 000 billion – is needed in OECD+ countries. Other Major Economies need an additional \$3 100 billion and Other Countries \$1 900 billion. On an annual basis, global additional investment needs reach nearly \$430 billion (0.5% of GDP) in 2020 and \$1 150 billion (1.1% of GDP) in 2030.
- The bulk of the incremental investment – \$3 400 billion – goes to buying more efficient light-duty vehicles, in particular hybrid and electric cars. Most of the investment in biofuels is in second-generation technologies, which are expected to become more widespread after 2020.
- Total investment in power generation in the 450 Scenario over the period 2010-2030 amounts to \$7 950 billion, 28% higher than in the Reference Scenario. Of this investment, 60% goes to renewables, 16% to nuclear and 7% to carbon capture and storage (CCS). In the period 2021-2030, investment in nuclear power, renewables and CCS makes up over 90% of total power-generation investment.
- The policies aimed at reducing energy-related $CO_2$ emissions in the 450 Scenario lead to a big reduction in emissions of air pollutants. This greatly improves human health, particularly in China and India. By 2030, sulphur dioxide ($SO_2$) emissions are 29% lower than in the Reference Scenario; nitrogen oxides ($NO_x$) emissions are 19% lower and emissions of particulate matter 9% lower.
- Energy bills in transport, buildings and industry are reduced by over \$8 600 billion globally over the period 2010-2030 and by \$17 100 billion over the lifetime of the investments. Oil and gas import bills in OECD countries in 2030 are much lower than in 2008, and in 2030 they are 30% lower in China and 31% lower in India than in the Reference Scenario. Local air pollution control costs are \$100 billion lower in 2030 in the 450 Scenario, compared with the Reference Scenario.

## Incremental investment needs in the 450 Scenario

The stabilisation of the concentration of greenhouse gases in the atmosphere at 450 parts per million (ppm) of carbon dioxide equivalent ($CO_2$-eq) will require substantial investment in low-carbon energy technologies and energy efficiency. This chapter quantifies that investment[1] and, where possible, the benefits it brings. Most of the chapter discusses the additional investment required – additional compared to that incurred in the Reference Scenario. For the power-generation sector, figures are also given for the total investment required, to illustrate the scale of the total activity in those fuels and technologies that best serve the purpose of curbing $CO_2$ emissions from this source. After first considering the overall picture, the chapter deals separately with each of the areas in which the additional investment will be required, before switching to those areas in which the investment commitment will actually be lower than in the Reference Scenario (though still substantial), such as oil, gas and coal. This departs from the sequence usually followed elsewhere in the *WEO*, in order to emphasise the changed focus of energy investment in this scenario and the scale of the change for the sectors and low-carbon technologies concerned.

Based on the 450 Scenario projections presented in Chapters 5 and 6, in the period 2010-2030 additional investment of close to $10 500 billion is needed globally (in the energy sector itself and in energy-consuming equipment in all sectors) relative to the Reference Scenario. This investment leads to a reduction in energy-related emissions of over 13 gigatonnes (Gt) of $CO_2$ in 2030. This additional investment is needed in five key sectors: transport, buildings, power plant, industry and biofuels (Figure 7.1).[2]

**Figure 7.1 • Cumulative additional investment needs by sector in the 450 Scenario relative to the Reference Scenario, 2010-2030**




Note: Investment in buildings includes rooftop photovoltaics.

1. Investment is expressed in billion dollars ($10^9$ or a thousand million dollars). By way of comparison, global GDP was $60 000 billion in 2007 (measured at market exchange rates).

2. These sectors accounted for 91% of $CO_2$ emissions from fossil-fuel combustion in 2007. They account for 95% of the 13.8 Gt of $CO_2$ savings in 2030 in the 450 Scenario. Investment needs of the agriculture sector are not considered in this chapter.

The results presented here serve as a basis for the analysis in Chapter 8 of how these investments might be financed. This chapter also quantifies the fuel-cost savings and other benefits arising from investment in clean energy.

The largest increase in investment relative to the Reference Scenario is in transport; the additional $4 750 billion there goes mainly into purchasing more efficient vehicles, including plug-ins and hybrids. The second-largest area of investment is in buildings, including households and commercial and public establishments, and is directed primarily at greater energy efficiency and wider use of renewables. Additional investment in this sector amounts to $2 550 billion. An extra $1 750 billion is needed in power plants mainly to make greater use of renewables and nuclear power, and to incorporate carbon capture and storage (CCS). Investment in industry in the 450 Scenario is $1 050 billion higher, the increase in investment being devoted mainly to more efficient processes and electric motors. Additional biofuels investments of $400 billion – supply-side investments by fuel providers – contribute to decreasing $CO_2$ emissions in the transport sector. All these investments and the associated $CO_2$ savings are shown in Tables 7.1 and 7.2.

7

**Table 7.1 • World cumulative incremental investment (2010-2030) and $CO_2$ savings (2030) in power generation and biofuels supply in the 450 Scenario, relative to the Reference Scenario**

| | Incremental investment ($ billion) | $CO_2$ savings due to low-carbon technologies (Gt) | $CO_2$ savings due to reduced demand (Gt) | Total $CO_2$ savings (Gt) |
|---|---|---|---|---|
| Power generation | 1 745 | 5.8 | 3.5 | 9.4 |
| Biofuels supply | 405 | n.a. | n.a. | 0.4 |

Note: $CO_2$ savings from biofuels arise from lower use of oil.

**Table 7.2 • World cumulative incremental investment (2010-2030) and $CO_2$ savings (2030) in end use in the 450 Scenario, relative to the Reference Scenario**

| | Incremental investment ($ billion) | Direct $CO_2$ savings (Gt) | Direct and indirect $CO_2$ savings (Gt) |
|---|---|---|---|
| Industry | 1 056 | 1.7 | 3.2 |
| Buildings | 2 533 | 0.6 | 2.5 |
| Transport | 4 730 | 1.2 | 1.2 |

Notes: Indirect savings arise from reduced electricity consumption in buildings and industry, which results in a lower requirement for fossil-fuel based power plants in the 450 Scenario. Emissions from increased use of electricity in transport are negligible because the additional demand for electricity is assumed to be supplied by low-carbon plant (nuclear, CCS and renewables). Investment in transport leads to lower $CO_2$ emissions because it reduces the demand for oil (mainly through greater efficiency and greater use of electric vehicles).

Most of the additional global investment – $5 000 billion – is needed in OECD+ countries. Other Major Economies need an additional $3 100 billion and Other Countries need $1 900 billion. The remaining $500 billion is needed in international shipping and aviation. The United States and China have the largest incremental investment needs, estimated at $2 050 billion each over 2010-2030 (Figure 7.2). The European Union also needs significant additional investment. China, India and Russia have the lowest investment cost per tonne of $CO_2$ emissions reduced, owing largely to their large potential for improved energy efficiency.

**Box 7.1 ● *Calculating the investment needs***

The term "investment" in this chapter covers not only capital spending by businesses but also spending by individuals on cars, equipment and appliances (but not on their operation). It is a measure of the cost of equipping our society to enable it to achieve ambitious carbon-reduction targets. Most of the time, we concentrate on the *additional* cost of this investment, relative to the Reference Scenario.

Presented in this way, investment expenditure may seem to be nothing but a burden. Of course, it is not. In the scenario we present here, there is every reason to suppose that the businesses making this additional investment earn a perfectly satisfactory commercial return on it; and, as discussed later in the text, individuals save very considerable sums in fuel costs (quite apart from other benefits) to set against their additional expenditure on equipment. How the additional expenditure can be financed is a different issue, which is explored in Chapter 8.

The results presented in the text concentrate on the quantification of the additional expenditure, by sector and by region (though we do also present *total* figures for the power generation sector, to illustrate the overall scale involved in the conversion in that sector).

Power plant investment costs are calculated internally in the World Energy Model, using unit costs specific to each technology. These costs are calculated separately for the Reference and 450 Scenarios, and then aggregated. Specific power-generation unit costs come from IEA analyses and have been reviewed by industry experts. Exceptionally in this chapter, we present the *total* investment costs for the power-generation sector in the 450 Scenario, as well as the *additional* costs.

Unit road-transport costs for a range of technologies have been obtained through a peer-review process (see also footnote 10). Investment in biofuels is based on specific costs used in the IEA's Mobility Model (MoMo), which is used to develop scenarios for the transport sector.

For other transport modes (mainly road freight and railways), industry and buildings, the underlying unit costs are less specific and more aggregated. No attempt has been made to calculate total investment costs in these sectors, our focus instead being solely on the *additional* costs associated with achieving the objectives of the 450 Scenario, measured against the costs of the Reference Scenario.

The main source of industry costs is an IEA report on industry (IEA, 2009a). Buildings costs have been obtained from a variety of sources, including internal

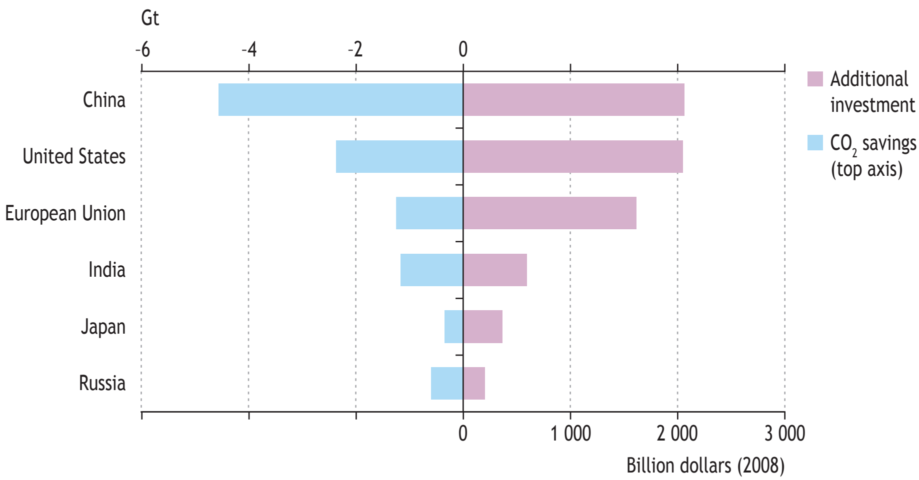
IEA data, literature review and communication with building technology experts.

The investment costs of installations such as power plants or industrial facilities, construction of which may take several years, are attributed to the year of their completion. For example, the construction cost of building a coal-fired power plant is attributed to the year in which the plant begins operation, although in reality construction takes about four years and costs are spread across the construction period. CCS investment costs refer to the total cost of plants fitted with carbon capture equipment but exclude transport and storage costs.

For the purposes of this chapter, investment in photovoltaics (PV) is included in power plant if solar panels are used for large-scale centralised electricity production and in buildings if used on rooftops. This is different from the approach taken in previous chapters, where *all* generation from PV is included in the power-generation sector.

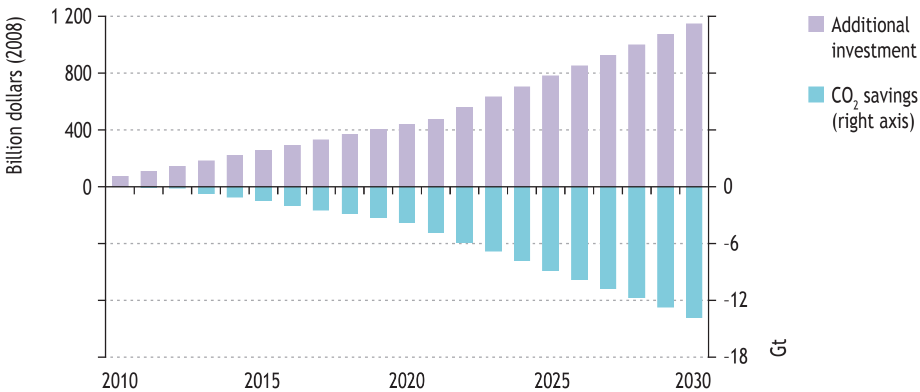


**Figure 7.2 • Cumulative incremental investment and $CO_2$ savings in 2010-2030 by country/region in the 450 Scenario, relative to the Reference Scenario**




Incremental investment averages almost \$220 billion per year in the period 2010-2020. Over this period, annual incremental investment rises at a moderate rate to reach nearly \$430 billion by 2020, equivalent to 0.5% of global GDP. Incremental investment needs rise sharply over the period 2021-2030, during which they average \$800 billion per year. Incremental investment reaches \$1 150 billion in 2030, which corresponds to 1.1% of global GDP in that year (Figure 7.3). More than three-quarters of the total additional investment in the 450 Scenario is needed in 2021-2030. This is because most of the $CO_2$ emissions reductions occur after 2020 (global $CO_2$ emissions are cut by 3.8 Gt in 2020 and by 13.8 Gt in 2030, compared with the Reference Scenario). $CO_2$ emissions decrease dramatically after 2020 for a number of reasons: because non-OECD countries are assumed to engage in deep emission cuts after 2020; because the rate of natural replacement of capital stock is higher after 2020; and because it takes time to develop low-carbon technologies on a large scale (for example, nuclear power expands rapidly after 2020, because of the long lead times to develop new nuclear power plants; CCS needs another ten years or so from now to be developed on a large scale; and electric vehicles are not widely available earlier on a commercial basis).

**Figure 7.3 • *Global annual incremental investment and $CO_2$ savings in the 450 Scenario relative to the Reference Scenario, 2010-2030***



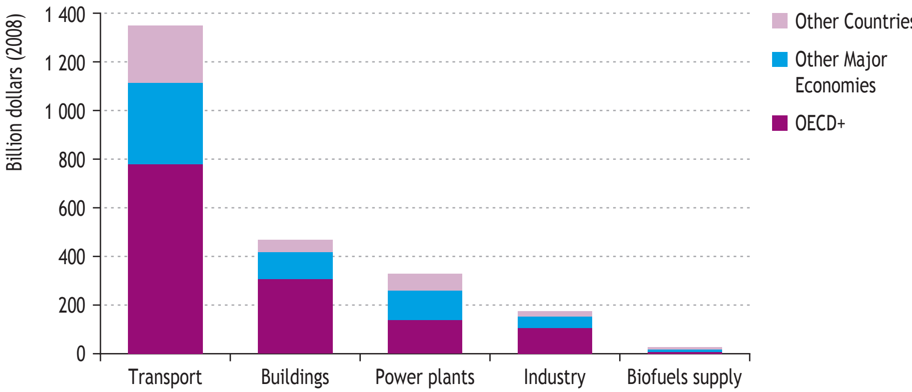

The current financial crisis has had a negative impact on investment in clean energy (see Chapter 3). Energy companies have cut back spending on power plants, including renewable energy projects such as wind farms and photovoltaics. Spending on appliances, equipment and vehicles has also slowed. Tighter credit and lower fossil-fuel prices make investment in clean energy less attractive financially, delaying the deployment of a more efficient generation of technologies. Although the bulk of the incremental investment is needed in the period 2021-2030, postponing investment in clean energy now could defer the peaking of greenhouse-gas emissions beyond 2020. This argues for greater government support now to encourage such investments. The stimulus packages provided by a number of governments to support investment in clean energy are a positive step in this direction, but not sufficient to put the world on the 450 Scenario pathway.

## Timing of incremental investment

### *The period 2010-2020*

A global climate agreement at the 15th Conference of the Parties (COP) to the United Nations Framework Convention on Climate Change (UNFCCC) (December 2009, Copenhagen) is likely to entail an immediate increase in spending on clean energy. As noted earlier, additional investment needs in the period 2010-2020 average $220 billion per year, reaching nearly $430 billion by 2020. Most of the $CO_2$ emission reductions during this period are achieved through investment in renewable energy and energy efficiency. The largest increase in investment requirements is in transport in OECD+ countries (Figure 7.4). Total incremental investment in OECD+ countries averages $120 billion per year. Other Major Economies need an extra $60 billion per year and Other Countries need $35 billion per year. Most of the investment in the non-OECD regions is needed in transport and in power plants.

**Figure 7.4 • Cumulative incremental investment in 2010-2020, by sector and region in the 450 Scenario, relative to the Reference Scenario**




### *The period 2021-2030*

Most of the additional investment in clean energy in the 450 Scenario is needed after 2020. During the period 2021-2030, the additional spending on clean energy increases sharply to reach $1 150 billion by 2030. On average, more than $800 billion are spent every year. Spending on new technologies, such as CCS and electric vehicles, rises considerably. OECD+ countries need $370 billion per year, while investment increases by $250 billion per year in Other Major Economies and by $150 billion per year in Other Countries.

## Overall investment in power plants[3]

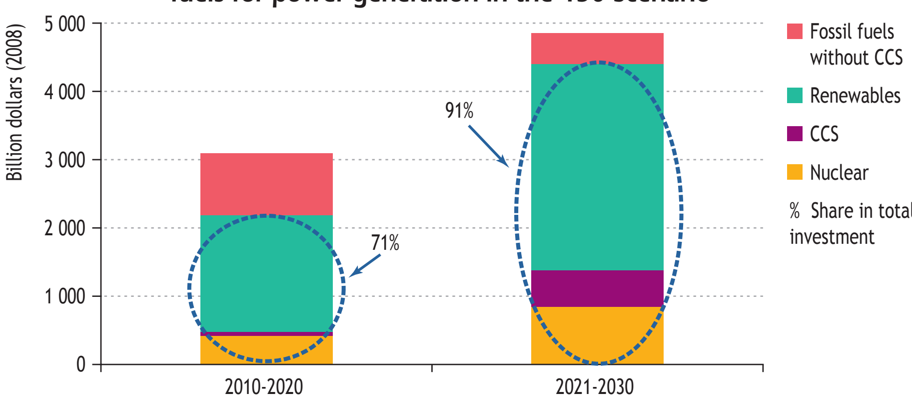
Total investment in power plants in the 450 Scenario over the period 2010-2030 is in excess of $7 900 billion. Total new capacity added in 2010-2030 amounts to just over 4 300 gigawatts (GW); over half of this capacity is added after 2020. The decarbonisation of power generation is achieved mainly through investment in renewables, nuclear power and CCS. Most of the investment goes into renewables ($4 750 billion or 60% of the total). Investment in nuclear power reaches nearly $1 300 billion (16% of the total) and CCS receives investment of $600 billion (7% of the total). The remaining investment goes mainly into coal- and gas-fired power plants without CCS.

3. With the exception of Table 7.3, this section focuses on overall power plant investment in the 450 Scenario (*i.e.* in absolute terms, rather than relative to the Reference Scenario) so as to highlight the scale of the demands on (and opportunities for) the technologies involved. As noted in Box 7.1, investment in rooftop photovoltaics is not included in the total as it is reported under investment in buildings.

In the period 2010-2020, investment in renewables, nuclear power and CCS makes up over 70% of the total (Figure 7.5). In the period 2021-2030, more than 90% of power-generation investment goes into these technologies, representing a momentous shift away from current trends.

In the period 2010-2020, more than half of the total investment is in generation using renewables, which totals $1 700 billion. Most investment in renewables is in the OECD+ region. Much support for the development of renewables during this period comes from government policies, other than the cap-and-trade-system, in which the power sector and industry participate. Investment in nuclear power amounts to $420 billion. This is over 40% higher than in the Reference Scenario; further increases during this period are unlikely given the long lead times to develop nuclear power plants and the current constraints in the supply chain (see below: Investement in nuclear power). Investment in plants using CCS is limited to less than $60 billion, as large-scale commercialisation of this technology is unlikely before 2020. Investment in fossil-fuel based power plants without CCS amounts to $900 billion.

**Figure 7.5 ● *Total global investment in renewables, nuclear, CCS and fossil fuels for power generation in the 450 Scenario***




In the period 2021-2030, total investment in power generation in the 450 Scenario is in excess of $4 800 billion. More than 60% of this is in plants using renewable energy. Investment in nuclear power totals $850 billion, while investment in plants with CCS reaches nearly $550 billion. This period marks the beginning of the end of carbon-intensive electricity generation, as very little investment goes into coal- or gas-based generation without CCS. All coal-based plants built in the OECD+ in the period 2020-2030 are equipped with CCS. Recent IEA analysis suggests that to achieve the 450 ppm trajectory, $CO_2$ emissions from power generation would need to be cut by 70% below 2005 levels by 2050 (IEA, 2008). This implies that virtually no fossil-fuel plants would be built after 2030, unless equipped with CCS, and that retired plants would have to be replaced by plants with CCS, nuclear or renewables.

Beyond the requirements of the Reference Scenario, incremental investment in power plants over the period 2010-2030 is close to $1 750 billion (28% higher) because it is directed toward more capital-intensive technologies.[4] Additionally, more existing fossil-based power plants are retired in the 450 Scenario. The incremental investment needs amount to $30 billion per year over the period 2010-2020 and to $140 billion per year over the period 2021-2030. Table 7.3 summarises the changes in investment needs in the 450 Scenario, relative to the Reference Scenario. Significantly higher investment goes into renewables, nuclear and CCS, while investment in fossil fuels, particularly coal, is reduced drastically.

**Table 7.3 • *Change in cumulative power-plant investment and capacity in the 450 Scenario relative to the Reference Scenario***

| | 2010-2020 | | 2021-2030 | |
|---|---|---|---|---|
| | Investment ($ billion) | Capacity (GW) | Investment ($ billion) | Capacity (GW) |
| Renewables | 430 | 212 | 1 674 | 791 |
| *Hydropower* | *112* | *56* | *571* | *234* |
| *Wind power* | *209* | *118* | *594* | *350* |
| CCS | 56 | 19 | 494 | 195 |
| Nuclear | 125 | 36 | 491 | 143 |
| Fossil fuels (without CCS) | -281 | -335 | -1 244 | -989 |
| *Coal* | *-197* | *-240* | *-961* | *-693* |
| **Total** | **330** | **-68** | **1 415** | **139** |

Note: Renewables do not include photovoltaics in buildings.

The transformation of the power sector, as envisaged in the 450 Scenario, creates tremendous opportunities for innovation in the power plant manufacturing industry. Clear policy frameworks would be required, as manufacturers would need to invest massively in new production facilities. The cost of new technologies is generally assumed to fall over time through learning effects, particularly the cost of renewables and, to a lesser extent, CCS. However, large demand for new plants, particularly in the period 2021-2030, could create steep competition for manufacturing, engineering and labour resources, driving costs and investment needs higher than estimated in this *Outlook*.

OECD+ countries invest a total of $3 600 billion in power generation over 2010-2030 (Table 7.4 and Table 7.5). Other Major Economies invest a total of $2 500 billion. China's investment needs amount to $1 750 billion, the largest of any country. Other Countries need to invest nearly $1 900 billion, of which about 40% is needed in India.

4. Over the period 2010-2030, total investment in power plant in the Reference Scenario amounts to $6 200 billion, excluding photovoltaics in buildings.

**Table 7.4 • Cumulative investment in power plant by country/region in the 450 Scenario** ($2008, billion)

| | Total 2010-2020 | Total 2021-2030 | Total 2010-2030 |
|---|---|---|---|
| **OECD+** | **1 399** | **2 187** | **3 586** |
| *United States* | *496* | *806* | *1 302* |
| *European Union* | *586* | *832* | *1 418* |
| *Japan* | *111* | *158* | *269* |
| **Other Major Economies** | **1 078** | **1 411** | **2 489** |
| *Russia* | *117* | *195* | *313* |
| *China* | *797* | *951* | *1 748* |
| **Other Countries** | **614** | **1 256** | **1 870** |
| *India* | *247* | *503* | *750* |
| **World** | **3 091** | **4 854** | **7 944** |

Note: Figures do not include investment in photovoltaics in buildings.

**Table 7.5 • Cumulative investment in renewables, CCS and nuclear power by country/region in the 450 Scenario** ($2008, billion)

| | 2010-2020 | | | | 2021-2030 | | | |
|---|---|---|---|---|---|---|---|---|
| | Renewables | CCS | Nuclear | % of total | Renewables | CCS | Nuclear | % of total |
| **OECD+** | **866** | **51** | **189** | **79%** | **1 190** | **411** | **449** | **94%** |
| *United States* | *228* | *35* | *87* | *70%* | *371* | *273* | *130* | *96%* |
| *European Union* | *474* | *9* | *32* | *88%* | *522* | *82* | *176* | *94%* |
| *Japan* | *40* | *1* | *29* | *63%* | *62* | *7* | *65* | *85%* |
| **Other Major Economies** | **549** | **6** | **194** | **69%** | **886** | **106** | **246** | **88%** |
| *Russia* | *24* | *3* | *26* | *45%* | *106* | *22* | *41* | *87%* |
| *China* | *451* | *1* | *153* | *76%* | *622* | *66* | *168* | *90%* |
| **Other Countries** | **292** | **1** | **39** | **54%** | **948** | **20** | **151** | **89%** |
| *India* | *102* | *1* | *15* | *48%* | *365* | *9* | *73* | *89%* |
| **World** | **1 707** | **58** | **422** | **71%** | **3 024** | **537** | **846** | **91%** |

Note: Figures do not include investment in photovoltaics in buildings.

## Investment in nuclear power

In the 450 Scenario, total investment in nuclear power in the period 2010-2030 is close to $1 300 billion, 16% of the total investment in power generation. This investment is needed to bring forth a total of 375 GW of new nuclear capacity by 2030, including capacity to replace retired reactors. Most of the investment ($850 billion) in nuclear power is in the period 2021-2030. This is because of the long lead times to develop nuclear power and because several existing reactors will come to the end of their lifetime and will need to be replaced during this period.

New nuclear capacity built over the period 2010-2030 in the 450 Scenario is almost eight times greater than the capacity currently under construction, implying that the pace of construction needs to be scaled up considerably over the next few years. Nuclear power plants have long lead times: construction takes at least four to five years and the preceding planning period can last for as long as ten years. Lengthy planning procedures tend to increase project costs and investor risk. This has been the case in a number of OECD countries in the past. Improved and shorter planning procedures will be crucial for accelerating the development of nuclear power.

**Table 7.6 ● Nuclear capacity under construction as of end-August 2009**

| Country | Number of reactors | Capacity (net, MW) |
|---|---|---|
| Argentina | 1 | 692 |
| Bulgaria | 2 | 1 906 |
| China | 16 | 15 220 |
| Chinese Taipei | 2 | 2 600 |
| Finland | 1 | 1 600 |
| France | 1 | 1 600 |
| India | 6 | 2 910 |
| Iran | 1 | 915 |
| Japan | 3 | 3 516 |
| Korea | 6 | 6 520 |
| Pakistan | 1 | 300 |
| Russia | 9 | 6 894 |
| Slovakia | 2 | 810 |
| Ukraine | 2 | 1 900 |
| United States | 1 | 1 165 |
| **Total** | **54** | **48 548** |

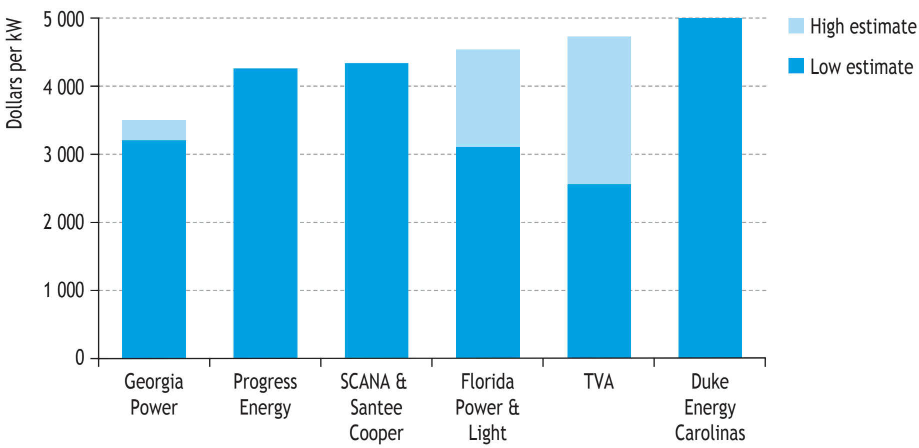
Sources: IAEA PRIS database, available at www.iaea.org; Japan's Ministry of Energy, Trade and Industry.

New nuclear power plants can generate electricity at a cost of between \$55 and \$80 per MWh, which places them in a strong competitive position against coal- or gas-fired power plants, particularly when fossil-fuel plants carry the burden of the carbon cost associated with the cap-and-trade system in OECD+ countries and in Other Major Economies, which is assumed in the 450 Scenario. Yet, nuclear power plants have very high up-front costs, and this is a serious risk factor for companies and financiers planning to invest in nuclear power in competitive markets. Governments may need to mitigate such risks, particularly in countries that have not built new nuclear power plants for many years or at all. In the longer run, however, a well-designed system that puts a price on carbon should lead to adequate investment in nuclear power.

China leads investment in nuclear power in the 450 Scenario. A total of \$320 billion is projected to be invested in the period 2010-2030 to bring 109 GW of new capacity on line. In the past, China has set targets for nuclear plant development that have not been met; but accelerating nuclear plant construction has become a priority for the government in recent years. Its rigorous strategy is evidenced by the large number of reactors currently being built. China now has the highest capacity under construction in the world (Table 7.6): at 15.2 GW, it is almost twice that of its current installed capacity of 8.4 GW (as of September 2009).

The United States also invests significantly in nuclear power in the 450 Scenario. Initially, investment in nuclear power will be supported by government incentives, the most important of them being a loan guarantee to support debt financing. Under the *Energy Policy Act of 2005*, these incentives are aimed at supporting up to 6 GW of new nuclear power plants to become operational by 30 September 2021. The United States Department of Energy plans to offer up to $18 billion of loan guarantees to new nuclear power plants.[5]

**Figure 7.6 • Current estimates of overnight project costs of planned nuclear power plants in the United States**




Note: Overnight project cost is the cost of a project excluding interest during construction, *i.e.* as if the project were built overnight.

Source: Georgia Public Service Commission (2008).

Globally, nuclear power investment costs are assumed to be in the range of $3 200 to $4 500 per kW for plants expected to begin operation between 2015 and 2030. The high end of this range applies to nuclear power plants in the United Sates, where no nuclear power plant has been built in a long time. The cost of building new nuclear power plants in the United States is very uncertain and current estimates vary significantly, as Figure 7.6 indicates. Given the range of the estimates, an average cost of $4 500 per kW for 2015 and 2020 has been used here for the United States, falling to $4 000 per kW by 2030. Construction cost uncertainty is a major risk factor for investors.

An ambitious target to reduce greenhouse-gas emissions, such as in the 450 Scenario, will provide enormous opportunities to develop nuclear power further. However, the industry faces a number of challenges, notably constraints in the supply chain. The current number of equipment suppliers is small. Japan Steel Works is the only company manufacturing very large forgings for reactor pressure vessels. The company already plans to expand its production capacity. For smaller forgings, a number of other manufacturers exist, which could scale up their production capacity to match orders. In the period 2021-2030, 24 GW of new nuclear plant are projected to come on line

5. Loan guarantees are available to cover other advanced technologies as well.

every year, significantly higher than recent trends. This means that, over the next ten years or so, nuclear manufacturers will have to step up substantially their production capacities. Investment in uranium mining will also have to rise considerably to meet the fuel needs of these new power plants.

### Investment in renewable energy for large-scale power production

A global agreement to reduce greenhouse-gas emissions will also provide tremendous growth opportunities for renewable energy. In the 450 Scenario, measures to reduce emissions in the power sector lead to massive investment in renewables. Power companies worldwide invest a total of $4 700 billion in the period 2010-2030 in renewables-based electricity production. This is 60% of the projected total investment in power generation. Annual investment in renewables reaches $340 billion by 2030, more than double the level reached in 2008.[6]



Wind power attracts the highest level of investment in renewable energy in the 450 Scenario, reaching almost $120 billion per year by 2030 (Figure 7.7). Investment in hydropower follows closely. Concentrating solar power (CSP) and biomass also see sizeable increases in investment. Investment in PV for large-scale electricity generation increases considerably, although it is less important than investment in PV in buildings.

During the period 2010-2020, investment in renewables for electricity generation reaches $1 700 billion. Most of the savings in $CO_2$ emissions during this period – relative to the Reference Scenario – result from the increase in investment in renewables. This period provides a unique opportunity for renewable energy to grow and become competitive, as CCS and nuclear can be developed on a very large scale only beyond 2020. Cost reductions anticipated in the period to 2020 pave the way for a dramatic increase in renewables investment over the period 2021-2030, which exceeds $3 000 billion.

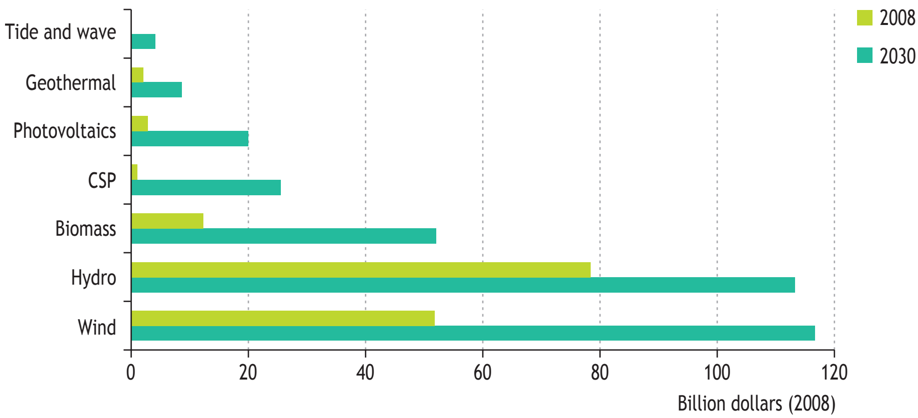
The investment costs of renewable energy technologies are assumed to decrease over time. Greater deployment accelerates technological progress and provides economies of scale in manufacturing the associated equipment. The extent of the reductions depends on the maturity of the technology. The costs of the more mature technologies, including geothermal, hydropower and onshore wind power, are assumed to fall less than those of new technologies. Falling unit investment costs result in roughly proportionate decreases in power-generating costs (Table 7.7).

Currently, the expansion of many forms of renewable energy is dependent upon government incentives aimed at reducing the cost and risk to investors (by providing, for example, guaranteed markets). The deployment of renewable energy in the 450 Scenario is assumed to continue to be based on incentives, at least up to 2020. Post-2020, the most cost-competitive forms of renewable energy, such as wind power,

6. For the purposes of single year comparisons (rather than comparisons over the periods 2010-2020 and 2021-2030), 2008 is used as the base year. There are considerable uncertainties over estimates of expenditure in 2010.

might rely solely on the indirect support they receive through cap-and-trade systems. Governments may decide, however, to continue direct support for some time for employment and energy security reasons, with the objective of achieving even greater deployment of renewables.

**Figure 7.7 • *Annual investment in renewables for large-scale power generation in the 450 Scenario***




Note: Investment refers to the cost of the capacity brought on line in that year (see Box 7.1 and footnote 6). Investment in photovoltaics does not include building installations.

**Table 7.7 • *Investment and generating costs of renewables for power generation in the 450 Scenario***

| | 2008 Investment ($/kW) | 2008 Gen. cost ($/MWh) | 2030 Investment ($/kW) | 2030 Gen. cost ($/MWh) |
|---|---|---|---|---|
| Hydropower | 1 970 - 2 600 | 45-105 | 1 940 - 2 570 | 40-100 |
| Wind - onshore | 1 770 - 1 960 | 90-105 | 1 440 - 1 600 | 70-85 |
| Wind - offshore | 2 890 - 3 200 | 100-120 | 2 280 - 2 530 | 80-95 |
| Biomass | 2 960 - 3 670 | 50-140 | 2 550 - 3 150 | 35-120 |
| Solar PV (central grid) | 5 730 - 6 800 | 360-755 | 2 010 - 2 400 | 140-305 |
| CSP | 3 470 - 4 500 | 135-370 | 1 730 - 2 160 | 70-220 |
| Geothermal | 3 470 - 4 060 | 65-80 | 3 020 - 3 540 | 55-70 |
| Tide and wave | 5 150 - 5 420 | 195-220 | 2 240 - 2 390 | 100-115 |

Note: The variation in investment costs is due to differences between regions. The variation in generating costs is due to differences both in investment costs and in capacity factors in different regions. Generating costs include discounted investment, operating and maintenance costs and, in the case of biomass, fuel costs.

Source: IEA analysis.

The very large expansion of renewables in the 450 Scenario will require an equally large expansion of the renewables manufacturing industry. Strong growth is now being seen in the wind and PV industries. Despite the current dominance of the wind industry by

European companies, these two industries are becoming more global, with production facilities spread throughout OECD and non-OECD countries, and Chinese manufacturers now feature in the top-ten (Table 7.8). Similarly, the PV manufacturing industry is also becoming global. The number and diversity of market participants will increase competition, pushing manufacturers to lower their prices.

**Table 7.8 • *The top ten wind turbine suppliers, by global market share***

| 2000 | | | 2008 | | |
|---|---|---|---|---|---|
| Supplier | Country | Market share | Supplier | Country | Market share |
| Vestas | Denmark | 17.9% | Vestas | Denmark | 19.8% |
| Gamesa | Spain | 13.9% | GE Energy | United States | 18.6% |
| Enercon | Germany | 13.7% | Gamesa | Spain | 12.0% |
| NEG Micon | Denmark | 13.4% | Enercon | Germany | 10.0% |
| Bonus | Denmark | 11.5% | Suzlon | India | 9.0% |
| Nordex | Denmark/Germany | 8.3% | Siemens | Germany | 6.9% |
| Enron | United States | 6.0% | Sinovel | China | 5.0% |
| Ecotecnia | Spain | 3.9% | Acciona | Spain | 4.6% |
| Suzlon | India | 2.3% | Goldwind | China | 4.0% |
| Dewind | Germany | 2.1% | Nordex | Germany | 3.8% |

Source: BTM Consult (2009) for 2008 and data provided by BTM Consult for 2000.

## Investment in carbon capture and storage (CCS)

CCS is deployed on a large scale after 2020 as a key technology to achieve the goals of the 450 Scenario. A total of almost $600 billion is injected into CCS projects over the period 2010-2030. Widespread commercialisation of CCS depends on developments in legal and regulatory frameworks, financing mechanisms, international co-operation, technological advances and public awareness. At the Hokkaido-Toyako Summit in Japan in 2008, G8 leaders committed to undertake a number of CCS-related actions to address these challenges: to announce 20 large-scale CCS demonstration projects globally by 2010, taking into account various national circumstances, with a view to beginning broad deployment of CCS by 2020; to establish an international initiative, with the support of the IEA, to develop CCS technology roadmaps and enhance global co-operation through existing and new partnerships; and to take various policy and regulatory measures to provide incentives for commercialising CCS technologies. There has, in fact, been a dramatic increase in government and industry demonstration activities in the past year. Nearly all of the major economies have announced ambitious plans and associated funding for large-scale CCS demonstration projects. Some of these, including projects in the oil and gas industry, are listed below.[7]

- Australia launched in April 2009 the Global CCS Institute (GCCSI) to foster international collaboration, particularly around near-term large-scale demonstration projects. In addition, domestically, the government has designated AUD 2 billion for large-scale demonstration.

7. Drawn from IEA (2009b).

- In Brazil, oil company Petrobras is investing in two to four large-scale demonstration projects as part of its sustainability and climate change plan.
- Canada announced in 2009 the allocation of CAD 2.5 billion for large-scale CCS project demonstration.
- A consortium of companies in China is moving forward with the GreenGen project, which has received support and approval from the government. GreenGen is also a partner in the UK-China Near Zero Emissions Coal (NZEC) agreement that intends to demonstrate CCS on a large scale by 2020.
- The European Union (EU) financial stimulus package includes EUR 1.05 billion for CCS demonstration. This complements the EU's early 2009 decision to set aside 300 million allowances from the EU Emissions Trading System to fund CCS through the avoided costs of buying the allowances.
- France is developing smaller-scale demonstration projects that will be expanded after their performance is assessed.
- Italy's Enel, the national electricity company, is developing one demonstration plant.
- In Spain, an oxyfuel CCS demonstration plant, which has received funds from the EU financial stimulus package (see above) is being developed.
- The German government has, since 2004, approved research projects in the field of power plant technologies and CCS involving about EUR 200 million of public funding, which is complemented by private financing. Additionally, the major power supply companies in Germany have announced several CCS pilot and demonstration plants, and some of the smaller plants are already in operation.
- Norway is continuing its leadership by developing the Mongstad and Kårstø projects.
- South Africa launched a CCS Centre in 2009, and plans to build capacity rapidly with the aim of having at least one full-scale project operational by 2020.
- The United Kingdom is promoting CCS via its large-scale demonstration competition, which will launch at least one major project in the next year. In addition, in April 2009, the government proposed that all new coal-fired power plants over 300 MW capacity should be at least *capture-ready* in order to provide for any requirement to apply CCS from the beginning of operation.
- The United States announced $3.4 billion in new funding for CCS projects in May 2009.

Coal-based CCS is assumed to cost an additional $750 per kW for a plant using ultra-supercritical steam condition and $700 per kW for an integrated gasification combined-cycle (IGCC) plant using post-combustion technology. Generating costs are on average $25 to $35 per MWh higher than the cost of conventional coal-based generation, in the absence of a carbon price.[8] Combined-cycle gas turbine (CCGT) plants are assumed to

8. CCS generating costs are higher because of higher capital costs, higher operating and maintenance costs, and higher fuel costs (because their efficiency is lower than that of plants without CCS). Transport and storage costs are not included in these figures.

cost an extra $400 per kW by 2030 if equipped with CCS, with generating costs being about $25 to $30 per MWh greater than for the same plant without CCS. A carbon price is therefore necessary to make CCS plants competitive with conventional plants. CCS commercialisation takes place in the period 2021-2030, during which a cap-and-trade scheme is assumed to be in place in OECD+ and Other Major Economies. Investment in CCS will require the support of governments in the first stages of commercialisation in order to mitigate risks.

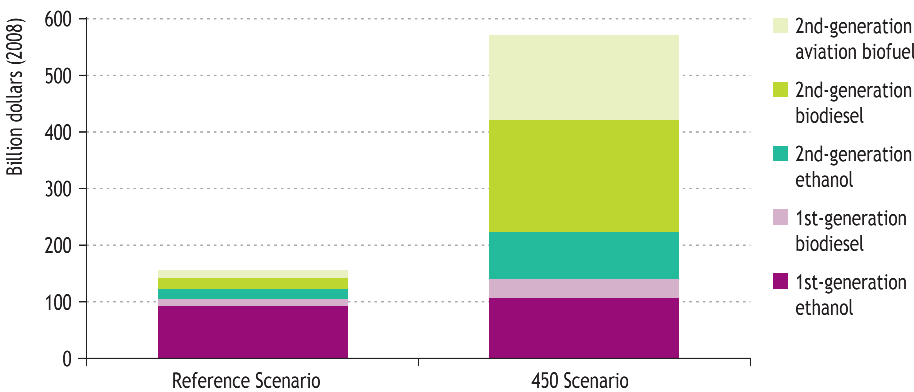
## Investment in biofuels production

Biofuels account for 4% of total transport fuel consumption by 2030 in the Reference Scenario, rising to 9% – more than double – in the 450 Scenario, an increase of 145 Mtoe. The increase is met by sustainable first-generation biofuels in the early years of the projection period; the lion's share of the increase, in the later half of the projection period, is met by second-generation biofuels after their introduction around 2020.



Relative to the Reference Scenario, the additional investment to increase the supply of biofuels is about $400 billion over the period 2010-2030 (Figure 7.8).[9] Second-generation biofuels for both road and aviation, which represent 60% of total biofuels consumption in 2030 in the 450 Scenario, take up $380 billion, or almost 95%, of this investment from 2010-2030. Second-generation biofuels are expected to be considerably cheaper to produce than first-generation biofuels, particularly close to 2030 by which time increased volumes, economies of scale and learning rates will have driven down their costs.

**Figure 7.8 • *Investment in biofuels production by scenario, 2010-2030***




The investment analysis in Figure 7.8 is split between five aggregate biofuels categories: sugar cane ethanol, corn ethanol and rapeseed biodiesel representing first-generation biofuels; and Fischer-Tropsch biodiesel and ligno-cellulosic ethanol for

9. Total investment in biofuels over the period 2008-2030 in the 450 Scenario is $569 billion against $163 billion in the Reference Scenario.

second-generation biofuels. The analysis is also based on the assumption of a 400 MW thermal plant. Bio-refineries could further lower costs by increasing plant size in order to benefit from economies of scale; however, larger plants require a greater volume of biomass, grown on a larger collection area. The increased transportation costs of distant biomass could set a natural limit on local plant size. The oil price also impacts on capital costs, construction costs and biomass prices. We have used the conservative assumption that feedstock prices will have a 20% elasticity relative to the oil price.

If the increased biofuels investment requirements for the 450 Scenario are to be realised, there will need to be a rapid reversal of the recent sharp decrease in biofuels investments, resulting from the drop in oil prices (which undermined short-term profitability) and the difficulty in accessing credit due to the credit crunch (see Chapter 3).

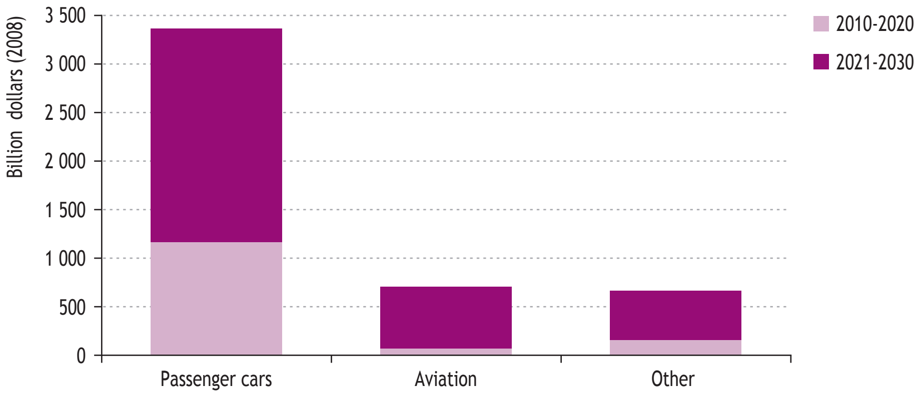
## Investment in transport

In the 450 Scenario, the assumed sectoral agreements in the passenger light-duty vehicle (PLDV) and aviation sectors (see Chapters 5 and 6), as well as national policies in other transport sectors, lead to additional investment of $4 750 billion for the entire transport sector over the period 2010-2030, accounting for over half of all the additional investment in final consumption. More than 70% of the additional investment is needed after 2020. OECD+ countries account for around half of this incremental transport investment. This share is a function of the higher cost of increasing fuel economy in some parts of OECD+, as efficiency standards are already relatively high in many countries and the greater part of vehicle sales over the projection period takes place in the region. The passenger car market requires over 70% of the additional transport investment worldwide. The incremental investment in the entire transport sector results in substantial fuel-cost savings, amounting to nearly $6 200 billion over 2010-2030. These fuel-cost savings extend beyond 2030, amounting to over $8 900 billion over the lifetime of the cars, trucks and planes purchased over the period 2010-2030.

### Passenger cars

The higher unit cost of more efficient passenger cars accounts for the bulk of the incremental investment, $3 350 billion (Figure 7.9). The assumed sectoral agreements bring forth energy and $CO_2$ savings well beyond those available from existing road-transport technologies. New technologies offer significant potential both through enhancements to the internal combustion engine (ICE) and, increasingly, hybridisation and electrification of vehicles. In addition, non-engine improvements, in aerodynamics, in the use of lightweight materials (such as high-strength steel or aluminium), and in tyres and lights, can go a long way to increase overall car efficiency. It is estimated that such non-engine improvements alone can increase fuel efficiency by up to 17% relative to a car manufactured around the year 2000. There has been a steady increase in the efficiency of new vehicles over recent years; this can be accelerated by providing the right incentives to manufacturers to undertake research, development and demonstration (RD&D) and to bring more efficient models to market.

**Figure 7.9 • Cumulative incremental investment in transport by mode in the 450 Scenario relative to the Reference Scenario**




Of the $3 350 billion additionally invested in passenger cars, about 60% goes towards the purchase of vehicles powered by electricity, indicating the scale of the challenge associated with the electrification of road transport. Additional consequential investments will be required in the power-generation and transmission sectors, as significant additions to electricity demand can be expected. Further investments are required for public and private charging stations, and for manufacturing facilities for batteries. Recent announcements by the car manufacturer, Nissan, suggest investment costs of $350 million for a production line with a capacity of 54 000 battery units per year in the state of Tennessee, United States. For the recharging infrastructure, the general expectation is that about 1.3 plugs per electric car will be required in the long run, which must be well distributed across public domains (such as parking spaces and streets) as well as in the private field (such as at home and in companies).

Our analysis shows a significant potential for improvements in the efficiency of conventional ICE vehicles, both in terms of the engine and non-engine parts.[10] While a significant share of engine-related efficiency potential can be seen as low-hanging fruit, cost-effective even in the short term, the additional costs for further increases in efficiency can be substantial (Figure 7.10). That part of the short-term potential which is already being incorporated into modern cars has been excluded from the investment cost analysis in this chapter.

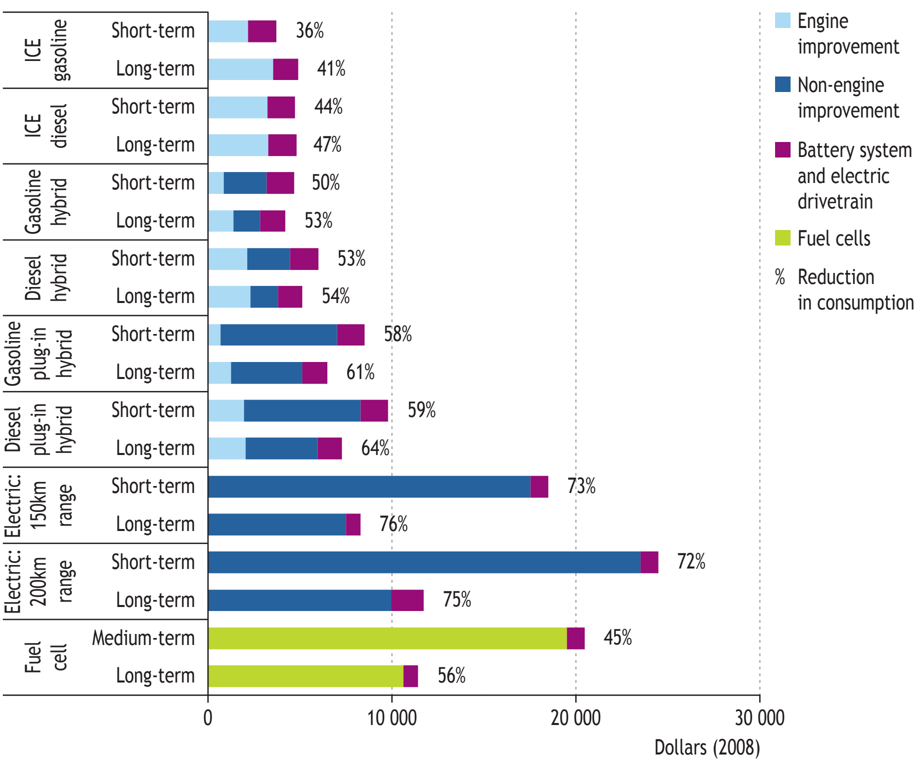
For non-conventional technologies, the picture is different. The electric powertrains and batteries that are used by all types of hybrid and electric cars offer substantial short-term reductions in fuel consumption, but at very high cost, especially for plug-in

10. For the analysis of the additional costs of more efficient conventional and advanced non-conventional cars, a comprehensive and detailed analysis of efficiency improvement potentials and associated costs was conducted for this edition of the *WEO* in collaboration with the Energy Technology Perspectives team of the IEA. The dataset was peer-reviewed by reviewers from industry and the science community.

hybrid and electric cars. The same holds true for fuel cell vehicles. In the long term, learning effects and economies of scale can be expected to drive down significantly these additional costs, though uncertainties are considerable.

The Reference Scenario sees the average efficiency of the global passenger car stock increasing by 25% by 2030 compared with 2007, while it increases by 53% in the 450 Scenario. Conventional ICE vehicles dominate the car market through to 2030 in the Reference Scenario, implying that a considerable part of the above-mentioned low-hanging fruit for improving fleet fuel economy will already be used in the Reference Scenario. As a result, the additional costs for the 450 Scenario are significant. The picture becomes less daunting when fuel savings are considered over the lifetime of a vehicle (which offset part of the required additional investment). In the 450 Scenario, the undiscounted fuel-cost savings from the use of more efficient passenger cars, relative to the Reference Scenario, amount to $3 150 billion.

**Figure 7.10 • *Maximum potential and incremental costs of vehicle technologies for fuel savings compared with a year-2000 gasoline ICE car***




These fuel savings over the lifetime of the vehicle imply that the capital cost of efficiency improvements might be entirely offset. But even where this is true on a discounted basis, domestic consumers typically give more weight to the level of up-front capital costs. This behavioural consideration could be a significant barrier to the purchase of more expensive fuel-efficient cars. Moreover, consumers have to pay the price demanded for these improvements – not the cost. As a rule of the thumb, the price to the consumer of innovation in the automotive sector, depending on the degree of innovation and on the market segment in which the car manufacturer operates, is generally calculated by the car industry using a factor of 1.1 to 2.0 on the costs of the technology, to reflect R&D costs and the required return on investment. Thus, the fuel savings over the lifetime of the vehicle have to be higher if the additional cost to the consumer is to be fully offset.

SPOTLIGHT

### $CO_2$ savings for free?

The review of cost data for this year's *Outlook* provides a clear picture of the challenge that road transport is facing when it comes to reducing $CO_2$ emissions. Advanced powertrains come at a cost, even more so if they use fuels other than oil-based transportation fuel, such as electricity or hydrogen. However, this is only one aspect. It is important to note that this analysis is based on the assumption that consumer preferences remain constant in the 450 Scenario. This implies that consumers will request at least the same level of sophistication from a future car as they do today, *i.e.* with a similar number of features irrespective of their impact on fuel economy. In addition, it implies that consumers are unlikely to alter their preferences with regard to the size of their cars, even though driving a small car rather than a sport utility vehicle (SUV) is clearly an effective way to save fuel and thereby emissions. Also excluded from the analysis are the cost-effective and efficient $CO_2$ savings that can arise from eco-driving practices or modal shifts. This means that consumers are assumed to be ready to pay for more fuel-efficient cars and the incremental investment cost calculated in our analysis shows the size of this burden. If consumers were to make different choices, the necessary fuel savings could be achieved at net negative cost.

Even assuming all of the above, the estimated long-term cost expectations as outlined in Figure 7.10 cannot be taken as definitive. When anti-lock braking systems (ABS) were initially introduced to the car market in the late 1970s, their application was very expensive and therefore limited to larger cars. However, ABS has become industry standard, the additional costs having been substantially reduced and absorbed into the cost of the vehicle. Standardisation and mass manufacturing could achieve the same for some of the other technologies considered here, making them available at even lower costs than expected. On the other hand, the downside of this holds true as well, *i.e.* without mass production, the expected cost reductions are likely never to be achieved.

Sectors other than transport could also see $CO_2$ savings at negative costs if consumers were to accept a slightly lower service level or slight changes to their usual behaviour, such as turning off lights, using appliances for shorter times, turning down the thermostat on the heating or turning off the air conditioning.

### Aviation

Cumulative emission reductions in the aviation sector of 1.6 Gt, relative to the Reference Scenario, come at a capital cost of $700 billion over the projection period. This cost is partially offset by fuel savings of $650 billion. Most of the savings come from a combination of technical, operational and infrastructure measures.

In the aviation industry, in which fuel costs are a major component of overall costs, the costs of some investment would be fully offset by fuel savings. These include, on the structural side, retrofitting of wingtips and drag reduction. On the operational side, they include use of ground power, in-flight fuel management, improved taxiing techniques, weight reductions and improved take-off and landing procedures. Investment in improvements to flight paths and air traffic management systems come at negative costs after fuel savings are offset. For example, it is estimated that flights between Lyon, France and Frankfurt, Germany are 41% longer than they need be. The International Air Transport Association (IATA) estimates that shorter, performance-based navigation routes could cut $CO_2$ emissions by 13 Mt per year if globally implemented. These measures, which are assumed to be partially implemented in the Reference Scenario, are fully implemented in the 450 Scenario. Over the projection period, fuel savings outweigh investment costs. After these low-cost savings are made, further $CO_2$ savings come at much higher costs. Further measures that are implemented towards the end of the *Outlook* period include the earlier retirement of aircraft, engine retro-fits and the introduction of aviation biofuels.

### Other transport

The remaining sectors in transport combined require $665 billion of additional investment over 2010-2030, relative to the Reference Scenario. Over 90% of that investment is made in in trucks and buses, as savings from technology advances in the PLDV fleet, brought about by international sectoral agreements, spill over, particularly to light commercial vehicles – often at reduced costs.[11] Mitigation measures in the remaining transport sectors include: increased investment in electric railways; improved logistics, downsizing and lightweighting in heavy-duty vehicles; and, in shipping, engine retrofits, speed reductions, and engine and hydrodynamic improvements.

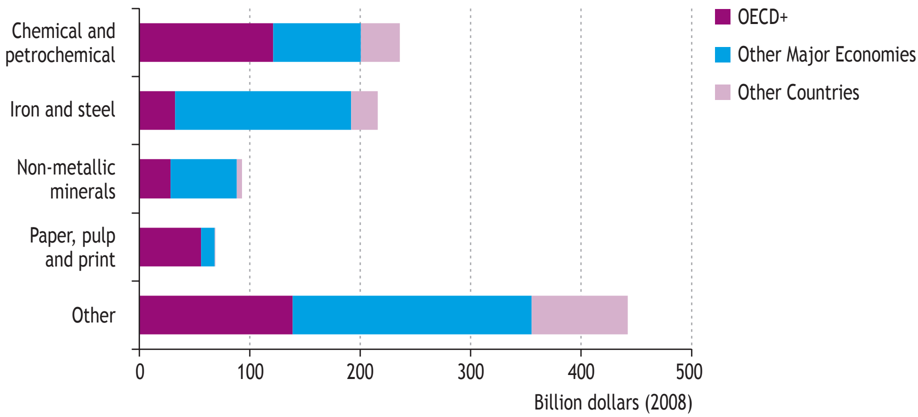
## Investment in industry

Globally, the industry sector invests an additional $1 050 billion dollars over the period 2010-2030, relative to the Reference Scenario. This investment is directed toward more efficient technologies, technologies that use electricity or gas instead of coal, and CCS. Nearly 60% of this investment is needed in the energy-intensive branches of industry – iron and steel, non-metallic minerals (mainly cement), chemicals and petrochemicals,

11. Considerable uncertainty exists with regard to required investment in heavy-duty vehicles.

and pulp and paper. Chemicals and petrochemicals need the largest increase in investment, followed closely by iron and steel (Figure 7.11). Additional investment in industrial CCS totals $150 billion.

**Figure 7.11 • *Cumulative incremental investment in industry in the 450 Scenario relative to the Reference Scenario, 2010-2030***




The largest industry investment needs arise in Other Major Economies, where an additional $530 billion is invested between 2010 and 2030. Most of this investment is in China's vast industrial sector, which already accounts for well over one-third of global industrial $CO_2$ emissions. China's industry is heavily dependent on coal-based technologies, such as blast furnaces. Many of its industrial processes are still inefficient compared with those in the OECD, although there have been significant improvements in technology in recent years. Introducing new technologies that produce lower emissions in China's industry comes at an additional cost of over $400 billion over 2010-2030. Investment in OECD countries amounts to $380 billion. Other Countries need to invest an extra $150 billion, of which $70 billion is needed in India.

The main drivers of this investment are a cap-and-trade system and international sectoral agreements to adopt best practices in industry. In the period 2010-2020, the additional investment by all sectors of industry as a result of the cap-and-trade system amounts to over $100 billion – all in OECD+ countries; in the period 2021-2030, when Other Major Economies join the cap-and-trade system, an additional $750 billion is to be invested. Investment in low-carbon technologies in industry is necessary not only to reduce emissions, but also to improve competitiveness in the long run. The cap-and-trade system will increase fuel costs for industry, but investing in energy efficiency will help reduce spending on fuel. In Other Countries, investment in low-carbon technologies is driven by international sectoral agreements. Total undiscounted fuel-cost savings over the period 2010-2030 are slightly higher than the incremental investment, while they are three times higher over the lifetime of these investments.

## Investment in buildings

In the 450 Scenario, investment in buildings over the period 2010-2030 increases by $2 550 billion, relative to the Reference Scenario. Nearly two-thirds of this investment is needed in houses and residential building blocks, with the remainder going into commercial buildings (for example, offices, hotels and shops) and public establishments (such as government offices). This investment is driven by national policies and measures aimed at energy efficiency and renewables. Close to 30% of the additional investment goes into renewables, notably into photovoltaics, solar water heaters, biomass and geothermal-based heating (Table 7.9).

**Table 7.9 • Cumulative incremental investment in 2010-2030 in renewable energy in buildings, in the 450 Scenario relative to the Reference Scenario** ($2008, billion)

| | Photovoltaics | Solar water heaters and geothermal | Biomass | Total renewables | % of buildings investment |
|---|---|---|---|---|---|
| OECD+ | 201 | 149 | 60 | 410 | 28% |
| Other Major Economies | 87 | 76 | 5 | 168 | 24% |
| Other Countries | 91 | 12 | 3 | 106 | 30% |
| **World** | **379** | **236** | **68** | **683** | **27%** |

Nearly 60% of the incremental investment is needed in OECD+ countries, where the additional investment needed to reduce energy consumption is very high because energy use is already quite efficient in most of the countries of the region. Significant investment is needed to reduce energy consumption for space heating and cooling, and to switch from oil and gas boilers to electricity-based systems. Retrofitting buildings saves energy but requires substantial up-front investment. Similarly, heat pumps reduce energy consumption, by a factor of three or four compared with the heat provided by a conventional boiler, but require much higher initial investment. Solar water heaters and photovoltaics also come at relatively high costs. Incremental spending on more efficient appliances and office equipment is also quite substantial, although the incremental cost is modest relative to the large savings in electricity bills achieved.

Other Major Economies need to invest an additional $730 billion, mainly in electrical appliances. More than half of this investment is needed in China. Other Countries need an extra $350 billion, of which $75 billion is in India. All these countries have a very large potential to switch to more efficient appliances at low cost.

Relative to the Reference Scenario, this incremental investment results in global fuel-cost savings of $1 200 billion over the period 2010-2030. Buildings in OECD+ countries face higher fuel costs than in the Reference Scenario because electricity prices include the carbon price generated by the cap-and-trade system. These higher electricity prices make many of the investments in buildings cost-effective. There are net cost savings for Other Major Economies and Other Countries. Lifetime global fuel-cost savings are close to $5 000 billion.

Tables 7.10 and 7.11 provide a summary of the annual additional investment needs by region for the periods 2010-2020 and 2021-2030.

**Table 7.10 • Average annual incremental investment by country/region and sector in the 450 Scenario relative to the Reference Scenario, 2010-2020** ($2008, billion)

| Region | Power plants | Biofuels | Transport | Industry | Buildings | Total |
|---|---|---|---|---|---|---|
| **OECD+** | **12.7** | **0.7** | **70.9** | **9.6** | **27.9** | **121.9** |
| *United States* | *6.1* | *0.0* | *25.5* | *5.0* | *11.1* | *47.5* |
| *European Union* | *3.5* | *0.4* | *29.2* | *1.3* | *9.3* | *43.8* |
| *Japan* | *0.3* | *0.1* | *4.1* | *0.5* | *2.9* | *8.0* |
| **Other Major Economies** | **10.8** | **1.0** | **30.3** | **4.2** | **10.1** | **56.5** |
| *Russia* | *0.0* | *0.0* | *3.7* | *0.3* | *0.4* | *1.6* |
| *China* | *10.9* | *0.1* | *15.1* | *3.8* | *5.5* | *35.4* |
| **Other Countries** | **6.4** | **0.8** | **21.4** | **1.9** | **4.5** | **35.0** |
| *India* | *3.3* | *0.1* | *4.7* | *0.8* | *0.7* | *9.6* |
| **World** | **30.0** | **2.5** | **126.3** | **15.8** | **42.6** | **217.1** |

Note: Russia's investment in power generation in 2010-2020 in the 450 Scenario is lower than in the Reference Scenario because of lower electricity demand and the longer operational lifetimes assumed for its nuclear power plants, which reduce the need to build new capacity. The incremental investment shown in this table is expressed as zero. The world total for transport and biofuels includes international aviation.

**Table 7.11 • Average annual incremental investment by country/region and sector in the 450 Scenario relative to the Reference Scenario, 2021-2030** ($2008, billion)

| Region | Power plants | Biofuels | Transport | Industry | Buildings | Total |
|---|---|---|---|---|---|---|
| **OECD+** | **66.7** | **22.3** | **137.1** | **27.1** | **114.4** | **367.6** |
| *United States* | *25.9* | *12.7* | *47.8* | *13.7* | *52.7* | *152.7* |
| *European Union* | *20.9* | *6.0* | *55.1* | *2.4* | *28.9* | *113.3* |
| *Japan* | *5.8* | *0.7* | *7.7* | *2.1* | *11.8* | *28.1* |
| **Other Major Economies** | **36.9** | **5.6** | **95.5** | **48.0** | **61.7** | **247.7** |
| *Russia* | *2.3* | *0.1* | *6.9* | *4.3* | *4.7* | *18.4* |
| *China* | *30.9* | *2.8* | *58.9* | *38.6* | *36.1* | *167.4* |
| **Other Countries** | **37.9** | **3.2** | **63.2** | **13.1** | **30.4** | **147.7** |
| *India* | *15.9* | *1.1* | *19.0* | *6.2* | *6.6* | *48.8* |
| **World** | **141.5** | **37.8** | **334.1** | **88.2** | **206.5** | **808.1** |

Note: The world total for transport and biofuels includes international aviation.

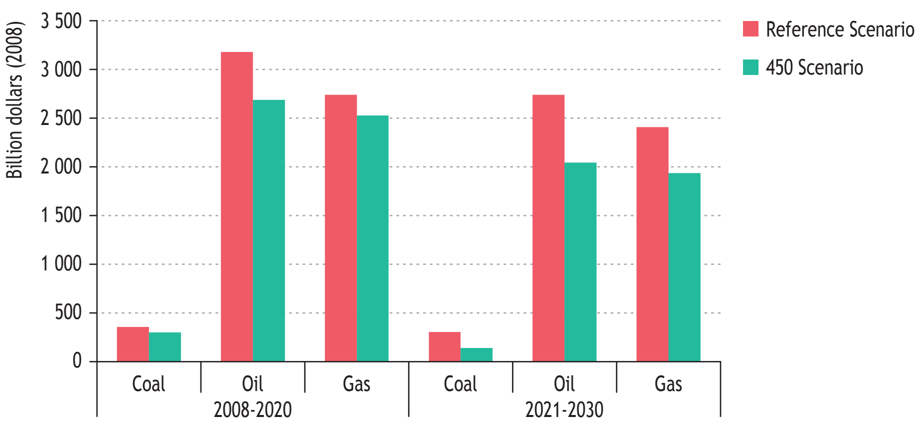
7

## Investment in fossil-fuel supply

In the 450 Scenario, investment in coal, oil and gas supply is lower than in the Reference Scenario by $2 100 billion over the period 2008-2030. Estimated at $9 650 billion, however, it remains very substantial. Most investment is needed in oil supply ($4 750 billion), followed by gas ($4 450 billion) and coal ($450 billion). In relative terms, investment in the coal industry falls furthest, as demand for coal is reduced dramatically in the 450 Scenario. Investment in coal supply is 34% lower than in the Reference Scenario, while investment in oil is reduced by 20% and investment in gas by 13%.

In the period 2008-2020, investment in oil supply in the 450 Scenario is 16% lower than in the Reference Scenario and investment in gas supply is reduced by 8% (Figure 7.12). The drop is much more substantial post-2020 for both fuels. In the period 2021-2030, investment in oil supply is lower by 25%, compared with the same period in the Reference Scenario, and investment in gas supply is 20% lower. Investment in coal supply is lower by 16% in the period 2008-2020 and by 55% over 2021-2030.

**Figure 7.12 • *Cumulative investment in fossil-fuel supply by fuel and scenario***



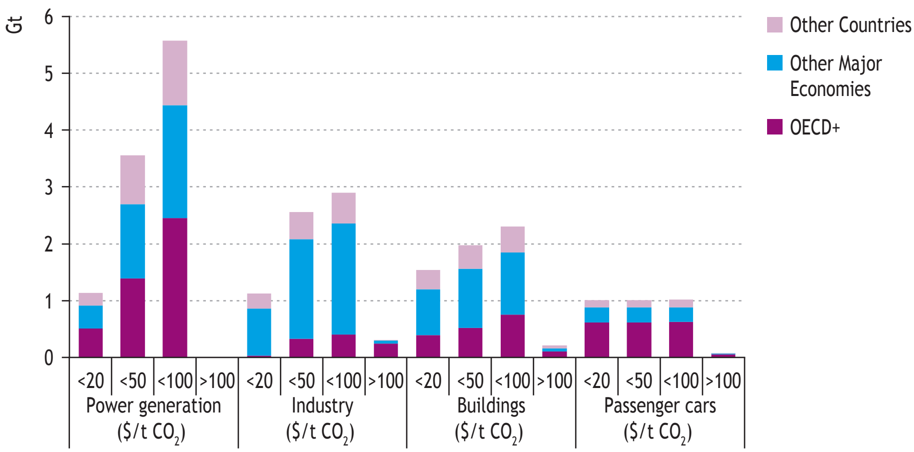

## Mitigation costs per unit of $CO_2$ reduction

In the 450 Scenario, $CO_2$ emissions from the combustion of coal, oil and gas are reduced by 13.8 Gt in 2030 relative to the Reference Scenario. Figure 7.13 summarises the $CO_2$ reductions and the costs at which these reductions are achieved, under the assumptions in this scenario in power generation, industry, buildings and passenger cars. The reductions are measured relative to the Reference Scenario. Emissions reductions from lower electricity demand, resulting from greater energy efficiency in buildings and industry, have been allocated to those sectors.

Almost all the emissions reductions come at a cost of below $100 per tonne $CO_2$ in the period to 2030. Low-cost mitigation options exist in all sectors and all regions. Almost 40% of the reductions come from measures costing less than $20 per tonne $CO_2$. Most of the low-cost options (less than $20 per tonne $CO_2$) are in non-OECD countries.

As discussed above, there is significant potential to reduce emissions in the power sector using renewables, CCS and nuclear power. Figure 7.14 shows the potential volumes of $CO_2$ reduction and their associated ranges of unit costs. These costs have been calculated by comparing the generating costs and the $CO_2$ emissions of low-carbon technologies with those of the technology they displace (relative to the Reference Scenario), which in most cases is a new coal-fired plant or a combination of a new coal-fired plant, a new gas-fired plant and an existing coal-fired plant.[12]

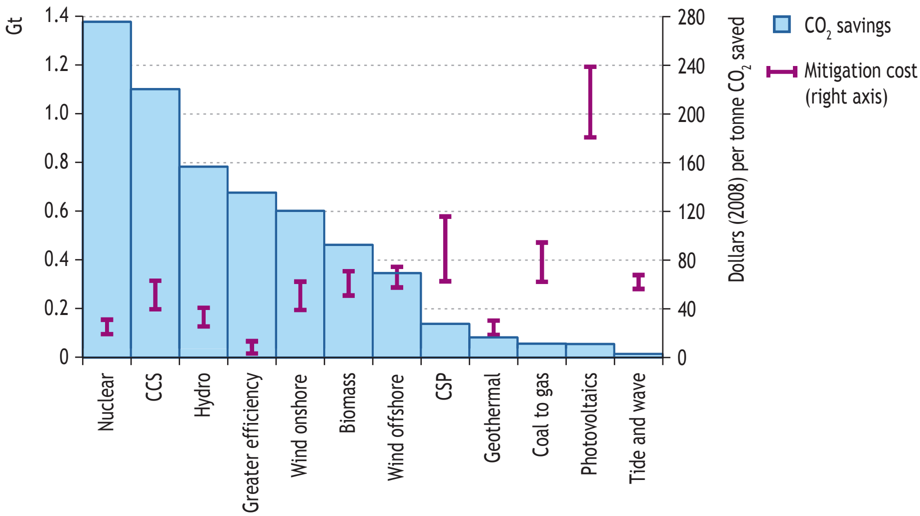
**Figure 7.13 • Mitigation costs of $CO_2$ reductions in 2030 in the 450 Scenario, relative to the Reference Scenario**




Significant emission reductions can be achieved through increased use of nuclear power, at costs ranging between $19 and $31 per tonne $CO_2$. Very low-cost reductions, at less than $13 per tonne $CO_2$, can be achieved through the use of more efficient coal- and gas-based power generation, for example, by building ultra-supercritical coal-fired power plants instead of supercritical. CCS in power generation comes at costs between $40 and $63 per tonne $CO_2$.

12. In the 450 Scenario, the power-generation sector in OECD+ countries is assumed to participate in a cap-and-trade system together with industry. Other Major Economies countries join the cap-and-trade system after 2020. The carbon price that emerges from trading reaches $110 per tonne $CO_2$ in 2030, reflecting the cost of industrial CCS. For the power sector, the most expensive option included in the cap-and-trade is also CCS, but it becomes competitive at less than $110 per tonne $CO_2$.

**Figure 7.14** • ***Mitigation costs and associated $CO_2$ reductions by power-generation technology in 2030 in the 450 Scenario, relative to the Reference Scenario***




The unit costs of $CO_2$ reductions from using renewables vary significantly, depending on the technology and location. Geothermal, hydropower and onshore wind power have some of the lowest costs per unit of $CO_2$ reduction. The $CO_2$ abatement cost of geothermal power is the lowest among all renewables, but the $CO_2$ reductions achieved are very small because geothermal power is constrained by resource availability. Hydropower saves significant amounts of $CO_2$, at costs ranging between \$26 and \$41 per tonne $CO_2$ but most of the resources are in non-OECD countries. $CO_2$ reductions through greater use of onshore wind power come at a cost between \$39 and \$62 per tonne $CO_2$. In the middle of the cost range, offshore wind costs between \$58 and \$75 per tonne $CO_2$, biomass between \$51 and \$71 per tonne $CO_2$, and tide and wave power at \$56 to \$68 per tonne $CO_2$. Higher mitigation cost renewables include concentrating solar power (\$63 to \$116 per tonne $CO_2$) and photovoltaics (\$181 to \$239 per tonne $CO_2$).

Several low-cost options are available to reduce emissions in industry, notably through the use of more efficient electric motors. Heavy industry has relatively low-cost options, too, but the cost estimates for these are not very accurate. Most of the emissions reduction potential is in China, a country for which costs are very difficult to establish. The most expensive option in industry in 2030 is CCS, at \$110 per tonne $CO_2$.

In buildings, substantial savings can be achieved, at moderate costs per unit of $CO_2$ saved, through the use of more efficient appliances. Building retrofit costs can be low per unit saved; although retrofitting requires substantial up-front investment, the energy and $CO_2$ emission savings extend over a long time. More expensive options include photovoltaics and heat pumps.

In passenger car transport, there is a large potential to reduce emissions at low cost by improving car efficiency. Significant potential costing less than \$20 per tonne $CO_2$ exists in OECD+, with a large part of it in the United States. The costliest options are plug-in hybrid and electric cars: electric car mitigation costs can go beyond \$100 per tonne of $CO_2$ saved.

### Box 7.2 ● *Uncertainties about calculating mitigation costs for transport*

Estimates of the marginal abatement costs of passenger cars can vary widely, depending on the assumptions used, such as the discount rate, the lifetime of the vehicle and the mileage driven. The marginal abatement costs of fuel-efficient gasoline ICE vehicles and hybrid cars in 2030 are mostly negative across world regions for a discount rate of 10%, as fuel-cost savings over the vehicle's lifetime (under most assumptions) substantially exceed the additional investment needed.

Just as the calculation is highly sensitive to the discount rate chosen, so the choice of the annual mileage is critical. The choice of a high mileage increases the amount of fuel saved by fuel-efficient cars, thereby, sometimes in itself implying a negative marginal abatement cost. Generally, it is safe to say that efficiency improvements to conventional ICE vehicles and the purchase of hybrid cars come at no net cost to the consumer over the lifetime of the vehicles and, in certain conditions, the higher investment cost can be paid back within a few years.

For plug-in hybrids and electric cars, the marginal abatement costs are even more sensitive to the assumptions. With their high up-front investment costs, the choice of discount rates is particularly important. Moreover, the uncertainty about future battery costs, about the required ratio of battery replacement rates over the lifetime of the vehicle (which tends to vary considerably, for example, with different climatic conditions) and about assumptions such as the value of used batteries in the second-hand markets, can shift estimates of marginal abatement costs from values lower than \$20 per tonne $CO_2$ to values in excess of \$200 per tonne $CO_2$.

Using a bottom-up approach to estimate mitigation costs provides useful insights for comparing technologies and can help identify least-cost options for reducing $CO_2$ emissions. However, these costs are very dependent on the underlying assumptions: the discount rate, fuel prices, the lifetime of the technology (technical or economic), the baseline technologies against which costs are measured and, in the case of road transport, the assumptions on mileage driven per car and per year. Measuring costs in the power sector and, to some extent, in industry is relatively straightforward. On the other hand, there are substantial difficulties about estimating the cost per unit of $CO_2$ saved in transport and households; these costs are highly sensitive to the extent to which an appliance is used over its lifetime and to discount rates, which tend to vary considerably. Moreover, decisions made by individuals encompass a number of criteria that go beyond the cost of the car or the appliance and are very difficult to quantify. These factors raise doubts over the value of some mitigation cost estimates. Overall, unit mitigation costs can be a very useful tool to identify least-cost options for reducing $CO_2$ emissions; however, estimates for the unit costs of mitigation measures for private transport and households should be considered with care.

## Benefits of investing in low-carbon technologies and energy efficiency

### Reduced local pollution

Rising energy consumption, increasing mobility and continuing reliance on fossil fuels are damaging ambient air quality in many countries, particularly outside the OECD. Emissions of sulphur dioxide ($SO_2$), nitrogen oxides ($NO_x$) and particulate matter are harmful to human health and cause environmental problems, such as acid rain, reduced visibility and ground-level ozone formation (though, in some cases, they can also reduce the overall warming impact of greenhouse-gas emissions). Air pollution has become a major public health issue in cities across the developing world. In addition to the local consequences, the effects of air pollution are felt beyond national borders. Regulatory programmes, international treaties and emissions control technologies already exist to tackle many of these problems. Projections of these pollutants for the Reference Scenario are presented in Chapter 2.

Actions to suppress air pollutants, inhibit climate change or pursue other energy-related goals can be mutually supportive: improving energy efficiency, for example, reduces fossil-fuel consumption, air pollution and greenhouse-gas emissions, while benefitting human health and contributing to energy security. Effective policy integration, producing what are termed "co-benefits", warrants attention in both developing and developed countries.

The policies aimed at reducing energy-related $CO_2$ emissions in the 450 Scenario cause an important reduction in the emission of air pollutants (Table 7.12). By 2030, $SO_2$ emissions are 25 million tonnes (Mt), or 29%, lower than in the Reference Scenario. The majority of that reduction (22 Mt) occurs in non-OECD countries. $NO_x$ emissions are 19% lower. In absolute terms, this means 16 Mt of $NO_x$ less, of which 13 Mt is due to lower emissions from non-OECD countries. Emissions of particulates (PM2.5) also decrease, compared with the Reference Scenario. In 2030, they are 3.8 Mt (or 9%) lower. Importantly, emissions in the OECD region are slightly higher (by 0.5 Mt) in the 450 Scenario, due to greater use of biomass in the residential sector. Emissions from non-OECD countries decrease by 4.3 Mt.

While reducing these pollutants has a positive impact on human health, there are no data available to allow for a quantitative global assessment of this impact. Estimates for European countries, China, India and the European part of Russia suggest that about 3.4 billion life-years were lost in those countries in 2005 due to PM2.5 exposure. This estimate is dominated by the figures for China and India, which together account for more than 90% of the life-years lost in 2005. The Reference Scenario implies increased loss of life-years, the numbers rising by about 70% by 2030 to 5.7 billion (Table 7.13). Relative to the Reference Scenario, the 450 Scenario saves 1.2 billion life-years in 2030, 560 million of these in China and 600 million in India.

**Table 7.12 • Emissions of major air pollutants by region in the 450 Scenario**
(Thousand tonnes)

| | 2005 | 2007 | 2020 | 2030 | Change versus Reference Scenario 2020 | Change versus Reference Scenario 2030 |
|---|---|---|---|---|---|---|
| | | | Sulphur dioxide ($SO_2$) | | | |
| **OECD+** | **30 125** | **25 203** | **11 718** | **9 670** | **-12%** | **-23%** |
| *United States* | *13 789* | *11 301* | *3 827* | *2 669* | *-13%* | *-29%* |
| *European Union* | *8 017* | *6 267* | *2 568* | *2 294* | *-7%* | *-13%* |
| *Japan* | *811* | *717* | *523* | *487* | *-3%* | *-8%* |
| **OME** | **44 922** | **44 685** | **39 590** | **28 916** | **-10%** | **-30%** |
| *Russia* | *5 416* | *5 532* | *3 976* | *3 739* | *-11%* | *-27%* |
| *China* | *31 557* | *31 525* | *29 524* | *19 558* | *-11%* | *-33%* |
| **Other Countries** | **20 155** | **20 408** | **22 525** | **23 185** | **-8%** | **-29%** |
| *India* | *5 929* | *6 263* | *9 158* | *9 376* | *-11%* | *-37%* |
| **World** | **95 202** | **90 297** | **73 835** | **61 772** | **-10%** | **-29%** |
| | | | Nitrogen oxides ($NO_x$) | | | |
| **OECD+** | **37 194** | **33 348** | **17 358** | **14 037** | **–8%** | **–17%** |
| *United States* | *17 191* | *15 225* | *6 895* | *5 180* | *-8%* | *-20%* |
| *European Union* | *10 854* | *9 625* | *4 990* | *3 988* | *-7%* | *-12%* |
| *Japan* | *2 163* | *1 926* | *930* | *697* | *-8%* | *-15%* |
| **OME** | **28 473** | **29 158** | **30 779** | **29 141** | **-8%** | **-23%** |
| *Russia* | *4 903* | *4 645* | *3 396* | *2 797* | *-6%* | *-19%* |
| *China* | *15 760* | *16 902* | *19 518* | *17 274* | *-10%* | *-29%* |
| **Other Countries** | **19 437** | **19 276** | **20 269** | **24 477** | **-6%** | **-16%** |
| *India* | *3 942* | *4 113* | *5 517* | *7 431* | *-8%* | *-22%* |
| **World** | **85 104** | **81 783** | **68 406** | **67 655** | **-7%** | **-19%** |
| | | | Particulate matter (PM2.5) | | | |
| **OECD+** | **4 210** | **3 944** | **3 378** | **3 818** | **3%** | **15%** |
| *United States* | *1 027* | *946* | *820* | *1 050* | *14%* | *51%* |
| *European Union* | *1 695* | *1 573* | *1 287* | *1 363* | *2%* | *10%* |
| *Japan* | *199* | *184* | *130* | *116* | *-4%* | *-8%* |
| **OME** | **15 619** | **16 162** | **14 634** | **12 316** | **-5%** | **-13%** |
| *Russia* | *1 113* | *1 098* | *1 115* | *1 056* | *-4%* | *-14%* |
| *China* | *12 553* | *13 100* | *11 451* | *9 313* | *-6%* | *-15%* |
| **Other Countries** | **18 695** | **19 014** | **20 119** | **20 038** | **-4%** | **-11%** |
| *India* | *5 098* | *5 139* | *5 347* | *5 398* | *-5%* | *-14%* |
| **World** | **38 524** | **39 121** | **38 131** | **36 171** | **-4%** | **-9%** |

Note: The base year of these projections is 2005 and 2007 is estimated by IIASA.
Source: IIASA (2009).

**Table 7.13 • Estimated life-years lost due to exposure to anthropogenic emissions of PM2.5** (million life-years)

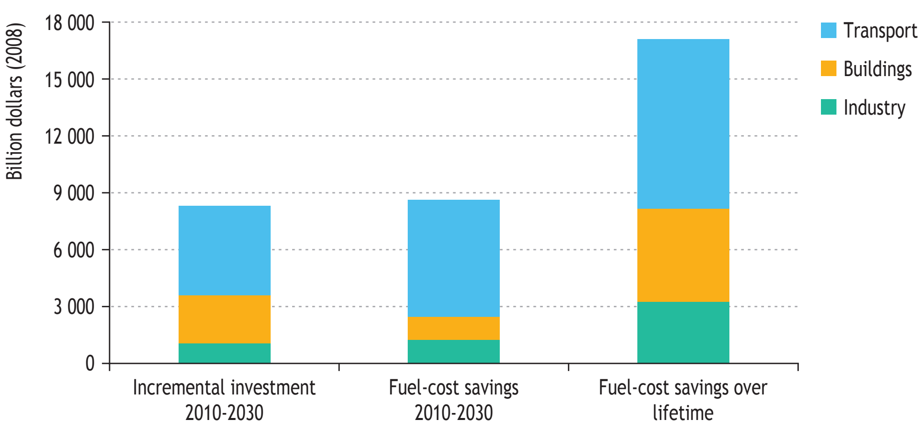
| | | Reference Scenario | | 450 Scenario | |
|---|---|---|---|---|---|
| | 2005 | 2020 | 2030 | 2020 | 2030 |
| China | 2 233 | 2 903 | 2 897 | 2 707 | 2 340 |
| India | 865 | 1 637 | 2 647 | 1 522 | 2 044 |
| Russia* | 47 | 45 | 47 | 43 | 41 |
| European Union | 206 | 122 | 117 | 118 | 111 |

* European part only.
Source: IIASA (2009).

## Valuing the benefits of the 450 Scenario

Valuing the benefits to humanity of avoiding precipitate climate change is beyond the scope of this study. Nonetheless, there are benefits more directly related to the energy sector that should be taken into account when facing up to the substantial additional investment requirements of the 450 Scenario. Savings on energy consumers' bills, lower import costs for energy-importing countries and reduced spending to deal with the effects of pollution, are benefits that can all be measured in financial terms. Globally, the undiscounted fuel-cost savings in industry, buildings and transport over 2010-2030 amount to over $8 600 billion (Figure 7.15). Investments made after 2020 generally come at higher cost; but the fuel-cost savings extend well beyond 2030, particularly in the buildings sector, where high investment cost measures (such as building-retrofit in OECD+ countries) result in significant fuel-cost savings over very long periods. The undiscounted fuel-cost savings over the lifetime of these investments exceed $17 000 billion. At a 3% discount rate, there are net savings of $3 600 billion, while at a 10% rate, there are still net savings of $450 billion over the lifetime.

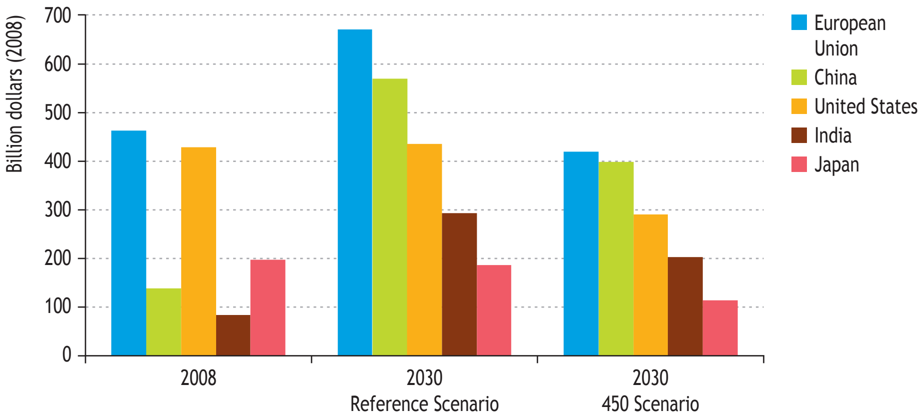
**Figure 7.15 • Incremental investment needs and fuel-cost savings for industry, buildings and transport in the 450 Scenario relative to the Reference Scenario**




Notes: The changes in power-generation investment and fuel costs are included in the electricity prices charged to the sectors shown in this graph. Costs are not discounted.

Spending on energy imports continues at a high level in the Reference Scenario, representing a major economic burden to importing countries. In the 450 Scenario, spending on oil and gas imports is lower than in the Reference Scenario, both because of reduced oil and gas imports and because fossil-fuel prices are assumed to fall. Import bills in OECD countries in 2030 are much lower than in 2008 (Figure 7.16). They are reduced by 30% in China and by 31% in India, compared with 2030 in the Reference Scenario.

**Figure 7.16** ● ***Oil and gas import bills in selected countries/regions by scenario***

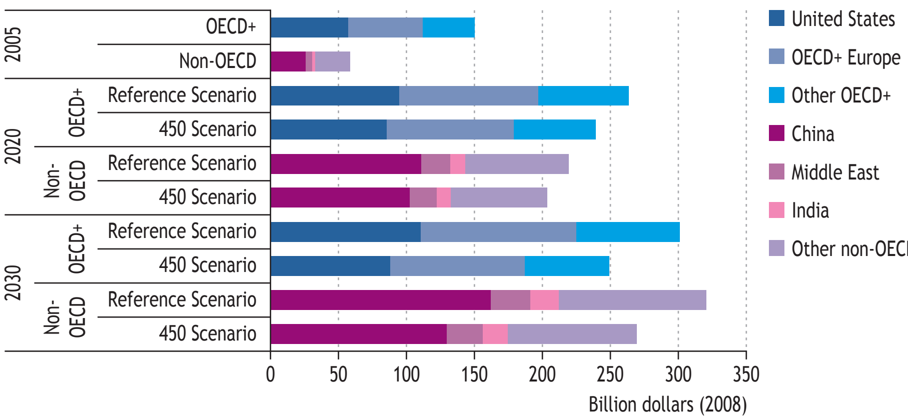



Note: Calculated as the average value of net imports at prevailing international prices.
Source: IEA databases and analysis.

Spending to curb air pollution was estimated at $200 billion worldwide in 2005 (Figure 7.17). In the Reference Scenario, these costs increase by a factor of 3.5 by 2030, due to both higher activity levels (for example, higher energy consumption, higher car ownership) and the increasing stringency of controls. More than 60% of the total cost of reducing emissions in 2030 arises in relation to road transport. In the 450 Scenario, reduced fossil-fuel consumption, brings a reduction of 17% in these costs in 2030, compared with the Reference Scenario, saving $100 billion. The largest savings are in China ($33 billion) and the United States ($23 billion). These cost figures, along with the figures on life-years saved, clearly demonstrate the value of the co-benefits of action directed at mitigating climate change.

Investment in electricity networks in the 450 Scenario amounts to $5 100 billion in 2010-2030, about 20% less than in the Reference Scenario because electricity demand is lower. In non-OECD countries, investment in networks is over $700 billion lower than in the Reference Scenario, which offsets most of the additional $900 billion these countries need to spend on power plant under the 450 Scenario. In countries struggling to raise finance, this reduction can also be seen as an important benefit.

**Figure 7.17** • *Annual air pollution control costs by region and scenario*




Source: IIASA (2009).

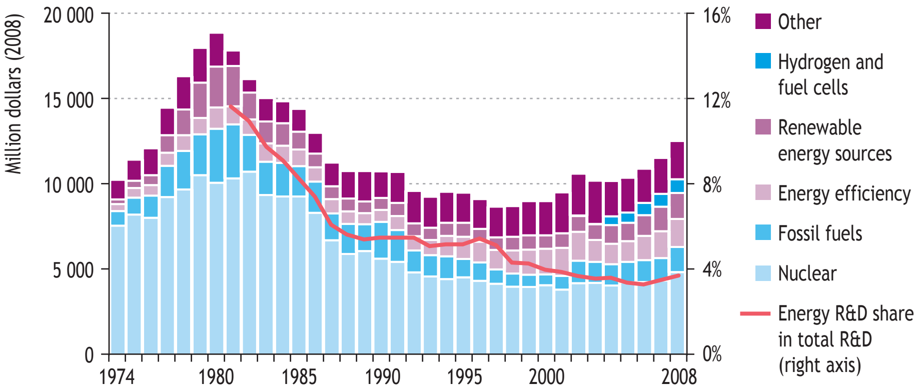
# Investment in research, development, demonstration and deployment

## Current status

Many low-carbon technologies needed to achieve the 450 Scenario currently have higher costs than the incumbents. It is only through technology learning from research, development, demonstration and deployment (RDD&D) that these costs can be reduced and the technologies become economic. New technologies require, at some stage, both the *push* of research, development and demonstration and the *pull* of market deployment. Often, and particularly when a rapid transition is required, both the *push* and the *pull* have to be organised or supported by governments.

Some low-carbon technologies (such as onshore wind, biomass, third-generation nuclear power, hybrid vehicles and many energy-efficiency technologies) are already commercially available – but their widespread diffusion remains dependent on supportive policy measures. Several other technologies are not yet available for deployment (*e.g.* ultra-high efficiency or ultra-low cost PV devices and fourth-generation nuclear power) and although they are not expected to be commercialised before 2030, they need RD&D now. A huge effort will be needed. Public energy RD&D spending in IEA countries has been slowly increasing in recent years, reaching $12.5 billion in 2008 (Figure 7.18). However, in real terms, it is about two-thirds the level it was in 1980. Private sector RD&D in energy technology exceeds public investment, at $40 billion to $60 billion per year, although this is only partly related to clean energy (IEA, 2008). Governments have made commitments to increase public RD&D and some countries have implemented their commitments, but, overall, the declared goals have yet to be fully realised.

**Figure 7.18 • *IEA government spending on energy research, development and demonstration***




Note: RD&D budgets for the Czech Republic, Poland and Slovak Republic have not been included for lack of availability.

Source: IEA databases.



In order to realise the energy technology revolution envisioned in the 450 Scenario, governments need to provide strong and coherent support, within and across technology families. RDD&D investment needs under the 450 Scenario are about $3 500 billion between 2010 and 2030, approximately equally spread between 2010-2020 and 2021-2030.[13] Deployment costs represent the bulk of these investments.

## Role for governments to enhance RD&D

The IEA has called on all countries to take such action on a large-scale – a Clean Energy New Deal – to exploit the opportunity the financial and economic crisis presents to affect a permanent shift in investment to low-carbon technologies. The required shift in energy RD&D investment to achieve a 450 ppm trajectory far exceeds that which is likely to result from current programmes, including additional spending on clean energy in the stimulus packages. The moves already taken by a number of IEA member countries and non-members alike are clearly an important and encouraging step in the right direction, but much more needs to be done.

13. For the purposes of this analysis we assumed that research, development and demonstration investments are 10% of deployment needs, as defined below. This figure is based on analysis of 17 key technologies representing 87% of $CO_2$ emission reductions for the energy sector under the ETP BLUE Scenario, published in IEA (2008). Deployment costs are the total amount that must be invested in cumulative capacity of a new technology up to the point where its unit costs (*e.g.* expressed in $/MWh for an electricity generating technology) reach those of the incumbent technology (break-even point). Deployment costs are, therefore, equal to the sum of the costs of the incumbent technology (which would have been incurred anyway), plus the additional investment costs (learning investments) required while the new technology becomes competitive. Data to accurately estimate RD&D needs are generally insufficient.

Support for RD&D is a critical area of government action. There is growing evidence that the private sector is, in current economic circumstances, slashing spending on energy RD&D. This is in part because investment in innovation is essentially pro-cyclical, as it mainly financed from corporate cash flows. These cash flows fall in most cases with lower prices and weaker demand; thus, to counter these risks, it is essential that governments take action directly or indirectly to bolster innovation. Regardless of the case for fiscal stimuli to combat the economic crisis, the need for governments to step up their support for research on clean energy has never been clearer. Governments should seek to develop stronger collaborative partnerships with the private sector on large-scale RD&D projects.

An international and stable carbon price forms the cornerstone of any successful policy in the longer term, but will not be sufficient by itself. It will need to be complemented by other policies and measures. While a significant increase in support for RD&D is the leading candidate, improvements in rules and regulations, especially those that are creating unintended barriers, must also be promulgated at all levels of government.

One of the most attractive options for now lies with refurbishing buildings. Renovating them to meet high energy-efficiency standards and replacing outdated heating systems would cut energy use dramatically, while also creating jobs in the manufacturing and building trades. Publicly owned buildings could be the first target. The transportation sector also holds enormous potential for energy savings and government support for the auto industry should be designed to promote more fuel-efficient vehicles, including scrappage and buy-back schemes (as has been the case, for example, in the United States). Renewable energy can also play a role, with support through tax changes and targeted investments.

Such a Clean Energy New Deal is not a substitute for other, long-term approaches. However, it could be a promising and concrete way to take a determined first step to a sustainable future — one that is more secure, more environmentally friendly and more affordable.

# FUNDING LOW-CARBON GROWTH
## How can we finance a clean-energy future?

### HIGHLIGHTS

- The geographical and sectoral distribution of abatement and investment in the 450 Scenario, as set out in previous chapters, does not determine how those actions are funded. That is entirely a matter for negotiation. UNFCCC Parties have agreed that developed countries will provide financial support to developing countries but the level of support is still open. It is clear that there is a wide range of potential funding outcomes. In the 450 Scenario, $197 billion of additional investment is made in non-OECD countries in 2020. Depending on the fields of support and within a range of co-funding assumptions varying from 25% to 75%, OECD+ could contribute anywhere between $13 billion and $148 billion of this, in addition to supporting technology transfer and adaptation.

- There are various channels through which funds can flow to developing countries, one of the most important being the international carbon market. In the 450 Scenario, depending on how the market is structured – again a matter for negotiation – primary trading of $CO_2$ emission reductions between OECD+ and other regions ranges between 0.5 Gt and 1.7 Gt in 2020. A central case sees a $CO_2$ price of around $30 per tonne and annual primary trading of around $40 billion. The current Clean Development Mechanism would need extensive reform to cope efficiently and robustly with a substantially increased level of activity. International funding pools are another important channel that could support an increase in financial transfers to developing countries.

- Based on the current distribution of investment in the energy sector, households may be responsible for around 40% of the additional investments in 2020 in the 450 Scenario. This reflects the heavy dependence of the 450 Scenario on the purchase of low-carbon vehicles and energy-efficient appliances by millions of households worldwide. Devising effective methods to achieve this result constitutes an important policy challenge for governments, particularly in some non-OECD countries where access to finance is more limited.

- Businesses are responsible for most of the remainder of the additional investment in the 450 Scenario. Many of the most important corporate investors in the 450 Scenario, such as solar, wind and biofuels companies, have been hit hard by the financial crisis, due to their relatively small size, more leveraged balanced sheets and perceived exposure to risk. In the short term, the maintenance of government financial stimulus efforts will be crucial to this investment. In the long term, policy certainty – at international, national and local level – is an important driver of efficient investment.

## Introduction

While Chapters 5 and 6 describe, by region and by sector, the extent and composition of the carbon dioxide ($CO_2$) abatement that takes place in the 450 Scenario, and Chapter 7 details the additional investments that are undertaken to bring about this abatement, the 450 Scenario deliberately stops short of allocating *responsibility* for these actions. Yet, if such a scenario is to be realised, the 15th Conference of the Parties (COP) of the United Nations Framework Convention on Climate Change (UNFCCC) (December 2009, Copenhagen) must be specific about each country's commitments (where they have them) under a post-2012 agreement. In particular, it must agree on how and by whom mitigation action, and its corresponding investments, would be funded.

There is no reason to assume that the geographical, or even sectoral, distribution of abatement and investment in the 450 Scenario determines how they would or should be funded. While the *Outlook* is able to provide insights into the level and distribution of efficient actions to abate $CO_2$ emissions from the energy sector, it is not able to assess fairness: burden sharing must be a matter for negotiation between countries. Instead, this chapter illustrates a broad range of possible distributional outcomes that might result from a deal in Copenhagen. All involve some level of support from OECD+ countries to promote abatement in non-OECD countries. The chapter also looks at the mechanisms, particularly carbon markets and international funds, that can be used, and enhanced where necessary, to allow this support to be provided.

Whatever financial assistance mechanisms may be set up, the investments and capital purchases necessary to realise the 450 Scenario are ultimately paid for by governments, businesses or households. Substantial efforts are required by all three groups, and each has access to a very different set of financing channels. The latter part of this chapter provides an indicative estimate, based on current trends, of how the financing of investments might be distributed between these three categories, commenting on the policy issues that arise.

Although this chapter focuses specifically on financing energy-related $CO_2$ abatement in the 450 Scenario, funding would, of course, also be needed for the mitigation of emissions from other sectors, reductions in emissions of other greenhouse gases (where these are not simply a co-benefit of investments that yield $CO_2$ reductions), adaptation to the impacts of climate change, and technology development and transfer. Estimates of the funding needed to finance adaptation to climate change are summarised in reports by the UNFCCC (2007a, 2008a and 2009).

## Financial support for mitigation in developing countries

In the Bali Action Plan, countries agreed to enhanced action on the provision of financial resources and investment to support action on mitigation, adaptation and technology co-operation. New and additional resources are to be provided to fund incentives for enhanced implementation of national mitigation strategies and adaptation action by developing countries.[1] In broader terms, there is an international consensus that developed countries will, in addition to taking responsibility for and carrying out mitigation actions domestically, provide some level of financial support to developing countries to help them achieve lower emissions.

The rationale for this is clear. As shown in the previous chapters, achieving stabilisation of the concentration of greenhouse gases at 450 parts per million of $CO_2$-equivalent (ppm $CO_2$-eq) requires significant reductions in global emissions from current levels. Opportunities for effective action exist worldwide. Emissions anywhere in the world have the same impact on the global climate. Thus the cost of achieving the required concentration can be minimised by implementing the measures that cost least per tonne of $CO_2$-eq, regardless of their location. Although the World Energy Model takes a more nuanced approach, this principle is the primary factor determining the geographical location of abatement action in the 450 Scenario. Since many of the cheapest abatement options are in non-OECD countries, 57% of the abatement in 2020 is achieved through measures taken in these countries. Incremental investment in non-OECD countries, additional to that in the Reference Scenario, totals $197 billion in 2020 (Table 8.1). However, many of these countries have low per-capita emissions, low historical emissions and low income and so require some level of financial and technological support to ensure that the emission-reduction measures are fully implemented. Without such support, there is little reason to expect that the level of abatement in the 450 Scenario would be achieved.



**Table 8.1 • *Incremental investment needs by region and sector in the 450 Scenario relative to the Reference Scenario in 2020*** *($2008, billion)*

| Region | Power | Biofuels | Industry | Transport | Buildings | Total |
|---|---|---|---|---|---|---|
| **OECD+** | **39** | **5** | **19** | **92** | **62** | **216** |
| United States | 16 | 2 | 10 | 34 | 25 | 86 |
| European Union | 9 | 2 | 2 | 36 | 19 | 68 |
| Japan | 4 | 0 | 1 | 5 | 7 | 17 |
| **Other Major Economies** | **30** | **2** | **14** | **51** | **26** | **124** |
| Russia | 0 | 0 | 1 | 6 | 1 | 8 |
| China | 26 | 1 | 12 | 27 | 14 | 80 |
| **Other Countries** | **18** | **2** | **5** | **36** | **12** | **73** |
| India | 10 | 0 | 2 | 9 | 2 | 23 |
| **World** | **88** | **10** | **38** | **192** | **100** | **427** |

Note: At world level only, transport includes international aviation and shipping.

1. Bali Action Plan, paragraph 1(e), UNFCCC (2007b).

There is no consensus yet on what the level of financial support should be, how the provision of support should be distributed across developed countries, how the available financial support should be shared between developing countries, or to what extent different financial mechanisms (such as carbon markets or international funds) should be employed to deliver these transfers. Moreover, there is considerable debate about how carbon markets, the Clean Development Mechanism (CDM) and other international financing systems need to evolve in response to a new global post-2012 agreement. Nevertheless, the strong recognition of developed-country commitments to support mitigation in developing countries, as set out under Articles 4.3 and 4.4 of the UNFCCC, is an important starting point. The Bali Action Plan calls for "provision of financial resources and investment to support action on mitigation and adaptation and technology cooperation" (UNFCCC, 2007b). This section explores the options available for elaborating on these arrangements, in the context of the results of the 450 Scenario.

## Overall level of support by OECD+ countries

The overall level of financial support by OECD+ countries for emission reductions in non-OECD countries is entirely a matter for negotiation; there is no objectively "right answer", since value judgements differ on what would constitute a "fair" distribution of responsibility. Nevertheless, the 450 Scenario can provide insights on the general order of magnitude of funding arrangements, under a range of assumptions about which types of investment OECD+ countries might support and what level of co-funding they could provide. As a starting point, given the consensus of the Bali Action Plan, it is reasonable to assume that all the energy-related $CO_2$ abatement and additional investment expenditure that takes place in OECD+ (amounting to 1.7 gigatonnes [Gt] and $216 billion, respectively, in 2020) will be financed domestically by OECD+.[2] In addition, to help other countries undertake some of their abatement and investment expenditure (totalling 2.2 Gt and $197 billion in 2020), OECD+ is assumed to provide some additional funding.

There is no consensus yet in the UNFCCC process as to the specific types of investment that OECD+ countries might co-fund in non-OECD countries after 2012 and there are many possible configurations. For example, OECD+ could part-fund all incremental investments, relative to a Reference Scenario baseline (the equivalent of part-financing all the 2.2 Gt of $CO_2$ abatement in 2020 in Other Major Economies and Other Countries), or could focus on particular sectors or abatement measures that are not covered by the policies and measures that non-OECD countries appear to be willing to implement without support (this is a key rationale for the CDM). Alternatively, specific types of investment may be included or excluded (as is also the case with CDM), or an alternative baseline could be set by which non-OECD countries qualify for financial

2. While this holds true for the region as a whole, it is likely that negotiations would lead to domestic responsibilities that differ from the 450 Scenario's geographical distribution of abatement within OECD+. There could be some cross-funding within OECD+, as is already the case within Europe under the EU Emissions Trading System.

support if they first undertake some defined extent of unilateral mitigation action or comply with a sectoral agreement. The types of investment co-funded could also be determined by the funding mechanisms adopted.

Similarly the proportionate rate at which investments or mitigation might be co-funded is subject to negotiation. OECD+ countries could, in theory, pay the full cost of additional investment. But non-OECD countries would receive considerable direct benefits from activities in the 450 Scenario in their territory, including lower investment in power transmission and distribution (worth $23 billion in non-OECD countries in the 450 Scenario in 2020), fuel-efficiency savings and improved air quality, making it unlikely that OECD+ countries would fully fund investments or mitigation costs (Chapter 7). Again, the rate of co-funding would be influenced by the funding mechanisms used: funding through a global carbon market would typically be at a rate corresponding to the marginal abatement cost of the best available solution, while direct financial transfers can be more specific (though not necessarily as economically efficient).

Table 8.2 provides an indication of the sums of financial support that OECD+ might provide, under a range of options. Financial support could take the form of funding abatement (*i.e.* paying for each million tonne [Mt] of emissions foregone) or funding the investment that will bring about the abatement in subsequent years. In reality, some combination of the two is likely, depending on which financing mechanisms are in place following a deal in Copenhagen. The table should be considered only as an indicative "menu".



**Table 8.2 • *Financial support from OECD+ to non-OECD countries under different funding assumptions, 2020***

| Non-OECD abatement measures co-funded | $CO_2$ abatement (Mt) | Investment ($ billion) | Co-funding by OECD+ ($ billion) | | |
|---|---|---|---|---|---|
| | | | at 75% | at 50% | at 25% |
| All 450 Scenario abatement | **2 166** | **196.9** | **147.7** | **98.4** | **49.2** |
| Sectoral agreements in industry and transport | 660 | 71.8 | 53.8 | 35.9 | 17.9 |
| Nationally appropriate mitigation actions (NAMAs)* | 907 | 71.4 | 53.5 | 35.7 | 17.8 |
| Other measures** | 599 | 53.7 | 40.3 | 26.9 | 13.4 |

*NAMAs in this table represent the national policies and measures that non-OECD countries are already considering adopting (excluding those that overlap with the sectoral agreements in industry and transport) as detailed in Chapter 5.

**Other measures are additional mitigation measures in non-OECD countries in the 450 Scenario, not covered by NAMAs or sectoral agreements. Without financial support, these may not be carried out.

Notes: The level of abatement achieved in 2020 does not directly correspond to investments that take place in that year: abatement is influenced by investments over a number of preceding years. However, both sets of figures are provided for information. Funding support may either be allocated to mitigation measures (offering finance in response to $CO_2$ savings in a given year, as is the case for the CDM) or may be allocated to investments (co-financing a specific capital project, for which the $CO_2$ mitigation will accrue over several years). For simplicity, the analysis here assumes all funding is for investments, although in practice a combination of the two would most likely prevail, depending on the financing mechanisms adopted.

For example, if it were agreed that OECD+ countries would cover 50% of the additional investment costs in non-OECD countries arising from the application there of sectoral agreements in the 450 Scenario, financial support would amount to $35.9 billion in 2020. Based on the examples in Table 8.2, the overall level of support in 2020 in respect of the energy sector could be anywhere between $13.4 billion (corresponding to 25% funding of only those measures that are additional to sectoral agreements and NAMAs [nationally appropriate mitigation actions]) and $147.7 billion (75% of funding of all non-OECD abatement). Table 8.3 further disaggregates these results, detailing specific sectors and technologies, to provide an indication of the potential financial impact of their inclusion in (or exclusion from) an international funding regime.

**Table 8.3 • *Financial support of specific abatement measures in selected sectors in non-OECD countries under different funding assumptions, 2020***

| Non-OECD sectoral abatement measures | $CO_2$ abatement (Mt) | Investment ($ billion) | Co-funding by OECD+ ($ billion) | | |
|---|---|---|---|---|---|
| | | | at 75% | at 50% | at 25% |
| **Power generation** | **779** | **85** | **63.9** | **42.6** | **21.3** |
| More efficient plants, coal to gas switch and early retirements | 52 | 5 | 3.7 | 2.5 | 1.2 |
| Carbon capture and storage | 16 | 3 | 2.2 | 1.5 | 0.7 |
| Nuclear | 221 | 9 | 6.8 | 4.6 | 2.3 |
| Renewables | 489 | 68 | 51.1 | 34.1 | 17.0 |
| *of which hydro* | *169* | *25* | *18.6* | *12.4* | *6.2* |
| *of which biomass* | *66* | *10* | *7.8* | *5.2* | *2.6* |
| *of which wind* | *220* | *28* | *20.9* | *13.9* | *7.0* |
| *of which solar* | *32* | *4* | *3.1* | *2.1* | *1.0* |
| **Transport** | **299** | **91** | **68.2** | **45.5** | **22.7** |
| *of which sectoral agreements in PLDVs* | *285* | *69* | *51.5* | *34.3* | *17.2* |
| **Industry** | **529** | **19** | **14.3** | **9.5** | **4.8** |
| *of which sectoral agreements in iron and steel and cement* | *375* | *7* | *5.4* | *3.6* | *1.8* |

Note: The reduced investments in fossil-fuel plants (see Table 7.3 in Chapter 7) are not included in the power generation total above.

As well as funding mitigation actions in the energy sector, it is likely that additional funding from OECD+ countries would be required to help pay for emission reductions in other sectors, particularly deforestation, as well as to support climate change adaptation measures in non-OECD countries. Funding for non-OECD countries could also come from international aviation and shipping, whose emissions are not attributable to countries, either through their future participation in a carbon market or through other financing mechanisms.

## Mechanisms for delivering financial support

Whatever the extent of the financial support that is put in place, strong mechanisms would be needed to allow funding to flow efficiently within the energy sector and across international borders. While financing may be allocated to investments or be directly related to the $CO_2$ saving, it needs to flow quickly, with minimal administrative burden, to the sectors and countries that need and earn it, so as cost-effectively to incentivise genuine abatement activity. Carbon markets and international climate change funds and facilities are already expanding and evolving, and both will probably continue to play a prominent role, but a step-change would be needed to deliver the clean energy revolution that the 450 Scenario describes.

### Carbon markets and the Clean Development Mechanism (CDM)

The term "carbon market" is applied to markets in which allowances or credits for greenhouse-gas emissions are traded.[3] There are many possible formulations of carbon markets (Capoor and Ambrosi, 2009) and the term carbon market can be used to describe multiple, connected carbon markets. The Kyoto Protocol created three market mechanisms: emissions trading, the CDM and the Joint Implementation mechanism. Every domestic emissions trading system establishes its own market, and voluntary markets can serve individuals and organisations that wish to offset (part of) their emissions.

8

These mechanisms offer an explicit means of separating responsibility for emission reductions from direct implementation of emission reductions. The national emissions-limitation commitments of developed countries under the Kyoto Protocol (or potentially under an agreement reached at the UN Climate Change Conference (COP 15) in Copenhagen) are a measure of each country's responsibility for emission reductions. If an international carbon market exists as expected, a developed country's domestic emissions can exceed its commitment – provided the country ensures that reductions equal to its excess emissions are achieved elsewhere. It can do this by buying surplus allowances/credits from other countries with quantitative commitments or from developing countries with no such emissions reduction commitments. This provides a financial incentive to implement mitigation measures in developing countries. By purchasing credits, a developed country can avoid implementing more costly mitigation measures domestically, thus lowering the cost of meeting its emission reduction commitment.[4] By ultimately establishing a common

3. Terminology varies and other terms, such as permit, are also used. An allowance is a government-issued permit to release a specified quantity of greenhouse gases (usually 1 tonne of $CO_2$-eq) during a specified period. The quantity of allowances issued is usually equal to an emissions cap established by the government for designated sources. A credit recognises a specified greenhouse-gas emission reduction (usually 1 tonne of $CO_2$-eq). Allowances and credits issued or approved by a government can be used for compliance by sources in an emissions trading system.

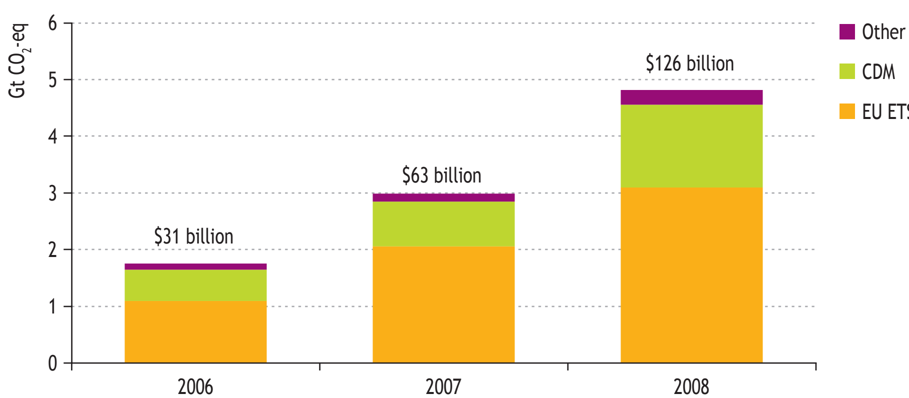
4. Lower compliance costs for developed countries benefit developing countries. Compliance with emission commitments imposes an economic cost on developed countries, which may have an adverse economic impact on developing countries through reduced trade flows.

global marginal abatement cost, the market reduces competitiveness impacts and emissions leakage.[5] In this way, developed countries can fund actions to reduce emissions in developing countries.

### *The carbon market today*

In 2008, almost 5 Gt $CO_2$-eq of allowances and credits were traded on international markets. At an average carbon price of $26 per tonne of $CO_2$, the value of these trades totalled $126 billion – a 100% increase over the previous year (Figure 8.1). By far the largest carbon market is the EU Emissions Trading System (EU ETS): the volume of European Union allowances (EUAs) traded in that system accounted for 64% of the global total in 2008. A distant second is the market for certified emission reductions (CERs) – the credits issued for emission reductions achieved by CDM projects (which accounted for 30% of the 2008 trade volume). Other markets – including Joint Implementation and international emissions trading under the Kyoto Protocol, Switzerland, New South Wales (Australia), the US Regional Greenhouse Gas Initiative (RGGI), the Chicago Climate Exchange and the voluntary market – are tiny by comparison.[6]

**Figure 8.1 • *Global carbon market trading volumes and values***




Source: Capoor and Ambrosi (2009).

The CDM is a particularly important market. Set up under the Kyoto Protocol, its purpose is specifically to facilitate and incentivise developed country co-funding of abatement in developing countries. As of 30 June 2009, a total of 1 699 projects had been registered and a further 2 768 were in the pipeline (posted for public comment or being validated) (Fenhann, Agger and Hansen, 2009). These projects are estimated

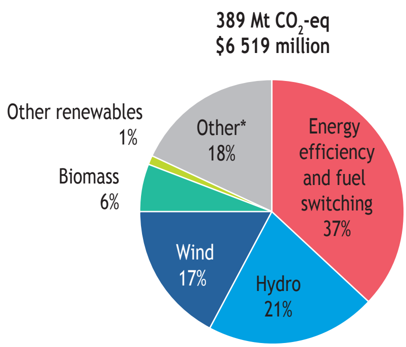
5. The international market price is the marginal abatement cost for all sources in developed countries that can use developing country credits for compliance. The market price is also an opportunity cost for emissions for all developing country sources eligible to generate credits.

6. During 2008, 3 093 million EUAs and 389 million CERs were traded, accounting for 72% of the total volume traded and 78% of the total value of trades (Capoor and Ambrosi, 2009).

to generate annual $CO_2$-eq emission reductions of over 600 Mt. Over 300 million CERs (1 tonne $CO_2$-eq each) have been issued so far and about 1 billion more are expected to be issued by the end of 2012. It is estimated that clean energy investments totalling $95 billion were leveraged by CDM between 2002 and 2008 (Capoor and Ambrosi, 2009).

Renewable energy projects feature prominently in CDM transactions: hydropower, wind, biomass, landfill gas, solar, geothermal and tidal power together account for 65% of all projects and 45% of the estimated annual emission reductions in 2008 (Figure 8.2). In contrast, energy-efficiency projects account for less than 15% of all projects and estimated annual emission reductions. In 2007, the CDM Executive Board agreed to allow projects that consist of many installations of a specified measure, such as energy-efficient light bulbs, with the expectation that this would lead to more energy-efficiency projects. Several methodologies for such projects have been approved but no projects had been registered by 30 June 2008.

**Figure 8.2 ● *Share of CDM emissions reduction by type of project, 2008***




* Includes agro-forestry, landfill gas, wastes management, coalbed methane, hydrofluorocarbons (HFCs), nitrous oxide ($N_2O$) and other projects.

Source: Capoor and Ambrosi (2009).

Technology transfer – *i.e.* the explicit sharing of technologies and know-how, widely accepted to be a pre-requisite to efficient abatement in the energy sector – is not a specific requirement of the CDM, although host-country governments can establish technology-transfer requirements as a condition for approval. Of the registered and proposed projects as of June 2008, 36%, representing 59% of the expected annual emission reductions, claim technology transfer (Seres, 2008). Technology transfer is very heterogeneous across project types, but tends to be less frequently associated with more mature technologies. Technology transfer is more common for projects that involve foreign participants than for unilateral projects. As more projects of a given type are implemented in a host country, the incidence of international technology transfer often declines. This suggests that the transfer of technology spreads domestically, beyond the individual CDM projects, which enables later projects to rely more on local knowledge and equipment.

### *The carbon market in the future*

In the event that an ambitious deal is reached in Copenhagen, the global carbon market is likely to expand and change considerably in the future. The 450 Scenario requires much greater funding of abatement in non-OECD countries and, while other sources of financing would be important, it is to be expected that some of the additional abatement would be funded through carbon markets. The analysis in this *Outlook* has benefited from a fully revised carbon-flow model (Box 8.1), integrated with the World Energy Model, which allows assessment of scenarios that optimise global abatement activity within a set of plausible constraints, such as limits on domestic emissions and credit purchases, differences in the number of participating countries, and variations in the forms and levels of abatement that would be eligible for CDM credits. Since the role and nature of the carbon market and, in particular, the distribution of national emission allowances, are a matter for negotiation, the following analysis does not constitute the "results" of the 450 Scenario. Rather, it explores how key aspects of the international carbon market, such as the trading volume and the CDM price, might vary depending on what format a carbon market takes, based on the global abatement level of the 450 Scenario. The carbon-market analysis here focuses on the primary credit and financial flows needed to achieve efficient energy-related $CO_2$ mitigation, not the full

**Box 8.1 • *WEO-2009* carbon-flow modelling**

A carbon-flow model, fully integrated in the World Energy Model, was developed to inform the 450 Scenario. The model allows quantification of international emission offsets and financing under different assumptions, estimating the price of permits, the volume and value of primary market trading, and the overall cost of abatement.

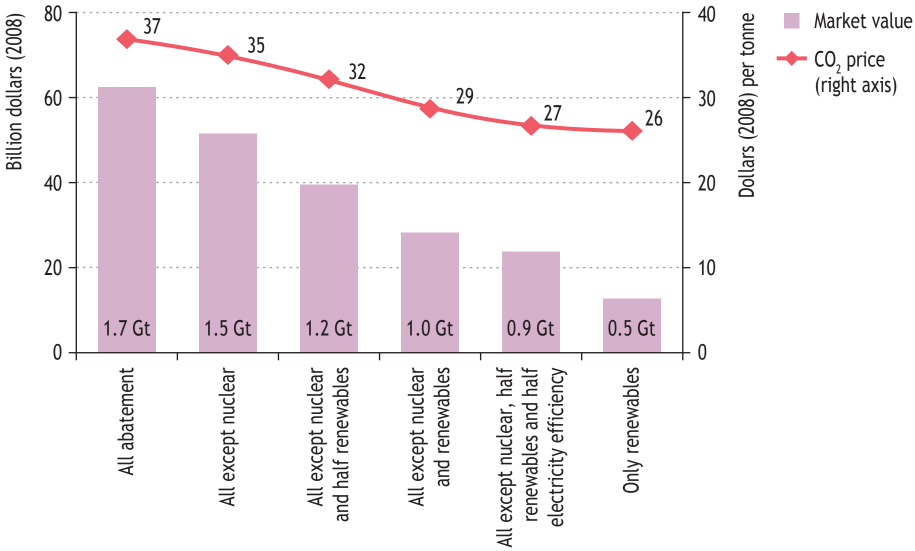
The model uses country- and sector-specific marginal abatement curves derived from the World Energy Model. These are summed for all prices to build a global abatement curve. The global emissions level in the 450 Scenario determines the international equilibrium price for credits along this supply curve, and trade can be determined depending on countries' marginal abatement costs – those with costs that are higher than the market price will purchase credits from those with costs below the market price. Subject to the constraints imposed on the model, such as a requirement to undertake a proportion of abatement domestically, marginal abatement costs are equalised, allowing the global abatement target to be met at minimum cost.

Our analysis adjusts the OECD+ demand for international credits to various configurations of the carbon market, each reflecting different levels of supply from non-OECD countries – depending on eligibility of different types of abatement – and each implying different levels of international funding support through the carbon market.

extent of market-trading activity, which may be substantially larger.[7] For simplicity, it also focuses solely on actual emission reductions in the relevant year of analysis, rather than allowing for any impact of banked credits.[8]

We have considered several configurations based on the 450 Scenario, by which OECD+ countries fulfil the required domestic emissions level[9] and additionally help fund a proportion of non-OECD abatement in power generation and industry through a global carbon market.[10] Figure 8.3 shows the resulting value of primary transfers (*i.e.* not including re-traded credits) between OECD+ and non-OECD countries according to the eligibility for the carbon market of different aspects of $CO_2$ abatement in non-OECD countries[11] and different levels of the OECD+ targets, that create the demand.

**Figure 8.3 • Carbon trade and $CO_2$ price for power generation and industry under different levels of financing by OECD+ countries in 2020**




Note: Includes primary trading only.

7. For example, in 2008, there were about 2 billion EUAs but trade amounted to over 3 billion (Capoor and Ambrosi, 2009). In more established markets, such as oil, trading activity is equal to several times the total stock.

8. In principle, banking can reduce global abatement costs by allowing an efficient allocation of abatement activity over time. However, careful design of banking provision is needed to maintain the integrity of the global climate goal and to provide sufficient certainty that countries' responsibilities will be fulfilled.

9. This is imposed as a constraint to our carbon model, although in practice it reflects an outcome only marginally different from an unconstrained efficient outcome.

10. While other $CO_2$ abatement, for example in other sectors, may also be funded by OECD+ countries, through the carbon market or other mechanisms, for the purposes of this analysis we consider the carbon market, covering power generation and industry, in isolation.

11. While the examples in Figure 8.3 are only indicative, to show the effects of varying the scope of the carbon market, the concept of including and excluding technologies is a valid consideration. For example, it may be relevant to exclude some politically contentious technologies or small-scale efficiency measures for which it may be difficult to monitor or prove additionality. The scope of the carbon market could also be changed by the non-participation of some countries or if credits could only be earned beyond a more stringent baseline.

In a situation in which OECD+ countries fund 1.2 Gt of $CO_2$ abatement in power generation and industry by non-OECD countries in 2020 through the carbon market, primary trade would deliver almost $40 billion of funding to non-OECD countries. In contrast, a relatively narrow carbon market, with 0.5 Gt of credit purchases (for example, in which only renewables are eligible), would transfer funds amounting to around $10 billion. A very broad market, allowing non-OECD countries to sell all 1.7 Gt of their abatement in power generation and industry, could transfer over $60 billion in 2020.

An important finding is that the volume of non-OECD $CO_2$ abatement that OECD+ countries fund through the carbon market affects the prevailing $CO_2$ price. At lower levels of OECD+ funding and for smaller market sizes, the carbon price will tend to be lower, since more expensive abatement options that would otherwise have influenced the $CO_2$ price may no longer be in the market. In contrast, if all the $CO_2$ abatement, across all technologies and all sectors in the 450 Scenario, were to be funded through the carbon market, this could, irrespective of how the burden is shared across countries, lead to a very high carbon price, determined by the most expensive technology. This supports the view that other mechanisms for transferring resources to non-OECD countries, in addition to the international carbon market, are needed to play a role in a post-2012 agreement.

The preceding carbon-model analysis also makes it possible to identify the potential sellers to the carbon market. For example, although Figure 8.4 shows just one possible configuration, based on the case of 1.2 Gt of eligible emission reduction, it indicates the likelihood that China, which in 2008 had an 84% share of the primary CDM market, would continue to be the dominant seller under our modelling assumptions at least until 2020.

**Figure 8.4 • *Potential suppliers of carbon credits given eligibility of 1.2 Gt of non-OECD abatement in power generation and industry in the 450 Scenario relative to the Reference Scenario***

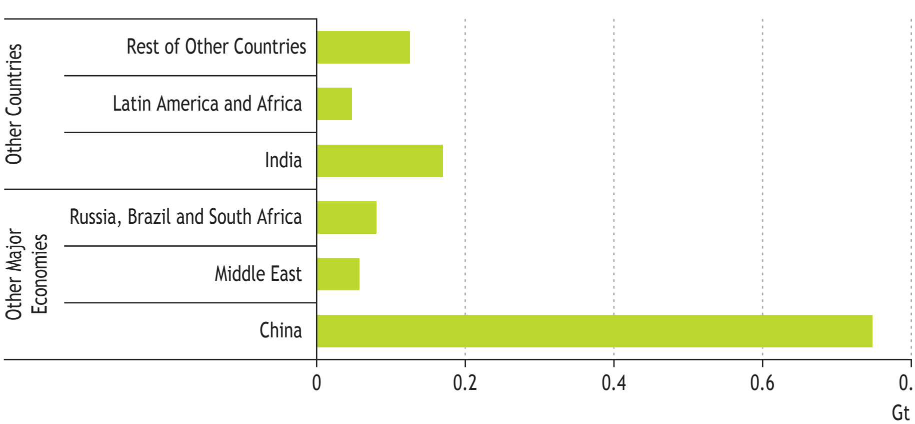
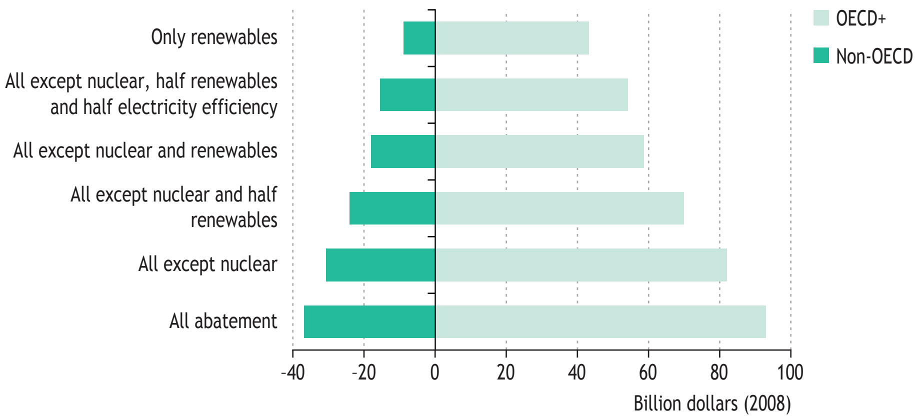


Figure 8.5 shows how non-OECD countries can profit from participating in the carbon market. Since they are able to sell credits at the marginal abatement cost set by the market (which is above the average abatement cost), their net abatement cost for emissions in the carbon market is negative. These profits could help to fund national policies and measures that are not funded through other mechanisms.

**Figure 8.5 • *Abatement costs incurred by OECD+ and non-OECD in the carbon market for power generation and industry under different levels of financing by OECD+ countries***




As well as the inclusion and exclusion of sectors, technologies and participants, the carbon market is also strongly influenced by the selection of the level below which emission reductions are eligible for credits. The above analysis assumes a baseline equivalent to Reference Scenario emissions for the relevant sectors and technologies, but another approach would be to use a more stringent point of reference. This could reflect the fact that non-OECD countries are likely and able to undertake some of their national policies and measures without the support of the carbon market (see Chapter 5), or that a different level or form of support may be more appropriate for the mitigation component that is due to sectoral approaches. Furthermore, as shown above, the fact that countries or businesses can generate a profit from the carbon market allows cross-funding of other mitigation activities, such that a more stringent baseline could be set. One option is a graduated, three-tier funding solution, whereby if non-OECD countries meet certain sectoral standards (perhaps with financial support), they could become eligible for further support to help them undertake national policies and measures to deliver further abatement. Any abatement beyond that level could then be eligible to earn CDM credits at the full market rate, thus generating profits. Such a structure has the potential to ensure funding for a large proportion of the investments in non-OECD countries in the 450 Scenario, although the financial incentives and qualification thresholds would need to be carefully determined.

Beyond 2020, the carbon market would need to change significantly in the 450 Scenario, with the assumption by Other Major Economies of quantified emissions targets from 2021 onwards, reflecting the need globally to achieve more substantial abatement in the period 2021-2030. We have assumed that, initially, the markets in OECD+ and Other Major Economies would not be linked (see Chapter 5). Our analysis indicates that $CO_2$ prices would rise to $110 per tonne in OECD+ and $65 per tonne in Other Major Economies in 2030, reflecting more stringent emissions caps and the corresponding uptake of more costly mitigation options. Depending on how it is structured, a possible outcome is that the CDM market shrinks between 2020 and 2030, reflecting the fact that much of Other Major Economies' abatement would be needed to meet their own emissions caps, and would not be offered for sale. Consequently, OECD+ countries would increasingly have to focus on their domestic abatement measures and, depending on the distribution of national emissions caps, some OECD+ countries could be net sellers to the international carbon market before 2030.

### *CDM reform options*[12]

Crediting mechanisms have the potential to lower significantly the future mitigation costs incurred by regions covered by emission caps. Therefore, in the absence of a global permit-trading architecture involving all main emitters, the CDM would have to be scaled up. A number of proposals have been made in that regard, *e.g.* to move from a project-by-project to a wholesale approach, in order to reduce transaction costs and bottlenecks (Bosi and Ellis, 2005). These approaches are not mutually exclusive, although potential overlap – in particular risks of double counting – would need to be carefully addressed. They may also complement, rather than replace the project-by-project approach, which may have to continue in sectors with dispersed emission sources (such as agriculture) or in which emission reductions are clearly additional, for example carbon capture and storage (CCS) projects or some non-$CO_2$ projects, such as nitrous oxide ($N_2O$) destruction activities, which bring no other revenues than the CERs. The three main CDM scaling-up options are:

- *Bundling and programmes of activities:* Some degree of scaling up is already in the pipeline in these two forms, which have been eligible within the CDM since a 2005 decision (4/CMP.1) at the Meeting of the Parties to the Kyoto Protocol (COP/MOP1) on "further guidance to the CDM". Under the first approach, credits are obtained for bundled projects – multiple, small dispersed projects with prohibitively high transaction costs. Under the latter approach, credits may be granted for a range of projects that differ in timing or geographical location (Hinostroza *et al.*, 2007). This may be especially useful in the area of energy efficiency, in which the CDM is currently under-developed. Bundling could ultimately lead to large emission reductions. It may also help expand CDM use to geographic regions in which its use is currently negligible, partly due to the relatively small scale of potential projects, such as in Africa.

12. This sub-section, a contribution by the OECD, is based on Burniaux *et al.* (2009).

- *Sectoral crediting mechanisms:* These would further scale up the CDM by allowing emission reductions at the sector level, relative to a pre-defined baseline, to yield credits after validation by the UNFCCC (see, for example, Baron and Ellis, 2006). Such a "sectoral CDM" would require setting up sectoral baselines for each selected industry in each potential recipient country, which would raise a number of methodological issues in practice. In particular, standardised baselines for a given industry across countries may not be appropriate, as there are valid economic reasons for cross-country differences in emissions levels and intensity within a given industry (*e.g.* heterogeneity in goods characteristics and/or production processes, factor prices or natural resource endowments), including to some extent in the power sector (Baron and Ellis, 2006). Intensity baselines (emissions per unit of output) are often considered easier to establish than overall baseline levels. However, the associated sectoral intensity targets might be met through increases in output rather than through emissions cuts, and would be more complex to monitor and enforce, as they would require measuring of both output and emissions.

- *Policy CDM:* This is an option under which specific government policies would deliver CERs (Aldy and Stavins, 2008). Eligible policies could be sectoral, in which case they would be equivalent to sectoral crediting mechanisms, or cross-sectoral in nature. They might include renewable energy policies, efficiency standards or even the implementation of carbon taxes or the removal of energy subsidies. One advantage of a policy-based CDM is that additionality may be easier to verify. However, this approach would share the drawbacks of technology standards, *i.e.* it would run the risk of pick-up commitments that could later turn out to be costlier than the alternatives and might also undermine innovation incentives. Furthermore, setting a baseline at a policy level and – even more so – monitoring and verifying the emission reductions achieved from a policy could raise major methodological difficulties and affect the environmental integrity of the scheme. One open issue is whether electorates in developed countries would support the large, transparent payments that are likely to be involved if that option were to be used extensively.

While these options could achieve drastic cuts in transaction costs and thereby vastly increase the volume of credits issued, they would not address *per se* the deeper problems of additionality, leakage and perverse incentives. One way to mitigate these concerns might be to negotiate today stringent (*i.e.* below business-as-usual), long-run baseline levels for as many sectors as possible and covering a sufficiently long time period (at least a decade). This would address the perverse incentive issue by ruling out the possibility that any future increase in emissions might, if offset by subsequent reductions, deliver CERs. It would also minimise the risk of leakage, particularly as the number of countries and sectors covered would be large. Setting these below business-as-usual levels might be seen as an insurance against the risk of over-estimation of baseline emissions – and thereby of excess supply of CERs – although it may come at the cost of some potential low-cost abatement opportunities being lost. The main weakness of such an approach is that estimating and negotiating reference emission levels simultaneously across a wide range of countries and sectors would require overcoming significant methodological and political obstacles.

One additional problem is the existence of linkages across different activities. For instance, in industries for which the emission-intensive component of the production process can be outsourced (for example, cement), the whole supply chain may have to be considered in order to avoid leakage.

An international agreement on CDM reform could also incorporate built-in "graduation mechanisms", under which developing countries would take on increasing greenhouse-gas mitigation actions or commitments as their income levels converge to the higher levels of developed countries and/or discontinue hosting crediting projects under certain conditions or after a given period of time. This would address environmental integrity concerns, reduce the disincentive for recipient countries to take on binding commitments once scaled-up CDMs are in place, and help put world emissions on a path that allows ambitious long-run global targets to be met. For instance, the sectoral and/or country baselines negotiated in the context of scaled-up CDM might be gradually tightened, along with some relaxation of restrictions on their use in countries covered by emission-trading arrangements, as additionality would then become less of a concern. This would induce some convergence between permit and credit prices, albeit at some cost to developed countries. Over the longer run, the tighter baselines might in turn be converted into binding emission caps, which could then be gradually lowered.

### *International funding pools*

Pooled international funds are another important source of finance for developing countries. These funds have expanded rapidly in recent years, covering mitigation and adaptation costs across all sectors, and many are tailored to provide appropriate support to specific mitigation measures in specific countries. An advantage of international funds is that they can be effective at transferring collectively raised pools of funding, such as from governments or industry programmes (in contrast, CDM finance tends to involve transfers by private companies, directly linked to the receipt of credits), and allow some flexibility in how the money is dispensed.

Many of the climate funds and facilities that exist today, not all of which relate to developing countries, fall under the management of the World Bank (Table 8.4). By the end of 2008, World Bank-managed climate funds had a combined level of capital of over $1.6 billion, with a portfolio of 186 projects and an estimated carbon asset value of over $2.3 billion (World Bank, 2009). The Global Environment Facility and regional development banks also disburse funding, often with the assistance of specialised agencies such as the United Nations Development Programme and the United Nations Environment Programme. As well as mitigation measures, such funds can play an important role in financing collaborative research and development to promote the development of new technologies (such as CCS) or, outside the energy sector, to finance programmes to reduce emissions from, particularly, deforestation and forest degradation.

**Table 8.4 • *World Bank climate funds and facilities, end-2008***

| Fund/facility | Remit | Fund capital ($m) | Mt $CO_2$ under contract |
|---|---|---|---|
| Prototype Carbon Fund | Mitigation | 220 | 31.0 |
| Community Development Carbon Fund | Clean energy and development | 129 | 9.4 |
| Bio Carbon Fund | Carbon sequestration and forestry | 92 | 5.7 |
| Danish Carbon Fund | Mitigation | 132 | 7.7 |
| Spanish Carbon Fund | Mitigation (energy efficiency) | 424 | >19.8 |
| Umbrella Carbon Fund | Mitigation | 1 168 | 129.3 |
| Netherlands Carbon Facility | Mitigation | *not available* | |
| Italian Carbon Fund | Mitigation (Transition Economies) | 156 | 16.3 |
| Carbon Fund for Europe | Mitigation (under EU ETS) | 73 | 2.9 |
| Forest Carbon Partnership Facility | Forestry | 155 | 0.0 |

Source: World Bank (2009).

International funds could play various roles as part of a post-2012 agreement and various potential reforms are under consideration. The extent to which international funding will continue to be delivered by the same institutions in the future, or whether there may be additional bodies, is the subject of ongoing negotiations. In any case, future institutionalised international funding for climate purposes is likely to be significantly larger, to reflect increased emphasis on adaptation and technology co-operation. This will require some restructuring of institutions to handle the larger flow of funds and the different needs. A number of options have been put forward as to how funds could be dispersed, in terms of decision making (such as a move away from bilateral arrangements to panel-based decisions, perhaps giving developing countries more influence relative to funders on how the money is spent) and in terms of the eligibility criteria for receiving support. There are also options in respect of how finance from these sources interacts with the carbon market, for example in respect of the use of international funds to purchase emissions allowances.

### *Raising funds*

To date, contributions from government budgets have been the main source of international public funding to address climate change. Almost all of the government funding has taken the form of voluntary contributions to support mitigation actions. In addition, a levy of 2% of the CERs issued is applied to most CDM projects, with the revenue allocated to the United Nations Adaptation Fund to assist developing countries in meeting the costs of adaptation. Proposals are under negotiation to extend this levy to other Kyoto Protocol mechanisms and to change the rate (UNFCCC, 2008b).[13]

13. However, a levy on transactions imposes a deadweight loss that increases exponentially with the rate of the levy, such that any substantial increase in global funds will need to draw on other sources.

A number of countries have put forward suggestions for how funds could be generated to provide direct financial support to developing countries for mitigation, adaptation and technology co-operation (Table 8.5). Essentially, these suggestions focus on four main sources of revenue: a levy on carbon-market transactions; funding by international aviation and shipping companies (which may fall outside national emissions commitments); auctioning a share of developed country allocations; and direct contributions from national government budgets.

**Table 8.5 • *National proposals for raising international funds for mitigation and adaptation***

| Proposal | Source of financing | Purpose | Nominal annual funding ($ billion) |
|---|---|---|---|
| **Proposals to increase the scale of existing mechanisms** | | | |
| European Union | Continue 2% levy on CDM proceeds | Adaptation | 0.2 to 0.68 |
| Bangladesh, Pakistan | 3% to 5% levy on CDM proceeds | Adaptation | 0.3 to 1.7 |
| Many Parties | CDM and other crediting mechanisms | Mitigation | 10 to 34 |
| **Proposals for defined budgetary contributions from developed countries** | | | |
| G77 and China | 0.5% to 1.0% of GNP of Annex I Parties | Adaptation, Mitigation | 201 to 402* |
| **Proposals for raising contributions through taxes and market-based mechanisms** | | | |
| Mexico | Contributions based on GDP, GHG and population and possibly auctioning permits in developed countries | Adaptation, Mitigation | 10 |
| Norway | 2% auctioning of allowances | Adaptation | 15 to 25 |
| Switzerland | Tax of $2 per tonne of $CO_2$ with exemption of 1.5 tonne per inhabitant | Adaptation | 18.4 |
| Republic of Korea | Crediting NAMAs | Mitigation | Uncertain |
| Colombia, LDCs** | 2% levy on proceeds from Joint Implementation and emissions trading | Adaptation | 0.03 to 2.25 |
| LDCs** | Levy on international air travel | Adaptation, Mitigation | 4 to 10 |
| LDCs** | Levy on bunker fuels | Adaptation | 4 to 15 |
| Tuvalu | Auction of allowances for international aviation and marine emissions | Adaptation, Mitigation | 28 |

* Due to a lack of information on gross national product, potential funding was calculated using gross domestic product (GDP).

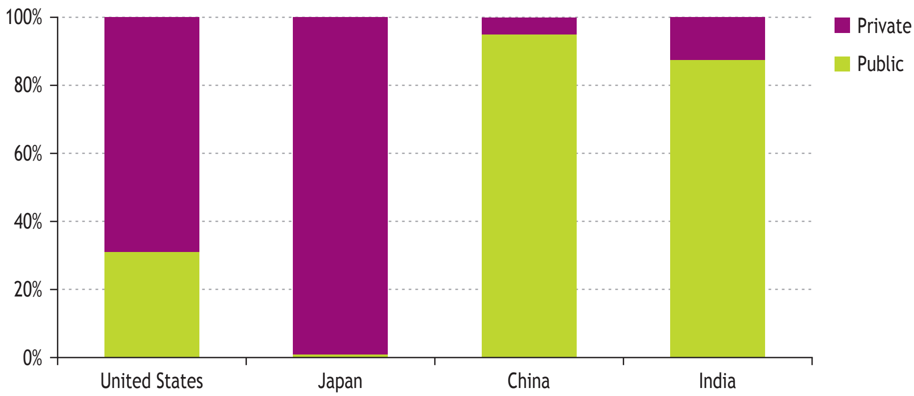
** Least developed countries.

Source: UNFCCC (2008a).

# Financing issues for businesses, households and governments

Whatever mechanisms may exist at international level to make financial assistance available for energy investments, individual investment decisions are ultimately made by businesses, households and government organisations. All have their own specific financing challenges. The significance of their individual roles depends to a large extent on the structure of each economy. For example, 95% of China's power is generated by state-owned utilities, while in Japan, which has a less centralised, market-driven economy, 99% of power generation comes from private companies (Figure 8.6). Consequently, there are significant differences between the two countries in how investment projects are financed, particularly concerning the sources and cost of funds. There are also big differences in how investment is financed in other sectors and other countries. Households own very little power-generation capacity, largely due to scale issues, but in buildings and transport, householder's decisions are crucial.

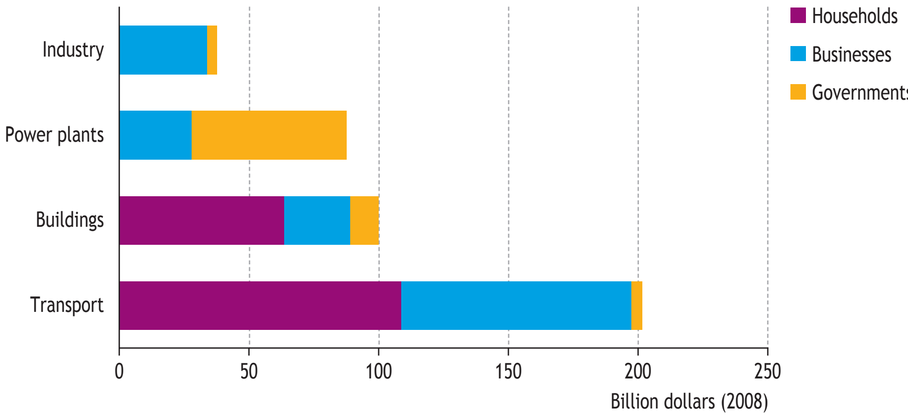
**Figure 8.6** • *Share of power generation output by status of utility, 2008*




Source: IEA analysis based on government sources.

It is impossible to predict with confidence who would undertake the investments in the 450 Scenario. This will depend on how countries respond to the challenge of transforming the energy sector. Some might decide to let businesses and households take the lead, in the interests of economic efficiency, while others may see the need for more direct government involvement to provide greater certainty that national responsibilities will be fulfilled. While the 450 Scenario makes no assumptions on ownership or financing, we have undertaken analysis for each sector, based on data from a range of countries and sources, of how much of today's energy investment is undertaken by households, businesses and governments, and have calculated on that basis what proportion of the additional investments in the 450 Scenario might fall to each (Figure 8.7).

**Figure 8.7 • Global additional investments in the 450 Scenario compared with the Reference Scenario by sector in 2020 based on current capital ownership**

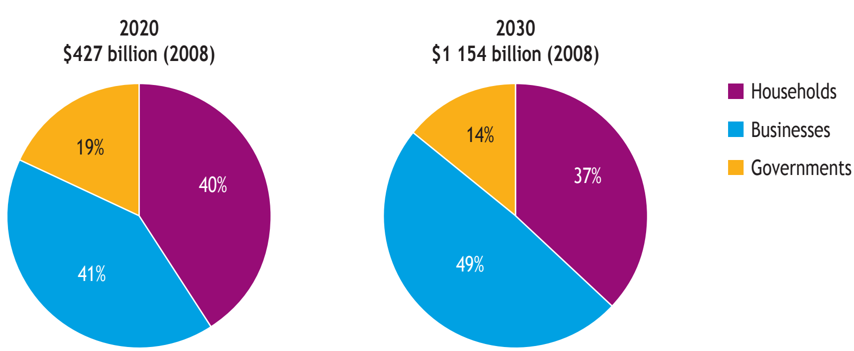



Note: International aviation and shipping is included in the data for transport. Although some investments may be co-funded, they have been fully allocated to the main investor (for example, in the case where government supports the purchase of an electric vehicle, the investment would still be fully attributed to the vehicle user). As a result, investment by government will tend to understate the total level of government expenditure. Our attribution of estimated investment to households, businesses and governments aims to reflect the legal ownership of those investments, a key determining factor in the method of financing. This differs from national accounts data, which attribute investment to the principal user, regardless of legal ownership and method of financing.

Source: IEA analysis.

Of the $427 billion of global additional investment in 2020, relative to the Reference Scenario, 40% would be attributable to households, with 41% undertaken by businesses and the remainder directly by governments (Figure 8.8). By 2030, business investment increases to almost half the total, with slightly lower shares of investment by households and government.

**Figure 8.8 • Global additional investments in the 450 Scenario compared with the Reference Scenario by sector based on current capital ownership**



## *Financing by businesses*

Under the above assumptions, businesses would account for 41% of the incremental investment in 2020 and almost half the incremental investment in 2030 in the 450 Scenario. They have a prominent role across all sectors, whether in building new, clean power plants, implementing more efficient processes in industry, purchasing low-carbon commercial vehicles, or building new-generation aeroplanes and ships. The financing for their investments will come from a range of sources, both domestic and foreign, including their own cash reserves, bank loans, debt issues, government support, foreign direct investment, overseas aid and venture capital funds. Retrofit measures are also important, particularly in the industry sector. Given the relatively low investment and quick payback on these measures, they are likely to be financed from internal cash flow or short-term debt.

The financial crisis has adversely affected corporate investment across the energy sector, with lower credit availability and rising interest charges. Many companies have had to reassess their balance sheets and rein back investment plans (Chapter 3), with highly geared companies particularly hard hit. Smaller firms and companies in emerging sectors, such as solar or biofuels, have been disproportionately affected: global biofuels investment in the first quarter of 2009 was 75% lower than the same period the previous year, and a number of major biofuels corporations in the United States and Brazil are in financial difficulties. In the transport sector, a slump in demand has curbed the production of new, more efficient vehicles.



In this context, the additional investment required in the 450 Scenario poses a major financing challenge for businesses, particularly those in high-growth renewables sectors. With risk becoming an increasingly important and costly dimension of energy-sector financing, effective government support is particularly important at this time; it is no coincidence that the majority of the clean energy stimulus measures announced to date aim to underpin private-sector investments. In the short term, special attention needs to be given to improving access to credit and lowering the cost of debt. Loan guarantees, clean energy bonds and monetised tax credits can be effective in boosting private investment.

Predictable, longer-term policies focused on clean energy technologies are important, reflecting the long life of most energy technologies and investments. Such policies help investors to evaluate more effectively potential investments and to reduce the financial risks. They permit investors to consider a longer payback period and lenders to finance a higher portion of the investment. For example, feed-in tariffs typically specify the price to be paid for the electricity for the first 10 to 20 years, while a carbon price and credible market mechanisms can fulfil a similar purpose across all sectors. Of course, a clear, credible global climate change agreement must be considered a key pre-requisite for realising the 450 Scenario.

Corporate investments to reduce energy-related $CO_2$ emissions are also affected by government policies directed at different objectives. Subsidies to fossil-fuel production or consumption make investments to reduce energy-related $CO_2$ emissions less attractive. In most non-OECD countries, at least one fuel or form of energy is subsidised, most often through price controls that hold the retail or wholesale price below the true market level.[14] Some OECD countries also continue to subsidise certain fuels, though generally on a much smaller scale. Subsidies to fossil fuels are assumed to be gradually reduced during the *Outlook* period in both the Reference and 450 Scenarios. By contrast, subsidies that favour lower emitting technologies (such as feed-in tariffs for renewables) promote investments in those technologies and are assumed to have a growing place in government policies. But governments need to assess these policies with care to ensure they are cost-effective compared with other ways of reducing emissions. Some subsidy programmes for biofuels, for example, involve very high costs per tonne of $CO_2$ abated[15] and have other adverse consequences.

## Financing by households

Based on today's distribution of the ownership of energy-sector investments, including energy-using consumer goods such as vehicles and appliances, households would finance around 40% of the additional investments in the 450 Scenario in 2020 — over and above those made in the Reference Scenario (Figure 8.8). Almost all this investment goes into energy-efficiency measures. Consequently, achieving the 450 Scenario outcome depends on hundreds of millions of households worldwide making $CO_2$-efficient decisions, often in countries where development priorities dominate. This is a huge challenge. Although in many cases the savings from such investments eventually outweigh the costs (see Chapter 7), the motivation of millions of citizens is a huge task for governments, requiring incentives, information and regulatory regimes to encourage such investments on a sufficiently large scale (Box 8.2).

Incremental investment in light-duty vehicles (LDVs) is the largest component of additional household investment in all regions in both 2020 and 2030. Financing trends are uncertain. While growing incomes may increasingly lead to vehicle purchases being financed through cashflow, rather than debt, a shift towards electric vehicles could lead to substantial leasing, related to expensive battery technologies. The last 12 months have also seen a growing trend of government co-financing of low-carbon LDVs (see Chapter 4). In the buildings sector, the incremental cost of most of the energy-efficiency and fuel-switching measures is incorporated into the initial cost households pay for the buildings, appliances and equipment. Thus, the investments will be financed as part of the overall investment in the building, appliance or equipment.

14. Energy-related consumption subsidies, which encourage consumption by pricing energy below market levels, in 19 non-OECD countries (accounting for over 80% of total non- OECD primary energy demand) totalled about $310 billion in 2007 (IEA, 2008a).

15. Marginal abatement costs vary considerably across countries and technologies, but can exceed $1 000 per tonne of $CO_2$ in some cases (OECD, 2008).

**Box 8.2 ● Negative-cost efficiency investments? Turning potential into reality**

Many analyses point to the huge potential of investments in energy efficiency that can "pay for themselves" through lower energy costs. Such measures include more efficient appliances and equipment, better insulation of buildings and, in some cases, more efficient vehicles. Energy-efficiency investments for which the net financial cost is below zero over the lifetime of the product, account for over 60% of the energy-related $CO_2$ emission reductions relative to the Reference Scenario. A large proportion of these investments would be carried out by households, a diverse group of decision makers worldwide.

These investments face many complex barriers and are actually among the most challenging for governments to influence. The barriers, which are generally more pronounced in developing countries, may include:

- Lack of information or insufficient expertise by consumers to evaluate investments.
- Preferences for other product characteristics.
- Consumer discount rates that exceed society's discount rate, as observed in the transport sector.
- Limited access to credit, particularly given the financial crisis; credit for efficient vehicles or home efficiency improvements is, in many cases, harder to obtain and more costly than credit for mortgages.
- Uncertainty; with technology constantly improving, people face the dilemma of when to invest.

Governments have been grappling with these issues for many years and would need to employ the full suite of policy levers in order to turn the energy-efficiency investments in the 450 Scenario into reality. Efficiency standards and regulations have proven to be effective, especially for measures incorporated into new appliances, buildings, equipment and vehicles. Implementation programmes and financial incentives can be effective, particularly for retrofit measures. Governments can lead the way by ensuring that their own purchases are efficient (IEA, 2007).

8

## Financing by governments

Governments are assumed to undertake around 19% of the additional investments in 2020 in the 450 Scenario, comprising efficiency measures in respect of public buildings and transport and, particularly in non-OECD countries, investment in nationalised power plant and other energy-sector infrastructure, as well as some efficiency measures in industry. Governments also provide various other forms of infrastructure, such as roads and port facilities, although many such investments are reduced in total in the 450 Scenario relative to the Reference Scenario.

Although they undertake a much smaller proportion of investment than households or corporations, governments also play an active role in incentivising investment decisions across the economy, in many cases contributing financially to them, whether through co-payments, tax relief or other forms of subsidy. Taking this into account, the total additional energy-related investment borne by government in 2020 approaches 19%. Alongside businesses, government has a particularly important role in supporting and co-ordinating research and development activity to help achieve the technological breakthroughs needed to realise the 450 Scenario (Box 8.3).

### Box 8.3 ● *Financing research and development of clean energy*

Current research and development (R&D) is heavily concentrated in the large developed countries, although spending is rising rapidly in a few developing countries (UNFCCC, 2009). Over 60% of R&D for energy-related $CO_2$ mitigation is funded and undertaken by private-sector companies. Governments fund some R&D by companies and research institutions directly through grants or indirectly through tax credits. Governments also fund and undertake R&D in their own research facilities. Almost all government funding for R&D is spent domestically (UNFCCC, 2009).

More R&D would help to lower the cost of adapting to and mitigating climate change (IEA, 2008b). At present, R&D spending for climate-related technologies represents only a small share (probably less than 3.5%) of global R&D. Total funding would need to increase in order to bring about the wholesale shift to low-carbon energy described in the 450 Scenario. Several studies have concluded that funding for climate-related energy R&D should be increased two- to ten-fold – and many countries already have R&D targets consistent with such an increase (UNFCCC, 2009). In particular, there is a need for increased funding for international R&D collaboration. Various institutional arrangements for this already exist, including IEA Implementing Agreements. But additional international funding could enhance developing country R&D capacity and support more active developing country participation in co-operative, international R&D.

Given the significant potential for energy-related $CO_2$ emission reductions in developing countries, more R&D devoted to the emission sources and conditions in those countries is warranted. Developed countries have agreed, in the UNFCCC and the Bali Action Plan (UNFCCC 2007b), to provide technological support for mitigation actions in developing countries. How to structure and fund international technology co-operation is part of the negotiations for an agreement at the UN Climate Change Conference (COP 15) in Copenhagen.

Governments have access to a range of financing mechanisms, beyond those available to businesses and households. These include taxation, gilt-edged borrowing, overseas aid, and other fiscal and monetary mechanisms. However, following the financial and economic crisis and the countervailing stimulus packages, most national government budgets, particularly in the OECD, have large deficits. Repayment of this debt will be a burden on government budgets for years to come. As a result the additional funding needed for climate purposes will need to come from cuts to other expenditures or new sources of finance. This presents a very good opportunity for countries to modernise their tax base to ensure that green objectives and, specifically, a strong carbon-price signal, are reflected across all sectors of the economy (Box 8.4).

**Box 8.4 ● *Greening the national tax system***

National taxation systems are constantly evolving. Their primary objective will always be to raise revenue, but the national tax structure can have very important effects on economic output, income distribution, trade flows, and patterns of consumption and production.

The changing nature of energy consumption can have a significant effect on tax revenues. A shift away from fossil fuels, which are heavily taxed in OECD countries, and improvements in energy efficiency could reduce tax intake in some countries, while growing energy use in countries with high levels of subsidy may become increasingly fiscally unsustainable. Such changes will induce the need for fiscal reform.

Higher taxes on polluting activities and relative low taxation on cleaner forms of consumption can ensure that carbon price signals are strengthened across all sectors while also raising revenue. This is particularly important for sectors not closely linked to the international carbon market. For example, a number of OECD countries are already imposing higher taxes on the most polluting vehicles and/ or lower taxes on more efficient vehicles. France this year announced a national $CO_2$ tax of €17 per tonne. An effective system of greener taxation would allow countries to strike the right balance between taxation and subsidies, and thereby to meet the joint objectives of raising sufficient funds, sending clear carbon-price signals and promoting sound public finances.

As well as taxation reform, governments may consider bond issuance to raise funds for greenhouse-gas mitigation investments. These can be structured to allow mitigation investments to be paid for over the lifetime of the equipment concerned. Where the investments yield cost savings, as in the case of energy efficiency, the debt can be repaid from the cost savings.

# COUNTRY AND REGIONAL PROFILES IN THE 450 SCENARIO

## What are the Steps Forward?

## What is included in the profiles?

Unlike most of the rest of the book, this chapter is primarily in the form of tables and figures. Statistical results for the 450 Scenario are presented in the form of profiles for ten major countries and regions: World, OECD+, United States, European Union, Japan, Other Major Economies (OME) as a group, China, Russia, Other Countries (OC) and India.[1] The profile for each country/region includes historical and projected carbon dioxide ($CO_2$) emissions and energy demand, key indicators (*e.g.* population, $CO_2$ intensity, per-capita emissions) and details of the emission reductions under the assumptions adopted about different measures and technologies (such as energy efficiency, renewables, nuclear, biofuels, and carbon capture and storage). The economic implications of the 450 Scenario are shown in the form of indicators, such as the increased investment required by sector or technology, the reductions in oil and gas import bills, and the value of the emission reduction credits purchased or sold. These differ by country/region. The policy opportunities for the country/region in order to achieve the required energy-related $CO_2$ emission reductions are listed.

The base year of the projections is 2007. The emission reductions shown in the profiles are achieved within the country/region shown and by the assumed measures; but this carries no implication that abatement measures and investments are funded wholly by the country in which they occur. These results therefore leave entirely open the negotiation of country commitments in the context of a post-2012 climate agreement.

The figures and tables that follow cover the world or various geographical sub-groupings (see above). The figures and tables are in the same format for each area. They fall into seven categories, as set out below. In each case, they are preceded by a set of Highlights, drawn from the figures, and conclude with three staccato points identifying appropriate actions to realise the assumed savings in each region/country.

### Energy-related $CO_2$ emissions
### Figures 9.1, 9.6, 9.11, 9.16, 9.21, 9.26, 9.31, 9.36, 9.41, 9.46

These charts show historical $CO_2$ emissions for 1990 and 2007 (the base year of our projections) and projections for 2020 and 2030 for the Reference and the 450 Scenarios. Emissions are shown by sector, along with the relative shares. Historical $CO_2$ data come from IEA databases.

1. The regional definitions are given in Chapter 5.

**Key indicators**
**Tables 9.1, 9.3, 9.5, 9.7, 9.9, 9.11, 9.13, 9.15, 9.17, 9.19**

These tables show indicators related to energy and $CO_2$ emissions: per-capita and intensity trends, cumulative emissions and sectoral efficiency. Gross domestic product (GDP) is measured in purchasing power parity (PPP) terms and in 2008 US dollars. Per-capita energy demand is measured in tonnes of oil equivalent (toe) of primary energy demand. Power $CO_2$ intensity is the average emissions (including new and existing power plants) per kWh of electricity output. Car fleet $CO_2$ intensity is the average on-road intensity of passenger cars (across the entire fleet) and is indexed to 2007. Historical cumulative $CO_2$ emissions are derived from Marland *et al.* (2006).

**Energy-related $CO_2$ emissions abatement**
**Figures 9.2, 9.7, 9.12, 9.17, 9.22, 9.27, 9.32, 9.37, 9.42, 9.47**

These charts show the $CO_2$ emissions savings achieved through the use of energy efficiency at end-use level and in power plants (including more efficient gas and coal plants, switching from coal to gas and early retirements) and from the use of renewables (for electricity generation and heat production), biofuels, nuclear power and carbon capture and storage (in power generation and industry). The table that accompanies the chart shows these savings in 2020 and 2030, as well as the corresponding cumulative incremental investment, relative to the Reference Scenario, in the periods 2010-2020 and 2021-2030. Investment in nuclear power in the 450 Scenario in Russia is lower than in the Reference Scenario in the period 2010-2020 because of lower electricity demand and because of the longer operational lifetimes assumed for its nuclear power plants, which reduce the need to build new capacity. Russia's incremental investment has been expressed as zero. The incremental investment in nuclear power in Other Major Economies as a whole for the period 2010-2020 takes account of the reduction in nuclear investment in Russia, with the net result that incremental investment in Other Major Economies is actually smaller than that of China. The breakdown of incremental investment needs in these charts is different from that presented in Chapter 7 in that it does not include lower investment in fossil-fuel plants.

**Power-generation capacity in the 450 Scenario**
**Figures 9.3, 9.8, 9.13, 9.18, 9.23, 9.28, 9.33, 9.38, 9.43, 9.48**

These charts show power generation capacity for 2007, 2020 and 2030 by technology: coal-fired capacity without carbon capture and storage (CCS), gas-fired capacity without CCS, CCS capacity (coal and gas are shown together), nuclear power, hydropower (including small and large), wind power (including onshore and offshore) and other renewables (biomass, geothermal, solar, and tide and wave power).

**Share of passenger vehicle sales by technology and average new vehicle on-road $CO_2$ intensity in the 450 Scenario**
**Figures 9.4, 9.9, 9.14, 9.19, 9.24, 9.29, 9.34, 9.39, 9.44, 9.49**

These charts show the shares of conventional (internal combustion engine), hybrid, plug-in hybrid and electric vehicles in total sales in 2007 and in the 450 Scenario for 2020 and 2030. They also show the average on-road $CO_2$ intensity that corresponds to these sales (measured in grammes of $CO_2$ per kilometre and taking into account the use of biofuels).

**Energy demand and electricity generation**
**Tables 9.2, 9.4, 9.6, 9.8, 9.10, 9.12, 9.14, 9.16, 9.18, 9.20**

These tables show historical data (1990 and 2007) and projections (2020 and 2030) for the 450 Scenario and the Reference Scenario. They are not balances.

**Additional investment in the 450 Scenario relative to the Reference Scenario**
**Figures 9.5, 9.10, 9.15, 9.20, 9.25, 9.30, 9.35, 9.40, 9.45, 9.50**

These charts show incremental annual investment needs in transport, biofuels production, buildings (including rooftop photovoltaics), power plants and industry (including industrial CCS), relative to the Reference Scenario.

# World

## Highlights

- 6% global increase in energy-related $CO_2$ emissions by 2020, relative to 2007, to meet 450 Scenario.
- Power-generation $CO_2$ intensity decreasing by 21% and average car fleet $CO_2$ intensity decreasing by 37% by 2020 in 450 Scenario compared with 2007.
- 3% increase in emissions from buildings and 9% increase in industry in 450 Scenario by 2020, relative to 2007.
- Additional investment, relative to Reference Scenario, in low-carbon technologies and energy efficiency close to $430 billion in 2020 to meet 450 Scenario.

## Emissions

**Figure 9.1 • World energy-related $CO_2$ emissions**

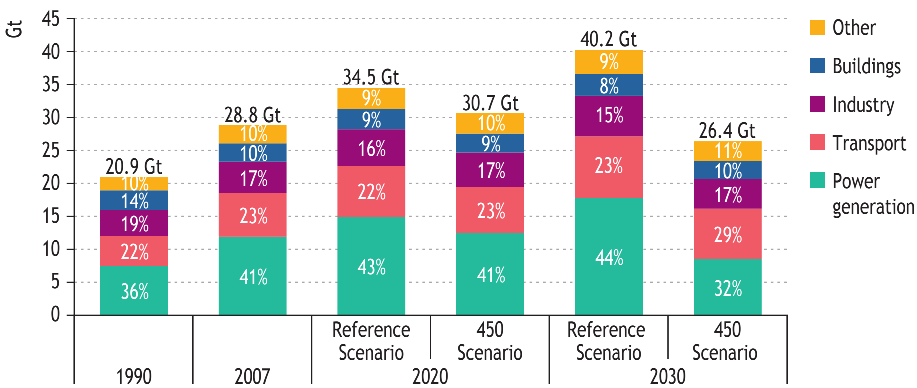
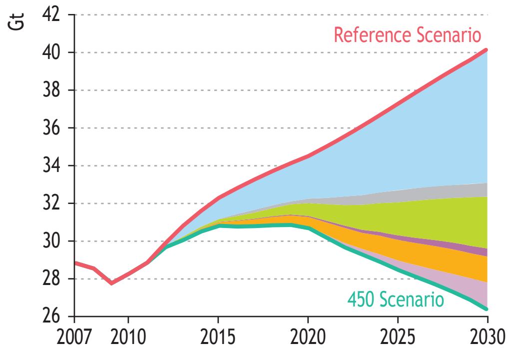



**Table 9.1 • World key indicators**

| | | | 2020 | | 2030 | |
|---|---|---|---|---|---|---|
| | 1990 | 2007 | RS | 450 | RS | 450 |
| Population (million) | 5 263 | 6 614 | 7 608 | | 8 236 | |
| Share of world population | 100% | 100% | 100% | | 100% | |
| GDP ($2008 trillion, PPP) | 38.6 | 67.2 | 102.1 | | 137.0 | |
| Share of world GDP | 100% | 100% | 100% | | 100% | |
| Share of world $CO_2$ emissions | 100% | 100% | 100% | 100% | 100% | 100% |
| $CO_2$ emissions per capita (t) | 4.0 | 4.4 | 4.5 | 4.0 | 4.9 | 3.2 |
| Energy demand per capita (toe) | 1.7 | 1.8 | 1.9 | 1.8 | 2.0 | 1.7 |
| $CO_2$ intensity index (world 2007=100) | 126 | 100 | 79 | 70 | 68 | 45 |
| Cumulative $CO_2$ since 1890 (Gt) | 778 | 1 201 | 1 608 | 1 589 | 1 984 | 1 871 |
| Share of cumulative world $CO_2$ | 100% | 100% | 100% | 100% | 100% | 100% |
| Power $CO_2$ intensity (g/kWh) | 632 | 603 | 549 | 479 | 520 | 283 |
| Car fleet $CO_2$ intensity (2007=100) | n.a. | 100 | 78 | 63 | 75 | 47 |

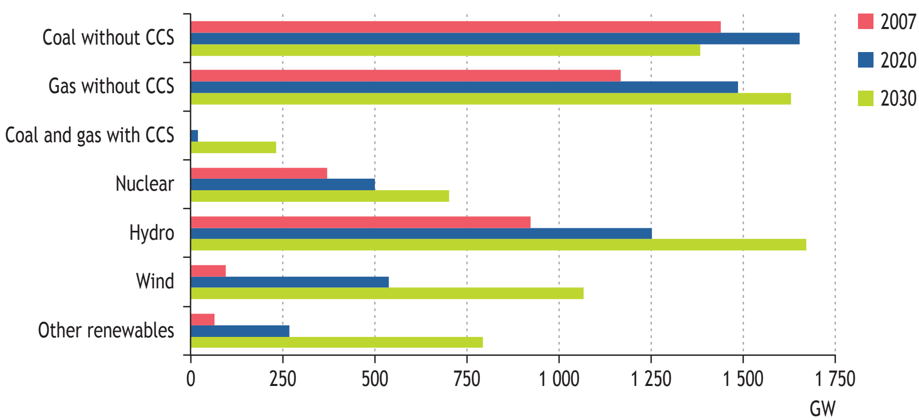
## Technology outlook

### Figure 9.2 • World energy-related $CO_2$ emissions abatement

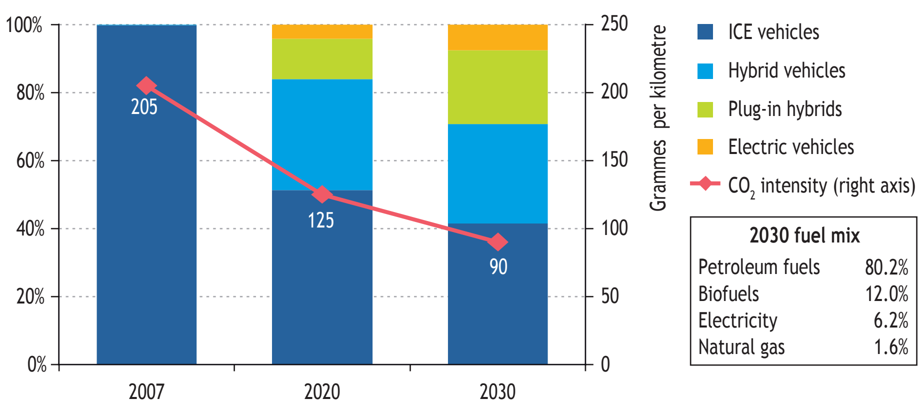



| | Abatement ($Mt\ CO_2$) 2020 | 2030 | Investment ($2008 billion) 2010-2020 | 2021-2030 |
|---|---|---|---|---|
| Efficiency | 2 517 | 7 880 | 1 999 | 5 586 |
| End-use | 2 284 | 7 145 | 1 933 | 5 551 |
| Power plants | 233 | 735 | 66 | 35 |
| Renewables | 680 | 2 741 | 527 | 2 260 |
| Biofuels | 57 | 429 | 27 | 378 |
| Nuclear | 493 | 1 380 | 125 | 491 |
| CCS | 102 | 1 410 | 56 | 646 |

### Figure 9.3 • World power-generation capacity in the 450 Scenario




### Figure 9.4 • World share of passenger vehicle sales by technology and average new vehicle on-road $CO_2$ intensity in the 450 Scenario

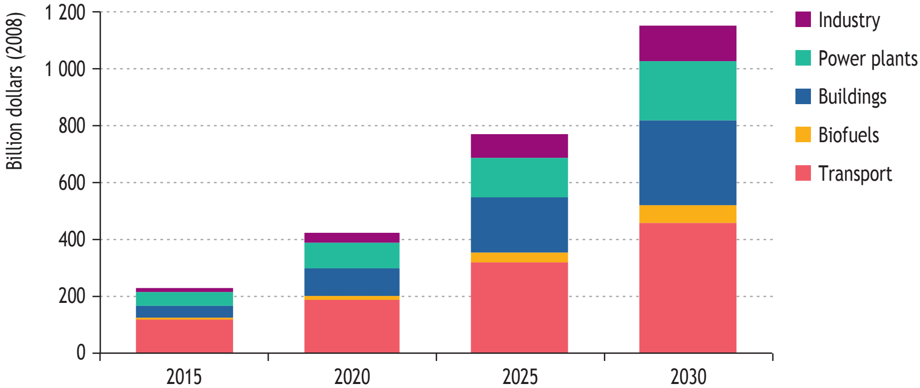


## Table 9.2 • World energy demand and electricity generation

| | 1990 | 2007 | 2020 Reference Scenario | 2020 450 Scenario | 2030 Reference Scenario | 2030 450 Scenario | Change vs. RS 2020 | Change vs. RS 2030 |
|---|---|---|---|---|---|---|---|---|
| | | | Energy demand (Mtoe) | | | | (%) | |
| **Total primary energy demand** | **8 761** | **12 013** | **14 450** | **13 600** | **16 790** | **14 389** | **-6** | **-14** |
| Coal | 2 221 | 3 184 | 4 125 | 3 507 | 4 887 | 2 614 | -15 | -47 |
| Oil | 3 219 | 4 093 | 4 440 | 4 121 | 5 009 | 4 250 | -7 | -15 |
| Gas | 1 671 | 2 512 | 3 035 | 2 868 | 3 561 | 2 941 | -6 | -17 |
| Nuclear | 526 | 709 | 851 | 1 003 | 956 | 1 426 | 18 | 49 |
| Renewables | 1 125 | 1 514 | 1 999 | 2 101 | 2 376 | 3 159 | 5 | 33 |
| **Power generation** | **2 981** | **4 557** | **5 823** | **5 427** | **7 042** | **5 816** | **-7** | **-17** |
| *of which coal* | *1 228* | *2 167* | *2 871* | *2 341* | *3 481* | *1 615* | *-18* | *-54* |
| *of which gas* | *576* | *988* | *1 202* | *1 136* | *1 464* | *1 158* | *-5* | *-21* |
| **Other energy sector** | **880** | **1 212** | **1 498** | **1 404** | **1 682** | **1 332** | **-6** | **-21** |
| **Total final consumption** | **6 293** | **8 273** | **9 838** | **9 361** | **11 405** | **10 147** | **-5** | **-11** |
| Coal | 761 | 727 | 878 | 814 | 961 | 696 | -7 | -28 |
| Oil | 2 607 | 3 527 | 3 961 | 3 702 | 4 581 | 3 901 | -7 | -15 |
| Gas | 957 | 1 292 | 1 510 | 1 432 | 1 728 | 1 505 | -5 | -13 |
| Electricity | 833 | 1 413 | 1 963 | 1 878 | 2 488 | 2 186 | -4 | -12 |
| Heat | 333 | 273 | 301 | 293 | 322 | 276 | -3 | -14 |
| Renewables | 801 | 1 041 | 1 225 | 1 242 | 1 325 | 1 582 | 1 | 19 |
| **Industry** | **1 800** | **2 266** | **2 836** | **2 702** | **3 302** | **2 816** | **-5** | **-15** |
| Coal | 470 | 581 | 706 | 653 | 789 | 572 | -7 | -28 |
| Oil | 327 | 320 | 336 | 323 | 355 | 314 | -4 | -12 |
| Gas | 355 | 460 | 544 | 517 | 622 | 543 | -5 | -13 |
| Electricity | 379 | 596 | 881 | 823 | 1 103 | 910 | -7 | -17 |
| Heat | 150 | 120 | 131 | 127 | 139 | 121 | -3 | -13 |
| Renewables | 118 | 189 | 239 | 258 | 294 | 357 | 8 | 21 |
| **Transport** | **1 578** | **2 297** | **2 753** | **2 574** | **3 331** | **2 994** | **-6** | **-10** |
| Oil | 1 485 | 2 161 | 2 524 | 2 306 | 3 052 | 2 510 | -9 | -18 |
| Biofuels | 6 | 34 | 104 | 123 | 133 | 278 | 19 | 109 |
| Other fuels | 87 | 101 | 125 | 145 | 146 | 206 | 16 | 41 |
| **Other sectors** | **2 440** | **2 941** | **3 377** | **3 222** | **3 830** | **3 448** | **-5** | **-10** |
| Coal | 254 | 110 | 116 | 107 | 108 | 78 | -8 | -28 |
| Oil | 437 | 453 | 472 | 448 | 505 | 427 | -5 | -15 |
| Gas | 456 | 613 | 689 | 650 | 796 | 686 | -6 | -14 |
| Electricity | 433 | 794 | 1 046 | 990 | 1 338 | 1 155 | -5 | -14 |
| Heat | 183 | 153 | 171 | 166 | 183 | 155 | -3 | -15 |
| Renewables | 678 | 818 | 882 | 861 | 899 | 948 | -2 | 5 |
| **Non-energy use** | **475** | **770** | **873** | **863** | **942** | **889** | **-1** | **-6** |
| | | | Electricity generation (TWh) | | | | (%) | |
| **Total generation** | **11 814** | **19 756** | **27 232** | **26 003** | **34 292** | **29 939** | **-5** | **-13** |
| Coal | 4 424 | 8 216 | 11 744 | 9 629 | 15 259 | 7 260 | -18 | -52 |
| Oil | 1 332 | 1 117 | 776 | 621 | 665 | 459 | -20 | -31 |
| Gas | 1 727 | 4 126 | 5 620 | 5 396 | 7 058 | 5 688 | -4 | -19 |
| Nuclear | 2 013 | 2 719 | 3 263 | 3 850 | 3 667 | 5 470 | 18 | 49 |
| Hydro | 2 144 | 3 078 | 4 027 | 4 215 | 4 680 | 5 659 | 5 | 21 |
| Wind | 4 | 173 | 1 010 | 1 323 | 1 535 | 2 779 | 31 | 81 |
| Other renewables | 169 | 326 | 792 | 969 | 1 427 | 2 624 | 22 | 84 |

## Costs and benefits

**Figure 9.5 • *World additional investment in the 450 Scenario relative to the Reference Scenario***




- Additional cumulative investment cost: almost $2 400 billion over 2010-2020 and $8 100 billion over 2021-2030.
- Total investment in the 450 Scenario of almost $6 600 billion in low-carbon power generation over 2010-2030 (72% renewables, 19% nuclear, 9% CCS).
- Incremental investment cost equal to 0.5% of GDP in 2020, rising to 1.1% of GDP in 2030.
- Total fuel-cost saving of $8 600 billion between 2010 and 2030, across industry, buildings and transport.
- Local air pollution costs reduced by $40 billion in 2020 and $100 billion in 2030, relative to the Reference Scenario.

## Policy opportunities

- An ambitious, robust global agreement in Copenhagen, which will credibly deliver substantial emissions abatement relative to the Reference Scenario, with financial and technology support to ensure that all regions contribute and including an expanded, reformed Clean Development Mechanism (CDM).
- Faster deployment of low-carbon power technologies, which together account for over 5 Gt of abatement relative to the Reference Scenario by 2030. This includes much faster roll-out of renewables and nuclear – and urgent investment in and development of carbon capture and storage.
- A transformation in end-use efficiency investment, to deliver over 7 Gt of abatement by 2030. Much of this will be carried out by households, who need strong incentives to purchase more efficient vehicles and appliances.

# OECD+

## Highlights

- 17% reduction in energy-related $CO_2$ emissions by 2020, relative to 2007, to meet 450 Scenario.
- Power generation $CO_2$ intensity decreasing by 29% and average car fleet $CO_2$ intensity decreasing by 39% by 2020, compared with 2007.
- 10% reduction in emissions from buildings and 17% reduction in industry by 2020, relative to 2007.
- Additional investment in low-carbon technologies and energy efficiency close to $220 billion in 2020 to meet the 450 Scenario.

## Emissions

**Figure 9.6 • OECD+ energy-related $CO_2$ emissions**

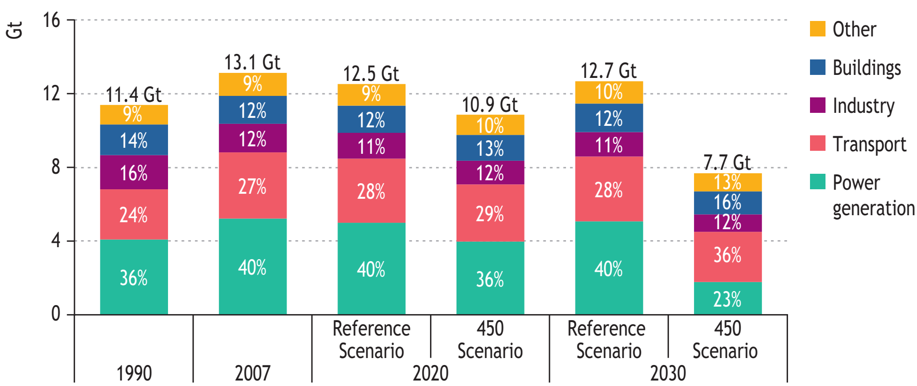
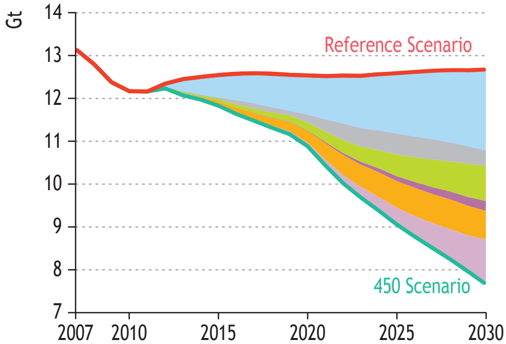



**Table 9.3 • OECD+ key indicators**

| | 1990 | 2007 | 2020 RS | 2020 450 | 2030 RS | 2030 450 |
|---|---|---|---|---|---|---|
| Population (million) | 1 090 | 1 229 | 1 307 | | 1 344 | |
| Share of world population | 21% | 19% | 17% | | 16% | |
| GDP ($2008 trillion, PPP) | 26.2 | 40.1 | 49.7 | | 60.0 | |
| Share of world GDP | 68% | 60% | 49% | | 44% | |
| Share of world $CO_2$ emissions | 54% | 46% | 36% | 35% | 32% | 29% |
| $CO_2$ emissions per capita (t) | 10.4 | 10.7 | 9.6 | 8.3 | 9.4 | 5.7 |
| Energy demand per capita (toe) | 4.2 | 4.5 | 4.3 | 4.1 | 4.4 | 3.9 |
| $CO_2$ intensity index (world 2007=100) | 101 | 76 | 59 | 51 | 49 | 30 |
| Cumulative $CO_2$ since 1890 (Gt) | 498 | 700 | 863 | 854 | 989 | 944 |
| Share of cumulative world $CO_2$ | 64% | 58% | 54% | 54% | 50% | 50% |
| Power $CO_2$ intensity (g/kWh) | 528 | 484 | 417 | 343 | 380 | 145 |
| Car fleet $CO_2$ intensity (2007=100) | n.a. | 100 | 74 | 61 | 69 | 43 |

## Technology outlook

**Figure 9.7 • OECD+ energy-related $CO_2$ emissions abatement**




| | Abatement (Mt $CO_2$) 2020 | Abatement (Mt $CO_2$) 2030 | Investment ($2008 billion) 2010-2020 | Investment ($2008 billion) 2021-2030 |
|---|---|---|---|---|
| Efficiency | 1 102 | 2 253 | 1 158 | 2 332 |
| End-use | 921 | 1 894 | 1 117 | 2 319 |
| Power plants | 181 | 359 | 42 | 13 |
| Renewables | 184 | 816 | 204 | 831 |
| Biofuels | 12 | 228 | 8 | 223 |
| Nuclear | 271 | 670 | 64 | 241 |
| CCS | 86 | 1 013 | 48 | 512 |

**Figure 9.8 • OECD+ power-generation capacity in the 450 Scenario**

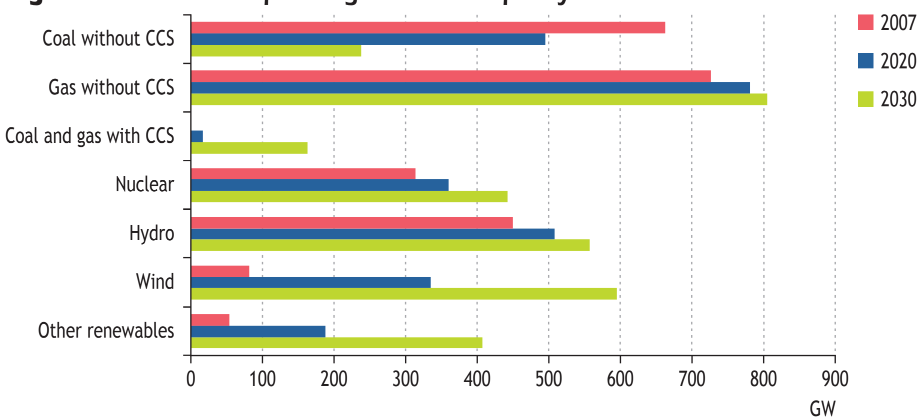
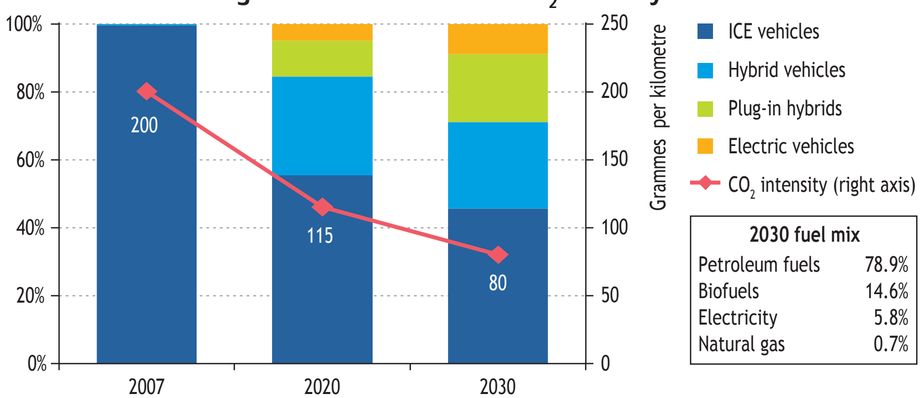



**Figure 9.9 • OECD+ share of passenger vehicle sales by technology and average new vehicle on-road $CO_2$ intensity in the 450 Scenario**



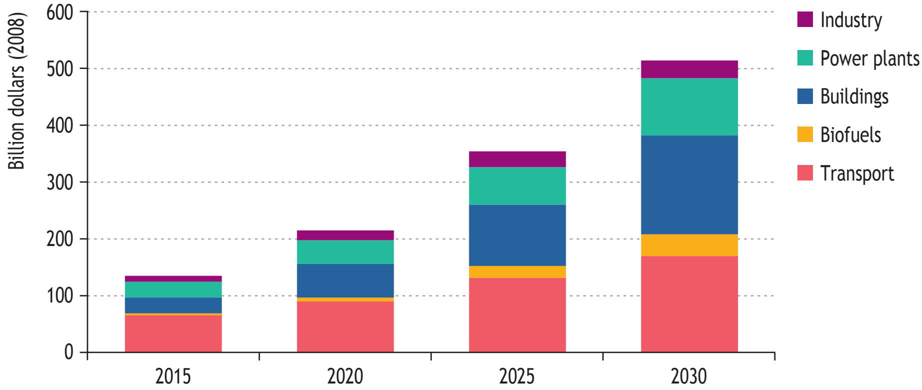

| 2030 fuel mix | |
|---|---|
| Petroleum fuels | 78.9% |
| Biofuels | 14.6% |
| Electricity | 5.8% |
| Natural gas | 0.7% |

## Table 9.4 • OECD+ energy demand and electricity generation

| | 1990 | 2007 | 2020 Reference Scenario | 2020 450 Scenario | 2030 Reference Scenario | 2030 450 Scenario | Change vs. RS 2020 | Change vs. RS 2030 |
|---|---|---|---|---|---|---|---|---|
| | | | Energy demand (Mtoe) | | | | (%) | |
| **Total primary energy demand** | **4 608** | **5 586** | **5 644** | **5 326** | **5 909** | **5 299** | **-6** | **-10** |
| Coal | 1 096 | 1 181 | 1 106 | 860 | 1 115 | 453 | -22 | -59 |
| Oil | 1 895 | 2 135 | 1 923 | 1 774 | 1 880 | 1 553 | -8 | -17 |
| Gas | 883 | 1 281 | 1 373 | 1 294 | 1 478 | 1 282 | -6 | -13 |
| Nuclear | 460 | 602 | 625 | 722 | 666 | 895 | 16 | 34 |
| Renewables | 275 | 386 | 617 | 677 | 770 | 1 116 | 10 | 45 |
| **Power generation** | **1 767** | **2 321** | **2 435** | **2 308** | **2 632** | **2 328** | **-5** | **-12** |
| *of which coal* | *771* | *955* | *922* | *706* | *925* | *332* | *-23* | *-64* |
| *of which gas* | *192* | *445* | *488* | *471* | *547* | *489* | *-3* | *-11* |
| **Other energy sector** | **402** | **451** | **456** | **415** | **469** | **360** | **-9** | **-23** |
| **Total final consumption** | **3 172** | **3 829** | **3 879** | **3 686** | **4 060** | **3 760** | **-5** | **-7** |
| Coal | 236 | 137 | 114 | 98 | 104 | 80 | -14 | -23 |
| Oil | 1 608 | 1 896 | 1 761 | 1 632 | 1 746 | 1 449 | -7 | -17 |
| Gas | 617 | 751 | 768 | 720 | 804 | 700 | -6 | -13 |
| Electricity | 559 | 804 | 897 | 866 | 1 010 | 936 | -3 | -7 |
| Heat | 57 | 73 | 81 | 77 | 87 | 77 | -5 | -12 |
| Renewables | 94 | 167 | 258 | 292 | 309 | 518 | 13 | 68 |
| **Industry** | **864** | **888** | **893** | **843** | **914** | **841** | **-6** | **-8** |
| Coal | 162 | 117 | 99 | 85 | 92 | 72 | -14 | -22 |
| Oil | 173 | 131 | 109 | 104 | 101 | 91 | -5 | -10 |
| Gas | 246 | 264 | 264 | 247 | 266 | 236 | -7 | -11 |
| Electricity | 227 | 275 | 294 | 274 | 309 | 276 | -7 | -11 |
| Heat | 20 | 28 | 29 | 27 | 29 | 27 | -5 | -8 |
| Renewables | 36 | 73 | 98 | 106 | 117 | 139 | 9 | 19 |
| **Transport** | **948** | **1 251** | **1 264** | **1 168** | **1 280** | **1 134** | **-8** | **-11** |
| Oil | 921 | 1 194 | 1 156 | 1 043 | 1 163 | 907 | -10 | -22 |
| Biofuels | 0 | 24 | 68 | 72 | 74 | 152 | 6 | 105 |
| Other fuels | 27 | 34 | 39 | 53 | 43 | 75 | 34 | 76 |
| **Other sectors** | **1 069** | **1 293** | **1 369** | **1 323** | **1 518** | **1 437** | **-3** | **-5** |
| Coal | 72 | 17 | 13 | 12 | 10 | 7 | -12 | -31 |
| Oil | 261 | 215 | 181 | 170 | 173 | 139 | -6 | -20 |
| Gas | 316 | 425 | 440 | 413 | 475 | 405 | -6 | -15 |
| Electricity | 324 | 520 | 591 | 564 | 685 | 610 | -4 | -11 |
| Heat | 38 | 46 | 52 | 50 | 58 | 50 | -4 | -14 |
| Renewables | 59 | 71 | 92 | 114 | 118 | 227 | 24 | 93 |
| **Non-energy use** | **292** | **396** | **353** | **353** | **347** | **348** | **-0** | **0** |
| | | | Electricity generation (TWh) | | | | (%) | |
| **Total generation** | **7 743** | **10 798** | **11 994** | **11 565** | **13 403** | **12 344** | **-4** | **-8** |
| Coal | 3 114 | 4 022 | 3 993 | 3 096 | 4 262 | 1 652 | -22 | -61 |
| Oil | 714 | 443 | 179 | 112 | 147 | 62 | -37 | -58 |
| Gas | 806 | 2 326 | 2 681 | 2 649 | 2 994 | 2 775 | -1 | -7 |
| Nuclear | 1 761 | 2 311 | 2 397 | 2 769 | 2 555 | 3 436 | 16 | 34 |
| Hydro | 1 191 | 1 284 | 1 456 | 1 491 | 1 533 | 1 668 | 2 | 9 |
| Wind | 4 | 150 | 735 | 817 | 1 080 | 1 576 | 11 | 46 |
| Other renewables | 152 | 263 | 553 | 630 | 833 | 1 175 | 14 | 41 |

## Costs and benefits

**Figure 9.10 • OECD+ additional investment in the 450 Scenario relative to the Reference Scenario**




- Additional cumulative investment cost: in excess of $1 300 billion over 2010-2020; nearly $3 700 billion over 2021-2030.
- Total investment in the 450 Scenario of over $3 100 billion in low-carbon power generation over 2010-2030 (65% renewables, 20% nuclear, 15% CCS).
- Incremental investment cost equal to 0.4% of GDP in 2020, rising to 0.8% of GDP in 2030.
- Oil savings of 7.3 mb/d in 2030 in the 450 Scenario, compared with the Reference Scenario – an amount close to China's 2008 oil demand.
- Local air pollution costs reduced in excess of $20 billion in 2020 and $50 billion in 2030, relative to the Reference Scenario.

## Policy opportunities

- Implement an OECD-wide emissions trading scheme to deliver emission reductions in power generation and industry.
- Expand support mechanisms for end-use sectors to encourage investment in energy efficiency in buildings and transport.
- Facilitate the transfer of low-carbon technologies to non-OECD countries, through international sectoral agreements, the purchase of carbon credits and other measures.

# The United States (US)

## Highlights

- 18% reduction in energy-related $CO_2$ emissions by 2020 (relative to 2007) to meet 450 Scenario.
- Power-generation $CO_2$ intensity decreasing by 25% and average car fleet $CO_2$ intensity decreasing by 41% by 2020, compared with 2007.
- 16% reduction in $CO_2$ emissions from buildings and 25% reduction in industry by 2020, relative to 2007.
- Additional investment in low-carbon technologies and energy efficiency of close to $90 billion in 2020 to meet 450 Scenario.

## Emissions

**Figure 9.11 • US energy-related $CO_2$ emissions**

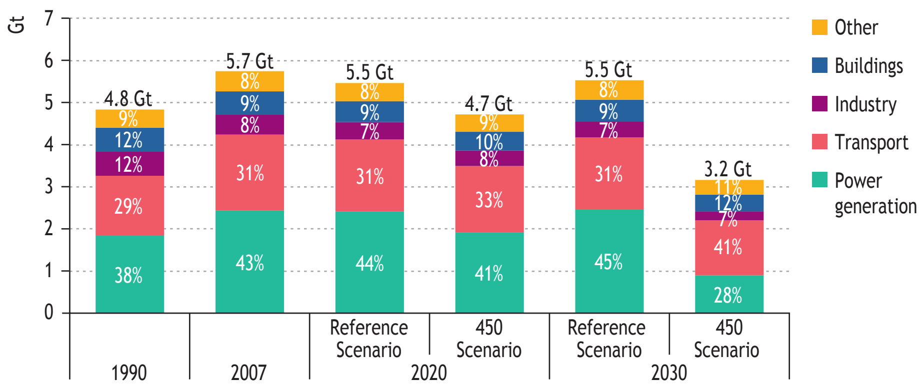
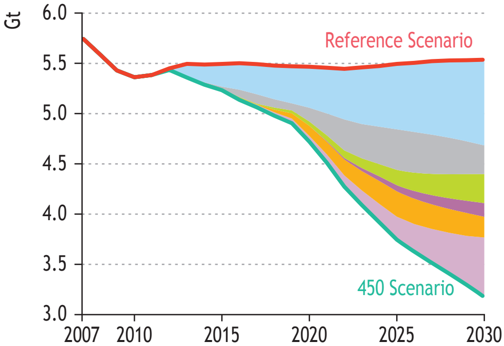



**Table 9.5 • US key indicators**

| | 1990 | 2007 | 2020 RS | 2020 450 | 2030 RS | 2030 450 |
|---|---|---|---|---|---|---|
| Population (million) | 254 | 306 | 343 | | 367 | |
| Share of world population | 5% | 5% | 5% | | 4% | |
| GDP ($2008 trillion, PPP) | 8.7 | 14.1 | 18.1 | | 22.4 | |
| Share of world GDP | 23% | 21% | 18% | | 16% | |
| Share of world $CO_2$ emissions | 23% | 20% | 16% | 15% | 14% | 12% |
| $CO_2$ emissions per capita (t) | 19.1 | 18.7 | 15.9 | 13.7 | 15.1 | 8.6 |
| Energy demand per capita (toe) | 7.5 | 7.6 | 6.7 | 6.3 | 6.5 | 5.7 |
| $CO_2$ intensity index (world 2007=100) | 130 | 95 | 70 | 61 | 58 | 33 |
| Cumulative $CO_2$ since 1890 (Gt) | 239 | 333 | 404 | 400 | 459 | 437 |
| Share of cumulative world $CO_2$ | 31% | 28% | 25% | 25% | 23% | 23% |
| Power $CO_2$ intensity (g/kWh) | 577 | 565 | 509 | 423 | 468 | 185 |
| Car fleet $CO_2$ intensity (2007=100) | n.a. | 100 | 80 | 59 | 72 | 39 |

## Technology outlook

**Figure 9.12 • US energy-related $CO_2$ emissions abatement**




| | Abatement ($Mt\ CO_2$) | | Investment ($2008 billion) | |
|---|---|---|---|---|
| | 2020 | 2030 | 2010-2020 | 2021-2030 |
| Efficiency | 548 | 1 141 | 475 | 955 |
| End-use | 411 | 855 | 443 | 949 |
| Power plants | 137 | 286 | 32 | 5 |
| Renewables | 43 | 288 | 36 | 330 |
| Biofuels | 0 | 136 | 0 | 127 |
| Nuclear | 101 | 206 | 62 | 77 |
| CCS | 57 | 593 | 33 | 300 |

**Figure 9.13 • US power-generation capacity in the 450 Scenario**

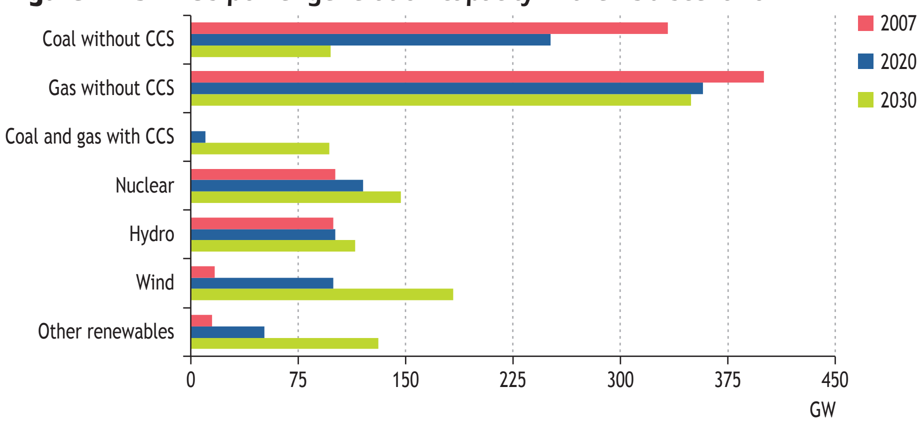
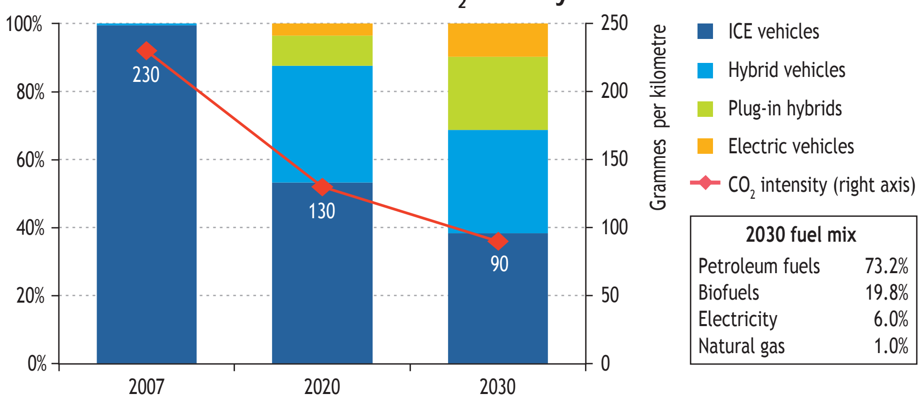



**Figure 9.14 • US share of passenger vehicle sales by technology and average new vehicle on-road $CO_2$ intensity in the 450 Scenario**




| 2030 fuel mix | |
|---|---|
| Petroleum fuels | 73.2% |
| Biofuels | 19.8% |
| Electricity | 6.0% |
| Natural gas | 1.0% |

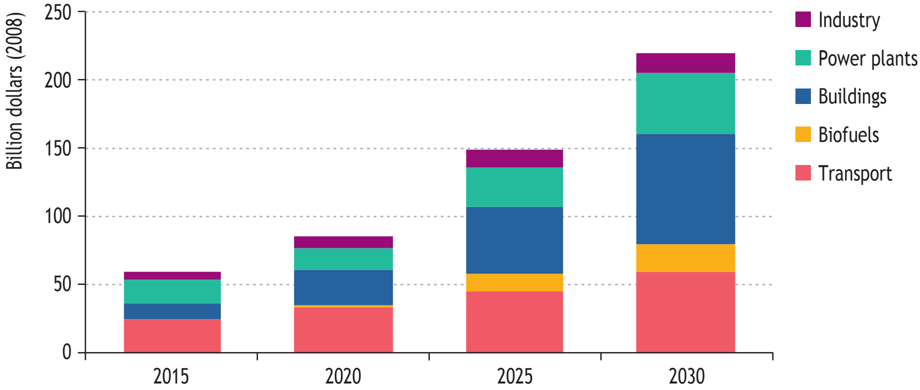
9

## Table 9.6 • US energy demand and electricity generation

| | 1990 | 2007 | 2020 Reference Scenario | 2020 450 Scenario | 2030 Reference Scenario | 2030 450 Scenario | Change vs. RS 2020 | Change vs. RS 2030 |
|---|---|---|---|---|---|---|---|---|
| | | | Energy demand (Mtoe) | | | | (%) | |
| **Total primary energy demand** | **1 913** | **2 337** | **2 316** | **2 167** | **2 396** | **2 092** | **-6** | **-13** |
| Coal | 458 | 554 | 548 | 415 | 581 | 234 | -24 | -60 |
| Oil | 757 | 910 | 806 | 750 | 772 | 627 | -7 | -19 |
| Gas | 438 | 538 | 522 | 517 | 533 | 515 | -1 | -3 |
| Nuclear | 159 | 218 | 231 | 260 | 248 | 316 | 13 | 28 |
| Renewables | 100 | 117 | 209 | 225 | 262 | 400 | 8 | 53 |
| **Power generation** | **750** | **963** | **1 016** | **945** | **1 091** | **923** | **-7** | **-15** |
| *of which coal* | *396* | *502* | *509* | *387* | *525* | *216* | *-24* | *-59* |
| *of which gas* | *90* | *173* | *167* | *189* | *175* | *216* | *13* | *24* |
| **Other energy sector** | **149** | **174** | **162** | **149** | **159** | **115** | **-8** | **-28** |
| **Total final consumption** | **1 292** | **1 588** | **1 563** | **1 479** | **1 614** | **1 481** | **-5** | **-8** |
| Coal | 54 | 30 | 24 | 18 | 21 | 14 | -26 | -35 |
| Oil | 683 | 835 | 754 | 701 | 743 | 592 | -7 | -20 |
| Gas | 303 | 321 | 313 | 290 | 318 | 269 | -7 | -15 |
| Electricity | 226 | 329 | 359 | 344 | 402 | 371 | -4 | -8 |
| Heat | 2 | 7 | 7 | 6 | 6 | 6 | -10 | -15 |
| Renewables | 23 | 65 | 106 | 120 | 124 | 229 | 13 | 84 |
| **Industry** | **283** | **292** | **280** | **256** | **271** | **239** | **-8** | **-12** |
| Coal | 45 | 28 | 23 | 17 | 21 | 14 | -26 | -34 |
| Oil | 44 | 31 | 22 | 21 | 20 | 17 | -8 | -14 |
| Gas | 110 | 111 | 103 | 94 | 98 | 83 | -9 | -15 |
| Electricity | 75 | 80 | 78 | 69 | 74 | 62 | -12 | -17 |
| Heat | 0 | 6 | 6 | 5 | 6 | 5 | -11 | -16 |
| Renewables | 9 | 36 | 47 | 50 | 52 | 59 | 7 | 13 |
| **Transport** | **488** | **636** | **628** | **588** | **629** | **561** | **-6** | **-11** |
| Oil | 472 | 605 | 572 | 526 | 568 | 435 | -8 | -23 |
| Biofuels | 0 | 15 | 39 | 39 | 44 | 90 | 0 | 106 |
| Other fuels | 16 | 16 | 17 | 23 | 17 | 36 | 38 | 104 |
| **Other sectors** | **403** | **502** | **518** | **499** | **580** | **548** | **-4** | **-6** |
| Coal | 10 | 2 | 1 | 1 | 0 | 0 | -20 | -70 |
| Oil | 62 | 56 | 38 | 33 | 35 | 20 | -12 | -42 |
| Gas | 164 | 180 | 179 | 166 | 189 | 156 | -7 | -17 |
| Electricity | 152 | 248 | 280 | 268 | 326 | 291 | -4 | -11 |
| Heat | 2 | 2 | 1 | 1 | 1 | 1 | -3 | -6 |
| Renewables | 14 | 15 | 20 | 30 | 28 | 80 | 53 | 183 |
| **Non-energy use** | **119** | **158** | **136** | **136** | **133** | **133** | **-1** | **-1** |
| | | | Electricity generation (TWh) | | | | (%) | |
| **Total generation** | **3 203** | **4 322** | **4 748** | **4 545** | **5 277** | **4 826** | **-4** | **-9** |
| Coal | 1 700 | 2 118 | 2 194 | 1 692 | 2 402 | 1 106 | -23 | -54 |
| Oil | 131 | 78 | 31 | 22 | 27 | 17 | -29 | -36 |
| Gas | 382 | 915 | 915 | 1 071 | 968 | 1 249 | 17 | 29 |
| Nuclear | 612 | 837 | 885 | 998 | 951 | 1 214 | 13 | 28 |
| Hydro | 273 | 250 | 274 | 274 | 279 | 328 | 0 | 18 |
| Wind | 3 | 35 | 243 | 265 | 325 | 500 | 9 | 54 |
| Other renewables | 103 | 89 | 207 | 223 | 325 | 413 | 8 | 27 |

## Costs and benefits

**Figure 9.15 • US additional investment in the 450 Scenario relative to the Reference Scenario**




- Additional cumulative investment cost: in excess of \$520 billion over 2010-2020; \$1 500 billion over 2021-2030.
- Total investment in the 450 Scenario of over \$1 100 billion in low-carbon power generation over 2010-2030 (53% renewables, 27% CCS, 19% nuclear).
- Incremental investment cost equal to 0.5% of GDP in 2020, rising to 1.0% of GDP in 2030.
- Oil and gas import bill reduced by \$80 billion in 2020 and nearly \$155 billion in 2030, compared with the Reference Scenario.
- Local air pollution costs reduced by close to \$10 billion in 2020 and in excess of \$20 billion in 2030, relative to the Reference Scenario.

## Policy opportunities

- Establish a cap-and-trade scheme that promotes domestic reductions and allows the purchase of credits to support emissions reductions in other countries and sectors.
- Provide funding for CCS to achieve commercialisation by 2020; encourage investment in renewables and nuclear power.
- Strengthen policies and standards for new and refurbished buildings, and reduce the $CO_2$ intensity of new passenger vehicles to 110 g/km by 2020.

9

# The European Union (EU)

## Highlights

- 20% reduction in energy-related $CO_2$ emissions by 2020 (relative to 2007) to meet 450 Scenario.
- Power generation $CO_2$ intensity decreasing by 37% and average car fleet $CO_2$ intensity decreasing by 37% by 2020, compared with 2007.
- 7% reduction in emissions from buildings and 17% reduction in industry by 2020, relative to 2007.
- Additional investment in low-carbon technologies and energy efficiency of $70 billion in 2020 to meet 450 Scenario.

## Emissions

**Figure 9.16 ● EU energy-related $CO_2$ emissions**

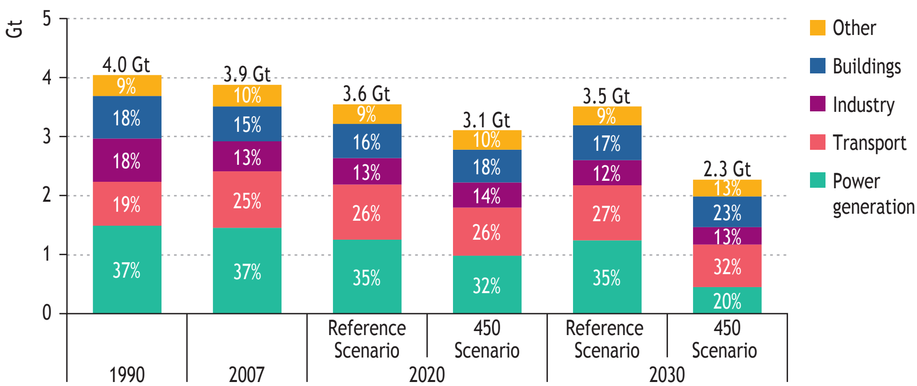
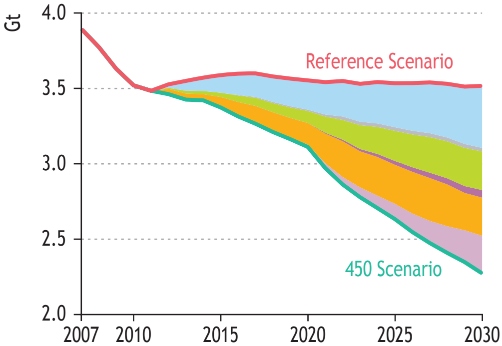



**Table 9.7 ● EU key indicators**

| | | | 2020 | | 2030 | |
|---|---|---|---|---|---|---|
| | 1990 | 2007 | RS | 450 | RS | 450 |
| Population (million) | 473 | 496 | 508 | | 508 | |
| Share of world population | 9% | 7% | 7% | | 6% | |
| GDP ($2008 trillion, PPP) | 10.4 | 15.1 | 17.9 | | 21.3 | |
| Share of world GDP | 27% | 22% | 18% | | 16% | |
| Share of world $CO_2$ emissions | 19% | 13% | 10% | 10% | 9% | 9% |
| $CO_2$ emissions per capita (t) | 8.5 | 7.8 | 7.0 | 6.1 | 6.9 | 4.5 |
| Energy demand per capita (toe) | 3.5 | 3.5 | 3.4 | 3.3 | 3.5 | 3.3 |
| $CO_2$ intensity index (world 2007=100) | 90 | 60 | 46 | 40 | 38 | 25 |
| Cumulative $CO_2$ since 1890 (Gt) | 211 | 276 | 322 | 320 | 358 | 346 |
| Share of cumulative world $CO_2$ | 27% | 23% | 20% | 20% | 18% | 18% |
| Power $CO_2$ intensity (g/kWh) | 581 | 436 | 348 | 275 | 312 | 118 |
| Car fleet $CO_2$ intensity (2007=100) | n.a. | 100 | 74 | 63 | 65 | 46 |

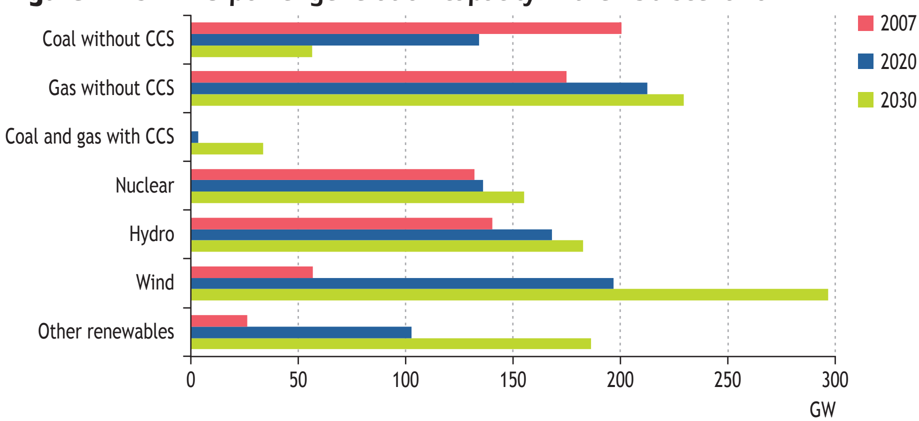
## Technology outlook

### Figure 9.17 • EU energy-related $CO_2$ emissions abatement

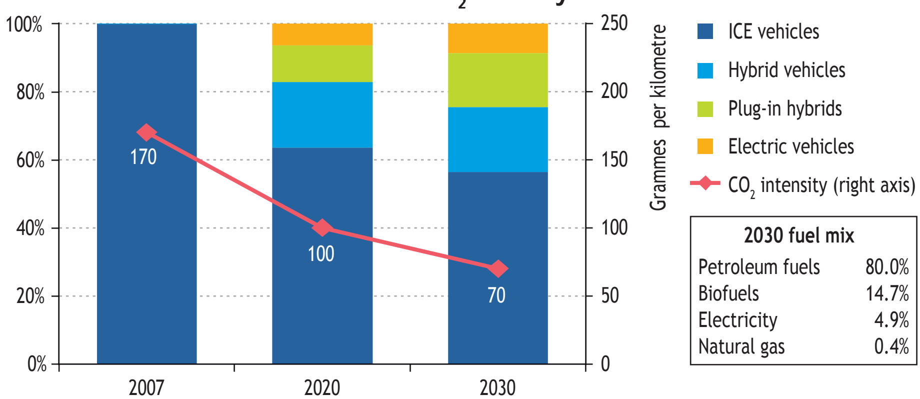



| | Abatement ($Mt CO_2$) | | Investment ($2008 billion) | |
|---|---|---|---|---|
| | 2020 | 2030 | 2010-2020 | 2021-2030 |
| Efficiency | 206 | 438 | 392 | 709 |
| End-use | 197 | 414 | 387 | 709 |
| Power plants | 9 | 24 | 5 | 0 |
| Renewables | 80 | 256 | 113 | 268 |
| Biofuels | 1 | 50 | 4 | 60 |
| Nuclear | 143 | 253 | 0 | 88 |
| CCS | 16 | 250 | 9 | 126 |

### Figure 9.18 • EU power-generation capacity in the 450 Scenario




### Figure 9.19 • EU share of passenger vehicle sales by technology and average new vehicle on-road $CO_2$ intensity in the 450 Scenario

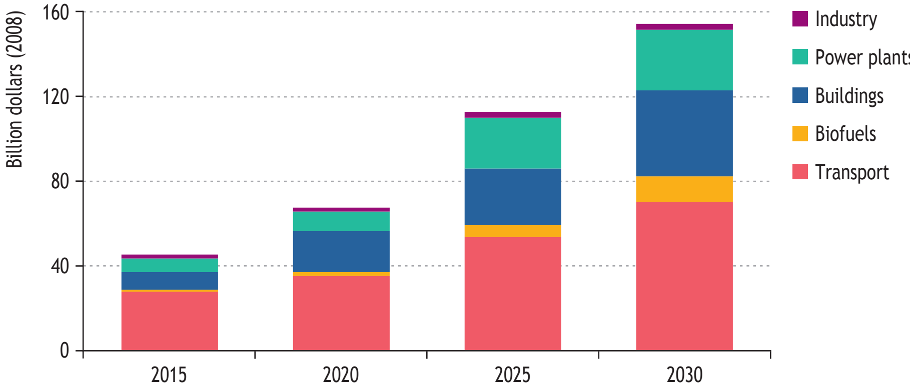


## Table 9.8 • EU energy demand and electricity generation

| | 1990 | 2007 | 2020 Reference Scenario | 2020 450 Scenario | 2030 Reference Scenario | 2030 450 Scenario | Change vs. RS 2020 | Change vs. RS 2030 |
|---|---|---|---|---|---|---|---|---|
| | | | Energy demand (Mtoe) | | | | (%) | |
| **Total primary energy demand** | **1 633** | **1 757** | **1 723** | **1 668** | **1 781** | **1 682** | **-3** | **-6** |
| Coal | 455 | 330 | 260 | 204 | 233 | 103 | -22 | -56 |
| Oil | 603 | 607 | 557 | 512 | 545 | 448 | -8 | -18 |
| Gas | 295 | 432 | 463 | 429 | 508 | 418 | -7 | -18 |
| Nuclear | 207 | 244 | 202 | 257 | 192 | 297 | 27 | 55 |
| Renewables | 74 | 144 | 241 | 267 | 302 | 415 | 11 | 37 |
| **Power generation** | **644** | **740** | **717** | **715** | **760** | **735** | **-0** | **-3** |
| *of which coal* | *286* | *250* | *201* | *153* | *185* | *66* | *-24* | *-64* |
| *of which gas* | *54* | *140* | *161* | *142* | *191* | *133* | *-12* | *-30* |
| **Other energy sector** | **149** | **146** | **136** | **128** | **133** | **113** | **-6** | **-16** |
| **Total final consumption** | **1 126** | **1 224** | **1 251** | **1 201** | **1 307** | **1 231** | **-4** | **-6** |
| Coal | 119 | 43 | 31 | 28 | 25 | 21 | -10 | -18 |
| Oil | 501 | 538 | 501 | 459 | 488 | 406 | -8 | -17 |
| Gas | 228 | 276 | 286 | 273 | 303 | 271 | -5 | -10 |
| Electricity | 185 | 244 | 268 | 267 | 300 | 289 | -1 | -3 |
| Heat | 54 | 58 | 65 | 62 | 71 | 63 | -4 | -12 |
| Renewables | 38 | 64 | 100 | 112 | 121 | 181 | 11 | 50 |
| **Industry** | **341** | **304** | **301** | **295** | **308** | **302** | **-2** | **-2** |
| Coal | 68 | 31 | 22 | 20 | 18 | 15 | -9 | -15 |
| Oil | 57 | 45 | 38 | 36 | 34 | 31 | -4 | -7 |
| Gas | 98 | 93 | 94 | 91 | 96 | 90 | -3 | -6 |
| Electricity | 85 | 99 | 104 | 102 | 110 | 106 | -2 | -3 |
| Heat | 19 | 17 | 17 | 17 | 17 | 17 | -2 | -3 |
| Renewables | 14 | 20 | 26 | 29 | 34 | 42 | 10 | 26 |
| **Transport** | **259** | **335** | **346** | **313** | **350** | **302** | **-10** | **-14** |
| Oil | 253 | 318 | 311 | 273 | 312 | 240 | -12 | -23 |
| Biofuels | 0 | 8 | 25 | 25 | 26 | 42 | 1 | 65 |
| Other fuels | 6 | 8 | 11 | 15 | 12 | 20 | 38 | 59 |
| **Other sectors** | **428** | **470** | **503** | **492** | **553** | **531** | **-2** | **-4** |
| Coal | 50 | 11 | 8 | 7 | 6 | 4 | -10 | -26 |
| Oil | 110 | 76 | 66 | 64 | 62 | 53 | -3 | -14 |
| Gas | 115 | 166 | 175 | 166 | 190 | 166 | -5 | -13 |
| Electricity | 95 | 139 | 157 | 152 | 181 | 166 | -3 | -8 |
| Heat | 35 | 41 | 48 | 45 | 53 | 46 | -4 | -14 |
| Renewables | 25 | 37 | 49 | 57 | 62 | 96 | 17 | 56 |
| **Non-energy use** | **97** | **115** | **101** | **101** | **96** | **96** | **-0** | **0** |
| | | | Electricity generation (TWh) | | | | (%) | |
| **Total generation** | **2 568** | **3 325** | **3 587** | **3 561** | **3 968** | **3 822** | **-1** | **-4** |
| Coal | 1 050 | 1 024 | 870 | 648 | 862 | 297 | -25 | -66 |
| Oil | 221 | 112 | 51 | 38 | 43 | 20 | -24 | -52 |
| Gas | 191 | 725 | 861 | 770 | 995 | 688 | -11 | -31 |
| Nuclear | 795 | 935 | 773 | 984 | 736 | 1 140 | 27 | 55 |
| Hydro | 286 | 309 | 381 | 388 | 408 | 430 | 2 | 5 |
| Wind | 1 | 104 | 412 | 451 | 581 | 770 | 9 | 32 |
| Other renewables | 23 | 115 | 239 | 282 | 341 | 477 | 18 | 40 |

## Costs and benefits

**Figure 9.20 ● *EU additional investment in the 450 Scenario relative to the Reference Scenario***




- Additional cumulative investment cost: nearly \$500 billion over 2010-2020; in excess of \$1 100 billion over 2021-2030.
- Total investment in the 450 Scenario of nearly \$1 300 billion in low-carbon power generation over 2010-2030 (77% renewables, 16% nuclear, 7% CCS).
- Incremental investment cost equal to 0.3% of GDP in 2020, rising to 0.6% of GDP in 2030.
- Oil and gas import bill reduced in excess of \$90 billion in 2020 and nearly \$240 billion in 2030, compared with the Reference Scenario.
- Local air pollution costs reduced by \$9 billion in 2020 and \$15 billion in 2030, relative to the Reference Scenario.

## Policy opportunities

- Continue policy support to increase the use of renewables in electricity, heat and biofuels production to reach the 20% target in 2020; strengthen the framework to support renewables for heat.
- Support the commercialisation of CCS through a carbon price via the emissions trading scheme and through additional funding, such as the revenues from 300 million allowances for early demonstration projects.
- Enhance policies to achieve greater efficiency in buildings; meet the target of 95 g $CO_2$/km for new passenger cars by 2020.

# Japan

## Highlights

- 22% reduction in energy-related $CO_2$ emissions by 2020 (relative to 2007) to meet 450 Scenario.
- Power generation $CO_2$ intensity decreasing by 28% and average car fleet $CO_2$ intensity decreasing by 39% by 2020, compared with 2007.
- 9% reduction in $CO_2$ emissions from buildings and 16% reduction in industry by 2020, relative to 2007.
- Additional investment in low-carbon technologies and energy efficiency of $17 billion in 2020 to meet 450 Scenario.

## Emissions

**Figure 9.21 • Japan energy-related $CO_2$ emissions**

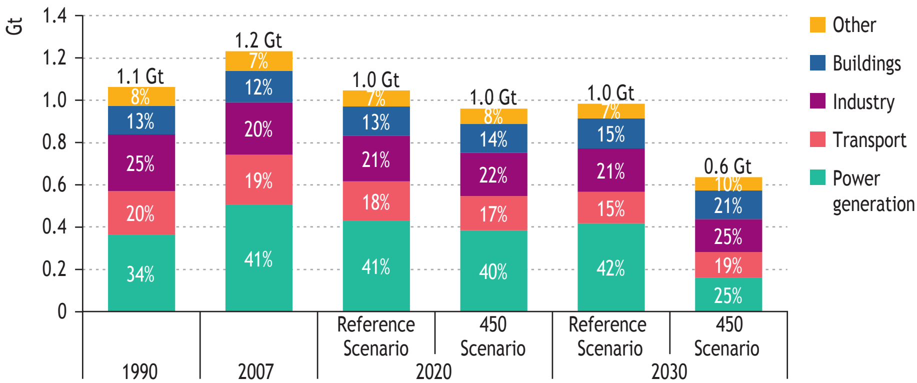
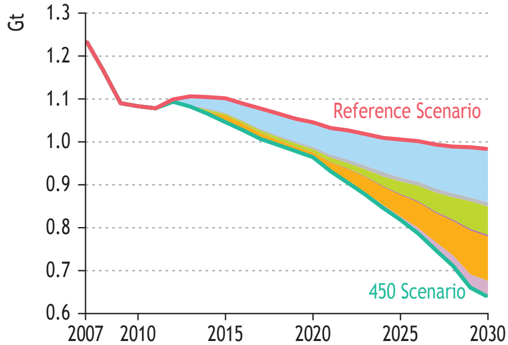



**Table 9.9 • Japan key indicators**

| | | | 2020 | | 2030 | |
|---|---|---|---|---|---|---|
| | 1990 | 2007 | RS | 450 | RS | 450 |
| Population (million) | 123 | 128 | 124 | | 118 | |
| Share of world population | 2% | 2% | 2% | | 1% | |
| GDP ($2008 trillion, PPP) | 3.5 | 4.4 | 4.9 | | 5.5 | |
| Share of world GDP | 9% | 7% | 5% | | 4% | |
| Share of world $CO_2$ emissions | 5% | 4% | 3% | 3% | 2% | 2% |
| $CO_2$ emissions per capita (t) | 8.6 | 9.6 | 8.4 | 7.8 | 8.4 | 5.4 |
| Energy demand per capita (toe) | 3.5 | 4.0 | 3.9 | 3.7 | 4.1 | 3.8 |
| $CO_2$ intensity index (world 2007=100) | 71 | 65 | 50 | 46 | 42 | 27 |
| Cumulative $CO_2$ since 1890 (Gt) | 29 | 48 | 63 | 62 | 73 | 70 |
| Share of cumulative world $CO_2$ | 4% | 4% | 4% | 4% | 4% | 4% |
| Power $CO_2$ intensity (g/kWh) | 435 | 450 | 354 | 326 | 321 | 134 |
| Car fleet $CO_2$ intensity (2007=100) | n.a. | 100 | 79 | 61 | 72 | 48 |

## Technology outlook

**Figure 9.22** • *Japan energy-related $CO_2$ emissions abatement*




| | Abatement ($Mt\ CO_2$) 2020 | Abatement ($Mt\ CO_2$) 2030 | Investment ($2008 billion) 2010-2020 | Investment ($2008 billion) 2021-2030 |
|---|---|---|---|---|
| Efficiency | 65 | 138 | 77 | 164 |
| End-use | 60 | 128 | 74 | 161 |
| Power plants | 5 | 10 | 3 | 3 |
| Renewables | 7 | 66 | 21 | 71 |
| Biofuels | 1 | 4 | 1 | 7 |
| Nuclear | 10 | 103 | 0 | 36 |
| CCS | 1 | 38 | 1 | 21 |

**Figure 9.23** • *Japan power-generation capacity in the 450 Scenario*

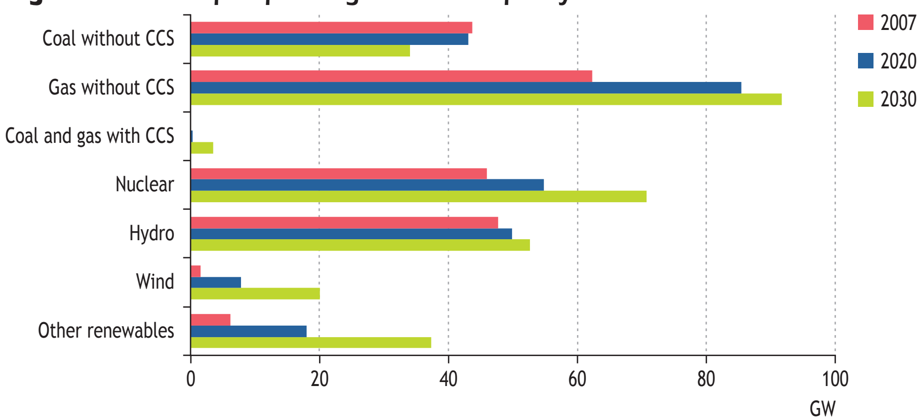
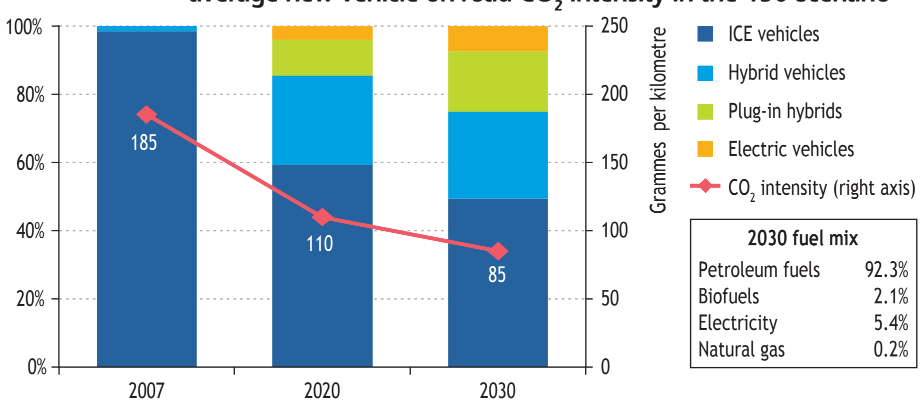



**Figure 9.24** • *Japan share of passenger vehicle sales by technology and average new vehicle on-road $CO_2$ intensity in the 450 Scenario*

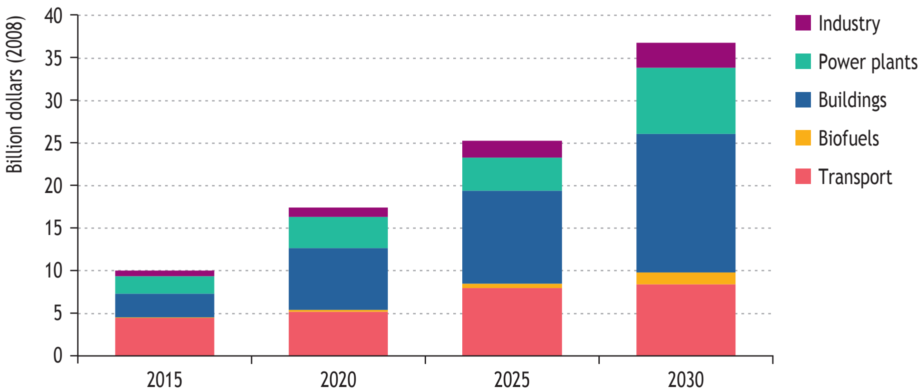


## Table 9.10 • *Japan energy demand and electricity generation*

| | 1990 | 2007 | 2020 Reference Scenario | 2020 450 Scenario | 2030 Reference Scenario | 2030 450 Scenario | Change vs. RS 2020 | Change vs. RS 2030 |
|---|---|---|---|---|---|---|---|---|
| | | | Energy demand (Mtoe) | | | | (%) | |
| **Total primary energy demand** | **438** | **514** | **485** | **465** | **488** | **446** | **-4** | **-9** |
| Coal | 75 | 115 | 105 | 99 | 98 | 44 | -6 | -55 |
| Oil | 250 | 230 | 169 | 154 | 152 | 131 | -9 | -14 |
| Gas | 44 | 83 | 86 | 76 | 92 | 81 | -11 | -12 |
| Nuclear | 53 | 69 | 99 | 105 | 113 | 139 | 6 | 23 |
| Renewables | 15 | 17 | 27 | 30 | 33 | 51 | 14 | 52 |
| **Power generation** | **174** | **232** | **244** | **236** | **262** | **234** | **-3** | **-11** |
| *of which coal* | *25* | *64* | *62* | *60* | *57* | *11* | *-3* | *-80* |
| *of which gas* | *33* | *54* | *54* | *46* | *58* | *49* | *-15* | *-15* |
| **Other energy sector** | **36** | **37** | **33** | **29** | **31** | **24** | **-11** | **-22** |
| **Total final consumption** | **300** | **342** | **314** | **301** | **307** | **290** | **-4** | **-6** |
| Coal | 33 | 31 | 27 | 26 | 26 | 22 | -6 | -17 |
| Oil | 184 | 187 | 150 | 141 | 133 | 122 | -6 | -8 |
| Gas | 15 | 34 | 35 | 34 | 37 | 35 | -2 | -5 |
| Electricity | 64 | 87 | 94 | 91 | 101 | 93 | -3 | -8 |
| Heat | 0 | 1 | 1 | 1 | 1 | 1 | -3 | -6 |
| Renewables | 4 | 4 | 7 | 8 | 9 | 18 | 23 | 91 |
| **Industry** | **103** | **99** | **97** | **94** | **97** | **90** | **-3** | **-8** |
| Coal | 31 | 30 | 26 | 25 | 25 | 21 | -6 | -17 |
| Oil | 37 | 30 | 24 | 23 | 21 | 20 | -2 | -6 |
| Gas | 4 | 8 | 10 | 10 | 11 | 10 | -2 | -6 |
| Electricity | 29 | 29 | 32 | 31 | 32 | 31 | -2 | -5 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | n.a. | n.a. |
| Renewables | 3 | 3 | 5 | 6 | 7 | 8 | 6 | 9 |
| **Transport** | **72** | **82** | **65** | **58** | **53** | **47** | **-10** | **-11** |
| Oil | 70 | 81 | 62 | 55 | 50 | 41 | -12 | -18 |
| Biofuels | 0 | 0 | 0 | 1 | 0 | 2 | 40 | n.a. |
| Other fuels | 1 | 2 | 2 | 3 | 2 | 4 | 55 | 69 |
| **Other sectors** | **91** | **118** | **118** | **114** | **125** | **120** | **-3** | **-4** |
| Coal | 1 | 1 | 1 | 1 | 1 | 1 | -3 | -5 |
| Oil | 43 | 35 | 30 | 29 | 30 | 28 | -3 | -6 |
| Gas | 11 | 25 | 24 | 24 | 25 | 24 | -3 | -5 |
| Electricity | 34 | 56 | 60 | 57 | 66 | 58 | -5 | -13 |
| Heat | 0 | 1 | 1 | 1 | 1 | 1 | -3 | -6 |
| Renewables | 1 | 1 | 1 | 2 | 2 | 8 | 87 | n.a. |
| **Non-energy use** | **35** | **42** | **34** | **35** | **33** | **33** | **1** | **2** |
| | | | Electricity generation (TWh) | | | | (%) | |
| **Total generation** | **836** | **1 123** | **1 215** | **1 178** | **1 302** | **1 189** | **-3** | **-9** |
| Coal | 117 | 311 | 303 | 299 | 283 | 60 | -1 | -79 |
| Oil | 248 | 156 | 47 | 18 | 46 | 9 | -61 | -81 |
| Gas | 167 | 290 | 335 | 290 | 348 | 335 | -13 | -4 |
| Nuclear | 202 | 264 | 380 | 403 | 435 | 535 | 6 | 23 |
| Hydro | 89 | 74 | 90 | 92 | 96 | 103 | 3 | 8 |
| Wind | 0 | 3 | 18 | 21 | 34 | 57 | 17 | 71 |
| Other renewables | 12 | 26 | 43 | 54 | 60 | 90 | 24 | 51 |

## Costs and benefits

**Figure 9.25 ● *Japan additional investment in the 450 Scenario relative to the Reference Scenario***




- Additional cumulative investment cost: close to $90 billion over 2010-2020 and $280 billion over 2021-2030.
- Total investment in the 450 Scenario in excess of $200 billion in low-carbon power generation over 2010-2030 (50% renewables, 46% nuclear, 4% CCS).
- Incremental investment cost equal to 0.3% of GDP in 2020, rising to 0.6% by 2030.
- Oil and gas import bill reduced in excess of $30 billion in 2020 and $60 billion in 2030, compared with the Reference Scenario.
- Local air pollution costs reduced by $2 billion in 2020 and $5 billion in 2030, relative to the Reference Scenario.

## Policy opportunities

- Promote the use of cleaner energy and efficiency in buildings – efficient though they are, there is scope for more – through greater use of photovoltaics, advanced water heaters and more heat insulation.
- Accelerate the construction of nuclear power plants and raise the average load factor to achieve a greater than 40% share of nuclear power in total electricity generation by 2030.
- Substantially increase the share of next-generation vehicles (including electric and hybrid cars).

# Other Major Economies (OME)

## Highlights

- 30% increase in energy-related $CO_2$ emissions by 2020 (relative to 2007) to meet 450 Scenario.
- Power generation $CO_2$ intensity decreasing by 21% and average car fleet $CO_2$ intensity decreasing by 38% by 2020, compared with 2007.
- 22% increase in emissions from buildings and 19% increase in industry by 2020, relative to 2007.
- Additional investment in low-carbon technologies and energy efficiency in excess of $120 billion in 2020 to meet 450 Scenario.

## Emissions

**Figure 9.26 • OME energy-related $CO_2$ emissions**

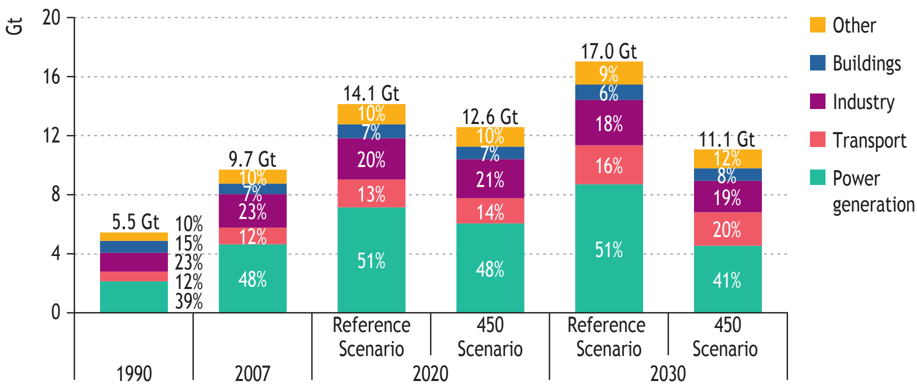
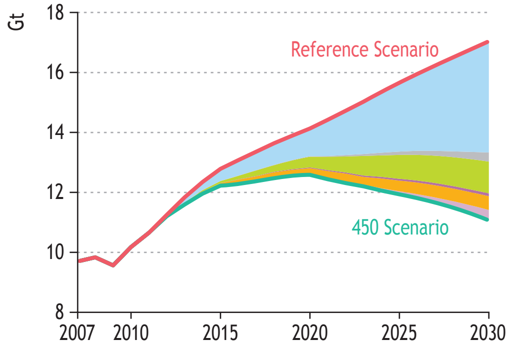



**Table 9.11 • OME key indicators**

| | 1990 | 2007 | 2020 RS | 2020 450 | 2030 RS | 2030 450 |
|---|---|---|---|---|---|---|
| Population (million) | 1 605 | 1 901 | 2 069 | | 2 140 | |
| Share of world population | 31% | 29% | 27% | | 26% | |
| GDP ($2008 trillion, PPP) | 6.2 | 14.4 | 29.8 | | 43.5 | |
| Share of world GDP | 16% | 21% | 29% | | 32% | |
| Share of world $CO_2$ emissions | 26% | 34% | 41% | 41% | 42% | 42% |
| $CO_2$ emissions per capita (t) | 3.4 | 5.1 | 6.8 | 6.1 | 8.0 | 5.2 |
| Energy demand per capita (toe) | 1.4 | 1.9 | 2.5 | 2.3 | 2.9 | 2.3 |
| $CO_2$ intensity index (world 2007=100) | 205 | 157 | 111 | 99 | 91 | 59 |
| Cumulative $CO_2$ since 1890 (Gt) | 187 | 319 | 476 | 468 | 633 | 586 |
| Share of cumulative world $CO_2$ | 24% | 27% | 30% | 29% | 32% | 31% |
| Power $CO_2$ intensity (g/kWh) | 906 | 814 | 715 | 641 | 664 | 421 |
| Car fleet $CO_2$ intensity (2007=100) | n.a. | 100 | 80 | 62 | 74 | 44 |

## Technology outlook

**Figure 9.27 • OME energy-related $CO_2$ emissions abatement**




| | Abatement (Mt $CO_2$) | | Investment ($2008 billion) | |
|---|---|---|---|---|
| | 2020 | 2030 | 2010-2020 | 2021-2030 |
| Efficiency | 944 | 4 018 | 491 | 1 889 |
| End-use | 927 | 3 713 | 477 | 1 883 |
| Power plants | 17 | 305 | 14 | 6 |
| Renewables | 357 | 1 059 | 231 | 685 |
| Biofuels | 23 | 94 | 11 | 56 |
| Nuclear | 209 | 459 | 57 | 134 |
| CCS | 12 | 345 | 5 | 109 |

**Figure 9.28 • OME power-generation capacity in the 450 Scenario**

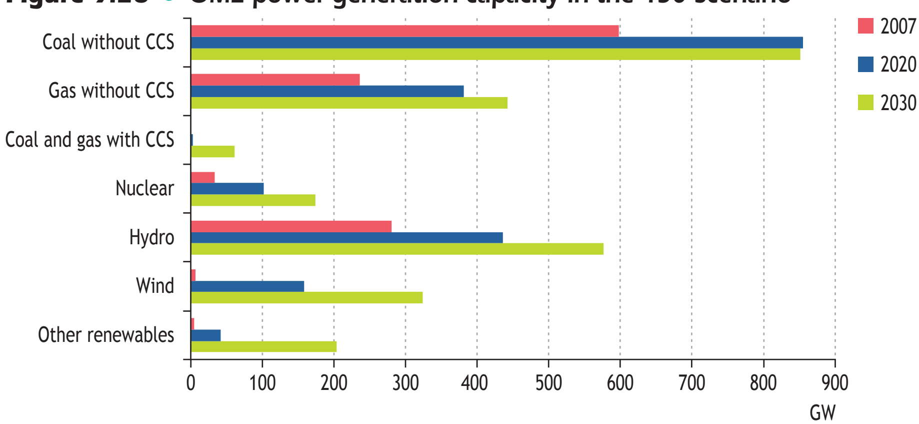
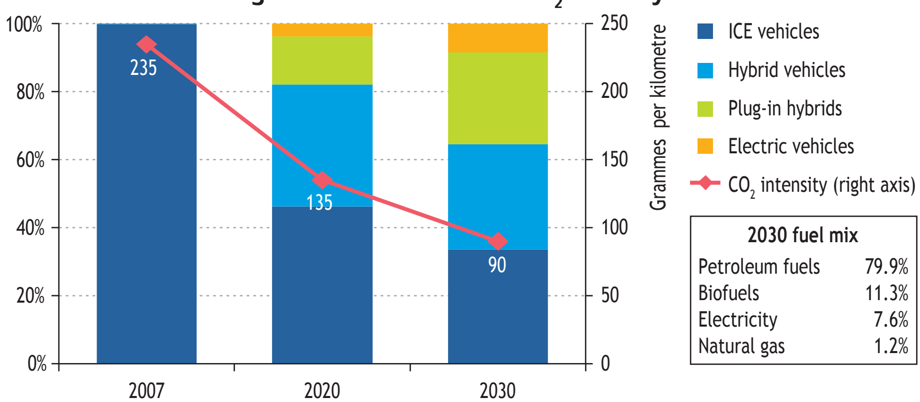



**Figure 9.29 • OME share of passenger vehicle sales by technology and average new vehicle on-road $CO_2$ intensity in the 450 Scenario**

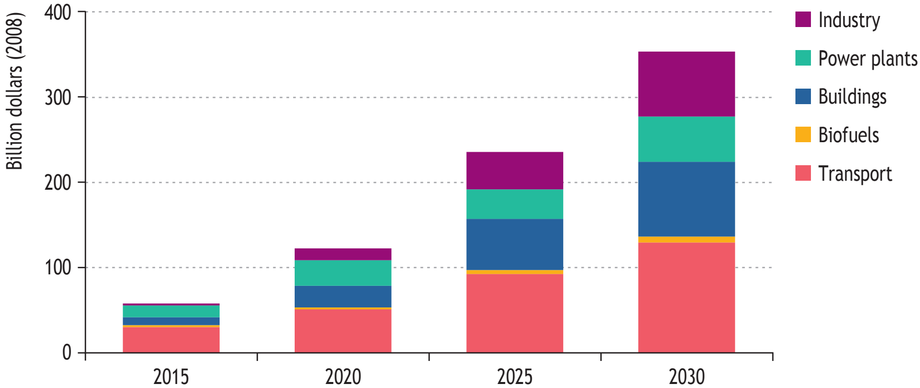


## Table 9.12 • OME energy demand and electricity generation

| | 1990 | 2007 | 2020 Reference Scenario | 2020 450 Scenario | 2030 Reference Scenario | 2030 450 Scenario | Change vs. RS 2020 | Change vs. RS 2030 |
|---|---|---|---|---|---|---|---|---|
| | | | Energy demand (Mtoe) | | | | (%) | |
| **Total primary energy demand** | **2 191** | **3 547** | **5 103** | **4 771** | **6 195** | **4 974** | **-7** | **-20** |
| Coal | 795 | 1 515 | 2 305 | 2 007 | 2 711 | 1 541 | -13 | -43 |
| Oil | 587 | 888 | 1 238 | 1 156 | 1 544 | 1 336 | -7 | -13 |
| Gas | 458 | 693 | 929 | 888 | 1 158 | 941 | -4 | -19 |
| Nuclear | 34 | 64 | 156 | 208 | 210 | 361 | 34 | 72 |
| Renewables | 316 | 386 | 476 | 512 | 572 | 795 | 8 | 39 |
| **Power generation** | **749** | **1 487** | **2 304** | **2 109** | **2 873** | **2 182** | **-8** | **-24** |
| *of which coal* | *298* | *899* | *1 472* | *1 218* | *1 808* | *925* | *-17* | *-49* |
| *of which gas* | *260* | *330* | *403* | *383* | *503* | *394* | *-5* | *-22* |
| **Other energy sector** | **273** | **461** | **651** | **618** | **743** | **575** | **-5** | **-23** |
| **Total final consumption** | **1 613** | **2 304** | **3 248** | **3 087** | **3 957** | **3 356** | **-5** | **-15** |
| Coal | 390 | 452 | 572 | 536 | 597 | 402 | -6 | -33 |
| Oil | 406 | 721 | 1 075 | 1 011 | 1 393 | 1 206 | -6 | -13 |
| Gas | 188 | 299 | 424 | 409 | 538 | 459 | -4 | -15 |
| Electricity | 161 | 395 | 712 | 671 | 943 | 783 | -6 | -17 |
| Heat | 216 | 170 | 190 | 186 | 201 | 168 | -2 | -16 |
| Renewables | 252 | 266 | 275 | 274 | 285 | 338 | -0 | 19 |
| **Industry** | **560** | **892** | **1 272** | **1 209** | **1 511** | **1 184** | **-5** | **-22** |
| Coal | 208 | 347 | 440 | 412 | 465 | 310 | -6 | -33 |
| Oil | 78 | 104 | 125 | 123 | 140 | 120 | -2 | -14 |
| Gas | 56 | 98 | 146 | 143 | 193 | 159 | -3 | -18 |
| Electricity | 91 | 227 | 424 | 395 | 549 | 426 | -7 | -22 |
| Heat | 108 | 80 | 89 | 87 | 96 | 81 | -2 | -15 |
| Renewables | 19 | 36 | 47 | 49 | 67 | 87 | 6 | 29 |
| **Transport** | **248** | **411** | **681** | **639** | **965** | **886** | **-6** | **-8** |
| Oil | 188 | 350 | 593 | 540 | 852 | 724 | -9 | -15 |
| Biofuels | 6 | 10 | 24 | 32 | 38 | 69 | 33 | 84 |
| Other fuels | 54 | 52 | 64 | 67 | 76 | 93 | 5 | 24 |
| **Other sectors** | **688** | **772** | **964** | **910** | **1 103** | **947** | **-6** | **-14** |
| Coal | 150 | 74 | 81 | 75 | 73 | 50 | -7 | -31 |
| Oil | 80 | 126 | 163 | 156 | 186 | 158 | -5 | -15 |
| Gas | 63 | 103 | 144 | 138 | 191 | 165 | -5 | -13 |
| Electricity | 59 | 158 | 270 | 250 | 369 | 305 | -7 | -17 |
| Heat | 108 | 90 | 101 | 99 | 105 | 87 | -2 | -18 |
| Renewables | 227 | 220 | 205 | 193 | 180 | 182 | -6 | 1 |
| **Non-energy use** | **117** | **228** | **332** | **329** | **378** | **340** | **-1** | **-10** |
| | | | Electricity generation (TWh) | | | | (%) | |
| **Total generation** | **2 360** | **5 750** | **10 004** | **9 418** | **13 099** | **10 817** | **-6** | **-17** |
| Coal | 799 | 3 149 | 5 757 | 4 753 | 7 500 | 3 924 | -17 | -48 |
| Oil | 297 | 316 | 335 | 297 | 325 | 244 | -11 | -25 |
| Gas | 619 | 947 | 1 507 | 1 427 | 2 101 | 1 640 | -5 | -22 |
| Nuclear | 129 | 246 | 596 | 797 | 804 | 1 383 | 34 | 72 |
| Hydro | 512 | 1 060 | 1 514 | 1 586 | 1 773 | 2 076 | 5 | 17 |
| Wind | 0 | 10 | 190 | 390 | 284 | 812 | 105 | 186 |
| Other renewables | 4 | 23 | 104 | 167 | 312 | 738 | 60 | 136 |

## Costs and benefits

**Figure 9.30 • *OME additional investment in the 450 Scenario relative to the Reference Scenario***




- Additional cumulative investment cost: in excess of $620 billion over 2010-2020; nearly $2 500 billion over 2021-2030.
- Total investment in the 450 Scenario of close to $2 000 billion in low-carbon power generation over 2010-2030 (72% renewables, 22% nuclear, 6% CCS).
- Incremental investment cost equal to 0.7% of GDP in 2020, rising to 1.3% by 2030.
- Oil savings of 4.7 mb/d in 2030 in the 450 Scenario, compared with the Reference Scenario, an amount close to Japan's 2008 oil demand.
- Local air pollution costs reduced in excess of $10 billion in 2020 and $40 billion in 2030, relative to the Reference Scenario.

## Policy opportunities

- Reduce the environmental footprint of fossil fuels, especially through price subsidy reform, and diversify energy supply to obtain greater reliance on renewables and nuclear power.
- Promote energy efficiency measures, such as setting building codes, and participate in international sectoral agreements in order to ensure adoption of less polluting technologies in industry and passenger cars.
- Further develop carbon credit markets through the implementation of CDM projects and capitalise on this experience to participate in an emissions trading scheme soon after 2020.

9

# Russia

## Highlights

- 1% increase in energy-related $CO_2$ emissions by 2020 (relative to 2007) to meet 450 Scenario.
- Power generation $CO_2$ intensity decreasing by 17% and average car fleet $CO_2$ intensity decreasing by 36% by 2020, compared with 2007.
- 2% increase in emissions from buildings and 3% decrease in industry by 2020, relative to 2007.
- Additional investment in low-carbon technologies and energy efficiency of close to \$8 billion in 2020 to meet 450 Scenario.

## Emissions

**Figure 9.31 • Russia energy-related $CO_2$ emissions**

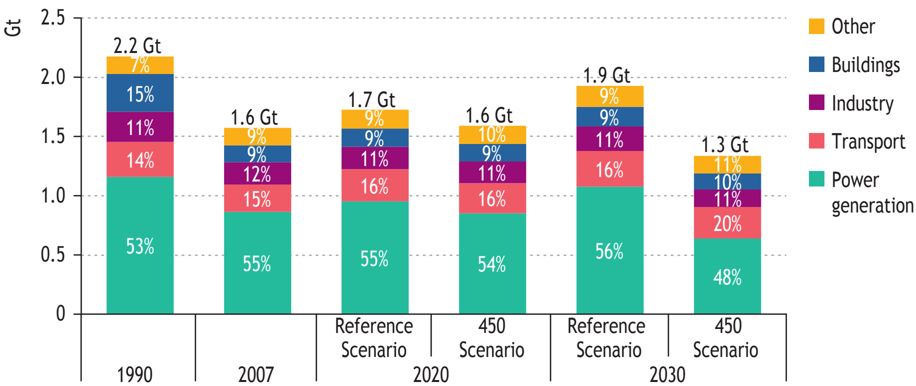
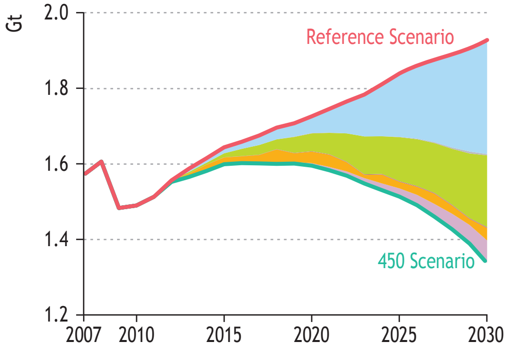



**Table 9.13 • Russia key indicators**

| | 1990 | 2007 | 2020 RS | 2020 450 | 2030 RS | 2030 450 |
|---|---|---|---|---|---|---|
| Population (million) | 148 | 142 | 135 | | 129 | |
| Share of world population | 3% | 2% | 2% | | 2% | |
| GDP (\$2008 trillion, PPP) | 2.0 | 2.1 | 3.4 | | 4.6 | |
| Share of world GDP | 5% | 3% | 3% | | 3% | |
| Share of world $CO_2$ emissions | 10% | 5% | 5% | 5% | 5% | 5% |
| $CO_2$ emissions per capita (t) | 14.7 | 11.1 | 12.8 | 11.8 | 15.0 | 10.4 |
| Energy demand per capita (toe) | 5.9 | 4.7 | 5.4 | 5.2 | 6.3 | 5.3 |
| $CO_2$ intensity index (world 2007=100) | 250 | 171 | 120 | 111 | 98 | 68 |
| Cumulative $CO_2$ since 1890 (Gt) | 107 | 135 | 156 | 156 | 175 | 170 |
| Share of cumulative world $CO_2$ | 14% | 11% | 10% | 10% | 9% | 9% |
| Power $CO_2$ intensity (g/kWh) | 1 074 | 854 | 781 | 711 | 756 | 501 |
| Car fleet $CO_2$ intensity (2007=100) | n.a. | 100 | 91 | 64 | 86 | 51 |

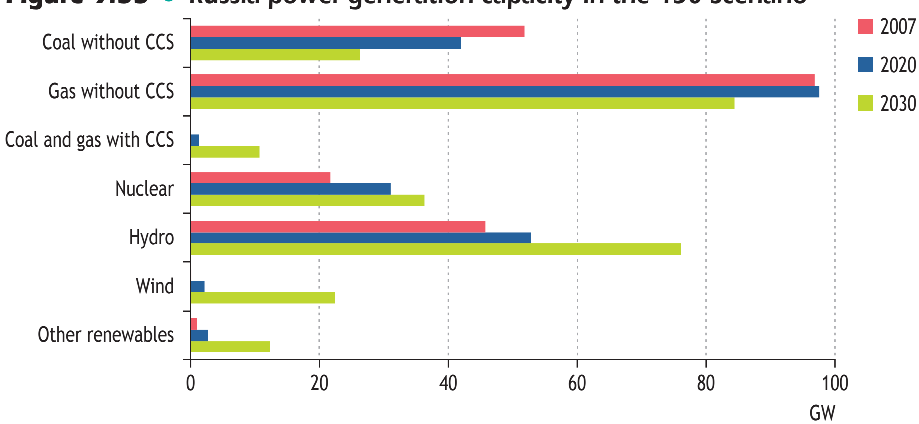
## Technology outlook

### Figure 9.32 • Russia energy-related $CO_2$ emissions abatement

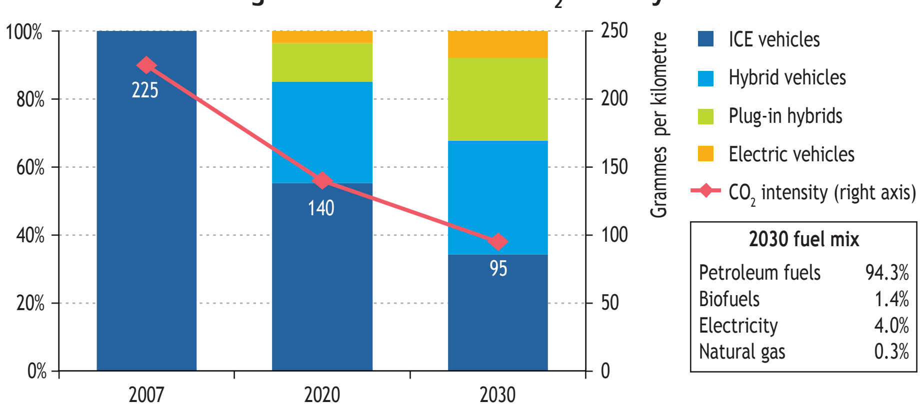



| | Abatement ($Mt CO_2$) | | Investment ($2008 billion) | |
|---|---|---|---|---|
| | 2020 | 2030 | 2010-2020 | 2021-2030 |
| Efficiency | 48 | 308 | 51 | 153 |
| End-use | 47 | 305 | 48 | 153 |
| Power plants | 1 | 3 | 3 | 0 |
| Renewables | 47 | 190 | 7 | 89 |
| Biofuels | 1 | 2 | 0 | 1 |
| Nuclear | 31 | 33 | 0 | 0 |
| CCS | 7 | 59 | 3 | 25 |

### Figure 9.33 • Russia power-generation capacity in the 450 Scenario




### Figure 9.34 • Russia share of passenger vehicle sales by technology and average new vehicle on-road $CO_2$ intensity in the 450 Scenario

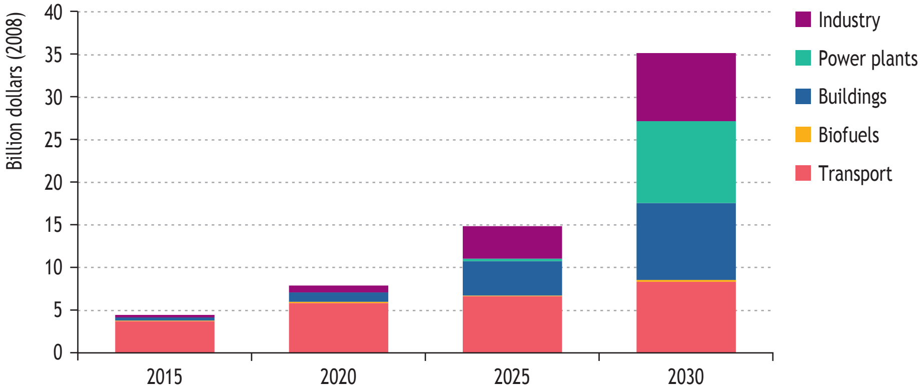


## Table 9.14 • Russia energy demand and electricity generation

| | 1990 | 2007 | 2020 Reference Scenario | 2020 450 Scenario | 2030 Reference Scenario | 2030 450 Scenario | Change vs. RS 2020 | Change vs. RS 2030 |
|---|---|---|---|---|---|---|---|---|
| | | | Energy demand (Mtoe) | | | | (%) | |
| **Total primary energy demand** | **871** | **665** | **735** | **703** | **812** | **679** | **-4** | **-16** |
| Coal | 182 | 102 | 128 | 108 | 159 | 80 | -16 | -50 |
| Oil | 264 | 132 | 146 | 139 | 146 | 135 | -5 | -8 |
| Gas | 367 | 366 | 371 | 364 | 403 | 327 | -2 | -19 |
| Nuclear | 31 | 42 | 59 | 61 | 65 | 73 | 4 | 12 |
| Renewables | 26 | 22 | 30 | 31 | 38 | 65 | 5 | 69 |
| **Power generation** | **444** | **365** | **403** | **383** | **446** | **367** | **-5** | **-18** |
| *of which coal* | *105* | *76* | *102* | *82* | *132* | *62* | *-19* | *-53* |
| *of which gas* | *228* | *214* | *202* | *201* | *204* | *165* | *-1* | *-19* |
| **Other energy sector** | **118** | **103** | **110** | **106** | **118** | **94** | **-3** | **-20** |
| **Total final consumption** | **625** | **430** | **472** | **461** | **519** | **456** | **-2** | **-12** |
| Coal | 55 | 18 | 17 | 16 | 17 | 10 | -5 | -38 |
| Oil | 145 | 100 | 111 | 106 | 118 | 108 | -4 | -9 |
| Gas | 143 | 131 | 146 | 142 | 166 | 142 | -3 | -14 |
| Electricity | 71 | 60 | 76 | 75 | 92 | 83 | -1 | -9 |
| Heat | 203 | 119 | 118 | 117 | 122 | 106 | -1 | -13 |
| Renewables | 8 | 3 | 3 | 4 | 5 | 7 | 28 | 65 |
| **Industry** | **210** | **128** | **137** | **134** | **151** | **126** | **-2** | **-16** |
| Coal | 16 | 13 | 12 | 12 | 12 | 8 | -4 | -32 |
| Oil | 25 | 13 | 13 | 13 | 13 | 12 | 1 | -9 |
| Gas | 30 | 27 | 31 | 30 | 37 | 29 | -5 | -21 |
| Electricity | 41 | 30 | 39 | 37 | 45 | 39 | -3 | -15 |
| Heat | 98 | 45 | 42 | 42 | 42 | 37 | 1 | -12 |
| Renewables | 0 | 0 | 0 | 1 | 1 | 1 | 33 | 62 |
| **Transport** | **116** | **93** | **111** | **105** | **124** | **115** | **-6** | **-7** |
| Oil | 73 | 50 | 63 | 58 | 72 | 64 | -8 | -11 |
| Biofuels | 0 | 0 | 0 | 1 | 1 | 1 | 124 | 105 |
| Other fuels | 43 | 42 | 48 | 46 | 52 | 50 | -3 | -4 |
| **Other sectors** | **259** | **162** | **172** | **170** | **188** | **162** | **-1** | **-14** |
| Coal | 39 | 4 | 4 | 4 | 4 | 2 | -7 | -56 |
| Oil | 28 | 14 | 11 | 10 | 8 | 7 | -2 | -14 |
| Gas | 57 | 45 | 50 | 50 | 59 | 50 | -2 | -14 |
| Electricity | 21 | 22 | 28 | 27 | 34 | 29 | -1 | -16 |
| Heat | 105 | 74 | 76 | 75 | 80 | 69 | -2 | -14 |
| Renewables | 8 | 2 | 3 | 3 | 3 | 5 | 17 | 57 |
| **Non-energy use** | **40** | **47** | **52** | **52** | **55** | **53** | **0** | **-5** |
| | | | Electricity generation (TWh) | | | | (%) | |
| **Total generation** | **1 082** | **1 013** | **1 220** | **1 201** | **1 424** | **1 272** | **-2** | **-11** |
| Coal | 157 | 170 | 258 | 217 | 372 | 170 | -16 | -54 |
| Oil | 129 | 17 | 22 | 17 | 18 | 12 | -21 | -32 |
| Gas | 512 | 487 | 504 | 510 | 541 | 389 | 1 | -28 |
| Nuclear | 118 | 160 | 226 | 234 | 248 | 279 | 4 | 12 |
| Hydro | 166 | 177 | 194 | 203 | 203 | 292 | 5 | 44 |
| Wind | 0 | 0 | 7 | 7 | 21 | 62 | 5 | 189 |
| Other renewables | 0 | 2 | 10 | 12 | 20 | 67 | 27 | n.a. |

## Costs and benefits

**Figure 9.35 • *Russia additional investment in the 450 Scenario relative to the Reference Scenario***




- Additional cumulative investment cost: $18 billion over 2010-2020 and $180 billion over 2021-2030.
- Total investment in the 450 Scenario of in excess of $220 billion in low-carbon power generation over 2010-2030 (58% renewables, 30% nuclear, 12% CCS).
- Incremental investment cost equal to 0.3% of GDP in 2020, rising to 1.0% by 2030.
- Oil savings of 0.3 mb/d in 2030 in the 450 Scenario compared with the Reference Scenario.
- Local air pollution costs reduced by $1 billion in 2020 and $3 billion in 2030, relative to the Reference Scenario.

## Policy opportunities

- Adopt the *Law on Energy Efficiency* and ensure its effective implementation to reduce energy losses in industry, the residential sector and transport.
- Create the conditions for greater use of renewable energy in electricity generation by deciding on support measures and engaging the private sector.
- Continue to implement price subsidy reform by following through on the government plans to raise domestic energy prices.

# China

## Highlights

- 38% increase in energy-related $CO_2$ emissions by 2020 (relative to 2007) to meet 450 Scenario.
- Power generation $CO_2$ intensity decreasing by 24% and average car fleet $CO_2$ intensity decreasing by 42% by 2020, compared with 2007.
- 37% increase in $CO_2$ emissions from buildings and 19% increase in industry by 2020, relative to 2007.
- Additional investment in low-carbon technologies and energy efficiency of \$80 billion in 2020 to meet 450 Scenario.

## Emissions

**Figure 9.36 • China energy-related $CO_2$ emissions**

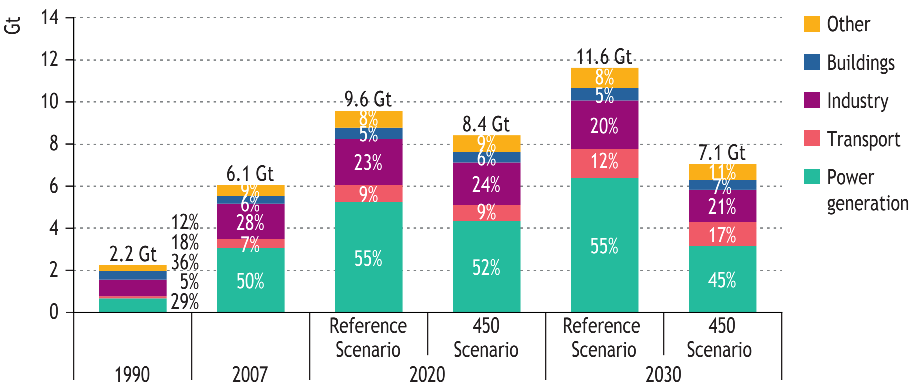
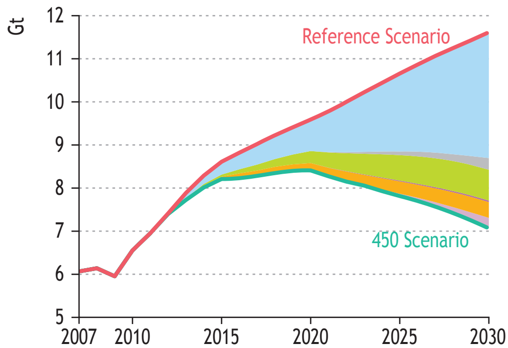



**Table 9.15 • China key indicators**

| | 1990 | 2007 | 2020 RS | 2020 450 | 2030 RS | 2030 450 |
|---|---|---|---|---|---|---|
| Population (million) | 1 141 | 1 327 | 1 429 | | 1 461 | |
| Share of world population | 22% | 20% | 19% | | 18% | |
| GDP (\$2008 trillion, PPP) | 1.5 | 7.6 | 18.8 | | 28.5 | |
| Share of world GDP | 4% | 11% | 18% | | 21% | |
| Share of world $CO_2$ emissions | 11% | 21% | 28% | 27% | 29% | 27% |
| $CO_2$ emissions per capita (t) | 2.0 | 4.6 | 6.7 | 5.9 | 8.0 | 4.8 |
| Energy demand per capita (toe) | 0.8 | 1.5 | 2.2 | 2.0 | 2.6 | 2.0 |
| $CO_2$ intensity index (world 2007=100) | 349 | 187 | 119 | 104 | 95 | 58 |
| Cumulative $CO_2$ since 1890 (Gt) | 42 | 104 | 208 | 202 | 315 | 280 |
| Share of cumulative world $CO_2$ | 5% | 9% | 13% | 13% | 16% | 15% |
| Power $CO_2$ intensity (g/kWh) | 1 003 | 922 | 782 | 698 | 722 | 448 |
| Car fleet $CO_2$ intensity (2007=100) | n.a. | 100 | 76 | 58 | 72 | 43 |

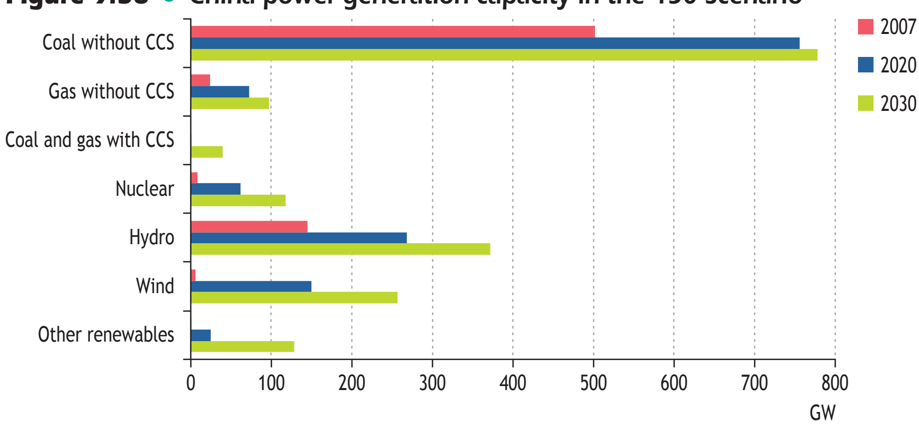
## Technology outlook

### Figure 9.37 • China energy-related $CO_2$ emissions abatement

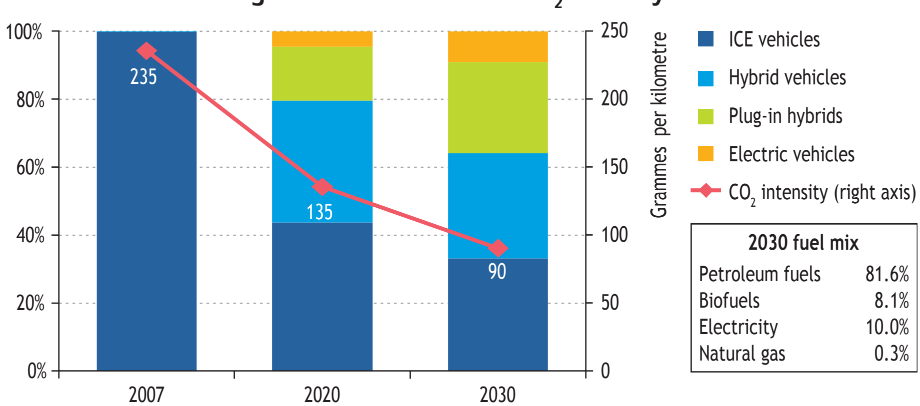



| | Abatement (Mt $CO_2$) 2020 | Abatement (Mt $CO_2$) 2030 | Investment ($2008 billion) 2010-2020 | Investment ($2008 billion) 2021-2030 |
|---|---|---|---|---|
| Efficiency | 728 | 3 195 | 266 | 1 210 |
| End-use | 728 | 2 923 | 257 | 1 205 |
| Power plants | 0 | 272 | 8 | 5 |
| Renewables | 279 | 715 | 208 | 485 |
| Biofuels | 0 | 35 | 1 | 28 |
| Nuclear | 168 | 366 | 63 | 107 |
| CCS | 3 | 243 | 1 | 68 |

### Figure 9.38 • China power-generation capacity in the 450 Scenario




### Figure 9.39 • China share of passenger vehicle sales by technology and average new vehicle on-road $CO_2$ intensity in the 450 Scenario

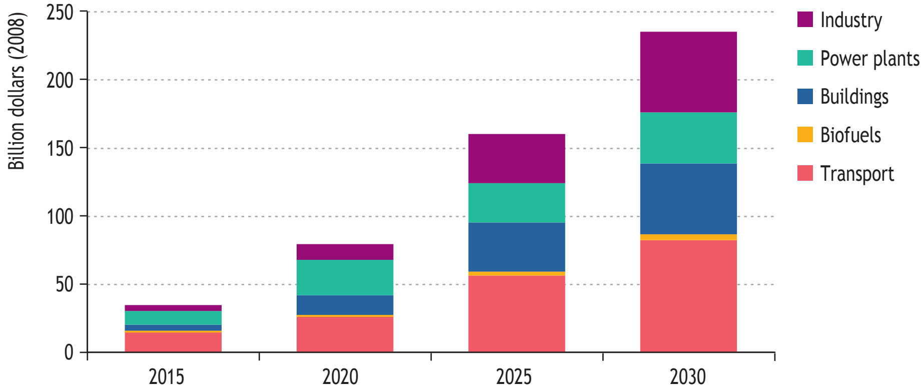


## Table 9.16 • China energy demand and electricity generation

| | 1990 | 2007 | 2020 Reference Scenario | 2020 450 Scenario | 2030 Reference Scenario | 2030 450 Scenario | Change vs. RS 2020 | Change vs. RS 2030 |
|---|---|---|---|---|---|---|---|---|
| | | | Energy demand (Mtoe) | | | | (%) | |
| **Total primary energy demand** | **872** | **1 970** | **3 116** | **2 876** | **3 827** | **2 934** | **-8** | **-23** |
| Coal | 534 | 1 293 | 2 040 | 1 777 | 2 397 | 1 370 | -13 | -43 |
| Oil | 114 | 358 | 557 | 522 | 758 | 664 | -6 | -12 |
| Gas | 13 | 61 | 147 | 136 | 202 | 166 | -7 | -18 |
| Nuclear | 0 | 16 | 84 | 131 | 127 | 249 | 56 | 96 |
| Renewables | 211 | 241 | 288 | 310 | 342 | 485 | 8 | 42 |
| **Power generation** | **181** | **836** | **1 509** | **1 364** | **1 908** | **1 378** | **-10** | **-28** |
| *of which coal* | *153* | *755* | *1 283* | *1 065* | *1 571* | *815* | *-17* | *-48* |
| *of which gas* | *1* | *10* | *32* | *28* | *46* | *35* | *-13* | *-25* |
| **Other energy sector** | **94** | **224** | **364** | **338** | **428** | **315** | **-7** | **-27** |
| **Total final consumption** | **668** | **1 256** | **1 910** | **1 795** | **2 353** | **1 924** | **-6** | **-18** |
| Coal | 315 | 412 | 533 | 499 | 557 | 373 | -6 | -33 |
| Oil | 86 | 315 | 524 | 494 | 736 | 636 | -6 | -14 |
| Gas | 10 | 46 | 106 | 101 | 147 | 124 | -5 | -16 |
| Electricity | 43 | 234 | 485 | 452 | 646 | 515 | -7 | -20 |
| Heat | 13 | 52 | 72 | 69 | 79 | 62 | -4 | -22 |
| Renewables | 200 | 198 | 191 | 180 | 188 | 214 | -6 | 14 |
| **Industry** | **242** | **575** | **885** | **826** | **1 053** | **781** | **-7** | **-26** |
| Coal | 177 | 319 | 412 | 385 | 436 | 288 | -7 | -34 |
| Oil | 21 | 41 | 48 | 45 | 51 | 41 | -6 | -20 |
| Gas | 3 | 19 | 37 | 34 | 50 | 38 | -7 | -24 |
| Electricity | 30 | 161 | 336 | 310 | 440 | 330 | -8 | -25 |
| Heat | 11 | 35 | 48 | 46 | 54 | 44 | -5 | -18 |
| Renewables | 0 | 0 | 5 | 6 | 22 | 40 | 36 | 80 |
| **Transport** | **38** | **140** | **295** | **277** | **487** | **443** | **-6** | **-9** |
| Oil | 28 | 134 | 277 | 255 | 458 | 391 | -8 | -15 |
| Biofuels | 0 | 1 | 7 | 7 | 13 | 25 | 0 | 90 |
| Other fuels | 10 | 6 | 11 | 15 | 16 | 27 | 31 | 68 |
| **Other sectors** | **345** | **433** | **560** | **525** | **622** | **533** | **-6** | **-14** |
| Coal | 109 | 64 | 71 | 66 | 64 | 44 | -8 | -31 |
| Oil | 18 | 67 | 102 | 98 | 121 | 103 | -4 | -15 |
| Gas | 2 | 18 | 42 | 41 | 65 | 57 | -4 | -12 |
| Electricity | 13 | 70 | 141 | 130 | 194 | 161 | -8 | -17 |
| Heat | 2 | 16 | 24 | 23 | 25 | 18 | -3 | -29 |
| Renewables | 200 | 196 | 179 | 167 | 152 | 149 | -7 | -2 |
| **Non-energy use** | **43** | **108** | **170** | **167** | **192** | **168** | **-2** | **-13** |
| | | | Electricity generation (TWh) | | | | (%) | |
| **Total generation** | **650** | **3 318** | **6 692** | **6 221** | **8 847** | **7 022** | **-7** | **-21** |
| Coal | 471 | 2 685 | 5 119 | 4 208 | 6 639 | 3 521 | -18 | -47 |
| Oil | 49 | 34 | 41 | 35 | 32 | 28 | -14 | -13 |
| Gas | 3 | 41 | 156 | 130 | 253 | 195 | -17 | -23 |
| Nuclear | 0 | 62 | 322 | 501 | 487 | 956 | 56 | 96 |
| Hydro | 127 | 485 | 848 | 889 | 1 046 | 1 232 | 5 | 18 |
| Wind | 0 | 9 | 168 | 365 | 225 | 629 | 116 | 180 |
| Other renewables | 0 | 2 | 38 | 93 | 165 | 461 | 142 | 179 |

## Costs and benefits

**Figure 9.40 • China additional investment in the 450 Scenario relative to the Reference Scenario**




- Additional cumulative investment cost: nearly \$400 billion over 2010-2020 and \$1 700 billion over 2021-2030.
- Total investment in the 450 Scenario of nearly \$1 500 billion in low-carbon power generation over 2010-2030 (73% renewables, 22% nuclear, 5% CCS).
- Incremental investment cost equal to 0.8% of GDP in 2020, rising to 1.5% by 2030.
- Oil and gas import bill reduced by nearly \$40 billion in 2020 and \$170 billion in 2030, compared with the Reference Scenario.
- Local air pollution costs reduced by around \$10 billion in 2020 and in excess of \$30 billion in 2030, relative to the Reference Scenario.

## Policy opportunities

- Continue recent ambitious policies to raise the share of nuclear, wind and solar power (16% of installed capacity by 2020) in power generation and raise hydropower capacity to 300 GW by 2020.
- Intensify efforts to rebalance the economy towards services, which would moderate growth in industrial emissions.
- Establish standards for the efficiency of new buildings, appliances and lighting and promote efforts to save energy in buildings, as prescribed in China's Medium and Long Term Energy Conservation Plan.

9

# Other Countries (OC)

## Highlights

- 22% increase in energy-related $CO_2$ emissions by 2020 (relative to 2007) to meet 450 Scenario.
- Power generation $CO_2$ intensity decreasing by 22% and average car fleet $CO_2$ intensity decreasing by 26% by 2020, compared with 2007.
- 14% increase in emissions from buildings and 28% increase in industry by 2020, relative to 2007.
- Additional investment in low-carbon technologies and energy efficiency in excess of $70 billion in 2020 to meet 450 Scenario.

## Emissions

**Figure 9.41 • OC energy-related $CO_2$ emissions**

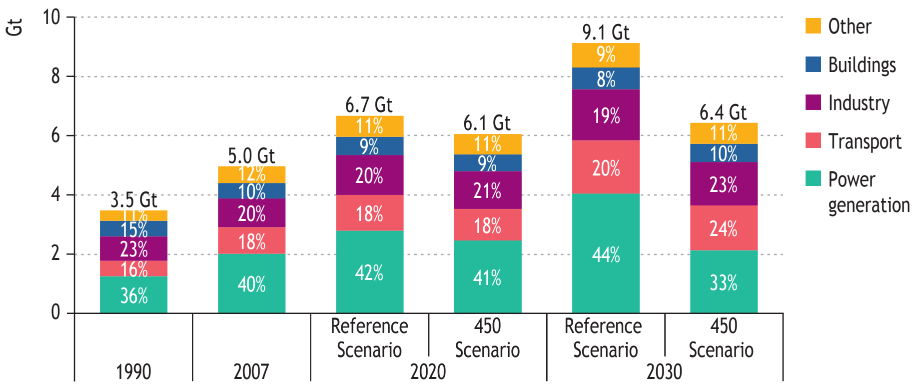
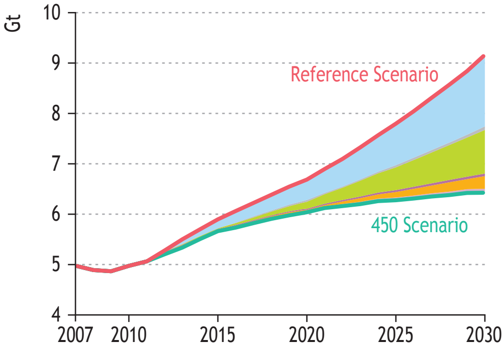



**Table 9.17 • OC key indicators**

| | 1990 | 2007 | 2020 RS | 2020 450 | 2030 RS | 2030 450 |
|---|---|---|---|---|---|---|
| Population (million) | 2 568 | 3 484 | 4 232 | | 4 753 | |
| Share of world population | 49% | 53% | 56% | | 58% | |
| GDP ($2008 trillion, PPP) | 6.2 | 12.7 | 22.6 | | 33.5 | |
| Share of world GDP | 16% | 19% | 22% | | 24% | |
| Share of world $CO_2$ emissions | 17% | 17% | 19% | 20% | 23% | 24% |
| $CO_2$ emissions per capita (t) | 1.4 | 1.4 | 1.6 | 1.4 | 1.9 | 1.4 |
| Energy demand per capita (toe) | 0.7 | 0.7 | 0.8 | 0.7 | 0.9 | 0.8 |
| $CO_2$ intensity index (world 2007=100) | 132 | 91 | 69 | 62 | 64 | 45 |
| Cumulative $CO_2$ since 1890 (Gt) | 92 | 178 | 252 | 249 | 331 | 312 |
| Share of cumulative world $CO_2$ | 12% | 15% | 16% | 16% | 17% | 17% |
| Power $CO_2$ intensity (g/kWh) | 727 | 627 | 535 | 489 | 518 | 314 |
| Car fleet $CO_2$ intensity (2007=100) | n.a. | 100 | 95 | 74 | 88 | 59 |

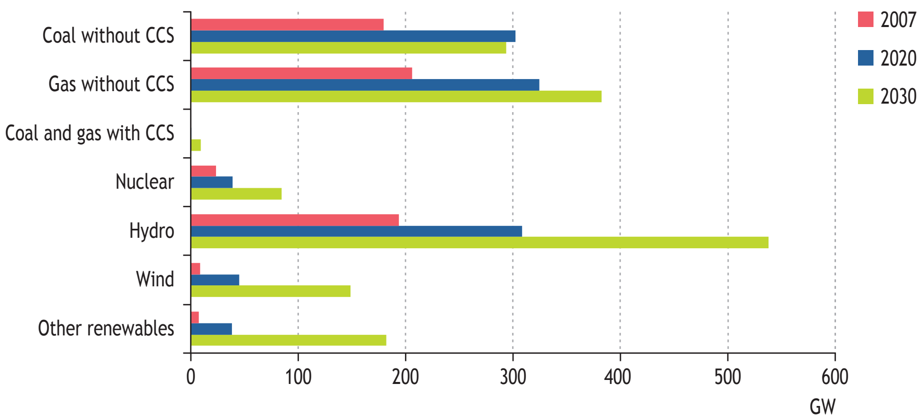
## Technology outlook

### Figure 9.42 • OC energy-related $CO_2$ emissions abatement

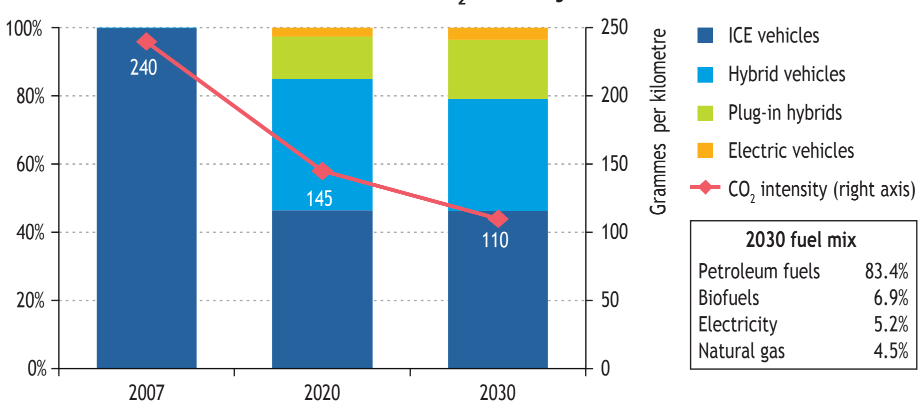



| | Abatement ($Mt\ CO_2$) | | Investment ($2008 billion) | |
|---|---|---|---|---|
| | 2020 | 2030 | 2010-2020 | 2021-2030 |
| Efficiency | 443 | 1 469 | 308 | 982 |
| End-use | 408 | 1 398 | 297 | 965 |
| Power plants | 35 | 71 | 11 | 16 |
| Renewables | 139 | 865 | 92 | 745 |
| Biofuels | 22 | 50 | 9 | 32 |
| Nuclear | 12 | 250 | 4 | 117 |
| CCS | 4 | 53 | 2 | 25 |

### Figure 9.43 • OC power-generation capacity in the 450 Scenario




### Figure 9.44 • OC share of passenger vehicle sales by technology and average new vehicle on-road $CO_2$ intensity in the 450 Scenario



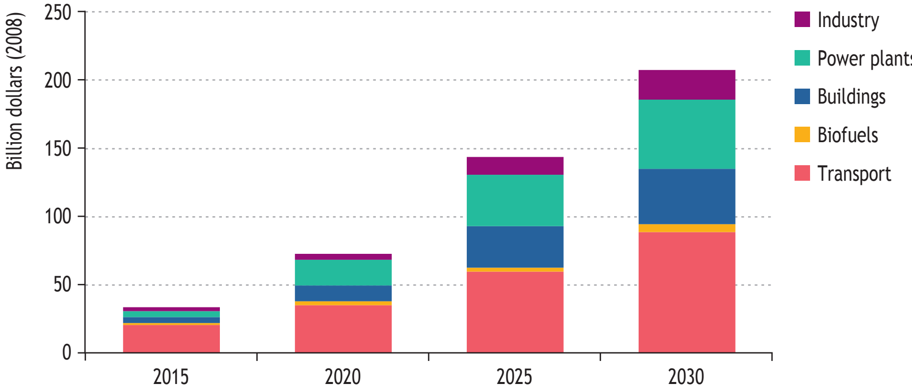

9

## Table 9.18 • OC energy demand and electricity generation

| | 1990 | 2007 | 2020 Reference Scenario | 2020 450 Scenario | 2030 Reference Scenario | 2030 450 Scenario | Change vs. RS 2020 | Change vs. RS 2030 |
|---|---|---|---|---|---|---|---|---|
| | | | Energy demand (Mtoe) | | | | (%) | |
| **Total primary energy demand** | **1 764** | **2 551** | **3 320** | **3 130** | **4 236** | **3 712** | **-6** | **-12** |
| Coal | 329 | 488 | 713 | 640 | 1 061 | 621 | -10 | -41 |
| Oil | 539 | 740 | 897 | 819 | 1 138 | 977 | -9 | -14 |
| Gas | 330 | 538 | 734 | 686 | 925 | 718 | -7 | -22 |
| Nuclear | 32 | 42 | 70 | 74 | 80 | 169 | 5 | 111 |
| Renewables | 534 | 742 | 906 | 912 | 1 033 | 1 227 | 1 | 19 |
| **Power generation** | **464** | **749** | **1 085** | **1 010** | **1 536** | **1 305** | **-7** | **-15** |
| *of which coal* | *159* | *314* | *477* | *418* | *747* | *358* | *-12* | *-52* |
| *of which gas* | *124* | *214* | *311* | *282* | *414* | *274* | *-9* | *-34* |
| **Other energy sector** | **206** | **300** | **392** | **371** | **470** | **397** | **-5** | **-15** |
| **Total final consumption** | **1 310** | **1 812** | **2 328** | **2 215** | **2 938** | **2 627** | **-5** | **-11** |
| Coal | 135 | 138 | 192 | 180 | 260 | 214 | -6 | -18 |
| Oil | 394 | 581 | 743 | 688 | 994 | 863 | -7 | -13 |
| Gas | 152 | 242 | 317 | 303 | 386 | 346 | -4 | -10 |
| Electricity | 114 | 213 | 354 | 340 | 535 | 468 | -4 | -13 |
| Heat | 60 | 30 | 31 | 30 | 34 | 32 | -3 | -8 |
| Renewables | 455 | 608 | 691 | 675 | 729 | 705 | -2 | -3 |
| **Industry** | **376** | **486** | **672** | **650** | **877** | **791** | **-3** | **-10** |
| Coal | 101 | 116 | 168 | 157 | 232 | 191 | -6 | -18 |
| Oil | 76 | 85 | 101 | 96 | 114 | 102 | -5 | -10 |
| Gas | 53 | 98 | 133 | 128 | 164 | 147 | -4 | -10 |
| Electricity | 61 | 94 | 163 | 153 | 245 | 208 | -6 | -15 |
| Heat | 22 | 13 | 13 | 12 | 14 | 13 | -2 | -5 |
| Renewables | 63 | 81 | 94 | 103 | 109 | 130 | 9 | 19 |
| **Transport** | **184** | **305** | **425** | **395** | **636** | **570** | **-7** | **-10** |
| Oil | 178 | 288 | 393 | 351 | 589 | 496 | -11 | -16 |
| Biofuels | 0 | 0 | 11 | 19 | 19 | 36 | 65 | 88 |
| Other fuels | 6 | 16 | 22 | 25 | 28 | 38 | 16 | 35 |
| **Other sectors** | **684** | **876** | **1 044** | **990** | **1 209** | **1 065** | **-5** | **-12** |
| Coal | 31 | 19 | 22 | 21 | 25 | 21 | -7 | -19 |
| Oil | 96 | 112 | 127 | 122 | 147 | 131 | -4 | -11 |
| Gas | 77 | 84 | 104 | 99 | 131 | 116 | -5 | -11 |
| Electricity | 50 | 116 | 186 | 176 | 284 | 240 | -5 | -16 |
| Heat | 38 | 17 | 18 | 18 | 21 | 19 | -4 | -10 |
| Renewables | 392 | 527 | 586 | 554 | 600 | 539 | -5 | -10 |
| **Non-energy use** | **66** | **145** | **187** | **181** | **217** | **202** | **-3** | **-7** |
| | | | Electricity generation (TWh) | | | | (%) | |
| **Total generation** | **1 710** | **3 207** | **5 234** | **5 020** | **7 790** | **6 778** | **-4** | **-13** |
| Coal | 511 | 1 045 | 1 995 | 1 780 | 3 497 | 1 684 | -11 | -52 |
| Oil | 321 | 358 | 262 | 212 | 193 | 153 | -19 | -21 |
| Gas | 302 | 853 | 1 432 | 1 319 | 1 964 | 1 273 | -8 | -35 |
| Nuclear | 123 | 163 | 269 | 284 | 308 | 650 | 5 | 111 |
| Hydro | 441 | 735 | 1 057 | 1 138 | 1 374 | 1 915 | 8 | 39 |
| Wind | 0 | 14 | 85 | 116 | 171 | 391 | 37 | 128 |
| Other renewables | 12 | 40 | 134 | 172 | 282 | 712 | 28 | 152 |

## Costs and benefits

**Figure 9.45 • *OC additional investment in the 450 Scenario relative to the Reference Scenario***




- Additional cumulative investment cost: nearly $400 billion over 2010-2020; close to $1 500 billion over 2021-2030.
- Total investment in the 450 Scenario of over $1 450 billion in low-carbon power generation over 2010-2030 (85% renewables, 13% nuclear, 1% CCS).
- Incremental investment cost equal to 0.6% of GDP in 2020, rising to 1.2% by 2030.
- Oil savings of 3.3 mb/d in 2030 in the 450 Scenario, compared with the Reference Scenario, an amount close to India's 2008 oil demand.
- Local air pollution costs reduced by $4 billion in 2020 and in excess of $10 billion in 2030, relative to the Reference Scenario.

## Policy opportunities

- Reduce the environmental footprint of fossil fuels, especially through price subsidy reform, and diversify energy supply through greater reliance on renewables and nuclear power.
- Define national potentials for energy efficiency, set building codes and participate in international sectoral agreements to adopt less polluting technologies in industry and passenger cars.
- Expand the role of CDM to attract much needed investment, to achieve economic development and cleaner energy technologies at the same time.

# India

## Highlights

- 44% increase in energy-related $CO_2$ emissions by 2020 (relative to 2007) to meet 450 Scenario.
- Power generation $CO_2$ intensity decreasing by 33% and average car fleet $CO_2$ intensity decreasing by 34% by 2020, compared with 2007.
- 25% increase in emissions from buildings and 66% increase in industry by 2020, relative to 2007.
- Additional investment in low-carbon technologies and energy efficiency of nearly $25 billion in 2020 to meet 450 Scenario.

## Emissions

**Figure 9.46 • India energy-related $CO_2$ emissions**

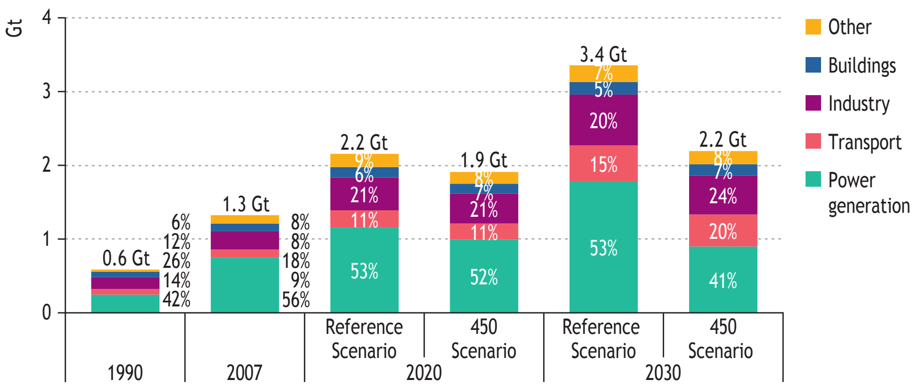
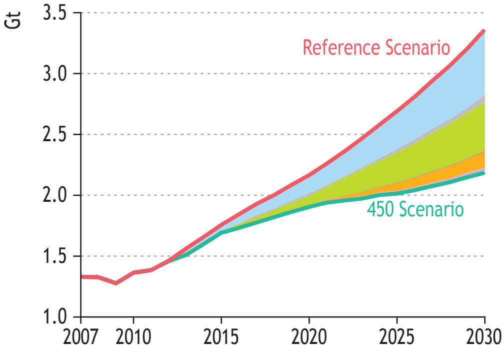



**Table 9.19 • India key indicators**

| | 1990 | 2007 | 2020 RS | 2020 450 | 2030 RS | 2030 450 |
|---|---|---|---|---|---|---|
| Population (million) | 850 | 1 123 | 1 319 | | 1 432 | |
| Share of world population | 16% | 17% | 17% | | 17% | |
| GDP ($2008 trillion, PPP) | 1.1 | 3.1 | 7.1 | | 12.5 | |
| Share of world GDP | 3% | 5% | 7% | | 9% | |
| Share of world $CO_2$ emissions | 3% | 5% | 6% | 6% | 8% | 8% |
| $CO_2$ emissions per capita (t) | 0.7 | 1.2 | 1.6 | 1.4 | 2.3 | 1.5 |
| Energy demand per capita (toe) | 0.4 | 0.5 | 0.7 | 0.6 | 0.9 | 0.8 |
| $CO_2$ intensity index (world 2007=100) | 126 | 101 | 71 | 63 | 63 | 41 |
| Cumulative $CO_2$ since 1890 (Gt) | 13 | 31 | 52 | 51 | 80 | 72 |
| Share of cumulative world $CO_2$ | 2% | 3% | 3% | 3% | 4% | 4% |
| Power $CO_2$ intensity (g/kWh) | 848 | 942 | 698 | 628 | 650 | 376 |
| Car fleet $CO_2$ intensity (2007=100) | n.a. | 100 | 89 | 66 | 83 | 53 |

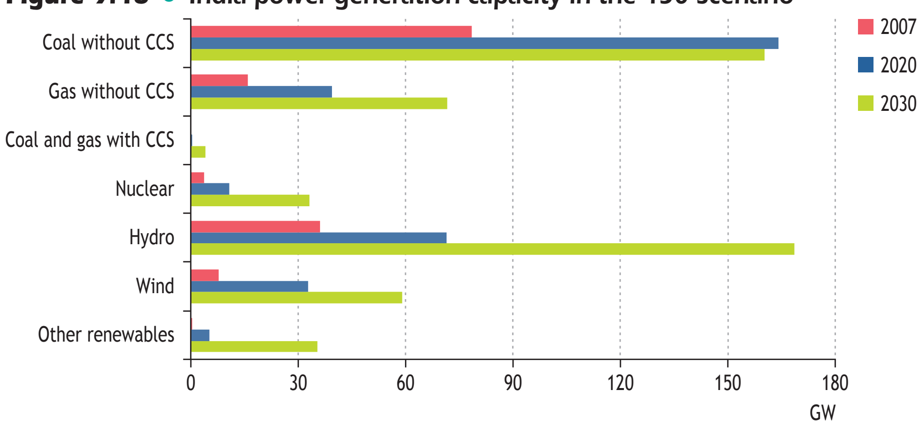
## Technology outlook

### Figure 9.47 • India energy-related $CO_2$ emissions abatement

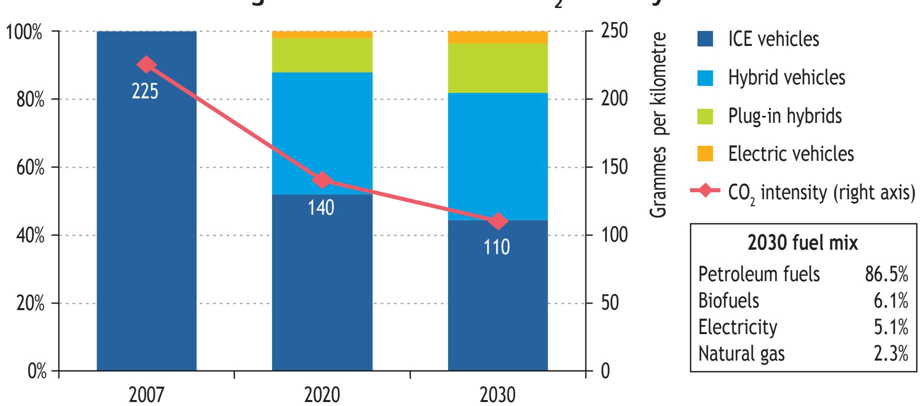



| | Abatement ($Mt\ CO_2$) 2020 | Abatement ($Mt\ CO_2$) 2030 | Investment ($2008 billion) 2010-2020 | Investment ($2008 billion) 2021-2030 |
|---|---|---|---|---|
| Efficiency | 170 | 601 | 74 | 301 |
| End-use | 148 | 544 | 66 | 290 |
| Power plants | 22 | 57 | 8 | 11 |
| Renewables | 76 | 400 | 48 | 312 |
| Biofuels | 1 | 5 | 1 | 11 |
| Nuclear | 0 | 131 | 0 | 59 |
| CCS | 2 | 30 | 1 | 11 |

### Figure 9.48 • India power-generation capacity in the 450 Scenario




### Figure 9.49 • India share of passenger vehicle sales by technology and average new vehicle on-road $CO_2$ intensity in the 450 Scenario



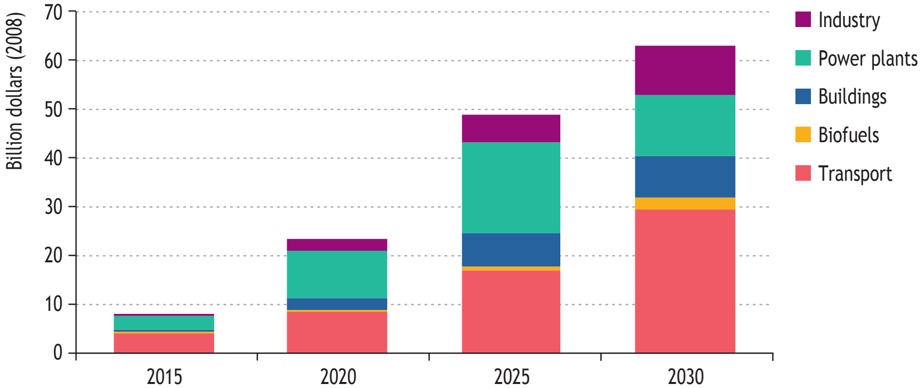

9

## Table 9.20 • India energy demand and electricity generation

| | 1990 | 2007 | 2020 Reference Scenario | 2020 450 Scenario | 2030 Reference Scenario | 2030 450 Scenario | Change vs. RS 2020 | Change vs. RS 2030 |
|---|---|---|---|---|---|---|---|---|
| | | | Energy demand (Mtoe) | | | | (%) | |
| **Total primary energy demand** | **318** | **595** | **901** | **833** | **1 287** | **1 084** | **-8** | **-16** |
| Coal | 106 | 242 | 378 | 330 | 586 | 326 | -13 | -44 |
| Oil | 61 | 141 | 223 | 203 | 341 | 292 | -9 | -14 |
| Gas | 10 | 33 | 80 | 76 | 113 | 113 | -5 | 0 |
| Nuclear | 2 | 4 | 19 | 19 | 28 | 67 | -1 | 144 |
| Renewables | 140 | 174 | 200 | 205 | 220 | 285 | 2 | 29 |
| **Power generation** | **73** | **217** | **358** | **329** | **554** | **449** | **-8** | **-19** |
| *of which coal* | *58* | *177* | *269* | *230* | *419* | *194* | *-14* | *-54* |
| *of which gas* | *3* | *13* | *35* | *34* | *55* | *63* | *-4* | *13* |
| **Other energy sector** | **19** | **55** | **96** | **85** | **136** | **110** | **-11** | **-20** |
| **Total final consumption** | **251** | **391** | **589** | **556** | **833** | **731** | **-6** | **-12** |
| Coal | 42 | 47 | 83 | 76 | 134 | 103 | -9 | -23 |
| Oil | 52 | 119 | 190 | 177 | 300 | 263 | -7 | -12 |
| Gas | 6 | 18 | 42 | 39 | 54 | 48 | -6 | -12 |
| Electricity | 18 | 47 | 100 | 97 | 169 | 150 | -4 | -12 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | n.a. | n.a. |
| Renewables | 133 | 161 | 174 | 167 | 176 | 167 | -4 | -5 |
| **Industry** | **70** | **113** | **192** | **180** | **287** | **242** | **-6** | **-16** |
| Coal | 29 | 36 | 72 | 65 | 121 | 93 | -9 | -23 |
| Oil | 10 | 21 | 28 | 25 | 32 | 26 | -9 | -18 |
| Gas | 0 | 7 | 15 | 15 | 20 | 19 | -3 | -4 |
| Electricity | 9 | 21 | 49 | 45 | 83 | 70 | -7 | -17 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | n.a. | n.a. |
| Renewables | 23 | 28 | 28 | 30 | 30 | 35 | 6 | 13 |
| **Transport** | **27** | **41** | **85** | **79** | **175** | **160** | **-6** | **-8** |
| Oil | 24 | 38 | 78 | 71 | 161 | 142 | -8 | -12 |
| Biofuels | 0 | 0 | 4 | 4 | 8 | 9 | 10 | 22 |
| Other fuels | 3 | 2 | 4 | 4 | 7 | 10 | 13 | 44 |
| **Other sectors** | **143** | **198** | **246** | **232** | **290** | **255** | **-5** | **-12** |
| Coal | 11 | 10 | 12 | 11 | 13 | 10 | -6 | -20 |
| Oil | 12 | 30 | 39 | 37 | 49 | 44 | -5 | -11 |
| Gas | 0 | 1 | 3 | 3 | 6 | 5 | -5 | -12 |
| Electricity | 9 | 25 | 50 | 48 | 83 | 72 | -4 | -13 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | n.a. | n.a. |
| Renewables | 111 | 133 | 142 | 133 | 138 | 124 | -6 | -11 |
| **Non-energy use** | **12** | **39** | **67** | **64** | **82** | **73** | **-4** | **-10** |
| | | | Electricity generation (TWh) | | | | (%) | |
| **Total generation** | **289** | **792** | **1 650** | **1 586** | **2 737** | **2 395** | **-4** | **-12** |
| Coal | 192 | 537 | 1 095 | 959 | 1 935 | 922 | -12 | -52 |
| Oil | 10 | 36 | 36 | 36 | 33 | 32 | -1 | -2 |
| Gas | 10 | 66 | 189 | 184 | 299 | 358 | -3 | 20 |
| Nuclear | 6 | 17 | 73 | 72 | 106 | 258 | -1 | 144 |
| Hydro | 72 | 124 | 188 | 233 | 251 | 537 | 24 | 114 |
| Wind | 0 | 12 | 56 | 79 | 72 | 151 | 41 | 111 |
| Other renewables | 0 | 2 | 12 | 23 | 41 | 137 | 89 | n.a. |

## Costs and benefits

**Figure 9.50 • *India additional investment in the 450 Scenario relative to the Reference Scenario***




- Additional cumulative investment cost: over \$100 billion over 2010-2020; nearly \$500 billion over 2021-2030.
- Total investment in the 450 Scenario in excess of \$550 billion in low-carbon power generation over 2010-2030 (83% renewables, 16% nuclear, 2% CCS).
- Incremental investment cost equal to 0.9% of GDP in 2020, rising to 1.4% by 2030.
- Oil and gas import bill reduced in excess \$30 billion in 2020 and \$90 billion in 2030, compared with the Reference Scenario.
- Local air pollution costs reduced by \$1 billion in 2020 and \$3 billion in 2030, relative to the Reference Scenario.

## Policy opportunities

- Accelerate investment in nuclear power plants and strengthen policies to promote renewables in power generation, a sector that provides major opportunities to reduce $CO_2$ emissions and local pollutants.
- Further define and strengthen policies to promote cleaner transport, including the use of mass transport and more efficient cars.
- Continue the implementation of CDM projects and expand CDM to more sectors.

9

PART C

# PROSPECTS FOR NATURAL GAS

## PREFACE

Natural gas has a lower carbon content than other fossil fuels and, for years, has been seen as a fuel with good prospects in a carbon-constrained energy market. Suddenly, in 2009, worldwide primary gas demand appears to be falling. Part C takes a close look at what is happening in the gas market and the prospects ahead.

Chapter 10 examines the demand picture. A near-term downturn in demand gives way to resumed growth; but there could even be a "demand peak" in the 2020s if governments really get tough on climate change.

Chapter 11 analyses worldwide gas resources: their extent, the various types of source rock, the profile of production and the technologies in play.

What this means for the future pattern of supply and how much investment will be going into gas-supply infrastructure is the theme of Chapter 12, while Chapter 13 looks at potential supply on a regional basis.

Finally, Chapter 14 discusses gas pricing – the way gas is priced today, its relationship with the oil price and how the picture might evolve.

# OUTLOOK FOR GAS DEMAND
## Driven by a thirst for power?

### HIGHLIGHTS

- The resumption of economic growth from 2010, the favourable environmental and practical attributes of natural gas over other fossil fuels, and constraints on how quickly low-carbon energy technologies can be brought on line all point to steady growth in demand for gas worldwide over the *Outlook* period. The power sector is expected to remain the single largest driver of gas demand.
- The main drivers of gas demand – and thus the main sources of uncertainty – are economic growth, gas prices and government policies. The share of gas in power generation is very sensitive to the price of gas relative to other fuels and technologies. The introduction of carbon prices would most likely boost gas use through lower coal burn, other things being equal.
- Government policies will be a key determinant of the pace of demand growth in the medium-to-long term. In the Reference Scenario, in which energy policies are assumed to remain unchanged, global gas demand rises from 3.0 tcm in 2007 to 4.3 tcm in 2030 – an average rate of increase of 1.5% per year. The share of gas in the global primary energy mix increases marginally, from 20.9% in 2007 to 21.2% in 2030. Over 80% of the increase in gas use occurs in non-OECD countries.
- The outlook to 2015 differs markedly from the longer-term picture. Although only partial and preliminary data on gas demand are available for 2008 and early 2009, it is likely that, worldwide, primary gas demand will fall in 2009 – perhaps by as much as 3% – as a result of the economic contraction. On the assumption that the economy begins to recover by 2010, primary gas demand is projected to rebound, growing on average by 2.5% per year between 2010 and 2015.
- In the 450 Scenario, which assumes government action to curb greenhouse-gas emissions consistent with a 2°C global temperature increase, world primary gas demand in 2030 is 17% lower than in the Reference Scenario. Demand peaks soon after 2020 and then slowly declines, though it is still higher in 2030 than in 2007. Measures to encourage energy savings, improved efficiency and low-carbon technologies, more than offset the effect on demand of the enhanced competitiveness of gas against coal and oil in power generation and in end-use applications (because of higher carbon prices and regulatory instruments).
- Gas demand in the OECD countries generally peaks by around the middle of the projection period in the 450 Scenario and then declines through to 2030, as generators switch investment away from coal- and gas-fired plants to plants using renewables and nuclear power. Demand continues to grow in most non-OECD regions through to 2030, though some regions see a decline after 2020.

# Projected trends in natural gas demand

## Reference Scenario

In the absence of radical government policy action, global demand for natural gas is set to resume its long-term upward path from 2010, when the global economy is assumed to begin to recover from the recession. In the Reference Scenario, in which it is assumed that there are no changes in policies, world primary gas consumption is projected to increase in all *WEO* regions over the period 2007-2030, with the exception of the United States where demand declines fractionally. As with all other fuels, demand falls back in the early years as a result of the global economic and financial crisis, and then recovers gradually with the assumed economic rebound. Globally, demand expands from 3.0 trillion cubic metres (tcm) in 2007 to 4.3 tcm in 2030, an average rate of increase of 1.5% per year (Table 10.1). This is well below the rate of 2.6% per year of 1980-2007 and the 1.8% rate projected in *WEO-2008*, mainly because of much weaker economic growth and, therefore, lower gas demand in all regions in the near term; world gross domestic product (GDP) is assumed to grow by only 1.3% per year in 2007-2010 compared with 3.4% in 2010-2030. The share of gas in the global primary energy mix continues to increase in line with past trends, but only marginally: from 20.9% in 2007 to 21.2% in 2030. The share was 17% in 1980.

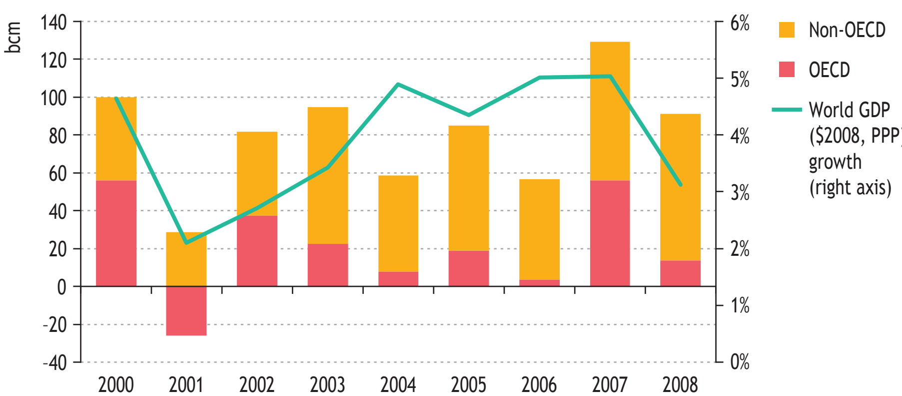
**Table 10.1 • Primary natural gas demand by region in the Reference Scenario** (bcm)

| | 1980 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007-2030* |
|---|---|---|---|---|---|---|---|
| **OECD** | **958** | **1 527** | **1 555** | **1 636** | **1 690** | **1 761** | **0.6%** |
| North America | 659 | 813 | 818 | 841 | 863 | 892 | 0.4% |
| *Canada* | *56* | *96* | *104* | *112* | *122* | *133* | *1.4%* |
| *United States* | *581* | *655* | *635* | *635* | *639* | *649* | *-0.0%* |
| Europe | 264 | 544 | 552 | 590 | 617 | 651 | 0.8% |
| Pacific | 35 | 170 | 185 | 205 | 210 | 218 | 1.1% |
| *Japan* | *25* | *100* | *102* | *103* | *105* | *111* | *0.4%* |
| **Non-OECD** | **559** | **1 523** | **1 840** | **2 042** | **2 307** | **2 553** | **2.3%** |
| E. Europe/Eurasia | 438 | 682 | 699 | 711 | 753 | 787 | 0.6% |
| *Russia* | *n.a.* | *453* | *454* | *460* | *486* | *500* | *0.4%* |
| Asia | 36 | 319 | 460 | 548 | 648 | 748 | 3.8% |
| *China* | *14* | *73* | *142* | *176* | *210* | *242* | *5.3%* |
| *India* | *1* | *39* | *78* | *94* | *113* | *132* | *5.4%* |
| Middle East | 36 | 294 | 380 | 446 | 519 | 602 | 3.2% |
| Africa | 14 | 101 | 143 | 163 | 181 | 187 | 2.7% |
| Latin America | 36 | 127 | 158 | 174 | 206 | 229 | 2.6% |
| *Brazil* | *1* | *21* | *35* | *39* | *44* | *50* | *3.8%* |
| **World** | **1 517** | **3 049** | **3 395** | **3 678** | **3 996** | **4 313** | **1.5%** |
| *European Union* | *n.a.* | *526* | *532* | *564* | *589* | *619* | *0.7%* |

* Compound average annual growth rate.

The outlook to 2015 differs markedly from the longer-term picture. Although only partial and preliminary data on gas demand are available for 2008 and early 2009, it is likely that, worldwide, primary gas demand will fall in 2009 as a result of the economic contraction. Gas demand in OECD countries increased overall by an estimated 1% in 2008, but the year was very much a tale of two halves. Demand continued to grow strongly during the first half of 2008, partly driven by more gas-fired power capacity coming on line and a rebound of European residential demand as the winter of 2007/2008 proved colder than the previous one. Gas demand trends changed substantially during the second half of 2008 and in particular during the last quarter, with the combined impact of a sharp economic downturn and relatively high oil-linked gas prices in some markets, notably continental Europe, pushing demand sharply lower. Preliminary data point to a similar slowdown in gas use in non-OECD countries in late 2008, though demand for the year as whole continued to grow (Figure 10.1).

**Figure 10.1** ● ***Year-on-year change in world primary natural gas demand by major region***



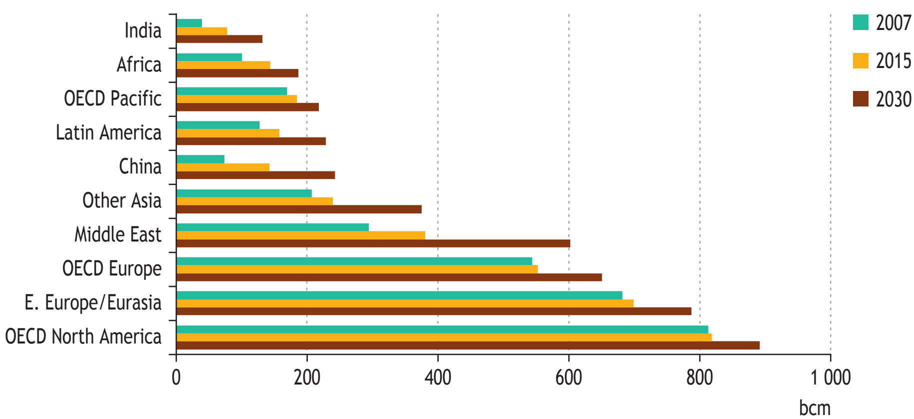

Note: 2008 data are preliminary.

The weakening of gas consumption in both OECD and non-OECD countries is expected to continue well into 2009 as the economic recession spreads and deepens, pushing demand down by as much as 3% compared with 2008. Use of gas in industry and for power generation is likely to fall sharply in some regions, particularly in Europe and Russia, mainly because of weak demand for electricity and relatively high gas prices. Demand in the United States appears to have held up better than in most other OECD countries, thanks to a sharp drop in prices. On the assumption that the economy begins to recover by 2010 (see Introduction), final gas demand is projected to rebound. Higher electricity demand would also push up the use of gas in power generation, as new gas-fired power plants now under construction are completed and plants whose launch was delayed by the crisis are given the green light. On average, primary gas demand worldwide is projected to grow by 1.4% between 2007 and 2015, but by a much brisker 2.5% between 2010 and 2015.

### *Regional trends*

Primary gas demand is projected to continue to grow in all regions bar the United States (where it is flat) over the entire projection period, despite the near-term dip in some of them. Gas use per capita and per unit of GDP remain very different among regions, largely according to their indigenous resource endowment and their proximity to low-cost external resources. Demand grows most in non-OECD regions, accounting for 80% of the overall increase worldwide to 2030. The biggest increment in absolute terms occurs in the Middle East, where ample resources in several countries are expected to fuel rising demand for power generation, for use in heavy industry and for feedstock (Figure 10.2).[1] Demand in non-OECD Asia and Africa also grows strongly: the rate of growth in Asia is actually higher than in the Middle East. The use of gas grows by more than 5% per year in both India and China, where gas use in the power sector and in industry increases rapidly, though demand in both countries in 2030 is still relatively low as a share of total energy use in 2030 as it starts from a very low base. The mature markets of North America and Europe see relatively low rates of demand growth through to 2030, but remain the largest markets in absolute terms in 2030. More details of demand (and supply) prospects by region in both the Reference and 450 Scenarios can be found in Chapter 13.

**Figure 10.2 • *Primary natural gas demand by region in the Reference Scenario***



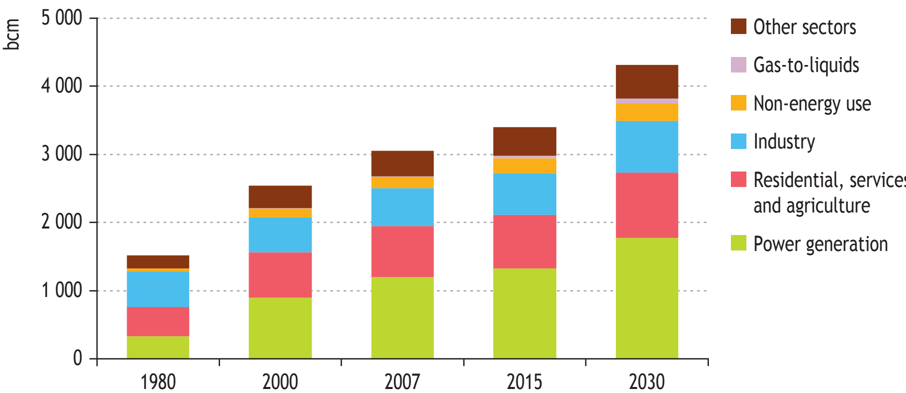

### *Sectoral trends*

In the Reference Scenario, the power sector[2] is expected to remain the leading driver of gas demand in most regions, accounting for 45% of the increase in world demand over the projection period and consolidating its position as the single largest gas-consuming sector (Figure 10.3). Gas use in power stations expands by about half between 2007 and 2030 (at an average annual rate of 1.7%); this sector's share of the

1. Notwithstanding temporary and seasonal shortages in some countries (see Chapter 13).
2. Gas use in power generation includes water desalination in combined water and power plants.

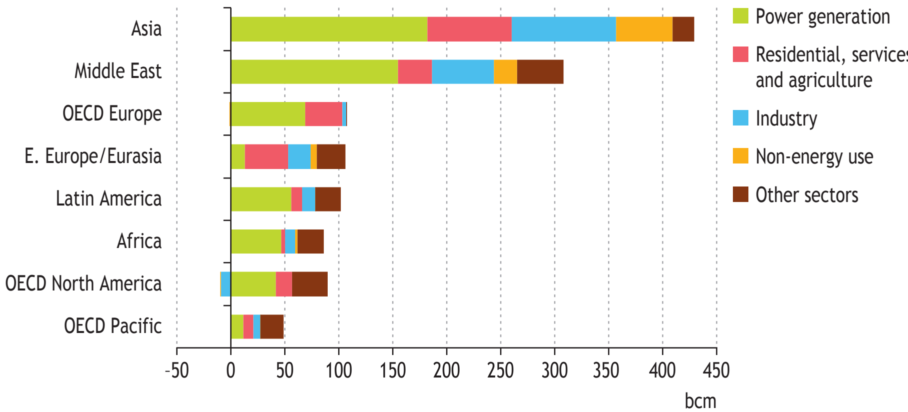
world gas market rises from 39% in 2007 to 41% in 2030. The power sector is the main driver of gas demand in most regions (Figure 10.4). Despite the assumption of rising gas prices in the longer term and the growing attractiveness of renewables-based generating technologies, natural gas is expected to remain the most competitive fuel in new power stations in many instances, especially when used in highly efficient combined-cycle gas turbines (CCGTs) and for mid-load generation. Gas-fired plants are often favoured over coal- and oil-fired plants for environmental reasons, for their relatively low capital costs (especially for small plants) and for their short construction lead times. In Europe, rising carbon penalties under the EU Emissions Trading System also enhance the competitiveness of gas against coal in power generation and heavy industry, though they benefit power generation based on renewables and nuclear power even more. The uncertainties surrounding power-sector demand for gas are discussed in detail in the next section.

**Figure 10.3 • *World primary natural gas demand by sector in the Reference Scenario***




Gas-to-liquids (GTL) plants, which convert natural gas feedstock into high-quality diesel and other oil products, account for a small but growing share of primary gas use. There are currently only three commercial-scale plants in operation: PetroSA's 35 thousand barrels per day (kb/d) facility in Mossel Bay, South Africa, which started up in 1991; Shell's 12.5 kb/d Bintulu plant in Malaysia, which was commissioned in 1993; and the Sasol/Qatar Petroleum 34 kb/d Oryx plant in Qatar, the world's biggest GTL plant, which came on line in 2006. Two more plants are under construction: Shell's 140 kb/d Pearl project in Qatar, which is scheduled to come on stream in 2010 and the 34 kb/d Escravos plant (a sister plant to Oryx, using Sasol technology), which is being built by Chevron and the Nigerian National Petroleum Company in the Niger Delta, with a planned start-up date of 2012. When all these plants are up and running at full capacity, they will consume an estimated 33 billion cubic metres (bcm) of gas per year – up from 5 bcm in 2007 (when Oryx had not reached full production) – and produce around 250 kb/d of liquids.

**Figure 10.4 • Incremental primary natural gas demand by region and sector in the Reference Scenario, 2007-2030**




The long-term prospects for additional GTL plants are very uncertain. Interest in developing GTL projects has waned in recent years due to rising construction costs and major technical hitches with Oryx, which even now is operating at only 90% of its nameplate capacity. A moratorium on new gas developments in Qatar, which has abundant reserves of cheap gas (see Chapter 13), is preventing any new GTL projects from proceeding there. Volatile oil prices and uncertainties surrounding future policies to reduce carbon-dioxide ($CO_2$) emissions are adding to investment risks. The high energy intensity of GTL plants limits the potential returns on investment. In the long term, we assume that planned projects in Australia and Uzbekistan are completed, together with a small number of other projects in the Middle East and Africa, taking total GTL production capacity to around 650 kb/d and requiring 70 bcm of gas input by 2030.

Global final consumption of gas in industry (including non-energy uses, but excluding power generation, GTL and other transformation), the residential sector, services and agriculture increases by 10% between 2007 and 2015, and 34% by 2030, an annual rate of increase over the whole projection period of 1.3%. Non-energy use of gas, mainly feedstock for petrochemical and fertilizer production, grows faster than use in any other end-use sector. Industrial demand expands by 1.3% per year in the period 2007-2030 and industry remains the largest end-consumer of gas. Almost all of the increase in industrial demand occurs in non-OECD countries, where faster economic growth drives a steady rise in industrial and commercial use of gas. Residential gas use remains relatively low outside the OECD and the Former Soviet Union, because heating needs are generally small and incomes are often insufficient to justify the necessary investment in distribution infrastructure. Efficiency gains, notably in Russia and other Eurasian countries, also temper the growth in residential gas demand. Some oil-producing non-OECD countries continue to encourage switching to gas in the industrial and commercial sectors, in order to free up more oil for export. Final consumption barely increases in the OECD, because of saturation effects, sluggish output in the heavy manufacturing sector and the modest increase in population.

**Box 10.1 ● *The potential for natural gas vehicles***

Globally, the use of natural gas in the road-transport sector remains negligible, even though natural gas vehicle (NGV) technology has been around for a long time and is well established in some countries. Worldwide, there were an estimated 9.6 million NGVs on the roads in 2008, mainly in Pakistan, Argentina, Brazil, India, Iran and Italy.[3] The majority are cars, but buses account for much of the consumption, and two- and three-wheelers powered by compressed natural gas (CNG) are prominent in Pakistan, India and some Southeast Asian countries. South America alone accounts for almost 40% of total consumption. Most light-duty NGVs are converted gasoline-powered vehicles, though an increasing number of vehicles worldwide are being manufactured to run on CNG.

In most cases, gas as a transport fuel (in compressed or, less commonly, in liquefied form) was introduced as a means of monetising abundant local supplies, but the environmental benefits of gas over gasoline and diesel have helped drive up demand in recent years. Compared with vehicles with a conventional engine, NGVs emit fewer noxious and toxic air pollutants, and generate lower $CO_2$ emissions on a well-to-wheels basis (Gielen and Unander, 2005). In an effort to combat local air pollution, some large cities have turned to NGVs. For example, all public transport vehicles in Delhi are required to be powered by CNG. Interest in promoting NGVs is growing in the United States, driven by low prices and the perception that indigenous supplies are ample.

Despite the environmental advantages of NGVs over conventional vehicle and fuel technologies, expanding the NGV fleet faces several barriers, including fuel storage and making available the infrastructure for delivery and distribution at existing refueling stations. On the vehicle, natural gas must be stored in cylinders, thus reducing storage space. The absence of an existing fuel-distribution network also discourages the uptake of NGVs – a classic chicken-and-egg problem. For these reasons, public buses and other fleet vehicles, such as taxis, are likely to continue to dominate the use of gas for road transport. More stringent emissions standards could encourage faster deployment of NGVs, especially in countries with abundant gas resources and low prices. In countries with an established distribution network, NGVs are likely to maintain their market share. But countries that do not yet have an extensive fuel-distribution infrastructure are likely to favour other alternative fuels, notably biofuels and electricity, in the quest to decarbonise the road-transport system because the required investments are smaller and the potential environmental gains greater.

The transport sector accounts for a small share of gas use. At present, oil and gas pipeline compressors take more than four-fifths of the gas used for transport. This source of demand is expected to continue to grow as global gas use rises, but at a much slower rate (0.4% per year between 2007 and 2030, compared with global primary gas demand

3. According to the International Association of Natural Gas Vehicles (www.iangv.org/home.html).

growth of 1.5%). This is because pipeline transportation capacity grows less rapidly than liquefied natural gas (LNG) capacity (see Chapter 12) and because the efficiency of compressors is expected to improve. In contrast, the use of gas as a road-transport fuel, which currently accounts for only 1% of total final gas consumption worldwide, is expected to grow at a brisk 3.7% per year to 2030, with most of the growth coming from non-OECD countries (which already account for most gas use for road transport). Nonetheless, the share of gas in world road-transport energy use reaches only 1% in 2030. The potential exists for much faster growth in this sector, but it hinges on stronger policy action (on environmental and energy-security grounds) to promote investment in distribution infrastructure and switching by consumers to natural gas vehicles (Box 10.1).

The projected shift in gas demand towards power generation may accentuate the near-term volatility and seasonality of gas demand worldwide. The greater short-term fuel-switching capability in the power sector will render demand more sensitive to short-term swings in relative fuel prices and to external factors affecting the availability of power-generating capacity (such as water levels for hydroelectric plants and unplanned shutdowns of nuclear plants). Electricity demand in most countries peaks in the winter months (especially in the Northern Hemisphere) because of the heating load and in the summer months in the Southern Hemisphere because of the air-conditioning load, causing global demand to peak around the turn of the year.

## 450 Scenario

The 450 Scenario illustrates how determined government action to curb greenhouse-gas emissions could affect gas demand over the projection period (see Part B for details). Energy-related $CO_2$ emissions in the 450 Scenario peak in 2020 and then decline steadily. By 2030 emissions are 8% lower than in 2007. In the 450 Scenario, natural gas use grows in all sectors *vis-à-vis* 2007, but at a slower pace than in the Reference Scenario. This results from two countervailing forces: measures to encourage energy savings, improved efficiency and low-carbon technologies reduce gas demand, more than offsetting the enhanced competitiveness of gas against coal and oil in power generation and in end-use applications (because of higher carbon prices and regulatory instruments). Worldwide, primary gas demand in 2030 is 17% lower in the 450 Scenario than in the Reference Scenario, peaking soon after 2020, though it is still nearly 17% higher in 2030 than in 2007 (Figure 10.5, Table 10.2). In fact, gas is the only fossil fuel that does not lose market share in this scenario.

Gas demand in the OECD countries generally peaks by around the middle of the projection period in the 450 Scenario and then declines through to 2030, as generators switch investment mainly from coal- and gas-fired plants to plants using renewables and nuclear power. This is the main reason for the overall fall in OECD gas demand *vis-à-vis* the Reference Scenario. The United States sees a faster increase in gas use than in the Reference Scenario level in the period to 2020, but demand dips thereafter as efficiency measures trim end-user needs, and as renewables and nuclear power take market share from gas in the power sector. Demand continues to grow in most non-OECD regions through to 2030, though some regions see a decline after 2020. Gas use falls most sharply in percentage terms, relative to the Reference Scenario, in Latin America, mainly because gas is largely backed out in power generation by hydropower and other renewables.

**Table 10.2 • Primary natural gas demand by region in the 450 Scenario** (bcm)

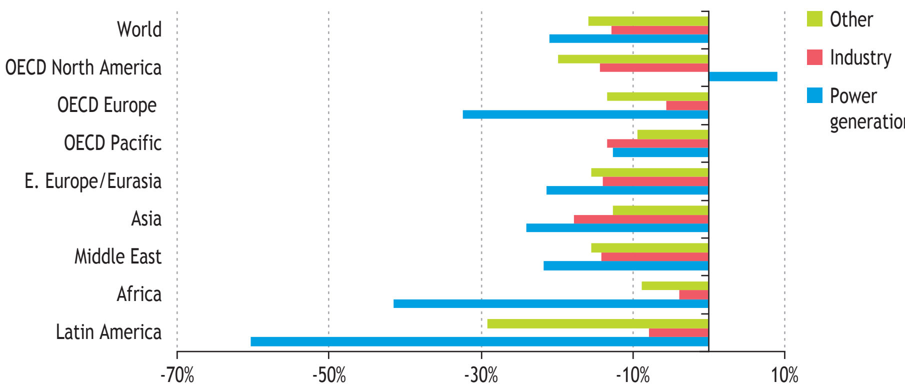
| | 2007 | 2020 | 2030 | 2007-2030* | Change versus Reference Scenario 2030 |
|---|---|---|---|---|---|
| **OECD** | **1 527** | **1 542** | **1 527** | **0.0%** | **-13%** |
| North America | 813 | 813 | 809 | -0.0% | -9% |
| *United States* | *655* | *629* | *626* | *-0.2%* | *-3%* |
| Europe | 544 | 541 | 525 | -0.2% | -19% |
| Pacific | 170 | 189 | 193 | 0.6% | -12% |
| *Japan* | *100* | *92* | *98* | *-0.1%* | *-12%* |
| **Non-OECD** | **1 523** | **1 934** | **2 033** | **1.3%** | **-20%** |
| E. Europe/Eurasia | 682 | 686 | 645 | -0.2% | -18% |
| *Russia* | *453* | *451* | *405* | *-0.5%* | *-19%* |
| Asia | 319 | 512 | 609 | 2.8% | -19% |
| *China* | *73* | *163* | *198* | *4.4%* | *-18%* |
| *India* | *39* | *89* | *132* | *5.5%* | *0%* |
| Middle East | 294 | 428 | 493 | 2.3% | -18% |
| Africa | 101 | 153 | 141 | 1.5% | -24% |
| Latin America | 127 | 154 | 145 | 0.6% | -37% |
| **World** | **3 049** | **3 476** | **3 560** | **0.7%** | **-17%** |
| *European Union* | *526* | *523* | *509* | *-0.1%* | *-18%* |

* Compound average annual growth rate.

Globally, the biggest reductions in gas demand in percentage and absolute terms are achieved in power generation. In most regions, the power sector is subject to carbon pricing under a $CO_2$ cap-and-trade scheme, giving generators an incentive to reduce their use of gas and other fossil fuels in favour of nuclear power and/or renewables. Gas use in power generation is 21% lower in the 450 Scenario than in the Reference Scenario. Over four-fifths of this reduction occurs in the non-OECD countries. The deployment of carbon capture and storage (CCS) facilities on a small number of gas-fired plants offsets part of the reduction in gas use, as CCS plants are significantly less energy efficient. Savings are also significant in the buildings sector, mainly thanks to measures to promote the development and deployment of more efficient heating and cooling, and to improve building insulation. Gas use in buildings is reduced worldwide by around 110 bcm, or 14%, compared with the Reference Scenario (Figure 10.5). In industry, gas demand drops by 13%, mainly through efficiency gains.

10

**Figure 10.5 • Change in primary natural gas demand by sector and region in the 450 Scenario versus the Reference Scenario, 2030**




International natural gas prices are assumed to be lower In the 450 Scenario than in the Reference Scenario, as a result of lower oil prices and lower demand for gas (see Chapter 5 for a detailed discussion of the methodology and assumptions used). However, the *effective* prices for gas paid by power generators and industrial consumers are significantly higher in the 450 Scenario in many regions, because of carbon penalties (though the cost of using coal and oil increases even more).

## Understanding the drivers of gas demand

The current level of gas consumption in any given region is the result of a host of factors that have driven the historical development of the gas industry, including: the overall demand for energy in stationary uses and the underlying economic activity driving that demand; the proximity of resources and the cost of delivering them to market; the competitiveness of gas against alternative fuels; climate (which affects, in particular, the need for fuel for space and water heating); technological developments affecting the way gas and alternative energy sources are used; and the policy, geopolitical and regulatory environment. Therefore, the medium-to-long term prospects for gas demand in each region depend on how these different factors, the relative importance of which varies markedly by sector and region, will change (Table 10.3). The gas-demand projections for the two scenarios presented above are based on assumptions about these drivers. Inevitably, one cannot be certain how any of the drivers will evolve over the projection period, though some changes are easier to predict than others. This section takes a closer look at how sensitive demand is to each of these factors and their predictability in order to shed light on the degree of uncertainty surrounding the outlook for gas demand.

**Table 10.3 ● *Summary of main drivers of gas demand by sector***

| Sector | Economic activity | Price | Policies | Technology |
|---|---|---|---|---|
| Power generation | Electricity demand is strongly correlated with industrial production and household incomes. | Competitiveness of gas-fired plants is highly sensitive to changes in relative fuel prices. | Policies on nuclear power and support for renewables (and carbon pricing) strongly influence need for gas-fired capacity. | Less potential for improving the thermal efficiency of gas plants than for coal plants (with and without CCS) and for renewables. |
| Industry | Industrial production is the main driver; less scope for efficiency gains compared with buildings. | Limited short-term switching capability and gas usually the preferred fuel for new equipment (boilers and processing). | In some countries, gas price regulation and policy can favour gas use for environmental reasons. | Some remaining potential for raising boiler efficiency, including in CCGT combined heat and power plants. |
| Buildings | Household income, which determines demand for residential living space and heating/cooling needs. | Gas use in buildings is relatively insensitive to price (in absolute or relative terms). | Standards, labelling and subsidies for insulation and efficient (low-emission) boilers/coolers can strongly affect demand. | Improved efficiency and reliability of condensing boilers could boost deployment and lower gas demand. |
| Other | Demand for gas for feedstock (petrochemicals) strongly correlated with industrial production and GDP. | Feedstock demand for gas is very sensitive to price of gas relative to naphtha and LPG. | Government policies on indigenous fertilizer production and GTL can affect gas demand. | Technological advances in GTL production (especially with regard to thermal efficiency) could greatly boost use of stranded gas. |



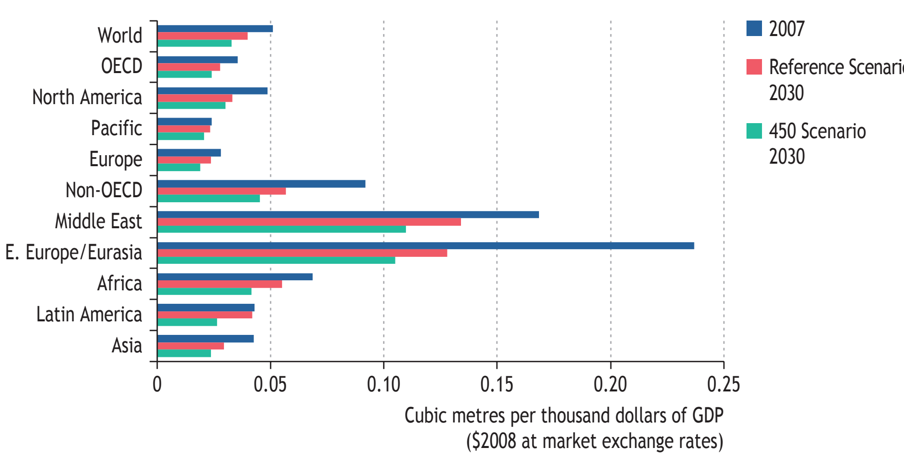
## The relationship between gas use and economic activity

In all markets, the level of economic activity is the primary determinant of demand for natural gas: economic growth typically correlates closely with increasing gas use in those sectors in which it is already well established. Rising industrial production boosts gas needs in factories for process heat and steam-raising; increased commercial activity raises gas demand for space heating; and rising personal incomes increase demand for gas for space and water heating in homes. Increased economic activity also boosts electricity demand, which in turn tends to push up demand for gas for power generation (where gas is competitive). The correlation aggregated across all sectors and regions is correspondingly strong (Figure 10.1 above).

The assumption that world GDP will resume its upward trajectory from the early 2010s is the main reason behind the projected growth in gas demand in both the Reference and 450 Scenarios. It follows, therefore, that a faster or slower rate of economic growth would have a significant impact on the rate of growth of gas demand over the projection period. This is a major source of uncertainty for the near term. Our GDP assumptions, which are based on the latest forecasts from the International Monetary Fund (IMF) and the OECD, point to a drop in global GDP of 1.4% in 2009, modest growth of 2.2% in 2010 as the world economy starts to recover, and a more robust rate of growth of 4.8% per year in 2011-2014 – significantly above the average annual rate of 3.8% over the period 2000-2008. However, there is an unusually wide range of views about near-term economic prospects, with some organisations forecasting a more robust recovery and others expecting a slower or less even return to growth (see Introduction).

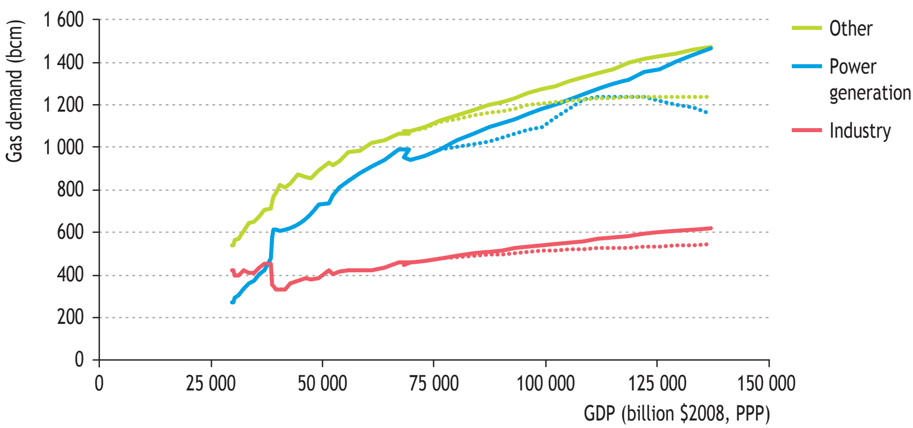
The overall intensity of gas use in a given economy – measured by the amount of gas consumed per unit of GDP – varies significantly across countries and regions, mainly because of differences in the ease of access to low-cost supplies and, therefore, the delivered price of gas. The climate influences strongly the demand for energy (for heating and cooling), as does the weight of heavy industry in the economy, so differences in these factors are important. Eastern Europe/Eurasia and the Middle East are by far the most gas-intensive regions (when GDP is measured using market exchange rates), by virtue of their large resource endowments (Figure 10.6). Gas intensity is expected to fall in all regions over the *Outlook* period, with the Middle East emerging as the most intensive region, as a result of the continued rapid development of heavy industry using gas as feedstock, and the heavy reliance on gas in new power and desalination plants. Intensity falls much more in the 450 Scenario, thanks to faster improvements in energy efficiency and switching to low-carbon fuels and technologies.

**Figure 10.6 • *Natural gas intensity by scenario and region***



Globally, gas use in the power sector is most strongly driven by GDP growth. Between 1990 and 2007, every 1% increase in GDP (expressed in purchasing power parity terms) resulted on average in a 1.6% increase in gas use in power, *i.e.* an elasticity of 1.6 (Figure 10.7). The two are also highly correlated, with a coefficient of 97%. The correlation between GDP and gas use in buildings is almost as strong, though the income elasticity of gas demand is much lower, at around 0.9 in buildings. By contrast, gas use in industry is much less highly correlated and has an elasticity of only 0.5, reflecting the diminishing share of industry in GDP. Gas demand is projected to slow relative to GDP over the projection period in all sectors, particularly in power generation and especially in the 450 Scenario.

**Figure 10.7 • *World primary natural gas demand versus GDP by sector and scenario, 1980-2030***

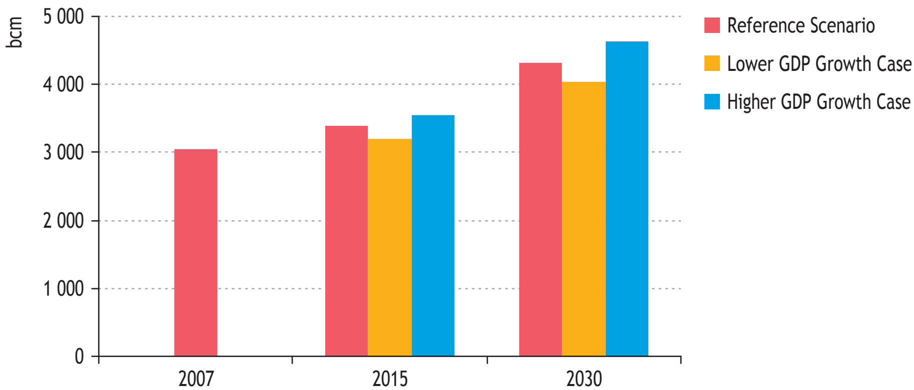



Note: Solid lines are for the Reference Scenario and dotted lines for the 450 Scenario.

For this *Outlook*, we have developed two variants of the Reference Scenario that assume different rates of economic growth (to reflect the uncertainty surrounding the near-term and long-term prospects for the world economy): a Higher GDP Growth Case, in which GDP is assumed to grow by half of one percentage point per year *faster* from 2010 in all regions; and a Lower GDP Growth Case, in which GDP grows by one-half of a percentage point per year *less* quickly. These cases, described in detail in Annex B, shed light on how sensitive gas markets are to the economic outlook. In the former case, world primary gas demand increases on average by 1.8% per year – 0.3 percentage points more quickly than in the Reference Scenario. As a result, demand in 2030 is more than 7% higher (Figure 10.8). Conversely, demand grows by only 1.2% per year – 0.3 percentage points less than in the Reference Scenario – in the

Lower GDP Growth Case, leaving demand more than 6% lower in 2030. The difference in demand in 2030 between the two cases is almost 590 bcm, or 15% of demand in the Lower GDP Growth Case.

**Figure 10.8 • Primary natural gas demand in the Reference Scenario and Higher and Lower GDP Growth Cases**




## Economics of inter-fuel competition

The price of gas is a vital determinant of the share of gas in the overall energy mix in any given market. Gas can be substituted by at least one other fuel in every application (transformation and end uses), such that inter-fuel competition is typically keen. Although flexibility is very limited in the short term – most gas users are not physically capable of switching to an alternative fuel at short notice – end users are almost always faced with a choice of fuel when deciding what type of energy-consuming equipment to install, whether it is a boiler, heating or cooling system, or power plant.

Gas competes against different fuels in different uses and regions: in power generation, gas competes primarily against coal, heavy fuel oil, nuclear power and renewables-based technologies; in industry, the main competing fuels are heavy fuel oil, coal and electricity; while in the commercial and residential sectors, the principal competitors are heating oil and electricity. Energy consumers and power generators have to weigh the costs of different fuels and technologies, taking account of differences in fuel prices, the costs of the equipment, operational factors, regulatory constraints and risks (including environmental restrictions), and market risks (including future changes in fuel prices and reliability of supply). Regulations and technological factors also affect the economics of inter-fuel competition, by changing the costs of, or opportunities for, using certain fuels or technologies. Governments may also intervene directly in energy markets to mandate the use of particular fuels.

The sensitivity of demand for gas to changes in price also varies markedly across regions and sectors, and over time. There is some flexibility to switch between natural gas and alternative fuels in boilers for steam-raising in power generation and manufacturing industry, and so take advantage of relative fuel price changes, though this capability varies across countries. Accurate statistics on dual- or multi-firing capacity and the extent of switching in practice are rare. A 2002 IEA survey found that nominal short-term fuel-switching capability by industrial customers and power generators amounts to about 12% of average daily gas consumption in Europe, 9% in North America and 50% in the Pacific.[4] Almost one-fifth of US industrial gas consumption could be avoided by switching to other fuels (DOE/EIA, 2002). Roughly one-third of US power plants that use gas as the primary fuel (mostly steam boilers) were also able to run on oil products in 2008, even though most of the new gas-fired capacity (largely CCGT) added at the beginning of the current decade cannot use oil as a backup or alternative fuel. In Europe, fuel-switching capability to or from gas in the power sector is thought to be smaller as a share of total capacity, perhaps amounting to about one-quarter, and has been declining. Some power generators, however, are able to bring oil- or coal-fired plants into operation to replace gas-fired plants when it is financially attractive to do so.

In recent years, few generators or industrial consumers that run their plants on gas have opted to install multi-firing equipment or maintain back-up facilities in the event of a sharp increase in the price of gas or interruption to supply. Some industrial gas consumers may simply stop using gas by halting production entirely when the price of gas exceeds a certain level: globalisation, by permitting companies to move production to countries where gas and other costs are lower, has accentuated this factor. A number of nitrogen fertilizer plants, notably in the United States, have shut down in recent years as the cost of the gas to produce the ammonia feedstock has risen to levels that make fertilizer production unprofitable.



Over the longer term, demand for gas is much more sensitive to the price of gas (in economists' parlance, the *own*-price elasticity of demand) and, even more, to the price of gas relative to the prices of alternative fuels (the *cross*-price elasticity of demand), as energy consumers make new choices as to which type of technology and fuel to use to provide a given energy service. But measuring these elasticities is complicated by the role played by other factors — notably income, climate, lifestyles, investment cycles, technology, price expectations and government policies. Elasticities also vary according to the actual level of prices: in other words, the shape of the demand curve may be far from linear. In some instances, the price of gas in a particular market may rise significantly without choking off much demand if the cost of the cheapest competing fuel (which determines the market value of the gas) is already much higher. This is most often the case in countries that regulate gas prices on the basis of cost of supply or the ability of consumers to pay (which may result in a price well below the

4. Actual switching capability may be significantly less in some countries as a large portion of capacity may no longer be effective, either because local sources of residual fuel oil no longer exist or because the equipment has not been maintained. In some countries, new environmental constraints rule out switching to a more polluting fuel.

market value of the gas). Once the price of gas rises above the threshold of its market value and the logic of conservation or efficiency measures becomes clear-cut, demand may fall off quickly.

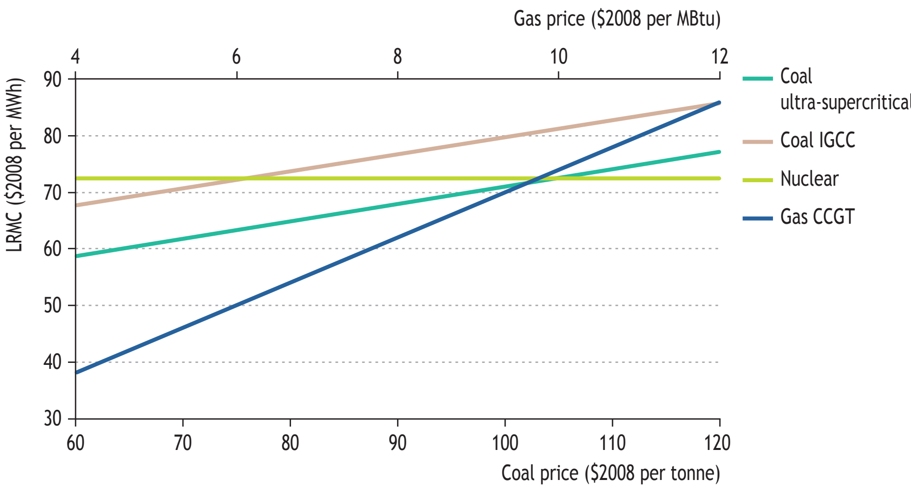
### *Fuel choice in power generation*

The overall cost of generation, taking account of differences in capital, maintenance and operational costs (including the prices of fuel inputs) is usually the most important factor determining the choice of technology for new generating plants — whether the decision is taken by private investors, by public utilities or by the central government. Assumptions about the competitiveness of gas prices against the prices of alternative fuels are a vital element in this calculation. Future fuel prices are, therefore, the principal source of uncertainty surrounding the prospects for gas use in power generation. But it is not simply a matter of which fuel is cheapest: the relative financial attractiveness of gas *vis-à-vis* other options depends on a range of other factors, including the efficiency of the plant, the utilisation rate (or capacity factor), investment costs per MW of capacity, plant life, construction lead times, operating and maintenance costs, decommissioning costs and any penalty for $CO_2$ emissions. The discount rate applied to such an investment will also have a marked influence on the relative cost of generation and, therefore, on the choice of fuel and technology. Other factors, which are not directly financial but have clear financial implications, also influence investment decisions. These include technical risk and construction lead times, both of which are relatively low for gas-fired plants, and operational versatility. The relatively low capital intensity of gas-fired plants also makes them more attractive for mid-load operation and makes financing easier (see Chapter 3).

At low gas prices, generation in CCGT plants using gas is typically the cheapest investment option, as construction costs per MW of capacity are significantly lower than for coal- and oil-based plants and for nuclear, wind and solar power. For example, in the OECD, for a new gas-fired CCGT plant, we estimate that the long-run marginal cost (LRMC) of generating electricity (excluding any $CO_2$ emission penalty) is around \$60/MWh (in 2008 dollars) at a gas price of just under \$8/MBtu (Figure 10.9).[5] A coal-fired ultra-supercritical plant would generate power at the same cost with a coal price of about \$70 per tonne. The average cost of nuclear power generation is estimated at just over \$70/MWh. A gas price of \$10/MBtu pushes the generating cost of the gas-fired CCGT plant up to more than \$70/MWh, making it uncompetitive with nuclear and coal-fired plants for base-load applications at a coal price of less than \$120 per tonne. The cost and technical parameters underlying this analysis are shown in Table 10.4.

5. These costs are based on average construction and operating costs across the OECD. In practice, these costs can vary significantly from one country to another, resulting in differences in the relative competitiveness of each fuel and technology.

**Figure 10.9 • Long-run marginal cost of generation for gas-fired CCGT power plants and other technologies at different fuel prices in the OECD**




Note: Based on an after-tax weighted cost of capital of 8%. Costs relate to plants brought into operation in 2015-2020. This analysis does not include any $CO_2$ emission penalty.

**Table 10.4 • Assumed cost and technical parameters of power plants in the OECD starting commercial operation in 2015-2020**

| | Unit | Gas (CCGT) | Coal ultra-supercritical | Coal IGCC | Coal IGCC with CCS | Nuclear power | Wind onshore |
|---|---|---|---|---|---|---|---|
| Capacity factor | % | 80% | 80% | 80% | 80% | 90% | 27% |
| Thermal efficiency (net, lower heating value) | % | 58% | 47% | 48% | 38% | 33% | n.a. |
| Capital cost (overnight) | $2008/kW | 900 | 2 400 | 2 800 | 3 400 | 3 800 | 1 700 |
| Construction lead time | Years | 3 | 4 | 4 | 5 | 5 | 2 |
| Economic plant life | Years | 25 | 35 | 35 | 35 | 40 | 20 |
| Unit cost of fuel | Various* | 11 | 95 | 95 | 95 | 10 | n.a. |
| Non-fuel O&M costs | $2008/kW | 13 | 49 | 83 | 72 | 117 | 40 |
| Long-run marginal cost | $2008/MWh | 78 | 69 | 78 | 95 | 72 | 94 |

* Based on the energy prices assumed in the Reference Scenario. Units for various fuels: gas in $/MBtu; coal in $/tonne; nuclear in $/MWh.

Sources: IEA databases; IEA/NEA (forthcoming).

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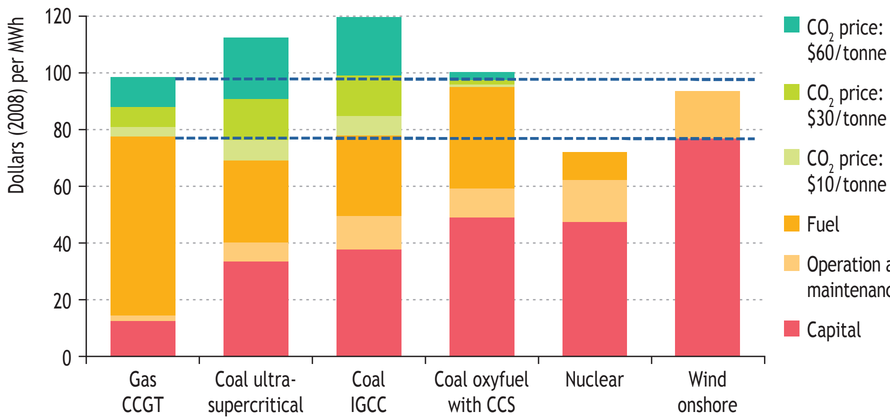
Based on the fossil-fuel prices assumed for 2015 in the Reference Scenario, we estimate that, on average in OECD countries, gas-fired CCGTs would be less competitive than ultra-supercritical coal technology for plants to be commissioned by the middle of the next decade if any penalty for $CO_2$ emissions is excluded (Figure 10.10). The gas-fired cost is comparable to the cost of nuclear power and coal-fired integrated gasification combined-cycle (IGCC) plants. If a carbon penalty of at least $30 per tonne is assumed, nuclear power (which carries no such penalty) emerges as the cheapest option. At a carbon price of around $50 per tonne of $CO_2$, onshore wind overtakes gas as the second-cheapest option. Costs from country to country vary somewhat around these averages.

**Figure 10.10 • Long-run marginal cost of generation for gas-fired CCGT power plants compared with other technologies and fuels in OECD countries in 2015-2020**




Note: See Table 10.4 and the note to Figure 10.9 for the parameters and assumptions underlying this analysis. The fossil-fuel prices used in this analysis correspond to the Reference Scenario assumptions for 2015-2020. Oxyfuel combustion systems, which can capture carbon in ultra-supercritical coal plants, produce high $CO_2$-concentration flue gases by using oxygen instead of air for fuel combustion.

The overall cost of generation in gas-fired plants is more sensitive to the price of the fuel input than is the case for coal-fired plant, as demonstrated in Figure 10.9 above. A 10% increase in the gas price (over and above the price of $11/MBtu assumed in the Reference Scenario for 2015) raises the cost of gas-fired generation from $78/MWh to $84/MWh – an 8% increase. The same percentage increase in the coal price raises the cost of coal-fired generation in an ultra-supercritical plant by only about 4% (not allowing for any carbon price). As nuclear and wind power require no fossil fuel, their competitiveness improves with higher gas and coal prices. Gas prices would have to increase by 26% (to $13.40/MBtu) for wind power to overtake gas as the cheapest option.

## *Fuel choice in industry*

In industry, depending on the sub-sector, gas competes against coal, oil products and electricity. Price is therefore an important factor in determining the preferred fuel, but other factors – including practical considerations, such as the fact that no on-site storage is required for gas – can be equally important. 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 it is often economic to do so only at relatively high gas prices. The iron and steel industry is also an important gas-consuming sector: though coking coal remains the leading fuel for steel production, the use of gas in the direct reduced-iron method, as a reducing agent to convert iron ore to pure iron, is growing worldwide. In other industrial sectors, gas can usually be replaced relatively easily by fuel oil or coal (especially in boilers) with the final choice of fuel being determined primarily by price and by environmental regulations (which may limit oil and coal use).

As gas prices often move in line with oil prices (whether market-based or regulated), gas generally remains competitive against oil, once it is established as an industrial fuel. Relative to coal in industry in most countries, more stringent air-pollution regulations are likely to favour increasingly the use of gas. A continuing trend towards less energy-intensive manufacturing processes, resulting from improvements in the energy efficiency of industrial equipment and processes, as well as a shift to production of goods that require less energy input, will also tend to favour gas as the capital costs of gas-fired equipment are generally lower.

### *Fuel choice in buildings*

Where distribution infrastructure exists, natural gas is often the preferred fuel for space and water heating – with the primary applications being in buildings (residential, commercial and public sectors). The principal competitor to gas in this sector 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 – which now account for most new sales in OECD countries – 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. In addition, gas boilers have practical advantages over oil (and coal) boilers, particularly the fact that no storage is required. As existing conventional boilers are replaced by more efficient condensing boilers, average boiler efficiency will improve, curbing to some degree the rate of increase in gas demand in these sectors. There is also potential for gas use in combined heat and power units, with overall energy efficiencies of up to 90%, in large building units. Space heating needs are largely a function of the number of households (and, therefore, population) and the size of dwellings (in turn, a function of income). But saturation effects are becoming apparent in the wealthiest countries.



### *Gas use as feedstock*

Gas is used as a feedstock mainly in the petrochemical and ammonia industries. It can be readily substituted by oil products (typically liquid petroleum gases or naphtha) in steam cracking, but less easily in making methanol and ammonia (gas accounts for close to 80% of the world's output of both products). Price is a critical factor in all three uses. Gas use in steam cracking can fluctuate markedly in the short term with movements in relative fuel prices. As the gas feedstock accounts for 70% to 90% of the total cost of making ammonia, production is typically halted when the price of gas rises above that share of the price of ammonia. In the long term, the use of gas as a feedstock is likely to continue to grow with rising GDP, though the rate of growth will vary across regions according to local market conditions and the abundance of gas *vis-à-vis* other feedstocks.

SPOTLIGHT

**Does carbon pricing mean more or less gas use?**

The impact on natural gas demand of the introduction or expansion of carbon pricing – an explicit penalty on $CO_2$ emissions through a tax or a cap-and-trade system – depends, in practice, mainly on the scope for cutting coal use in the sectors covered by carbon pricing and the potential for expanding non-fossil energy supply. The introduction of a carbon price raises the price of all fossil fuels to power generators and large industrial end users, thereby lowering the relative price of energy from low-carbon fuels and technologies. Coal prices increase the most and gas the least, reflecting their different carbon intensities. In other words, carbon pricing favours gas over coal, and favours renewables and nuclear power over gas. In the short run, the introduction of a carbon price could lead to switching from coal to gas to the extent that dual-firing or back-up capacity is available. In the longer term, a carbon price would favour investment in gas-fired capacity over coal-fired capacity, and investment in renewables and nuclear power over fossil-based capacity. Other things being equal, gas demand would go up compared with the baseline if it wins more market share from coal than it loses to renewables and nuclear power.

The net effect depends critically on the carbon price. At relatively low carbon prices, there could be a significant amount of switching from coal to gas (if total long-run marginal generation costs excluding carbon penalties are similar). This surge in gas demand may be offset to only a limited extent by improvements in end-use efficiency (which reduces the overall need to generate power) and by switching from gas to renewables (if the cost of renewables remains too high to compete effectively with gas in power generation), resulting in a net increase in gas use. But at high carbon prices, the switching effect to renewables and the efficiency gains that higher gas prices would induce would be more likely to outweigh the demand gains from switching from coal, leading to lower gas demand.

In the 450 Scenario, carbon pricing (in combination with other measures to curb greenhouse-gas emissions) leads to an overall *reduction* in gas demand of 17% *vis-à-vis* the Reference Scenario, though demand is still almost 20% higher than in 2007. This is because the carbon price is high, driven by the extent of the emissions reduction. Of course, other scenarios, involving less ambitious climate targets and/or different mixes of policy approaches, could result in higher gas demand than in the Reference Scenario. Increased gas use – especially in power generation – could well result were less onerous targets adopted than in the 450 Scenario and were the scale of investment envisioned in that scenario not to be forthcoming.

### *Sensitivity of gas demand to gas prices*

In a similar fashion to the two GDP sensitivities, we have developed Higher and Lower Energy Prices Cases to test the sensitivity of energy demand to different assumptions about prices than assumed in the Reference Scenario (see Annex B). In these two cases, international gas prices in Europe and Asia-Pacific are assumed to rise and fall, respectively, by 30% relative to those assumed in the Reference Scenario by 2030, with a similar rise in oil and coal prices. The changes in prices are assumed to occur in the early part of the projection period. In North America, prices deviate by only 20% by 2030, reflecting the weaker link between gas and oil prices in that market (see Chapter 14).

Not surprisingly, gas demand globally is boosted significantly by lower prices, both in end-use sectors and in power generation. In 2030, demand is more than 6% higher in the Lower Energy Prices Case than in the Reference Scenario, reaching almost 4 590 bcm – 50% above the 2007 level (Table 10.5). Already in 2015, global gas demand is around 75 bcm higher than in the Reference Scenario, which would significantly reduce the gas glut that is expected to emerge in the Reference Scenario (see Chapter 12). In the Higher Energy Prices Case, demand reaches 4 120 bcm in 2030 – over 4% lower than in the Reference Scenario.

**Table 10.5 • *World primary natural gas demand in the Reference Scenario and the Higher and Lower Energy Prices Cases*** (bcm)

| | 2007 | 2015 | 2030 | 2007-2030* | Change versus Reference Scenario 2030 |
|---|---|---|---|---|---|
| Reference Scenario | 3 049 | 3 395 | 4 313 | 1.5% | - |
| High Energy Prices Case | 3 049 | 3 290 | 4 123 | 1.3% | -4.4% |
| Low Energy Prices Case | 3 049 | 3 471 | 4 588 | 1.8% | 6.4% |

* Compound average annual growth rate.

## The impact of technological innovation and climate change

Continuing improvements in the technology of gas-consuming equipment and appliances will affect fuel choice and gas consumption in all sectors. The advent of CCGT technology at the end of the 1980s led to a boom in gas use in power generation (in centralised plants and industrial co-generation) in OECD countries, as it gave gas-fired plants a large efficiency advantage over plants using other fuels. The average thermal electrical efficiency of CCGT plants – the percentage of the fuel input that is converted to electricity – has continued to rise over the last two decades, consolidating the competitive advantage of gas in many cases. The remaining scope for efficiency gains in these plants is now small, though overall efficiency can still be increased sharply, in many cases, by capturing and using waste heat. Other generating technologies, such as IGCC plants, could see faster efficiency gains, which could favour coal over gas (not taking into account any carbon pricing or other environmental regulations). But, even without further advances in technology, the average efficiency of the gas-fired plants in use will tend to rise as old plants are retired and replaced by more efficient units.

In other sectors, technological developments are unlikely to have a major impact on fuel choice, but they could improve significantly the efficiency with which gas is used. There remains considerable scope for lowering gas intensity across manufacturing industry simply by adopting advanced technologies already in commercial use, notably in the co-generation of heat for producing steam and power (IEA, 2007). In all the energy-intensive manufacturing industries in which energy is a major cost component, energy efficiency has improved substantially over the last 25 years in every region, reflecting the adoption of such cutting-edge technology. The potential for still wider application of the best available technology is greatest in non-OECD regions. Generally, new manufacturing plants are more efficient than old ones. Energy efficiency is a vital factor in how quickly capital stock is replaced and the choice of new technology: enterprises usually respond quickly to strong financial incentives to invest in more efficient equipment, sometimes even retiring a plant well before the end of its normal operating lifetime.

The potential for technology-induced efficiency gains in gas use is thought to be even greater in the residential and commercial sectors. This is because households and small enterprises are generally slower than large energy-intensive firms to adopt new technology. They seek shorter pay-back periods and may be less willing to put up with the inconvenience of replacing equipment — even when it is, in principle, financially attractive to do so. Government policies can persuade or require residential and commercial consumers to exploit this potential: a minimum efficiency performance standard, for example, can effectively impose high-efficiency condensing boilers on consumers when they need to replace their existing boiler. Similarly, increasing taxes on gas strengthens the incentive for consumers to opt for the most efficient boilers. The persuasiveness, stringency and breadth of measures to promote the deployment of such boilers will be a strong determinant of gas demand in the residential and commercial sectors.

Building design also affects gas use in the building sector. The better insulated the building shell, the less gas is needed for space heating. Several recently developed technologies, such as high-performance windows and vacuum-insulated panels, can achieve large reductions in building energy consumption (IEA, 2008). Other technologies under development, such as integrated intelligent building control systems, could (with further research, development and deployment) offer even bigger energy savings over the next two decades. Deploying these technologies will take time: buildings typically last decades and even centuries,[6] and retrofitting old buildings can be very expensive or even impractical. All OECD countries and many non-OECD countries have adopted building codes with the aim of reducing energy needs, for a variety of social, economic, environmental and energy-security reasons. The impact on gas demand of building codes for new construction and refurbishment is likely to be biggest in the

6. Retirement rates in Europe, for example, typically range from 0.1% to 0.3% per year (Norris and Shiels, 2004).

OECD and Former Soviet Union countries, where gas accounts for more than one-third of total final energy use in buildings. Although most new buildings erected in the period to 2030 will be in non-OECD countries, their gas use is generally small (as their space heating needs are minimal due to climate and because gas-distribution networks are less developed).

How actual climate change might affect gas demand is particularly uncertain. The energy trends in the Reference Scenario would lead to a significant increase in average temperatures already by 2030 in some regions. This would effect gas demand in two ways: demand for space and water heating in the winter would, in most cases, be reduced; but demand for gas for power generation in the summer would rise in regions where there is a large cooling load.

### Government policies and geopolitics

Governments will undoubtedly continue to influence directly and indirectly trends in gas demand. The results of the 450 Scenario illustrate how determined government policies to reduce greenhouse-gas emissions might affect the use of gas in different sectors, by introducing carbon pricing, by promoting fuel switching (to and from gas), by enhancing efficiency (lowering the amount of gas input needed to provide a given energy service) and by encouraging conservation (forgoing an energy service). Local pollution and energy security may also lead to policy intervention in energy markets. Governments can influence fuel choice and the level of energy consumption in many different ways, including through economic instruments (such as taxes and subsidies) through regulatory instruments (such as mandatory efficiency standards, labelling and price controls) and through direct intervention (such as fuel-choice mandates or through actions based on ownership of energy-consuming entities). The two scenarios point to the outcomes under particular policy paths – one in which no measures to curb energy demand and fossil-fuel uses are introduced (the Reference Scenario) and the other in which countries around the world implement a particular package of measures that put the world on a path that would see global temperature rise by around 2°C (the 450 Scenario). But many other possible policy paths are open, which could lead to quite different gas-market outcomes.

Geopolitics also influence demand. Geopolitical barriers to investment can impede the supply of gas and result in unsatisfied demand. The use of gas is, to a large degree, supply-driven: where gas is readily available at reasonable cost, it is usually able to secure market share in the main stationary sectors. But where gas has to be imported by pipeline, geopolitical factors may, in some cases, impede investment, even if the economics of the project are compelling (so long as supply is assumed to flow without interruption). The dispute between Russia and Ukraine, which led in early 2009 to the worst disruption to European gas supply in history, is driving efforts by the European Union to diversify supply routes and to reduce gas consumption by improving efficiency and encouraging fuel switching, thereby reducing import needs. In general, geopolitical factors tend to favour investment in LNG over pipelines crossing several countries, as the risk of a supply disruption is lower.

# GAS RESOURCES, TECHNOLOGY AND PRODUCTION PROFILES

## An unconventional revolution in the making?

### H I G H L I G H T S

- Proven gas reserves at the end of 2008 are estimated at more than 180 trillion cubic metres (tcm) globally – more than enough to meet the demand to 2030 and well beyond. Over half of the reserves are located in just three countries: Russia, Iran and Qatar. Reserves have more than doubled since 1980; during 2008, additions amounted to 190% of production, with the largest increases coming from the Middle East and North America. Proven reserves of unconventional gas – tight sands, shale and coalbed methane – have grown most rapidly and now account for 4% of the worldwide total.
- Worldwide gas resources are much bigger than proven reserves and are more than sufficient to meet projected demand well beyond 2030. Remaining recoverable resources of conventional gas alone at the end of 2008 are estimated to be more than 400 tcm, equivalent to almost 130 years of production at current rates. In addition, unconventional gas resources in place are estimated at more than 900 tcm and more than 380 tcm of this gas is likely to prove recoverable.
- Technology, notably horizontal wells and hydraulic fracturing, has enabled the exploitation of large unconventional gas resources in North America, in many cases at costs below those of conventional resources. Large unconventional resources exist in other parts of the world, including Europe, China and India, but their large-scale exploitation will depend on gaining access to land for drilling operations, availability of water and infrastructure, and environmental regulations.
- The total long-term recoverable gas resource base is estimated at more than 850 tcm, including only those categories of resource with currently demonstrated commercial production. Some 66 tcm of this total has already been produced (or flared) at costs up to $5/MBtu (in 2008 dollars). Production costs for that part of the remaining conventional gas resource which is easily accessible – 55 tcm – vary from $0.50/MBtu to about $6/MBtu. Producing the 380 tcm of tight gas, coalbed methane and shale gas will cost between about $2.70/MBtu and $9/MBtu.
- The rate of decline in production from existing fields is the prime factor determining the amount of new capacity and investment needed to meet projected demand. Based on a detailed field-by-field analysis of historical production trends, we estimate that the observed average post-peak decline rate of the world's largest gas fields, weighted by production, is 5.3%. Based on these figures and estimates of the size and age distribution of gas fields worldwide, the global, production-weighted, decline rate is 7.5% for all fields beyond their peak. Output from existing fields is set to drop by almost half between 2007 and 2030.

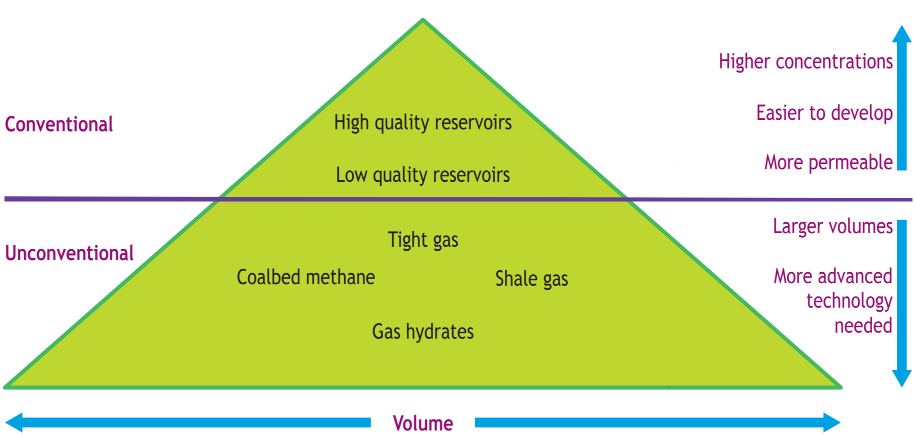
# Gas resources and reserves

This chapter reviews global gas resources and highlights the continuous role played by advances in technology to increase actual production and the fraction of resources that can be profitably produced. Natural gas, or methane, is produced worldwide from a variety of different resources. Technological advances that facilitate production or reduce its cost from a particular category of resource influence both global supplies and prices. Today, there is growing interest in exploiting unconventional sources of gas, using new techniques at lower costs. In the past ten years, shale gas has emerged as a major new source of gas supply in the United States, shifting from being a resource to which established methods are applied to produce small quantities of gas from older, well-known basins to an exciting new prospect to which state-of-the-art technology is applied in several new basins, involving much greater capital and volumes of gas. The prospects for unconventional resources and production technology, drawing mainly on recent experience in the United States, are assessed in detail below.

## Classifying gas resources

There are many different types of gas resource, each with markedly different characteristics requiring different production techniques. The concept of a resource triangle (Figure 11.1) illustrates how natural gas resources of all types are distributed according to their size and ease of extraction. Near the apex of the triangle for natural gas, representing a relatively small portion of the total resource base, are the highest quality accumulations, largely conventional gas, which can be developed relatively easily and cheaply. Resources found lower down the triangle – mainly unconventional – are much larger but are generally more difficult to produce, requiring more complex technology and/or higher prices if they are to be extracted profitably.

**Figure 11.1 • Typology of natural gas resources**




Sources: Masters (1979); Holditch (2006).

Hydrocarbon deposits are generally classified into conventional and unconventional resources. Conventional gas, in many cases found together with oil (associated gas)[1], is in widespread production worldwide today. Unconventional natural gas resources include tight gas sands, coalbed methane (CBM)[2], shale gas and gas (or methane) hydrates. Each of these unconventional types is fairly widely distributed worldwide, though their production is currently limited to a few countries and the technology is at a relatively early stage of development and deployment.

Unconventional gas resources have traditionally been thought too complex or expensive to produce because of the extremely low permeability of the rock (which hinders well flow rates), requiring specialised well-completion techniques to supply gas in commercially viable quantities. Unconventional resources have recently been exploited by the application and adaptation of technologies that increase significantly the area of rock in direct contact with the well and therefore improve flow rates. In fact, the term "unconventional" is becoming a misnomer, at least with respect to tight gas sands, CBM and shale gas; "previously overlooked" would now be a more accurate term. On the other hand, gas hydrates, described in a later section of this chapter, remain a truly unconventional resource, in the sense that commercial production has still to be demonstrated.

North America is the leading producing region for all types of unconventional gas, with these sources accounting for more than half of the production in the United States and more than one-third in Canada. Recent increases in both production and proven gas reserves in North America have been largely due to the development of unconventional resources. The average cost of production for unconventional gas in the United States fell below that of conventional gas in 2007, causing the focus of gas drilling to shift towards the least costly shale plays[3] – especially since gas prices began to plummet in mid-2008.

## Proven reserves

11

Global proven reserves of natural gas were estimated at 182 trillion cubic metres (tcm) at the end of 2008 (Figure 11.2), according to Cedigaz, an international centre for gas information (Cedigaz, 2009). This estimate includes both conventional and unconventional resources, the latter now amounting to 4% of the total, with more than half in North America. Other sources give very similar amounts for total proven reserves, with differences due to different definitions, estimation techniques and reporting standards.[4] Proven reserves continue to increase, having more than doubled since 1980. During 2008, reserve additions amounted to 190% of production: in other words, almost twice as much gas was "proved up" as was produced. The largest increases[5] were recorded in the Middle East and North America, the latter mainly due to large revisions to unconventional reserves. Increases in reserves

1. Associated gas is gas produced from fields that also produce considerable quantities of crude oil. A non-associated field is one that produces primarily gas, together with only minor quantities of liquid hydrocarbons.

2. Called coal-seam methane in Australia.

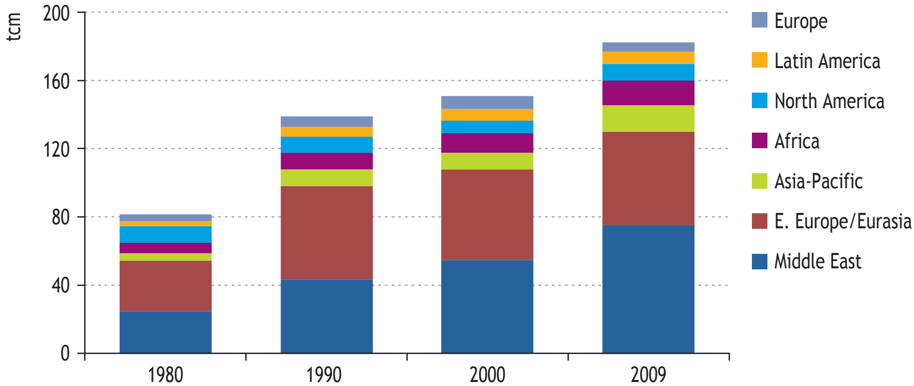
3. A play refers to an area in which hydrocarbon accumulations are found.

4. Reserve estimates in many countries are unaudited.

5. Field reappraisals in Turkmenistan, detailed in Table 11.1, are not included.

come both from newly discovered fields and from upward revisions of volumes in fields in production or being appraised. Over the last five decades, the volume of newly discovered gas, alone, has consistently exceeded the volume of gas produced.

**Figure 11.2 ● Proven reserves of natural gas by region**




Note: As at 1 January 2009.
Source: Cedigaz (2009).

**Box 11.1 ● Resource and reserve definitions**[6]

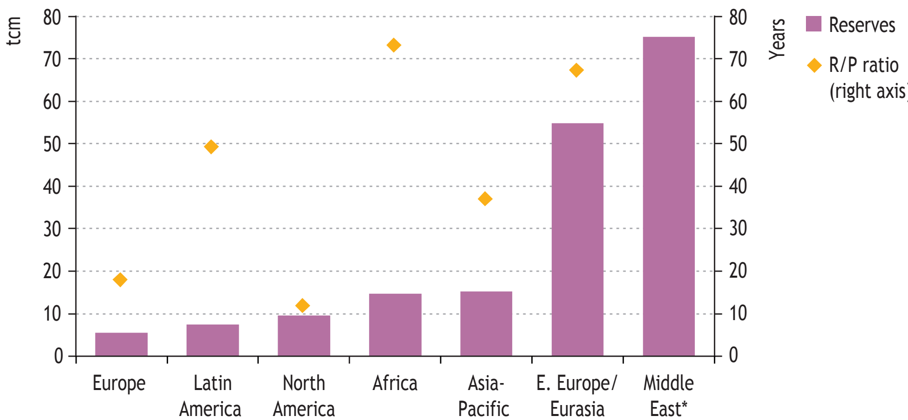
Different reporting systems and standards in use around the world give rise to large variations in definitions and estimates of natural gas (and oil) resources and reserves. The following terms are used in the *Outlook* to classify hydrocarbon resources, based on the most recent Petroleum Resources Management System (SPE, 2007):

- *Proven reserves* (or 1P reserves) are hydrocarbons remaining in gas fields that have been discovered and for which there is a 90% probability that they can be extracted profitably on the basis of assumptions about cost, geology, technology, marketability and prices.
- *Ultimately recoverable resources* refer to the total volume of a resource that is both technically and economically recoverable. They include proven, probable (2P) and possible (3P) reserves in discovered fields, as well as hydrocarbons that have yet to be found.
- *Remaining recoverable resources* are ultimately recoverable resources, less cumulative production.
- *Original gas in place* is the (latest available estimate of) the total volume of gas contained in a reservoir, regardless of the ability to produce it (technically and economically).

6. See Chapter 9 of last year's *Outlook* for a detailed discussion of hydrocarbon resource classification (IEA, 2008). These definitions apply equally to conventional and unconventional resources.

Reserves are unevenly spread globally, with just three countries – Russia, Iran and Qatar – holding more than half of the total. Furthermore, 38% of overall reserves are concentrated in the world's ten largest fields, including five in Russia (see Table 11.6 in the last section of this chapter). The largest fields, the North Field/South Pars complex, shared by Qatar and Iran, alone hold 23% of the total. At current extraction rates, today's proven reserves worldwide could sustain production for 58 years.[7] However, the volume of production regionally differs widely from the regional distribution of reserves. North America, for example, has only 12 years of proven reserves left at current production rates; Europe has the second-lowest reserves-to-production ratio (R/P), at 18 years (Figure 11.3).

**Figure 11.3 • Proven reserves and reserves-to-production ratio by region**




* The R/P ratio for the Middle East is almost 200 years.

Note: Annual production for 2008 and reserves as at 1 January 2009.

Sources: Cedigaz (2009); IEA databases.

Reserve reappraisals, evaluations and new discoveries amounted to over 9 tcm in 2008. The most significant changes included the South Yolotan-Osman and Yashlar fields in Turkmenistan[8] and the pre-salt Jupiter field offshore Brazil (Table 11.1). Of note is that some 10% of the volume additions of 2008 were in deepwater. This trend has strengthened significantly during the first half of 2009, with more deepwater additions in Brazil, Israel and Norway.

7. Reserves-to-production ratios are commonly used in the oil and gas industry as they are easy to understand and compare. They are used as strategic indicators, but do not imply continuous production for a certain number of years. Ratios are affected by new discoveries and reappraisals, changes in technology and production levels.

8. Note that these are mean estimate numbers that have not been fully included in Turkmenistan reserves (Cedigaz, 2009).

**Table 11.1 • Major conventional gas discoveries and reserve additions, 2008**

| Field/concession | Country | Location | Classification | Estimated reserves (bcm) |
|---|---|---|---|---|
| South Yolotan-Osman | Turkmenistan | land | reappraisal | 6 000 |
| Yashlar | Turkmenistan | land | reappraisal | 700 |
| Jupiter | Brazil | deepwater | potential | 660 |
| B structure - Farsi block | Iran | offshore | revision | 311 |
| Abadi | Indonesia | deepwater | evaluation | 283 |
| Magnama and Hatiya | Bangladesh | offshore | potential | 150 |
| Xinjiang | China | land | evaluation | 100 |
| Deendayal Upadhyay | India | offshore | potential | 84 |
| Intrepid Block 5c | Trinidad and Tobago | offshore | potential | 74 |
| WA-390-P licence | Australia | offshore | potential | 56-400 |

Note: Reserves are initial estimates.

Source: Cedigaz (2009).

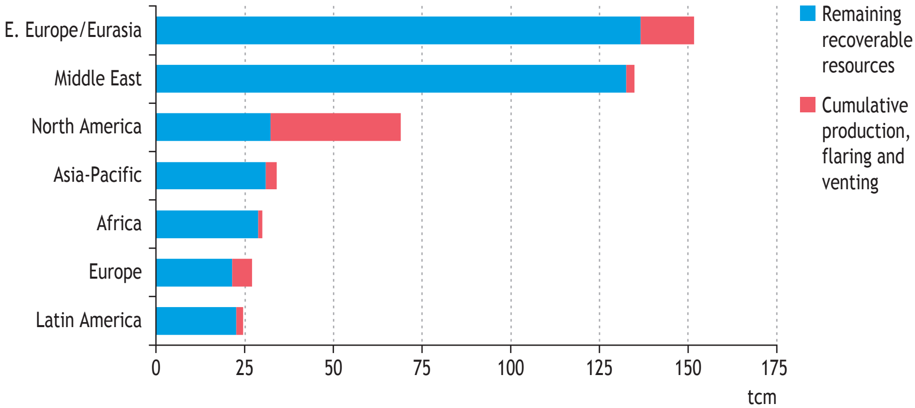
## Gas in place and ultimately recoverable resources

Most work on quantifying resources of natural gas has focused on conventional sources. The most widely respected source of information on global conventional oil and gas resources is the US Geological Survey (USGS). Combining the results of its year-2000 *World Petroleum Assessment* (USGS, 2000) with updates and assessments of other basins and the *2008 Circum-Arctic Resource Appraisal* (USGS, 2008b) yields an estimate of ultimately recoverable conventional gas resources of 471 tcm (mean value).[9] This compares with an estimate from the German Federal Institute for Geosciences and Natural Resources of 509 tcm (BGR, 2009). Ultimately recoverable resources include cumulative production to date, remaining reserves, reserve growth and as yet undiscovered resources. Cumulative production marketed until the end of 2008 amounted to nearly 13% of total ultimately recoverable conventional resources. We estimate that a further 1.5% of the initial resources have been flared or vented. As a result, we estimate that there are 405 tcm of *remaining* recoverable resources of conventional gas – equivalent to almost 130 years of production at current rates (Table 11.2, Figure 11.4). The Middle East and Eastern Europe/Eurasia each hold about one-third of these remaining resources.

Information about global unconventional resources is much less complete and reliable. Indeed, comprehensive assessments of unconventional gas resources are available only for some North American basins. For this reason, this assessment of the worldwide unconventional gas resources starts by discussing what is known about the North American resource.

9. Some provinces and basins were re-assessed in the *Circum-Arctic Resource Appraisal*.

**Figure 11.4 • Ultimately recoverable conventional natural gas resources by region, end-2008**




Sources: Reserves - Cedigaz (2009); resources - USGS (2000, 2008b); production - IEA databases and analysis.

**Table 11.2 • Conventional natural gas resources by region, end-2008**

| | Proven reserves (tcm) | Share of worldwide proven reserves (%) | Ultimately recoverable resources (tcm) | Cumulative production flaring and venting (tcm) | Remaining recoverable resources (tcm) | Share of worldwide remaining resources (%) |
|---|---|---|---|---|---|---|
| Middle East | 75.2 | 41.2% | 134.8 | 2.3 | 132.5 | 32.8% |
| E. Europe/Eurasia | 54.9 | 30.1% | 151.8 | 15.2 | 136.5 | 33.8% |
| Asia-Pacific | 15.2 | 8.3% | 33.9 | 3.1 | 30.8 | 7.6% |
| Africa | 14.7 | 8.1% | 29.9 | 1.2 | 28.7 | 7.1% |
| North America | 9.5 | 5.2% | 68.8 | 36.6 | 32.2 | 8.0% |
| Latin America | 7.5 | 4.1% | 24.5 | 2.1 | 22.4 | 5.5% |
| Europe | 5.4 | 3.0% | 27.0 | 5.7 | 21.3 | 5.3% |
| **World** | **182.4** | **100%** | **470.6** | **66.1** | **404.5** | **100%** |

Sources: Reserves - Cedigaz (2009); resources - USGS (2000, 2008b); production - IEA databases and analysis.

The USGS has estimated unconventional gas resources in some basins using methodologies that include studies of production records from wells in producing basins or from analogous areas. Using these assessments and others from the US Mineral Management Service, the US Energy Information Administration reports that there are 7.6 tcm of technically recoverable resources of shale gas alone yet to be discovered in the United States (US DOE/EIA, 2009). The Potential Gas Committee, a non-profit organisation that releases biennial assessments of US gas resources, estimates that at the end of 2008 the total US potential future gas resource was almost 59 tcm, with 52 tcm of potential resources (including 17.4 tcm of shale gas and 4.6 tcm of CBM) to be added to the 6.7 tcm of currently proven reserves of all types of gas.[10]

A recent study investigating resources in seven well-known North American basins (Old, 2008) concluded that unconventional resources constitute the majority of recoverable hydrocarbons – conventional resources amount to only 10% of the total. The modelling software developed for these studies could be used to estimate unconventional resources in less well-known basins, particularly those with known conventional hydrocarbons in which unconventional resources have yet to be evaluated. These evaluations of the North American unconventional gas potential have transformed the outlook for the regional gas industry.

**Box 11.2 ● *Assessments of unconventional resources***

Although the amount of recoverable unconventional resources worldwide is thought to be very large, they are currently poorly quantified and mapped. This is true even in the United States, where despite significant effort, large uncertainties remain. Assessments of conventional resources typically include volumetric calculations and the measuring and modelling of pressure changes within the reservoir. This method is harder to apply to unconventional gas resources, as assessments are complicated by the heterogeneity of the rock formations, their extremely low permeability and uncertainty as to the volume of reservoir that can be connected to a production well. Accurate unconventional resource quantification requires geological modelling and study of the production behaviour of several wells or assessment by analogy to other, known resources. As unconventional gas begins to play an increasingly important role in worldwide supply, more accurate assessments of recoverable resources become more important.

Detailed estimates of unconventional gas resources outside North America are mainly limited to areas that are already being developed or appraised for development, or are confined to specific categories of resource. Several private studies (including confidential oil-company assessments) are underway to identify and prioritise new locations to be assessed in detail, based on basin geology, size and maturity, proximity to existing oilfield activity, availability of infrastructure and other above-ground considerations. Despite these limitations, global unconventional gas resources are thought to be abundant, with total volumes in place estimated at more than 900 tcm (Table 11.3). How much of this gas may ultimately be recoverable is uncertain. Regions with few remaining conventional reserves and high dependence on imports – notably Europe and parts of Asia-Pacific – are the most likely to follow the North American lead in assessing and exploiting these resources.

10. Highlights are available at www.mines.edu/Potential-Gas-Committee-reports-unprecedented-increase-in-magnitude-of-U.S.-natural-gas-resource-base

**Table 11.3 • Global unconventional natural gas resources in place** (tcm)

| | Tight gas | Coalbed methane | Shale gas | Total |
|---|---|---|---|---|
| Middle East and North Africa | 23 | 0 | 72 | 95 |
| Sub-Saharan Africa | 22 | 1 | 8 | 31 |
| Former Soviet Union | 25 | 112 | 18 | 155 |
| Asia-Pacific | 51 | 49 | 174 | 274 |
| *Central Asia and China* | 10 | 34 | 100 | 144 |
| *OECD Pacific* | 20 | 13 | 65 | 99 |
| *South Asia* | 6 | 1 | 0 | 7 |
| *Other Asia-Pacific* | 16 | 0 | 9 | 24 |
| North America | 39 | 85 | 109 | 233 |
| Latin America | 37 | 1 | 60 | 98 |
| Europe | 12 | 8 | 16 | 35 |
| *Central and Eastern Europe* | 2 | 3 | 1 | 7 |
| *Western Europe* | 10 | 4 | 14 | 29 |
| **World** | **210** | **256** | **456** | **921** |

Sources: Rogner (1996); Kawata and Fujita (2001); Holditch (2006).

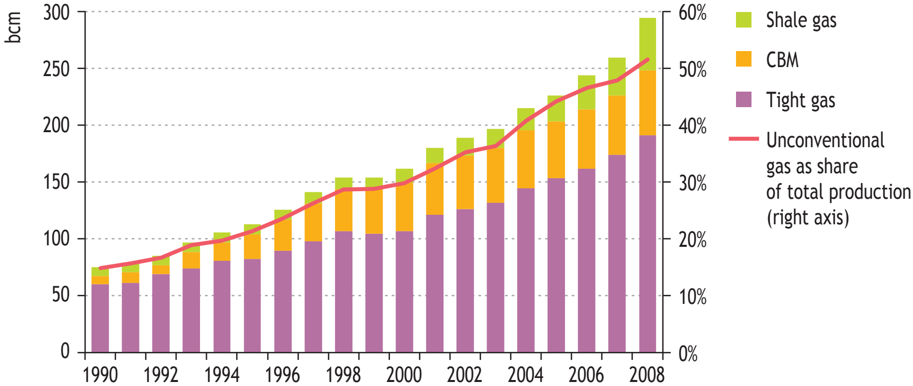
Combining the reasonably well-established estimate of remaining recoverable resources of conventional gas (Table 11.2) with a plausible estimate of recoverable portions of unconventional gas in place (Table 11.3) yields a grand total of some 785 tcm of remaining recoverable gas resources. The principal assumptions are that unconventional gas resources are technically and economically recoverable worldwide in fractions similar to those already demonstrated in North America, and that the assessment of global unconventional gas in place is not significantly overestimated. These combined resources are equal to 250 years of current production.



## Unconventional gas: characteristics and production technology

Although unconventional gas currently accounts for only 4% of the world total of proven gas reserves, it made up nearly 12% of global production in 2008. The United States accounted for three-quarters of global unconventional output, having expanded production nearly four-fold since 1990 to reach just under 300 billion cubic metres (bcm) (Figure 11.5), more than half of total US gas production. Canada was the next biggest producer at nearly 60 bcm, around one-third of its total gas output. Exploitation of unconventional resources is gathering momentum elsewhere as the experience gained is transmitted to other regions. Tight gas, CBM and shale gas resources have followed different routes from initial discovery to commercial exploitation, but the common factor has been the successful development and deployment of technologies that enable unconventional resources to be produced at costs similar to those of conventional gas.

**Figure 11.5 • Production of unconventional gas in the United States**




Source: Data provided from US Department of Energy/Energy Information Administration.

## Tight gas

Tight gas sands were originally defined, for fiscal purposes in the United States, as natural gas reservoirs with permeability (*i.e.* the ability for gas to flow through the rock) of less than a specific threshold (0.1 mD[11]). A working definition today might be a natural gas reservoir that cannot be developed profitably with conventional vertical wells, due to low flow rates. These reservoirs hold continuous accumulations of gas over large areas and, like conventional reservoirs, are found over wide ranges of depths, temperatures and pressures in many differing geological formations and contexts. Development of these resources is usually more challenging than development of conventional gas, requiring more detailed understanding and engineering to optimise the location, drilling and completion of wells. The key technology to increase gas flow rates is hydraulically fracturing (or cracking open) the productive formation in order to expose a large surface area of rock to facilitate gas flow into the wells.[12] This is usually done by pumping into the well large quantities of water, chemicals and sand at high pressure.

Tight gas sands have now been producing for more than 40 years in the United States, with new technologies constantly emerging and existing technologies evolving to improve production rates, quantities of gas recovered and financial returns. Significant quantities of tight gas are now being produced by national, international and independent oil and gas companies in more than ten countries around the world. Development of these resources was stimulated by the depletion of areas producing mature and higher grade resources. Canadian tight gas production has been rising rapidly and is expected to exceed 55 bcm in 2009. In other countries, tight gas production and reserve numbers are not generally reported separately from those of conventional sources.

11. Darcy and milliDarcy (mD) are units of permeability widely used in the oil and gas industry.

12. Hydraulic fracturing is used to increase production rates in many reservoir types, including conventional gas reservoirs.

The large number and geographic reach of oil and gas companies with experience and knowledge of tight gas projects, together with the almost worldwide availability of the necessary services and technologies, has facilitated exploitation of similar resources in other areas. This trend will continue as higher quality, conventional resources in other basins are depleted and the economics of the unconventional projects become more favourable. In the United States, the volume of reserves per well drilled has declined in recent years – evidence that some of the higher quality tight gas reserves have already been developed. This has stimulated both a more concentrated development of the best areas and a shift in the focus of drilling activity to other less-developed resources, notably shale gas (see below: Shale gas).

## Coalbed methane

Coalbed methane (CBM) is natural gas contained in coal beds. This gas is usually produced from coal that is either too deep or of too poor a quality to be mined commercially. Some gas is also produced (for safety and co-generation reasons) before coal is mined. CBM is produced in more than a dozen countries worldwide – notably the United States, Canada, Australia, India and China – using well drilling and completion technologies similar to those for conventional oil and gas production. Other countries, including Botswana, Chile, France, Indonesia, Italy, New Zealand, Poland, Russia, Ukraine, the United Kingdom and Vietnam, produce small quantities or are undertaking trials and pilot studies.

CBM resources are usually appraised with simple vertical wells, which can then be used to test various production methods. Hydraulic fracturing is a commonly used technique to improve production in less permeable beds and, in a few cases, horizontal and even multi-lateral wells[13] have been used to enhance productivity and optimise drainage of the reservoirs. Pumping water out of most coalbeds before gas production can begin – and treating and disposing of the resulting large quantities of waste water – are important cost and environmental factors in CBM production.

Commercial production of CBM in the United States started in the late 1980s and reached its current plateau of around 50 bcm, or 10% of total gas production, by 2004. Proven reserves continue to grow and amounted to 620 bcm, or 9% of total US gas reserves, at the beginning of 2008. Canada also has substantial CBM resources. Commercial production started in 2003 and is projected to exceed 8 bcm, or 4% of total gas production, in 2009. In Australia, CBM production has increased steadily over the last decade to reach 3.5 bcm, or 8% of total production, in 2008. CBM reserves doubled between 2005 and 2007, and almost doubled again in 2008: they now make up 9% of the country's total and over 40% of the onshore reserves. Both production and reserves are projected to continue their rapid growth in the near term as the eastern Australian gas market grows, conventional onshore production declines and plans advance to develop CBM as feedstock for liquefied natural gas (LNG) export.

After the United States, the largest proven coal reserves are found in China, Russia, India and Australia. Some experimental CBM projects are being conducted in Russia, but future commercial developments will have to compete with projects to develop

13. A well with more than one branch radiating out from the main borehole.

Russia's vast conventional gas reserves. China has made coal gas production one of the 16 major projects in the 11th Five-Year National Plan and has set a goal to produce 10 bcm annually by 2010. CBM production marketed in 2008 was 1.6 bcm – a fraction of China's total national gas output of 76 bcm. India continues to encourage CBM production, with new areas currently being auctioned. Appraisal and testing of appropriate development techniques are underway in the 26 blocks previously awarded and commercial production is beginning.

The location of some CBM resources in areas distant from existing gas pipeline infrastructure has led to different commercialisation models. These include direct use in locally constructed power stations, piping to direct residential and industrial customers, transportation as compressed natural gas (CNG) to both residential and transportation users (in India), and feed for future LNG export (in Australia). CBM production in areas that also have shale gas developments has tended to decline as the newer shale plays have, in many cases, proved to be more profitable.

### *Shale gas*

Shale gas is natural gas composed primarily of methane and contained in a commonly occurring, widespread rock loosely classified as shale. These formations are rich in organic matter and, unlike most hydrocarbon reservoirs, are typically both the source of the gas and its reservoir or storage-medium.[14] In oil and gas producing regions, any potential shale gas formations that overlie developed conventional reservoirs already have several wells drilled through them, so appraisal of the shale can start with interpretation of information from existing wells. Mature basins often have deep exploration wells that can also give information about potential underlying plays. As with other unconventional gas resources, production technologies have been adapted from those of conventional oil and gas developments.

Gas can be stored in shale by different mechanisms: within the pores of the rock, within a naturally occurring system of fractures, or adsorbed[15] onto the shale minerals and organic matter within the shale. Releasing the gas from the rock in commercial quantities requires the opening of a large surface area of rock, normally accomplished by massive hydraulic fracturing. For shale gas, these operations typically involve significantly more equipment and much larger volumes of fluid, pumped at higher pressures, than tight gas fracturing processes. Consequently, commercial development of shale gas depends on the availability of very large quantities of water for drilling and completing wells, and solutions to the economic and environmental challenges of treating and disposing of the waste water that is later produced with the gas. These factors, together with access to the resources, are vital to the development of a large-scale shale gas industry in many parts of the world.

14. Oil and gas developers have historically disregarded the potential resources in shale formations as they were widely considered either as source rocks or as seals of conventional reservoirs.

15. Adsorption refers to the formation of a thin film on the surface of a material.

**Box 11.3 ● *Shale gas production technology***

The key technologies that have been proven to work in all shale plays include the drilling of numerous long, horizontal wells from a single surface location and fracturing the rock at multiple intervals. The length of horizontal lateral sections varies from less than 1 000 m to over 2 000 m per well, and the number of fracture stages varies from 4 to 15. Different designs and processes need to be tested and adapted early in the development cycle in each play, and then be applied in a manufacturing style process across similar areas, incorporating improvements as they are discovered. Substantial productivity improvements have been documented in various plays, with operators able to increase initial production per well up to ten-fold in the trial stages of the first dozen or so wells in geologically similar areas.

Experimenting with technologies or production methods in one area or in one well has little or no influence on the resources and gas pressure in other areas of the play, due to the very low permeability. So long as the wells are not drilled too closely together or the fractures from adjacent wells do not intersect each other, each well effectively draws on its own small, independent reservoir. In this sense, gas production is akin to the extraction of a resource by mining. In conventional reservoirs, overall reservoir pressure is affected by the production rate from each well and wells interfere with each other if they are drilled too closely together, as they attempt to produce from overlapping resource volumes.

The shale[16] plays that have been appraised and developed so far vary widely in depth, thickness, mineral composition, richness in organic material and the amount of gas in place. The common properties shared by the plays include richness in organic material, maturity as petroleum (gas) source rocks, and sufficient brittleness to aid fracturing. Different technologies, particularly those used in the fracturing processes, are tried out and adapted in each play to optimise project economics. In most cases, drilling rigs capable of quickly drilling multiple, long horizontal wells from a single surface location, combined with large multi-stage fracturing treatments, can most economically open up the large surface areas of rock necessary to permit greater flow of gas.

Shale gas has an extremely long history. The first commercial well was drilled, to a depth of just 8 m, in New York in the late 1820s (Shirley, 2001) and in the early 20$^{th}$ century, the Devonian shale gas fields in the Appalachian Basin were the world's largest known gas fields. In the early 1980s, there were over 10 000 wells, producing a total of 3 bcm to 4 bcm per year, mainly from the Antrim shale in the US Midwest. These numbers continued to grow gradually until larger-scale developments commenced about a decade ago. The Barnett shale play in North Texas (around Fort Worth) was the first play that attracted significant development, after experimentation with newer technologies and well designs resulted in consistently higher well productivity.

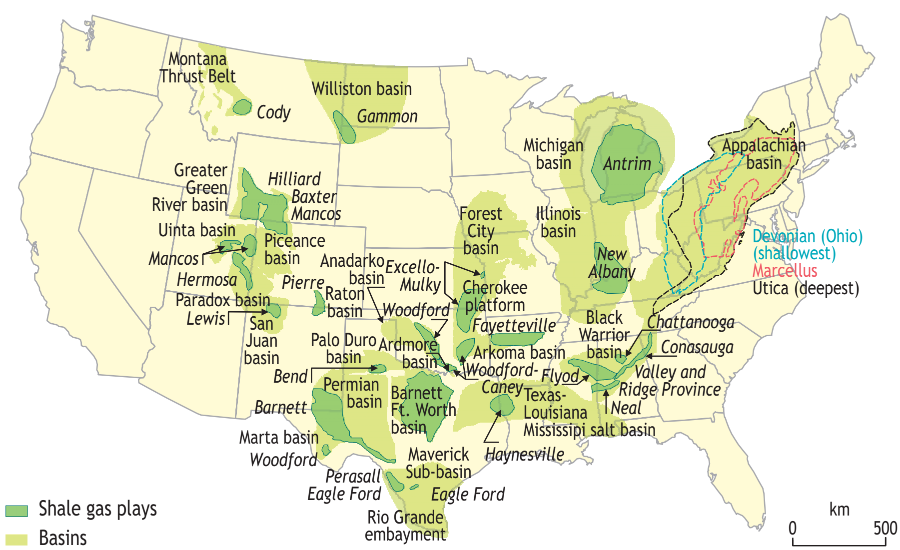
16. Few are true shale in its geological meaning; some are mudstones or siltstones, others include sand layers and other minerals, and some produce oil as well as gas. Note that these are not "oil shales", a term that refers to immature petroleum source shale, which contains kerogen rather than oil.

Drilling increased more than ten-fold there between 2000 and 2007, as more and more operators joined the rush. Activity spread quickly to other plays in North America in the four to five years to 2008, but falling gas prices and the deepening economic crisis in late 2008 caused many projects, particularly in more marginal areas, to slow down or stop.[17] US shale gas production reached nearly 50 bcm, or 8% of total gas output, in 2008 and proven reserves grew by 50% to over 600 bcm by the start of 2008. Canadian production has also risen and is expected to exceed 1 bcm in 2009. Today, there is commercial production in more than a dozen plays in the United States and Canada (Figure 11.6). Outside North America, shale gas production remains negligible.

A number of factors appear to be common to the successful development of shale gas plays. These include:

- Early identification of the location and potential of the best producing areas.
- Rapid leasing (at low cost) of large, prospective areas.
- Experimentation and adaptation of drilling and completion techniques, and development processes akin to those used in industrial manufacturing.
- Awareness and acceptance by local communities.
- Resolution of environmental issues related to fracturing and water use and disposal.
- Adequate local infrastructure (particularly transportation), as most equipment and supplies (particularly the vast quantities of water used and then disposed of) have to be trucked to and from the wells.

**Figure 11.6 • *United States shale gas plays***




The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Note: Devonian, Marcellus and Utica are stacked shale plays in the Appalachian basin.
Source: DOE/EIA (2009).

17. The largest declines were actually in conventional gas developments.

The initial experimentation and technology adaptation to develop shale gas plays was carried out largely by independent US oil and gas companies, with services and technology supplied by traditional oilfield service companies. Only recently have some of the major international and national oil companies become involved in shale gas production through partnerships, and by acquiring properties and smaller companies. This trend is likely to continue as limited access to credit affects more of the smaller operators in the United States (see Chapter 3) and as more of the larger companies assess more positively the future potential of larger plays elsewhere.

The boom in shale gas production in North America is prompting new studies of shale gas resources and prospects in other parts of the world. Prospective shale formations are widespread worldwide. In Europe, a research programme, Gas Shales in Europe (GASH), sponsored mainly by industry and co-ordinated by the German national laboratory for geosciences, was launched in May 2009 and will initially run for three years. It aims to compile a database of European black shale formations, conduct basic research on key elements of gas shale deposition, and understand factors critical to estimating resource potential. The main focus of the work is on assessing the volume of gas in place and the ability to produce profitably. Several upstream companies, including some of the leading international companies, are looking actively at shale gas prospects in Austria, France, Poland and Sweden. In South America, prospects in both Argentina and Chile are being reviewed. In Asia, ONGC (a state-owned Indian oil and gas company) has begun an assessment of the national availability of shale gas. Some wells to appraise shale gas prospects have been drilled in China. However, the scope and pace of this work do not indicate that a rapid global uptake of US experience is likely in the near term.

### *Focus on the Barnett shale: birthplace of the revolution*

The Newark East field in Northeast Texas – commonly referred to as the Barnett shale[18] – is the most developed shale gas play in the world. Approximately 44 bcm of gas was produced from more than 12 000 wells in the formation in 2008, with almost 3 000 more wells added during the year. Many of the wells were drilled in urban areas. At the peak of activity in 2008, there were more than 180 drilling rigs operating in the Barnett shale, equal to nearly 10% of all the active rigs in the United States and 5% of all the rigs operating worldwide.[19] Already in 2007, the development represented 8% of total economic activity in Northeast Texas (Perryman, 2008). At times the rate of drilling has outpaced that of the construction of pipelines to export gas, so wells in certain areas have had to be shut in. Horizontal wells now account for by far the most wells drilled (Figure 11.7). The intensity of fracturing per well has increased and more wells are being drilled from a single surface location.

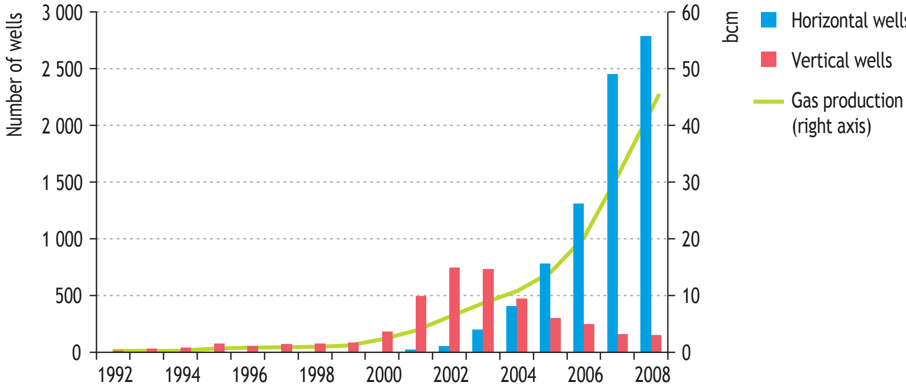
Nearly 200 companies are active in drilling in the play, but 80% of the production comes from the six largest operators. The total area that might be developed could extend to 13 000 km$^2$. While the magnitude of recoverable reserves is not yet known with certainty, the play has already earned a place in the list of the ten largest

18. Note that the same productive formation (the Barnett) is also present in other areas and fields.

19. According to the Baker Hughes rig count, a leading measure of drilling activity (www.bakerhughesdirect.com).

fields in the world, ranked by peak production (see Table 11.5 in the last section of this chapter). Production from this one field is equivalent to the total gas output of Argentina – the world's 19th-biggest producer.

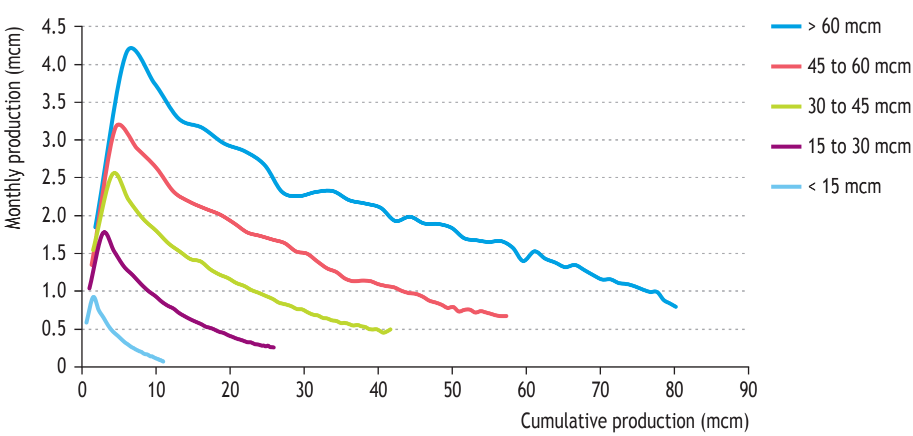
**Figure 11.7 • Barnett shale wells completed and gas production**




Source: Powell (2009).

In our detailed study of more than 7 000 Barnett shale wells, the production profiles were found to be remarkably similar (Figure 11.8). All wells, regardless of their productivity, exhibit an early peak of production and then a rapid decline – for both horizontal and vertical wells. The reasons for the differences in well productivity are reservoir quality at the location of each well (*i.e.* the quantity of gas in place) and the effectiveness of the completion process in maximising the area of contact with the reservoir rock. The variation in productivity from well to well is significantly greater than that usually encountered in conventional reservoirs.

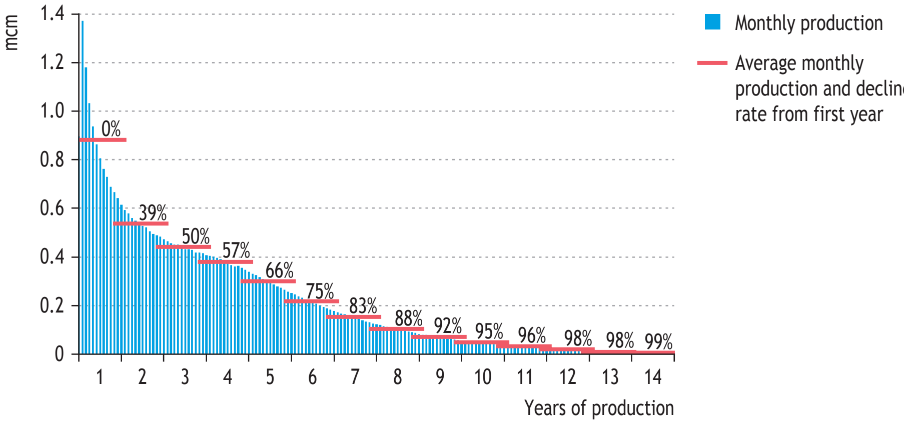
**Figure 11.8 • Gas production and recovery profiles of Barnett shale horizontal wells**




Source: IEA databases and analysis.

The production decline rates of the Barnett shale gas wells are much higher than those of most conventional gas wells. On average, weighted by production, horizontal Barnett wells have declined by 39% from the first to the second year of production and by 50% from the first to the third year (Figure 11.9). Decline rates tend to slow after several years but remain high, such that most of the recoverable gas is extracted after just a few years. Monthly production declines by 57% over the 12 months following the initial peak. Vertical wells have declined almost as rapidly: their annual rate of decline is 42% from the first to second year and 55% from the first to the third year.

**Figure 11.9 • Production decline rates for Barnett shale horizontal wells**

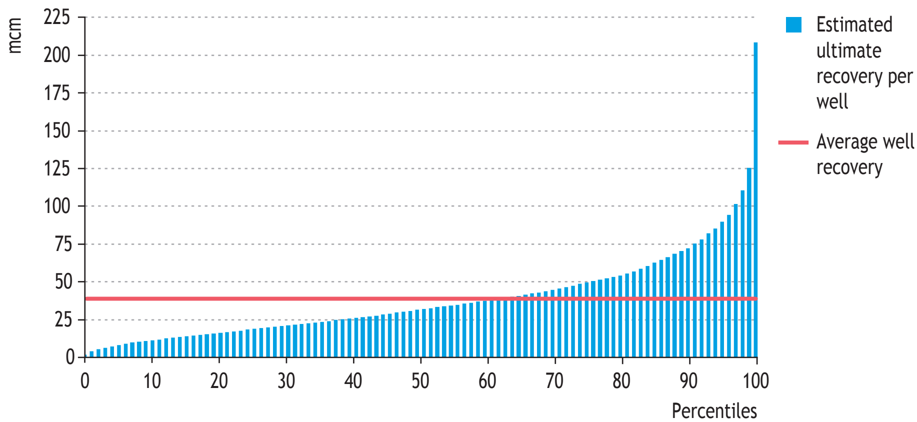



Source: IEA databases and analysis.

We have projected the ultimately recoverable resources per well drilled in the Barnett shale, based on historical production data. Average recovery per horizontal well is 38.6 million cubic metres (mcm), but the median is significantly lower, at 32 mcm; 60% of wells fall below the mean value (Figure 11.10). These calculations are based only on gas produced from the initial well completion, so the number is conservative as production may be boosted by fracturing new zones or re-fracturing existing zones. The distribution of ultimately recoverable resources for vertical wells is very similar, but with lower overall values: a mean of 20.7 mcm per well, with 60% of wells below the average. Although both figures vary markedly across wells, few wells that are drilled are dry.

A wide range in well-by-well production rates and recoverable resources characterises all shale plays and types of wells. This reflects differences in the amount of gas in place, the local geology of the formation, the lateral reach of the well, and the scale and effectiveness of fracturing done. The area with highest average production per well within a particular shale play is called the core area. Even within relatively small areas, production and recovery rates from individual wells can vary widely, reflecting significant variations in geology laterally over distances of a few tens of kilometres.

**Figure 11.10 • Projected ultimate recoverable resources of existing Barnett shale horizontal wells**



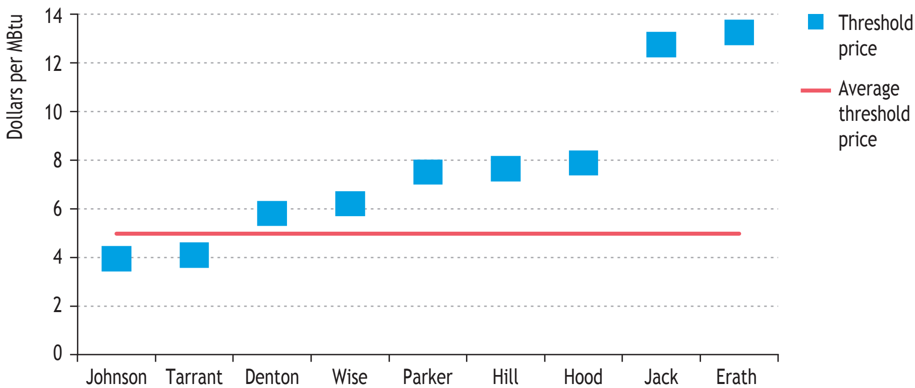

Source: IEA databases and analysis.

Production and estimated recovery rates per well have not improved significantly since the widespread adoption of horizontal wells in 2005. This is mainly because the play has been developed over an extensive region (including many less productive areas) by a large number of companies operating, initially, in an environment of high gas demand and prices – the "gold-rush" effect.

As a result of the wide range of recoverable resources and production rates for Barnett shale gas wells, their financial value, expressed in net present value (NPV) terms, varies substantially. We estimate the mean NPV for horizontal wells at $580 000 per well (based on 2008 drilling and operating costs, US fiscal costs, a 10% discount rate and a wellhead gas price of $6 per million Brithish thermal units [MBtu]). The median NPV, however is close to zero; in other words, half of the individual wells are unprofitable at $6/MBtu. Using similar assumptions, the mean NPV for vertical wells (costing less but recovering less gas) is less than $100 000, with a lower but similar distribution: 60% of individual wells are loss-making. The wide range of NPVs reflects differences in the productivity and resources across different geographical areas of the Barnett shale. The threshold gas price (at the wellhead) needed to yield a 10% return on capital ranges from $4/MBtu to over $13/MBtu across the main producing counties (Figure 11.11).[20] Not surprisingly, more than half of the horizontal production wells drilled to date have been in the two most productive counties, Johnson and Tarrant, and less than 2% have been drilled in the least productive counties, Jack and Erath.

20. These adjoining Texas counties each cover areas of roughly 2 500 km$^2$.

**Figure 11.11 • Threshold wellhead gas price needed to yield a 10% return on capital in the main producing counties of the Barnett shale**




Note: Assumes US fiscal costs; a discount rate of 10%; capital costs of $3 million per well; leasehold costs of $225 000 per well; a royalty rate of 12.5%; and operating expenses of $18 000 per mcm.

Sources: Powell (2009); IEA databases and analysis.

These threshold prices are averages over all operators in the counties: the range of values for smaller areas or for particular operators within these counties is wide and operators in more productive areas have managed to reduce their threshold prices to values much lower. Key to reducing production costs is experimentation with different well designs and completion processes in a given area, particularly the length of the horizontal section drilled per well and the number of stages fractured, together with their size, spacing and execution. By quickly discovering the designs and techniques that give better results in a specific area, applying them in subsequent wells and continually updating the standard practices used with results of other trials, operators have been able to improve their production and recovery rates, reduce unit costs and improve profitability.

11

### *Other North American shale gas plays*

The Barnett shale has attracted most drilling activity in recent years, but the focus of shale gas development is now shifting to other plays in North America, notably the Haynesville (on the border of Texas and Louisiana), the Fayetteville (in Arkansas) and the Marcellus shale (in the northeast of the country). There are many shale gas plays across the continent, widely spread geographically and covering huge areas. Those currently being appraised and developed have a range of characteristics that have been widely publicised but the effects of which on productivity and economics are still poorly understood. The physical and geological properties vary significantly from play to play (Table 11.4). There is also considerable variation of properties within plays. The economics of developing these resources – and shale plays in other parts of the world – hinge on improving our understanding of the relationship between these properties and productivity, and of the location within the plays of rock with better properties for production.

**Table 11.4 • Principal physical properties of the leading shale gas plays in North America**

| | Basin area (km²) | Depth (metres) | Thickness (metres) | Total organic carbon (weight %) | Thermal maturity (Ro %) | Gas in place (bcm/km²) |
|---|---|---|---|---|---|---|
| Barnett | 13 000 | 2000 - 2800 | 50 - 200 | 3.8 - 8.0 | 1.1 - 1.7 | 0.5 - 3.0 |
| Fayetteville | 23 000 | 300 - 2100 | 15 - 100 | 4.0 - 9.5 | 1.2 - 3.0 | 0.5 - 3.0 |
| Haynesville | 23 000 | 3200 - 4100 | 60 - 90 | 0.5 - 5.0 | 2.2 - 3.0 | 1.6 - 2.7 |
| Horn River | 39 000 | 2000 - 3000 | 150 - 175 | 0.5 - 10.0 | 2.8 - 3.8 | 1.4 - 2.5 |
| Marcellus | 250 000 | 1000 - 2600 | 15 - 75 | 1.0 - 12.0 | 0.6 - 3.0 | 0.2 - 1.1 |
| Montney | 11 000 | 900 - 3000 | 150 - 300 | 2.5 - 6.0 | 1.0 - 1.7 | 1.0 - 3.2 |
| Woodford | 28 000 | 1800 - 3300 | 15 - 70 | 1.0 - 14.0 | 1.1 - 3.0 | 0.4 - 1.3 |

Note: Data should only be used for general comparative purposes, as they have been compiled from multiple sources.

Sources: DOE (2009); *O&GJ* (2008); IEA databases and analysis.

A common characteristic of the North American shale gas plays is the relatively low concentration of resources, with gas in place ranging from 0.2 bcm/km$^2$ to 3.2 bcm/km$^2$. On the basis of the low recovery factors (ultimately recoverable resources divided by original gas in place) of up to 20% estimated to date, recoverable resources range from between 0.04 bcm/km$^2$ and 0.6 bcm/km$^2$. By comparison, the recoverable resoures of the world's largest conventional fields average about 2 bcm/km$^2$ and, in some cases, exceed 5 bcm/km$^2$. Shale plays cover much larger areas and require at least ten times the number of wells, drilled much more closely together, than those required to exploit conventional resources. This means that a much larger surface area is affected by drilling and production operations. Most shale gas developments have used well spacing of 16 hectares (Ha) to 65 Ha, but to improve recovery, some areas have been drilled with wells every 6 Ha to 8 Ha – equal to as many as 16 wells/km$^2$. Today, 20 to 40 wells are often drilled from a single surface location: it is clear that a technology breakthrough that further reduces the footprint would allow more plays to be developed, particularly in more densely populated or environmentally sensitive areas.

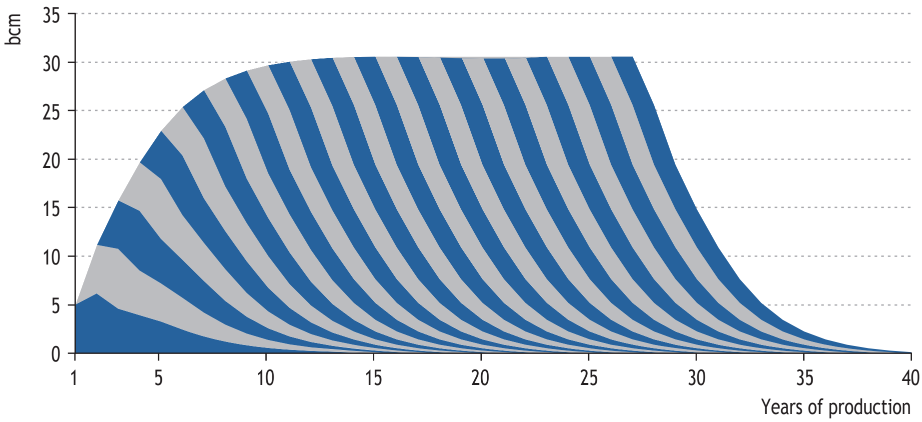
Another property that changes considerably from play to play is the pressure gradient of the gas; it varies from a normal, or water gradient, up to double that value in parts of some plays. Higher pressures lead to greater well productivity, so the increased costs of the generally deeper wells needed to exploit these plays is offset by increased gas recovery.

The economics of shale gas production vary somewhat less from play to play than the geological properties. We estimate that the threshold gas price (at the wellhead) needed to yield a 10% return on capital for the seven main plays[21] currently being

21. Barnett, Fayetteville, Haynesville, Horn River, Marcellus, Montney and Woodford.

developed in the United States and Canada[22] ranges from $3/MBtu to $6/MBtu.The lower figure corresponds to better quality areas of resource, exploited efficiently, while the higher thresholds are for average resource qualities, developed at higher costs.[23] Individual operations in smaller areas show wider variations, with mean values varying spatially within the plays, per well type, and with the effectiveness of the well drilling and completion operations. As operators have increased the total area leased in specific plays, lease costs and royalty rates have increased significantly, so the higher costs for latecomers would push their thresholds towards the upper end of the ranges.[24]

**Figure 11.12 • Hypothetical production profile of a new gas shale play, based on the typical profile of Barnett shale wells**




Notes: Assumes 800 wells drilled annually for 27 years. Coloured segments represent production from each vintage.

Analysis of the production profiles of Barnett shale wells provides pointers to how production at yet-to-be-developed shale plays in North America and elsewhere could evolve as a function of the number of wells drilled. By way of a hypothetical example, assuming a constant rate of drilling of 800 wells per year and no change in well designs and production characteristics, a new shale play would require seven years to reach plateau production[25] (Figure 11.12). Drilling must be maintained to sustain the plateau; were drilling to stop completely, production would fall to half of the plateau value in just three years. The relationship between investment, production and, therefore, cash flow is quite different from that of a conventional gas field development; with shale plays, most of the capital costs of drilling and completing individual wells are recovered within the first few years, but drilling must be maintained to sustain

22. For the purposes of this comparison, US fiscal costs have been utilised for all plays.

23. This could be due to capital costs, leasehold costs or royalty rates.

24. In some cases, leasehold costs up to $62 000/ha and royalty rates up to 25% have been publicised.

25. Defined as more than 85% of the peak sustained production level.

production. This implies that greenfield shale gas developments will tend to be less influenced by the risk of medium-term instability in both costs and prices. As a result, shale gas could play the role of swing gas producer, with production swinging up and down relatively rapidly in response to market signals.

### *Outlook for shale gas production costs*

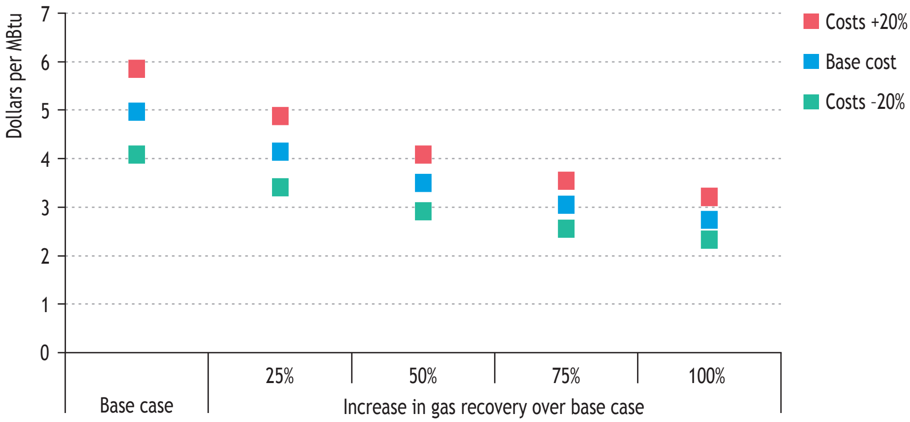
The main way in which shale gas production costs are likely to be driven lower is through improved technologies to locate areas of better quality resources (those to be developed first) and to help increase gas recovery from each well. Experience in the Barnett shale suggests that while the lowest average threshold values shown are close to $3/MBtu, companies in the most productive areas that have optimised their well designs and operations have been able to reduce this figure to closer to $2.50/MBtu. With continuing technological advances, it may be possible to reduce further the average costs at current drilling and completion rates. However, those rates are assumed to rise in the Reference Scenario, more than offsetting cost reductions through technology.

Current estimates of gas recovery vary from below 8% to up to 30% of gas in place — significantly less than the 60% to 80% range of conventional gas reservoirs. As noted above, improvements in recovery have already been made, with long horizontal wells drilled into rock fractured at multiple intervals. Advances in measurements and other technologies are being applied to increase the volume of rock from which gas can be produced by improving the effectiveness of the completion design and execution. For example, a 30% reduction in the threshold price could be obtained if average well recovery rates increase 50% for the same cost per well (Figure 11.13). However, the effect of technology may be offset by the rising costs of equipment, materials and services, and by stricter environmental regulations relating to the supply and disposal costs of water used for fracturing. Variations in total capital costs change threshold prices by approximately the same percentages.

Operators are already experimenting with different lengths of wells, different numbers and spacing of fractures, and different spacing between wells. Testing several well designs has allowed companies to improve the ratio of cost to initial production rates, in some cases by up to 40%. EnCana more than doubled the productivity of wells in the Montney shale by increasing their lengths and the number of intervals fractured, while at the same time reducing the cost per interval.[26] Although the best results come from testing and adapting technologies for each play, the speed of implementation has increased notably since the early days of Barnett. It took more than 20 years for the annual production capacity of Barnett to reach 5 bcm, but this was accomplished in just four years at the Fayetteville shale gas play. Exploitation has also been attempted of some deeper, thicker plays, with concentrations of gas in place up to five times that of the averages shown in Table 11.4 and above those of many conventional resources, but it has not yet proved possible to sustain production for long enough to be commercial.

26. According to information provided by the company to the IEA.

**Figure 11.13** ● *Sensitivity of threshold wellhead price to increases in gas recovery and variations in capital cost per well*

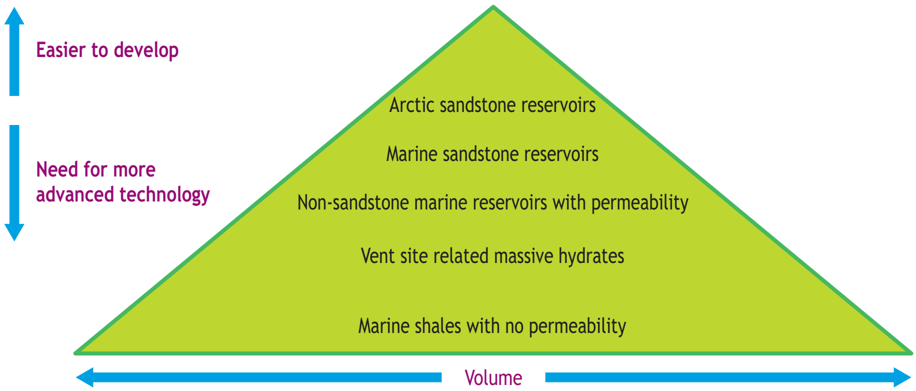



## Gas hydrates

Gas hydrates are another form of unconventional gas deposit. A gas or methane hydrate is an ice-like crystalline solid, formed from a mixture of water and natural gas. Hydrates are known to occur in shallow rock sediments in cold northern regions or in deepwater offshore sediments at low temperature and high pressure conditions, where they form physically stable structures. If either pressure or temperature conditions are altered so that hydrates move outside their envelope of stability, they dissociate into gas and water. The gas resource contained in hydrates is estimated to be larger than all other sources of natural gas combined, but most such gas is not commercially producible with today's technologies. The total volume of gas in place contained in hydrates worldwide has been estimated in various studies over the last 30 years, with figures decreasing as the knowledge of distribution and concentration of deposits has increased as a result of drilling programmes and measurements. One of the most recent studies (Milkov, 2004) estimates the total worldwide resource to be between 1 000 tcm and 5 000 tcm – still several times the volume of conventional gas reserves. The resource triangle (Figure 11.14) illustrates the categories of hydrates known today: those for which production is more likely to be feasible with technologies either currently available or easier to develop are closer to the top.

The US Arctic region has been assessed in most detail. The USGS estimates that there are 2.4 tcm of technically recoverable gas hydrates in northern Alaska alone (USGS, 2008a). This area of study has benefitted from data analysis of wells drilled through some hydrate deposits to access conventional oil and gas reservoirs below. A study of the Mackenzie Delta and Beaufort Sea region of Canada puts the hydrate resource in place at between 8.8 tcm and 10.2 tcm (CCA, 2008). Both these resources lie at the top of the triangle; it is in this category of deposits that short-term tests have been carried out, both in Canada and the United States, to investigate potential methods of production from these resources.

**Figure 11.14 • Gas hydrate resource triangle**




Source: Boswell and Collett (2006).

Marine hydrate deposits were initially inferred from seismic studies, in which certain signals from below the seabed and broadly parallel to it (known as bottom simulating reflectors) were thought to be indicative of hydrate layers. Wells drilled to confirm hydrate occurrence have shown that many such signals were due to other geological features and more advanced seismic techniques have since been employed. While this has reduced global estimates of marine hydrate gas in place, even the lower numbers are significantly larger than the total gas in place assessments of all conventional gas resources. Deepwater drilling programmes to locate hydrates and determine their properties have been carried out at several sites globally, with the most recent confirmation of hydrate resources being in the Gulf of Mexico, where the US Mineral Management Service estimates a mean of 600 tcm of gas hydrates in place (CRS, 2008). National research and development programmes for hydrate assessment and exploitation have been undertaken or are ongoing in several countries, including Canada, China, India, Japan, Korea and the United States.

To date, there has been no commercial production of methane hydrates, although some gas reservoirs in the Arctic produce conventional gas from rocks directly overlain by hydrate deposits. It is thought that in some cases the hydrates are dissociating and recharging the conventional reservoirs as pressure drops due to gas production. This is believed to be the case in both the Barrow Gas Fields in Alaska and the Messoyakha Field in Siberia (Grover, 2008). Hydrate resources of this kind are likely to be the easiest to exploit, as they present few new technical challenges. Short-term production tests from Arctic sandstone reservoirs have been carried out successfully in both Canada and the United States, and future tests are planned to investigate and demonstrate how commercial gas production could be sustained from these sources. These experiments could provide the insights and technology required to permit exploitation of Arctic hydrates, with initial development trials likely to be in more easily accessible deposits, in areas with existing oil and gas infrastructure. Marine hydrate deposits lower in the triangle still need to be better appraised, and offshore production is unlikely to occur before considerable understanding and experience has been gained from Arctic deposits in various geological settings. It is unlikely that exploitation of gas hydrates on any significant scale will occur before the end of the *Outlook* period.

## Exploitation of unconventional gas resources outside North America

The unconventional gas resource outside North America is unquestionably large, but the extent to which this potential will be exploited in practice is far from certain. Without question, the impact on gas supply and security could be dramatic. For example, unconventional resources in OECD Europe are large enough to displace 40 years of imports of gas at the current level, assuming recovery rates in line with those in North America. China and India are other countries with large estimated volumes of unconventional resources, the development of which could significantly reduce future dependence on imports. Our projections of gas production (set out in Chapter 12) point to rising unconventional gas production in these regions, especially after 2020, though the uncertainties surrounding these projections are large.

The consolidation of US gas producers, resulting from the current economic crisis, and the entry into shale gas exploitation of several companies with global experience will contribute to the spread of exploitation of these resources around the world. The large number of entrepreneurial companies that jump-started the development of shale gas in North America did so initially in a climate of intense competition to obtain and develop large holdings in the best plays, and of relatively high gas prices. This caused rapid cost inflation, particularly of leases and royalties, and resulted in development practices that were not optimised. Initial developments were in communities that were largely supportive of the industry because of the boost to the local economy, familiarity with the oil and gas business, relatively low population densities and, in some cases, the royalty and lease payments. Positive features of the initial activity included the rapid advance in knowledge resulting from the varied development approaches of numerous operators in different areas and types of play.



### Technology to exploit shale gas

The technologies that can contribute most to reducing unit costs of production are those that provide the capacity to drill quickly numerous, long horizontal wells from a single surface location and the ability to fracture massively multiple intervals along their horizontal lateral sections. To optimise project economics, adaptation of these basic methods to the characteristics of a specific play, or to an area within it, is the next critical step. In most cases, unit production costs have been significantly reduced by the construction of longer, more complex and more expensive wells in rock fractured in more numerous stages along the length of the wells. In some plays, the use of fluids more expensive than water as a base fracturing solution has been necessary to avoid reaction and swelling of the shale in contact with the fluids.

There is growing use of techniques, particularly microseismic monitoring of fracturing operations, to improve understanding of the geometry and effectiveness of the drainage system created in the rock, as these networks have been shown to be much more complex than those in more traditional rock types. Trials have been carried out of innovative well completion designs and hardware, and of multiple simultaneous fracturing of the rock from neighbouring wells. Understanding of methods to optimise the (sustained) production rate per unit cost is developing and evolving for these plays. Technology proven to date is suitable only for exploitation of onshore plays, as it relies on intense drilling and fracturing from closely spaced wells across the reservoir, and recovery of gas is still limited to around 20% of the original volume in place. Large variations of resource characteristics within the area of each play have been demonstrated, so resource appraisal to locate the more productive areas and adaptation of techniques to these areas must be undertaken prior to development. A trend to developing deeper, hotter and more highly pressurised plays has begun, requiring technologies capable of working in harsher conditions.

All these techniques are easily transferable to other regions, and service companies have equipment and personnel capable of providing the required services in most countries with oil or gas production. Rapid deployment could be assured by suitable contractual commitments, and sufficient operator demand could lead to these technologies becoming available in other regions at costs similar to those in North America.

Basic research and investigation into resource deposition and production mechanisms are still lacking and should, in due course, lead to alternative methods of reservoir identification and exploitation, since the successful production techniques currently utilised have been derived principally from empirical approaches. Assessment and appraisal of resources in other prospective regions is also essential before the potential scale of developments can be estimated.

### *Above-ground considerations*

The most important surface considerations affecting unconventional gas developments are access to the resources on a basis acceptable to local communities, and the availability of land for installations and of water in sufficient quantities for use in fracturing operations. The entry of an unfamiliar, invasive industry can be resisted by communities in many areas on grounds of concerns about the environment, increased use of local infrastructure and access-ways for pipelines. Although all developments use networks of pipes to collect and transport to market the gas produced, all other supplies and equipment are currently trucked to and from the work-sites. Lack of nearby facilities to treat and dispose of waste water has already slowed development and increased costs significantly in some North American plays.

Companies entering the unconventional plays in North America have needed large up-front investments to secure holdings at a time when resource quality and distribution is not well known. Additional capital needs to be invested to sustain drilling and completion of numerous wells across the play. The high initial production and rapid decline from each well means that most resources are recovered quickly, more than two-thirds within the first four years. This ensures early payback of investment per well and allows production to be increased rapidly with additional drilling activity. But when drilling and well maintenance are stopped, production falls rapidly.

SPOTLIGHT

**What might prevent the take-off of unconventional gas production worldwide?**

Although production of unconventional gas has expanded rapidly in North America over the last several years, and similar resources are known to be widely present worldwide, their exploitation will face severe barriers. The most likely obstacle to shale gas production elsewhere will be limitations on physical access to resources. Communities in areas with high population density, or in which land is owned in numerous small tracts, may be unwilling to accommodate drilling on a large scale because of the disruption it would cause and the increased demands on local infrastructure, in particular transport. Although significant steps have been taken in the United States both to limit the impact on local communities (including the use of specially modified, smaller, quieter equipment) and to gain acceptance through efforts in public relations and education, working in countries with little or no experience of onshore drilling may prove very difficult, especially if local communities perceive little direct benefit.

Environmental regulations may also be a major barrier to the development of shale gas resources. Shale gas drilling leaves a comparatively large and invasive footprint on the landscape, because of the nature of drilling operations and the large number of wells needed to produce a given volume of gas. The treatment and disposal of the large quantities of water required in the fracturing process may fall foul of environmental regulations, especially where contamination of ground water is a major concern, and will, in any case, represent a substantial operating cost. Access to sufficient water may also be a barrier, although technological progress is beginning to reduce the volume required. Obtaining environmental approval will be most difficult in ecologically sensitive areas, and the time and expenditure required to obtain licences and permits for drilling and related activities will complicate development projects.

The geological characteristics of resources that have yet to be properly appraised might also present serious technical and economic challenges to their development. Some geological basins in which the resources lie are relatively small and the resource concentrations could be low. The complexity and cost of drilling, and sufficient brittleness to facilitate fracturing, are critical aspects.

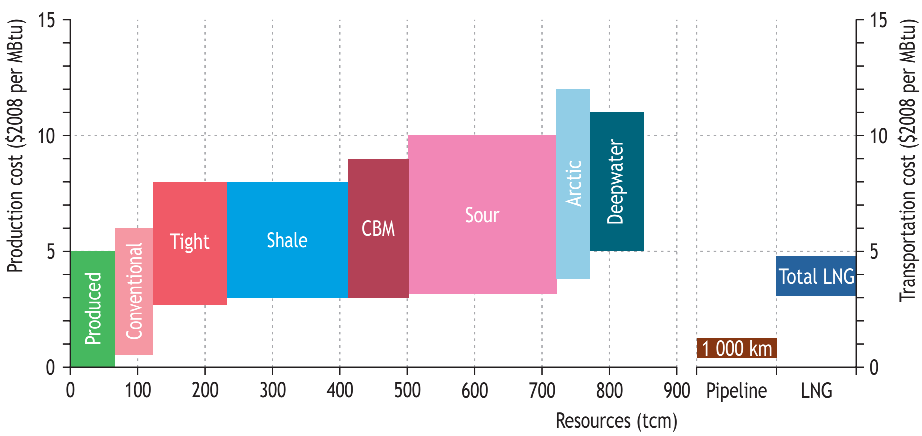
The proximity to existing pipeline infrastructure — a major driver behind the development of the industry in the United States — is another critical factor. The lack of adequate capacity in the vicinity of a shale gas play may discourage large-scale initial investment in developing the resources and prevent the industry from achieving the critical mass required to sustain investment over the longer term.

Those areas with existing oil and gas infrastructure, and in which mineral rights or exploitation licenses have already been obtained (possibly by operating companies originally interested in conventional resources at deeper or shallower horizons), are likely to be among the first to be developed. There have already been several cases of co-location or close proximity of different categories of gas resource (and corresponding surface infrastructure) in North America. Although the Barnett is the best known and currently the most developed of the US shale plays, it is neither the most productive nor has it been the most economical to develop. Total shale gas production in the United States could have been significantly higher if the same total number of wells had been drilled, but spread amongst the other more prolific plays.

## Long-term gas-supply cost curve

The blocks plotted in Figure 11.15 illustrate the potential long-term contributions to global gas supply from each of the various resources currently in commercial production, together with their range of production and transportation costs in 2008. Volumes are based on the latest estimates of resource potential. Gas hydrates have not been included, as commercial production has not yet been proven and they are not expected to contribute appreciably to supply in the period of this *Outlook*.

**Figure 11.15 • Long-term gas-supply cost curve**




Note: Areas indicate availability of gas resources as a function of estimated costs of production in 2008. Only sources with significant potential production before 2030 are included. These costs are based on the economics of gas production only, not taking into account the value or cost of any liquids production. However, some costs for associated gas production are shared with liquids production costs, thereby generally lowering overall costs for associated gas. Transportation costs are additional and apply to all resource types.

The total long-term potential gas resource base from these sources is estimated at approximately 850 tcm. Of this total, some 66 tcm have already been produced (and flared and vented) at costs of up to $5/MBtu. Production costs for associated gas would generally be lower than for non-associated gas, particularly in fields in which infrastructure for production of oil had already been installed before exploitation of the gas resource had been planned. Significant quantities of associated gas are still flared because the cost of treatment and transporting the gas make it unprofitable to market. More than 1.5 tcm has been flared worldwide in the last decade alone, equal to more than 5% of marketed production.

The most easily accessible part of the remaining conventional resources amounts to about 55 tcm, with typical production costs between $0.50/MBtu and $6/MBtu. Unconventional resources totalling 380 tcm (including 110 tcm tight gas, 180 tcm shale gas and 90 tcm CBM) could be produced at costs between $2.70/MBtu and $9/MBtu. Sour gas resources, with high concentrations[27] of hydrogen sulphide ($H_2S$) or carbon dioxide ($CO_2$), total some 220 tcm and could be produced at costs between $3.10/MBtu and $10/MBtu. Resources in the Arctic Circle could amount to 50 tcm, at costs between $3.80/MBtu and $12/MBtu. Deepwater[28] resources of 80 tcm could be produced at costs ranging from $5/MBtu to $11/MBtu.

Transport costs (Figure 11.15, lower right-hand corner) are $0.30/MBtu to $1.20/MBtu per 1 000 km of pipeline, varying for onshore and offshore segments and according to pipe capacity and installation age. Total LNG costs for liquefaction, transport and re-gasification vary from $3.10/MBtu to $4.70/MBtu, depending on the installation size and the transportation distances involved.

Gas is currently produced from all of these categories of resource. Factors determining the order and intensity of future resource exploitation include regional availability and accessibility, emerging technologies (which could alter their relative costs of production) and market dynamics. In some of North America's more mature basins, exploitation of more than one type of resource is now occurring simultaneously through wells specifically designed for this purpose.

## Special analysis of the production profiles of big gas fields



### The world's largest gas fields

World gas production is dominated by a relatively small number of very large fields – a degree of concentration that is even greater than for oilfields.[29] The rate of decline in production from these and other, smaller fields is a prime factor determining the amount of new capacity and investment needed to meet projected demand. Specially for this *Outlook*, we have compiled a database of the production history of super-giant, giant and large fields[30] in order to understand better the underlying production profiles and the rate of decline from gas fields once they have passed their production peak. The almost 600 fields included in our analysis cover all the main producing regions

27. $H_2S$ concentration above 100 parts per million and/or $CO_2$ concentration above 2%.
28. Located in water depths of more than 400 m.
29. See IEA (2008) for a detailed field-by-field analysis of oil production.
30. In this report, a super-giant is defined as a field with initial 2P (proven and probable) reserves of at least 1 tcm. A giant is defined as a field with initial 2P reserves of between 100 bcm and 1 tcm. A large field is defined as a field with initial 2P reserves of between 10 bcm and 100 bcm.

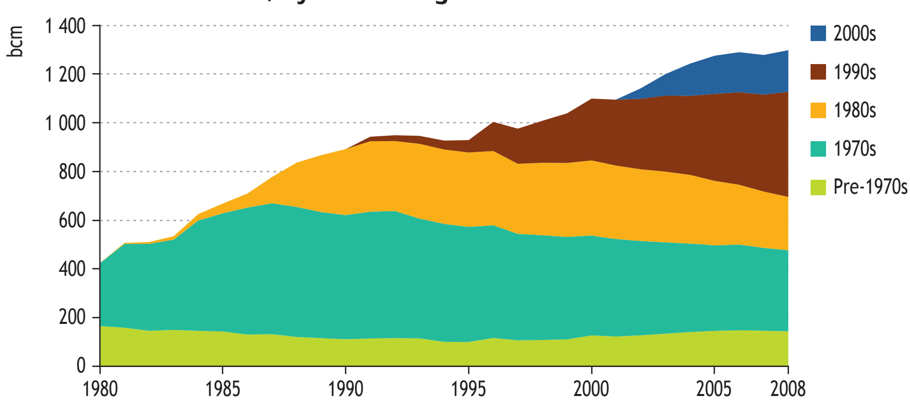
and account for more than half of global conventional gas production (Box 11.4). The outlook for production from these and other large fields is crucial. Our analysis of past and current production behaviour has allowed us to improve our projections of future field performance and hence of the need for additional gas field development and investment to safeguard future global gas supplies.

Our analysis reveals that fields developed during the 1990s, which are now mostly at plateau production, are currently the most productive, contributing one-third of the total production of all the fields in our database (Figure 11.16). Another one-third comes from fields initially developed before 1980. The fields in our database are projected to continue to supply more than one-third of the world's gas for the next decade and most will continue to produce significant volumes of gas far beyond that period.

### Box 11.4 • The IEA field-by-field gas production database

Our field-by-field analysis of gas production involved building a database containing the full production history and a range of technical parameters of most of the world's largest conventional gas fields – 587 in total. These fields account for 55% of current world conventional gas production and 45% of remaining proven reserves. The database contains, to the best of our knowledge, almost all of the world's super-giant fields and many of the giant fields already in production. A range of sources was used to compile the database, including IHS Energy, Cedigaz, official statistics published by the governments of gas-producing countries, and information provided directly by both national and international oil and gas companies. The absence of data in some countries, and differences across regions in definitions and reporting standards, restricted the total number of fields that could be included. Nevertheless, the analysis gives a robust picture of the current and future global supply base.

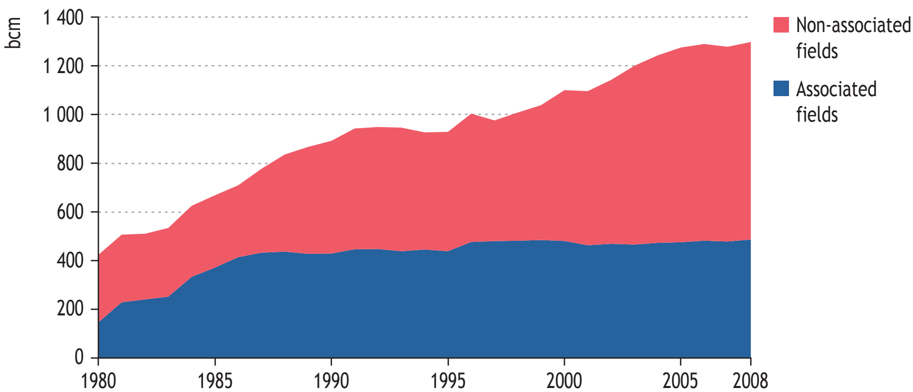
### Figure 11.16 • World gas production from selected super-giant and giant fields, by field vintage




Sources: IHS Energy databases; official national statistics and other industry sources; IEA database and analysis.

Although only 22% of worldwide conventional gas reserves are contained in associated fields, these sources accounted for 27% of the total conventional gas marketed in 2008. Additionally, some 17% of the total associated gas currently produced is flared because of the lack of infrastructure, market or technology to make economic use of it. Associated gas is often re-injected to maintain reservoir pressure and help maximise oil recovery during primary reservoir development phases. The production of associated gas frequently increases towards the end of a field's life. Detailed analysis of associated gas field behaviour is complicated by these factors. The share of total production from non-associated fields has been steadily increasing in recent years, as oil and gas companies increasingly explore for and develop such gas fields to meet rising gas demand (Figure 11.17).

**Figure 11.17** • ***Associated and non-associated gas production from selected super-giant and giant fields***




Sources: IHS Energy databases; official national statistics and other industry sources; IEA database and analysis.

11

The ten most prolific[31] conventional gas fields in our database (Table 11.5) still contribute 20% of global supply, though some were first developed in the 1960s. Production from these fields today is one-third less than the sum of their individual peaks. Four of the fields are in Russia and three are in the Middle East. Eight of the fields are situated principally on land; only the North Field and South Pars (by far the world's largest gas fields), which straddle Qatar and Iran, are (almost entirely) offshore. North Field/South Pars has so far only been partially developed and its peak annual production rates (to date) are below 0.4% of initial reserve volumes: these fields could continue to produce at these rates for over 300 years. On average, the other eight fields originally contained sufficient reserves to produce at peak rates for over 37 years. However, even plateau production rates[32] of 85% of the peak value are rarely sustained for more than 15 years, so actual field lives are significantly longer than this.

31. Defined as the fields with highest recorded levels of annually marketed production.

32. See Box 11.5.

Seven of the ten most prolific conventional gas fields are in the list of the world's ten largest fields ranked by initial volumes of proven reserves (Table 11.6). The other three super-giants in this list have yet to commence production. The ten fields with the largest reserves collectively contain more than one-third of the world's remaining proven reserves and the seven producing fields in this list together provided one-fifth of global supply in 2008.

**Table 11.5 • The world's biggest conventional gas fields by peak production**

| Field | Country | Discovered | Developed | Peak annual production (bcm) | Peak annual production (% reserves) | Reserves (tcm) |
|---|---|---|---|---|---|---|
| Urengoy | Russia | 1966 | 1976 | 299 | 2.9% | 10.2 |
| Yamburg | Russia | 1969 | 1983 | 177 | 2.9% | 6.1 |
| Zapolyarnoye | Russia | 1965 | 1999 | 103 | 2.9% | 3.5 |
| Groningen | Netherlands | 1959 | 1963 | 83 | 2.8% | 3.0 |
| North Field | Qatar | 1971 | 1988 | 75 | 0.3% | 28.0 |
| Medvezhye | Russia | 1967 | 1968 | 74 | 3.4% | 2.2 |
| Hassi R'Mel | Algeria | 1957 | 1961 | 69 | 2.2% | 3.1 |
| Ghawar | Saudi Arabia | 1948 | 1962 | 53 | 1.3% | 4.2 |
| South Pars | Iran | 1993 | 2002 | 49 | 0.4% | 14.0 |
| Dovletabad-Donmez | Turkmenistan | 1973 | 1980 | 39 | 2.8% | 1.4 |

Notes: Definitions and values reported by some sources differ; reserves are initial 2P estimates; peak production is the maximum annual production rate to date; peak annual production as % reserves is the peak rate as a percentage of the initial 2P values; development year is the first year of significant production. Ghawar is the world's largest oilfield and also contains sufficient natural gas reserves to be classified as a super-giant gas field - see Chapter 10 of last year's *Outlook* for a description (IEA, 2008).

Sources: IHS Energy databases; official national statistics and other industry sources; IEA database and analysis.

**Table 11.6 • The world's biggest conventional gas fields by initial reserves**

| Field | Country | Discovered | Developed | Reserves (tcm) |
|---|---|---|---|---|
| North Field | Qatar | 1971 | 1988 | 28.0 |
| South Pars | Iran | 1993 | 2002 | 14.0 |
| Urengoy | Russia | 1966 | 1976 | 10.2 |
| Yamburg | Russia | 1969 | 1983 | 6.1 |
| South Yolotan-Osman | Turkmenistan | 2006 | - | 6.0 |
| Bovanenkovskoye | Russia | 1971 | - | 4.4 |
| Ghawar | Saudi Arabia | 1948 | 1962 | 4.2 |
| Shtokman | Russia | 1988 | - | 3.8 |
| Zapolyarnoye | Russia | 1965 | 1999 | 3.5 |
| Hassi R'Mel | Algeria | 1957 | 1961 | 3.1 |

Notes: Definitions and values differ according to source; reserves are initial 2P estimates; development year is the first year of significant production. Ghawar is the world's largest oilfield and also contains sufficient natural gas reserves to be classified as a super-giant gas field — see Chapter 10 of last year's *Outlook* for a description (IEA, 2008).

Sources: IHS Energy databases; Cedigaz (2009); Official national statistics and other industry sources; IEA database and analysis.

**Box 11.5 ● *Defining field production profiles, plateaus and decline rates***

Applying a similar approach to that used for our field-by-field study of oil production in Chapter 10 of *WEO-2008*, the following definitions and methodology were used to calculate plateau production characteristics and decline rates of gas fields.

**Peak production** is the highest level of production recorded over a single year at a given field. **Plateau production** is when annual production is more than 85% of peak production.

A gas field is in **decline** when aggregate production in the latest year is below production in the peak year, even if production in the latest year is higher than it was at some time in the interim. A field is in the **post-plateau phase** when it has fallen below plateau.

The period of production decline after peak is broken down into phases for the purposes of measurement: **post-peak decline** is the decline rate in the period from peak annual production to the latest year of production (*i.e.* it encompasses the complete decline history of the field); **post-plateau decline** is the decline rate in the post-plateau phase, measured from the year at which output first falls below plateau to the latest year of production.

The **observed decline rate** is the cumulative average annual rate of change in observed production between two given years (for example, between peak production and the latest year). For the purposes of our decline rates calculations, we include only those fields with production in the latest year that is below the level of the first year of post-plateau production.

Unless otherwise mentioned, all the decline rates referred to here are **production-weighted.** In other words, the average for a particular group of fields (by type or size) takes into account the contribution of production from each field to total production, so that the results truly represent the overall production decline rate for the group of fields. Cumulative production over the full life of each field was used to weight decline rates.

Fields are classified into groups of similar sizes, locations and types with the aim of understanding and projecting production profiles of global gas supply and its principal components. Although decline rates per group obviously change if group definitions are modified,[33] combining results from all the groups gives the same overall result for the complete database.



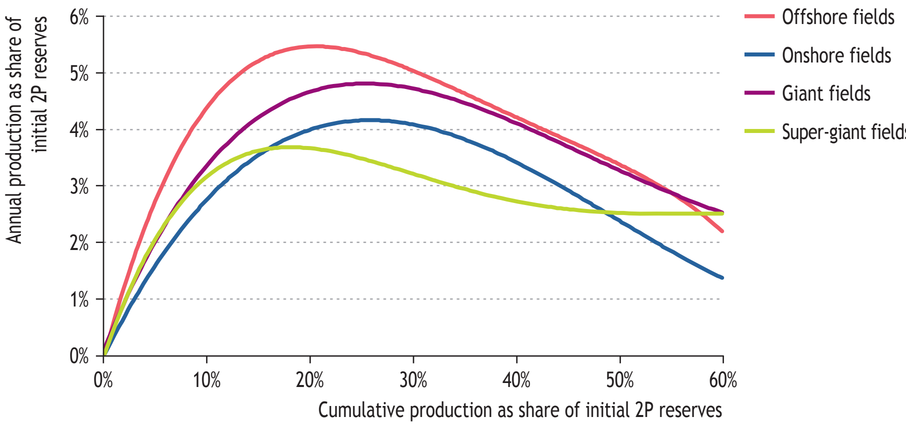
## Production profiles and decline rates

The production profiles of different types of gas fields depend on their technical characteristics, and on how they are developed and managed during their productive lives. Our analysis shows that the geological variables that most influence the shape

33. For example, if the minimum field size for a particular group is lowered to include additional smaller fields, the observed decline rates for the enlarged group increase.

of the production profile are field size (or volume of reserves) and whether the field is located on land or offshore (Figure 11.18). Additionally, the production profiles of associated fields are determined to a large extent by the oil production policies adopted.

**Figure 11.18 • Typical gas production profiles by category of field**




In general, larger fields maintain plateau production for longer periods than smaller ones and produce at lower rates, measured as a percentage of initial reserves. However, on average, all fields produce only about one-third of their initial reserve volumes during the plateau production phase. Production at offshore fields, compared to production at onshore fields of similar size, rises more rapidly to higher peak and plateau values, which are shorter lived but recover reserves more quickly (Table 11.7). Production profiles for associated gas fields are affected by field management processes to optimise recovery of both oil and gas reserves; as a result, associated fields plateau later and for a shorter time than non-associated fields. There are no significant differences between the plateau production profiles of sandstone or carbonate fields. The time to the first year of plateau production is, of course, highly dependant on the pace of the field development programme.

The observed post-peak decline rate averaged across all fields in our database on a production-weighted basis is 5.3% per year (Table 11.8). Decline rates are lowest for the largest fields: the super-giant fields average 4.1% per year, the giant fields 8.2% per year and the large fields 11.1% per year. Offshore fields decline at an average of 7.2% per year compared to just 5.2% for onshore fields. Post-plateau decline rates are generally higher than the post-peak rates although they are the same for the associated gas fields, which habitually produce larger gas volumes relative to oil at later stages of field life.

Direct comparisons of average post-peak decline rates can be distorted by the varying number of fields in each category at each stage of decline. To supplement the overall averages, we have also calculated decline rates by category of field from peak to end of plateau, from peak to 50% of peak, and from peak to the latest year of production.

Decline rates increase from the end of plateau to 50% of peak and, in most cases, then slow as production falls further. The effects of field size and location are again apparent at all stages of decline. Differences in production profiles with lithology and from one country or region of the world to another were found to be less significant than differences in average field sizes and whether the fields were located on land or offshore. Our database also contains numerous examples showing that decline rates can be slowed and even temporarily reversed with additional or continual investment.

**Table 11.7 ● *Plateau production characteristics by size, location and type of gas field***

| | Field type | Plateau production (% of reserves/year) | Plateau length (years) | Time to reach plateau (years) |
|---|---|---|---|---|
| Size | Super-giant | 3.0% | 9.8 | 9.7 |
| | Giant | 4.3% | 7.6 | 9.7 |
| | Large | 6.7% | 5.4 | 4.8 |
| Location | Onshore | 3.6% | 8.8 | 10.2 |
| | Offshore | 5.0% | 6.3 | 8.8 |
| Type | Associated | 3.5% | 7.8 | 12.8 |
| | Non-associated | 4.4% | 8.0 | 8.5 |
| Lithology | Carbonate | 4.0% | 8.5 | 12.2 |
| | Sandstone | 4.2% | 7.7 | 8.5 |

Notes: Results shown by location, type and lithology are for super-giant and giant fields.

**Table 11.8 ● *Production-weighted, average observed decline rates by size, location and type of gas field*** (%/year)

| | Field type | Post-peak | Post-plateau | Peak to end of plateau | Peak to 50% of peak | Peak to past 50% of peak |
|---|---|---|---|---|---|---|
| Size | Super-giant | 4.1 | 5.5 | 3.7 | 5.1 | 4.2 |
| | Giant | 8.2 | 9.4 | 6.1 | 8.1 | 8.6 |
| | Large | 11.1 | 13.7 | 10.5 | 13.8 | 11.4 |
| Location | Onshore | 5.2 | 6.7 | 4.2 | 5.9 | 5.4 |
| | Offshore | 7.2 | 6.5 | 7.0 | 8.7 | 7.0 |
| Type | Associated | 4.1 | 4.1 | 4.1 | 4.7 | 4.0 |
| | Non-associated | 6.3 | 8.3 | 4.8 | 7.5 | 7.5 |
| Lithology | Carbonate | 7.5 | 9.4 | 5.6 | 7.5 | 8.3 |
| | Sandstone | 4.9 | 6.2 | 4.3 | 5.9 | 5.2 |
| **Total** | | **5.3** | **6.7** | **4.5** | **6.2** | **5.8** |

Notes: Decline rates split by reservoir lithology are influenced by the relative difference of field sizes in each category. Peak to past 50% of peak decline rate is measured to the latest year of available production (for fields that have declined more than 50%).

Based on these figures and estimates of the size and age distribution of gas fields worldwide, we estimate that the global, production-weighted, decline rate is 7.5% for all post-peak fields. Taking account of fields that are not yet at plateau, we project that production from all existing fields (in production in 2008) will fall by more than 1 400 bcm between 2007 and 2030. The fall in production is equivalent to more than twice the annual production of Russia, the world's largest producer. This result is taken into account in the modelling of gas production and the calculation of upstream gas investment needs in the Reference and 450 Scenarios, the details of which are set out in the next two chapters.

# OUTLOOK FOR GAS SUPPLY AND INVESTMENT

## Feast and famine?

### H I G H L I G H T S

- In the Reference Scenario, non-OECD countries collectively account for almost all of the projected increase in global natural gas production between 2007 and 2030. The Middle East – with the largest reserves and lowest production costs – sees the biggest increase in absolute terms, though Eurasia remains the largest producing region and Russia the single biggest producer.
- The share of production worldwide from unconventional sources – mainly tight gas, coalbed methane and shale gas – expands from 12% in 2007 to almost 15% in 2030, with most of the increase coming from North America. The share of conventional output from non-associated fields grows less significantly, from 73% to 75%. Inter-regional gas trade is projected to grow substantially over the projection period, from 677 bcm in 2007 to around 1 070 bcm in 2030. OECD Europe and Asia-Pacific see their imports rise in volume terms.
- The outlook for gas trade is nonetheless significantly weaker than projected in last year's *Outlook* as a result of the recession, which has depressed demand, and strong production growth in North America, which reduces the region's import needs. Projected global demand points to significant under-utilisation of inter-regional pipeline and LNG capacity around the world, amounting to around 200 bcm by 2012-2015 between the main regions, up from only 60 bcm in 2007. This looming glut could have far-reaching effects on gas pricing.
- In the 450 Scenario, gas production in all regions and total inter-regional trade are markedly lower than in the Reference Scenario, especially after 2020. Output falls as a result of lower international prices, which discourage investment in exploration and development. Worldwide, output is 4% lower than in the Reference Scenario in 2015 and 17% lower in 2030. Imports are reduced most in volume terms in Europe, while exports fall most in Russia and the Middle East.
- Cumulative global gas investment along the supply chain in the Reference Scenario totals $5.1 trillion (in year-2008 dollars), or around $220 billion per year. Almost 60% is needed in exploration and development, 10% for LNG facilities and the rest for transmission and distribution. Total investment needs are 13% less in the 450 Scenario, because of lower demand and, therefore, capacity needs. The inexorable rise in upstream capital and operating costs that got underway in the early to mid-2000s has finally abated. Averaged across all regions, the annual inflation rate for capital costs declined from a peak of about 15% in 2006 to around 6% in 2008, based on the IEA Upstream Investment Cost Index. Costs are expected to fall by around 12% in 2009. In the longer term, costs are likely to rebound with higher oil and gas prices.

# Projected trends in natural gas production and trade

## Reference Scenario

### *Global and regional outlook*

The world's remaining resources of natural gas are unquestionably large enough to support the projected growth in global demand in the Reference Scenario to 2030 and probably well beyond, on condition that the necessary investment is made in supply infrastructure. Nonetheless, regional disparities in resource endowment and production costs will lead to shifts in regional supply patterns, with production of gas, like that of oil, set to become increasingly concentrated in the small number of countries with the largest resources. The proximity of reserves to markets, the level of production costs and geopolitical considerations will remain the main factors determining which countries benefit most from rising demand (Box 12.1). Transporting gas by pipeline or as liquefied natural gas (LNG) remains very expensive and usually represents a significant share of the overall cost of gas delivered to consumers. As a result, resource-rich countries located closest to the main centres of demand often enjoy a considerable cost advantage and, to the extent that production costs, geography and geopolitical considerations allow, are typically best-placed to profit from continuing demand growth in those markets.

**Box 12.1 ● *Modelling natural gas production and trade in WEO-2009***

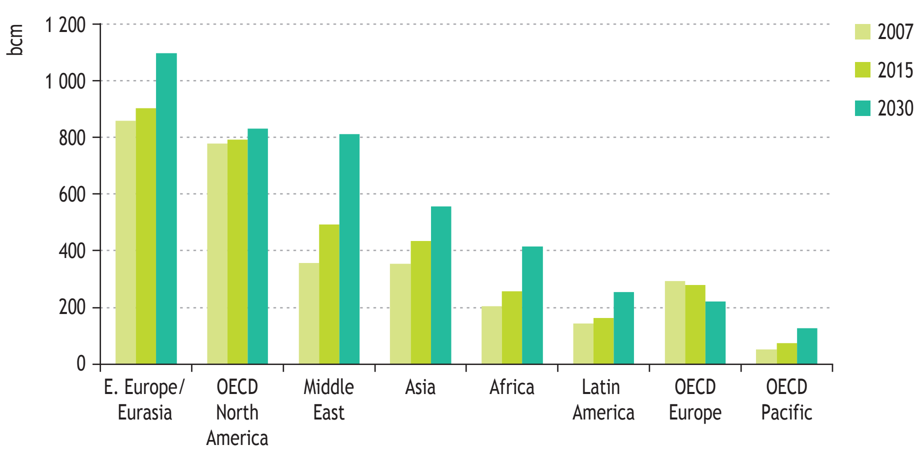
The gas production and trade projections in this *Outlook* are derived from a hybrid model involving bottom-up and top-down approaches. Indigenous production is first modelled by country for the main net gas-importing countries, on the basis of ultimate recoverable resources and depletion rates, taking account of country-specific production costs and prices in the region in which each country is situated. Subtracting domestic production from demand, in aggregate for each importing *WEO* region or country, yields gas import requirements. For each net gas-exporting region, aggregate production is determined by the level of domestic demand and the call on that region's exportable production (which is determined by the import needs of the net importing regions and supply costs).

Production within each region is then allocated to individual countries according to ultimately recoverable resources, depletion rates and relative supply costs. Production in all countries in the near and medium term is adjusted to take account of actual investment commitments and specific major development projects. Production in the longer term incorporates assumptions about major new projects affecting production directly or indirectly, taking account of institutional and geopolitical constraints.

Trade flows between net exporting and net importing regions are modelled on the basis of supply costs including exploration and development, processing, and transportation by pipeline or as LNG (in turn, a function of distance). The model takes account of the terms of existing long-term supply contracts, and of the LNG and pipeline projects under construction or assumed to be built during the projection period.

The non-OECD countries as a whole are projected to account for almost all of the projected increase in global natural gas production[1] between 2007 and 2030 (Figure 12.1). Consequently, their collective share of global production rises from 63% to 73%. Among the major *WEO* regions, the Middle East sees the biggest increase in absolute terms, its output jumping from 357 billion cubic metres (bcm) in 2007 (and an estimated 324 bcm in 2008) to over 810 bcm in 2030 (Table 12.1). That region holds the largest reserves and has the lowest production costs, especially when the gas is produced in association with oil. The bulk of the additional production is consumed locally, mainly in power stations, while the remainder is exported. By 2030, the Middle East accounts for 19% of world production, up from only 12% in 2007. The projected increase in Middle East gas output is nonetheless significantly less than that projected in last year's *Outlook*, as a result of a downward revision in the rate of global demand growth (resulting, in turn, from lower gross domestic product [GDP] growth in the near term) and, accordingly, a lower call on Middle East gas supplies. Africa, Central Asia, Latin America and Russia also see significant growth in production. Output in the OECD rises marginally over the projection period, with increases in North America and the Pacific more than offsetting decline in Europe, as North Sea resources are depleted. In fact, OECD Europe is the only major region to experience a decline in output between 2007 and 2030. All of the net increase in North American production is in the form of unconventional gas.

**Figure 12.1 ● *Natural gas production by region in the Reference Scenario***




Among the leading gas-producing countries, Qatar, Iran and Russia – the world's three largest reserve holders – see the biggest increases in output between 2007 and 2030 (Figure 12.2). Russia remains the world's largest gas producer throughout the projection period, ahead of the United States. Reversing the trend projected last year, US production is now projected to expand by over 60 bcm, or 12%, by 2030, reflecting a reappraisal of the prospects for unconventional gas production – notably shale gas

1. Marketed output, measured after purification and extraction of liquids. Reinjected, vented or flared volumes are not included.



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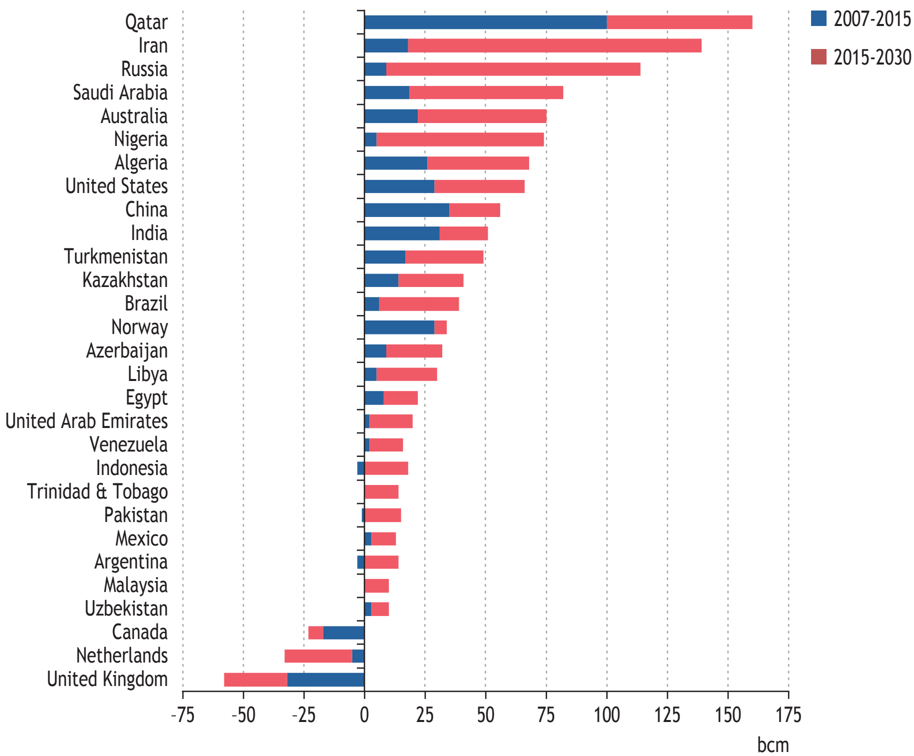
(see Chapter 11).[2] The United Kingdom, Canada and the Netherlands are the only major producers expected to experience a fall in output.[3] More details of production trends by region and country can be found in Chapter 13.

**Figure 12.2** ● ***Change in natural gas production by major country in the Reference Scenario***




These Reference Scenario projections show a 42% increase in global gas supply between 2007 and 2030. Our supply modelling incorporates assumptions about decline rates of fields already in production based on our detailed field-by-field analysis (see the last section of Chapter 11) together with assumptions about ongoing field developments, particularly of super-giants and major unconventional resources. Projected supply from all currently producing fields increases from 3 040 bcm in 2007 to 3 200 bcm in 2015 and then declines to 1 620 bcm in 2030. Additional capacity of more than 2 700 bcm is needed by 2030, therefore, to satisfy world demand of 4 310 bcm (Figure 12.3). This is equivalent to almost 90% of the total global production in 2007 and 63% of the 2030 level. Slightly more than half of the additional capacity is needed to offset the decrease in supply from existing fields and the remainder is required to meet the increase in global demand.

2. US production already increased by 42 bcm, or 8%, from 2007 to 2008.

3. Output in other European countries also declines, despite a rise in their unconventional output from almost zero today to around 15 bcm in 2030.

**Table 12.1 • Natural gas production by country/region in the Reference Scenario** (bcm)

| | 1980 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007-2030* |
|---|---|---|---|---|---|---|---|
| **OECD** | **889** | **1 124** | **1 146** | **1 183** | **1 179** | **1 181** | **0.2%** |
| North America | 657 | 777 | 791 | 819 | 829 | 831 | 0.3% |
| *Canada* | *78* | *184* | *166* | *175* | *167* | *160* | *-0.6%* |
| *Mexico* | *25* | *52* | *55* | *58* | *62* | *65* | *1.0%* |
| *United States* | *554* | *541* | *570* | *585* | *600* | *606* | *0.5%* |
| Europe | 219 | 294 | 279 | 260 | 239 | 222 | -1.2% |
| *Netherlands* | *96* | *76* | *71* | *64* | *52* | *43* | *-2.5%* |
| *Norway* | *26* | *92* | *120* | *127* | *129* | *126* | *1.4%* |
| *United Kingdom* | *37* | *76* | *44* | *31* | *23* | *19* | *-6.0%* |
| Pacific | 12 | 53 | 75 | 104 | 111 | 128 | 3.9% |
| *Australia* | *9* | *44* | *66* | *95* | *103* | *119* | *4.4%* |
| **Non-OECD** | **648** | **1 918** | **2 249** | **2 495** | **2 817** | **3 132** | **2.2%** |
| E. Europe/Eurasia | 480 | 858 | 903 | 958 | 1 023 | 1 097 | 1.1% |
| *Azerbaijan* | *n.a.* | *11* | *20* | *33* | *38* | *43* | *6.2%* |
| *Kazakhstan* | *n.a.* | *30* | *43* | *50* | *59* | *70* | *3.8%* |
| *Russia* | *n.a.* | *646* | *655* | *688* | *723* | *760* | *0.7%* |
| *Turkmenistan* | *n.a.* | *69* | *86* | *96* | *106* | *118* | *2.4%* |
| *Uzbekistan* | *n.a.* | *65* | *68* | *70* | *73* | *75* | *0.6%* |
| Asia | 70 | 354 | 434 | 480 | 529 | 555 | 2.0% |
| *China* | *14* | *69* | *104* | *127* | *136* | *125* | *2.6%* |
| *India* | *1* | *29* | *60* | *66* | *73* | *80* | *4.6%* |
| *Indonesia* | *17* | *74* | *71* | *73* | *82* | *88* | *0.8%* |
| *Malaysia* | *3* | *64* | *64* | *67* | *71* | *74* | *0.6%* |
| Middle East | 38 | 357 | 493 | 569 | 700 | 812 | 3.6% |
| *Iran* | *4* | *116* | *135* | *167* | *207* | *256* | *3.5%* |
| *Qatar* | *3* | *66* | *165* | *180* | *201* | *225* | *5.5%* |
| *Saudi Arabia* | *11* | *67* | *85* | *99* | *120* | *149* | *3.5%* |
| *United Arab Emirates* | *8* | *51* | *53* | *56* | *63* | *71* | *1.4%* |
| Africa | 23 | 206 | 257 | 303 | 352 | 414 | 3.1% |
| *Algeria* | *14* | *82* | *107* | *121* | *134* | *149* | *2.7%* |
| *Egypt* | *2* | *58* | *66* | *71* | *75* | *80* | *1.4%* |
| *Libya* | *5* | *16* | *22* | *28* | *36* | *47* | *4.7%* |
| *Nigeria* | *2* | *35* | *44* | *56* | *78* | *109* | *5.0%* |
| Latin America | 36 | 143 | 162 | 185 | 213 | 254 | 2.5% |
| *Brazil* | *1* | *11* | *17* | *23* | *35* | *49* | *6.8%* |
| *Trinidad & Tobago* | *3* | *34* | *34* | *38* | *43* | *48* | *1.5%* |
| *Venezuela* | *15* | *24* | *26* | *30* | *35* | *40* | *2.3%* |
| **World** | **1 536** | **3 042** | **3 395** | **3 678** | **3 996** | **4 313** | **1.5%** |
| *European Union* | *n.a.* | *214* | *167* | *139* | *116* | *103* | *-3.1%* |

* Compound average annual growth rate.

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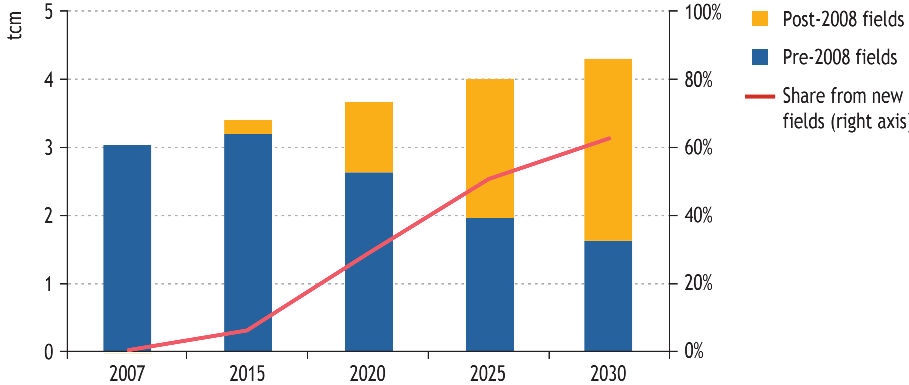
**Figure 12.3 • *World natural gas production by field vintage in the Reference Scenario***




Note: Field vintage refers to the first year of significant production.

## Gas production by type

The share of gas produced from unconventional sources – mainly coal beds (coalbed methane), low-permeability sandstone (tight gas) and shale formations (shale gas) – is projected to rise significantly in the Reference Scenario, from around 12% in 2007 to nearly 15% in 2030. In absolute terms, unconventional gas output rises from 367 bcm in 2007 to 629 bcm in 2030, with most of the increase coming from the United States. US output of all three types of unconventional gas has grown steadily in recent years, accounting today for just over half of total US gas production; this share is set to grow further over the projection period (see Chapter 13). Unconventional production in Canada is also growing strongly. In other parts of the world, unconventional gas production is still very small but it could expand rapidly in some regions. Output is projected to grow most in China, India, Australia and Europe, though the share of unconventional gas in total production in those regions remains small. This projection is subject to considerable uncertainty, especially after 2020, as unconventional resources have not yet been appraised in detail outside the United States. There is potential for output to increase much more.

An estimated 27% of all the conventional gas produced and marketed worldwide in 2008 was produced in association with oil[4] (23.5% of total gas production, including unconventional). The share of associated gas production is highest in the Middle East. Producing oil is usually much more profitable than producing gas, as oil is less costly to transport and sells at a higher price on a calorific value basis. Associated gas may be flared or vented where regulations allow and where it is uneconomic to process and transport it to market, or may be reinjected to enhance oil recovery. Just less than 150 bcm of associated gas, equivalent to almost 5% of total marketed gas, was flared in 2007, according to the World Bank – half of it in Russia, Nigeria and Iran alone (Table 12.2). The volume and share of flared gas has been falling in recent years as producing

4. Natural gas which is found or produced in association with crude oil either dissolved in the oil or as a cap of free gas above the oil in the reservoir.

countries, including Algeria, Iran, Nigeria, Russia and Venezuela, have stepped up efforts to market the gas, for economic and environmental reasons. This trend is expected to continue. The share of associated gas in total gas output is nonetheless expected to fall over the longer term as exploration and development focuses more on non-associated conventional resources (which make up about three-quarters of remaining gas resources) and the share of unconventional gas (which is predominately non-associated) increases. In the Reference Scenario, the share of associated gas drops to 25% of conventional output in 2030 (and 21% of total gas supply). The biggest increases in non-associated gas are projected to come from the Middle East.

**Figure 12.4 • World natural gas production by type in the Reference Scenario**

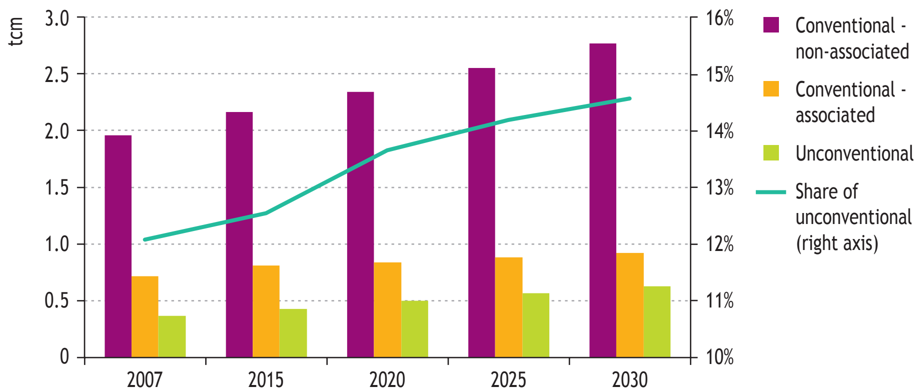



**Table 12.2 • Flared gas based on satellite data** (bcm)

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| Russia | 55.2 | 48.8 | 50.0 |
| Nigeria | 21.3 | 19.3 | 16.8 |
| Iran | 11.3 | 12.1 | 10.6 |
| Iraq | 7.1 | 7.4 | 7.0 |
| Kazakhstan | 5.8 | 6.0 | 5.3 |
| Algeria | 5.2 | 6.2 | 5.2 |
| Libya | 4.4 | 4.3 | 3.7 |
| Angola | 4.6 | 4.0 | 3.5 |
| Saudi Arabia | 3.0 | 3.3 | 3.4 |
| Qatar | 2.7 | 2.8 | 2.9 |
| Rest of the world | 41.0 | 43.0 | 39.0 |
| **World** | **161.6** | **157.2** | **147.4** |
| *Share of marketed output* | *5.6%* | *5.3%* | *4.8%* |

Source: World Bank Global Gas Flaring Reduction Partnership website (http://go.worldbank.org/NEBP6PEHS0).

In 2007, an estimated 81% of the natural gas produced globally came from onshore fields – a slightly lower share than for oil. This share is projected to fall to around three-quarters in 2030, as low-cost onshore resources are depleted and exploration and development shifts to less-developed offshore areas. Offshore fields account for around 40% of the world's remaining proven reserves. The share of offshore production is expected to grow in almost every region. The biggest increments to offshore production are expected to come from the Gulf of Mexico (United States and Mexico), Brazil, West Africa, Russia (where almost all current output is onshore) and the Arabian Gulf. A growing share of production is also expected to come from deepwater fields, notably in West Africa and Brazil, where large volumes of gas have recently been discovered in strata below salt deposits (pre-salt layers).

### *Outlook for inter-regional trade*

The geographical mismatch between natural gas resource endowment and rising demand points to a rapid expansion of international trade in the coming two decades. In the Reference Scenario, inter-regional gas trade (between all *WEO* regions) is projected to increase significantly over the projection period, from 677 bcm in 2007 to around 1 070 bcm in 2030 – an increase of 58% (Table 12.3). This compares with growth in production of 42%. Trade grows to 760 bcm already by 2015. OECD North America, OECD Europe and OECD Asia, together with some parts of developing Asia, see their imports rise, both in volume and (with the exception of OECD Asia) as a share of their total gas consumption. Nonetheless, the rate of growth in trade is less marked than in last year's *WEO*. This is because the downward revision to demand growth in the importing regions – especially Europe and North America – is bigger than the downward revision of production, resulting in less need to import gas to meet demand.

A striking result of this analysis is that by 2015 there could be significant under-utilisation of inter-regional transportation capacity around the world, based on our bottom-up assessment of ongoing investment and capacity additions from upstream, pipeline and LNG projects that are already under construction or are expected to proceed. The decisions to proceed with most of those projects were taken long before the full extent of the economic downturn became apparent. We estimate that the under-utilisation of inter-regional pipeline capacity (between the main regions) and LNG liquefaction capacity combined rises from around 60 bcm in 2007 to close to 200 bcm in the period 2012-2015 in the Reference Scenario. The utilisation rate of this capacity drops from 88% to less than three-quarters (Figure 12.6). This calculation (unlike the projections shown in Table 12.4 and Figure 12.9) assumes some delays in the commissioning of new liquefaction plants and pipelines, though longer delays are certainly possible (which would reduce the amount of spare capacity). The fall in capacity utilisation is likely to be most marked for pipelines; the owners of new LNG capacity are likely to be more willing to offer uncontracted supplies onto spot markets at whatever price is needed to find buyers, backing out gas that would otherwise have been traded internationally by pipeline (though the volume guarantees in long-term take-or-pay contracts will limit the extent to which buyers will be able to reduce their offtake of piped gas).

SPOTLIGHT

**Is peak gas on the horizon?**

In discussions of energy-resource depletion and rising production costs, most attention has been trained on oil and the timing of peak oil production. But what about natural gas? As a finite fossil resource, how imminent is the ultimate peak in gas production? As with oil, the answer depends as much on above-ground factors and their impact on price and investment, as on the quantity of recoverable resources in the ground.

No one doubts that remaining gas resources are very large (see Chapter 11). Conventional resources alone are big enough to last 130 years at current production rates. Were production to rise at the rate of 1.5% per year projected in our Reference Scenario, half of all resources (including gas flaring and venting) would still be left in 2050. But this calculation takes no account of unconventional resources, which are also very big. Estimates of remaining economically recoverable resources of coalbed methane, tight gas and shale gas range widely, but they could be as big as conventional resources (adding another 130 years of potential production at current rates). Even that does not include gas hydrates, a huge additional resource, a significant part of which may one day be technically and economically recoverable. Exploiting these unconventional resources could, in theory at least, push back peak gas by many decades.

But we do not live in a theoretical world. The real world is characterised by all manner of uncertainties and risks that generate substantial potential barriers to investment in exploring for, proving up and developing these resources. In short, just because the gas is there does not mean that it will be produced. Investment needs are set to rise in the coming years, both to meet rising demand and to make up for the loss of capacity through the decline of existing fields (equivalent to about half current global production or more than twice current Russian production by 2030). Upstream and downstream gas companies – both private and publicly owned – may not have the opportunity or the incentive to invest. This depends very much on host government policies, including licensing and fiscal arrangements, and the overall business climate. Uncertainty about future climate-change and other environmental policies adds to investment risk (see Part B). Moreover, logistical, practical and technical factors may constrain the ability of gas companies to launch major new projects in a timely way.

Demand-side factors will play as large a role in determining future gas-production trends as supply-side concerns. Peak gas implies peak *demand* as well as peak production. The primary driver in this respect is climate policy: the use of gas (and other fossil fuels) will need to peak much sooner than pure resource considerations would imply if we are to put the planet onto a sustainable energy path; for that to happen, governments around the world are going to need to take radical action. Whereas in the Reference Scenario, gas use continues to grow through to 2030, albeit at a decelerating rate, the peak of gas use is reached as early as 2025 in the 450 Scenario. So, though peak gas is not on the horizon just yet and the resource base remains large, a major change in the policy landscape could bring it quickly into view.

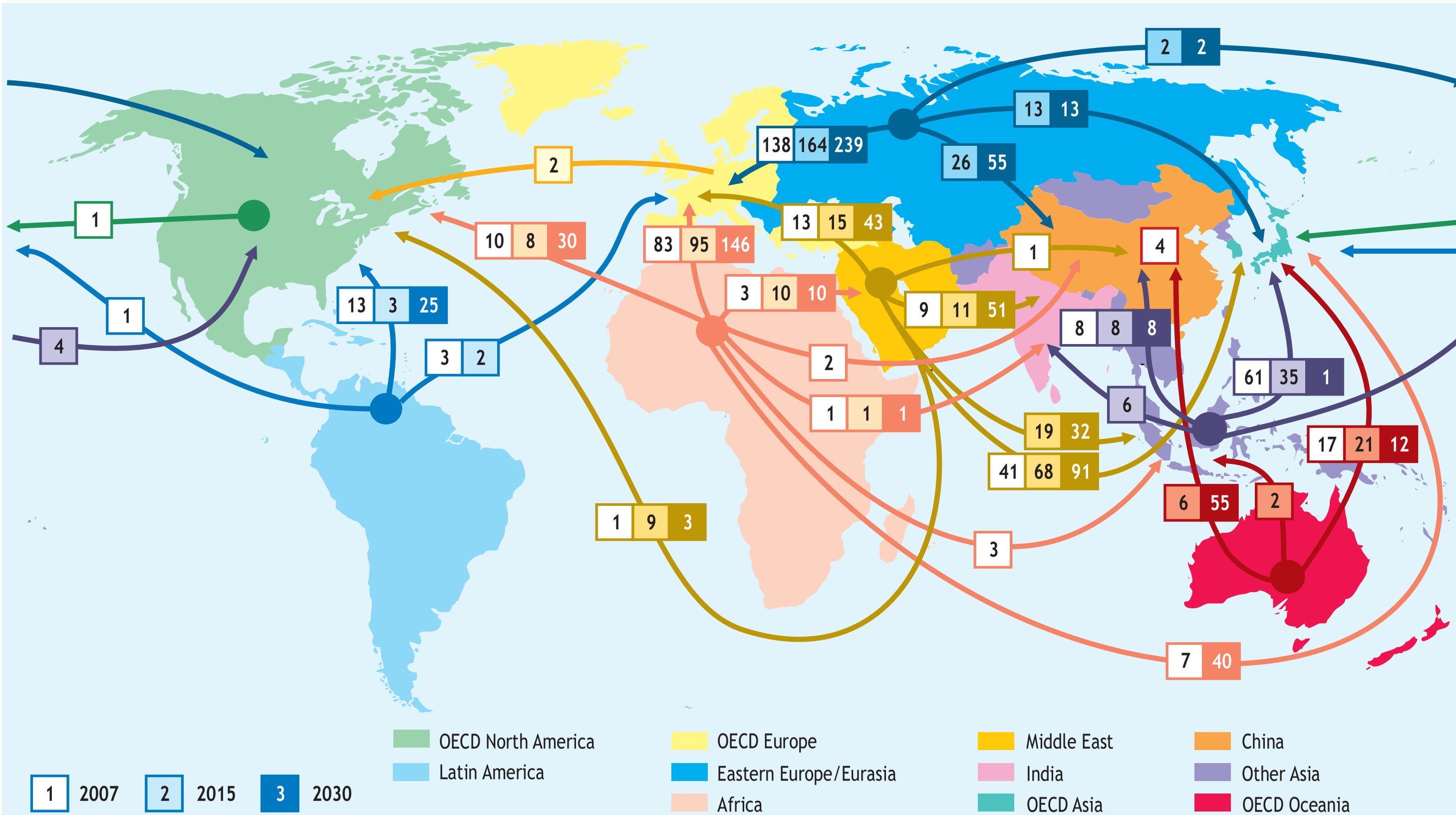
## Table 12.3 • Net inter-regional natural gas trade in the Reference Scenario

| | 2007 | | 2015 | | 2030 | |
|---|---|---|---|---|---|---|
| | bcm | % of primary demand* | bcm | % of primary demand* | bcm | % of primary demand* |
| **OECD** | **-402** | **26%** | **-409** | **26%** | **-579** | **33%** |
| North America | -36 | 4% | -27 | 3% | -61 | 7% |
| *United States* | *-114* | *17%* | *-65* | *10%* | *-43* | *7%* |
| Europe | -250 | 46% | -273 | 49% | -428 | 66% |
| Pacific | -117 | 69% | -109 | 59% | -91 | 42% |
| *OECD Asia* | *-131* | *97%* | *-138* | *97%* | *-157* | *97%* |
| *OECD Oceania* | *14* | *29%* | *29* | *41%* | *66* | *54%* |
| **Non-OECD** | **395** | **21%** | **408** | **18%** | **579** | **18%** |
| E. Europe/Eurasia | 176 | 21% | 204 | 23% | 309 | 28% |
| *Russia* | *193* | *30%* | *201* | *31%* | *260* | *34%* |
| Asia | 35 | 10% | -26 | 6% | -193 | 26% |
| *China* | *-4* | *5%* | *-39* | *27%* | *-117* | *48%* |
| *India* | *-10* | *26%* | *-18* | *23%* | *-52* | *40%* |
| Middle East | 63 | 18% | 113 | 23% | 210 | 26% |
| Africa | 105 | 51% | 113 | 44% | 228 | 55% |
| Latin America | 16 | 11% | 4 | 2% | 25 | 10% |
| **World**** | **677** | **22%** | **760** | **22%** | **1 069** | **25%** |
| *European Union* | *-312* | *59%* | *-365* | *69%* | *-516* | *83%* |

* Production for exporting regions. ** Total net exports.

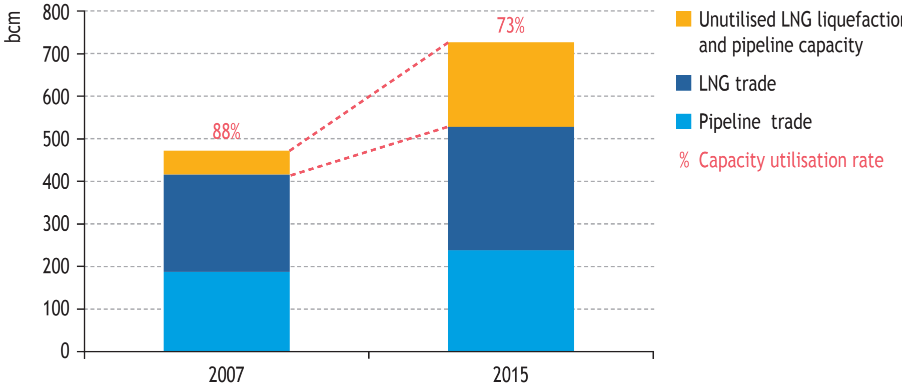
Note: Trade between *WEO* regions/countries only (some of which are not shown in this table), not including trade between countries within a *WEO* region. Positive figures denote exports; negative figures imports. The difference between OECD imports and non-OECD exports for 2007 is due to stock changes.

**Figure 12.5** • **Net inter-regional natural gas trade flows between major regions in the Reference Scenario, 2007, 2015 and 2030**
(bcm per year)




The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

**Figure 12.6** • **Transportation capacity between major regions in the Reference Scenario**




Note: Pipeline capacities are between main regions only (as per Figure 12.5), not between countries within a region.

The looming glut in gas-export capacity results from factors on both the supply and demand sides. Chief among these are an ongoing surge in LNG capacity coming on line and a dramatic improvement in the prospects for unconventional production in North America, on the one hand, and the unexpected severe slump in demand in 2008-2010 caused by the recession on the other. Investment in new pipelines from Russia to reduce transit through Ukraine is another factor. In the short term, at least, trade will not grow as quickly as most investors in new LNG and pipeline capacity originally expected (though the long-term outlook for trade remains strong). In fact, the current global economic recession explains almost all of the increase in spare capacity to 2015. Had global primary gas demand continued to grow at 2.7% per year over 2008-2010 – the average rate of growth over 2000-2007 – instead of falling by 1.5%, demand would have been about 300 bcm higher in 2015 than is now projected in the Reference Scenario. In that case, capacity would have been more highly utilised between 2007 and 2015, and fewer planned projects would have been delayed or cancelled.

The emergence of surplus capacity could have far-reaching consequences for the structure of the gas market. The much-reduced need for imports into the United States could lead to less connectivity between the major regional markets (North America, Europe and Asia-Pacific) in the coming years. Gas over-supply could also lead to a marked shift in the way gas is traded and priced. In particular, sliding spot prices for LNG are likely to increase the pressure on gas exporters and marketers in Europe and Asia-Pacific to move away from or to adjust the formal linkage between gas and oil prices in long-term contracts (see Chapter 14). The longer the gas glut lasts, the more that pressure will grow.

The emergence of a large overhang in transportation (and, therefore, production) capacity in the next few years assumes no change in pricing mechanisms. This is a major uncertainty. The major exporting countries may bend to pressure from importers to modify the pricing terms in their long-term contracts and may make available uncontracted supplies to the spot market, resulting in lower prices. This could boost the competitiveness of gas and help drive up demand, especially in power generation (in which some short-term switching capability exists and new gas-fired capacity could be brought on stream within three to four years). Were this to happen, under-utilisation of capacity in the medium term would be less than projected in the Reference Scenario.

In the longer term, inter-regional trade is expected to grow significantly, which could lead to a rebound in capacity utilisation rates (depending on future investment). The biggest increase in imports in volume terms over the projection period occurs in the European Union, where they rise (in net terms) from 312 bcm in 2007 to 365 bcm in 2015 and around 516 bcm in 2030. By 2030, imports account for 83% of EU gas consumption, compared with 59% at present.[5] Most of the additional gas imports come from Russia, Africa, the Middle East and the Caspian/Central Asian region (Figure 12.5 above). North America remains almost self-sufficient in gas, with only small volumes of LNG (relative to the size of the overall market) being imported into Mexico and the United States (Canada continues to export to the United States, though volumes decline progressively). This is a major revision to last year's projection, the result of both weaker demand prospects and a rosier outlook for production (thanks mainly to shale gas). The absence of a significant rise in LNG imports into North America would reduce the degree to which prices would converge among regional gas markets.

Net imports into OECD Asia (Japan and Korea), which is already almost completely reliant on imports to meet its gas needs, rise from 131 bcm in 2007 to almost 140 bcm in 2015 and over 155 bcm in 2030. Incremental supplies come from non-OECD Asian countries, the Middle East, Australia and Russia (Sakhalin). Developing Asia as a whole, currently a net exporter, becomes a major gas importer over the projection period. China's gas imports – LNG and piped gas from Turkmenistan and Russia – increase sharply, covering just under half of the country's gas needs in 2030. Supplies from Turkmenistan are due to begin in 2010, once the first phase of a new pipeline into western China is completed, while imports from Russia are projected to begin after 2020, on the assumption that a long-discussed pipeline from Eastern Siberia is built by then. China's imports from Russia and Central Asia combined reach 55 bcm in 2030. Imports into India grow more modestly, with most of the country's rising gas needs being met by indigenous supplies; nonetheless, imports reach 18 bcm in 2015 and around 50 bcm in 2030, accounting for 39% of total consumption, compared with just over one-quarter now.



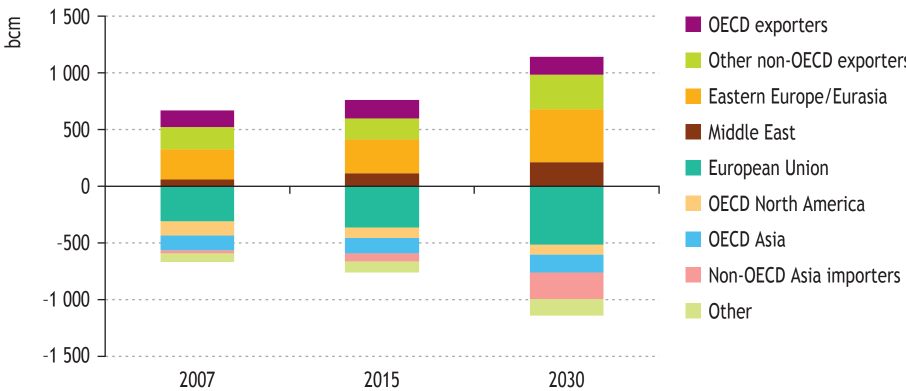
The bulk of the increase in exports worldwide is projected to come from Russia and the Caspian region (Eastern Europe/Eurasia), the Middle East and Africa. Russia, which sees its net exports rise from 193 bcm in 2007 to 260 bcm in 2030, remains far and away the biggest single gas-exporting country (Figure 12.7). Eurasian net exports in total almost double to 310 bcm by 2030, destined mainly for Europe and China. Apart from exports from the Sakhalin project, all exports from Russia and the Caspian/Central Asia are via pipeline.[6] Middle East gas exports jump by 150 bcm, to reach

5. See Chapter 2 for a discussion of the energy-security implications of this trend.

6. Gazprom, the dominant Russian gas company, plans to export LNG from Yamal or from the Shtokman field in the Barents Sea. But our projections assume that all incremental exports from Russia over the *Outlook* period, other than from Sakhalin, are by pipeline, on the grounds that the cost of supplying LNG would be too high to compete effectively with other supply options (see the discussion of supply costs to Europe in Chapter 13).

210 bcm in 2030, with Qatar expected to continue to account for the bulk of the region's exports. Most Middle East exports are in the form of LNG. Iran is assumed to become an LNG exporter by around 2020. Africa's exports rise from 105 bcm now to around 230 bcm by 2030, with most of the increase coming after 2015. Most of the increase in exports is destined for Europe, already the main market for African gas exports. Most of the growth in exports is as LNG, though pipeline exports to Europe also rise modestly. Africa also begins to export small volumes to the Middle East from Egypt via the Arab Gas Pipeline.

**Figure 12.7 • *Inter-regional natural gas exports and imports by producing and importing region in the Reference Scenario***

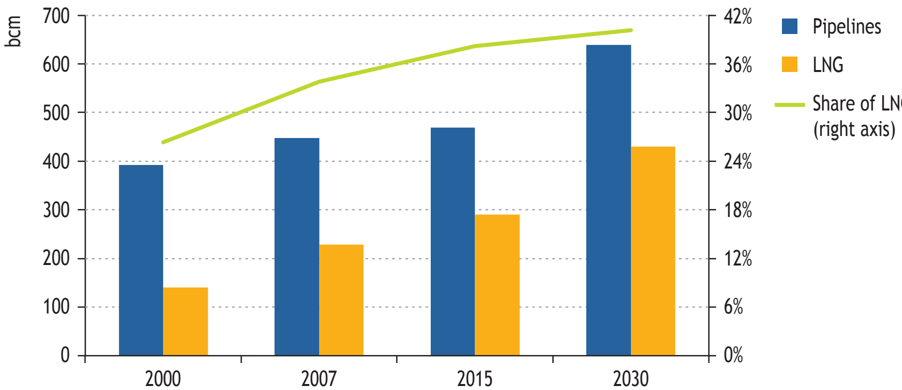



Note: LNG trade is between the 24 regions modelled in this *Outlook* and does not include international trade within each region (which is small on a global scale). Positive figures denote exports; negative figures imports.

With rising LNG exports from the Middle East, Africa, Australia and Latin America, the share of LNG in world inter-regional gas trade continues to grow, from around 34% in 2007 to 38% in 2015 and 40% in 2030 (Figure 12.8). The total volume of LNG traded rises by 27% by 2015 and almost doubles by 2030, though this is still markedly less than projected in *WEO-2008*. Pipeline trade increases less rapidly, by 5% by 2015 and 43% by 2030. LNG is usually the cheaper option for distances of more than about 4 000 km (compared with a 20 bcm/year pipeline) and is often the only practical option between continents because of the difficulties in laying long-distance pipelines along the sea-bed. In some cases, geopolitical factors also favour LNG over long-distance pipelines.

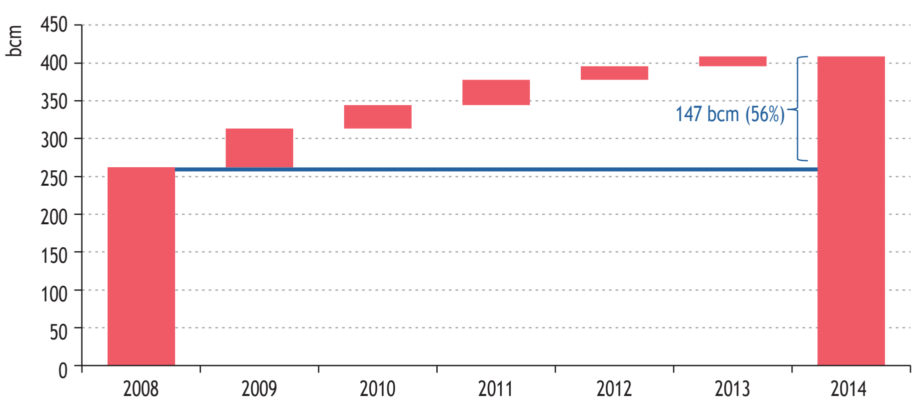
The LNG business is in the midst of an unprecedented period of expansion, with a number of liquefaction plants – many of them the largest ever built – due to be commissioned in the next few years. Some 147 bcm/year (107 million tonnes per year [Mt/year]) of liquefaction capacity is currently under construction, including plants that were officially commissioned in 2008 but were not yet operating at full capacity in early 2009 (Table 12.4). All this capacity is due to be commissioned by 2013, pushing up total capacity from 262 bcm at end-2008 to over 400 bcm/year by 2014 – an increase of 56%. Capacity is set to come on stream in steady increments, with the biggest gross additions coming in 2009 and 2011 (Figure 12.9). Eleven countries have plants under construction. Qatar accounts for around half of the total capacity being built, with six 7.8 Mt/year mega-trains due to be commissioned between 2009 and 2011 (Table 12.5). Russia began exporting LNG in 2009, while Angola, Peru and Yemen will enter the ranks of LNG exporters for the first time in the near future.

**Figure 12.8 • World inter-regional natural gas trade by type in the Reference Scenario**




Note: Trade is between all 24 regions modelled in this *Outlook* (excluding the ASEAN-4 countries) and does not include international trade within each region.

**Figure 12.9 • Natural gas liquefaction capacity in operation and under construction** (peak capacity and date when first production due)




Note: Existing capacity does not include capacity commissioned in 2008 that was not then operated at full capacity. Capacity under construction and due to be commissioned in 2010-2014 includes capacity additions due to de-bottlenecking, but does not take into account possible delays in completing and commissioning new plants.

Source: IEA databases.

**Table 12.4 • Natural gas liquefaction capacity** (bcm/year)

| | Capacity end-2008* | Capacity under construction** | Projected total capacity*** | | | | |
|---|---|---|---|---|---|---|---|
| | | | 2009 | 2010 | 2011 | 2012 | 2013 |
| **OECD** | **28** | **13** | **34** | **34** | **41** | **41** | **41** |
| Australia | 21 | 13 | 27 | 27 | 34 | 34 | 34 |
| Norway | 5 | - | 5 | 5 | 5 | 5 | 5 |
| United States | 2 | - | 2 | 2 | 2 | 2 | 2 |
| **Non-OECD** | **234** | **134** | **279** | **310** | **337** | **355** | **368** |
| Algeria | 28 | 13 | 28 | 28 | 28 | 28 | 41 |
| Angola | - | 7 | 0 | 0 | 0 | 7 | 7 |
| Brunei | 10 | - | 10 | 10 | 10 | 10 | 10 |
| Egypt | 16 | - | 16 | 16 | 16 | 16 | 16 |
| Equatorial Guinea | 1 | 3 | 4 | 4 | 4 | 4 | 4 |
| Indonesia | 38 | 10 | 42 | 48 | 48 | 48 | 48 |
| Libya | 1 | - | 1 | 1 | 1 | 1 | 1 |
| Malaysia | 31 | 2 | 33 | 33 | 33 | 33 | 33 |
| Nigeria | 25 | 6 | 31 | 31 | 31 | 31 | 31 |
| Oman | 15 | - | 15 | 15 | 15 | 15 | 15 |
| Peru | - | 6 | - | - | 6 | 6 | 6 |
| Qatar | 40 | 65 | 60 | 73 | 94 | 105 | 105 |
| Russia | - | 13 | 7 | 13 | 13 | 13 | 13 |
| Trinidad and Tobago | 21 | - | 21 | 21 | 21 | 21 | 21 |
| United Arab Emirates | 8 | - | 8 | 8 | 8 | 8 | 8 |
| Yemen | - | 9 | 3 | 9 | 9 | 9 | 9 |
| **World** | **262** | **147** | **313** | **344** | **378** | **396** | **409** |
| *OPEC* | *141* | *101* | *170* | *189* | *210* | *228* | *241* |

* Does not include capacity commissioned in 2008 that was not then operated at full capacity. ** Includes capacity commissioned in 2008 that was not yet operated at full capacity and capacity additions by de-bottlenecking. *** At end-year; excludes planned and proposed capacity; does not take into account possible delays in completing and commissioning new plants.

Source: IEA databases.

**Table 12.5** ● *Natural gas liquefaction capacity to be commissioned in 2009-2013*

| Country | Project | Operator | Capacity | | Scheduled start-up date |
|---|---|---|---|---|---|
| | | | Mt/year | bcm/year | |
| Algeria | Arzew 3 | Sonatrach | 4.7 | 6.4 | 2013 |
| | Skikda | Sonatrach | 4.5 | 6.1 | 2013 |
| Angola | Angola LNG | Chevron | 5.2 | 7.1 | 2012 |
| Australia | Pluto 1 | Woodside | 4.8 | 6.5 | 2011 |
| Indonesia | Tangguh 1 | BP | 3.8 | 5.2 | 2009 |
| | Tangguh 2 | BP | 3.8 | 5.2 | 2009 |
| Malaysia | Dua de-bottlenecking | Petronas | 1.3 | 1.8 | 2009 |
| Peru | Peru LNG | Hunt Oil | 4.4 | 6.0 | 2010 |
| Qatar | Rasgas 3-1 | RasGas | 7.8 | 10.6 | 2009 |
| | Rasgas 3-2 | RasGas | 7.8 | 10.6 | 2010 |
| | Qatargas 2-1 | Qatargas | 7.8 | 10.6 | 2009 |
| | Qatargas 2-2 | Qatargas | 7.8 | 10.6 | 2009 |
| | Qatargas 3 | Qatargas | 7.8 | 10.6 | 2010 |
| | Qatargas 4 | Qatargas | 7.8 | 10.6 | 2011 |
| Russia | Sakhalin 2-1 | Sakhalin Energy | 4.8 | 6.6 | 2009 |
| | Sakhalin 2-2 | Sakhalin Energy | 4.8 | 6.6 | 2009 |
| Yemen | Yemen LNG-1 | Total | 3.4 | 4.6 | 2009 |
| | Yemen LNG-2 | Total | 3.4 | 4.6 | 2009 |
| **Total** | | | **95.7** | **130.3** | |

Source: IEA databases.

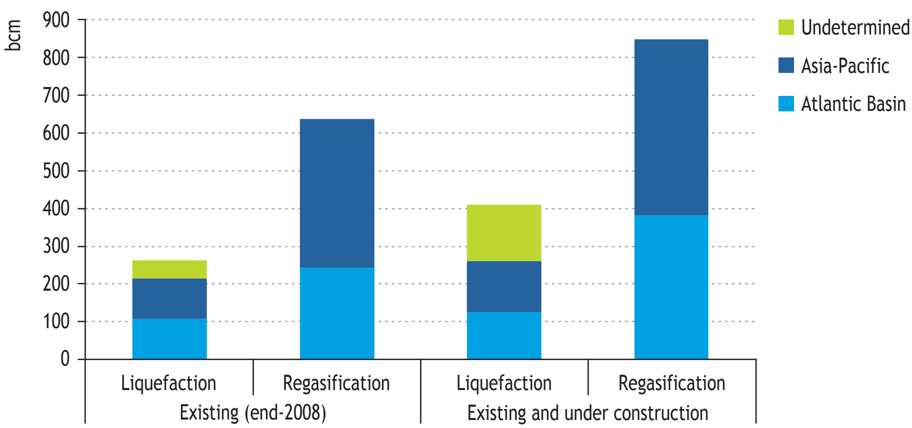
A very substantial increase in export capacity in the next five years or so is not in question, though there is some uncertainty about whether the plants being built will come on stream on schedule (as indicated in Table 12.4), given construction delays that have plagued recent projects (IEA, 2009) and actual and potential technical problems in achieving full capacity throughput. In addition, overall capacity may be constrained by supply problems at existing plants: there have been a number of incidents at liquefaction plants over the last two years, including in Nigeria (related to the conflict in the Delta region), Qatar (transformer problems at Qatargas-1) and Algeria (corrosion of a feedgas pipeline at the Arzew plant). Delays in commissioning new plants would reduce the peak of the medium-term capacity overhang described above.

Beyond the period to 2015, the outlook for LNG is even less certain. A number of additional projects are planned and negotiations on sales contracts are advancing, but the financial crisis and weaker-than-expected prospects for gas demand have cast doubts over many of them. Although final investment decisions are due for several projects in the coming two years, only two plants have been given green lights since

2007 – Gassi Touil in Algeria in 2008 and Gorgon in Australia in September 2009. The hiatus in new projects looks certain to result in a levelling-off of installed liquefaction capacity by around 2014-2015, possibly lasting several years. Growth in capacity worldwide is expected to resume closer to 2020.

Regasification capacity in importing countries is also expanding in anticipation of a surge in supply. At the end of 2008, there was just over 600 bcm/year of regasification capacity worldwide – more than twice the amount of liquefaction capacity.[7] The amount of regasification capacity under construction, around 210 bcm/year, is slightly larger than liquefaction capacity (Figure 12.10). The ratio of regasification to liquefaction capacity is nonetheless set to drop slightly, to around two, once all the new capacity is brought on stream.

**Figure 12.10 • *Liquefied natural gas capacity***




Growth in shipping capacity is also expected to outpace demand growth in the next few years, as ships under order are delivered. Capacity additions in 2007 were nearly 5 million cubic metres (mcm) of liquefied gas – a record at the time – and reached almost 10 mcm in 2008, pushing the utilisation of capacity down to around two-thirds. This capacity surplus is one reason why the market has been able to support long-haul spot trades from the Atlantic basin to Northeast Asia (Jensen, 2009). More than 16 mcm of capacity is under order, due to become available in the period 2009-2012.

The Asia-Pacific region is expected to dominate increasingly global LNG trade. Most LNG already goes to the region and the share is expected to rise progressively over the projection period, as new importers such as China and India step up imports. Total flows to and within Asia-Pacific are projected to rise from 154 bcm in 2007 to 190 bcm

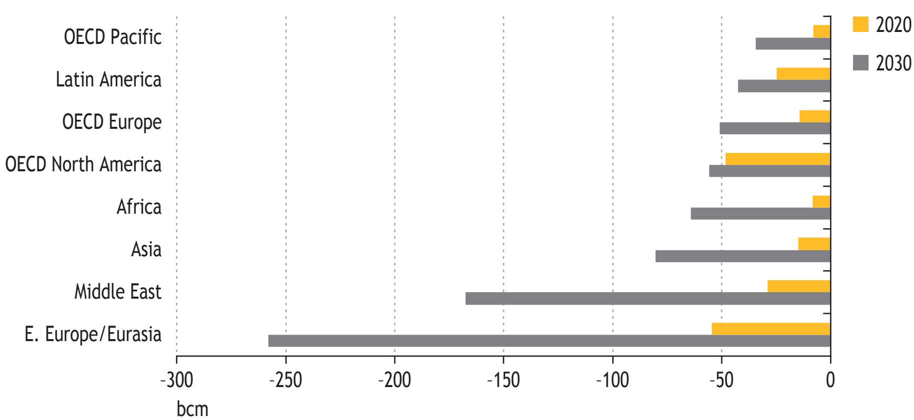
7. There has been a large surplus of regasification plants for several years, as many of them are used for seasonal load balancing or for arbitraging periodic regional price differences. Annual capacities are generally calculated using daily (peak) capacity. The annual figures may be overstated, because it may not always be possible to operate at peak capacity for extended periods because of storage and wharfing limitations.

in 2015 and 300 bcm in 2030. Imports of LNG into Europe are set to grow much less – from 51 bcm in 2007 to 73 bcm in 2015 and 94 bcm in 2030 – while annual LNG imports into North America are marginally higher in 2015 than in 2007 and are more than double by 2030. LNG trade within Latin America is expected to grow, with LNG imports set to grow in Chile, Argentine and (in the near term at least) Brazil; but the region as a whole is expected to remain a small net exporter of LNG, on the assumption of a long-term expansion of export capacity in Trinidad and Tobago and new capacity in Peru (due on-stream shortly) and Venezuela in the longer term.

## 450 Scenario

Trends to 2030 in gas production and trade in the 450 Scenario are markedly different from those in the Reference Scenario, especially after 2020 (differences in 2015 are relatively small, as most of the policies assumed take time to take effect). Production in all regions is lower (Table 12.6), as a result of lower international gas prices, which discourages investment in exploration and development (prices are reduced by the lower demand that results from the range of new policies and measures that are assumed to be introduced in this scenario). Worldwide, output reaches 3 480 bcm in 2020 (200 bcm, or 5% lower than in the Reference Scenario) and 3 560 bcm in 2030 (750 bcm, or 17% lower). In volume terms, the fall in production *vis-à-vis* the Reference Scenario is biggest in Eastern Europe/Eurasia and the Middle East (Figure 12.11). The relative size of the projected reductions in production across countries largely reflects differences in marginal supply costs to the key domestic and export markets (production costs plus transportation).[8]

**Figure 12.11 • *Change in natural gas production by region in the 450 Scenario compared with the Reference Scenario***




8. In countries that are assumed not to export or import gas, production is assumed to change in line with regional demand.

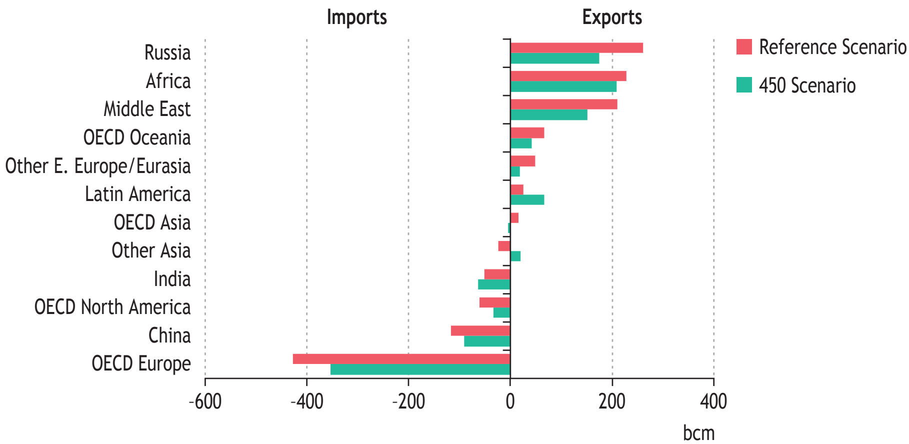
**Table 12.6 • Natural gas production by country/region in the 450 Scenario (bcm)**

| | 1980 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007-2030* |
|---|---|---|---|---|---|---|---|
| **OECD** | **889** | **1 124** | **1 091** | **1 112** | **1 105** | **1 040** | **-0.3%** |
| North America | 657 | 777 | 751 | 771 | 800 | 776 | -0.0% |
| *Canada* | *78* | *184* | *158* | *165* | *162* | *149* | *-0.9%* |
| *Mexico* | *25* | *52* | *53* | *55* | *60* | *61* | *0.7%* |
| *United States* | *554* | *541* | *540* | *551* | *579* | *565* | *0.2%* |
| Europe | 219 | 294 | 268 | 245 | 210 | 171 | -2.3% |
| *Netherlands* | *96* | *76* | *69* | *61* | *47* | *34* | *-3.4%* |
| *Norway* | *26* | *92* | *114* | *120* | *113* | *96* | *0.2%* |
| *United Kingdom* | *39* | *12* | *9* | *7* | *6* | *6* | *-3.3%* |
| Pacific | 12 | 53 | 72 | 96 | 95 | 93 | 2.5% |
| *Australia* | *9* | *44* | *63* | *88* | *87* | *87* | *3.0%* |
| **Non-OECD** | **648** | **1 918** | **2 160** | **2 364** | **2 537** | **2 520** | **1.2%** |
| E. Europe/Eurasia | 480 | 858 | 872 | 904 | 897 | 838 | -0.1% |
| *Azerbaijan* | *n.a.* | *11* | *20* | *31* | *34* | *34* | *5.1%* |
| *Kazakhstan* | *n.a.* | *30* | *41* | *47* | *52* | *53* | *2.6%* |
| *Russia* | *n.a.* | *646* | *634* | *649* | *633* | *580* | *-0.5%* |
| *Turkmenistan* | *n.a.* | *69* | *82* | *90* | *93* | *90* | *1.2%* |
| *Uzbekistan* | *n.a.* | *65* | *65* | *66* | *64* | *57* | *-0.6%* |
| Asia | 70 | 354 | 420 | 465 | 497 | 475 | 1.3% |
| *China* | *14* | *69* | *101* | *124* | *128* | *108* | *1.9%* |
| *India* | *1* | *29* | *58* | *64* | *68* | *69* | *3.9%* |
| *Indonesia* | *17* | *74* | *68* | *71* | *76* | *75* | *0.0%* |
| *Malaysia* | *3* | *64* | *61* | *65* | *66* | *63* | *-0.1%* |
| Middle East | 38 | 357 | 464 | 540 | 628 | 645 | 2.6% |
| *Iran* | *4* | *116* | *126* | *152* | *171* | *179* | *1.9%* |
| *Qatar* | *3* | *66* | *155* | *174* | *188* | *190* | *4.7%* |
| *Saudi Arabia* | *11* | *67* | *83* | *96* | *113* | *128* | *2.8%* |
| *United Arab Emirates* | *8* | *51* | *51* | *54* | *59* | *61* | *0.8%* |
| Africa | 23 | 206 | 250 | 295 | 329 | 350 | 2.3% |
| *Algeria* | *14* | *82* | *104* | *118* | *127* | *129* | *2.0%* |
| *Egypt* | *2* | *58* | *64* | *69* | *71* | *69* | *0.8%* |
| *Libya* | *5* | *16* | *21* | *27* | *34* | *41* | *4.0%* |
| *Nigeria* | *2* | *35* | *43* | *54* | *70* | *86* | *4.0%* |
| Latin America | 36 | 143 | 154 | 160 | 187 | 211 | 1.7% |
| *Brazil* | *1* | *11* | *16* | *20* | *31* | *41* | *5.9%* |
| *Trinidad & Tobago* | *3* | *34* | *32* | *33* | *37* | *40* | *0.7%* |
| *Venezuela* | *15* | *24* | *24* | *26* | *30* | *33* | *1.5%* |
| **World** | **1 536** | **3 042** | **3 251** | **3 477** | **3 642** | **3 560** | **0.7%** |
| *European Union* | *n.a.* | *214* | *162* | *132* | *103* | *81* | *-4.2%* |

* Compound annual average growth rate.

As the reductions in production and demand in the 450 Scenario, compared with the Reference Scenario, are not of the same magnitude in each region, inter-regional trade flows change – markedly in some cases. Globally, trade is 50 bcm, or 7% lower, in 2015 than in the Reference Scenario and 165 bcm, or 15%, lower in 2030. OECD Europe imports are reduced the most in volume terms, reaching 354 bcm in 2030 compared with 428 bcm in the Reference Scenario (Figure 12.12). Exports from Russia and the Middle East are reduced the most.

**Figure 12.12 • Natural gas trade by scenario, 2030**



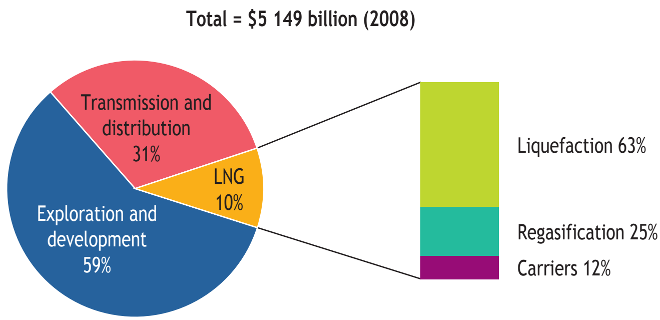

# Investment and cost outlook

## Investment requirements to 2030

Projected gas-market trends over the period 2008-2030 in the Reference Scenario call for cumulative global investment along the supply chain of about $5.1 trillion (in year-2008 dollars), or around $220 billion per year (Table 12.7). This investment is needed to replace existing capacity that is lost to natural declines in production and to retirement of assets, as well as to expand capacity to meet rising demand during the projection period. Close to 60% of total gas investment goes to exploration and development of gas fields (Figure 12.13). Rising costs of equipment and services, and a need to develop more technically difficult fields, push up the average unit capital cost of gas production (see below: Cost trends). LNG liquefaction and regasification plants and LNG carriers account for 10% of total investment needs; downstream infrastructure – high-pressure transmission pipelines, local distribution networks and storage facilities – account for the rest.

More than half of global gas investment is needed in non-OECD countries (primarily in Eastern Europe/Eurasia, Asia and the Middle East), the bulk of it for exploration and production. The Middle East has the largest requirement for LNG investment (almost entirely for liquefaction facilities), accounting for almost half of total liquefaction investment worldwide. OECD investment totals $2.3 trillion ($100 billion per year), the bulk of which is needed in North America, where capital needs are pushed up by high production-decline rates.

**Figure 12.13 • Breakdown of cumulative investment in gas-supply infrastructure by activity in the Reference Scenario, 2008-2030**




Global investment requirements are considerably reduced in the 450 Scenario, because of lower demand and, therefore, capacity needs. Cumulative global gas investment amounts to $4.5 trillion (in year-2008 dollars), or $194 billion per year – $685 billion, or 13%, less than in the Reference Scenario (Figure 12.14). The difference is nonetheless smaller in percentage terms than that in demand, as a significant share of total investment is needed simply to replace obsolete and depleted capacity. The biggest reductions in investment occur in Eastern Europe/Eurasia and Asia, because of both lower domestic and export demand, which lowers the need for investment in refurbishing and expanding long-distance pipelines in particular. Investment in Latin America barely falls, because increased spending on LNG export plants almost entirely offsets lower spending in the upstream and downstream.

**Figure 12.14 • Change in cumulative investment in gas-supply infrastructure by region and activity in the 450 Scenario compared with the Reference Scenario, 2008-2030**

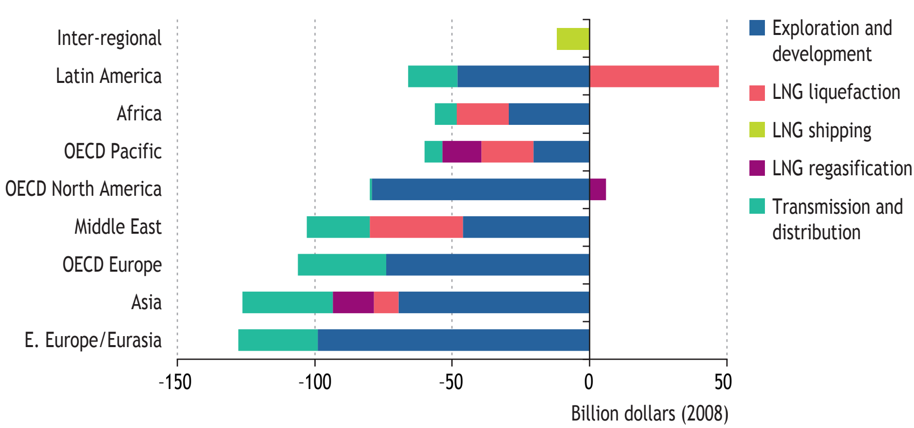


**Table 12.7 • Cumulative investment in gas-supply infrastructure by region and activity in the Reference Scenario, 2008-2030**

($ billion in year-2008 prices)

| | Exploration and development | Transmission and distribution | LNG | | | Total |
|---|---|---|---|---|---|---|
| | | | Liquefaction | Carriers | Regasification | |
| **OECD** | **1 392** | **757** | **50** | **0** | **63** | **2 262** |
| North America | 966 | 398 | 0 | 0 | 25 | 1 389 |
| Europe | 309 | 286 | 0 | 0 | 17 | 611 |
| Pacific | 117 | 74 | 50 | 0 | 21 | 262 |
| **Non-OECD** | **1 600** | **862** | **292** | **0** | **70** | **2 824** |
| E. Europe/Eurasia | 553 | 311 | 6 | 0 | 0 | 870 |
| *Russia* | *386* | *200* | *6* | *0* | *0* | *592* |
| Asia | 452 | 234 | 22 | 0 | 60 | 769 |
| *China* | *134* | *77* | *0* | *0* | *21* | *233* |
| *India* | *103* | *42* | *0* | *0* | *19* | *165* |
| Middle East | 232 | 184 | 160 | 0 | 1 | 577 |
| Africa | 206 | 59 | 95 | 0 | 0 | 361 |
| Latin America | 157 | 73 | 9 | 0 | 9 | 248 |
| **World** | **2 992** | **1 619** | **342** | **63** | **133** | **5 149** |
| *European Union* | *195* | *272* | *0* | *0* | *17* | *484* |

As always, it is far from certain that all the investment required in each scenario will be forthcoming, at least at the prices assumed. The uncertainties are typically biggest with respect to large-scale upstream, LNG and long-distance, cross-border pipeline projects. There are a number of potential barriers to investment, including the policies of resource-rich countries, the ability and willingness of national companies to develop their resources, opportunities and incentives for international companies to invest, and geo-political factors (IEA, 2008). The strategic aims of the resource-rich countries and their national companies may not always be conducive to the development of new pipeline or LNG projects. Much will depend on future gas (and oil) price levels and the relative importance given to short-term budget demands over longer-term strategic considerations. Higher prices (and, therefore, revenues) could undermine incentives to exploit resources in those countries that are particularly dependent on hydrocarbon resources, including some Middle East states, simply because they would have less need for additional revenue in the near term and may prefer to hold back resources for future generations. As ever, internal political and broader geopolitical tensions will also influence future supply-side investments in the Middle East and elsewhere.

## Cost trends

### *Exploration and production*

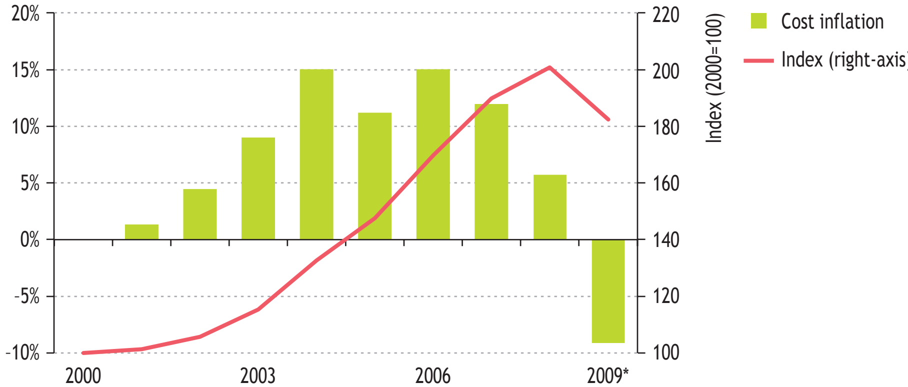
The persistent rise in upstream capital and operating costs that got underway in the early to mid-2000s has finally abated, with costs in the first half of 2009 generally significantly lower than in 2008. The cost to companies of exploring for oil and gas, developing new and existing fields, and operating and maintaining their production facilities, expressed in dollars, soared over the eight years to 2008, with rising unit costs of all the inputs to upstream activities, including drilling and oilfield services, skilled labour, materials and energy.[9] The fall in the value of the dollar, which pushed up the cost of materials, equipment and labour sourced in countries with currencies that appreciated against the dollar, was a major contributor to this cost inflation. Costs peaked in mid to late 2008, with the peak in oil prices.

The degree to which costs surged and then fell back varied considerably across regions and according to the type of upstream development. Averaged across all regions, the annual inflation rate for capital costs reached a peak of about 15% in 2006 but then declined to just over 5% in 2008, based on the IEA Upstream Investment Cost Index, or UICI (Figure 12.15).[10] In the first half of 2009, costs were on average around 9% lower than in 2008.

9. For example, rig rates accounted for 30% of the near-100% increase in deepwater development costs, and steel and service company margins each for about one-fifth (Goldman Sachs, 2009).

10. The UICI measures the average annual rate of increase in underlying costs incurred directly by operating companies for both exploration and production, stripping out the effect of shifts in spending on different types of upstream projects and in different locations and regions. These costs include the acquisition of seismic data, project management, rig hiring, drilling services and the construction of production facilities (including treatment and processing plants, compressors, generators and gathering pipelines). See IEA (2008) for a detailed explanation of the methodology.

**Figure 12.15** ● *IEA Upstream Investment Cost Index and annual inflation rate*




* First half of the year.

The outlook for upstream capital and operating costs is very uncertain, largely reflecting uncertainty about the prospects for oil and gas prices as well as about the degree of "stickiness" in reducing the costs of certain types of equipment, materials and services on the downside of the cost cycle. Historically, costs have tended to rise very much in parallel with oil and gas prices (Figure 12.16). Causality works both ways: rising costs, by discouraging investment in the most expensive projects, certainly contributed to higher prices in 2000-2008, though higher prices also dragged up costs, by boosting demand for all types of inputs. The slump in upstream investment in all regions (see Chapter 3) in the wake of the price collapse in the second half of 2008 has led to sharp falls in drilling costs.

On the assumption that oil prices begin to rebound in 2010, unit costs are expected to bottom out in 2009-2010 and resume their upward path thereafter. But costs will not follow a single path: some costs are stickier than others – in other words, they respond to different degrees and at different rates to movements in oil and gas prices (Figure 12.17). Generally, major facility construction and operating and maintenance costs are the least responsive and the slowest to react, as they cover the types of equipment, materials, logistical and labour inputs that are least specific to the oil and gas business; these costs are driven more by the general economic environment. In contrast, the costs of land-drilling services and equipment, especially in the United States, are very volatile, reflecting the sensitivity of the financial returns on drilling wells onshore to oil and gas price movements, and the short lead times involved.

A major factor concerns the extent to which the costs of services and equipment supplies are fixed under contracts covering periods of between several months and several years (for the biggest offshore projects). Some oil companies have attempted to renegotiate costs under their existing contracts with suppliers and service providers, taking advantage of the general downturn in activity. Taking account of the lags involved, on balance, upstream capital costs worldwide are expected to fall by around 12% in 2009 compared with the year before, with operating costs falling by less than 10%. These averages mask some very big differences across regions: costs are set to fall the most in North America and the least in West Africa and offshore Brazil, where deepwater drilling dominates.[11]

**Figure 12.16 • Oil price and upstream costs, 2000-2008**

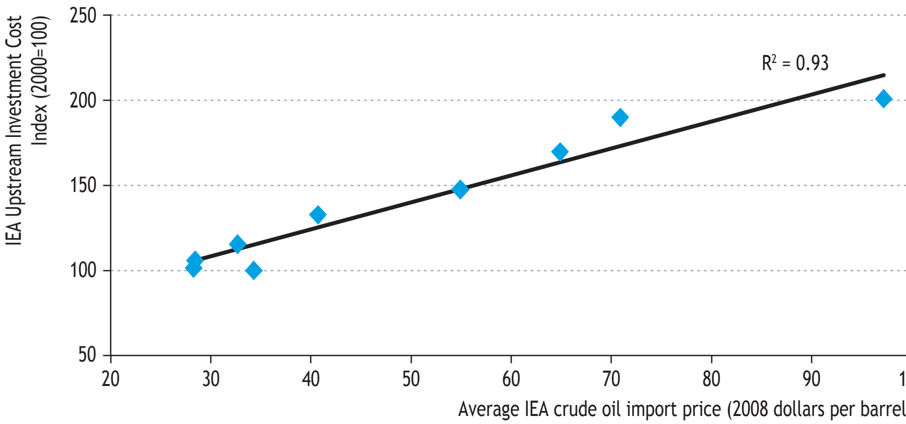
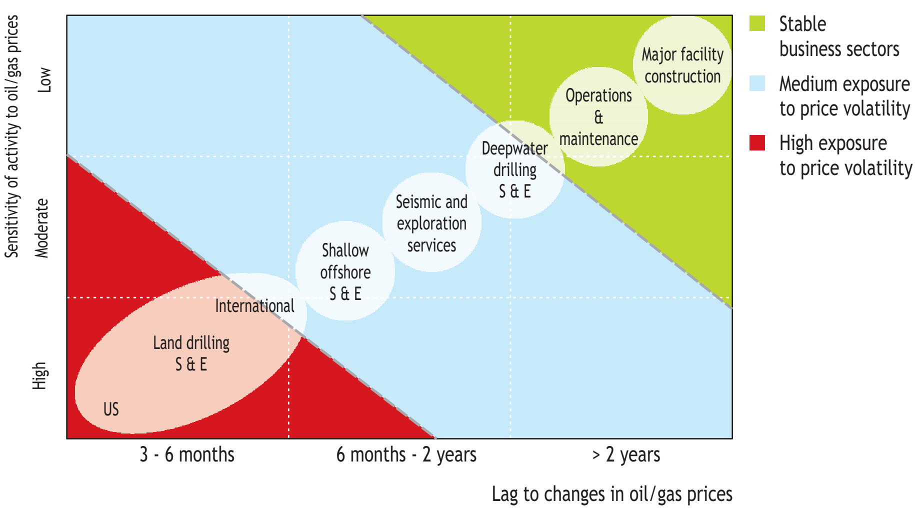



**Figure 12.17 • Relationships between upstream cost components and oil and gas prices**



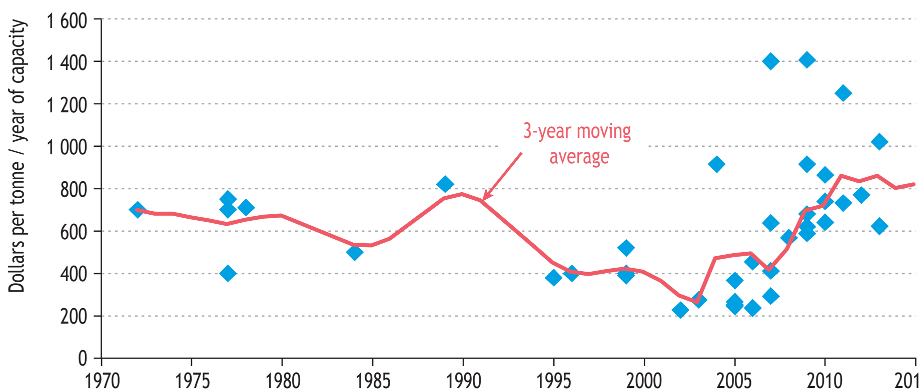

Note: S&E is services and equipment.

11. The cost of hiring a deepwater drillship, for example, has barely fallen since 2008. Most deepwater rig capacity is contracted for several years, limiting the scope for negotiating lower costs.

### *Liquefied natural gas facilities*

LNG development costs also increased significantly between 2004 and mid-2008, reversing the downward trend of the previous decade. The cost of building liquefaction plants almost doubled on average over that period, per unit of capacity. The cost of plants still under construction will be higher still: the average cost of the 13 plants that are due to be commissioned between 2009 and 2013 is estimated at around $830 per tonne/year of capacity, compared with $430 for the 13 plants commissioned in 2005-2008 (Figure 12.18). The costs of building regasification terminals also increased, but generally by less than liquefaction plants in percentage terms. In some cases, it has proved possible to build floating terminals, which can cost less than half that of a fixed onshore terminal (excluding harbour and other related infrastructure). Costs for LNG tankers have also risen, but again at a slower pace than liquefaction plants. General cost pressures have been alleviated by scale economies for larger tankers.[12] With higher costs along the supply chain, break-even prices for new LNG projects increased correspondingly.

**Figure 12.18 • *LNG liquefaction plant capital costs***




Source: IEA databases.

Engineering, procurement and construction costs increased for a number of reasons – some industry-specific and some general. In a way, the LNG industry became a victim of its own success. The number of LNG liquefaction trains under simultaneous construction increased from an average of eight during the 1990s to an average of 12 in 2000-2004 and an average of 16 between January 2005 and December 2008.[13] Demand for specialised equipment and contractor services reached unprecedented levels,

12. Qatar's new tankers – Q-Flex (with a 216 000 $m^3$ of liquefied gas capacity) and Q-Max (260 000 $m^3$) – have boosted significantly the average size of LNG tankers in operation, a trend that will continue as new tankers are brought into service.

13. Estimates based on an assumption of a construction period of 48 months.

skewing bargaining positions in favour of contractors and causing bottlenecks and delays. A handful of contractors have built nearly all existing gas liquefaction plants.[14] Net profit margins for these companies as a group increased steadily from 2003 to 2008, reflecting strong demand and increasing backlogs.

Conditions are now changing. A dearth of new investment decisions in the last two to three years, together with a general decline in construction and material costs, points to lower costs for the construction of any new plants that may be launched in the next couple of years or so, as well as some cost savings for those already under construction. Key raw material prices have plummeted under the weight of the global recession. Steel prices dropped by half between mid-2008 and early 2009, though they remain well above the levels of the early 2000s and began to show signs of recovering in mid-2009. These falls have started to affect LNG project costs, though other costs – notably skilled labour – are unlikely to fall much if at all.[15] On average, capital costs along the LNG chain could fall by up to 15% in 2009, but may not fall much further thereafter and could even rebound (our long-term investment projections allow for a modest bounce-back in unit costs). The location of new liquefaction plants will also affect costs: safety and security concerns may push up the costs of facilities in Nigeria, while new plants in the Middle East and Latin America might enjoy lower costs because of their favourable access to low-cost labour and because of lessons learned in building earlier plants. New liquefaction technology, including floating production platforms, could help to reduce unit costs and permit the development of remote resources.

14. Bechtel, Chiyoda, Foster Wheeler, KBR, JGC, Snamprogetti and Technip are the leading companies. In addition, Linde built the Snøhvit plant in Norway and Chicago Bridge & Iron is building Peru LNG.

15. Equipment, including bulk items and more sophisticated equipment, accounts for around 30% of the total costs of building an LNG liquefaction plant. Construction costs, including salaries and wages, make up 40% of the total. Project management, transportation and overheads each account for roughly 10%.

# REGIONAL ANALYSIS
## Who will shape the global gas market?

### HIGHLIGHTS

- North America is a highly integrated regional gas market, accounting for more than one-quarter of global demand. The regional market is projected to grow by 10% to 2030 in the Reference Scenario and remain at its present size in the 450 Scenario. Unconventional gas has boosted regional production substantially over the last three years and will continue to increase supplies throughout this *Outlook* period. This has profound implications for global gas markets, not least because of the impact on regional LNG imports: these reach just 61 bcm in 2030 in the Reference Scenario, significantly less than previously projected.
- Russia holds the world's largest gas reserves, and produces and exports more gas than any other region. Its production is projected to rise to 760 bcm in 2030 in the Reference Scenario; development of gas reserves on the Yamal peninsula will be essential to reach this figure. A lower demand *Outlook* has eased concerns about supply in the period 2012-2014, but questions remain about the timing and adequacy of investment in complex offshore and Arctic fields.
- In Europe and Eurasia, the effects of the recession, the EU Climate and Energy Package, and the introduction in former Soviet republics of market-based import prices and domestic price reform are expected to play a major role in curbing gas demand growth to 2030; this effect is particularly marked in the 450 Scenario. Nonetheless, EU gas-import needs continue to grow in both scenarios.
- Gas producers in the Caspian region are looking to benefit from improved commercial conditions for gas trade as they open up new export markets. Confirmation of large gas reserves and a new large-capacity pipeline to China are expected to foster production growth in Turkmenistan, which emerges as a large gas producer by 2030, with projected output of 118 bcm in the Reference Scenario.
- Qatar is one of the world's leading countries for new natural gas developments. Qatar's gas production rose quickly to an estimated 79 bcm in 2008 and is set to expand further: current projects will push production to 165 bcm in 2015 and it rises to between 190 bcm and 225 bcm in 2030 (depending on the scenario). Most of the increase will be exported, primarily as LNG; LNG export capacity is set to reach 105 bcm/year in 2013, from 41 bcm in 2007. Projected higher output after 2015 is contingent upon ending the current moratorium on new export projects.
- Iran is the world's third-largest gas consuming country, after the United States and Russia. The South Pars field is expected to provide the bulk of projected increases in output to 2030. In the Reference Scenario, Iran's marketed gas production rises from 121 bcm in 2008 to 256 bcm in 2030; in the 450 Scenario it reaches 179 bcm. Growth in domestic consumption and oilfield re-injection needs continue to curtail the potential for gas exports.

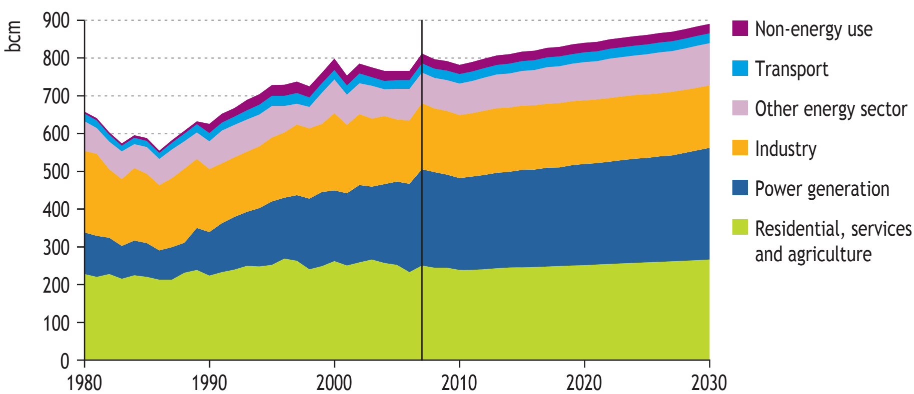
## North America

The United States is the world's largest gas consuming country, with a total demand of 658 bcm in 2008. It is also the second-largest gas producer, after Russia, with 583 bcm of domestic supply in 2008, an increase of 8% or 42 bcm from the previous year. Unconventional gas[1] has boosted domestic production over the last three years and will continue to increase supplies throughout the period of this *Outlook* and beyond. This has profound implications for global gas markets. Liquefied natural gas (LNG) imports into the United States have fallen in the past year and are projected to decline further in coming decades. Canada is the world's third-largest producer, with output of 175 bcm in 2008 and net exports of 88 bcm. Mexico currently produces around three-quarters of its annual demand of 67 bcm. There are extensive pipeline links and substantial flows of gas between Canada and the United States, creating a highly integrated regional market. Links between Mexico and the United States are also increasing.

### Gas demand

In the Reference Scenario, projected North American demand for gas shows an overall growth of 10% in the period from 2007 to 2030, with a slight fall in the near term during a sluggish economic recovery and then steady growth from early in the 2010s, as demand for power generation picks up (Figure 13.1). Total demand increases 80 bcm from 2007 to 2030, considerably less than the 260 bcm increase from its low point in 1986 to 2007. Over half of the regional growth in demand comes from Mexico over the projection period; demand increases by just over one-third in Canada, but in the United States there is even a marginal decline to 2030.

**Figure 13.1 • North American natural gas demand by sector in the Reference Scenario**




Power generation remains the principal driver of gas-demand growth, despite overall thermal efficiency improvements with the retirement and replacement of older plant by more efficient combined-cycle gas turbines (CCGTs) and open-cycle turbines. Residential demand for gas rises only very slowly while industrial demand falls slightly over the

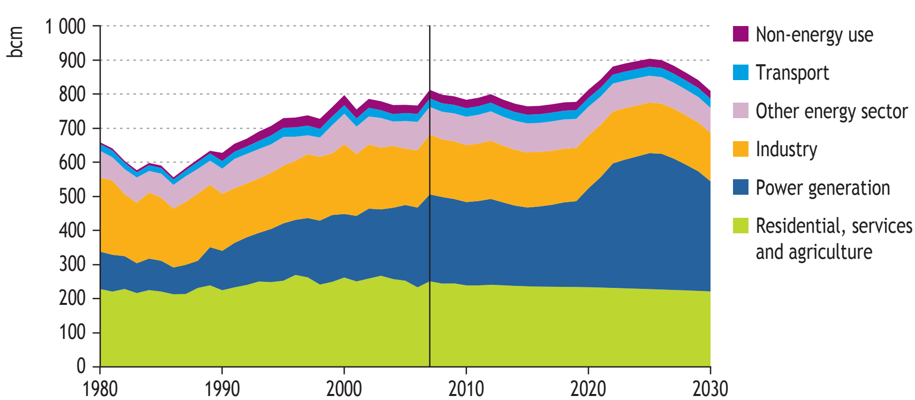
1. A detailed discussion can be found in Chapter 11.

projection period. In some government circles, a large potential market is seen for natural gas growth by substitution for oil products in transportation. However, although compressed natural gas (CNG) and some LNG is already used in local fleets of vehicles (such as buses) widespread public use of gas for transport will be constrained by the lack of refuelling infrastructure, increased costs and the shorter refuelling range of CNG vehicles (see Chapter 10).

New measures to address rising greenhouse-gas emissions are high on the political agenda of all three countries. The new US administration has given priority to introducing legislation to permit the setting up of a cap-and-trade system. Likely future legislation is already steering investment decisions in power generation towards plant with a lower carbon footprint and, in some cases, delaying decisions, especially on coal-fired plant, until policies are more defined. In the 450 Scenario, which assumes a wide range of policies are introduced to bring down emissions growth across the region, gas demand is initially lower than in the Reference Scenario – but it then rises rapidly to a peak in the mid-2020s before falling to a level well below that in the Reference Scenario by 2030.

These trends result from several countervailing factors. In the 450 Scenario, electricity use per capita at the end of the *Outlook* period is 3% below its 2008 level and 8% lower than the Reference Scenario. This lower electricity demand, combined with the effect of carbon pricing, strongly influences the composition of the pool of electricity generating plants over the projection period. Initially, the lower level of demand, coupled with the moderate increase of generation from renewable sources that can occur within a short timeframe, depresses demand from gas- and coal-fired plants. As carbon prices increase, coal-fired plants are retired in greater numbers, to be replaced by gas plants, more renewables and nuclear power. Towards the end of the projection period, the steadily increasing contribution from renewables and nuclear power, together with the reintroduction of some coal plants equipped with carbon capture and storage (CCS), then depresses demand for gas in power generation. Gas needs for power generation across the region are projected to increase by 56% from 2007 to 2025 – a 140 bcm increase. About half of this increase is then lost by 2030, as renewable and coal-CCS plants take more of the load (Figure 13.2).

**Figure 13.2 • North American natural gas demand by sector in the 450 Scenario**

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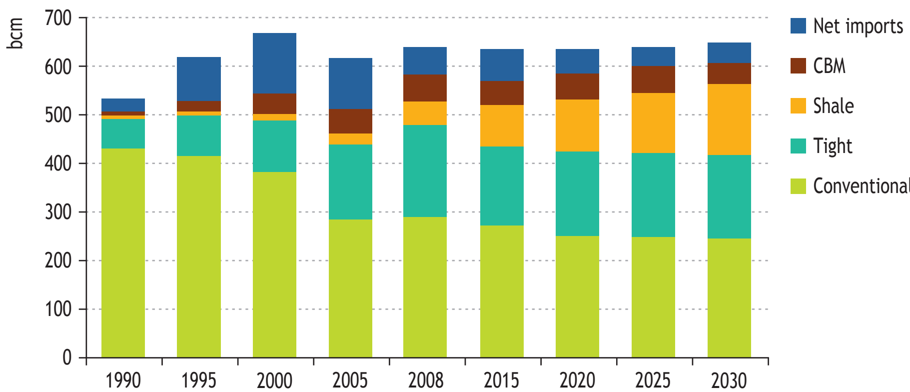
## Gas supply: United States

In the Reference Scenario, gas production in the United States is projected to grow steadily over the next two decades, though at a more moderate pace than since 2005 (Figure 13.3). At present, production is effectively constrained by local demand, a situation that is expected to persist for most of the projection period. Production reaches more than 600 bcm in 2030, up by around 20 bcm from 2008. Canada remains an exporter to the United States, but volumes gradually decline as US supplies increase, Canadian production dwindles and more Canadian gas is utilised for oil sands production. In the 450 Scenario, US gas production grows more slowly relative to the Reference Scenario, despite stronger domestic demand to 2025, as lower international prices boost the competitiveness of LNG imports.

**Figure 13.3 • United States natural gas supply in the Reference Scenario**

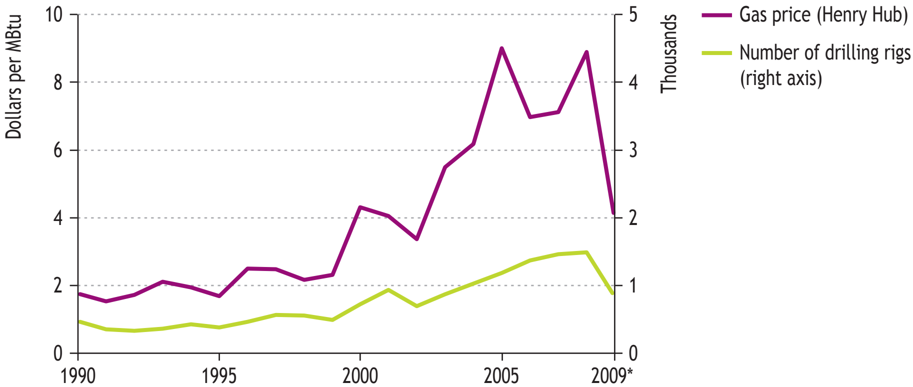



Sources: IEA databases and projections; historical unconventional data provided by US DOE/EIA.

The idea of building a pipeline to transport proven reserves of gas from the North Slope of Alaska to markets in the US mainland has been under discussion and negotiation since the 1970s. At present, there are two competing proposals, both of which plan "open seasons" during 2010 – a procedure to solicit expressions of potential interest in committing to capacity from Alaskan producers and gas distribution companies. The maximum transport capacity planned is approximately 45 bcm/year and capital-cost estimates of up to $30 billion have been reported. One of the options also includes a potential LNG export terminal at Valdez on the Southern Alaskan coast. Our projections (in both scenarios) include a new pipeline transporting Alaskan gas to US markets and increasing conventional gas supply from after 2020, but they do not assume LNG exports.

Development of unconventional gas resources has boosted US domestic production significantly over the last three years, with an especially large increase in 2008, despite falling prices in the latter half of the year. From just over 50% in 2008, the share of unconventional gas in total US gas production is projected to rise to nearly 60% in 2030 in the Reference Scenario. New technology has increased productivity per well from unconventional sources and this supplement to supply, combined with weak demand following the economic crisis and higher than usual storage levels, has led to a steep drop in prices and a dramatic reduction of gas drilling activity in the United States. The number of active drilling rigs has been cut to half of the peak levels of 2008, and in the first half of 2009 was similar to the level in 2003 and 2004. By mid-2009, prices at Henry Hub (the leading North American benchmark) had fallen to little more than $3 per million British thermal units (MBtu), from an average of almost $9/MBtu in 2008 (Figure 13.4).

**Figure 13.4 • *United States average gas price and drilling activity***




* First half year average.

Sources: IEA databases; Baker Hughes rig count data, available at http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm.

The new sources of supply have the potential to increase overall North American production at a wellhead cost of between $3/MBtu and $5/MBtu (in year-2008 dollars and including drilling and completion costs) for the coming several decades, though rising material costs and rig-rates are expected to exert upward pressure on unit costs (see Chapters 11 and 12). Recent improvements in production per well, particularly for shale gas plays, will result in the need for fewer wells and reduced drilling activity in the future, although the high decline rates of unconventional gas will require constant drilling and completion of new wells to maintain supply volumes. The fleet of land drilling rigs in the United States will probably decline in overall numbers, but will include a much larger proportion of higher powered, easily moved rigs, capable of drilling long, horizontal wells in fields at 4 000 metres depth.



As of mid-2009, we estimate that at least 5% of US gas-production capacity is shut-in. A substantial proportion of the drilling that is continuing in 2009 is being carried out by operators with binding commitments to drill wells (or relinquish prospective areas that they have leased at high costs) and by operators taking advantage of currently depressed drilling and completion costs.

At the end of 2008, the United States had 7.5 trillion cubic metres (tcm) of proven reserves[2] of conventional gas, equivalent to less than 13 years of current production volumes. But the latest estimates of remaining recoverable resources of all types of

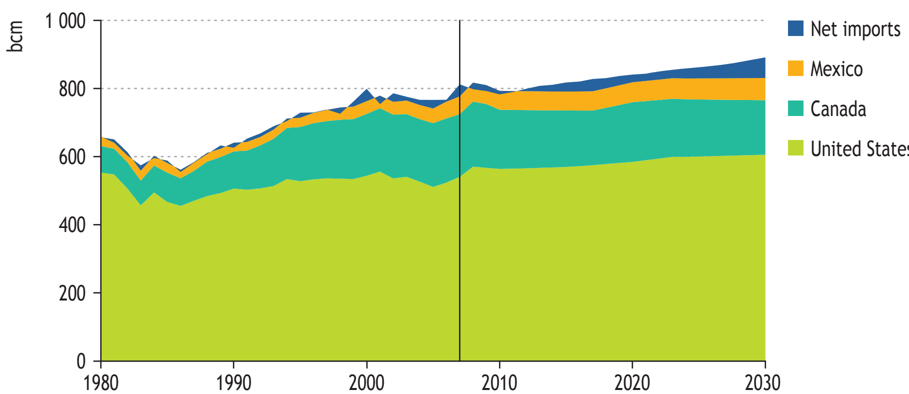
2. All reserve estimates cited in this chapter are from Cedigaz (2009).

gas, including huge deposits of unconventional gas, are sufficient to sustain current levels of production for more than 80 years, ensuring supplies well beyond the period of this *Outlook*. Although most of the mainland (lower 48 states) US pipeline system is already in place, some new connections will need to be added, as has been the case in the past five years, especially to connect to the grid the newer plays being developed (as, for example, in the Rockies). As some of these supplies are located closer to major consuming areas of the Northeast coast than the traditional producing states of Texas and Louisiana, competition between different geographic sources are likely to affect transmission tariffs. Environmental challenges also need to be overcome (see Chapter 11).

## Gas supply: Canada and Mexico

Gas production in Canada has followed a very similar trend to that in the United States, with an increasing proportion of unconventional gas being developed as conventional basins mature. Several producing and service companies operate in both countries, using largely the same technologies, and knowledge is transferred rapidly from one market to the other. Production in Canada is projected to decline gradually, by 15 bcm between 2008 and 2030 in the Reference Scenario (Figure 13.5); it falls by a more marked 26 bcm in the 450 Scenario.

**Figure 13.5 • North American natural gas supply in the Reference Scenario**




The bulk of Mexico's gas production is associated with oil, though a significant share comes from tight sands (see Chapter 11). The country has only 360 bcm of proven reserves – equal to seven years at current rates of production – but this reflects minimal exploration activity in recent years; ultimately recoverable resources are thought to be much larger. Problems in mobilising investment mean that Mexico currently has to import gas to meet its burgeoning demand, both from the United States (via pipelines) and as LNG. Domestic production is projected to grow in the Reference Scenario by 13 bcm, or 25%, in 2008-2030 to 65 bcm, though this will depend on adequate investment. In the 450 Scenario, it reaches only 61 bcm.

## LNG imports

North America currently has 13 LNG terminals, with a total import capacity of 145 bcm/year. Another six are under construction (including one being expanded), which will give a total import capacity of 214 bcm/year. Total imports in 2008 dropped by half to 14 bcm – just 9% of capacity at that time (Table 13.1) and well below the worldwide average capacity utilisation rate of 37%. In addition, there are 19 approved projects to construct new terminals or expand existing capacity, mainly in the Gulf of Mexico. Given current conditions, it is doubtful that any of these projects will proceed in the near future. Total LNG imports into the United States and Mexico remain at low levels for much of the projection period and then rise to a peak of 61 bcm in 2030 in the Reference Scenario. They increase much more in the 450 Scenario, as a combination of stronger demand and weaker supply pushes up LNG imports to 100 bcm in 2025, before they fall back to 35 bcm by 2030 as demand drops.

**Table 13.1 • North American existing and planned LNG import capacity**

| Location | Status | Number of terminals | Capacity (bcm/year) | 2007 (imports bcm) | 2008 (imports bcm) |
|---|---|---|---|---|---|
| US Atlantic Seaboard | Existing | 5 | 38 | 14.0 | 9.3 |
| | Under construction | 2 | 13 | | |
| | Approved | 4 | 46 | | |
| US Gulf of Mexico | Existing | 5 | 82 | 8.0 | 0.7 |
| | Under construction | 3 | 51 | | |
| | Approved | 11 | 199 | | |
| US Pacific | Approved | 1 | 10 | | |
| Canada Atlantic | Existing | 1 | 10 | | |
| | Approved | 2 | 10 | | |
| Mexico Gulf | Existing | 1 | 5 | 3.5 | 3.5 |
| Mexico Pacific | Existing | 1 | 10 | | 0.2 |
| | Under construction | 1 | 5 | | |
| | Approved | 1 | 15 | | |
| **Total** | | **38** | **494** | **25.5** | **13.7** |

Note: Additional capacity resulting from expansion projects is included in the categories under construction and approved.
Sources: FERC (2009a, 2009b); IEA databases and estimates.

13

# Russia and the Caspian Region[3]

## Gas demand

In the Reference Scenario, demand for gas across East Europe and Eurasia rises from 697 bcm in 2008 to around 790 bcm in 2030. This is considerably less than the 850 bcm projected for this region in 2030 in last year's *Outlook*, primarily because of lower

3. Discussion of the Caspian region refers here to Azerbaijan, Kazakhstan, Turkmenistan and Uzbekistan.

gross domestic product (GDP) growth assumptions, as a result of the economic crisis, and higher expectations of future efficiency improvements. Russia is the second-largest consumer of natural gas in the world, after the United States, consuming 462 bcm in 2008. Gas demand in Russia is expected to fall sharply in 2009, with significant declines in industrial consumption, power generation (due to lower electricity consumption[4]) and residential gas demand. The effects of the recession, alongside anticipated improvements in efficiency, mean that demand for natural gas in Russia does not reach 2008 levels again until 2021 and remains below 500 bcm/year in the Reference Scenario throughout the projection period.

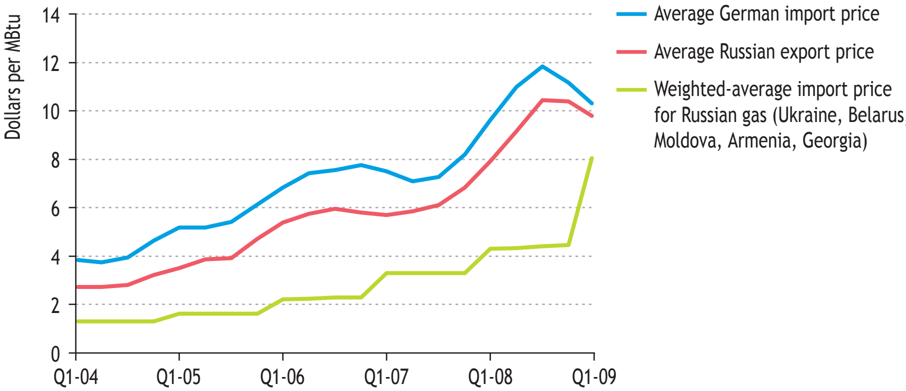
Efficiency gains in both electricity and gas use play a part in decoupling gas demand from GDP growth over the projection period; this effect is particularly visible in the 450 Scenario. In this scenario, gas demand in Russia does not return to 2008 levels, peaking at a little more than 450 bcm before 2020 before falling back to 405 bcm in 2030. While this appears to be a dramatic change in the pattern of gas use in Russia, such a scenario is consistent with some of Russia's own ambitions with regard to efficiency and gas saving. Gas demand in the 450 Scenario for the whole of East Europe and Eurasia comes to 650 bcm in 2030, less than the 697 bcm consumed in this region in 2008.

Market-based import prices, domestic price reform and the removal of subsidies are expected to play a major role in curbing gas demand growth throughout the region to 2030. Before 2006, prices for natural gas and for gas-related services such as transit among the former Soviet republics (excluding the Baltic States) were low and insulated from international market developments. However, the opportunity cost to Russia, the main supplier, of keeping these arrangements in place increased markedly as international gas prices rose after 2003. Russia's Gazprom consequently promoted a change in the pricing arrangements; the declared intention has been to move to a European netback price for regional gas trade, calculated by reference to the price available at the German border, minus the costs of transportation. No importing country has been immune from this change, although countries with close political ties to Russia, such as Armenia and Belarus, have seen a more gradual upward price trajectory. The weighted-average import price for five Eurasian countries increased more than six-fold between 2004 and the beginning of 2009, while the international oil-based price at the German border rose by around 2.7 times over the same period (Figure 13.6). Russia has also set targets to meet European netback levels for domestic consumers and, although the original deadlines of 2011 for industrial consumers and 2015 for households were extended to avoid large increases, we assume that full netback pricing will be implemented in Russia only by 2020 in the Reference Scenario.[5]

4. Electricity consumption in Russia for the first eight months of 2009 was down 6.6% compared to the same period in 2008.

5. We also assume that Russia takes an emissions cap as of 2021 and participates in a cap-and-trade scheme in the 450 Scenario.

**Figure 13.6 • Selected natural gas import prices versus Russian average export price**




Sources: BMWi (www.bmwi.de); Russia Central Bank (www.cbr.ru); IEA analysis.

The introduction of European netback-based pricing across the whole of East Europe/Eurasia promises to have significant effects on gas demand, power-generation choices and efficiency, and industry development. Because of proximity to gas resources and lower transportation costs, gas prices in Russia and other East Europe/Eurasian markets will tend to remain lower than in OECD Europe, particularly in Russia (and in members of a customs union including Russia) because of the Russian export duty on gas. Nonetheless, a clear market-based link to an international price would create a strong incentive to reduce the inefficiency of gas consumption. It would also increase the attractiveness of domestic sales for gas producers, particularly for independent producers with restricted access to export markets, as well as putting inter-state relationships among the former Soviet republics on a more transparent commercial basis.

The scope for energy saving in East Europe/Eurasia is huge, particularly in Russia, Ukraine and Central Asia (Figure 13.7). Over-consumption of energy was built into the Soviet-era industrial and municipal infrastructure, and low prices since 1991 have offered few incentives to replace ageing capital stock and improve efficiency. Russia and other hydrocarbon producers in Central Asia are among the countries that use the most energy per unit of GDP. Ukraine – a net energy importer – also stands out as an inefficient consumer of energy, a fact that compounds its reliance on imported natural gas. Russia has announced its intention to reduce its energy intensity by 40% by 2020 (which compares with a 32% reduction in the 450 Scenario), and other countries in the region have also introduced programmes and policies aimed at achieving greater efficiency (Box 13.1).

There are three main sectors in which gas demand in East Europe/Eurasia could be reduced, with the greatest potential savings to be found in Russia, Ukraine and the countries of Central Asia:

- *Power generation*: the power sector in Russia consumed more than 170 bcm in 2007 (OIES, 2009), which was more than one-third of all gas consumed in Russia and more than one-quarter of gas demand in the whole of East Europe/Eurasia. The share of gas in total power generation in Russia has increased by four percentage points since 2000, with low domestic prices making gas the fuel of choice; gas-fired power accounts for just under half of total generation. While international benchmarking of the efficiency of Russian power generation is difficult because of the prevalence of combined heat and power plants, Gazprom estimates that the average efficiency levels of gas-fired generation plants are less than 35%, compared with about 50% for modern combined-cycle units. Higher prices for natural gas, alongside continued restructuring of the electricity sector, should create strong incentives to invest in more efficient technology.[6] Over the projection period to 2030, higher prices will also shift the use of gas away from generating base-load power, particularly in regions where coal and nuclear power are more competitive, towards meeting peak demand; this effect has been seen in Ukraine since 2006.

- *Industry*: industrial production in much of East Europe/Eurasia is highly inefficient. Taking the iron and steel industry as an example, we estimate that the specific savings potential in Ukraine's steel industry is 0.21 tonnes of oil equivalent (toe) per tonne of steel produced (a savings potential equivalent to around 230 $m^3$ of natural gas per tonne). This is more than double the global average and higher than in both Russia and China (both around 0.14 toe/tonne) (IEA, 2009a). Before the economic crisis, evidence from Ukraine suggested that most industrial sectors were coping with higher gas input costs, helped by buoyant international prices for their products, and that companies were starting to put a renewed emphasis on energy-saving, measures. However, the recession is making it more difficult to fund investments in modernisation and energy-saving, and this could delay future reductions in the gas intensity of industrial output as well as putting pressure on governments to adopt a more gradual approach to domestic price reform.

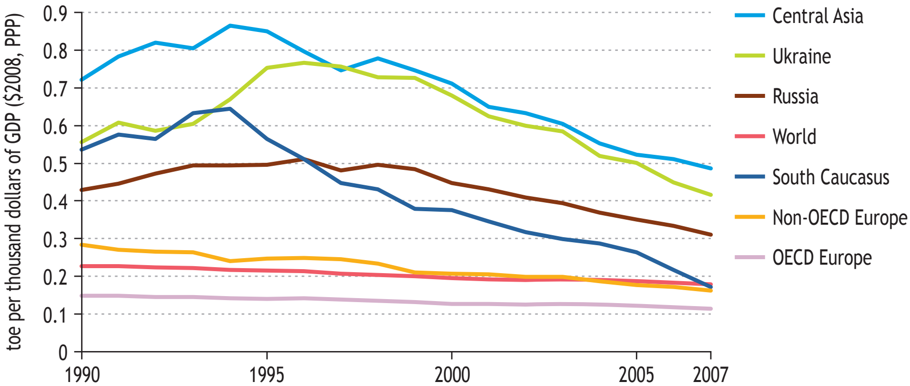
- *Residential sector and district heating*: energy used in buildings (*i.e.* for heating, hot water, cooking, lighting and appliances) accounts for around one-third of energy end use in Russia and Ukraine. Potential energy savings in this sector are linked in large measure to improvements in the extremely low efficiency of district heating systems (IEA, 2004) and enhancing the energy performance of buildings through better insulation and construction materials. Relatively high energy use in the residential sector in Russia can partially be explained by low average temperatures. However, the World Bank (2008) has compared energy intensities in Russia with those of Canada, a country with comparable average annual temperatures, and found that the energy intensity of Russia's residential sector and heating systems is still more than double the figure for Canada.

Domestic pricing reforms and energy savings from new, more efficient capital stock now represent the most economic source of incremental gas supply across much of East Europe/Eurasia. In the case of Russia, energy resources released through increased efficiency can be made available at one-third of the cost of constructing new energy supply facilities (World Bank, 2008). The increase in prices paid by Russia for gas

6. The Energy Research Institute of the Russian Academy of Sciences has calculated that the economics of upgrading capital stock become compelling once domestic gas prices rise above $100 per thousand cubic metres ($2.6/MBtu) (OIES, 2009); the average regulated wholesale gas price in Russia in 2008 was around $68 per thousand cubic metres (Gazprom, 2009).

from Central Asia (see below: Caspian gas supply) and the high costs anticipated for development of new gas fields mean that improvements in domestic gas efficiency are becoming indispensable to a healthy Russian gas balance and economy.

**Figure 13.7 ● *Energy intensity of GDP in selected countries and regions***




Note: South Caucasus refers to Armenia, Azerbaijan and Georgia; Central Asia refers to Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

Source: IEA databases and analysis.

## Russian gas supply

Russia holds the world's largest gas reserves and is the largest global gas producer and exporter. Russia has one-quarter of total proven global gas reserves, amounting to some 45 tcm, with a large undiscovered resource potential on top of this figure. The main production areas are in the Nadym-Pur-Taz region of Western Siberia and in particular three super-giant fields (Yamburg, Urengoy and Medvezhye) that were initially developed in the 1970s-1980s. Production at these fields is in long-term decline and decreased by a further 14 bcm in 2008,[7] putting pressure on state-owned Gazprom to find alternative sources of gas supply and to develop new fields, such as the nearby Zapolyarnoye field, which started producing in 2001. Over half of Russian gas is delivered to domestic consumers (Figure 13.8), but Russia is also a major exporter of gas to European markets. Both OECD Europe and the European Union as a whole rely on Russia for around one-quarter of their total gas needs, delivered in the main via transit pipelines through Ukraine and Belarus.

Gazprom has a dominant position in Russian gas production and transportation; it owns the Russian gas transmission system and has a monopoly on gas export. It also has the largest share of Russia's gas reserves. In 2008, Gazprom's internationally audited proven plus probable reserves rose 0.9% to 21 tcm and its reserves under the Russian

7. In 2008, production from the more accessible cenomanian layers of these three super-giants was 168 bcm and the depletion of the initial geological reserves of the cenomanian layers of these fields is now greater than 50%. Production declines in the Nadym-Pur-Taz region have been mitigated by the development of more challenging deeper layers at the main existing fields and by investment in neighbouring fields, both by Gazprom and by non-Gazprom companies.

classification system (A+B+C1)[8] were estimated at 33.1 tcm, an 11% increase. Aided by acquisitions, Gazprom booked more gas than it produced for the fourth year in a row: the reserve-replacement ratio for gas was a healthy 133% in 2008, up from 116% in 2007. This performance served to confirm that the adequacy of reserves in Russia is not the main issue for the period examined in this *Outlook*.

**Box 13.1 ● *Azerbaijan: a tale of higher GDP... and lower energy demand***

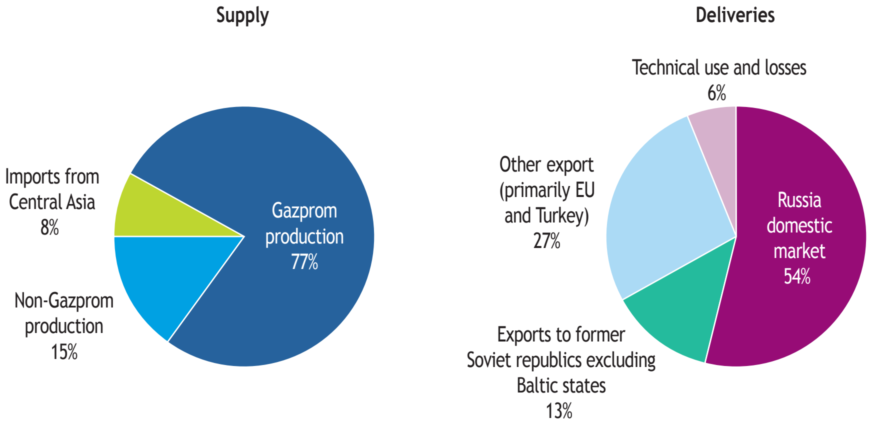
There is usually a close correlation between GDP growth and energy-demand growth, yet in Azerbaijan in 2007 these indicators started to diverge in a way that hints at the size of the energy-savings potential in parts of East Europe/Eurasia. Boosted by strong oil exports, the Azerbaijani economy expanded by 23% in 2007, one of the fastest rates of growth in the world; yet demand for electricity and for natural gas *declined* by around 15% and 12%, respectively. The discrepancy continued in 2008 in the electricity sector, with GDP growth of 11% accompanied by another 5% fall in electricity demand. Rising Azerbaijani gas production encouraged higher domestic gas use in 2008, but demand remained below 2006 levels, despite gas taking a larger share of electricity generation (substituting for fuel oil in the power mix) and serving a larger number of households connected to the grid.

How can this unusual demand-side performance be explained? Price increases for electricity and gas in January 2007 were a trigger, as was the abrupt cessation of Russian gas imports at the end of 2006 after Azerbaijan rejected Gazprom's demands for a sharply higher price. However, these events were, crucially, accompanied by a large-scale metering programme for all energy users. Over 2005-2008, Azerbaijan imported some 2.5 million meters for water, gas and electricity: this appears to have prompted both better payment discipline and a marked demand response from consumers. A second factor has been a major increase in the efficiency of Azerbaijan's gas-fired power generation, which accounts for around 90% of electricity output. Fuel consumption per kWh fell by around 10% in 2005-2008 as more efficient generating capacity came on stream, including one combined-cycle unit.

Azerbaijan's pattern of GDP growth in 2007 may not be easily replicated, but the policy of more cost-reflective prices, better metering and more efficient electricity generation could be transferred to other countries in the region. Azerbaijan is far from exhausting its energy-saving potential, but its example suggests that 10% efficiency gains can quickly be available in case of determined policy action in other former Soviet countries. A 10% share of the combined gas demand of Russia and Ukraine in 2008 would represent just under 50 bcm – more than the annual gas consumption of France.

8. The Russian reserve system differs significantly from the standards developed by the SPE-PRMS (see Box 11.1 in Chapter 11) in particular with respect to the way that commercial factors are taken into account in calculating reserves.

**Figure 13.8 • *Russia's gas balance, 2008***




Note: Figures are net of withdrawals and injections into gas storage, and do not include flared gas.

Sources: Gazprom (2009); Russian Ministry of Industry; IEA statistics.

Despite this strong underlying position, there are still uncertainties about the future trajectory of Russian gas production and exports. Russian officials acknowledge that the gas provinces in western Siberia that provide much of current production could account for as little as 26% to 30% of total output by 2030. Many observers, including the IEA, have looked at the high cost and complexity of new fields that will need to be developed in places such as the Yamal peninsula and the Barents Sea, and asked whether sufficient investments are being made to ensure adequate and timely gas supplies to domestic and foreign consumers. A lower demand outlook has given Gazprom additional time to bring new fields into production and eased concerns about supply in the period to 2012-2014. But, in some ways, the task of getting the timing and adequacy of investment right in Russia has become even more complicated since the last *Outlook*.

First, the precipitous short-term decline in demand for Russian gas, due to the economic crisis, has meant a similarly sharp fall in revenue, reducing the funds available for new investment. Gazprom expects export earnings to fall by 38% in 2009 compared to 2008, and company officials have indicated that Gazprom's investment programme for 2009 will fall by around 47%, from the $27.8 billion foreseen in mid-2008, to a revised figure of $14.6 billion (see Chapter 3). Funds available for new field development have been squeezed by continued Gazprom acquisitions, including in 2009 the purchase of Eni's 20% stake in Gazpromneft for $4.2 billion. This followed other large financial investments such as the 50% stake in Sakhalin Energy (the Sakhalin-II project), as well as assets in the power sector, including Mosenergo, the power company that provides heat and electricity to Russia's capital. Total Gazprom spending on acquisitions since 2004 had reached $43 billion as of mid-2009.

Second, there are greater medium-term uncertainties on the demand side, complicating decisions on the timing of new investment. It is not certain how quickly gas demand will recover following the crisis and, more broadly, how much gas Gazprom's domestic consumers and main European export markets will require as new policies on efficiency, nuclear power and renewable energy resources are implemented in the period to 2020 (see below: OECD Europe/European Union). New gas market dynamics – particularly in North America – have also called into question the viability of Russia's ambitions to become a player in the Atlantic LNG market.

Third, the imports from Central Asia that had provided a relatively cheap and flexible supplement to the Russian gas balance in recent years have become more expensive and subject to competition from other purchasers, notably from China. Finally, the gas dispute with Ukraine in January 2009 has cast a shadow over the reliability of existing transportation routes for Russian gas export (see Chapter 2).

Development of gas fields on the Yamal peninsula (Figure 13.9) has become the key to Russia's future gas supply over the projection period. Explored reserves on the peninsula amount to more than 10 tcm and Gazprom projects that the peninsula and adjacent offshore areas could support gas production of 310 bcm to 360 bcm/year by 2030. Development of Yamal had been held back by concerns over costs and economic viability at a time of lower international prices and continuing subsidies to domestic sales. In the meantime, imports from Central Asia, additional output from the Nadym-Pur-Taz region (notably the major Zapolyarnoye field, see Table 13.2) and production from non-Gazprom producers helped to bridge the gap. However, despite efforts to extend production and mitigate decline rates in the Nadym-Pur-Taz region, Gazprom is reaching the limits of this "bridging strategy" and has yet to take alternative action – for example, the development of smaller fields in the Ob-Taz bay area – that could help to bolster supply in the period to 2015. Getting the timing right for Yamal production is of crucial strategic importance for Gazprom and Russian policy makers.

**Figure 13.9 ● *Eurasian main gas production areas and pipeline routes***

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Sources: Petroleum Economist; IEA databases.

Gazprom formally launched the Yamal mega-project in 2008 with the start of construction of an export pipeline across the Baidarata Bay that will link the peninsula to the main export route from Western Siberia. Gazprom invested around $4 billion in Bovanenkovskoye field development in 2008 and has made substantial progress with some of the most technically challenging aspects of the project, notably the difficult underwater crossing of Baidarata Bay. However, planned investment at Bovanenkovskoye in 2009 has been cut by 15% to $5.9 billion, which has slowed the envisaged pace of field operations and pipeline construction. First gas from the field is now expected by Gazprom in the latter part of 2012, a year behind the previous schedule, pushing the date for peak production at this field beyond 2015. As suggested by Table 13.2, there are no other major fields likely to deliver substantial incremental gas during the period to 2015. Yamal presents considerable technical and logistical challenges, due to its remote location, extreme climate and permafrost, which could easily cause further delays. If such delays materialise and demand for Russian gas picks up quickly following the end of the economic crisis, this could yet lead to a tightening of the Russian gas balance during the period 2012-2014.

After 2015, there are numerous fields that could deliver production growth in Russia, in particular from the Yamal peninsula and surrounding areas, but also from the offshore Barents and Kara Seas, East Siberia and the Russian Far East. The Shtokman field in the Barents Sea is estimated to contain 3.8 tcm of gas and is the first major offshore gas project for the Russian gas industry. Shtokman is a very challenging field that is located 550 km from the northern Russian coastline in inhospitable Arctic conditions. According to current plans, the field will be developed in three phases of 24 bcm each, with output split between export by pipeline (linking eventually to the Nord Stream pipeline) and LNG export of 30 million tonnes (Mt) per year (around 40 bcm/year) from a new liquefaction plant near Murmansk. No final investment decision for the project has yet been taken and the official expectations of first pipeline gas from Shtokman in 2013 and first LNG in 2014 are already looking very optimistic. In the Reference Scenario, we anticipate that Shtokman will reach peak production only towards 2025.

**Table 13.2 ● *Selected current and prospective gas fields in Russia***

| Name of field | Production area | Peak production (year*) | Remarks |
|---|---|---|---|
| ***In production*** | | | |
| Yuzhno-Russkoye | Nadym-Pur-Taz | 25 bcm/y *(2009)* | Gazprom partnership with Wintershall and (from 2009) E.ON |
| Kharvutinskaya (at Yamburg) | Nadym-Pur-Taz | 30 bcm/y *(2010)* | Southern part of the existing super-giant Yamburg field |
| Sakhalin II | Russian Far East | 13 bcm/y *(2010)* | Twin train LNG export, Gazprom-Shell-Mitsui-Mitsubishi |
| Zapolyarnoye | Nadym-Pur-Taz | 130 bcm/y *(2012)* | First gas 2001, output accelerated to offset decline in nearby fields |
| Astrakhanskoye | Volga region | 50-60 bcm/y *(post-2015)* | Expansion of production (current 12 bcm/y) |
| ***Prospective*** | | | |
| Bovanenkovskoye | Yamal peninsula | 115-140 bcm/y *(post-2015)* | Gazprom license-holder, first and main Yamal development |
| Kharasaveiskoye | Yamal peninsula | 40-45 bcm/y *(post-2015)* | 70% onshore, second major Gazprom priority on Yamal |

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**Table 13.2 • Selected current and prospective gas fields in Russia** (continued)

| Name of field | Production area | Peak production (year*) | Remarks |
|---|---|---|---|
| Kovytka | East Siberia | 30 bcm/y *(post-2015)* | Licence owned by TNK-BP, although 2007 agreement to sell to Gazprom |
| Shtokman | Offshore Arctic | 71 bcm/y *(post-2020)* | Barents Sea, first phase Gazprom with Total and StatoilHydro |
| Chayandinskoye | East Siberia | 32 bcm/y *(post-2020)* | License transferred to Gazprom in 2008 |
| Yuzhno-Tambeiskoye | Yamal peninsula | 31 bcm/y *(post-2020)* | Among largest of the Tambey group of fields; Novatek 51% share |

* IEA estimate of date of peak production for prospective gas fields.

Sources: Gazprom (2009); press and other company reports.

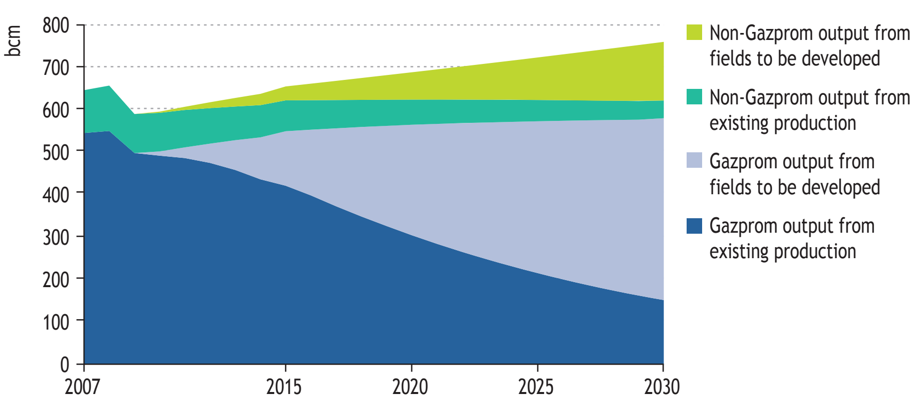
Gas production in East Siberia and the Russian Far East is a priority for Gazprom but, with the exception of the Sakhalin-II project, growth in output is expected only closer to 2020. Gas from eastern parts of Russia is seen by Russian policy makers both as a driver for regional social and economic development and also as a resource for export to East Asian markets. Both of these ambitions will require a substantial amount of new gas infrastructure; gas export would also require sale and purchase agreements with foreign partners that have yet to be put in place. After the Sakhalin projects, the 2-tcm Kovytka field in Eastern Siberia had been seen as the most likely new source of gas from this region, but the licence-holder, Rusia Petroleum (in which TNK-BP had a majority share), has been restricted in its ability to pursue field development and gas marketing. A deal to sell TNK-BP's stake in Rusia Petroleum to Gazprom was provisionally concluded in 2007 but has yet to be completed; Gazprom has indicated that development of the field could be pushed back past 2017. Gazprom also received in 2008 a licence for the 1.2-tcm Chayandinskoye oil and gas condensate field in the Republic of Sakha, but first gas from this field is likewise not foreseen until after 2015. Russian pipeline exports to East Asian markets, including China, are expected only after 2020.

Gazprom is expected to maintain its predominant position in the Russian gas industry throughout the projection period, but the role of other producers will nonetheless grow. By 2020, price reform and the removal of subsidies in the Russian market are expected to increase the commercial attraction of domestic sales – to the point at which sales in both domestic and export markets will be equally profitable for producers. Under these circumstances, even if non-Gazprom producers are left without access to export markets they will still have strong commercial reasons to produce and market gas output. Non-Gazprom producers already account for around 15% of total production and companies such as Novatek and Lukoil have very substantial gas reserves that could be developed if the price incentives are in place and if they have reliable access to the gas transportation network. Novatek, in which Gazprom owns a 19.4% stake, produced more than 30 bcm in 2008 and plans to increase output to 65 bcm by 2015.

Reductions in the amount of flared gas could make an important contribution to output growth and reduce $CO_2$ emissions at the same time (IEA, 2006). Data on associated gas and the extent of flaring differ widely by source, but a study completed for the Global Gas Flaring Reduction partnership (GGFR, 2008) estimated that Russian oil producers flare some 38 bcm/year of gas, around 45% of the country's associated gas production, with a further 10 bcm/year being flared from gas condensate production. Together, producers in Russia and the Caspian region account for around 40% (60 bcm) of the 147 bcm of gas that is estimated to have been flared globally in 2007 (Table 12.2). Options for commercialisation of this gas depend on field size and location, but the study estimated that it could be viable to utilise up to 80% of gas, currently flared within Russia. Russian policy aims to achieve a 95% use of associated gas, and a balanced combination of regulation and economic incentives could reduce flaring substantially by 2015.

In the Reference Scenario, total Russian gas production is projected to rise from 657 bcm in 2008 to 760 bcm in 2030 (Figure 13.10). Based on production forecasts and assuming a decrease in flared gas, non-Gazprom production could increase from 101 bcm in 2008 to at least 180 bcm by 2030, which would represent 24% of total gas output in the Reference Scenario. Gazprom output is expected to recover to around 580 bcm by 2030. Three-quarters of this production – close to 430 bcm – will need to come from new fields, taking account of decline at existing fields. In the 450 Scenario, however, Russian output is constrained by the lower demand for gas, both in the domestic market and in Russia's main export markets. In this case, Russian output does not return to 2008 levels and peaks at around 651 bcm after 2020, before declining to 580 bcm in 2030. Russia would nonetheless remain the largest global gas producer in the 450 Scenario and its 16% share of global gas production in 2030 is comparable to the 18% projected in the Reference Scenario. The 450 projections have very significant implications for the level, type and timing of investment necessary in the Russian upstream and midstream. While we calculate that total investment of $386 billion in gas exploration and production would be required from 2008-2030 in the Reference Scenario, this figure would fall to $318 billion in the 450 Scenario.

**Figure 13.10 • *Russia's gas production by source in the Reference Scenario***




Note: Split between Gazprom and non-Gazprom production is indicative.

Source: IEA analysis.

Gazprom's current pipeline priorities are the Nord Stream pipeline, which would connect Russia directly to Germany across the Baltic Sea, and the Yamal pipeline system, which will bring new gas production from the remote peninsula across

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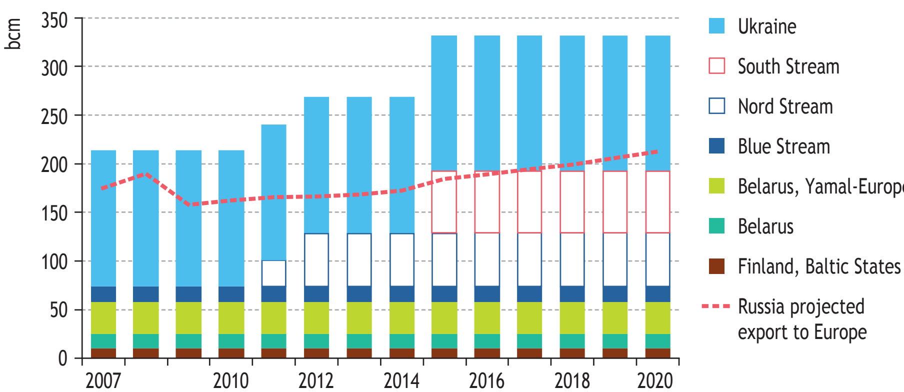
Northwest Russia towards Europe. Progress with Nord Stream depends in the short term on securing all necessary environmental permits; if these are forthcoming by the end of 2009, then the first 27.5 bcm capacity line could be commissioned towards the end of 2011, with a later second string doubling capacity. Alongside Gazprom (51%), other current project partners are E.ON Ruhrgas and Wintershall (20% each) and Gasunie (9%), with GDF Suez also a potential shareholder.

The 55-bcm capacity of the completed pipeline has the potential to change the pattern of Russia's export flows significantly and result in lower utilisation of the existing routes through Ukraine and Belarus – and therefore also the routes through Slovakia, Poland and the Czech Republic (Figure 13.11).[9] This effect would be amplified if the South Stream pipeline across the Black Sea to southeast Europe is also constructed. The main project partners, Gazprom and Italy's Eni, announced their intention in 2009 to double the design capacity of this pipeline project to 63 bcm; a final investment decision on South Stream is provisionally foreseen for 2011.

**Figure 13.11 • Projected Russian gas exports to Europe and potential growth in gas-export capacity**




Note: Russia's projected export to Europe is from the Reference Scenario; it includes export to OECD Europe, the European Union and other countries in Southeast Europe, and excludes export to Ukraine, Belarus and Moldova. Dates for commissioning of Nord and South Stream are planned dates indicated by project sponsors and are not IEA projections.

Disputes over gas supply and transit with Belarus (in 2004) and with Ukraine (in 2006 and 2009) have reinforced Russia's quest for diversity of transportation routes and – wherever possible – direct connections with export markets, in order to reduce dependence on transit countries. If both Nord Stream and South Stream are built with the capacities currently envisaged, some 118 bcm of new export capacity would be added – significantly more than would be required to meet Russia's projected medium-term exports to Europe. With spare capacity potentially available on other routes, the question remains whether transit costs and risks justify the additional up-front investment in new underwater pipeline

9. During the 1990s, over 90% of Russia's gas exports to Europe were exported via Ukraine. Dependence on Ukrainian transit routes fell below 70% with the launch of new pipelines through Belarus (Yamal-Europe) in 1999 and across the Black Sea to Turkey (Blue Stream) in 2003.

capacity; capital expenditure per kilometre of sub-sea pipeline tends to be significantly higher than for overland routes, even if the pipeline length and operating costs over the lifetime of a project may be lower. In our projections, we assume that Nord Stream is completed before 2015 and that additional pipeline capacity is built for transportation of gas through southeast Europe by 2025. We do not take a view on the timing of the main pipeline projects (South Stream, Nabucco, the Greece-Italy Interconnector and the Trans-Adriatic Pipeline) that are foreseen for this region.

## Caspian gas supply

Projections of gas supply from the Caspian region to 2030 are adjusted upwards in this year's *Outlook*, on the back of new estimates of gas reserves in Turkmenistan and improved prospects for access to international gas markets on a commercial basis. In the Reference Scenario, production of natural gas in four Caspian producers (Azerbaijan, Kazakhstan, Turkmenistan and Uzbekistan) is projected to grow from 180 bcm in 2008 to almost 220 bcm in 2015 and 310 bcm in 2030, making a significant contribution to production growth in Eurasia. The 450 Scenario continues to project growth in Caspian gas output, albeit at a far slower rate, with production from the four Caspian countries reaching 208 bcm in 2015 and 235 bcm in 2030.

Reliable estimates of Caspian gas reserves have been held back by a lack of exploration and verifiable appraisal in Turkmenistan, the largest gas producer in the region. This started to change in 2008 with an international audit of gas discoveries in southeast Turkmenistan, including the South Yolotan/Osman field (Box 13.2). More work is still required to define the resource base and higher reserve estimates for Turkmenistan are not yet reflected in all the international reference sources,[10] but the available evidence suggests that gas reserves in Turkmenistan are more than sufficient to support an expansion in gas production and export.

**Table 13.3 ● Natural gas production of Caspian region producers and Russia in the Reference Scenario** (bcm)

| | 2000 | 2007 | 2015 | 2030 | 2007-2030* |
|---|---|---|---|---|---|
| Azerbaijan | 6 | 11 | 20 | 43 | 6.2% |
| Kazakhstan | 12 | 30 | 43 | 70 | 3.8% |
| Turkmenistan | 47 | 69 | 86 | 118 | 2.3% |
| Uzbekistan | 56 | 65 | 68 | 75 | 0.6% |
| **Total Caspian** | **121** | **175** | **217** | **306** | **2.5%** |
| Russia | 583 | 646 | 655 | 760 | 0.7% |

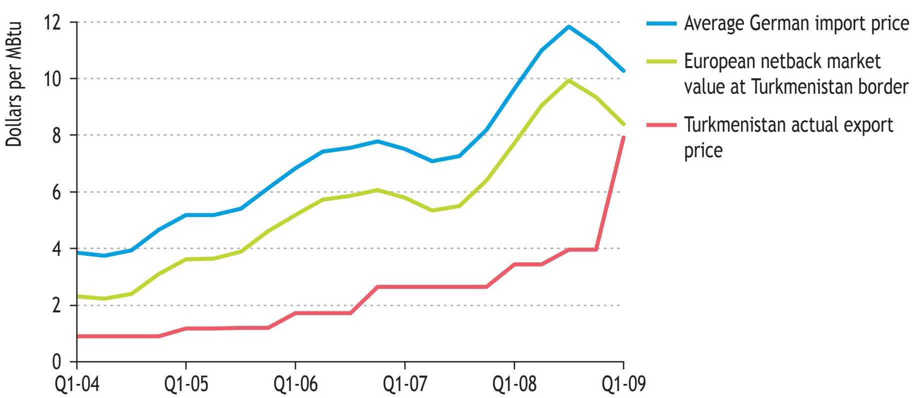
* Compound average annual growth rate.

10. Cedigaz (2009) provides a figure of 3 tcm for Turkmenistan gas reserves (up from 2.68 tcm in 2008) while BP (2009) revised its estimate from a similar starting point up to 7.94 tcm; these are still lower than Turkmenistan's own estimates, which are in excess of 20 tcm.

Russia provides the route to market for over 85% of the gas exported from Kazakhstan, Turkmenistan and Uzbekistan. The price paid by Gazprom for East Caspian gas has increased sharply since 2006 and, in March 2008, Gazprom and the heads of the national oil and gas companies announced that trade in Central Asia gas would, from 2009, take place at "European-level" prices – implying parity with the price for Russian exports to the main European markets, minus the costs of transportation and storage back to the relevant delivery point in Central Asia. The terms of gas trade with Turkmenistan have since become a major source of contention, as Gazprom has been interested in limiting its take in 2009, while European gas demand remains weak. Nonetheless, Gazprom's readiness to concede higher export prices reflects the importance that Central Asian gas has assumed in the Russian gas balance, as well as increased competition for Caspian gas resources from China and other potential consumers in Europe and southern Asia.

The availability of Turkmenistan gas at relatively low prices has been an important feature of the Eurasian gas balance in recent years. Based on natural gas prices at the German border and available information on transportation and transit costs, we estimated the European netback price for deliveries at the Turkmenistan-Uzbekistan border (Figure 13.12) for the years 2004-2009 and measured the actual Turkmenistan price at this delivery point against this benchmark. The difference between these two prices represents potential value from Turkmenistan gas export that did not accrue to Turkmenistan itself. The value of this lost rent is estimated at $25.9 billion over the five years to 2009; most of this went to Ukraine, whose import price was closely correlated with the Turkmenistan export price over this period, but a significant share also went to non-transparent intermediaries involved in the gas trade from Central Asia.

**Figure 13.12 • Turkmenistan gas-export price and the European netback market value**




Sources: BMWi (www.bmwi.de); IEA analysis.

Caspian producers are seeking to diversify their export options, as a means to ensure more reliable market-based export pricing, and improvements in the region's access to international markets underpin a more positive investment and production outlook to 2030. A pipeline from Turkmenistan to China, via Uzbekistan and southern Kazakhstan, is expected to begin operation in 2010, meaning that Central Asian producers will have pipeline links both to Europe via Russia and also to the fast-growing Chinese market. There are plans to upgrade and partially re-build the export pipelines leading northwards to Russia, although these intentions have yet to be turned into investment commitments. To the west of the Caspian, deliveries from Azerbaijan to Georgia and Turkey along the South Caucasus Pipeline began at the end of 2006. Gas trade along this southern corridor is expected to expand during the projection period, with several pipelines, including the Nabucco project and the Italy-Greece-Turkey interconnector, seeking to bring additional gas from Azerbaijan and other regional producers to Turkey and other European markets.

*Turkmenistan* is the Caspian region's largest gas producer and, with a relatively small domestic market and a population of fewer than 5 million, by far the largest exporter. Of the 71 bcm produced in 2008, just over 50 bcm was exported, primarily to Russia but also to Iran. The Turkmenistan government has ambitious targets to raise production to 250 bcm/year by 2030, of which 200 bcm would be exported. While the resource base could conceivably support an expansion of this magnitude, there is considerable uncertainty that sufficient investment will be forthcoming. The next generation of Turkmenistan gas output will be more expensive and complex to develop than gas produced up until now because it is deeper, at higher pressure and temperature, and has higher concentrations of hydrogen sulphide and carbon dioxide ($CO_2$). We estimate that, in order to reach the official target, cumulative investment in Turkmenistan gas exploration and production would need to reach $100 billion during the period 2009-2030, an average of $4.5 billion per year. Improved access to external financing and a large increase in foreign direct investment will be essential even to get close to these levels of upstream spending. Turkmenistan's total revenue from gas export in 2008 was $6.2 billion (ADB, 2009) – and this is the main source of Turkmenistan public sector spending.

The Amu Darya basin in onshore eastern Turkmenistan will continue to be the primary source of Turkmenistan gas output, but with a shift over time from the Dauletabad and Shatlyk production areas – the mainstays of Turkmenistan output up until today – to new fields, such as South Yolotan/Osman (see Box 13.2) and the area being explored by China's CNPC on the right bank of the Amu Darya river. The offshore Caspian shelf will also emerge as a source of higher gas production, with the Turkmenistan government welcoming foreign direct investment in this area. Offshore output is projected to reach 10 bcm/year by 2015; further increases thereafter will be facilitated by agreement between Turkmenistan and Azerbaijan on their maritime border, which would open up development of a large and promising field (called Serdar in Turkmenistan, Kyapaz in Azerbaijan) lying in a disputed area of the Caspian Sea.[11]

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11. Turkmenistan announced its intention in July 2009 to submit this dispute to international arbitration.

**Box 13.2 ● *South Yolotan/Osman: a Turkmen super-giant***

Confirmation of a major gas discovery in south-eastern Turkmenistan is helping to resolve some of the uncertainty about the size of Turkmenistan's gas resources. Fields at South Yolotan and nearby Osman were discovered in 2003 and 2006, respectively, and in 2008 an international audit assessed the amount of gas initially in place at South Yolotan/Osman (now considered a single structure) as falling within a range of 4 tcm to 14 tcm of natural gas, with a best estimate of 6 tcm – equal to more than the entire proven reserves of Europe. More appraisal work will be needed to see how much of this gas can be recovered, but even if one uses the lower estimate of initial gas and then applies some pessimistic assumptions about the level of recoverable resources, South Yolotan/Osman is still one of the largest discoveries of recent years. The best estimate of 6 tcm puts the Turkmenistan field fourth among the world's biggest conventional gas fields by initial reserves (Table 11.6; assuming that South Pars and the North Field are counted as a single field).

The initial development plan for South Yolotan/Osman envisages four phases, each of 10 bcm/year, with first gas being produced in 2011-2012 and initial production reaching 40 bcm/year by 2014. A challenge for Turkmenistan is to mobilise all the expertise and financial resources required to develop such a large and complex gas field. China agreed in June 2009 to provide a loan of $3 billion for South Yolotan/Osman, but given technical challenges (including an average non-hydrocarbon gas content of around 8%) and the pattern of delays experienced by other large investment projects in the Caspian region, the announced schedule could well slip. The involvement of international companies in onshore gas development in Turkmenistan has been held back by the government's insistence that their role be limited to providing assistance on a contractual basis to state-owned Turkmengaz. Although one exception was made in 2007 for China's CNPC, which has a production-sharing agreement for gas development on the right bank of the Amu Darya river, near the border with Uzbekistan.

Turkmenistan has existing export commitments to Russia, Iran and, from 2009, also to China, and there are signs that Turkmenistan is seeking as much flexibility as possible in making future gas volumes available for export. An international tender was launched in 2008 for an East-West pipeline that would link the new production areas in eastern Turkmenistan with the Caspian coast. This pipeline would enhance Turkmenistan's ability to bring large volumes of gas to delivery points for different potential purchasers. Although the focus in the projection period will be upon exports to Russia, China and Iran, Turkmenistan's future export options could include a link across the Caspian Sea to Azerbaijan and along a southern gas corridor to southeast Europe.

In the Reference Scenario, Turkmenistan's gas production is projected to rise from 71 bcm in 2008 to 86 bcm in 2015, and then increase more strongly to 118 bcm in 2030. An initial challenge for Turkmenistan will be to recover from a significant fall in output in 2009, resulting from an explosion on the main northern export route in April and a lengthy dispute with Russia about the terms of gas sales. Nonetheless, the medium-term signs are positive, as new export options become available. After 2015, production increases are expected to come mainly from the South Yolotan/Osman field and other new fields in the Amu Darya basin. Our Reference Scenario projections would require total exploration and production investment of $65 billion during the period to 2030. China has a strong interest in supporting and financing development of Turkmenistan reserves in order to bring exports along the new Turkmenistan-China pipeline up towards the contracted level of 40 bcm/year. Exports from Turkmenistan to Russia and Iran are expected to increase more slowly from the current levels of around 50 bcm. In the 450 Scenario, Turkmenistan output rises to 82 bcm in 2015 and to 90 bcm in 2030.

In contrast to Turkmenistan, most gas output in *Kazakhstan* is associated with oil production. Although Kazakhstan has proven reserves of 1.91 tcm, upstream operators in Kazakhstan have not given priority to gas output and this has a significant impact on the timing and volume of gas available for sale and export. Total gas production was 26 bcm in 2008, but volumes of sales gas have been less than 50% of total output in recent years, with most of the balance re-injected to maintain reservoir pressure and support oil production. A further complication is that — with the exception of the Karachaganak field, Kazakhstan's main gas-producing field — gas reserves are sour, with over 15% non-hydrocarbon content at the Tengiz and Kashagan fields. In the case of Karachaganak in northern Kazakhstan, the gas output is not processed within Kazakhstan but is piped untreated across the border to the Orenburg gas processing plant in Russia.

For these reasons, production of marketable gas in Kazakhstan and the amounts of gas available for export are set to remain modest for much of the projection period. This is expected to change after 2025, as oil reserves in some of the main fields become depleted and the incentives improve to produce and market the associated (and re-injected) gas. In the Reference Scenario, Kazakhstan's total gas output rises to 70 bcm in 2030 from 26 bcm in 2008, although this output falls to 53 bcm in 2030 in the 450 Scenario. As well as export to Russia, Kazakhstan will have also the possibility of feeding gas into the Turkmenistan-China pipeline that will be in operation through southern Kazakhstan from 2010.



*Uzbekistan* is the second-largest of the Caspian producers, after Turkmenistan, with production of 67 bcm in 2008. But it is only a marginal player in international gas trade, because of high and inefficient domestic consumption: exports in 2008 were around 15 bcm. A constraint on future output growth is the fact that, although reserves are estimated at 1.75 tcm, remaining reserves are spread among a large number of relatively small fields. Funds available for investment have been scarce because of subsidised low prices on the domestic market and the limited participation of international investors: Russia's Gazprom and Lukoil and companies from Malaysia, Korea and China are the main foreign investors in the Uzbekistan gas sector. Lukoil, in particular, is set to increase its gas production to more than 10 bcm/year by 2015. However, foreign investors accounted for only 5% of total production in 2007 and their role is likely to remain small relative to state-owned Uzbekneftegaz. Gas savings through greater efficiency in the domestic market could increase the volumes available for export, but a fast growing population and political constraints on gas-sector reforms will dampen this effect. Overall, gas output in Uzbekistan is expected to rise only slightly over the projection period in the Reference Scenario, from 65 bcm in 2007 to 68 bcm in 2015 and 75 bcm in 2030; the 450 Scenario projects a decline to 57 bcm in 2030. Reference Scenario projections would allow gas exports to increase to 20 bcm to 25 bcm/year by 2030: Russia remains the predominant export market, although – as in Kazakhstan – new infrastructure running through Uzbekistan from 2010 opens up the possibility of gas trade with China.

On the western side of the Caspian Sea, *Azerbaijan* is set to consolidate and expand its position as a net exporter with a focus on European markets, but the timing, direction and marketing arrangements for future gas export remain uncertain. Despite Azerbaijan's potential, these uncertainties hold back projections of future output, which are seen in the Reference Scenario as 20 bcm in 2015 and 43 bcm in 2030. Lower demand also plays a greater role in the 450 Scenario in constraining future output, which is projected to be 34 bcm in 2030.

Azerbaijani gas production increased by around 50% to 16 bcm in 2008 on the basis of Phase I development of the offshore Shah Deniz field, but a decision to sanction Phase II development has been delayed to 2016, pending the outcome of discussions on the terms for gas trade with Turkey and other European markets. Phase II field development, which could bring an additional 14 bcm to 16 bcm/year to market, will be the main incremental gas supply potentially available for European markets from the Caspian region before 2020. Future increments before 2030 are also possible from the Absheron field, where Total will drill a first exploratory well in 2010, and from deep horizons under currently producing reservoirs at Shah Deniz and the oil-producing ACG complex.

## OECD Europe/European Union

### Gas demand

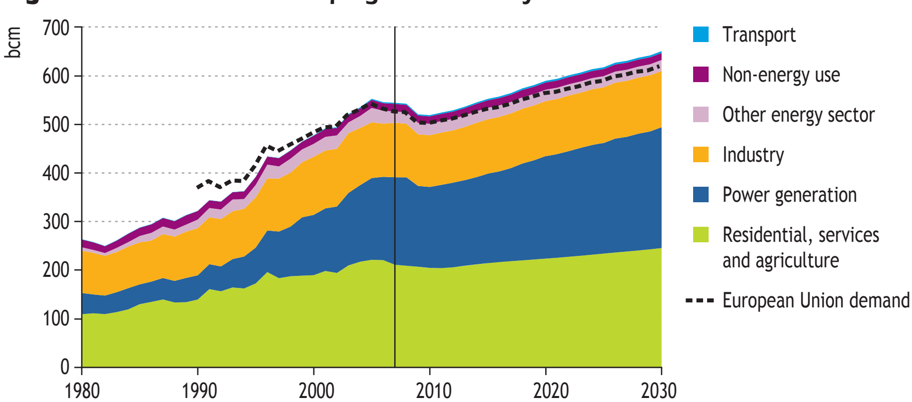
Gas demand in Europe has been severely affected by the economic slowdown and it will take time before demand recovers to the levels seen in 2007-2008. Lower industrial and electricity demand has fed through into the gas sector, and this effect was amplified in the first half of 2009 in continental Europe because of the way that gas is priced. The delayed link between continental European gas prices and falling oil prices meant that gas-fired power remained relatively expensive and was among the first fuels to be affected by lower electricity demand. Lower demand pushes the gas plants with lower efficiency out of the electricity generation mix, meaning that less gas is needed to generate a given amount of electricity. New national and European policies on efficiency and renewable energy sources have raised additional questions about the future trajectory of European gas demand.

Despite these uncertainties, some fundamental drivers continue to underpin gas demand in Europe throughout the projection period and chief among these is the use of gas for electricity generation. Gas burned in efficient combined-cycle gas turbines has some important advantages over competing fuels, notably over coal, which has been the main rival to gas for thermal generation in Europe. As discussed in Chapter 10, these advantages include lower up-front investments, shorter construction lead times, more flexible operation and lower greenhouse-gas emissions. Clear signals for carbon prices coming from the EU Emission Trading System can also improve the position of gas versus coal, since coal-fired generation produces around twice the amount of $CO_2$ per unit of electricity generated.

Gas-fired capacity can also support indirectly Europe's drive to increase the share of electricity generated from renewable energy sources. Output from a number of renewable energy technologies, such as wind but also wave, tidal, solar and run-of-river hydro, varies according to the availability of the resource and this variability can affect the reliability of electricity supply. However, if an overall power system is sufficiently flexible in terms of production, load management, interconnection and storage, the importance of the variable profile of renewable power generation is reduced (IEA, 2008b). Gas turbines are able to respond quickly to the need for additional generation and their relatively low capital cost makes them a preferred choice to provide back-up capacity. This means that an increasing share of electricity generated from renewable sources can be associated with continued growth in gas-fired capacity.

In the Reference Scenario, gas demand in OECD Europe recovers to the 2008 level of 552 bcm in 2015 and then rises steadily to 651 bcm in 2030 (Figure 13.13). The projections for the European Union show a similar trajectory, with demand amounting to 619 bcm in 2030. The gap between projected demand in OECD Europe and in the European Union increases slightly through the projection period, mainly because gas demand increases more quickly in Turkey than in other, more mature, European markets. Gas demand for power generation increases more quickly than demand in other sectors. While the average annual increase in gas demand in OECD Europe for the period 2007-2030 is 0.8%, the figure for gas used in electricity generation is 1.4%.

**Figure 13.13 • OECD Europe gas demand by sector in the Reference Scenario**




In the 450 Scenario, gas demand takes longer to return to the 2008 levels, reaching 550 bcm in OECD Europe only after 2020, before falling away to 525 bcm in 2030. Demand figures for the European Union in the 450 Scenario likewise peak in the early 2020s, before tailing off to 509 bcm in 2030. These figures are driven by the assumption that the European Union – along with all OECD countries – adopts stringent targets to reduce greenhouse-gas emissions by 2020 that affect both industry and power generation, and that these are intensified in the period to 2030. Higher prices for $CO_2$ feed into electricity prices, reducing overall demand, and they also constrain the position of gas in the fuel mix. Whereas gas-fired power generation accounts for 24% of all electricity generated in the European Union in 2030 in the Reference Scenario, up from 22% in 2007, the corresponding figure in the 450 Scenario for 2030 is only 17%. The commercial introduction of CCS technology in power generation after 2020 only partially mitigates the decrease in gas demand for power generation.

**Table 13.4 • Europe's gas balance by scenario** (bcm)

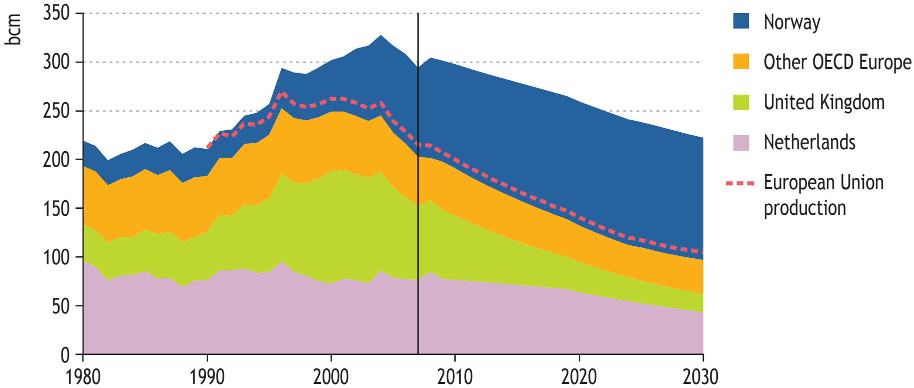
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007-2030* |
|---|---|---|---|---|---|---|
| ***OECD Europe:*** *Reference Scenario* | | | | | | |
| Demand | 544 | 552 | 590 | 617 | 651 | 0.8% |
| Supply | 294 | 279 | 260 | 239 | 222 | -1.2% |
| Net imports | 250 | 273 | 330 | 379 | 428 | 2.4% |
| ***OECD Europe:*** *450 Scenario* | | | | | | |
| Demand | 544 | 527 | 541 | 550 | 525 | -0.2% |
| Supply | 294 | 268 | 245 | 210 | 171 | -2.3% |
| Net imports | 250 | 259 | 295 | 340 | 354 | 1.5% |
| ***European Union:*** *Reference Scenario* | | | | | | |
| Demand | 526 | 532 | 564 | 589 | 619 | 0.7% |
| Supply | 214 | 167 | 139 | 116 | 103 | -3.1% |
| Net imports | 312 | 365 | 425 | 473 | 516 | 2.2% |
| ***European Union:*** *450 Scenario* | | | | | | |
| Demand | 526 | 512 | 523 | 533 | 509 | -0.1% |
| Supply | 214 | 162 | 132 | 103 | 81 | -4.2% |
| Net imports | 312 | 350 | 391 | 430 | 428 | 1.4% |

* Compound average annual growth rate.

## Gas supply

Despite rising output in Norway up to 2025, the Reference Scenario projects that overall gas production in Europe will decline steadily over the period to 2030 (Figure 13.14). Gas produced in OECD Europe falls from 309 bcm in 2008 to 279 bcm in 2015 and 222 bcm in 2030. The decrease within member states of the European Union is even more pronounced, since Norwegian production is excluded: from 217 bcm in 2008, EU gas supply tails off to just over 100 bcm in 2030, less than half the current level. Production of unconventional gas (mainly coalbed methane [CBM] and shale gas) in Europe is projected to pick up after 2020 and to reach 15 bcm by 2030; this partially mitigates the rate of decline but is not seen for the moment as changing substantially the overall gas supply picture for Europe (see Chapter 11).

**Figure 13.14 • OECD Europe gas production by source in the Reference Scenario**




Bolstered by the recent development of fields such as Ormen Lange and Snøhvit, the Reference Scenario projects a continued rise in Norway's gas production to 120 bcm in 2015 and 129 bcm in 2024, before it falls back slightly to 126 bcm in 2030. Norway's oil output has been declining since 2001, but natural gas production has continued to increase and exceeded 100 bcm in 2008. Reserves are estimated at 3 tcm, 1.6% of the global total, but there has been an encouraging success rate from recent exploration. Fifteen gas discoveries in 2008 added a total of 49 bcm to 97 bcm to recoverable gas reserves and in 2009 Shell announced the discovery of the Gro field in the Norwegian Sea with 10 bcm to 100 bcm of recoverable gas. Total investment in upstream oil and gas in 2009 is estimated at $22.7 billion, with investment in exploration slightly higher than in 2008 and investment in field development 12% up on the previous year. This bucks the trend observed by the IEA of lower upstream investment resulting from the economic slowdown (see Chapter 3). Norway is the second-largest exporter of gas to the European Union after Russia and is set to remain an important gas supplier to European markets, notably to Germany, the United Kingdom and France. The Snøhvit project in the Barents Sea exports around 6 bcm/year of LNG to Europe, and possibly North America, during the projection period to 2030, but the bulk of Norway's gas exports continues to go via pipeline to European markets. Existing export pipelines have a capacity of around 120 bcm/year, with most spare capacity estimated to be on routes to the United Kingdom. With sufficient new field developments and market interest, a new pipeline may be required in the medium term to accommodate growth in exports to continental European markets.

After three years of falling output, production in the Netherlands jumped to 85 bcm in 2008, but the trajectory through the projection period is expected to return to gradual decline, reaching 43 bcm by 2030 in the Reference Scenario. Proven reserves of 1.24 tcm have been falling for several years, as the super-giant Groningen field edges closer to depletion and as smaller fields reach maturity, although a report for the Dutch government (EBN, 2009) has suggested that undiscovered resources of conventional gas could amount to an additional 400 bcm. The Dutch government's small fields policy has been successful in promoting the development of more than 250 minor fields since the 1970s, including almost 100 fields with reserves of less than 1 bcm. This policy has extended the life of the Groningen field by allowing it to play a balancing role in Netherlands gas supply. This pattern is set to continue as new small fields are developed and existing output is maximised through innovative well and reservoir management, but higher prices will be needed to make their development economic.

The United Kingdom continental shelf is also a mature gas production area and proven reserves now amount to only 625 bcm. A 25th licensing round in 2008 resulted in the award of 171 licenses for oil and gas exploration in the North Sea and this level of commercial interest will help to lessen the decline rate in output. Nonetheless, UK gas supply – which fell from 115 bcm in 2000 to 73 bcm in 2008 – is projected to fall further, to 44 bcm in 2015 and less than 20 bcm in 2030 in the Reference Scenario.

With limited gas resources and rising demand, Europe's demand for imports is also set to grow over the projection period. Both the Reference Scenario and the 450 Scenario see a significant increase in Europe's gas-import requirements (Table 13.4). In the Reference Scenario, gas imports to the European Union are more than 200 bcm higher in 2030 than in 2007; even in the 450 Scenario, the gas-import requirement increases to 428 bcm in 2030 from 312 bcm in 2007, having peaked in the late 2020s.

## Europe's 2020 supply options

Although indigenous resources are limited and output is declining, Europe is geographically well placed to secure gas supplies from a variety of external sources. Gas reserves in Russia, the Caspian, the Middle East and North Africa are within pipeline reach of European markets, and LNG can also be delivered to European consumers from producers around the world, primarily from the Middle East, North and West Africa, and the Caribbean. The pattern of gas trade that will emerge in Europe over the projection period to 2030 will depend on a range of factors, including the comparative supply costs of different producers, existing contractual arrangements, the availability of gas for export in some major gas producers, upstream investment risks, the reliability of different supply routes into Europe, and government and/or EU policies on supply diversity.

The cost of producing and delivering gas to European markets is a critical part of this picture. Figure 13.15 describes graphically the results of our analysis of indicative cost levels for new supplies from different sources for delivery to European borders around 2020. All costs are given in $2008 dollars. The numbers shown should be treated with caution: actual supply costs for specific individual projects could differ significantly, depending on the detailed design of each project. Costs are also highly sensitive to the assumed discount rate. The results, nonetheless, give an indication of the cost ranking of the main supply options.

For the purposes of this analysis, we used industry and publicly available data to estimate a range of production costs, then took an average figure for each supplier (or region within a supplier country, where appropriate). In some cases such as Qatar, the low estimate of production costs is at zero since the costs of gas production are typically covered by output of gas condensate and liquids. In other cases, the estimated costs are much higher, for example where gas output is not associated with oil production, where the gas is sour and requires expensive processing, or where there are particular technical or environmental challenges facing upstream projects. Production costs do not include taxes or royalties, nor do they include export duties.

The pipeline and LNG transportation costs taken into account in Table 13.5 and Table 13.6 are based on generic capital and operating cost assumptions, including a 10% discount rate and 30-year asset lives. Construction costs for pipeline and LNG infrastructure are at the lower end of the range of costs for projects undertaken or announced in 2006-2009, and take no account of project-specific factors.[12] Assumed utilisation rates are 90% for LNG liquefaction and 85% for pipelines. For pipelines, incremental capacity is assumed to be necessary for all routes, but a cost distinction is made between construction of new pipelines, where no pipeline or insufficient capacity currently exists, and the expansion and rehabilitation of capacity along existing routes. Transit costs over and above operating expenditure on pipelines are a function of distance and the number of countries crossed. The delivery points in our analysis, represented by the arrows in Figure 13.15, are the Turkish western border (Istanbul area), the Mediterranean (Spain and Italy), the German border and the UK market.

**Table 13.5 ● *LNG supplies and indicative total costs for new supplies to Europe, 2020*** ($/MBtu)

| Source | Delivery point | Production range | LNG | Transportation | Total |
|---|---|---|---|---|---|
| Algeria | Mediterranean | $0.00-1.80 | $3.17 | $0.18 | $3.35-5.15 |
| Egypt | Mediterranean | $2.50-3.50 | $3.17 | $0.23 | $5.90-6.90 |
| Nigeria | Mediterranean | $0.00-0.30 | $3.17 | $1.23 | $4.40-4.70 |
| Norway (Barents) | United Kingdom | $3.80-4.20 | $3.17 | $0.37 | $7.33-7.73 |
| Qatar | Mediterranean | $0.00-0.15 | $2.83 | $1.14 | $3.98-4.13 |
| Russia (Barents) | United Kingdom | $4.00-4.50 | $3.17 | $0.50 | $7.67-8.17 |
| Trinidad & Tobago | Mediterranean | $1.25-1.75 | $3.17 | $1.22 | $5.64-6.14 |

Notes: Production costs of zero can occur in cases where all project costs are covered by output of gas condensate and other liquids. LNG includes the cost of liquefaction, regasification and LNG tankers: projects are assumed to be greenfield, with 5 Mt/year capacity, except for Qatar with 10 Mt/year. Costs for delivery from Algeria, Qatar, Nigeria and Trinidad and Tobago to the UK market are also included in Figure 13.15; all costs are in year-2008 dollars.

Source: IEA analysis and estimates.



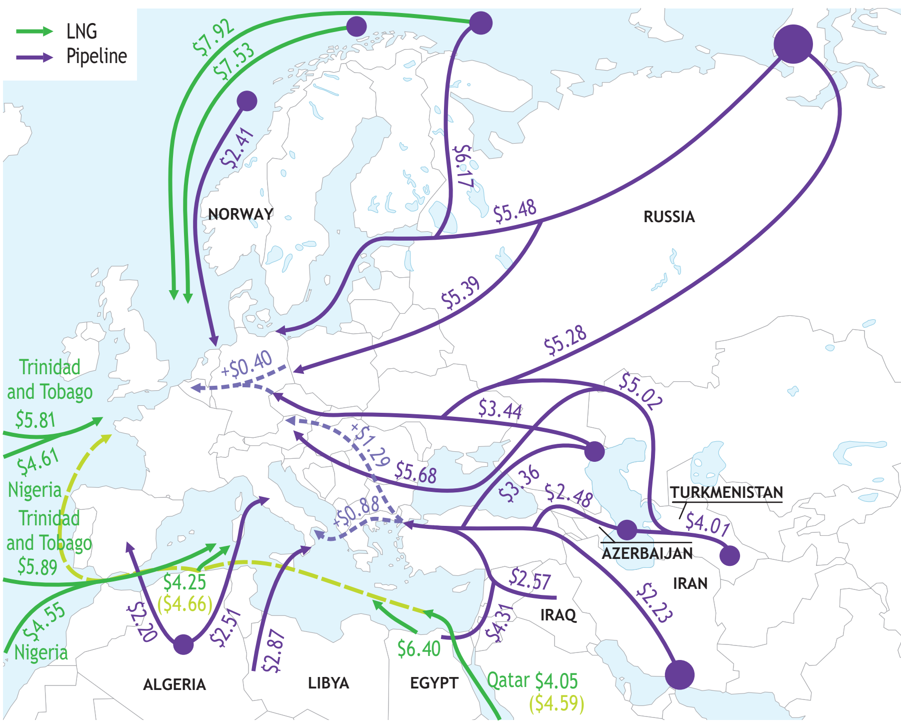
Our analysis suggests that the lowest cost incremental sources of gas to the main European gas markets are to be found in North Africa, notably in Algeria, and in the Norwegian Sea. Pipeline deliveries from these sources emerge as significantly less expensive than LNG shipments, since the capital costs of building LNG infrastructure mean that shipping LNG short distances is not economic. However, LNG has flexibility

12. For example, capital expenditure on a 5 Mt/year capacity greenfield LNG liquefaction facility is assumed in all cases at $3.9 billion, *i.e.* $780 per tonne.

in terms of destination and this continues to underpin interest in LNG projects. Iranian and Iraqi supplies are also among the cheapest potential options, especially in southeast European markets.

The largest volumes to be developed for the European market are those in Russia, in particular the gas reserves of the Yamal peninsula. Even though economies of scale on large-capacity transportation projects help to bring down unit costs, the Yamal development remains an expensive proposition: gas from Yamal delivered to the German border is estimated to cost between \$5/MBtu and \$6/Mbtu, depending on the route to market.[13] Offshore developments in the Barents Sea are even more costly. The cheapest incremental Russian gas for delivery to Europe is estimated to come from the Volga region, where the Astrakhanskoye field is scheduled to increase production in the coming years. However, the additional volumes available from this region in 2020 (a maximum of 30 bcm to 40 bcm) do not compare with the reserves and potential annual deliveries from the Yamal peninsula, which could exceed 100 bcm in the same time period.

**Figure 13.15 • *Indicative costs for potential new sources of gas delivered to Europe, 2020*** (\$/MBtu)




The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Note: All costs are in year-2008 dollars.

13. In practice, gas delivered from this region during the projection period is likely to be a mix of Yamal and cheaper Nadym-Pur-Taz gas at averaged cost, with the balance shifting towards Yamal over time. The analysis does not include the effects of the Russian export duty on natural gas, which is currently levied at 30% of the contract sale price (deliveries through Blue Stream are exempt from this export duty).

**Table 13.6 • Pipeline routes, assumptions and indicative costs for new supplies to Europe, 2020** ($/MBtu)

| Source and route | Delivery point | Assumptions | Production range | Transport & transit | Total |
|---|---|---|---|---|---|
| Iran | Turkey | *New 15 bcm line from southern Iran, Turkey grid enhanced* | $0.00-0.50 | $1.98 | $1.98-2.48 |
| Caspian offshore via South Caucasus | Turkey | *20 bcm new capacity from Caspian via Georgia* | $1.20-1.80 | $0.98 | $2.18-2.78 |
| Iraq via Syria | Turkey | *New 12 bcm line from Iraq, Turkey grid enhanced* | $0.75-1.45 | $1.47 | $2.22-2.92 |
| Russia (Volga) via Black Sea | Turkey | *Expansion of existing land routes, new 16 bcm line sub-Black Sea* | $1.90-2.40 | $1.21 | $3.11-3.61 |
| Turkmenistan via South Caucasus | Turkey | *New 30 bcm line incl. trans-Caspian, capacity expanded in Turkey* | $2.20-2.80 | $1.51 | $3.71-4.31 |
| Egypt via Mashreq | Turkey | *10 bcm new capacity along route of Arab Gas Pipeline* | $2.50-3.50 | $1.31 | $3.81-4.81 |
| *Onward costs for the above: to the German border (for 30 bcm new capacity in southeast Europe) = $1.29; and to southern Italy (via 12 bcm new offshore link from Greece) = $0.88* | | | | | |
| Russia (Volga) via Ukraine | Germany | *Rehabilitation of 20 bcm existing overland routes* | $1.90-2.40 | $1.29 | $3.19-3.69 |
| Turkmenistan via Ukraine | Germany | *New 30 bcm line to Russia border, then expansion existing routes* | $2.20-2.80 | $2.52 | $4.72-5.32 |
| Russia (Yamal) via Ukraine | Germany | *New 50 bcm link to existing export routes from Western Siberia* | $3.60-4.00 | $1.48 | $5.08-5.48 |
| Russia (Yamal) via Belarus | Germany | *50 bcm new capacity Yamal-Torzhok, expansion of line via Belarus* | $3.60-4.00 | $1.59 | $5.19-5.59 |
| Russia (Yamal) via Baltic Sea | Germany | *50 bcm new capacity Yamal-Gryazovets-Vyborg and sub-Baltic Sea* | $3.60-4.00 | $1.68 | $5.28-5.68 |
| Turkmenistan via Black Sea / Bulgaria | Germany | *New 30 bcm line (except within Russia) with sub-Black Sea link* | $2.20-2.80 | $3.18 | $5.38-5.98 |
| Russia (Barents) via Baltic Sea | Germany | *New 30 bcm link offshore Barents to Vyborg and sub-Baltic Sea* | $4.00-4.50 | $1.92 | $5.92-6.42 |
| *Onward costs from the eastern German border to the UK market (based on expansion of existing networks) = $0.40* | | | | | |
| Algeria | Med*/Spain | *Additional 8 bcm capacity including sub-sea link Algeria-Spain* | $0.00-1.80 | $1.30 | $1.30-3.10 |
| Norway (Norwegian Sea) | Germany | *New 20 bcm sub-sea connection to Germany* | $1.20-1.55 | $1.04 | $2.24-2.59 |
| Algeria | Med/Italy | *Additional 12 bcm capacity including sub-sea link via Sardinia* | $0.00-1.80 | $1.61 | $1.61-3.41 |
| Libya | Med/Italy | *Additional 12 bcm capacity including sub-sea link via Sicily* | $0.90-1.35 | $1.24 | $2.14-3.59 |

* Med = Mediterranean.
Note: Production costs of zero can occur in cases where all project costs are covered by output of gas condensate and other liquids. All costs are in year-2008 dollars.
Source: IEA analysis and estimates.

The more expensive profile of Russian gas supply as it moves away from the established but declining production area of Nadym-Pur-Taz has the effect of improving the competitive position of other potential suppliers, notably from the Caspian region and the Middle East. New gas delivered from offshore fields in the Caspian Sea, either from Azerbaijan or Turkmenistan, is estimated to cost \$2.18/MBtu to \$2.78/MBtu at the Turkish western border and between \$3.47/MBtu and \$4.07/MBtu at the German border. Gas from the larger onshore fields in eastern Turkmenistan is more expensive, but still comes in at the German border at an estimated \$5.00/MBtu to \$5.60/MBtu if delivered through Turkey and Southeast Europe, with slightly lower costs if delivered through the Russian system via Ukraine and slightly more if delivered through a new pipeline system across the Black Sea to Bulgaria. Pipeline supplies from the Middle East to Turkey are highly competitive, based on the low costs of production and relative proximity. Gas deliveries from Iran are estimated to cost between \$1.98/MBtu and \$2.48/MBtu at the western Turkish border, and gas from Iraq, supplied via Syria, between \$2.22/MBtu and \$2.92/MBtu. The viability of pipeline deliveries to Turkey and across Southeast Europe is highly sensitive to assumptions about the costs of transit, since these routes cross multiple national borders.

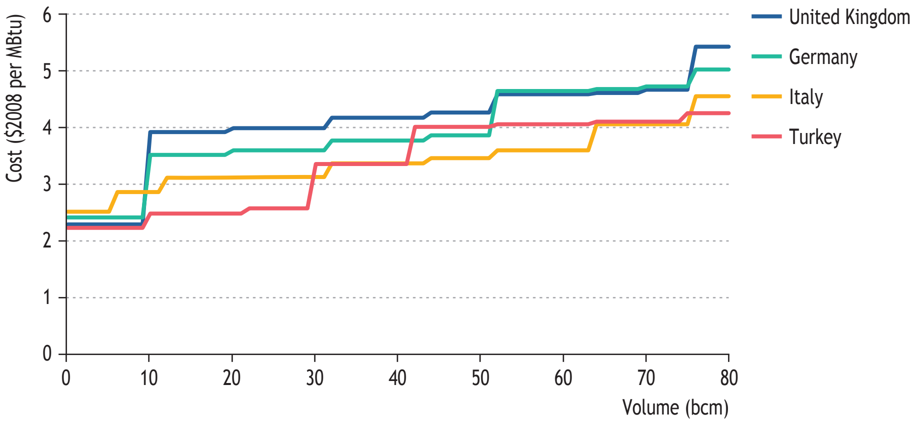
The development of a more competitive market in Europe increases the incentives for companies to seek out the cheapest sources of gas supply. However, in practice, supplies to Europe are not likely to be developed in strict cost-order, since other factors have a strong influence over the choices made by exporters and importers.[14] Apart from the constraints arising from existing long-term supply contracts, political constraints include potential or actual limitations on trade with specific suppliers (such as Iran), risks of political instability in supplier or transit countries, and the possibility of interruptions to gas transit because of disputes or conflicts. Producers with a record of dependable supply and with established relationships with gas purchasers are likely to be favoured over new entrants or suppliers deemed potentially unreliable. On the other hand, government policies may actively seek to encourage new supply sources in order to increase the diversity of supply: an example is the planned Nabucco pipeline that would bring gas from the Caspian and possibly the Middle East to Europe via Turkey, a project which is strongly backed by the European Union. Four EU countries and Turkey signed an agreement in July 2009 on the legal framework for the Nabucco gas pipeline, marking an important step forward in the long, drawn-out planning for this pipeline. The European Commission is also looking at the possibility of a consolidated purchasing mechanism for East Caspian gas, provisionally called the Caspian Development Corporation.

On balance, incremental EU gas-import needs are likely to be met through a combination of increased pipeline supplies from Europe's main traditional suppliers (Russia, Norway and Algeria), along with new supplies by pipeline from the Caspian and Middle East, and LNG imports from a range of potential exporters. The supply mix will vary across Europe, with central and eastern markets more dependent on pipeline supply. The supply cost curve also varies for different European markets (Figure 13.16). Combining the data from the supply

14. Under a system of long-term contracts based on replacement or netback value, the sale price of the gas does not depend as such on transportation costs — although these costs do reduce revenue and the net present value of projects to producers and may therefore make them economically unattractive. For an extended discussion of gas-pricing mechanisms, see Chapter 14.

costs analysis with assumptions about possible volumes that could be available for export to Europe in 2020, this graph suggests that Turkey, followed by Italy, is well positioned for access to the cheaper sources of gas supply, with over 40 bcm potentially available at a delivered cost of less than \$3.5 MBtu. With the exception of supplies from Norway, the cost of deliveries to Germany and the UK market tend to be progressively more expensive, reflecting greater distance from the cheaper sources of incremental gas.

**Figure 13.16 • Indicative cost curves for new supplies to selected European gas markets, 2020**




# The Middle East

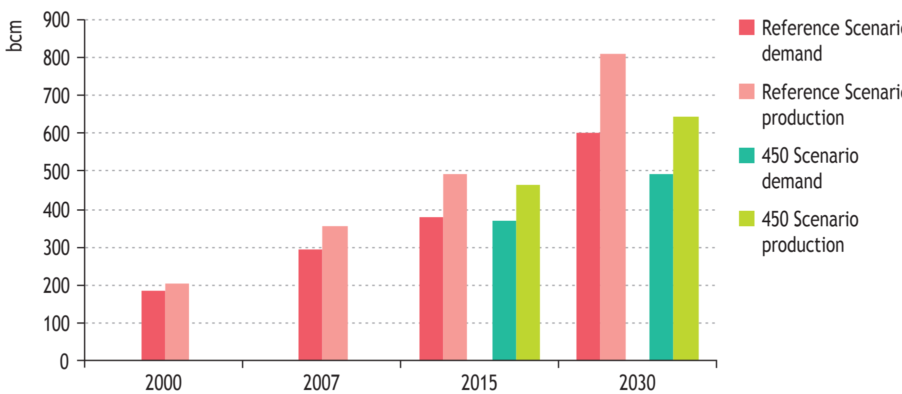
## Regional demand and supply

The Middle East as a whole is exceptionally well-endowed with gas resources, holding some 75 tcm of proven reserves, or 41% of the world total. Yet several countries across the region are struggling to meet fast-growing domestic demand. Artificially low domestic sales prices have accelerated gas consumption and slowed investment in developing non-associated gas resources. A large proportion of associated gas is re-injected into oilfields to enhance crude oil production, restricting the amount of gas available to meet demand. In total, primary gas use in the region more than tripled in 1990-2008 and increased by 80% in the eight years to 2008, reaching 327 bcm, or 10% of world consumption. As in most other regions, the power sector is the main driver of demand growth, underpinned by low gas prices and rapid population growth. Energy-intensive petrochemicals, aluminium smelting and water desalination (see Chapters 1 and 10) account for most of the rest of the increase in gas demand in recent years. As the region leans more heavily on natural gas, significant changes in pricing and marketing are on the cards.

The region's gas production is projected to rise from 379 bcm in 2008 to over 810 bcm in 2030 in the Reference Scenario. It reaches only 645 bcm in the 450 Scenario by that date, as export demand is disproportionately hit by lower global gas use because of the high cost of shipping gas to distant markets in Europe and Asia-Pacific. Net exports of gas to destinations outside the region climb from 63 bcm in 2007 to 210 bcm in 2030 in the Reference Scenario and 152 bcm in the 450 Scenario. Qatar and Iran, which share the world's biggest gas field (North Field/South Pars), account for about two-thirds of regional gas reserves, and they account for the bulk of the increase in production and exports in both scenarios.

While the global downturn, which is hurting the region's exports and industrial production, is expected to result in some contraction of domestic gas demand in the near term, demand growth is expected to recover in the medium term, though its pace will hinge on pricing and subsidy policies, as well as the degree of policy action to curb greenhouse-gas emissions in the region and in the rest of the world. Middle East gas demand is projected to almost double over the projection period – from 327 bcm in 2008 to 602 bcm in 2030 in the Reference Scenario – despite an assumed reduction in the size of subsidies to gas consumption. It increases to 493 bcm in 2030 in the 450 Scenario. In both scenarios, production is driven to a large degree by exports and continues to outpace demand from within the region (Figure 13.17). Thus, regardless of the policy environment, the Middle East's importance as both consumer and supplier to the world market is set to grow substantially.

**Figure 13.17 • Natural gas balance in the Middle East by scenario**




Several Middle East countries are planning to counter temporary and seasonal shortages of gas through LNG imports, mainly using new, less-costly floating regasification technologies (thereby avoiding the need to build permanent onshore terminals). In response to a chronic shortage of associated gas, which had already forced the closure of some fertilizer plants, Kuwait imported its first LNG cargo in late August 2009 at a new terminal being built at Mina al-Ahmadi port. It expects to be able to discontinue imports in the longer term by developing abundant non-associated gas reserves in the north of the country. In Dubai (in the United Arab Emirates), another import terminal, which will supply gas for power mainly to meet peak summer air-conditioning load, is due to be commissioned in 2011. Bahrain is also considering building a terminal following disappointing results from a recent deep-gas drilling programme. Imports are also under consideration in the northern emirates of the United Arab Emirates and in parts of Saudi Arabia.

## Qatar

Qatar has become a leader in new natural gas development in the last few years. In 2000-2008, the increase in its production was the fifth-highest in the world behind Russia, Iran, China and Norway. Qatar's gas production rose quickly from 28 bcm in 2000 to 66 bcm in 2007 and jumped to an estimated 79 bcm in 2008. It is set to expand further: current projects will push production to 165 bcm in 2015 and 225 bcm in 2030 in the Reference Scenario (190 bcm in the 450 Scenario). Projections for increases in output after 2015 are contingent upon ending the current moratorium on new gas export projects (discussed in detail below).

Most of the growth in both scenarios comes in the near term, as a number of new developments already under construction come on stream. Qatar Petroleum, the national oil and gas company, in joint ventures with foreign partners, is in the midst of a major programme to expand its LNG export capacity to 105 bcm/year from 41 bcm in 2008 (Table 13.7). Six new trains, each with a capacity of 10.6 bcm/year (7.8 Mt/year) – the largest in the world – are due to be commissioned in 2009-2011. It is also building a second gas-to-liquids (GTL) plant with Shell – the largest in the world, with a capacity of 140 thousand barrels per day (kb/d) – to add to the 34-kb/d Oryx plant it built with Sasol in 2007. Additional facilities will supply gas to the Dolphin pipeline system that connects several Gulf States. Additional production capacity is being added to meet surging domestic demand, mainly for power generation and the petrochemical industry. In total, wellhead gas production capacity is set to reach 238 bcm/year when all of these projects are completed.[15]

The current expansion of the gas industry in Qatar is underpinned by a huge resource base. Proven reserves alone are estimated at close to 26 tcm. All but 1% of these reserves are located in the North Field – the southern part of the world's biggest gas reservoir that Qatar shares with Iran (where it is called South Pars) (Figure 13.18). This field, which alone accounts for about 14% of the world's proven reserves, has not yet been fully appraised. Estimates of ultimately recoverable resources in the field have been put as high as 37 tcm. The North Field has been developed sequentially, initially to meet local demand and later to supply two large-scale major LNG projects, Qatargas 1 and 2, and RasGas 1 and 2, and the Dolphin regional pipeline project (Table 13.7). The Qatargas 3, Qatargas 4 and RasGas 3 LNG projects and the Pearl GTL project are under development, with first production scheduled in the period 2009-2011.

The prospects for Qatari gas production and exports beyond 2012 remain uncertain because of a moratorium on new export projects imposed in 2005 to allow time to study the effect of the existing project load on the reservoirs of the North Field. Before seeking to increase exports, in the form of LNG, GTL or pipeline gas, there are indications that Qatar will seek to increase its resource base through further exploration, potentially

15. The wellhead production figure includes associated liquids production. The start-up of North Field gas production in 1991 resulted in a rapid increase in the volumes of condensate and natural gas liquids (NGLs) production, which are not subject to the oil production quotas of the Organization of the Oil Exporting Countries (OPEC). Indeed, the value of these liquids is high enough to cover the full cost of the upstream developments, with the gas effectively produced for free. The associated liquid production will continue to increase with the Barzan project to supply gas to the local power sector and expected new developments in the future.

targeting new North Field reservoir depths. In any event, priority is likely to continue to be given to meeting the needs of domestic consumers, including a burgeoning petrochemical sector. In 2007, when a planned GTL project being pursued by ExxonMobil was cancelled, the reserves associated with that project were re-assigned to the Barzan domestic gas development (which was postponed in April 2009 by 12 months because of slower than expected demand growth in Qatar resulting from the economic downturn). Qatar is also under political pressure from gas-short neighbouring countries to step up North Field production to feed into the Dolphin system and expand regional trade, but Qatar may be reluctant to do so – at least until this trade attracts higher prices.

### Figure 13.18 • Qatari and Iranian gas infrastructure

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Sources: Petroleum Economist; IEA analysis.

Sustaining the productive life of the North Field is a key national priority, alongside previous priorities that included world LNG market leadership (already achieved since 2006) and the maximisation of economies of scale in the LNG project chain (making good progress in the existing project cycle). Officials have mentioned a desire to sustain production levels for the next 100 years in order to create a sustainable legacy for future generations and to set the foundations for long-term partnerships with gas buyers. The assessment of the impact of the development of the North Field is focusing on the four Khuff layers that support current production and the factors behind differences in gas quality, particularly sulphur content, across different blocks. These quality differences, which were not expected, were one of the main reasons for imposing the moratorium on new developments. Two dry holes drilled on the North Field's northwest flank earlier this decade also contributed to that decision. The study also allows more careful analysis to be undertaken of the social and economic impact of rapid development of the gas business on a small Emirate.

A decision on whether and when to lift the moratorium will not be taken until the study has been completed, the timing of which is very uncertain. Initially, it was intended to be finished by 2010, but this was later extended to 2011. No further official comment has been made, though there have been indications that the deadline will probably be extended to 2012 or even 2013.[16] If the moratorium is lifted in 2011-2013, it is likely that emphasis will be placed initially on exploration and appraisal to ensure that resources are available for further development. If gas reserves are deemed sufficient and domestic needs are adequately met, priority may then be given to the expansion of existing projects through de-bottlenecking of LNG facilities, the maximisation of pipeline capacity or the expansion of GTL facilities. Development prospects beyond this will depend on the results of the North Field study and any subsequent exploration work. Whatever the outcome, it seems likely that Qatar will continue to seek to maintain a balance in allocating reserves between exports and domestic use, in marketing its gas as GTL, LNG and through pipelines, and in the choice of regional markets in Asia-Pacific or the Atlantic basin. Our projections assume some LNG, GTL and pipeline capacity additions in the period 2020-2030, totalling around 50 bcm in the Reference Scenario, with another 15 bcm in additional increments in production capacity to meet domestic demand growth.

**Table 13.7 ● Major gas projects in Qatar based on North Field gas reserves**

| Project | Start (initial target) | Capacity (bcm/ year) | Partners |
|---|---|---|---|
| North Field Alpha | 1991 | 7.2 | Qatar Petroleum (QP) |
| Al Khaleej Gas | 2005 | 20.7 | QP |
| Dolphin | 2007 | 20.7 | QP |
| Pearl GTL | 2011 | 16.5 | QP, Shell |
| Barzan | 2013 | 15.5 | QP |
| *Subtotal - GTL, piped exports and domestic* | | *80.6* | |
| **LNG - Qatargas** | | **55.4** | |
| Qatargas 1: Trains 1-3 | 1997-1998 | 12.9 | QP, ExxonMobil, Total, Marubeni, Mitsui |
| Qatargas 2: Train 4 | Q2 2009 (2008 Q1) | 10.6 | QP, ExxonMobil |
| Qatargas 2: Train 5 | Q3 2009 (2008) | 10.6 | QP, ExxonMobil, Total |
| Qatargas 3: Train 6 | 2010 (2009) | 10.6 | QP, ConocoPhillips, Mitsui |
| Qatargas 4: Train 7 | 2011 (2010) | 10.6 | QP, Shell |
| **LNG - RasGas** | | **49.4** | |
| RasGas: Trains 1-2 | 1999 | 9.0 | QP, ExxonMobil, Kogas, Itochu, LNG Japan |
| RasGas 2: Train 3 | 2004 | 6.4 | QP, ExxonMobil |
| RasGas 2: Train 4 | 2005 | 6.4 | QP, ExxonMobil |
| RasGas 2: Train 5 | 2007 | 6.4 | QP, ExxonMobil |
| RasGas 3: Train 6 | Q3 2009 (2008) | 10.6 | QP, ExxonMobil |
| RasGas 3: Train 7 | 2010 (2009) | 10.6 | QP, ExxonMobil |
| *Subtotal LNG* | | *104.8* | |
| **Total** | | **185.4** | |

Source: IEA databases.

16. Qatari Energy Minister Abdullah al-Attiyah, in comment to the press in January 2009, said that study would not be finished before 2013, stating "we're not in a hurry".

**Box 13.3 ● *Qatar's booming LNG industry***

Qatar will contribute by far the biggest expansion of liquefaction capacity worldwide in 2009-2011, consolidating its position as the biggest exporter of LNG in the world – a position it has held since 2006. The size of this expansion is enormous and unprecedented, from 41 bcm/year (30 Mt/year) at the end of 2008 to 105 bcm/year (77 Mt/year) in 2011-2012 when all the additional six trains are due to be in operation. By that time, Qatar will account for 27% of global LNG liquefaction capacity. In order to cover the associated increase in maritime transportation (larger volumes and longer distances than in the past), giant LNG carriers are being delivered from Korean shipyards to the export ventures: 31 Q-Flex (each with a capacity of 209 000 to 217 000 liquid cubic metres [$m^3$]) and 14 Q-Max (260 000 $m^3$ to 266 000 $m^3$) ships.

When final investment decisions were made in 2004 and 2005, the start-up schedule for the six trains of the Qatargas and RasGas projects was from 2007 to 2010. Partly due to the sheer size of both the new trains themselves and the expansion as a whole, these projects have not proved to be immune to the delays and cost overruns that have characterised the industry in recent years. All the construction and commissioning activities of these LNG projects, as well as one GTL plant and other projects, have been concentrated in the 106 $km^2$ Ras Laffan Industrial City (equivalent in size to the city of Paris), creating logistical nightmares. Lack of human resources and materials have added to the logistical constraints to delay the completion of these projects.

At the beginning of 2008, the LNG project sponsors still insisted that the first shipment from the first mega-train could start in the third quarter of 2008. The start date was subsequently pushed back several times and the inauguration of the train was finally carried out on 6 April 2009. Ramping up to the plateau capacity production is also expected to take more time than originally anticipated. Although all the liquefaction facilities may start up by 2011, full production capacity may not be reached until 2013.

Qatar has been expanding and diversifying its market reach since it started exporting LNG in 1997 to Japan. The current expansion phase was originally aimed at markets in the United Kingdom and United States. But from 2006, reflecting the changing *Outlook* for imports in these markets, particularly the United States, Qatar started to market some of the expected mega-train output to other regional markets on a medium – and long-term basis, in pursuit of a strategy to diversify its markets in terms of geographic spread, contract duration and pricing terms (which vary considerably across regions – see Chapter 14).

The unprecedented scale of the current expansion programme is expected to have a major impact on the balance of the global LNG market, and much attention will be paid to Qatar's LNG marketing strategy. The nature of the market changes is likely to become clearer in the next couple of years.

## Iran

Although it holds the world's second-largest gas reserves, Iran is also the world's third-largest gas consuming country, after the United States and Russia. It is routinely a marginal net importer of gas, with imports by pipeline from Turkmenistan slightly larger than modest exports to Turkey. Domestic demand for natural gas in Iran is rising steeply. Consumption of marketed gas grew at an annual average rate of 9% from 2000 to 2008, from 62 bcm to 122 bcm. Despite the worsening economic climate, this trend is likely to continue and could even accelerate in the near term, due to heavy subsidies on domestic sales and moves by the authorities to promote gas as a transport fuel in order to reduce dependence on imported gasoline. In addition, ambitious plans for expansion in the petrochemical sector will require large volumes of gas. Priority is likely to be given to satisfying domestic demand: during peak demand periods in the exceptionally cold winter of 2007/2008, the Iranian government opted to reduce gas flows to both export projects and oilfield re-injection in favour of residential and other domestic users. A cut-off in imports from Turkmenistan at that time provided a further illustration of the vulnerability of the domestic system: there is limited infrastructure in place to transport domestic gas supplies, which are concentrated in the south, to demand centres in northern Iran.

In May 2008, government officials announced a plan to raise domestic gas prices in order to encourage energy conservation and free up gas for exports. No implementing action has yet been taken and no details are available on how the reform might be implemented or on the timeline. Iran has some of the biggest gas subsidies in the world, totalling around $16 billion in 2007 (IEA, 2008a). Prices currently cover only one-third, on average, of the true economic value of the gas. We assume in the *WEO* projections that subsidies are lowered gradually but are not completely removed before 2030.

Iran's ability to meet its rapidly growing domestic needs and also to produce gas for export will depend to a large degree on the climate for investment; the country's gas resources are, in principle, more than adequate to support rapid growth in output. In the Reference Scenario, Iran's marketed gas production is projected to rise from 121 bcm in 2008 to 256 bcm in 2030; in the 450 Scenario output reaches 179 bcm.

The Iranian gas industry is still in its infancy, as only a small proportion of Iran's massive gas reserves of 29 tcm have been developed. Only 5% of the total gas reserve has been produced to date. An estimated 8 tcm to 12 tcm of the country's reserves are in the South Pars field in the Persian Gulf (the Iranian part of the field known as North Field in Qatar — see above). South Pars, which only came into production in 2004, accounted for well over one-third of Iran's gas production in 2008. More than 60% of Iran's gas reserves are located in non-associated fields, most of which have not yet been developed. In addition to South Pars, the main gas fields in production are North Pars, Tabnak and Kangan-Nar.

13

Contrary to a widely held belief, additions to production capacity at South Pars have been larger than those at the North Field since 2000. The first five development phases, brought into production between 2004 and 2008, had a total capacity of 45 bcm/year (Table 13.8), compared with capacity additions of just over 40 bcm in Qatar. Commissioning of Phases 6-8 sour gas production started in summer 2008 and the 504 km IGAT-5 sour gas pipeline from the Assaluyeh processing complex to the giant Aghajari oilfield was opened soon after. This gas will eventually replace sweet gas that is currently being injected into the Aghajari field and will boost oil production at the field three-fold to 300 kb/d.[17] Phases 9 and 10 were officially inaugurated in March 2009 and are expected to reach full production toward the end of 2010. All but the first phase were developed with foreign partners under buy-back deals – essentially service contracts under which the foreign partner funds the initial investment and receives a fixed rate of return, payable as a share of the output of the project.

**Table 13.8 ● South Pars development phases**

| Phase | Upstream partners (date of award) | Start date (initial target) | Gas/condensate production | Notes |
|---|---|---|---|---|
| 1 | Petropars (NIOC subsidiary) (September 1997) | November 2004 (2001) | 9 bcm/year; 40 kb/d | |
| 2/3 | Total; Gazprom; Petronas (September 1997) | 2002 (2001) | 18 bcm/year; 80 kb/d | |
| 4/5 | Eni; Petropars; Naftiran (July 2000) | April 2005 (2004) | 18 bcm/year; 80 kb/d | |
| 6/7/8 | Petropars; StatoilHydro (October 2002) | 2008-2009 (2004) | 27 bcm/year; 120 kb/d | Sour gas re-injection |
| 9/10 | Iranian companies and Korea's LG (September 2002) | 2009-2010 (2007) | 18 bcm/year; 80 kb/d | |
| 11 | Total, Petronas (& possibly CNPC) | Not known (2010) | 20 bcm/year; 70 kb/d | Known as Pars LNG |
| 12 | Petropars | Not known (2009) | 31 bcm/year; 120 kb/d | To domestic market and possibly to Iran LNG |
| 13/14 | Shell, Repsol | Not known (2011) | 31 bcm/year; 105 kb/d | To domestic market and possibly to Persian LNG |
| 15/16 | Iranian Revolutionary Guard | 2013-2014 | 18 bcm/year; 80 kb/d | |
| 17/18 | Iranian companies | 2014-2015 | 18 bcm/year; 80 kb/d | |
| 19 | To be awarded | Not known | 18 bcm/year; 80 kb/d | |
| 20/21 | Offshore Industries Engineering and Construction Company (May 2009) | 2015-2016 (2013) | 18 bcm/year; 80 kb/d | |
| 22-24 | To be awarded | Not known | 15 bcm/year; 57 kb/d | Possibly including exports to Turkey |
| 27-28 | Petropars | Not known | 8 bcm/year 70 kb/d | |
| *Capacity added 2002-2008* | | | *45 bcm/year; 200 kb/d* | |
| *Capacity to be added 2009-2010* | | | *45 bcm/year; 200 kb/d* | |

Source: IEA databases.

17. Transporting sour gas across such long distances is unusual because of potential environmental and safety hazards. Plans to treat this gas have been postponed because of major cost escalations. However, these are still seriously being considered in order to cope with seasonal demand fluctuations in the local market and may be implemented by 2011.

The South Pars field is expected to continue to provide the bulk of incremental capacity in Iran in the medium term, both to supply local markets and export projects. The field is planned to be developed further in up to 26 phases in total over the next 20 to 30 years. Each phase is expected to produce on average around 9 bcm/year of dry gas and 40 kb/d of condensate. In addition, the capacity of the existing phases could be boosted by up to about 10 bcm/year in total.

A large proportion of new South Pars capacity is expected to be committed to LNG projects. At least three LNG projects, with a total capacity of 38 bcm/year (28 Mt/year), are under serious consideration. However, the slow pace of project development for the South Pars phases assigned to LNG projects and of new upstream awards since 2004, due to changes in political priorities and international sanctions, means that production growth is likely to slow significantly in the early part of the next decade. International restrictions on the participation of western companies in the Iranian oil and gas industry have hampered plans to build an LNG business. Iran has signed up to extensive long-term commitments to supply LNG with companies in India, China and Thailand. But without the participation of foreign companies with expertise and experience in building and operating LNG liquefaction facilities, it is very unlikely that these sales commitments will be met before 2015. Projects involving Total/Petronas and Shell/Repsol have been on hold for some time and in mid-2008 Iran officially postponed them, leaving in place as part of Phase 12 only the all-Iranian Iran LNG project led by the National Iranian Oil Company. Site preparation works for that project have begun but no realistic completion date is in sight. Shell and Total may switch to later phases of the South Pars field for their LNG development. Chinese, Indian, and Malaysian companies have held intermittent talks on LNG developments based on other fields.

In November 2006, Iran signed a deal with China National Offshore Oil Corporation (CNOOC) to develop the North Pars gas field as an LNG export project. The North Pars gas field, 85 km north of the giant South Pars field in the Persian Gulf, contains about 2 tcm of reserves. CNOOC plans to invest $5 billion in the upstream and $11 billion in LNG facilities, in exchange for the right to lift 50% of the production of the field. CNOOC is seeking to buy 13.6 bcm/year of LNG over 25 years. Russia has also shown interest in developing the field. An Indian consortium of ONGC, India Oil Corporation and Oil India Limited is also in talks with the Iranians to develop the Farzad gas field for an LNG project.



Exports are central to the government's 20-year strategic plan for the gas industry. Our projections assume that LNG exports begin by around 2020. Nevertheless, the persistent delays to development, the weight of international sanctions and rising domestic needs raise doubts about whether the country will become a major exporter during the projection period. Financing projects in Iran has become extremely difficult because of political problems and the credit squeeze. The choice of domestic contractors with limited technical expertise, on political rather than economic grounds, is contributing to the problems in bringing new projects to fruition. Domestic consumption and oilfield re-injection requirements are likely to soak up most of the increased production in the medium term, leaving little spare for export. The need for re-injection in Iran's maturing oilfields is about to increase sharply. Currently 30 bcm to 40 bcm/year of gas is re-injected and the volume required for this purpose may grow to more than 100 bcm in 2015. There are, nevertheless, disagreements between different governmental bodies on how the gas should be used. Short-distance pipelines or small-scale expansions of existing infrastructure are the most likely outlets for any surplus gas.

In addition to LNG projects, Iran is also pursuing various pipeline export projects. In May 2009, the longstanding idea of a pipeline link to South Asia moved closer to fruition with an agreement to supply Pakistan with gas from South Pars. This pipeline project had been originally developed with the Indian market in mind as well, but negotiations had stalled on transit issues, political tensions and improved prospects for gas production in India (see below). Pakistan has agreed to take 7.5 bcm/year for 25 years, with first gas due to be delivered in 2014. Nonetheless, the project is far from certain to go ahead.

Iran has plans to export up to 35 bcm/year of gas to Turkey and other European markets, either through the proposed Nabucco pipeline or through alternative routes to and through Turkey. Aside from international political considerations, these plans will depend on further development of South Pars[18] and on the expansion of the existing export line linking southern Iran with Turkey. The availability of Iranian gas for export will be linked also to the volumes imported to northern Iran from Turkmenistan.[19] Iran has a contract to supply Turkey with 9 bcm/year, but the deal has been marred by several interruptions in Iranian delivery, which have damaged Iran's standing as a potential supplier to Europe; the average supply since deliveries started in 2003 has been only 4 bcm to 5 bcm/year. We assume only a modest increase in exports from Iran to Turkey over the projection period to 2030.

Iran signed a contract in early 2008 with Oman for the supply of 10 bcm/year by pipeline, potentially to be processed for export at the Omani Qalhat LNG plant. The deal implies that Oman and Iran will jointly develop the Kish gas field in the Persian Gulf as well as the Hengam gas field, and envisages joint petrochemical projects. Iran has not resolved a long-standing contract dispute with Crescent Petroleum of the United Arab Emirates for the supply of 6 bcm/year of associated gas from the offshore Salman field.

### Other Middle East

Despite having 7.6 tcm of proven gas reserves — the fourth-largest in the world — *Saudi Arabia* continues to struggle to meet rapidly rising demand for gas in the petrochemical sector, for water desalination and in power generation. Demand has been rising at an average annual rate of 6.7% since 2000, reaching an estimated 70 bcm in 2008, fuelled by an economic boom. Saudi Arabia is the second-biggest gas consumer in the Middle East after Iran. In response to worsening shortages of gas, the government decided in 2006 to halt the construction of new gas-fired power plants, shifting to oil for future generation needs.

18. In September 2007, state-owned Turkish upstream operator Turkiye Petrolleri Anonim Ortakligi (TPAO) signed a preliminary deal to develop three phases of South Pars with an option to transport the gas to Turkey.

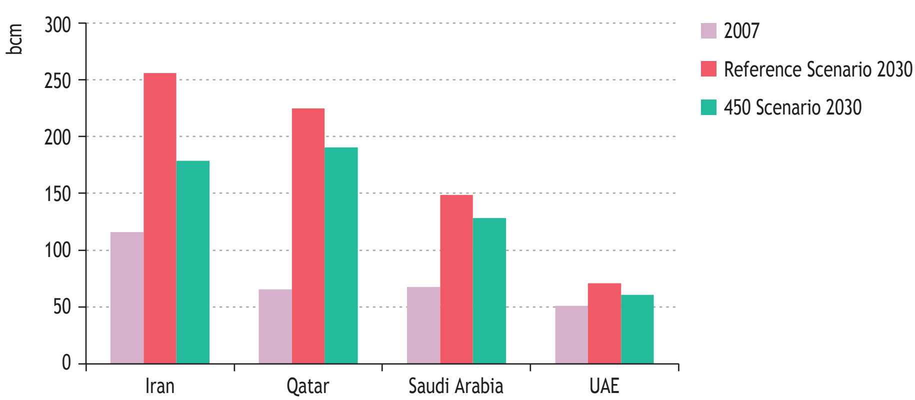
19. Iran agreed, in 2009, to increase imports from Turkmenistan to 14 bcm/year, both by expanding deliveries along the existing Korpedzhe-Kurt Kui pipeline near the Caspian coast and also through a new planned pipeline running from the Dauletabad field in southeast Turkmenistan to Hangeran in Iran.

The main reason for gas shortages is that more than half of the country's gas production is associated with crude oil and a significant share of this supply has to be re-injected to enhance crude oil output. In addition, cutbacks in production, as required under OPEC agreements on production quotas, have squeezed gas supplies. As a result, Saudi Aramco, the national oil company, is shifting the focus of its exploration and development activities to non-associated gas. It has made several discoveries recently, including new reserves in the offshore Arabiyah, Rabeeb and Hasbah fields. It recently started work on developing the Karan field – the first offshore gas field development in the country – which will produce around 16 bcm of wet gas, to be processed alongside gas from the Manifa oilfield. The Karan is expected to come on stream in 2012, almost a year later than originally planned. Saudi Aramco is also planning to fast-track the development of the Arabiyah and Hasbah fields.

The prospects for gas production in the Empty Quarter in the south of the country remain uncertain. Nearly five years after deals were signed with several foreign companies – including Shell, Total, China's Sinopec, Russia's Lukoil and a consortium of Italy's Eni and Spain's Repsol YPF – to drill for gas there in partnership with Saudi Aramco, no commercial discoveries have been made. Total has since pulled out, but the others are continuing to explore. Shell and Lukoil have asked for extensions to their deals. Lukoil is the only company to have announced a discovery, but is still appraising it so it is not known whether or not it will prove commercial. It has been suggested that one reason for the lack of drilling success is that the companies are more interested in finding condensate than gas, as the terms on which any gas might be sold are poor.

As in previous *Outlooks*, we assume that Saudi Arabia does not sanction any gas export projects and that all the gas produced goes to the domestic market. Output is projected to reach 85 bcm in 2015 and almost 150 bcm in 2030 in the Reference Scenario. In the 450 Scenario, production grows slightly less quickly, reaching a little less than 130 bcm in 2030 (Figure 13.19).

**Figure 13.19 • *Natural gas production in selected Middle Eastern countries by scenario***




The *United Arab Emirates (UAE)* faces similar challenges in meeting rapidly growing gas demand, which has led to severe shortages in the Emirates of Abu Dhabi and Dubai.

Proven reserves, at around 6.5 tcm, are large, but most existing production is set aside for re-injection into oilfields and for LNG exports from the Emirates' only plant, at Das Island in Abu Dhabi. Gas-quality problems and highly subsidised prices are holding back investment, particularly that aimed at meeting local demand. Production is projected to grow very slowly from about 51 bcm in 2008 to about 53 bcm in 2015 and then rise more quickly to over 70 bcm in 2030, on the assumption that technical challenges can be met and that higher domestic prices provide a stronger incentive to development. In the 450 Scenario, production reaches 61 bcm in 2030.

Imports from Qatar through the Dolphin pipeline have provided some relief since 2007, although, as noted above, the United Arab Emirates is already asking for the next phase of supplies to be increased from 20 bcm/year to 32 bcm/year. Potential supply from Iran has been held back by a pricing dispute. The Dubai Supply Authority (Dusup) has a plan to import LNG at Jebel Ali from 2011. The Shah and Bab sour gas fields have been put out to tender for development in association with foreign contractors. ConocoPhillips and state-owned ADNOC in July 2009 announced a final investment decision on their Shah joint venture (near the border between Abu Dhabi and Saudi Arabia) to produce around 6 bcm of sales gas, 50 kb/d of condensates, 4 400 tonnes/day of NGLs (ethane and liquid petroleum gas) and 10 000 tonnes/day of sulphur. The integrated gas project and the sour gas development at Hail and Bab are expected to provide additional volumes. Much of this gas will be required for re-injection to boost production at the country's oilfields.

*Iraq* hardly produces any marketable gas, but has the potential to become a major producer. At present, although the country produces well over 10 bcm/year of gas, most of it in association with oil; barely more than 1 bcm is marketed with the rest flared or vented because of a lack of infrastructure to process and transport the gas to market. Most of the country's proven reserves of gas, which total 3.2 tcm, are located in the main oilfields – the Kirkuk and Bai Hassan fields in the north and the Rumaila and Zubair fields in the south (IEA, 2005). The only non-associated gas production comes from the Anfal field, which supplies about half of all the gas consumed in Iraq.

The Iraqi government is keen to boost gas supplies to the domestic market, mainly for power generation and industry. It signed a $3 billion deal with the US firm GE in December 2008 to build new power stations that will initially run on heavy fuel oil but will later be converted to use gas. To develop an internal gas market, major investment will be required in gas-processing and pipeline infrastructure. The government is targeting total energy-sector investment of $50 billion over the five years to 2014, of which only 10% will be needed for upstream developments. It is keen to attract foreign companies into the gas sector, despite some domestic political opposition.

Late in 2008, Shell signed Heads of Agreement under which it would process and market all the gas produced in the Basra region in the south of Iraq. This South Gas Utilization Project (SGUP) is to be set up in partnership with Iraq's state-owned South Gas Company. In August 2009, Mitsubishi agreed to join SGUP with a 5% stake. Shell has also formed a partnership with Turkey's BOTAS to develop and market gas from northern Iraq. Hungary's MOL and Austria's OMV have bought into a consortium developing gas fields under a deal with the Kurdistan Regional Government. The latter investment raises the thorny question of national versus regional control of Iraq's oil and gas but, if these and other issues can be resolved, developments in the north could conceivably bring additional gas to Turkey and to the planned Nabucco pipeline (see above). The Iraqi government has included gas fields in two upstream licensing rounds in 2009. The first round, concluded in July, included the Akkas field close to the Syrian border and the Mansouriya field in northeast Iraq. However, the remuneration fee sought by the only consortium bidding for Akkas was way above the Iraqi ministry's maximum, while the Mansouriya field received no bids. In the second round, now scheduled for decisions in December, the Siba field in southern Iraq has been withdrawn (possibly to be developed by the state-owned South Oil Company), leaving Khashm al-Ahmar in eastern Iraq as the last field open to foreign bidding.

Attracting foreign investment in either the upstream or downstream in Iraq will remain difficult, given persistent security problems and an uncertain regulatory regime and business climate. We project production to reach 35 bcm in 2030 in the Reference scenario and 25 bcm in the 450 Scenario, with output accelerating gradually through the projection period in each case. Inevitably, these projections are very uncertain.

## Africa

There are enormous differences in per-capita use of gas across Africa, reflecting different levels of economic development and resource endowment. Most production and consumption is concentrated in North Africa, mainly in Algeria and Egypt (which together account for just under two-thirds of total African gas use). Power generation accounts for just under half of total African gas demand and, as in most other regions, is expected to be the main driver of demand growth through the projection period. African gas use rises from 102 bcm in 2008 to almost 190 bcm in 2030 in the Reference Scenario, and just over 140 bcm in the 450 Scenario.

Africa's gas resources and production are highly concentrated in a small number of countries. Algeria, Egypt and Nigeria account for over 80% of both proven reserves and production (Table 13.9). Nigeria has the largest reserves, most of which are associated with oil; but its production lags behind that of both Algeria and Egypt, partly because of a difficult investment climate and remoteness from export markets. The proven reserves of the region as a whole total 14.7 tcm, equal to about 8% of the world total and close to 70 years of production at current levels (compared with a worldwide average of 60 years). The region's estimated remaining recoverable resources, including undiscovered volumes, are about 7% of the world total (see Chapter 11). Production is projected to rise from 209 bcm in 2008 to more than 410 bcm in the Reference Scenario, and around 350 bcm in the 450 Scenario. The three main producers account for the bulk of the increase in both scenarios, but the shares of other countries, notably Libya, rise over the *Outlook* period.

**Table 13.9 • *Africa's proven natural gas reserves and production*** (bcm)

| | **Reserves** (start-2009) | **Production 2007** | **Production 2008*** | **R/P ratio**** |
|---|---|---|---|---|
| Algeria | 4 500 | 81.5 | 82.3 | 54.7 |
| Egypt | 2 170 | 58.3 | 58.4 | 37.2 |
| Libya | 1 515 | 16.5 | 17.0 | 89.1 |
| Nigeria | 5 292 | 35.4 | 35.4 | 149.5 |
| Other | 1 231 | 14.0 | 17.8 | 69.2 |
| **Total** | **14 708** | **205.7** | **210.9** | **69.7** |

* Estimate. ** Reserves-to-production ratio (number of years of production at 2008 rate).
Sources: Cedigaz (2009); IEA databases.

Africa's net exports of gas are set to continue to grow steadily through to 2030. It currently exports about half of its marketed production, a share that is expected to remain broadly constant in both scenarios. In volumes terms, exports rise from an estimated 109 bcm in 2008 to 228 bcm in 2030 in the Reference Scenario, and around 210 bcm in the 450 Scenario (Figure 13.20). Most of the increase in exports flows to Europe, already the main market for African gas. Small volumes also go to the Asia-Pacific region. Most of the growth in exports will be in the form of LNG, though pipeline exports to Europe also rise modestly and the region begins to export small volumes to the Middle East from Egypt via the Arab Gas Pipeline.

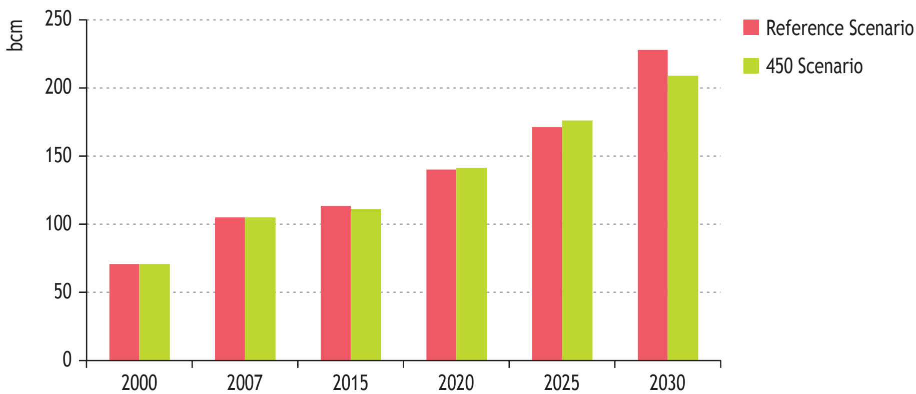
*Nigeria* has considerable potential for expanding supply to both local and export markets. The country holds 5.3 tcm of proven gas reserves, equal to around 150 years of production at the 2008 rate. In the Reference Scenario, Nigeria's gas production is projected to rise from 35 bcm in 2008 to 44 bcm in 2015 and 109 bcm in 2030. In the 450 Scenario, output rises much more slowly, mainly because of modest export demand, reaching 86 bcm in 2030.

Despite abundant resources, per-capita gas consumption in Nigeria is low at around 100 $m^3$ in 2008 (around one-tenth of the average per-capita consumption in OECD Europe), with total gas demand standing at little more than 14 bcm. Local infrastructure for distributing gas is limited and poorly maintained, and power generation capacity is small. Demand is expected to be boosted by the expected completion of three gas-processing facilities under the Gas Master Plan (GMP), described below, as well as by the completion of Chevron's much-delayed 34-kb/d Escravos GTL plant, which is now due on stream in 2012. Feed gas for the GTL plant will come from an expansion of the Escravos gas-processing facility. The rest of Nigeria's output of marketed gas is exported, mainly as LNG (21 bcm in 2008). Exports to neighbouring countries via the West Africa Gas Pipeline (WAGP) began in December 2008 and are expected to rise gradually to 5 bcm/year in the next few years. Up to 5 bcm of gas is re-injected into oilfields to maintain pressure. An estimated 17 bcm of associated gas was flared in 2007 due to lack of distribution infrastructure.[20]

20. According to World Bank data (see Chapter 11).

Eliminating flaring and extracting economic value from associated gas is a major priority for the Nigerian government. In 2008, it announced a Gas Master Plan, involving the construction of three gas gathering and processing plants and three pipeline systems to feed gas to power plants. In March 2009, it shortlisted 15 companies, including international oil companies and Gazprom, to implement the plan. The projects, which will boost supplies by up to 9 bcm/year, are due to be completed by 2011. The government has indicated that it is prepared to push back the deadline for ending gas flaring to the end of 2010, having missed the end-2008 target agreed by OPEC members. Even so, it seems unlikely that sufficient infrastructure will be in place by then to permit an end to flaring.

**Figure 13.20** ● **Net exports of African natural gas by scenario**




Prospects for increasing LNG exports are clouded by uncertainties over the business and political climate. With the commissioning of the 6 bcm/year (4 Mt/year) Train 6 at the Nigerian LNG (NLNG) project on Bonny Island in the Niger Delta in late 2007, Nigeria's LNG capacity now stands at 31 bcm/year. NLNG is considering adding two more trains, each with a capacity of 10.9 bcm/year (8 Mt/year), but there is no sign that final decisions will be taken in the near future, even though buyers have been lined up. Norway's Flex, which was planning the world's first floating LNG production plant in Nigeria, has also postponed a decision on the facility, which would have a capacity of 2.1 bcm/year (1.5 Mt/year). It is unlikely that even one plant will be brought on stream before 2015, but a start date of 2020 is possible (which we assume in the Reference Scenario). In addition to the WAGP, plans are also afoot to export gas through a 4 200-km pipeline through Niger and Algeria to the Mediterranean to supply European markets. The Trans-Sahara Gas Pipeline project has attracted interest from a few organisations, including Total, Gazprom and the European Union, but no consortium has yet been formed. A decision on whether to proceed with this project is probably several years away. Given the high cost of building the line, cheaper alternative supplies and uncertainties about European gas needs, it is assumed in the *WEO* projections that the project will not get the green light soon enough to come on stream before 2030.

Production and exports are set to expand significantly in *Algeria,* Africa's largest gas producer and consumer, despite the prospect of continuing growth in domestic demand. Algeria holds 4.5 tcm of proven gas reserves, the second highest level in Africa, after Nigeria, and the eighth-largest in the world. Power demand is set to jump, with a wave of construction of new gas-fired plants. Total gas demand hit 25.2 bcm in 2008. A number of projects are under construction to expand pipeline and LNG export capacities and meet rising gas needs for power generation and water desalination. In addition, a final investment decision is due in 2010 on the Galsi pipeline to Italy (we assume it goes ahead). Export capacity is set to rise from 67 bcm in 2008 to 102 bcm as and when all planned projects are completed, probably by 2013-2014 (Table 13.10). The Algerian government is targeting exports of 85 bcm by 2012 and 100 bcm by 2015. Under-lifting by European customers (who may prefer to buy spot LNG if it is cheaper) and shortages in feed-gas supplies may mean these goals are not attained.

**Table 13.10 • *Algeria's gas export capacity*** (bcm/year)

| | Existing (2008) | Under construction | Total |
|---|---|---|---|
| **Pipelines** | **39** | **23** | **62** |
| Transmed (via Tunisia) | 27 | 7 | 34 |
| Maghreb-Europe | 12 | | 12 |
| Medgaz | | 8 | 8 |
| Galsi | | 8* | 8 |
| **LNG** | **28** | **12** | **40** |
| Skikda | 4 | 6 | 10 |
| Arzew | 23 | 6 | 29 |
| **Total** | **67** | **35** | **102** |

* Planned. A final investment decision is due in 2010.
Sources: IEA databases.

A number of major new gas development projects are underway in Algeria, including the Gassi Touil field (which is due on stream in 2012) Timimoun, Touat and Reggane. But recent exploration activity has not been very successful, with the gas that has been found being generally in small, poorly located and technically difficult reservoirs. In recognition of the need to boost exploration and development activity, the government is considering changes in the next licensing round, following a disappointing response to the last round held in late 2008. We project production to rise from 82 bcm in 2008 to close to 110 bcm in 2015 and around 150 bcm in 2030 in the Reference Scenario; output reaches only 129 bcm in 2030 in the 450 Scenario.

The gas industry in *Egypt* has boomed in recent years, with a surge in domestic demand to 41 bcm in 2008 (driven by the power sector) and the start-up of two LNG plants (with a combined capacity of 17 bcm). The Arab Gas Pipeline (AGP), running from Egypt via Jordan to Syria and Lebanon, was commissioned in 2003 and now has a capacity of around 10 bcm; since 2008, there has also been a small-capacity submarine link from Egypt to Israel. However, production is struggling to keep pace with domestic demand. The government has decided to give priority to the domestic market and has declared a moratorium on new LNG export contracts until 2010. The prospects for production depend at least in part on the regulatory system and, specifically, on pricing policy. The government is planning to reduce subsidies on end-user prices, a move that would allow state company EGAS to pay higher prices for gas purchased from the international companies operating in the country, thereby encouraging both investment and more efficient domestic use. There have been some significant onshore and offshore gas discoveries in the past year, which suggest that production could resume its upward path in the near-to-medium term; this could result in new LNG projects and an expansion of the AGP, possibly to supply gas to Europe via Turkey. There are doubts about whether resources will be sufficient in the longer term to permit further production increases. Proven reserves amount to 2.2 tcm, equal to 37 years of current production. We project a rise in output from 58 bcm in 2008 to over 70 bcm by 2020 and 80 bcm in 2030 in the Reference Scenario. In the 450 Scenario, output peaks at just over 70 bcm by around 2025 and falls slightly, to just under 70 bcm, by 2030.

*Libya* aims to increase gas production significantly in the coming years to supply the domestic market (mainly to displace oil in power generation and industry in order to free up more oil for export) and to increase exports to Europe. The country's resources are large: proven reserves are 1.5 tcm, which would last almost 90 years at current rates of production. In 2008, Libya produced about 17 bcm of marketed gas (plus about 10 bcm of re-injected gas), of which over 10 bcm was exported. Exports are predominantly made via the 10-bcm/year trans-Mediterranean Green Stream pipeline, although small volumes are also exported from a single-train LNG plant with an effective capacity of 1 bcm. Around 7 bcm was used domestically. The government plans to expand the capacity of Green Stream and has been trying to upgrade the LNG plant, to bring it up to its design level capacity of 4 bcm/year and to initiate new LNG projects. The results of exploration activity have been disappointing of late, which has dampened prospects for exporting more gas soon. But several international companies, including Shell and BP, have recently launched new exploration drilling programmes, which could pave the way for higher production in the longer term. We project output to rise to more than 20 bcm by 2015 and over 45 bcm by 2030 in the Reference Scenario. In the 450 Scenario, production reaches 41 bcm by 2030.

## Asia-Pacific[21]

13

*Australia* is the leading gas producer among the four OECD Pacific countries. Output has been rising steadily in recent years, reaching 45 bcm in 2008, driven by modest domestic demand growth and the needs of the country's expanding fleet of LNG plants. Proven conventional gas reserves of 2.6 tcm[22] could support continuing growth in output, though most of the reserves yet to be developed are located offshore, sometimes in deep water and in remote locations, which complicates their exploitation. CBM (known as coal-seam methane in Australia) is expected to make a growing contribution to gas production. CBM production, concentrated in Queensland, jumped by nearly 40% to almost 4 bcm in 2008 and is set to continue to grow rapidly, as more reserves are proved up and companies

21. See Chapter 15 for a discussion on natural gas supply in Southeast Asia (Malaysia, Indonesia and Brunei Darussalam).

22. According to Cedigaz (2009): other sources have lower figures.

improve their production techniques. In total, gas output is projected to reach 66 bcm by 2015 and almost 120 bcm by 2030 in the Reference Scenario. Output rises much more slowly in the 450 Scenario, to less than 90 bcm in 2030, as the high cost of production and lower LNG demand in the region discourages investment in new export facilities.

The outlook for Australian production hinges largely on new LNG projects. One plant, the 6.5 bcm/year (4.8 Mt/year) Pluto project in Western Australia, is under construction and is expected to be completed by late 2010. A number of other projects are planned, including a second train at Pluto and various plants in Gladstone, based on locally produced CBM (Table 13.11). It is unlikely that all of these projects will proceed, even by 2030, though at least one CBM-LNG plant is likely to get the green light in the near future with first deliveries assumed soon after 2015. Sales agreements with Japan, China and India led Chevron to take a final decision in September 2009 to proceed with the much-delayed 20 bcm/year (15 Mt/year) Gorgon LNG project; we assume that the plant will not be fully operational until after 2015.

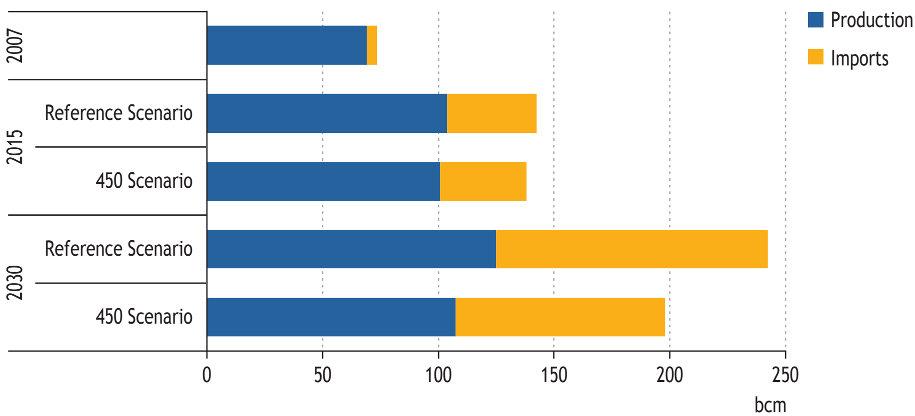
**Table 13.11 • *Australian LNG projects***

| Project | Partners | Start-up | Capacity (bcm/year) |
|---|---|---|---|
| **Existing** | | | **26.3** |
| North West Shelf (1-4) | NWS Australia* | 1989-93, 2004 | 16.2 |
| North West Shelf Train 5 | NWS Australia* | 2008 | 6.0 |
| Darwin | ConocoPhillips/Santos/Inpex/Eni/ Tepco/Tokyo Gas | 2006 | 4.1 |
| **Under construction** | | | **6.5** |
| Pluto | Woodside/Tokyo Gas/Kansai | 2010 | 6.5 |
| *Sub-total* | | | *32.8* |
| **Planned** | | | **102.5** |
| Gorgon | Chevron/ExxonMobil/Shell | 2014 | 20.0 |
| Pluto (expansion) | Woodside | 2014 | 6.5 |
| Gladstone LNG | Santos/Petronas | 2014 | 4.8 |
| Queensland Curtis LNG | QGC/BG | 2014 | 9.5 |
| Shell CSG Australia LNG | Shell/Arrow | 2014 or 2015 | 5.4 |
| Australia Pacific LNG | Origin/ConocoPhillips | 2015 | 9.5 |
| Ichthys | Inpex/Total | 2015 | 8.0 |
| Browse | Woodside | n.a. | 14.0 |
| Wheatstone | Chevron | n.a. | 10.0 |
| Pilbara | BHP Billiton | n.a. | 6.0 |
| Prelude FPSO | Shell | n.a. | 3.5 |
| Greater Sunrise | Woodside | n.a. | 3.3 |
| Gladstone LNG | LNGL/Golar LNG/Arrow Energy | n.a. | 2.0 |
| **Total** | | | **135.3** |

* A consortium of Woodside, Shell, BHP Billiton Petroleum, BP, Chevron, and MiMi (Mitsubishi and Mitsui), each with a 16.67% stake.
Source: IEA databases.

*China's* gas market is set for further growth, fuelled increasingly by imports and driven by a need to boost the use of cleaner energy. Demand reached 78 bcm in 2008, but that is still only 4% of the country's primary energy use, which remains dominated by coal. Urbanisation, which is boosting residential gas use, and industrialisation will continue to drive demand growth. Price reform, which is starting to bring prices along the supply chain more into line with import plus transportation costs, will help balance demand growth with available supplies. Much of the growth in demand is expected to come from the power sector. By 2015 demand is expected to reach around 140 bcm, still a small share of China's total primary energy supply, but nonetheless double the level of 2007; by 2030 it reaches over 240 bcm in the Reference Scenario and almost 200 bcm in the 450 Scenario (Figure 13.21). Gas demand is reduced less in the latter scenario than in most other regions, as switching from coal in industry and the power sector offsets to a large degree the reduced need to burn gas (as a result of efficiency gains).

**Figure 13.21 ● *Natural gas balance in China by scenario***




Chinese gas production is poised for continued strong growth in the medium term. It is projected to rise from 76 bcm in 2008 to over 100 bcm in 2015. In 2000, domestic production was only 27 bcm. Output has been boosted in recent years by the construction of a high-pressure, west-east pipeline and spur lines, which have, encouraged the development of gas resources in the west and centre of the country for supply to markets in the east. In the longer term, it may prove hard to maintain the pace of production growth. Proven reserves amount to 2.7 tcm, equal to about 35 years of current production. This includes the 100-bcm Klameli field in the Junggar Basin, recently discovered by the national company, CNPC. There are also large resources of CBM, though only 134 bcm have so far been proven up. The government is targeting CBM production of 3.5 bcm by 2015. In total, Chinese gas production is projected to reach about 125 bcm in 2030 in the Reference Scenario and almost 110 bcm in the 450 Scenario, as more reliance is placed on imported LNG. The gap between projected demand and indigenous production will be bridged by a mixture of LNG and piped imports, initially from Turkmenistan and, after 2020, also possibly from Russia. A second west-east pipeline to bring gas from Turkmenistan, with an eventual capacity of 30 bcm/year, is under construction. Total imports are projected to rise to around 40 bcm in 2015 and to around 120 bcm in 2030 in the Reference Scenario, and to 91 bcm in 2030 in the 450 Scenario.

As in China, from a low starting point gas is expected to play an increasingly important role in *India's* energy mix, with use set to double to 2015. At 39 bcm in 2007, gas accounted for only 6% of the country's primary energy use. Recent increases in gas demand have been met in large part by imports of LNG, which started in 2003. Consumption is set to increase sharply in the next few years as major new gas fields are brought on stream, notably the giant Krishna-Godavari field, which is being developed by the private company, Reliance Industries. The government has allocated output from this field to the power sector, fertilizer producers and other industries, at regulated prices.

Total Indian gas output is likely to reach at least 60 bcm in 2015, with half the total coming from Krishna-Godavari, while production from other new fields largely offsets declines at mature fields. Renewed interest in drilling, as a result of recent changes in the licensing and regulatory regime in India's upstream sector, is expected to lead to an increase in proven reserves, which currently stand at only 1.1 tcm. By 2030, production reaches 80 bcm in the Reference Scenario. The expected short-term surge in output is set to hold down LNG imports in the coming years , which reach less than 20 bcm in 2015 (compared with 10 bcm in 2008). But LNG imports then rise strongly in both scenarios, reaching about 50 bcm by 2030 in the Reference Scenario.

## Latin America

Latin America is characterised by contrasting trends and prospects for consumption and production across the region. Production of 148 bcm in 2008 marginally exceeded the region's consumption of 132 bcm, with the difference exported by Trinidad and Tobago, an LNG producer. The main consuming countries are Argentina, Venezuela and Brazil, which together account for almost 70% of demand but around 55% of total production. Bolivia is a net exporter, as was Argentina until 2008, although its surplus has been constrained since 2000 by a lack of incentives to invest in the upstream sector. Historically, the region has relied on production from Argentina and Bolivia, and developed a network of pipelines between countries. Regional disputes, a surge in resource nationalism and frequent supply shortages have led three countries — Argentina, Brazil and Chile — to turn to LNG to diversify their supply sources and meet rising demand.

For the region as a whole, demand is projected to rise from 132 bcm in 2008 to around 160 bcm in 2015 and 230 bcm in 2030 in the Reference Scenario, although demand growth in the 450 Scenario is much more modest. While most of this increase will be met by local production, LNG imports to the region are also set to grow. Latin America holds 7.5 tcm of proven reserves, equal to more than 50 years of production at current rates. We project production to rise from 148 bcm in 2008 to 162 bcm in 2015 and 254 bcm in 2030 in the Reference Scenario. This implies a drop in regional net exports to almost zero by 2015 but a rebound (entirely as LNG) in the longer term to 2030.

LNG capacity in the region is set to expand, with part of the increase in supply going to other Latin American countries. Peru will soon join the ranks of LNG exporters, when its 6 bcm/year (4.4 Mt/year) plant comes on stream in 2010. In the longer term, Brazil and Venezuela could also follow suit, depending on the success of efforts to prove up and develop more reserves. Argentina became an importer of LNG in 2008, and Brazil and Chile in 2009. Brazil could become a net exporter of gas in the longer term, but may still import gas in the dry season to meet peak demand. The biggest uncertainty surrounds Venezuela. The country has long had plans to export LNG, based on its large reserves of 4.9 tcm. Agreements were recently reached with foreign companies to build two plants, but a final investment decision on both plants appears to be some way off in view of the weak medium-term outlook for demand in the Atlantic basin and the political risk.

# PROSPECTS FOR NATURAL GAS PRICING

## Will regional prices converge?

### H I G H L I G H T S

- The current surge in liquefaction capacity, coupled with the prospect of a large glut in gas supplies persisting to at least the mid-2010s, could have a profound impact on gas-pricing mechanisms. Market reforms in some regions could also drive a wider move towards spot trading and gas-price indexation (replacing oil-price indexation) in long-term contracts. Rising LNG flows and new or expanded cross-border pipelines will boost globalisation of gas markets in the long term, though the links between North America and other regional markets may weaken in the near term.
- In North America, gas-to-gas competition is well established, with prices fluctuating in response to short-term shifts in gas supply and demand. Oil prices do exert some influence over gas prices, though this is set to diminish. North American prices are set to remain below European and Asia-Pacific prices, limiting LNG imports (unless LNG prices drop sufficiently for gas to displace coal in power generation). As new export liquefaction capacity is unlikely to be built in North America, the gas market there may remain largely disconnected from the rest of the world and from oil prices.
- In Europe, over 70% of gas is sold under long-term contracts with prices indexed mainly to oil, even though oil-based fuels compete less and less with gas. The growing glut of gas will increase pressure on gas importers and external suppliers to adopt gas-indexation and could boost spot gas trade, though this would not necessarily lead to lower prices in the longer term. Further EU and national moves to open up gas and power markets to competition could accelerate this trend.
- Oil indexation looks set to remain the dominant pricing mechanism in cross-border gas trade in the Asia-Pacific region, with domestic prices in most countries continuing to be regulated on a cost-of-service basis. Gas-on-gas competition could make inroads, perhaps less as a result of gas exchanges being established in the region than because of competitive bidding for short-term or spot LNG.
- The shift away from long-term contracts for LNG supply based on a specified physical supply chain looks set to continue, along with shorter contract durations, increased flexibility and possibly more use of gas-price indexation. But only modest growth in imports in North America and Europe may hold back the development of spot LNG trade – unless LNG can displace US unconventional gas production, pipeline gas in Europe or coal in power generation in both regions.
- The new Gas Exporting Countries Forum is constituted as a vehicle for debate, information sharing and dialogue with transit and importing countries. The Forum could seek a more pro-active role on market-related issues in the longer term, but the relative ease with which other fuels can substitute for gas would limit the scope for cartel-like behaviour.

## Gas pricing along the supply chain

The structure of gas markets around the world is evolving in response to policy action to reform the way gas is traded and priced, changes in contractual arrangements, and supply and demand trends. Rising demand and expanding transportation networks are leading to greater market integration at the regional level and between regions, though a truly global gas market – characterised by strong price linkages among all the main regional markets – is still some way off. As demand weakens sharply and new supplies come on stream, global gas markets have evolved from a seller's market driven by tight supply and demand to a buyer's market. Rising liquefied natural gas (LNG) flows and enhanced inter-regional pipeline connections are expected to enhance globalisation of gas markets in the longer term, though falling demand in Europe and the Pacific and abundant indigenous supplies in North America could diminish the relationship between those markets in the next several years. In this sense, gas markets are replicating – to some degree – the historical evolution of the international oil market.

The growth in capacity to trade gas between regions, coupled with the prospect of a large glut in gas supplies persisting to at least the middle of the 2010s (see Chapter 11), could have a profound impact on the way gas is traded and the gas-pricing mechanisms. In particular, the unexpected surge in unconventional gas production in the United States, sustained at prices of less than $4 per million British thermal units (MBtu) has had important spill-over effects on the global gas balance, while the record high oil prices up to mid-2008 have put pressure on the formal oil-linkage in long-term contracts. This chapter reviews current and future trends in how gas markets function, focusing on the evolution of pricing mechanisms, the relationship between the prices of gas and other competing forms of energy, and the impact of the emergence of a global LNG market on the relationship between regional gas markets.

There are big differences across countries and regions in the way gas prices are set at the various stages along the supply chain. Most of the gas traded across borders or sold in bulk directly by producers to marketers or distributors is sold under long-term contracts. Gas prices are usually calculated according to a formula under which they are periodically adjusted according to changes in reference prices – either the prices of competing fuels or quoted gas prices (where they exist) – or in some index of costs. In some cases, gas is traded at a fixed (spot) price for delivery over a short period, typically several days or weeks. End-user gas prices in OECD countries usually take into account the wholesale price paid by the buyer and the cost of transportation and associated services or, in the case of a vertically integrated supplier, the direct cost of producing, distributing and marketing the gas. A tax or subsidy may then be applied to the final price. In almost all cases, the public authorities intervene in the price-setting process, either by fixing the prices of the gas within national borders at the different stages of the supply chain (especially at the retail level) or by regulating the prices charged for monopoly transportation and storage services only (usually on the basis of actual costs). Outside the OECD, prices are often set in ways that bear little direct relation to costs. The result of these differences in pricing approaches is that actual end-user prices can, and do, vary substantially from one country to another and from one sector to another.

Almost one-third of the gas consumed worldwide is priced at the wholesale level on the basis of gas-on-gas competition (spot trading and gas-price indexation in term contracts), while one-fifth is indexed to crude oil and/or refined products (Table 14.1). Just under 40% of gas consumed is subject to direct price regulation of one form or another, and about one-quarter is sold at prices below the cost of supply (*i.e.* at subsidised prices). The importance of each type of price-formation mechanism varies widely from region to region: gas-to-gas competition determines the price of almost all the gas sold wholesale in North America and the United Kingdom, while oil-price indexation is the dominant pricing mechanism in Continental Europe. In the Pacific region, the two approaches are used (depending on the country), while price regulation – often below cost – is the norm in most of the rest of the world, especially in gas-exporting countries.

Although gas prices are set directly by supply and demand in liberalised markets with gas-to-gas competition and regulated third-party access to transportation infrastructure, market fundamentals also influence gas prices, to varying degrees, in markets where gas-to-gas competition is weak or non-existent. Supply costs set a floor for gas prices, unless the state is willing to provide a subsidy, while the prices of competing fuels ultimately set a ceiling. As described in Chapter 10, gas can be replaced by alternative fuels in all end uses and in power generation. So, gas producers or wholesale marketers are obliged to take into account the competitiveness of gas against other fuels while negotiating contracts with their customers. Similarly, governments that set gas prices directly need to take inter-fuel competition into account. The fuel that sets the price ceiling and the rigidity of that ceiling depends on several factors: the switchable share of gas consumption in the market in question; the investment costs of replacing equipment unfit for switching with equipment that can burn alternative fuels; the readiness of the end user to switch; the speed with which alternative energy-delivery infrastructure can be installed; and the presence or absence of legal, regulatory and environmental restrictions on switching.

A critical element in determining end-user gas prices in a given market, in absolute terms and relative to other fuels, is the system of energy taxation or subsidy. Many countries – especially in the Former Soviet Union, the Middle East, Africa and Asia – subsidise gas and, in some cases, other forms of energy; in other words, prices are set below their true economic value. Decisions on sustaining or lowering these subsidies, and on the timing and pace of subsidy reform, have a significant impact on gas demand, investment in gas supply to domestic markets, regional market balances and inter-regional gas flows (see the Introduction for our assumptions about subsidies). Continued subsidisation would boost domestic gas demand, erode exports available for the rest of the world and increase global competition for imports.



## North America: what will drive gas prices?

The United States, together with the United Kingdom, was the first country with a major gas market to liberalise gas trade and establish competition in wholesale markets, a process that was launched in the 1970s and not completed until the 1990s. Canada followed suit, creating a highly integrated competitive market across North

**Table 14.1 • Composition of wholesale *gas* transactions by price-formation mechanism and region, 2007** (%)

| | Gas-to-gas competition | Oil-price indexation | Bilateral monopoly | Netback from final product | Regulation - cost-of-service | Regulation - social/ political | Regulation - below cost | No price | Unknown | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| North America | 98.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.3 | 0.0 | 100 |
| Europe | 22.0 | 72.2 | 1.8 | 0.1 | 0.4 | 3.0 | 0.0 | 0.6 | 0.0 | 100 |
| Pacific | 16.3 | 51.9 | 7.6 | 0.0 | 3.0 | 19.3 | 0.0 | 0.0 | 1.9 | 100 |
| Former Soviet Union | 1.1 | 0.0 | 24.1 | 0.0 | 0.0 | 1.6 | 72.7 | 0.6 | 0.0 | 100 |
| Asia | 8.3 | 19.5 | 4.7 | 11.4 | 8.0 | 48.2 | 0.0 | 0.0 | 0.0 | 100 |
| Middle East | 0.0 | 0.0 | 3.4 | 0.0 | 0.0 | 14.2 | 80.3 | 1.3 | 0.8 | 100 |
| Africa | 0.0 | 5.0 | 0.0 | 1.1 | 29.8 | 9.0 | 54.2 | 0.9 | 0.0 | 100 |
| Latin America | 3.4 | 12.1 | 11.4 | 0.0 | 18.9 | 51.2 | 3.0 | 0.0 | 0.0 | 100 |
| **World** | **32.8** | **19.7** | **7.7** | **0.6** | **2.6** | **9.4** | **26.2** | **0.8** | **0.3** | **100** |

Note: The world total is calculated by weighting the share of each mechanism by each region's share of world primary gas consumption in 2007.

Source: IGU (2009).

America. Today, gas is traded almost exclusively on a spot basis from the wellhead to the city-gate. Prices fluctuate in response to short-term shifts in supply and demand. The surge in North America drilling for shale gas in recent years, with improvements in technology, lower costs and the opening up of large new areas to development, has boosted overall supply and driven down prices, both in absolute terms and relative to oil prices. The slump in demand for gas, especially in industry, resulting from the sharp recession that took hold in 2008, has also contributed to the price collapse; by mid-2009, prices were less than one-third their peak in mid-2008 (see Chapter 13).

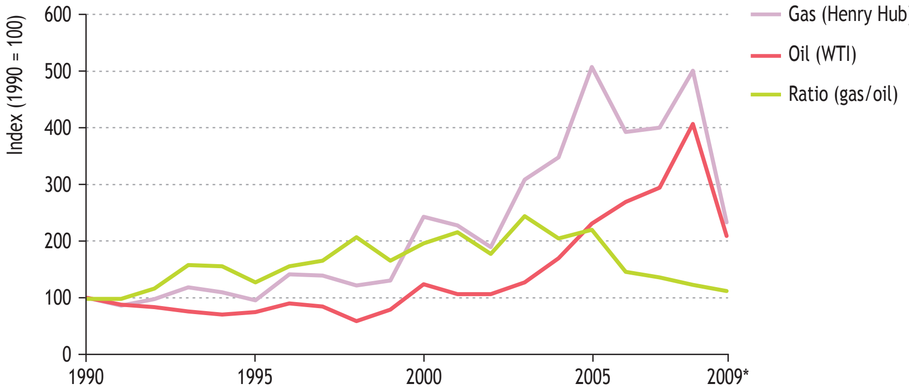
Oil prices still influence gas prices to a significant degree, but this phenomenon may be expected to weaken over time. Oil and gas prices historically have tended to move in tandem, albeit with a time lag, with the ratio between the two fluctuating much less than prices themselves. Statistical analysis of Henry Hub spot prices and the price of West Texas Intermediate (WTI) crude oil points to a relatively stable long-run relationship, despite the occasional spike in either market producing the appearance of decoupling (Figure 14.1).

#### Box 14.1 • *Pricing mechanisms defined*

The different models of gas-price formation used around the world, and used in Table 14.1, are defined as follows:

- Under gas-to-gas competition, gas is priced in open free-market trade on a spot basis or under term contracts.
- With indexation to oil prices, prices are set by formula under long-term contracts, usually of several years duration (see Box 14.2).
- Bilateral monopoly is the dominant pricing mechanism in interstate gas dealings in the Former Soviet Union, in Central and Eastern Europe, and in many immature gas markets with one dominant supplier facing one or a couple of dominant buyers.
- With the netback from final product approach, the price received by the gas seller reflects the price received by the buyer for this product.
- With regulation – cost of service, prices are approved according to set procedures by a regulatory authority so as to cover supply costs including a reasonable return on investments.
- With regulation – social-political, prices are set and adjusted typically on an *ad hoc* irregular basis by the government taking account of buyers' perceived ability to pay, sellers' perceived costs and the government's revenue needs.
- With regulation – below cost, the government knowingly sets prices below the sum of production and transportation costs as a form of subsidy to the buyers and usually reimburses the seller from the state budget.
- No price is the extreme form of regulation – below cost.

**Figure 14.1 • Oil and natural gas prices in the United States**




* First half year average.

Source: IEA databases.

Oil prices influence gas prices through their impact on gas supply and demand. Based on data for the period 1990-2005, a lasting 20% increase in WTI would be expected to produce an immediate 5% increase in the Henry Hub gas price and a 16% increase after one year (Table 14.2). By contrast, a temporary 20% spike in the WTI price would have almost negligible long-term impact on the gas price (Villar and Joutz, 2006).[1] That said, recent changes in North American gas market dynamics may have changed the way gas prices move in relation to oil prices (see below).

**Table 14.2 • Impacts of changes in oil prices on gas prices in the United States**

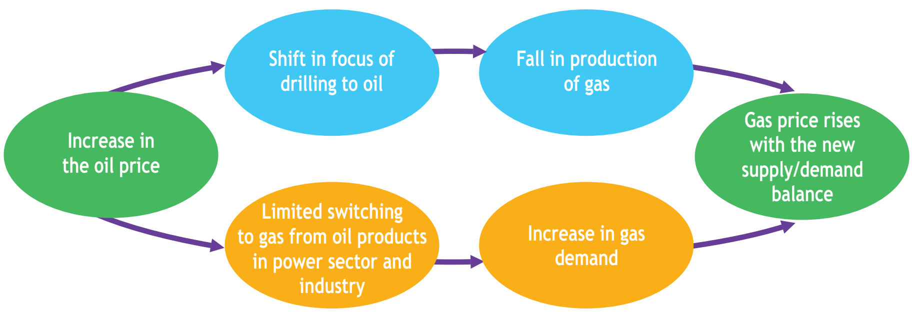
| Effect of a permanent change in the price of crude oil | | |
|---|---|---|
| Period (months) | Change in price of WTI (%) | Change in gas price at Henry Hub (%) |
| 0 | 20.0 | 5.0 |
| 1 | 0.0 | 7.8 |
| 2 | 0.0 | 9.8 |
| 12 | 0.0 | 16.0 |
| **Effect of a transitory change in the price of crude oil** | | |
| **Period (months)** | **Change in price of WTI (%)** | **Change in gas price at Henry Hub (%)** |
| 0 | 20.0 | 5.0 |
| 1 | -16.7 | 2.8 |
| 2 | 0.0 | 2.1 |
| 12 | 0.0 | 0.6 |

Source: Villar and Joutz (2006).

1. Other studies, including Neumann (2009) and Brown and Yücel (2009) come to broadly similar conclusions. Indeed, the latter concludes that linkages between natural gas prices in North America and Europe reflect co-movements with WTI more closely than gas-to-gas arbitrage.

Oil prices affect gas prices both on the supply and demand sides (Figure 14.2). On the supply side, an increase in oil prices relative to gas prices prompts exploration and production companies to redirect their investments from gas to oil, with the effect of boosting oil supply at the expense of gas supply. A decline in oil prices relative to gas prices can trigger the opposite chain of events. This effect may be expected to weaken over time as drilling increasingly focuses on offshore developments, for which the lead times are much longer. Another supply-side reason why gas and oil prices are linked is that oil and gas companies face largely the same cost issues whether they are developing oil or gas fields. However, the falling relative cost of drilling for unconventional gas, because of technological advances specific to this type of gas and the fact that gas drilling is increasingly carried out by specialised gas companies, are likely to weaken this link (see Chapter 11).

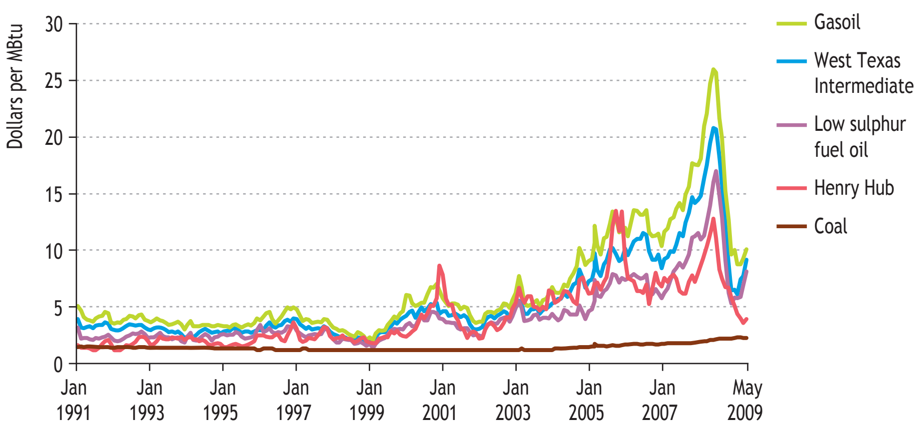
**Figure 14.2 ● How oil prices affect gas prices in North America**




On the demand side, oil and other energy prices influence gas prices through inter-fuel competition in all stationary market segments (see Chapter 10). In North America, only a small and decreasing fraction of industrial fuel demand is switchable at short notice, through use of multi-burners or back-up equipment that can use an alternative fuel; but under tight market conditions, minor shifts in demand can have a large impact on price. Fuel-switching capability is significantly larger in the power sector, where gas competes mainly against coal. Between January 1994 and May 2009, the Henry Hub spot price was above the price of distillate only 5% of the time, between the prices of distillate and residual fuel oil 43% of the time (mainly during the peak winter and summer months) and below the price of residual fuel oil 51% of the time. During the two years to mid-2009, gas has been cheaper than residual fuel oil in all but two months. Coal prices effectively set a floor for gas prices during periods of relatively low electricity demand. The sharp decline in North American gas prices in 2008 and early 2009 led to significant displacement of coal in the power sector, in particular on the East Coast, boosting gas demand and preventing gas prices from falling much below coal prices.

The linkage between oil and gas prices typically emerges during times of relatively tight gas supply and weakens during off-peak periods or when supply is particularly abundant. At this point, gas demand becomes highly price-inelastic because there is virtually no more potential for switching *to* gas (Jensen, 2009). The boom in shale gas drilling has helped to weaken the link between oil and gas prices in the last year or two, with gas prices dropping to well below half the level of residual fuel oil prices in energy-equivalent terms by the middle of 2009 (Figure 14.3). Nonetheless, higher oil prices during the projection period – as assumed in both the Reference and 450 Scenarios – would be expected to drag up gas prices to some degree. In the near term, prices will gain some support from the recent drop in shale gas drilling, which is curbing output. Tighter environmental legislation, including the introduction of carbon pricing (as assumed in the 450 Scenario), would push up the cost of coal and (other things being equal) set a higher floor for gas prices, even though weaker demand growth (in North America and worldwide) would be expected to drive down gas prices on average in absolute terms (see Introduction).

**Figure 14.3 • *Monthly oil and natural gas prices in the United States***




Sources: IEA databases, EIA and Platts.

LNG imports may play a role in linking North American gas prices to those prevailing in Europe and Asia-Pacific, at least during periods when the price difference provides an incentive to import uncommitted cargoes. The last such period was early to mid-2007. However, robust indigenous output and dwindling import needs in the long term, as projected in both scenarios presented in this *Outlook*, would limit the North American region's interest in competing for available LNG supplies. This prospect implies that the North American market may remain largely disconnected from the rest of the world – and also, therefore, from oil prices (see below) – though markets may periodically reconnect at times of peak demand. For that reason, North American gas prices are expected to remain lower than import prices in Europe and the Pacific region. However, LNG exporters may be prepared to sell LNG on a spot basis into the United States (and Europe) at prices that enable it to displace domestic gas production and compete effectively against coal in power generation. In this case, spot prices in North America would tend to converge with those in Europe, as LNG suppliers arbitrage between the two markets.

The outlook for LNG imports into North America, nonetheless, remains a major uncertainty. The key factor is whether LNG prices are low enough to compete at the margin with US unconventional gas and win market share from coal in power generation: higher development costs for shale gas in particular and/or lower LNG prices could pave the way for increased LNG imports into the United States and Mexico. LNG prices could weaken in the near-to-medium term, with the start-up of a number of new LNG plants and the prospect of over-supply (see Chapter 11). US gas prices in mid-2009 yielded lower netbacks to Middle Eastern LNG suppliers than markets in Europe and the Pacific. But this situation could reverse, if only temporarily, if prices in the latter markets drop further, possibly due to unexpectedly weak demand. Selling LNG into the United States at a Henry Hub price of $3/MBtu will be a more attractive option than shutting in capacity; once up and running, LNG supply chains have low variable costs. But, though it may still be profitable to export LNG at such low prices, doing so may undermine long-term pricing positions. Moreover, it seems unlikely that prices could remain as low as this for any prolonged period, given that the marginal cost of production in North America is probably considerably higher. The United States appears likely to remain the market of last resort for surplus LNG.

So, although North American gas prices are set through gas-to-gas competition, both oil and coal prices will continue to exert an influence over them (albeit a weaker one than in the past) through supply-side linkages and inter-fuel competition. Nonetheless, gas demand and supply factors may for extended periods – including the next few years – result in gas prices moving well outside the normal band (whereby oil prices set an upper limit and coal prices a lower boundary). In the medium term, abundant supplies of unconventional gas are expected to keep gas prices at historically low levels relative to oil prices. Rising marginal supply costs are assumed to reverse the trend in the longer term. Potential new environmental policies, including the introduction of penalties on carbon-dioxide ($CO_2$) emissions, would boost incremental demand for gas, in power generation in particular, and boost gas prices relative to coal prices.

## Continental Europe: what role for gas-on-gas competition?

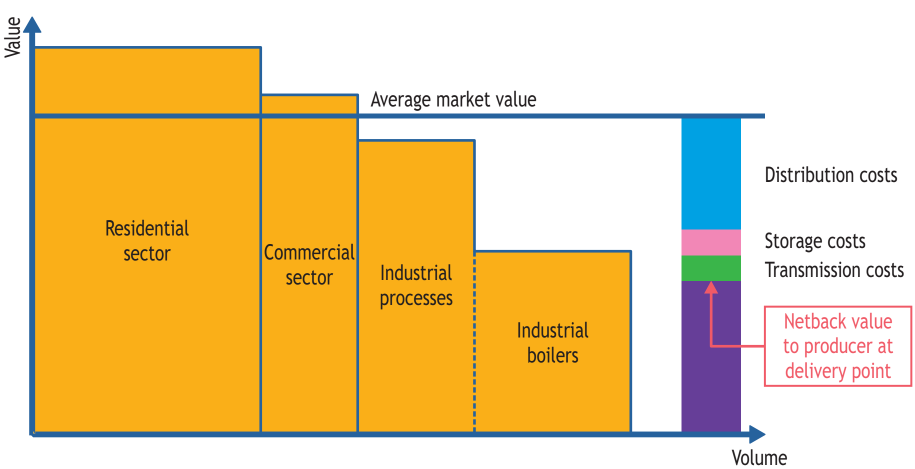
Gas pricing in most of Europe is – and is likely to remain – very different to that in North America. Europe is much more reliant on imports, mostly supplied under long-term contracts. Despite efforts to open up gas markets to gas-to gas competition, Continental Europe remains a bastion of netback market-value pricing of gas imports – a mechanism whereby the price of gas is indexed under long-term contracts to the prices of the fuels that compete with gas (Box 14.2). Market values are typically calculated for the points at which European wholesalers take delivery of gas, *i.e.* at border crossings for pipeline supplies and at regasification terminals for LNG. This approach was established in the early days of the development of the European industry as a means of ensuring, in the face of fluctuating oil prices, that gas would remain competitive against oil products – then the principal alternative to gas. Producers agreed to accept the risk of prices dropping with oil prices, while taking any rent that might emerge with higher oil prices. The importers, selling on into markets that were, at the time, largely monopolies, could count on a margin over the gas purchase price to pay for the costs of distributing and marketing the gas, and to provide a reasonable return on their investments.

### Box 14.2 ● The mechanics of netback market-value pricing

The netback market-value pricing approach aims to ensure that gas remains competitive with competing fuels, the prices of which can fluctuate strongly. It does so by setting the border or "beach price" in each long-term sales contract marginally below the weighted-average price of the cheapest alternative fuels across all customer categories, adjusted to allow for differences in efficiency, for gas transportation and storage costs from the beach or the border, and for any taxes on gas (Figure 14.4). The approach was first introduced in 1962 to market gas from the Groningen field in the Netherlands and subsequently became the norm for all large-volume, long-term supply contracts for indigenous and imported gas (Energy Charter, 2007).

There are, in principle, three different average netback market values, corresponding to existing gas users with or without fuel-switching capability and new gas users (such as a new power station). In practice, the price negotiated corresponds to a level somewhere between the highest and the lowest of the three values (to ensure that additional gas supplies are able to compete effectively for new customers), weighted across the different end-user customer categories. The gas price is typically indexed to heating oil and/or heavy fuel oil or simply to crude oil (on the implicit assumption that the ratio of crude-to-product prices will remain broadly constant), to ensure that prices over the life of the contract remain broadly in line with market values. In some cases, inflation indices are used to reflect the importance of electricity as the competitor to gas, or coal prices are used to reflect the role of coal as the competitor to gas in power generation. Gas prices are then adjusted periodically, using averages of the competing fuel prices over a period of six to nine months to reduce price volatility. The contract usually includes a price-reopener clause allowing each party to request changes to the formula when the market has undergone a major structural change.

### Figure 14.4 ● Illustration of netback market-value pricing



Although liberalisation of the gas market has led to the development of some spot trade in gas and the increasing availability of uncontracted gas has fuelled further growth in European spot trade in 2009, around 80% of the gas consumed in Continental Europe is bought wholesale (from external suppliers or indigenous producers) in this traditional way, under long-term contracts with oil-price indexation. This pricing mechanism continues to be used for new supplies, even though gas increasingly competes against electricity in industry and in the residential and commercial sectors, and competes against coal, renewables and nuclear power in the power sector, the main source of incremental demand growth for gas in recent years. This continued reliance on netback market-value pricing contrasts with the dominant role played by gas-to-gas competition in the British market (as in North America) following the establishment of a third-party access regime in the 1980s and 1990s.

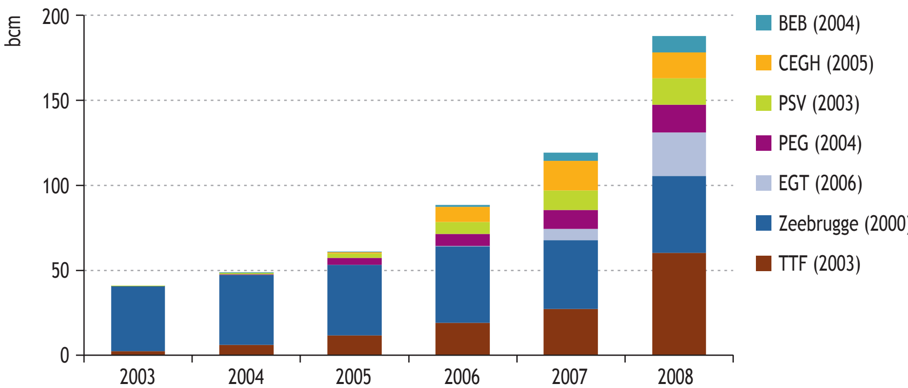
Further regulatory reforms at the EU and national levels, aimed at opening up the gas (and power) market to competition and breaking down the dominant positions of the major European gas companies, should promote more gas-to-gas pricing and spot trade, and encourage a move towards spot gas-price indexation in long-term contracts in Continental Europe (IEA, 2008b). The EU's third energy package, in September 2007, proposed full ownership separation of the gas companies' transmission activities from their supply activities, seen as a precondition for non-discriminatory third-party access to Europe's gas grids and effective competition. After a considerable amount of discussion, the EU Council adopted an amended version of the package on 25 June 2009. It offers member states a choice of three types of unbundling:

- Full ownership separation (as per the original 2007 proposal).
- An Independent System Operator (ISO) model, with an independent body managing the country's transmission pipeline grids (which may still belong to their current owners).
- An Independent Transmission Operator (ITO) model, with an independent body monitoring the operations of legally unbundled transmission companies (which will retain the operatorship of the grids and may still belong to the current grid owners).

The package also has provisions for the establishment of two new bodies: a European Agency for the Cooperation of Energy Regulators (ACER), to regulate cross-border gas transmission, and a European Network for Transmission System Operators (ENTSO), to develop codes for cross-border transmission on the basis of ground rules worked out by ACER and the Commission. Member states were given 18 months to implement most of the provisions in the package, but a 30-month timeframe to decide on an unbundling model and to act on that part of the package.

Another important step towards gas-to-gas competition will be the development of large-scale liquid and efficient gas exchanges. The main gas-importing companies in Europe already trade on these exchanges to a limited extent in order to exploit gaps between spot prices (which fluctuate according to market fundamentals) and the prices in their long-term contracts (which fluctuate according to oil prices), since their contracts typically allow flexibility of 10% to 15% in the volumes they are obliged to take (or pay for anyway). Gas exchanges providing spot price information already operate in several Continental European countries (Figure 14.5), though their size pales beside that of the National Balancing Point (NBP) in Great Britain: the volume of trading at the NBP in 2008 was more than five times that on all the Continental European exchanges taken together. The NBP churn rate – the ratio of the volume of traded gas to physically delivered gas (a measure of market liquidity) – stood at about 15 in 2008, compared with only 3.3 at the Dutch Title Transfer Facility (the leading Continental European hub), 3 at Austria's Central European Gas Hub and 5.2 at Belgium's Zeebrugge Hub. The rate at the Henry Hub in the United States is far higher still, at around 100.

**Figure 14.5 • *Gas trading hubs in Continental Europe***




Note: CEGH is the Central European Gas Hub (physical) in Austria; PSV is the Punto di Scambio Virtuale (virtual) in Italy; PEG is the Point d'Echange de Gaz (a set of virtual hubs) in France; TTF is the Title Transfer Facility (virtual) in the Netherlands; EGT and BEB are both virtual hubs in Germany. The date each exchange started is in parentheses.

Sources: Data published by each exchange on their websites and information provided to the IEA by the National Grid in Great Britain.

The main external suppliers to the European market are Russia's Gazprom and Algeria's Sonatrach. Both fear a move away from oil-price indexation and long-term contracts in the expectation that gas-to-gas competition would be likely to result in lower gas prices, at least in the near-to-medium term (with readily growing LNG supplies and increased import capacity into southeast Europe). They argue that oil-price indexation is necessary, on the grounds that no acceptable alternative exists. They claim that gas hubs and trading platforms in Continental Europe are too illiquid to make gas-price indexation (as in the United Kingdom or North America) viable, even though volumes traded continue to grow rapidly (IEA, 2009). Replacing the link to oil with a link to a mix of coal, electricity and carbon prices has been discussed as a possibility in contracts with power generators, but the producers/suppliers are generally resisting such a move as it would allow power generators to sell gas onto the non-power sector when prices permit, depriving the producers/suppliers of rent (Stern, 2007).[2]

Despite the (limited) use they make of the gas exchanges, the large companies that import and distribute most of Europe's gas, and currently own and operate national and cross-border transmission and distribution systems, themselves have only a weak incentive to change the pricing basis of their long-term import contracts. In most areas of Continental Europe, where competition in national gas and electricity markets is still far from perfect, the importers can pass through oil-driven increases in gas prices to end users. Higher gas prices can benefit some large gas and power companies with coal-fired and nuclear capacity, as they make these sources of power more profitable. These companies echo the arguments of the main external gas suppliers about the inadequacy of the volumes handled by the existing European gas exchanges as a revised basis for pricing.

The structure of long-term import contracts into Continental Europe constitutes a formidable formal constraint on the pace at which alternative pricing mechanisms can be introduced. Many of these contracts will still be in force in 15 to 20 years time. Even if no more such contracts were signed, the share of oil-indexed contracts in total gas supply would not dip below 50% until after 2020, unless existing contracts were to be modified to incorporate different pricing mechanisms.

Nonetheless, the prospective surge in uncommitted gas supplies in the spot market could be a potent force for change in European gas pricing. By mid-2009, spot prices had fallen well below contract prices, as a result, on the one hand, of weak demand, a rapid build-up of LNG supplies (imports rose 11% in the first half of 2009) and even lower prices in the United States and, on the other, the lagged nature of the oil link in European long-term contracts. The persistently lower spot prices that could result from the looming gas surplus, could drive importers to demand contract price formula revisions, particularly if higher oil-prices threatened to drive up gas prices in long-term contracts as a result of oil-price indexation, even though they will be constrained by fears that such a move could precipitate a collapse of the oil-indexation pricing approach, undermining the whole system of long-term contracts, opening up the market to great competition and driving down margins. The external suppliers selling at oil-indexed prices would certainly initially resist such a change. But, ultimately, gas suppliers into Europe and many of the dominant importers do have an interest in keeping gas competitive against coal and other fuels and generating technologies. They may accept the need for lower prices and at least a degree of gas-to-gas pricing in long-term contracts in the interest of sustaining the gas market and, particularly, their part in it. It would be prudent to expect the introduction of indexing against spot prices to occur first in new contracts; but change could gather pace in the right market circumstances. Even so, and even if the formal contractual link between gas and oil prices were to disappear, oil prices would continue to influence

2. Gazprom publicly announced in June 2009 it had no plans to review its use of oil indexation in response to plummeting gas sales (Aleksandr Medvedev, CEO of Gazpromexport, quoted in *ICIS Heren European Spot Gas Markets*, June 24, 2009). Recent initiatives to sign new oil-indexed contracts and extend existing contracts to 2030 came from European large buyers and not from Gazprom or Sonatrach (Finon, 2009).

gas prices in Europe, largely as a result of inter-fuel competition and indirect gas-price linkages with the Asia-Pacific markets as a result of increased LNG trade (see below). Gas-price indexation could even lead to higher prices in the longer term, depending on the evolution of the supply/demand balance.

## Asia-Pacific: how will pricing evolve in the main importing countries?

Gas pricing in the Asia-Pacific region is very heterogeneous, reflecting big differences in resource endowments, demographic characteristics, political traditions, economic organisation and stage of economic development. Southeast Asian countries, as a group, are net exporters, with 41% of their total marketed gas production exported in 2008, mostly as LNG (see Part D). Australia is a growing exporter of gas and Papua New Guinea is expected to become an LNG exporter by around 2015. Almost all other countries in the Asia-Pacific region are net importers. Japan, Korea and Chinese Taipei rely exclusively on LNG imports for their gas supply; the first two are the world's biggest LNG buyers. Most cross-border gas sales involve long-term contracts and crude oil-linked prices, though the precise mechanisms have evolved over the years (Box 14.3). But spot supplies have been growing, at least until 2007: Japan obtained about 15% of its supply from the spot LNG market in 2008, down from the 2007 level but well up on the early part of the current decade; for Korea, the share was an estimated 27%. Taiwan, India and China have also stepped up their spot purchases.

### Box 14.3 ● Evolution of the pricing of *Japan's* LNG imports

Japan was the third country in the world to import LNG, the first cargo arriving in 1969. Initially, prices were fixed on the basis of project costs, with no mechanism for adjusting prices in line with the market. After the first oil shock in 1973, LNG import prices were gradually raised in line with the price of oil. After the second oil shock in 1980, this practice was codified into a formula based on the concept of "oil-parity pricing". After the 1986 oil price collapse, however, suppliers selling LNG at oil-related prices ran into financial difficulties as they failed to cover the costs of their LNG projects. As a result, the pricing formula was renegotiated again, resulting in the principle of setting the LNG price equal to 80% to 90% of the weighted-average price of crude oils imported into Japan (the so-called "Japan Crude Cocktail"), plus a constant amount. In this way, the LNG price was kept slightly more stable than the oil price.

In the 1990s, low oil prices once again eroded the economics of LNG projects. In response, the so-called S-curve was introduced, thereby reducing the sensitivity of the LNG price to oil-price movements outside certain oil price limits. This shielded suppliers in periods of unusually low oil prices and buyers in periods of extraordinarily high oil prices. As LNG markets tightened, in particular in 2007-2008, some suppliers started to push to bring LNG pricing closer to parity with crude oil and with no protective mechanisms in the form of S-curves, floors or ceilings. The global recession and the prospect of prolonged LNG oversupply have since weakened suppliers' negotiating position.

Traditionally, gas and power companies in Japan, Korea and Chinese Taipei have paid more than European and North American importers for LNG, reflecting their preoccupation with supply security as well as their ability under the cost-of-service based pricing regimes prevailing in these countries to pass the higher costs on to their customers (dampening the incentive to negotiate the lowest possible price).

The Japanese gas market used to be highly fragmented, characterised by regional monopolies within geographical concession areas, but the market is now changing rapidly. The revised *Gas Utility Law* provides for third-party access to LNG terminals and pipelines, and for competition in supplying those customers who use in excess of 100 000 cubic metres of gas per year. Competition between incumbent city-based utilities and new entrants is developing, causing prices to fall and margins to drop to very low levels (Miyamoto, 2008). This could have repercussions for LNG pricing arrangements throughout Asia-Pacific. Lower margins are forcing Japanese LNG importers to take a tougher stance on pricing with their suppliers. This could mean moving away from crude oil-linked pricing or at least supplementing the so-called Japan Crude Cocktail (JCC) price with other indices. Noting the possibility of US gas-price weakness for several years, one Japanese LNG buyer recently proposed basing prices in future contracts on a weighted average of the JCC and Henry Hub spot prices, or switching to a formula including Brent crude oil and UK NBP prices. Another possibility is to adopt a netback market-value pricing system like that in Europe. However, few Japanese buyers are prepared just yet to embrace radically different pricing approaches. The recent collapse of gas demand in Japan has prompted most buyers to make use of the downward quantity tolerance (DQT) provisions in their LNG imports contracts but, in a context of weak demand, it is still difficult for buyers to benefit from cheap spot LNG cargoes. It is likely that, in their future contract negotiations, Japanese buyers will ask for higher DQT and upward quantity tolerance as well as shorter contract duration.

In Korea, ambitious plans to liberalise the gas sector have made limited progress. The government in 2006 delayed until 2012 the planned abolition of Kogas' monopoly on commercial LNG operations. Another three companies can import LNG, but only for their own use. Gas prices in Korea are regulated on a cost-plus basis, under which Kogas' commodity costs are passed through to end users with charges and taxes added. There are plans to open up the power-sector market and then the industrial market, allowing new entrants to compete for uncovered demand. A major issue, however, is access to storage.

Gas prices in China are controlled by the National Development and Reform Commission on the basis of the actual cost of production or imports, processing and transportation. In late 2007, the government announced price increases for all end-use sectors, but with special, subsidised rates kept in place for the fertilizer industry. Prior to the financial crisis, end-user prices were well below the prices of imported LNG. This gap has narrowed somewhat as LNG prices have fallen. In the longer term, increased imports of LNG and of Turkmen and Russian gas via pipeline will increase

China's exposure to international prices (see Chapter 13). The cost of more expensive imported gas will be rolled in with the cost of cheaper indigenous gas in calculating domestic prices, while also taking into account domestic consumers' ability and willingness to pay. Retail prices will need to rise. Regional price differences may decline as the building of a national gas grid proceeds.

In India, gas supply has three components, each of which is priced differently. Gas produced by the state oil companies, ONGC and OIL, is subject to the so-called Administered Price Mechanism (APM). In 2006-2007, this gas made up about 65% of total supply. The APM price is indexed to a basket of fuel oil prices. In 2008, this mechanism resulted in wholesale prices of $2.00/MBtu to $2.40/MBtu, not including transmission and distribution charges and taxes. Customers in the northeast paid less as part of a regional support policy package. By contrast, gas produced by private companies is sold at negotiated prices with no contractual linkage to oil prices and no caps: in 2008, prices varied between $3.50/MBtu and $5.70/MBtu. Gas produced from the Krishna Godavari basin, which is currently ramping up to full capacity of 30 bcm/year, is sold at $4.20/MBtu. As production rises, the share of private companies will overtake the state share, so that the pressure on dualistic APM and non-APM pricing will grow. Finally, imported LNG is sold at prices that are set on a cost-plus basis and are subject to government approval.

The price of LNG under India's first LNG import contracts (with Qatar's RasGas II), at a constant $2.53/MBtu, is very low, as the deal was struck at a time when buyers had the upper hand. The price will be linked to oil prices from 2009, but for several years the pass-through factor will be much lower than is normal for newer contracts. The viability of new LNG imports will hinge on price reform that allows importers to pass through the full cost of gas imported at international prices, as well as on the competitiveness of gas versus other fuels. As in China, growing import needs in India will probably lead to a gradual alignment of prices with those prevailing in OECD Asia, though the process may be far from complete by 2030.

Oil indexation looks set to remain the dominant pricing mechanism in cross-border gas trade in the Asia-Pacific region, despite arguments similar to those used in Europe that the rationale for such a system has largely disappeared.[3] Domestic prices in most countries are likely to continue to reflect import prices and transmission, distribution and — where appropriate — storage costs, plus a regulated return on investments. Prices set by gas-to-gas competition could make inroads, perhaps less as a result of gas exchanges being established in the region than because of competitive bidding for short-term or spot LNG. This could increase Asian gas-price volatility but may not lead to either a higher or a lower long-term price trend.

3. See, for example, Miyamoto and Ishiguro (2009).

**Box 14.4 ● *The Australian gas market: a case study of competitive pricing in Asia-Pacific***

Australia was the first country in the Asia-Pacific region to introduce gas-market reforms based on third-party access to the network and gas-to-gas competition is well established. Prices have typically remained far below North American and European levels, reflecting comparatively low supply costs and the fact that in Australia gas competes primarily against coal, which is relatively cheap in Australia. Prices have, nonetheless, risen steadily since the early 2000s, as development costs have risen, droughts have boosted demand for gas for power generation to replace reduced hydropower capacity, and as the prices of exported LNG have increased (Figure 14.6).

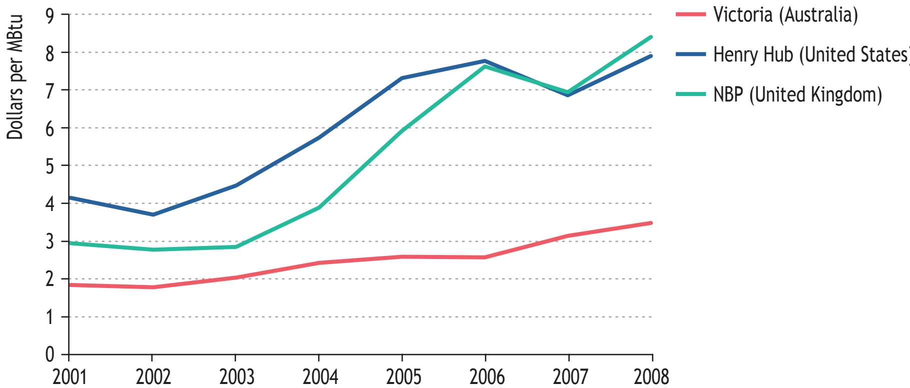
The upstream sector is highly competitive, with more than 100 companies carrying out exploration and around 30 of these involved in production. The number of players has increased since the 1990s as a result of growing demand and booming interest in coalbed methane (CBM), known as coal seam methane in Australia. A small group of Australian majors – BHP Billiton, Woodside, Santos, Origin, Queensland Gas, Arrow and AGL – dominate both conventional gas and CBM production, with several international majors also playing major roles in the production of gas as feedstock for LNG and for domestic supply. Australia's wholesale gas market remains dominated by long-term, take-or-pay contracts, though the length of deals has shortened. The only spot market for gas that exists in Australia was set up in 1999 in Victoria; it currently accounts for up to 10% to 20% of the wholesale volumes traded in Victoria.

The gas transmission industry was significantly restructured in the 1990s, with vertically integrated gas utilities broken up and most state-owned pipelines privatised. Gas transmission is still concentrated, with four players controlling the bulk of the country's almost 20 000 km of trunk pipelines and usually providing services on a third-party basis. Given the risk of monopoly pricing, pipeline tariffs are regulated under the *National Gas Law* and *National Gas Rules* which took effect on 1 July 2008. Gas retailing was subjected to effective competition in July 2008. Since then, consumers have been able to choose among retailers and available contracts in accordance with their individual needs and preferences.

Further reforms are in the pipeline. Recognising that real-time information on pipeline flows is essential to the effective functioning of a market, a Gas-Market Leaders' Group (appointed in 2005) recommended the establishment of a gas-market bulletin board, a short-term gas market and an operator for both the bulletin board and the market. The bulletin board – a website offering timely information on major gas fields, storage facilities, demand centres and transmission pipelines in southern and eastern Australia – commenced operations in 2008. The board's coverage will be extended to include Western Australia and the Northern Territories. The short-term market, intended to facilitate daily trading under a mandatory balancing mechanism at defined gas hubs, will be launched in 2010.

Source: ACCC (2009).

**Figure 14.6 • *Average spot natural gas prices in Australia, the United States and the United Kingdom***




Note: Based on fiscal year from 1st of July to 30th of June.
Sources: ABARE (2009); IEA databases.

## Rest of the world: will price-setting become more market-based?

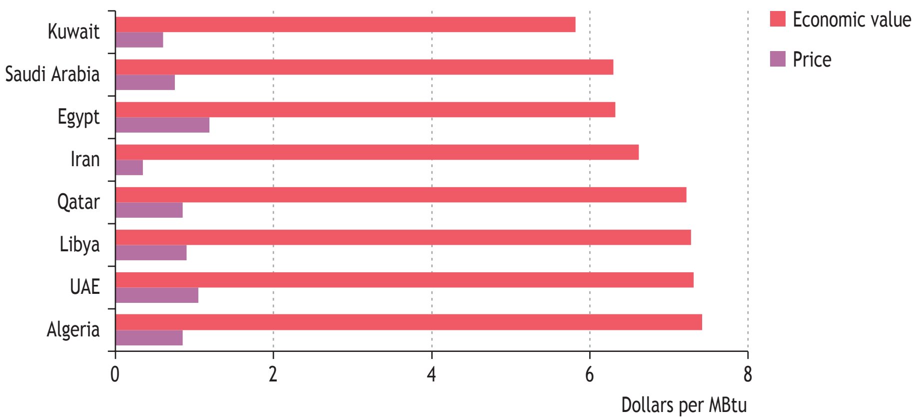
Outside North America, Europe and the Asia-Pacific region (which together account for over half of global gas consumption), pricing regimes and actual prices vary widely. In some cases, steps are being taken or are planned to reform pricing, in order to ensure that prices better reflect supply costs or market values. But few countries are planning to introduce gas-to-gas competition along the lines of the North American or British markets. The pace of reform, particularly where it involves raising prices to end-users and eliminating subsidies, remains highly uncertain, given political sensitivities and resistance from consumers that has been stiffened by the economic recession.

Russia has, for long, had some of the biggest gas subsidies in dollar terms in the world, amounting to $30 billion in 2007 (IEA, 2008a). The federal government has begun to remove those subsidies by gradually raising the prices charged to Russian consumers to the same levels in netback terms as the prices charged to European importers, *i.e.* to parity with European border prices, minus the added costs of transporting the gas to Europe compared to Russian demand centres and, currently, a Russian export duty on gas (see Chapter 13). The timeline for this reform remains uncertain: the original decision to reform gas pricing in 2006 envisaged that the process would be completed within five years for industry and ten years for households. The steep decline in European border gas prices in 2009 has narrowed the gap the Russian price reform is meant to bridge, but the global recession has hit Russia hard and reduced the tolerance of industry and households to significantly higher prices. Both the Reference and 450 Scenarios assume that the process of introducing market-based prices is completed only by 2020. Central Asian exporters to Russia are also raising their prices to European export netback levels.

Many Middle East and North African countries also continue to subsidise gas heavily. In 2007, the value of gas subsidies in Iran alone amounted to about $16 billion. Actual prices are far below economic levels in almost every country in the region (Figure 14.7).

Some countries are likely to seek to keep the lid on domestic prices for as long as possible. But others, such as Oman, that face potentially crippling gas shortage problems and need to turn to gas-rich neighbours for supply will come under growing pressure to cut subsidies. Egypt, which has experienced rapid growth in domestic demand in recent years, has embarked on price reform and others are expected to follow. Intra-regional trade will probably be priced more in line with European or Asia-Pacific border prices, netted back to account for differences in transportation costs. For the importers, at least a partial alignment of domestic prices with imported gas or LNG prices should be expected. But complete subsidy removal (involving prices rising to parity with netback export market values) is highly unlikely in most cases. For the purposes of the projections, we have assumed that subsidies will be reduced, but that prices will remain on average around 20% below economic levels across the Middle East and Africa at the end of the projection period.

**Figure 14.7 • *Actual gas prices and the economic value of gas in power generation in the Middle East and North Africa, 2006***




Note: The netback value of gas used for power generation refers to the assumed value of the fuel – typically oil – displaced from new power plants, netted back to the wellhead after adjustments for differences in capital and operating costs, thermal efficiency, fuel processing and delivery costs. Values are calculated using a 10% discount rate.

Source: Razavi (2009).

Pricing in Latin America is diverse. Chile and Brazil have introduced market reforms to ensure market-based pricing. But other countries, including Venezuela, have retained social-based pricing, sometimes resulting in prices below the actual cost of supply. Argentina backed away at the beginning of the 2000s from earlier moves to introduce gas-to-gas competition.



## LNG trade and the prospects for regional gas market convergence

The regional character of the global gas industry has become less pronounced in recent years with the emergence of a sizeable inter-regional LNG business, driven by the growing import needs of the main consuming countries in North America, Europe and Asia, and by lower costs (at least until the middle of the current decade). This trade, which is projected to continue to grow strongly through to 2030 in both scenarios presented in this *Outlook*, is increasing the price links between the main regional markets through the potential for arbitrage (though reduced import needs in North America is expected to weaken price links with other regional markets). LNG trade rises from 229 bcm in 2007 to 430 bcm in 2030 in the Reference Scenario (see Chapter 12). The manner in which LNG is traded and the way LNG projects are financed has evolved considerably in recent years. Developments in regional markets, including the growing role of gas-to-gas competition and the increased size of the global LNG industry, are expected to lead to further changes in the LNG business model.

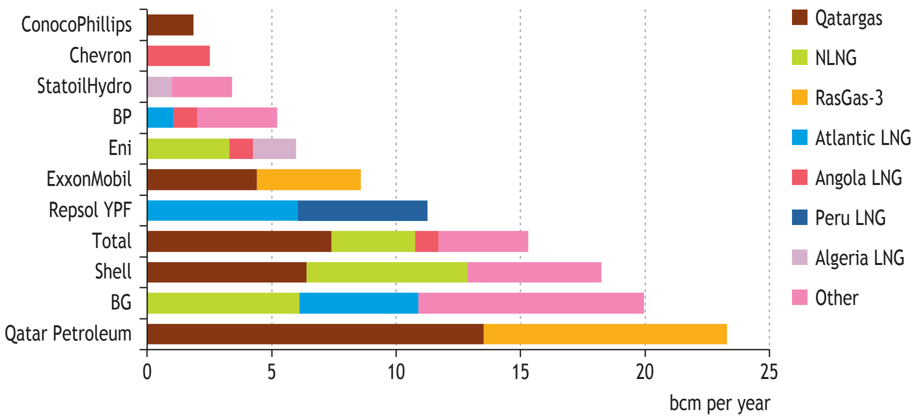
## Contractual arrangements: more flexibility in prospect

The gradual shift away from rigid long-term contracts, which tie LNG producers to specific buyers along a specified physical supply chain, looks set to continue. The traditional LNG business started as a point-to-point value chain, with very little flexibility for buyers or sellers on volumes. This model involved a long-term sales agreement between the LNG producer and the distribution/marketing company in the importing country, often incorporating some form of oil-price indexation (described above). These contracts usually covered virtually all of the output of the LNG plant. These arrangements were necessary to provide guarantees to investors in liquefaction and related upstream projects that the project would remain viable over the longer term.

Liberalisation of the gas market in North America and Europe made buyers demand more flexibility in contracts with regard to destinations and duration. At the same time, the development of spot trading in these markets, together with the prospect of strong growth in demand for LNG, gave confidence to LNG producers that they would be able to market volumes not covered by long-term contracts. In effect, North America came to be seen as a reliable market of last resort, amid expectations of rapidly rising import requirements and a more welcoming attitude by the US Federal Energy Regulatory Commission to the building of new regasification terminals. Project financers became increasingly comfortable with the idea of backing projects based on short-term contracts and gas-price indexation (though it has always been necessary for at least part of the capacity of the liquefaction plant to be covered by long-term contracts). The fall in unit construction costs of LNG plants and tankers at the end of the 1990s and early 2000s (see Chapter 12) contributed to this change.

In addition, several international oil and gas companies started in the early 2000s to have their own trading arms commit to take large amounts of LNG from their upstream businesses for direct marketing to end users and/or for on-selling to other marketers via the spot market. They had two motives for doing this. All of them wished to jump-start their projects, rather than wait in line and perhaps miss attractive market windows. At least some of them, confident in the robust outlook for LNG sales, also aimed to build strength as gas portfolio players exploiting combinations of upstream and market positions to optimise transportation and capture arbitrage opportunities wherever and whenever possible. Today, 11 companies have self-contracted for a total of more than 1 250 million tonnes (1 660 bcm) of LNG over the period 2009-2025; Qatar Petroleum and BG have the largest commitments for the period 2012-2015 (Figure 14.8).

**Figure 14.8** • ***Average international oil and gas company LNG self-contracting* commitments, 2012-2015***




* Purchases by the marketing affiliate of companies owning and operating liquefaction facilities.

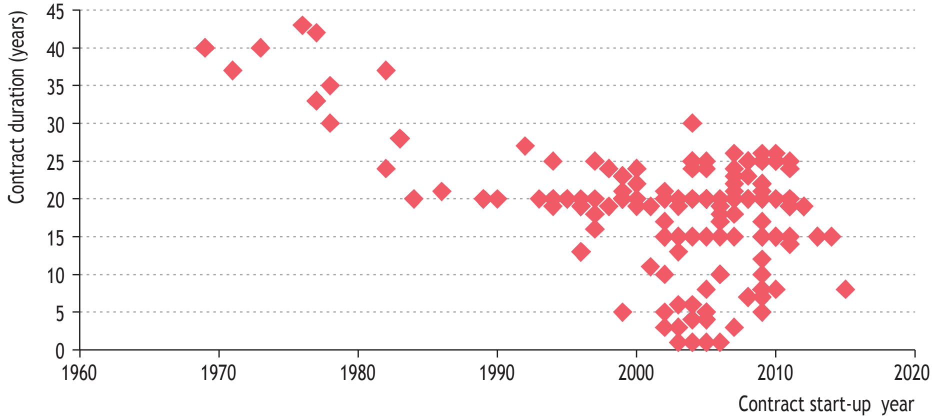
Sources: Cedigaz databases; IEA analysis.

While the proportion of LNG output that is covered by long-term sales contracts (of more than four years) has fallen significantly in recent years, from almost 95% in 2000 to 82% in 2008, the weighted-average length of contracts has not changed much since the early 2000s. Most such contracts, which typically include take-or-pay clauses, still last between 15 and 25 years, though several short contracts have been signed in recent years (Figure 14.9). Contracts for periods of ten years or less generally involve smaller volumes, reflecting their role in balancing gas needs with availability for sellers as well as buyers.

## Spot trade: renewed growth or consolidation?

Of particular importance for gas-price formation worldwide is the share of LNG traded on a spot basis (*i.e.* cash sales of gas at a fixed price for immediate delivery) or under short-term contracts (of less than four years duration). Spot LNG is made available to the market by projects in the ramp-up phase whose contracts have not yet taken effect, by projects that have deliberately set aside some capacity for spot trade and by project developers that have self-contracted for supply, seeking to exploit profitable opportunities to engage in short-term trade. In addition, cargoes bought under long-term contracts may increasingly be diverted from their originally intended destinations to different buyers on a spot or short-term basis. Spot LNG may be re-traded and re-routed many times before delivery and final regasification. The spot LNG market allows buyers in the Atlantic Basin and in the Asia-Pacific region to compete directly for supply, thereby contributing to price convergence across continents.

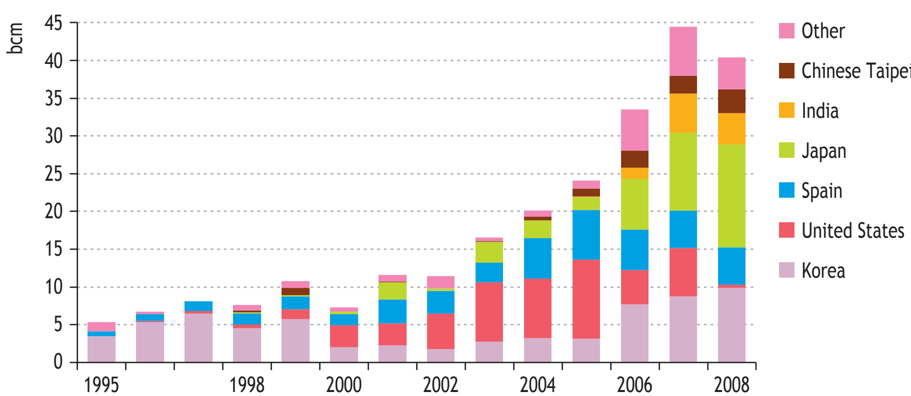
**Figure 14.9** • **LNG contract start-up years and durations**




Sources: Cedigaz databases; IEA analysis.

Spot and short-term LNG trade has been growing steadily in recent years, but in 2008 dropped back to about 40 bcm, or 18% of total LNG trade (Figure 14.10). This fall was due mainly to the disappearance of short-lived factors that had boosted spot demand in 2006 and 2007. Japan and Korea had been big buyers of spot gas in these years for particular reasons. In the case of Japan, Tokyo Electric Power Company (TEPCO) had temporarily lost much of its nuclear power capacity, forcing it to burn more gas; in the case of Korea, a delay in signing new long-term contracts, caused by regulatory uncertainty, had forced Kogas into buying more spot LNG. In both cases, a shortfall in contracted Indonesian supply added to their need to turn to spot LNG.

**Figure 14.10** • **Spot LNG trade by country**




Source: GIIGNL (2009).

Spot LNG trade may remain subdued in the near term. In the next few years, Japan and Korea will almost certainly continue buying LNG on a spot basis, but not necessarily on the same scale as in 2007-2008. Elsewhere, demand for spot gas will hinge on how quickly the global economy pulls out of recession. Many buyers that have recently been active in the market are now receiving all the gas they need under their long-term contracts and are sometimes having to ask for additional downward volume flexibility as a result of weak end-user demand.

In the longer term, the outlook for spot LNG trade looks brighter for the following reasons:

- Liquefaction, shipping and regasification capacities are set to continue to increase rapidly through to the early 2010s, providing an opportunity for any uncontracted capacity to be used for spot sales.

- Global regasification capacity is twice as big as liquefaction capacity – a ratio expected to be maintained over the coming years. Access to regasification capacity for non-incumbents has improved in Europe or Asia, providing more flexibility and arbitrage opportunities.

- Growth of spot gas trading volumes at hubs in Europe, and perhaps also eventually in Asia, will provide an outlet for incremental LNG supply and reduce the volume risk for LNG producers.

- Competition in Europe and Asia is set to intensify, albeit slowly, pushing up the value that the market places on gas-supply flexibility.

- The number of actors at all stages of the LNG chain is likely to continue to grow, providing a more competitive global environment conducive to further growth in spot LNG trade.

On the other hand, the expectation that the opportunity to sell spot LNG into the North American market will become more limited, because of ample local gas supply availability, may hold back the global development of spot LNG trade. The likelihood of only modest demand growth in Europe may also limit the opportunity to sell LNG on a spot basis. So it may take some time before the share of spot sales in total LNG transactions tops the 19% reached in 2007. Spot-market growth, and the share of spot transactions in total LNG trade, may become more volatile in the years ahead than over the past decade, as the market reacts to specific events that cause an unexpected surge in gas demand or LNG availability.

The growth of cross-border spot trade in both LNG and piped gas has important implications for the possibility of collective action by the world's leading exporters to curb exports on a short-term basis, in order to shore up prices at times of over-supply. There are real concerns on the part of the consuming countries that the Gas Exporting Countries Forum may eventually evolve into an organisation along similar lines to the Organization of the Petroleum Exporting Countries, which carries out this market-balancing role through production quotas. But such an outcome would hinge on much greater contractual flexibility on the part of the exporters than is available at present (see Spotlight).

SPOTLIGHT

### Is the Gas Exporting Countries Forum the new "Gas-OPEC"?

After seven years' existence as an informal grouping, a ministerial meeting of the Gas Exporting Countries Forum (GECF) decided in December 2008 to transform the Forum into a full-fledged international organisation with permanent headquarters in Doha, Qatar. Eleven countries, including the world's largest gas reserve holders – Russia, Qatar and Iran (the "gas troika") – signed an agreement in Moscow creating the GECF and confirming its statute. The signatory states together hold around two-thirds of global gas reserves (98 tcm). They accounted for 36% of global gas production in 2007 and 42% of exports. Their share of global gas production rises to 41% by 2030 in the Reference Scenario and 39% in the 450 Scenario. The gas troika could have a strong influence over the path that the Forum will follow (though Iran is still a net gas importer); this group has agreed to meet regularly and, along with Algeria, forms the political core of the GECF.

Despite being tagged as a potential "Gas OPEC", the role of the GECF is still loosely defined, reflecting a variety of views among participating states as to its purpose. The Forum's founding documents steer clear of contentious issues and the stated objectives of the Forum are expressed in very general terms: to "support the sovereign rights of member countries over their natural gas resources and their abilities to independently plan and manage the sustainable, efficient and environmentally conscious development, use and conservation of natural gas resources for the benefit of their peoples." GECF member countries have agreed to promote these objectives through "exchange of experience, views, information, and coordination" in areas such as exploration, the supply-demand balance, gas technologies, the structure and development of gas markets, and transportation. As it stands, the organisation is not recognisable as an OPEC-style cartel: the words "price" and "pricing" are not even mentioned in its statute.

The deterioration in gas market conditions since mid-2008 undoubtedly played its part in helping gas exporters find common cause. Shared concerns about price levels will surely grow in the face of the looming supply glut, with a large number of new LNG projects coming on stream in 2009-2013. But it will be difficult for GECF countries to act collectively to improve their market position in the short term, as long-term gas supply contracts limit the ability of individual producers to control exports or prices. In the longer term, more flexibility may emerge, with the prospect of increased reliance by producers on spot sales of LNG and possibly piped gas. The projected increased concentration of gas production in a few resource-rich countries dominated by national oil and gas companies would make co-ordinated action to control regional markets more feasible. Yet it is not clear that GECF countries are willing to go down this path: Gazprom, for one, has reiterated its desire to maintain the current system of long-term contracts with oil-price indexation (see above).

In the near term, the GECF looks set to facilitate information-sharing and dialogue among the main gas exporters. Although the Forum could seek a more pro-active role on market-related issues in the longer term, the relative ease with which other fuels can substitute for gas would limit the scope for cartel-like behaviour that some observers predict. Indeed, efforts to raise prices could backfire on producers if they led to greater substitution of alternatives for gas and, hence, lower demand.

## *LNG as a driver of regional gas market integration*

The growth in LNG trade – and spot trade in particular – is beginning to forge linkages between regional gas markets. But a truly global gas market, functioning in a similar way to the international crude oil market, is still a very long way off. The volumes of gas traded over long distances remain small, limiting their ability to influence prices in distant markets and drive convergence of regional prices (whereby price differentials would simply reflect marginal transportation costs). The volume of LNG supplied to North America across the Atlantic in 2008 amounted to 5 bcm, equal to only about 2% of global LNG trade and just 0.15% of total world gas consumption. The small scale of this trade limits the impact that changes in market conditions in Europe and Asia-Pacific could have on the North American market (and *vice versa*).

Inter-regional gas trade will need to increase significantly for it to affect prices both in the regions from which supply is diverted and in the regions gaining that supply. Certainly, the projected expansion of trade in both the Reference and 450 Scenarios would encourage greater integration of regional gas markets, especially if accompanied by increased spot trade, a fall in the average duration of LNG (and piped gas) contracts, and greater flexibility in the terms and conditions of those contracts. But, in practice, physical bottlenecks in supply capacity, as well as contractual constraints, will continue to hinder global market integration.

The North American market may remain largely disconnected from Europe and the rest of the world – an apparent paradox in view of the highly competitive nature of that market and the ongoing large-scale expansion of regasification capacity.[4] But in both the Reference and 450 Scenarios, continued growth in unconventional gas production more than compensates for the decline in conventional gas output and outpaces demand across the region. As a result, import requirements – already small relative to total gas consumption – reach only 30 bcm in 2015 and 60 bcm in 2030 in the Reference Scenario. On average, prices in North America are assumed to remain below European and Asia-Pacific levels, discouraging LNG imports (though there will no doubt be times when prices are high enough to attract small volumes of LNG). A persistent price differential to the detriment of North American producers would, in principle, encourage US or Canadian LNG exports, but we assume that the construction of liquefaction plants will not be allowed on environmental grounds. Production costs in the North America are, in any case, too high to make the region competitive with other LNG exporting regions (see Chapter 13). On the other hand, the ongoing expansion of liquefaction capacity in the Middle East and Africa will increase opportunities for LNG suppliers to arbitrage between European and Asia-Pacific markets in the long term (notwithstanding the prospect of reduced opportunities in the next two years or so with lower demand).



4. New facilities under construction will push up combined regasifcation capacity in Canada, Mexico and the United States from around 130 bcm/year at present to well over 200 bcm (IEA, 2009).

PART D
# ENERGY PROSPECTS IN SOUTHEAST ASIA

## PREFACE

The ten countries of Southeast Asia (Brunei Darussalam, Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Thailand and Vietnam) are set to play an increasingly important role in global energy markets in the decades ahead and are contributing to a refocusing of the global energy landscape towards Asia. But many challenges will need to be overcome if the region is to secure access to the energy required to meet its growing needs at affordable prices and in a sustainable manner.

Recognising this growing influence Southeast Asia is having on global energy markets, Part D of the *Outlook* analyses its energy prospects. Chapter 15 starts by setting out our Reference Scenario projections for the region as a whole for energy demand and supply, energy investment and energy-related $CO_2$ emissions to 2030. It then presents the results of the 450 Scenario, in which energy use corresponds to a long-term stabilisation of greenhouse-gas concentration at 450 parts per million, to illustrate how new policies in the region (and elsewhere) could enhance energy security and/or address local pollution and climate change. This is followed by analysis of several topical issues including the role that cross-border trade in gas and electricity could play in improving the region's energy security and market flexibility, and the opportunities for co-operative action to enhance oil security. Chapter 16 follows with detailed analysis of energy trends in Indonesia, Thailand, Malaysia and Philippines.

# OVERVIEW OF ENERGY TRENDS IN SOUTHEAST ASIA

## How will ASEAN energy needs be met?

### H I G H L I G H T S

- In the Reference Scenario, ASEAN primary energy demand expands by 76% between 2007 and 2030, an average annual rate of growth of 2.5% - much faster than the average rate in the rest of the world. By 2030, significant variations remain in energy-use patterns among the ASEAN countries, as they are extremely disparate in terms of their stages of economic development.
- Fossil fuels account for 76% of the ASEAN primary energy mix in 2030 — up slightly on today. Coal sees the biggest increase, with its share of total demand rising from 15% to 24%, while the shares of oil and natural gas both decline. Renewables expand by 1.8% per annum on average through to 2030, with the deployment of modern renewables increasing much faster than traditional biomass. The region needs to add 243 GW to its generating capacity by 2030.
- Although ASEAN is currently a net energy exporter, its oil and gas fields are maturing and several coal-producing countries are considering export restrictions in order to safeguard reserves. ASEAN net oil imports approach 4 mb/d in 2030, from less than 1 mb/d today, at a cost of 4.8% of the region's GDP. Several ASEAN countries also become increasingly dependent on gas imports. Given the scale of the region's prospective dependence on imports, interest in the introduction of nuclear power is growing. In the Reference Scenario, the number of people in the region lacking access to electricity falls to 63 million in 2030, from 160 million today.
- Cumulative energy investment of $1.1 trillion is needed in the ASEAN region to 2030. Some 55% of this is needed in the power sector, even though the financial crisis has reduced the need for new generation capacity. If realised, expansion of cross-border connections, by developing an ASEAN Power Grid and a Trans-ASEAN Gas Pipeline, would offer economic and security gains through more efficient and diversified utilisation of resources.
- The projected rise in energy demand has environmental implications. By 2030, ASEAN's share of global energy-related, carbon-dioxide emissions reaches 5%, up from 3.5% today. Per-capita emissions in the region remain well below the OECD average, but the gap narrows, from a factor of six in 2007 to three in 2030.
- In the 450 Scenario, in which ASEAN countries adopt stricter policies to promote energy efficiency and clean energy technologies, primary energy demand grows at an average 2.1% per year to 2030. The overall energy savings by 2030, relative to the Reference Scenario, exceed the current consumption of Malaysia, while greenhouse-gas emissions and local pollution are also reduced.

# ASEAN energy overview

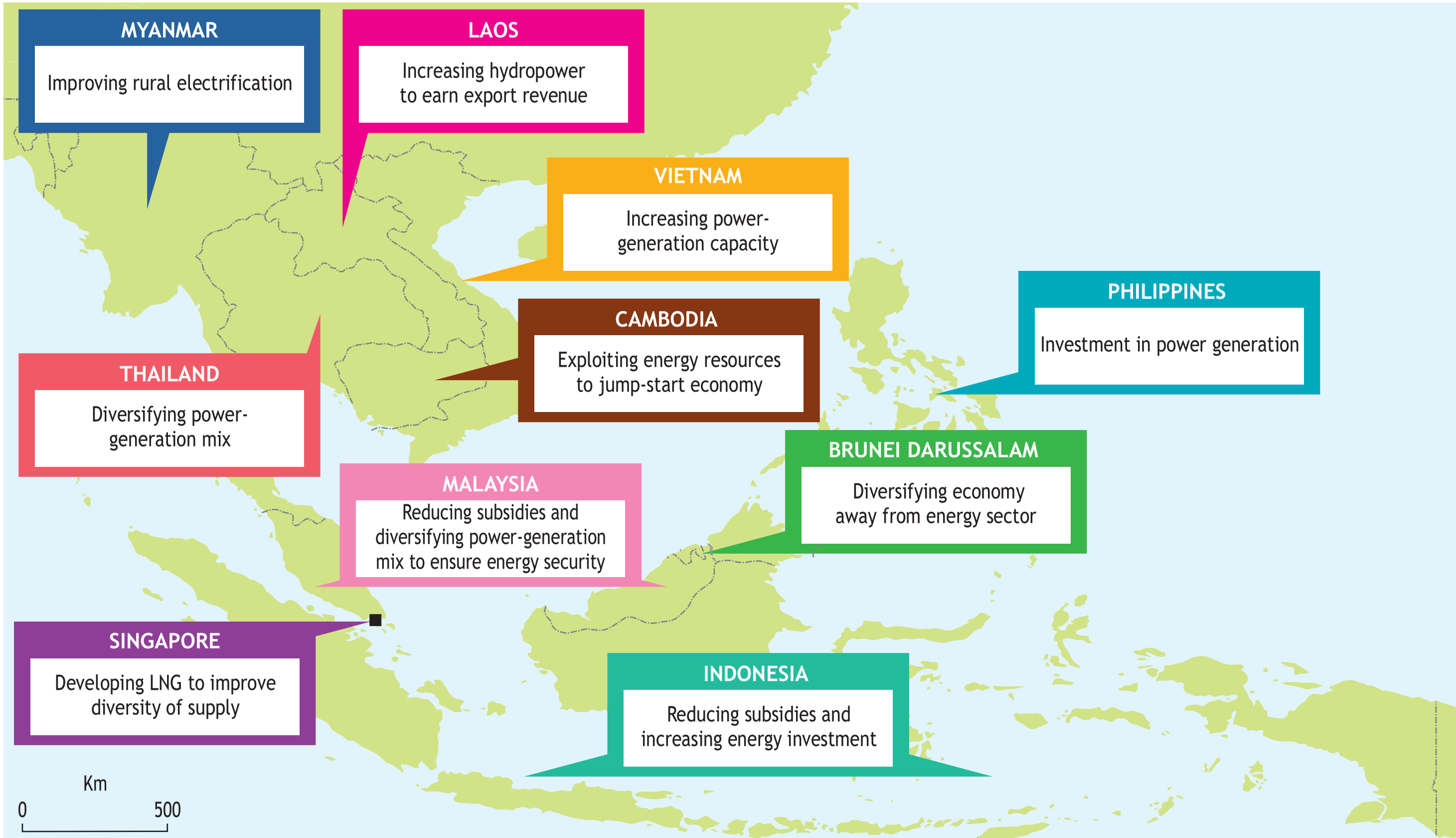
The ten countries of the Association of Southeast Asian Nations (ASEAN) – Brunei Darussalam, Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Thailand, and Vietnam – are set to play an increasingly important role in global energy markets in the decades ahead.[1] They make up one of the world's most dynamic and diverse regions, with an economy as large as Canada and Mexico combined and a population that exceeds that of the European Union. Their energy consumption is already comparable to that of the Middle East and continues to grow rapidly from a comparatively low per-capita level, fuelled by rapid economic and population growth and continuing urbanisation and industrialisation. Coupled with the emergence of China and India on the global energy scene, these trends point to a refocusing of the global energy landscape towards Asia.

But many challenges will need to be overcome if Southeast Asia is to secure access to the energy required to meet its growing needs at affordable prices and in a sustainable manner (Figure 15.1). The energy sector in most parts of the region is struggling to keep pace with the rapid growth in demand experienced since the region's recovery from the Asian Financial Crisis of 1997-1998. With around 1% of the world's proven reserves of oil, the region is heavily dependent on imports and is set to become even more so in the future. It will also face a looming natural gas supply shortage in the decades ahead, despite rapidly growing reliance on coal-fired power generation. While parts of Southeast Asia have relatively abundant sources of renewable energy, various physical and economic factors have left a significant share of it untapped. A huge amount of investment will be needed to expand the region's energy infrastructure – especially in the power sector, in which demand has been growing at seven times the rate of the OECD since 1990. Financing is a major challenge, exacerbated by the recent global financial crisis, which has forced energy companies to cut back on capital spending and delay or cancel projects. At the same time, access to modern energy services still remains limited in some pockets of the region: it is estimated that 160 million people have no access to electricity, with detrimental health and social consequences – particularly for women and children.

The countries of the ASEAN region currently account for 4.3% of global energy demand. In 2007, per-capita energy consumption in the region was relatively low, at around one-fifth of the OECD average (Table 15.1). ASEAN's primary energy mix is dominated by fossil fuels, with oil, natural gas and coal collectively accounting for 73% of total demand in 2007. Biomass and waste resources, such as wood and agricultural residues, also represent an important source of energy and met 23% of demand in 2007. Energy intensity, measured by the ratio of energy demand to gross domestic product (GDP), has declined marginally over the past three decades. Over the same period, carbon dioxide ($CO_2$) emissions have increased sharply as the region has industrialised, involving switching from biomass to fossil fuels, but on a per-capita basis these emissions still remain less than 20% of the OECD average.

1. ASEAN was established on 8 August 1967 (in Bangkok) by Indonesia, Malaysia, Philippines, Singapore and Thailand. Brunei Darussalam joined on 8 January 1984, Vietnam on 28 July 1995, Laos and Myanmar on 23 July 1997, and Cambodia on 30 April 1999.

**Figure 15.1 • Key energy challenges in each ASEAN country**




The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

**Table 15.1 • Key energy indicators for ASEAN by country**

| | Unit | 1980 | 2007 | 1980-2007* |
|---|---|---|---|---|
| Share of world population | % | 8.0 | 8.5 | n.a. |
| Share of world GDP (PPP) | % | 2.3 | 3.9 | n.a. |
| Total primary energy demand | Mtoe | 149 | 513 | 4.7% |
| Total primary energy demand per capita | toe | 0.42 | 0.91 | 2.9% |
| Energy intensity | toe per $1 000 (2008, PPP) | 0.22 | 0.19 | -0.5% |
| Net oil trade** | mb/d | 1.0 | -0.9 | n.a. |
| Net natural gas trade** | bcm | 21 | 60 | 4.0% |
| $CO_2$ emissions*** | Mt | 196 | 1013 | 6.3% |
| $CO_2$ emissions per capita*** | t | 0.5 | 1.8 | 4.5% |
| Share of global $CO_2$ emissions*** | % | 1.1 | 3.5 | n.a. |

* Compound average annual growth rate.

** Negative value indicates net imports.

*** Includes only energy-related $CO_2$ emissions.

Southeast Asia's energy resources – including about 10.3 billion barrels of proven oil reserves, 6.6 trillion cubic meters (tcm) of proven gas reserves, 12.5 billion tonnes of proven coal reserves and abundant hydropower – are relatively meagre, compared with the scale of demand. The resources that it has are unevenly distributed, leaving some countries, such as Philippines and Singapore, heavily dependent on energy imports while other countries, such as Malaysia, Vietnam, Brunei Darussalam and Indonesia, are important exporters of energy to world markets. The Southeast Asia region was once a prominent exporter of oil, but since the late 1980s it has become increasingly dependent on imports. The region remains a net exporter of natural gas, due largely to Brunei Darussalam, Malaysia and Indonesia, which are amongst the world's top ten suppliers of LNG. Similarly, it is home to some major steam coal producers and exporters, most notably Indonesia and Vietnam.

While the ten ASEAN countries have much in common, there are vast differences between their energy markets (Table 15.2). As mentioned above, some countries in the region are completely dependent on energy imports, while others are major exporters of energy to world markets. Some countries' leading energy companies are completely state-owned, with prices heavily subsidised, while the energy sector in other countries has been privatised and/or liberalised, with cost-reflective prices. In some countries, access to modern energy services remains limited; in others, universal electrification has been achieved.

**Table 15.2 • Energy sector overview for ASEAN by country**

| | Overview |
|---|---|
| Brunei Darussalam | Oil and gas have been the backbone of the economy since their discovery in 1929. Today, it is the third-largest oil producer in ASEAN and ninth-largest LNG exporter in the world. Diversifying the economy to reduce reliance on oil and gas export earnings is a key priority. |
| Cambodia | Energy infrastructure remains damaged by decades of civil war. Increasing the rate of electrification, currently the lowest in ASEAN, is one of the main priorities. Exploitation of offshore oil and gas resources discovered in 2005 could jump-start economic development. |
| Indonesia | The world's fourth most-populous country and the largest economy in ASEAN. It is the world's leading steam coal exporter, third-largest LNG exporter, and, until 2004, a net exporter of oil. Increasing energy investment will be essential for its economic development. |
| Laos | It has significant hydropower potential and exports of hydroelectricity are one of the main sources of export earnings. As access to modern energy services remains limited, rural electrification is one of the major priorities. |
| Malaysia | The third-largest energy consumer in ASEAN and heavily dependent on fossil fuels. It has significant oil and gas resources and is the world's second-largest exporter of LNG. A key challenge will be to diversify the power-generation mix to meet the increase in demand for electricity. |
| Myanmar | The bulk of the population lives in rural areas and depends heavily on traditional energy, such as fuel wood, charcoal and biomass. Rural electrification is a priority, as is the development of the country's hydropower resources and offshore gas deposits, which could play a key role in fostering economic development. |
| Philippines | Its reliance on imported energy is high and it faces serious challenges attracting investment to overcome electricity shortages. It is pushing to reduce imports by developing renewables, including geothermal – of which it is already the world's second-largest producer. |
| Singapore | It is the world's third-largest oil trading and refining hub and was the first country in ASEAN to have liberalised its electricity market. Due to its small size and low energy resource endowments, it is heavily dependent on imported energy and is currently constructing an LNG import terminal to improve diversity of supply. |
| Thailand | It is the second-largest energy consumer in ASEAN and is heavily dependent on imports – particularly oil but also natural gas, coal and electricity. A key challenge will be to meet growing demand for electricity, including through expanding imports, while diversifying the generation mix. |
| Vietnam | It is rich in coal, oil and hydropower and has been a net energy exporter since 1990. Domestic energy demand is growing rapidly and reliance on traditional biomass remains high in rural areas. The government is currently pursuing policies to increase rural electrification and the use of renewables. |

# Principal assumptions[2]

## Economic growth

Over the past four decades, the ASEAN region has experienced a profound economic transformation. This has largely been attributed to its openness to trade and foreign investment, particularly in Singapore, Indonesia, Malaysia, Philippines and Thailand. Economic development of the ASEAN countries varies widely. For example, in 2008 GDP per capita in purchasing power parity (PPP) terms ranged from just $1 159 in Myanmar to $50 083 in Brunei Darussalam.

2. These assumptions apply to both the Reference and 450 Scenarios.

In 2008, a little over a decade since the 1997-1998 Asian Financial Crisis, the region was once again shaken by economic turmoil. This time, however, the turbulence was triggered by an exogenous event – in the form of the global financial crisis – rather than events within the region. Rates of economic growth began slowing across the ASEAN region in late 2008, with Thailand and Singapore sliding into recession, although growth has since rebounded sharply. The global financial crisis, which prompted a sharp downturn in global trade, hit Southeast Asia particularly hard as many countries in the region are heavily dependent on exports (see Spotlight). Those countries within the region where domestic consumption composes a greater share of GDP, such as Indonesia and Philippines, have been relatively less affected.

While the agricultural sector has traditionally played a dominant role in the economic structure of Southeast Asia, this has been declining in favour of manufacturing and, to a lesser extent, services. Agriculture's share of the region's gross economic output fell from 16.4% in 1990 to 11.7% in 2007, although this sector continues to employ the largest share of the workforce (ESCAP, 2008). At the same time, the composition of the region's exports has also started to shift away from primary commodities to higher value-added manufactured products.

In line with the objective of integrating the economies of countries within the region, as envisaged under the founding documents of ASEAN signed in 1967, in 2007 the member countries agreed to establish the ASEAN Economic Community (AEC) by 2015. The AEC reflects the ASEAN member countries' common interest in working towards a competitive single market and production base for the region that is integrated into the global economy. Regionally, this means a free flow of goods, services and investments, and a freer flow of capital and skilled labour.

In 2008, the GDP of the ASEAN region approached $2.8 trillion, roughly equivalent to that of Canada and Mexico combined. In the Reference Scenario, ASEAN GDP is assumed to grow at 4.0% per year from 2007 to 2015 and then 3.7% per year from 2015 to 2030 (Table 15.3). The assumed rates of growth take into account the current financial crisis and so are somewhat lower than rates utilised in energy plans by several of the ASEAN countries in recent years.

**Table 15.3 • *ASEAN key economic indicators and GDP growth assumptions by country in the Reference Scenario***

| | Share of exports in GDP (2007) | GDP per capita in 2007 ($2008) | GDP growth rates | |
|---|---|---|---|---|
| | | | 1980-2007 | 2007-2030 |
| Indonesia | 29% | 3 795 | 4.8% | 3.7% |
| Malaysia | 110% | 13 826 | 6.2% | 3.4% |
| Philippines | 43% | 3 484 | 3.0% | 3.8% |
| Thailand | 73% | 8 340 | 5.9% | 3.3% |
| Other ASEAN | 147% | 3 688 | 6.2% | 4.6% |
| **ASEAN** | **74%** | **4 705** | **5.2%** | **3.8%** |
| World | n.a. | 10 156 | 3.1% | 3.1% |

Note: The compound average annual growth rates are calculated based on GDP expressed in purchasing power parity terms. The share of exports in GDP can exceed 100% as export data is recorded as total turnover while GDP data is recorded in value-added terms.

Sources: ADB (2008) and IEA analysis

SPOTLIGHT

**Time for Southeast Asia to reduce its reliance on exports for growth?**

Southeast Asia has been affected more severely by the global financial crisis than many other parts of the world. This was largely unexpected as the region's banking system underwent major reform after the Asian Financial Crisis of 1997–1998 and did not take part in the risky financial practices that had become commonplace elsewhere. Nevertheless, economic growth throughout the region has slowed to rates last seen during the Asian Financial Crisis of 1997–1998. Cambodia, Singapore, Malaysia and Thailand slipped into recession in either late 2008 or early 2009, while growth in Indonesia slowed to its weakest pace in ten years. For the region as a whole, economic growth fell from 6.4% in 2007 to 4.3% in 2008 and is expected to be virtually flat in 2009. Neighbouring economies, including China and India, have been relatively less affected.

The pronounced impact of the current crisis on Southeast Asia has been attributed to the region's heavy dependence on exports. For example, in 2007 the value of merchandise exports from ASEAN countries amounted to 74% of the region's GDP, compared with just 35% in China (ADB, 2009a). The simultaneous downturn in consumption in the United States, Asia and Europe that began in early 2008 sharply reduced demand for Southeast Asia's leading exports, such as electronics, automobiles, machinery, textiles and footwear. On a year-on-year basis, exports in 2009 are projected to decline by 32% in Vietnam, 25% in Indonesia, 18% in Thailand and 13% in Malaysia (ADB, 2009b). Foreign direct investment inflows into the region, which have historically been a key driver of economic expansion, have also fallen dramatically as international companies have scaled back their spending.

Many governments in Southeast Asia have launched stimulus packages to combat the slump in economic activity and employment, and to stave off deflation. These appear to be working, with the forecasts from the International Monetary Fund (IMF) released on 8 July 2009 now pointing to a rebound in economic growth in 2010. But given the current economic structure of the region, any recovery will depend on a rebound in spending by consumers in the West. The crisis has therefore raised questions as to whether the region needs to shift away from its traditional export-driven model of economic development by rebalancing towards greater reliance on domestic demand and demand within the planned ASEAN Economic Community (AEC).



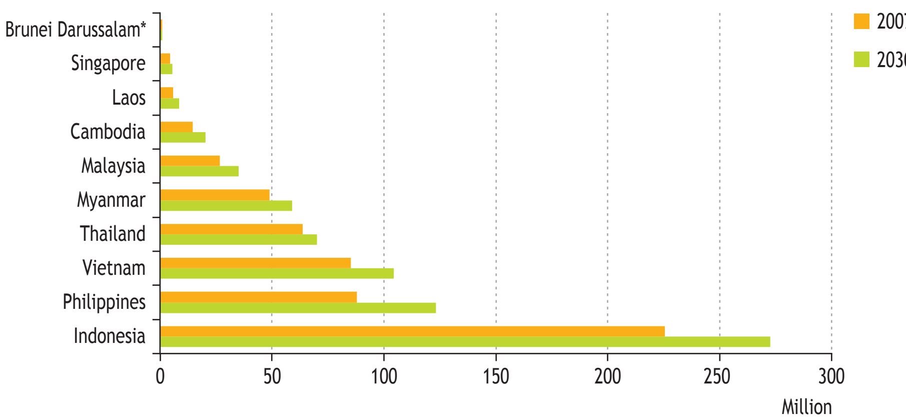
## Population

Between 1990 and 2007 Southeast Asia's population grew at an average rate of 1.5% per annum (reaching 563 million), a level that far exceeds that of the European Union. The population of individual countries in the region varies from 389 000 in

Brunei Darussalam to 226 million in Indonesia. ASEAN's age-dependency ratio,[3] which stood at 54% in 2006, has been declining since the 1990s. This will have implications for the distribution of demand for energy services and the generation of GDP by increasing the working proportion of the population. In the Reference Scenario, Southeast Asia's population is assumed to grow at a rate of 0.9% per annum between 2007 and 2030 (Figure 15.2).

At 46% in 2007, the proportion of the population in Southeast Asia residing in urban areas, while still below the world average, is growing at 3.9% per annum – well above the world average rate of 2.4% from 1980 to 2007. This will influence the growth in energy consumption at the aggregate level, as well as the evolution of the fuel mix. The levels of urbanisation in Southeast Asia differ considerably, with the highest rates in the industrially advanced nations, such as Singapore and Brunei Darussalam, and the lowest rates in the developing countries, such as Cambodia and Laos.

**Figure 15.2 • *ASEAN population by country***




* Brunei Darussalam population in 2007 was 389 000 and is projected to reach 553 000 in 2030.

## Energy pricing and subsidies

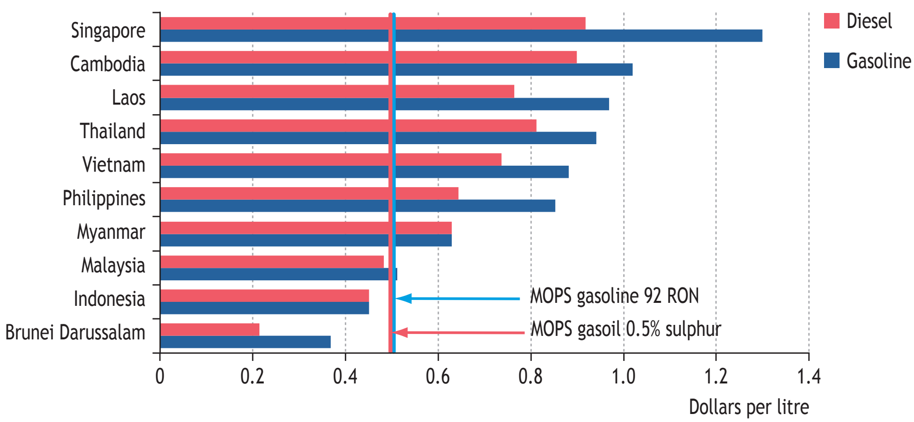
Southeast Asian countries, with the exception of Philippines and Singapore, subsidise fuel and electricity prices. These subsidies are, in large part, directed at gasoline and diesel as well as socially sensitive products, namely liquefied petroleum gas (LPG) and kerosene. Within the ASEAN region, government spending on subsidies is largest in Indonesia and Malaysia, both significant energy producers. For example, energy subsidies in 2008 cost the Indonesia government $22 billion, around 4.5% of GDP (Purnomo, 2009), and are reported to have cost the Malaysian government $14 billion, around 4% of GDP. In the *Outlook*, it is assumed that policies will gradually be introduced in Southeast Asia to ensure that energy prices are more cost-reflective and/or align more closely with world market prices.

3. The ratio of those aged 0 to 14 and 60 plus to the population aged between 15 and 59.

Rising oil prices in 2007 and 2008 prompted some countries in the region, including Indonesia, Malaysia, Thailand and Vietnam, to review their subsidy policies as they were creating a mounting fiscal burden, undermining efforts to improve energy efficiency, encouraging consumption substitution into the subsidised fuel, and providing incentives for fuel smuggling. For example, Malaysia increased gasoline prices by more than 40% in June 2008, while Indonesia increased prices by 28% in May 2008. Following the subsequent decline in the global oil price, several ASEAN countries partly reversed previous cuts in fuel subsidies. In late August 2009, with oil prices around $70 per barrel, the retail price of gasoline and diesel in Malaysia, Indonesia and Brunei Darussalam was below the international spot price, not even allowing for distribution and marketing margins (Figure 15.3).

Many countries in ASEAN provide generously subsidised electricity prices, including Thailand and Malaysia but particularly Vietnam and Indonesia. Power tariffs that fail to cover the full costs of supply tend to slow infrastructure development in the power sector by depriving utilities of the revenues needed for new investment.

**Figure 15.3 • *ASEAN retail prices of gasoline and diesel by country, August 2009***




Note: MOPS is Mean of Platts Singapore.
Sources: FACTS Global Energy; IEA analysis.

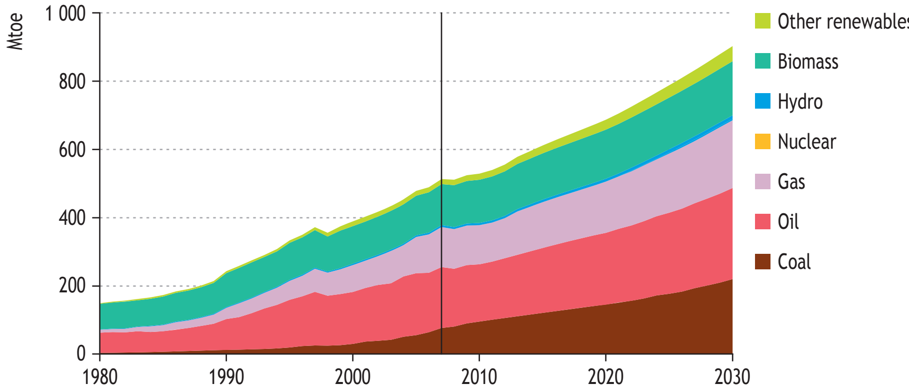
# The Reference Scenario

## *Energy demand*

15

In the Reference Scenario, primary energy demand in Southeast Asia is projected to increase from 513 million tonnes of oil equivalent (Mtoe) in 2007 to 903 Mtoe in 2030, an average growth rate of 2.5% per annum (Figure 15.4). Southeast Asia's share of global primary energy demand rises from 4.3% in 2007 to 5.4% in 2030. Despite this rapid growth, the region's average projected per-capita energy consumption in 2030 of 1.3 tonnes of oil equivalent (toe) is only 28% of the current level in the OECD, although there are large variations from country to country. Indonesia is responsible for about 36% of the overall increase in ASEAN energy demand to 2030, followed by Thailand at about 18%, Malaysia at 11% and Philippines at about 9%.[4]

**Figure 15.4 • *ASEAN primary energy demand by fuel in the Reference Scenario***




Throughout the *Outlook* period, oil remains the dominant fuel in the primary energy mix in Southeast Asia, although its share declines to around 30% in 2030. The region's oil consumption, which stood at 179 Mtoe in 2007, is projected to reach 191 Mtoe in 2015 and 267 Mtoe by 2030. Demand for natural gas increases at 2.3% per annum, rising from 117 Mtoe in 2007 to 199 Mtoe in 2030, but its share in the region's primary energy mix declines slightly, to 22% in 2030. Gas-fired power plants account for the bulk of incremental gas demand. The region's use of coal advances by 4.7% per year on average, its share in the region's energy demand climbing from 15% in 2007 to 24% in 2030. As with natural gas, most of the increase in demand for coal comes from power generation. In view of the rising demand for coal within ASEAN, several coal-exporting countries in the region have put their export levels under review.

The use of biomass and waste as energy in Southeast Asia is projected to increase by 1.2% per year. There are considerable differences among countries in how this energy source is used: the use of biomass in modern applications, such as biofuels and power generation, rises quickly as does the use of traditional biomass in inefficient cooking stoves in poor households in less developed parts of the region, but at a much slower pace. The overall share of biomass and waste in the region's energy mix falls from 23% in 2007 to 18% in 2030.

Use of other renewables, a category that includes wind, solar and geothermal energy, grows faster than growth in the use of any other energy source, at an average rate of 4.9% per year over the projection period. Most of the increase occurs in the power sector. The overall share of other renewables (excluding hydropower and traditional biomass) in the region's energy mix reaches 5% in 2030, up from just under 3% in 2007.

4. Chapter 16 sets out a detailed analysis of energy trends in Indonesia, Thailand, Malaysia and Philippines.

Hydropower's share of Southeast Asia's primary energy mix is projected to remain at around 1% over the course of the *Outlook* period. A number of countries in the region have abundant hydropower potential, including Indonesia, Vietnam, Myanmar, Cambodia and Laos, and are now developing significant new capacity. For Laos, one of the poorest nations in the region, exports of hydroelectricity to Thailand generate a large share of the country's total export earnings. However, in some cases large-scale hydro projects face considerable public opposition. In the Reference Scenario, nuclear is projected to start making a minor contribution to Southeast Asia's primary energy demand towards the end of the *Outlook* period.

Southeast Asia's energy intensity – primary energy demand per unit of real GDP (in PPP terms) – is expected to decline over the projection period by 1.3% a year, as the share of services in the economy increases and ongoing efficiency improvements are made in the power and end-use sectors. By 2030, energy intensity in Southeast Asia is around 4% higher than the current level in the OECD.

**Box 15.1 ● *Nuclear power: what role could it play in ASEAN?***

Concerns over energy security, surging fossil-fuel prices and rising $CO_2$ emissions have revived discussion about the role of nuclear power. Over recent years, several governments around the world, including some in Southeast Asia, have made statements favouring an increased role of nuclear power in the future energy mix. A few have taken concrete steps towards the construction of a new generation of cost-effective reactors.

There are currently no nuclear power plants in Southeast Asia, but Philippines, Thailand and Vietnam each include the introduction of nuclear power in their medium- and long-term power development plans. Malaysia is looking at the possible deployment of nuclear energy after 2020. Indonesia had plans for the introduction of a significant nuclear power programme, but these were put on hold in June 2009.

There is, of course, considerable uncertainty about the prospects for nuclear power in the region as there are many challenges to overcome, including financing, site selection, developing safety and security regulations, and building up human resources and technological capability. In the Reference Scenario, nuclear power is projected to start making a contribution to Southeast Asia's energy needs soon after 2020 and to make up a modest share of the energy mix by 2030. This is well behind the ambitious proportion envisaged in the plans of some individual ASEAN member states. In contrast, in the 450 Scenario, nuclear plays a much greater role in the region's energy mix.

### *Demand by sector*

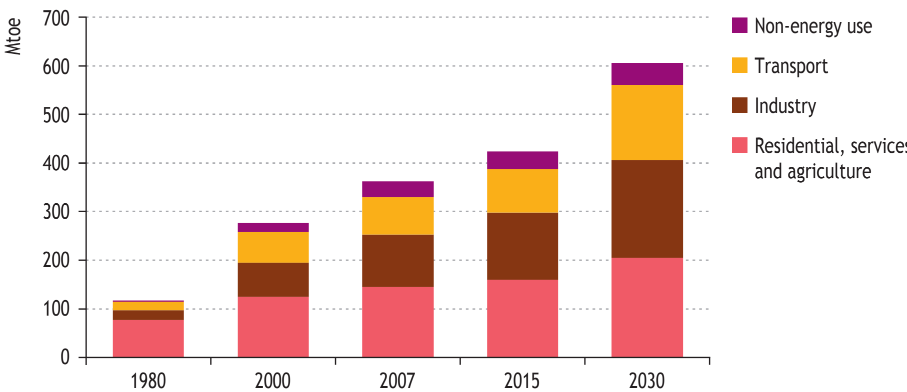


The power-generation sector is projected to make up a growing share of Southeast Asia's primary energy demand through the *Outlook* period. Its share increases from 25% in 2007 to 37% in 2030. This upward trend is driven by urbanisation and improvements in rural electrification rates. Coal overtakes natural gas to become the leading input for power generation, its share of total inputs rising from 30% in 2007 to 48% by 2030.

In contrast, the share of gas falls by 13 percentage points, to 29% in 2030. Inputs from biomass and waste grow at an average rate of 10.3% per year between 2007 and 2030, the fastest rate of growth of all energy sources, with their share rising to 3% in 2030. Nuclear power starts making a modest contribution soon after 2020.

Energy demand in end-use sectors – industry, transport, residential, services, agriculture and non-energy uses – grows by 2.3% per year over 2007-2030 (Figure 15.5). This is marginally slower than growth in primary energy demand. The *industry* sector (comprising manufacturing such as iron and steel, chemicals, non-metallic minerals and paper, as well as related products and processes) remains the largest end-use sector with energy demand growing at a rapid 2.7% per annum. Oil's share of industrial energy demand is expected to decline substantially in favour of electricity and gas, on the assumption that transmission and distribution networks improve and oil subsidies are reduced.

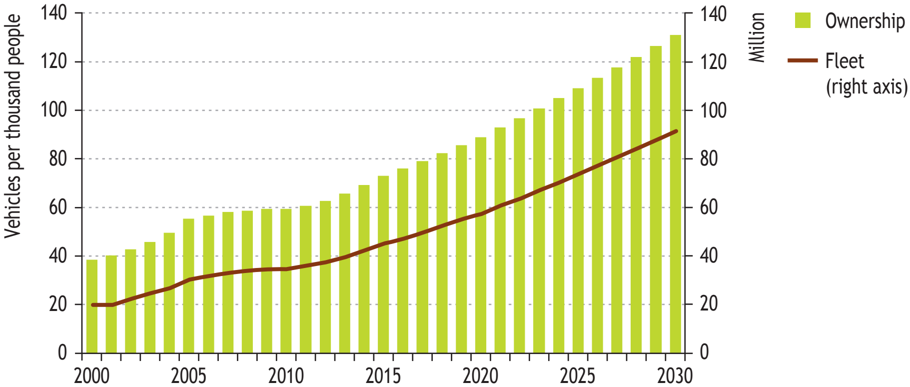
**Figure 15.5 • *ASEAN total final consumption by sector in the Reference Scenario***




Demand for energy in the *transport* sector grows more rapidly than in any other end-use sector, at 3.0% per annum, as the growth in motor transport within the region continues in line with urbanisation and rising incomes. Transport in the region continues to be overwhelmingly reliant on oil, although the share of biofuels (as gasoline and diesel fuel extenders) steadily increases. By 2030, the vehicle fleet in Southeast Asia is projected to reach 92 million vehicles (about three times as many as in 2007), although the ownership rates at that time of around – 130 per 1000 people – is just one-quarter of the current OECD average (Figure 15.6). The majority of the vehicle population throughout Southeast Asia is concentrated in the main cities, leading to serious congestion problems in cities such as Manila, Jakarta and Bangkok.

*Residential* energy consumption grows at an average annual rate of 1.3%. Electricity rapidly takes a larger share of the energy mix in this sector, as households continue to switch away from biomass and kerosene because of more widespread electrification, the convenience of electricity and an increasing uptake of electrical appliances. Given that Southeast Asia has a hot and humid climate, it is projected that air conditioners will give rise to the largest share of the increase in electricity demand in the residential sector, particularly as they will be decreasingly seen as a luxury item as incomes continue to rise. Despite strong growth, per-capita residential energy demand in Southeast Asia will remain significantly lower than in the OECD, partly reflecting lower incomes and the minimal demand for space heating.

**Figure 15.6 • *ASEAN vehicle ownership and fleet in the Reference Scenario***




Note: Excludes two- and three-wheelers.

**Box 15.2 • *Energy strategy for an island state: Singapore***

Singapore is an island city-state without fossil fuel resources; moreover, limited land space and geography restrict the application of alternative energies. Nuclear power is ruled out at present on safety grounds. As a result, Singapore is a price-taker, dependent on imports for almost its entire energy needs. Nonetheless, Singapore has not ruled out any fuel option, nuclear or otherwise, in the long run. Because the scope for alternative energy forms is limited, Singapore has concentrated on measures to improve energy efficiency, promote competition and boost international co-operation.

Singapore's electricity market was the first in ASEAN to introduce competition and to allow market signals to drive investment. There is currently excess generating capacity. Steps are being taken to improve energy security by diversifying the fuel mix in the power sector. For example, an LNG import facility is expected to be operational in 2013.

International and regional co-operation has been embraced. Singapore is a member of Asia-Pacific Economic Cooperation (APEC) and ASEAN, and is also in bilateral dialogue with East Asian countries. It has recognised the importance of developing the Trans-ASEAN Gas Pipeline (TAGP) and the ASEAN Power Grid (APG) as a contribution to long-term regional energy security. It is also supportive of the revised ASEAN Petroleum Security Agreement (APSA) and its Annex on Co-ordinated Emergency Response Measures (CERM), both of which both seek to enhance petroleum security and reduce emergency risks in the region.

Overcoming resource constraints will require technological progress. Clean energy development and demonstration has therefore been identified as a priority. A multi-agency Clean Energy Programme Office (CEPO) has been set up with the goal of developing Singapore into a global clean energy hub. Several clean energy initiatives have been launched, including an Energy Research and Development Fund (ERDF) to provide financial support for new energy solutions and the Jalan Bahar Clean Tech Park to support research, development and demonstration of clean technologies. The Energy Efficiency Programme Office (E2PO) was established in 2007 to promote greater adoption of energy-efficiency measures and technologies in all sectors, and to build the capability needed to sustain energy-efficiency efforts. A Sustainable Development Blueprint was developed in April 2009, which recommends strategies and initiatives to enable Singapore to continue to achieve vigorous economic growth and a good living environment, despite its unique constraints. Under the Blueprint, Singapore aims to reduce its energy intensity (per dollar GDP) by 20% from 2005 levels by 2020 and by 35% by 2030.

## Oil supply

### *Resources and production*

The *Oil & Gas Journal* puts Southeast Asia's proven reserves of oil at the start of 2009 at 10.3 billion barrels, or around 1% of the world total.[5] The region's proven oil reserves are concentrated in Indonesia and Malaysia, each with around 4.0 billion barrels, while Brunei Darussalam (1.1 billion), Vietnam (0.6 billion) and Thailand (0.4 billion) hold the bulk of the remainder. At current levels of production, existing reserves would sustain output for another 12 years. The *Outlook* for significant new oil discoveries in the region is generally considered to be poor due to uncertain prospectivity, uncompetitive fiscal terms in some areas and long-running territorial disputes. However, there are a number of under-explored regions with good potential, such as the disputed Spratlys chain of islands in the South China Sea and parts of eastern Indonesia (Box 15.4).

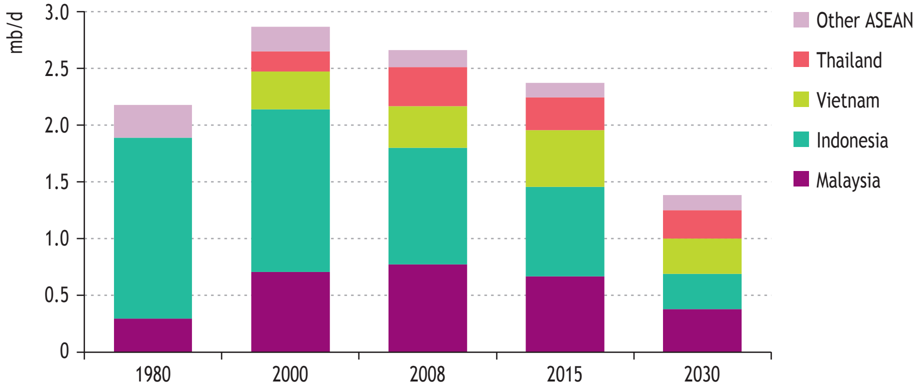
Oil production in Southeast Asia totalled 2.7 million barrels per day (mb/d) in 2008. This included production from Indonesia (1.0 mb/d), Malaysia (771 kb/d or thousand barrels per day), Vietnam (368 kb/d), Thailand (344 kb/d) and Brunei Darussalam (144 kb/d). The region's oil output has been falling steadily, since peaking at around 2.9 mb/d in 1996, due largely to reduced production in Indonesia. In the Reference Scenario, oil production is projected to drop to 2.4 mb/d in 2015 and to 1.4 mb/d in 2030 (Figure 15.7).

### *Oil refining*

At the start of 2009, ASEAN crude oil distillation capacity totalled 4.7 mb/d. Singapore, with 1.3 mb/d of capacity, is one of the world's top three oil trading and refining hubs, alongside Rotterdam and Houston (Table 15.4). Thailand and Indonesia have around

5. All the reserve figures cited here are from the *Oil & Gas Journal* (O&GJ, 2008).

**Figure 15.7** • *ASEAN oil production by country in the Reference Scenario*




1.2 mb/d and 1.1 mb/d of capacity, respectively, in both cases predominately for domestic supply. Malaysia and Thailand have expressed interest in developing export-orientated refining hubs.

Several projects are underway to expand Southeast Asia's refining capacity. Vietnam recently opened its first refinery, the 136-kb/d Dung Quat project, and could develop additional facilities to meet strong demand growth and reduce the country's product import dependence. Several smaller refinery expansions are currently being undertaken in Thailand, Malaysia and Indonesia. Singapore's Jurong Aromatics Company (JAC) had planned to build a condensate splitter by 2011. However, JAC has delayed that project due to the tight access to commercial credit during the global financial crisis.

**Table 15.4** • *ASEAN oil refining capacity and planned additions by country (kb/d)*

| | Existing capacity | Planned addition to 2012 |
|---|---|---|
| Brunei Darussalam | 12 | n.a. |
| Indonesia | 1 116 | 27 |
| Malaysia | 592 | n.a. |
| Myanmar | 57 | n.a. |
| Philippines | 292 | n.a. |
| Singapore | 1 300 | n.a. |
| Thailand | 1 221 | 50 |
| Vietnam | 136 | n.a. |
| **Total** | **4 724** | **77** |

Source: FACTS Global Energy.

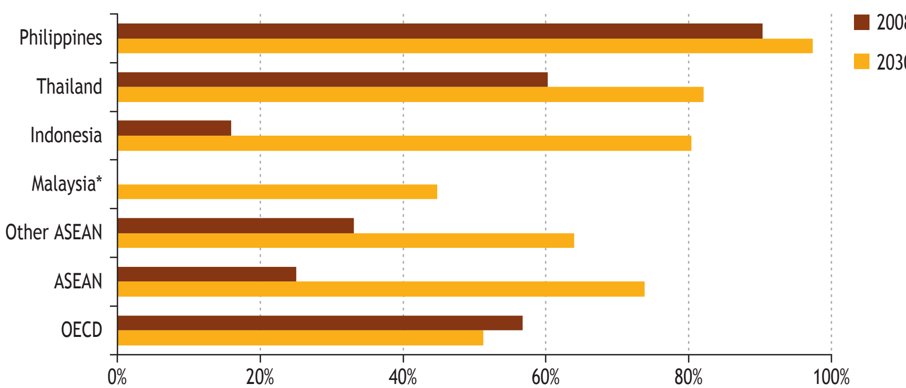
15

## *Oil trade*

Southeast Asia imported around 900 kb/d of oil in 2008. The vast majority of this came from the Middle East and transited the narrow Strait of Malacca, sandwiched between the Indonesian island of Sumatra, Singapore and Malaysia (Box 15.3). ASEAN is projected to require net imports of 1.4 mb/d in 2015 and 3.9 mb/d in 2030 as domestic production fails to keep up with demand. By 2030, imports make up 74% of the region's total oil demand, compared with 25% in 2008.

Brunei Darussalam is expected to remain a net oil exporter through the *Outlook* period but all other countries, including those that are currently major oil producers, such as Indonesia (80%) and Malaysia (45%), become heavily dependent on imports (Figure 15.8). Indonesia – which suspended its OPEC membership in 2008 – became a net importer of oil in 2004 and is projected to be importing 1.3 mb/d by 2030, while Malaysia's imports reach around 310 kb/d by that time. All other ASEAN countries are expected to remain net oil importers.

**Figure 15.8 • *ASEAN oil net-import dependence by country in the Reference Scenario***




* Malaysia is projected to become a net oil importer soon after 2015.

The Reference Scenario projections imply a persistently high level of spending on oil imports in ASEAN as a whole. As a share of GDP at market exchange rates, spending on oil imports in the region spiked in 2008 as prices soared. While the level of spending has since dropped back, it is projected to rise again through the *Outlook* period, reaching 4.8% of GDP in 2030 (Figure 15.9). The level is highest in Thailand, reaching 8.6% of GDP in 2030, reflecting the country's high and growing dependence on imports. In dollar terms, annual expenditure on oil imports in ASEAN totals $164 billion in 2030, up from $32 billion in 2008. At the household level, the greatest financial burden will be felt by low-income earners, who typically spend a greater share of their income on energy.

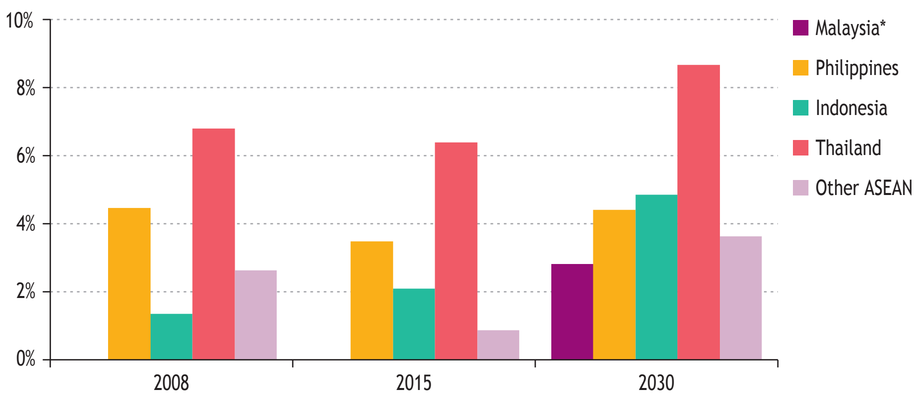
**Box 15.3 • Bypassing piracy in the Strait of Malacca**

The vulnerability of Southeast Asia's sea lanes, namely the Straits of Malacca, Sunda and Lombok, and the passage into the South China Sea, give rise to concern as the oil-import dependence of the region (and northeast Asia) grows. In 2007, an estimated 14.3 mb/d of oil was moved by tankers through the Strait of Malacca, mainly from the Middle East and Africa. The volume shipped through this already congested waterway is set to continue to rise. In addition, increasing volumes of LNG will pass through Southeast Asia's sea lanes from producers in the Middle East and Australia to buyers in Japan, Korea, China and Chinese Taipei.

The narrowest width of the Strait of Malacca is just 2.7 km, raising concerns that traffic could be disrupted by terrorism, accidents or piracy. In recognition of these risks, the three littoral states – Indonesia, Malaysia and Singapore – are engaged in tri-partite co-operation including co-ordination of air and maritime patrols. They have also improved their surveillance systems and operating procedures. These measures appear to be paying off. The number of reported attempted pirate attacks dropped from 38 in 2004 to just two in 2008 and one in the first quarter of 2009 (ICC CCS, 2009).

A number of proposals exist to bypass the congested Strait of Malacca. Two long-standing projects (now in abeyance) are Thailand's proposed Kra Canal, which would cut through southern Thailand to link the Indian Ocean and the South China Sea, and Malaysia's proposed Trans-Peninsular pipeline, which would cut across Peninsular Malaysia. A more recent proposal is the China-Myanmar pipeline, which would reduce China's vulnerability to a disruption in the Strait of Malacca and also cut shipping times from the Middle East and Africa.

**Figure 15.9 • Spending on oil imports as a share of GDP at market exchange rates in ASEAN by country in the Reference Scenario**




* Malaysia becomes a net oil importer soon after 2015.

Note: Calculated as the value of net imports at prevailing average international prices. The split between crude/refined products is not taken into account.

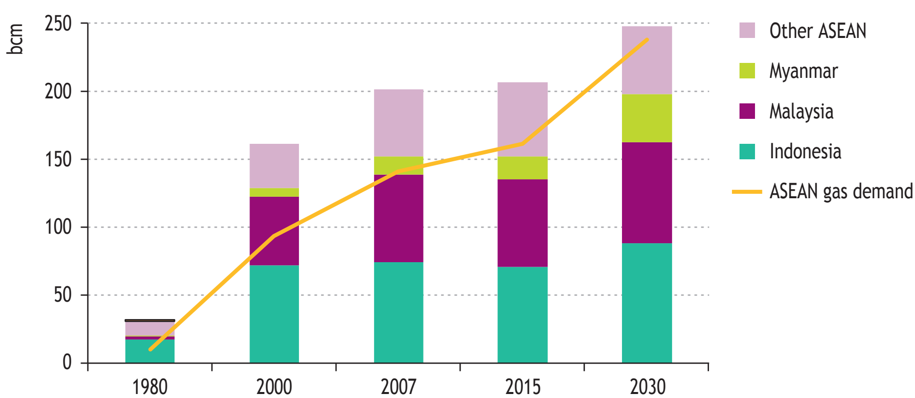
Source: IEA databases and analysis.

## Natural gas supply

Southeast Asia is richer in natural gas than it is in oil, but its gas reserves tend to be in remote locations. This raises the challenge of building pipelines or LNG supply infrastructure. According to the *Oil & Gas Journal*, the region's proven reserves of natural gas stood at 6.6 tcm at the start of 2009, or 3.7% of the world's total endowment. Production of natural gas in the region grew at an average rate of 7.0% per year from 1980 to 2008, reaching 203 bcm. At current levels of production, Southeast Asia's proven reserves of natural gas would sustain production for another 33 years. The bulk of the region's gas is located in Indonesia, Malaysia and Brunei Darussalam.

In the Reference Scenario, natural gas production in Southeast Asia as a whole is projected to increase from 203 bcm in 2008 to 248 bcm in 2030 (Figure 15.10). The surplus of supply over demand is expected to narrow from 63 bcm in 2008 to just 10 bcm by 2030. In the absence of major new discoveries, exports are set to decline. Some countries would have to import growing volumes of LNG. There is potential for faster growth of unconventional gas production (notably CBM), which, if exploited, could lead to higher overall gas production than projected here.

**Figure 15.10 • *ASEAN gas production by country in the Reference Scenario***




Southeast Asia is an important exporter of LNG to world markets and in mid-2009 had 31% of global LNG production capacity, or capacity of 59 million tonnes (Mt) per year, spread across Malaysia, Indonesia and Brunei Darussalam (Table 15.5). In view of the limited gas interconnections in the region (particularly in the case of Philippines) and in a bid to increase supply flexibility, Indonesia, Philippines, Singapore and Thailand are building or have plans to build domestic LNG receiving/regasification terminals.

**Table 15.5 • ASEAN existing and planned LNG infrastructure**

| | Project | Location | Capacity (mtpa) | Capacity (bcm/y) | Status | Start |
|---|---|---|---|---|---|---|
| **Liquefaction** | | | **71.2** | **97.1** | | |
| Brunei Darussalam | Brunei Darussalam LNG | Lumut | 7.2 | 9.8 | Existing | 1972 |
| Indonesia | Bontang A-H Trains | East Kalimantan | 22.3 | 30.3 | Existing | 1977 |
| | Arun | North Sumatra | 4.1 | 5.7 | Existing | 1978 |
| | Tangguh | Bintuni Bay, Papua | 7.6 | 10.3 | Existing | 2009 |
| | Donggi | Central Sulawesi | 2.0 | 2.7 | Proposed | 2012 |
| | Masela | | 4.0 | 5.6 | Proposed | 2014 |
| Malaysia | MLNG | Bintulu, Sarawak | 8.1 | 11.0 | Existing | 1983 |
| | MLNG Dua | Bintulu, Sarawak | 7.8 | 10.6 | Existing | 1995 |
| | de-bottlenecking | Bintulu, Sarawak | 1.3 | 1.8 | Construction | 2009 |
| | MLNG Tiga | Bintulu, Sarawak | 6.8 | 9.3 | Existing | 2003 |
| **Regasification** | | | **13.8** | **19.0** | | |
| Indonesia | | East Java | 1.5 | 2.1 | Proposed | 2011 |
| | | North Sumatra | 1.5 | 2.1 | Proposed | 2011 |
| | | West Java | 1.5 | 2.1 | Proposed | 2012 |
| Philippines | | Bataan | 1.3 | 1.8 | Proposed | 2012 |
| Singapore | | Jurong Island | 3.0 | 4.1 | Proposed | 2013 |
| Thailand | | Map Ta Phut | 5.0 | 6.8 | Construction | 2011 |

*Indonesia* has proven reserves of natural gas of 3 tcm, the 11th largest in the world and enough to support 39 years of production at current levels. Most of these reserves are located in Sumatra and Kalimantan, far away from demand centres. Indonesia has one of the largest undeveloped gas fields in the world – Natuna D-Alpha. The block contains 6.3 tcm of gas reserves, of which about 1.3 tcm are thought to be commercially recoverable. Though extensive, the Natuna block will be difficult and expensive to develop as its $CO_2$ content is very high, at an estimated 70%. Indonesia's state-owned oil and gas company, PERTAMINA, is expected to decide soon on partners to develop the field. Companies that have been named as possible partners include ExxonMobil, Chevron, Total, Shell, StatoilHydro, Eni, Petronas and China National Petroleum Corporation (CNPC).

As recently as 2005, Indonesia was the world's leading LNG exporter, but it now ranks third, after Qatar and Malaysia. In recent years, exports of LNG have declined due to robust domestic demand for gas and dwindling production from the fields supplying the eight-train complex at Bontang in Badak, East Kalimantan, and the six-train complex at Arun in North Sumatra. Indonesia currently exports LNG to Japan, South Korea, Chinese Taipei and China, and piped gas to Singapore and Malaysia. Production from Indonesia's new Tangguh LNG project, located in the far eastern Papua province, commenced in July 2009. The Tangguh project will initially produce 9.8 bcm/year of LNG from a basin with total proven gas reserves of 408 bcm. Export destinations are the west coast of North America, China and Korea. There are also plans to sell uncommitted gas into Indonesia's domestic market.

In the Reference Scenario, Indonesia's gas production in total is projected to remain broadly flat over the next decade. Beyond 2020, it is assumed that Natuna is developed, adding up to 20 bcm/year of capacity by 2030. This helps to temper the decline at other fields. CBM, resources of which are thought to be substantial, is also expected to make a small but growing contribution to output in the last decade of the projection period. In total, Indonesian natural gas production is projected to climb from 77 bcm in 2008 to close to 90 bcm in 2030.

As of January 2009, *Malaysia's* proven reserves of natural gas ranked 14$^{th}$ in the world, at 2.4 tcm. Most of Malaysia's gas is found offshore of the east coast of Peninsular Malaysia (from which production is dedicated to the domestic market) and offshore of the states of Sabah and Sarawak on Borneo Island (which is predominately utilised for LNG exports). Malaysia's production of natural gas has been steadily increasing over recent years and reached 61.5 bcm in 2008. The country is the world's second-largest exporter of LNG, after Qatar. LNG exports were around 30 bcm in 2008, mainly to Japan, South Korea and Chinese Taipei.

Although a major exporter of natural gas, Malaysia is facing a potential gas shortage as production at the fields that currently supply the domestic market is struggling to match the strong demand from industry in Peninsular Malaysia. This has led to calls for supplies contracted to independent power producers (IPPs) and export markets to be redirected to domestic industry. The substantial cuts to natural gas subsidies made in 2008 should encourage more efficient usage, thereby reducing the risk of domestic shortages. In addition, Petronas, the Malaysian national oil company, has signed an agreement to buy LNG from the Gladstone LNG (GLNG) project in eastern Australia from 2014, for supply into the domestic Malaysian market.

*Myanmar* has proven reserves of natural gas of 283 bcm. In 2008, its gas production totalled 12.4 bcm. Exports of natural gas from the offshore Yadana and Yetagun fields in the Gulf of Martaban have been the main source of Myanmar's foreign earnings in recent years. Gas is delivered primarily to Thailand, via pipeline. Additional production in the Bay of Bengal, including from the prospective Shwe fields, is set to come on stream soon. In December 2008, Myanmar signed an agreement with CNPC to sell 10 bcm/year of gas from the Shwe gas fields over a 30-year period, starting in 2012.

*Brunei Darussalam* had proven natural gas reserves of 391 bcm in 2008. In 2008, the country's gas production totalled 12 bcm, about 80% of which was sold as LNG to Japanese and Korean companies. Oil and gas exports accounted for more than half of GDP in 2008. Brunei Darussalam is intensifying its exploration and development efforts with the intention of extending LNG sales contracts to Japan and Korea beyond their scheduled 2013 expiration. However, due to disputes with Malaysia over maritime boundaries, potential deepwater areas remain undeveloped.

**Box 15.4 • *Territorial claims in the South China Sea***

The South China Sea (SCS) covers an area of around 800 000 km$^2$ and comprises over 200 small islands, rocks and reefs, including the Spratly group. Within the region, there are unresolved territorial claims involving Brunei Darussalam, China, Indonesia, Malaysia, Philippines, Chinese Taipei and Vietnam. Two of the principal reasons behind the intense interest in the area are that the SCS, as host to some of the busiest shipping lanes in the world, is vital to the economic prosperity of the region, and is thought to contain significant energy resources, which the littoral states are eager to develop.

The magnitude of the SCS's oil and gas resources is very uncertain, as there has been a lack of exploratory drilling. However, significant discoveries in surrounding regions have led to speculation that the resource base could be substantial. The US Geological Survey (USGS) has estimated the reserves and undiscovered gas resources in the offshore basins of the SCS could be 7.5 tcm (USGS, 2000), while the reserves and undiscovered resources of oil could amount to 28 billion barrels (USGS, 1994).

In 2002, the ASEAN states and China signed a Declaration on the Conduct of Parties in the South China Sea, pledging to resolve their conflicts peacefully. To date that approach has been maintained.

## Coal supply

Southeast Asia's coal reserves stood at 12.5 billion tonnes in 2007 or slightly over 1% of the world total, while total coal resources are estimated to be nearly 25 times higher (BGR, 2009). Reserves of hard coal and lignite are similar, while potential resources comprise 80% lignite and 20% hard coal. Indonesia, Vietnam and Thailand, which accounted for almost all of Southeast Asia's production in 2007, hold the greater part of these coal resources. Their reserves-to-production ratios today stand at 26 years, 76 years and 103 years, respectively.

In total, Southeast Asia produced 276 million tonnes of coal equivalent (Mtce) of coal in 2007, of which more than three-quarters was steam coal, 12% brown coal and 10% coking coal. In 2007, Southeast Asia's net hard coal exports totalled 170 Mtce, coming principally from Indonesia (the world's largest steam coal exporter) and Vietnam.



In the Reference Scenario, fuelled by a tripling of domestic demand and growing demand elsewhere, coal production in Southeast Asia is projected to rise by more than three-quarters to 486 Mtce, of which close to 82% comes from Indonesia, around

11% from Vietnam and 5% from Thailand. With Indonesia supplying much of the import demand of its Southeast Asian partners, the region's net external trade balance is projected to remain at around today's level — *i.e.* at 170 Mtce of net exports.

*Indonesia's* coal exports more than quadrupled between 1998 and 2008. This rapid growth was underpinned by the country's low-cost reserves of low-sulphur coal, ample port facilities and proximity to demand centres in Asia. Indonesia overtook Australia as the world's largest exporter of steam coal in 2005. Around two-thirds of Indonesia's 6.8 billion tonnes of coal reserves are located in Sumatra, with the remainder in Kalimantan, West Java and Sulawesi. By 2007, Indonesia's coal production had risen to 230 Mtce. Indonesia exports coal mainly to Japan, Chinese Taipei, Korea, Philippines, China and OECD Europe.

*Vietnam* had coal reserves of 3.4 billion tonnes as of 2007 and its resources of mainly brown coal are thought to be more than 60 times greater than its reserves (BGR, 2009). The majority of reserves, located in the north of the country, are high-quality anthracite coal. Vietnam's coal production has increased sharply over recent years, from 9 Mtce in 2000 to 35 Mtce in 2007. Around 90% of this increase went for export, as Vietnam is well placed to supply demand centres in South China with high quality anthracite coal. In recent years, Vietnam has increased export tariffs in order to safeguard supplies to meet domestic demand, which has more than doubled since 2000 due to strong demand from power plants and the cement industry. In 2008, strong domestic demand and typhoon damage at Cam Pha port led to a sharp drop in exports, to 17 Mtce, down from 26 Mtce in 2007. Nevertheless, Chinese investment should ensure continued exports in the future, especially as resources in the Red River Delta are exploited. By 2030, Vietnam's coal production is projected to have risen by nearly 50%, to 52 Mtce, with exports of 20 Mtce. Net exports will be somewhat lower. Due to increased demand in the south of the country and the availability of competitively priced imports, Vietnam started importing minor quantities in 2005 and is projected to import 5 Mtce, or 13% of domestic demand, by the end of the projection period.

## Power sector

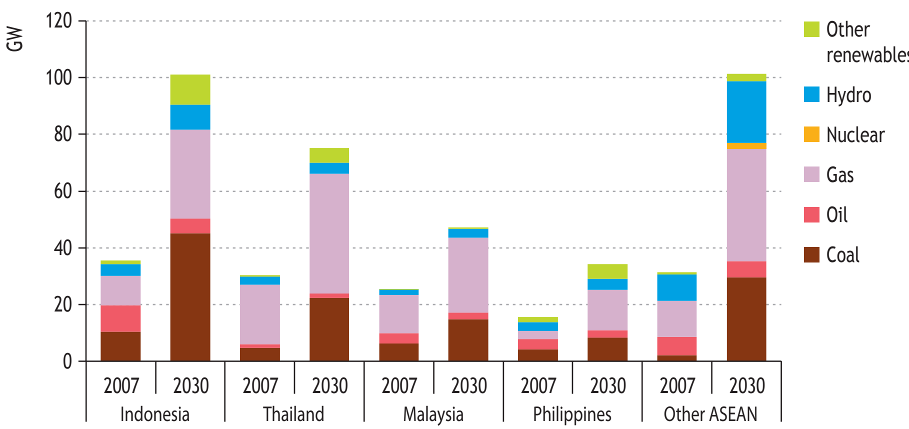
Electricity generation in Southeast Asia totalled 568 TWh in 2007. The region relies heavily on fossil fuels, with the share of natural gas in the electricity mix at 46%, coal at 27% and oil at 11%. Hydropower also makes an important contribution, generating 12% of the region's electricity, primarily in Laos, Myanmar and Vietnam. Southeast Asia's considerable potential to generate electricity from agro-industrial residues remains largely untapped: this source currently makes up just 1% of the region's electricity production.

In the Reference Scenario, electricity generation in Southeast Asia is projected to exceed 1 550 TWh in 2030. Generation grows by 4.5% per year between 2007 and 2030. Oil, natural gas and coal are expected to remain the principal primary fuels, contributing 84% of total generation in 2030. Electricity production from hydropower increases at 2.5% per year on average, with growth primarily in the Mekong Region, where long-term agreements are in place for exports of hydropower-generated electricity from countries with adequate hydropower-generation capacity (such as Laos and Myanmar) to countries with burgeoning energy demand (such as Thailand and China) (Park, 2009; Zhai, 2009).

Electricity from biomass expands at 10% per annum on average through to 2030, with much of the growth arising in Thailand and Malaysia, and making use of rice husks, bagasse or palm oil waste as the main fuels. Other renewables represent 5% of generation by 2030, stimulated by the feed-in tariffs and other incentives that are being put in place in many parts of the region. Nuclear power is expected to start making a modest contribution to the region's electricity needs soon after 2020.

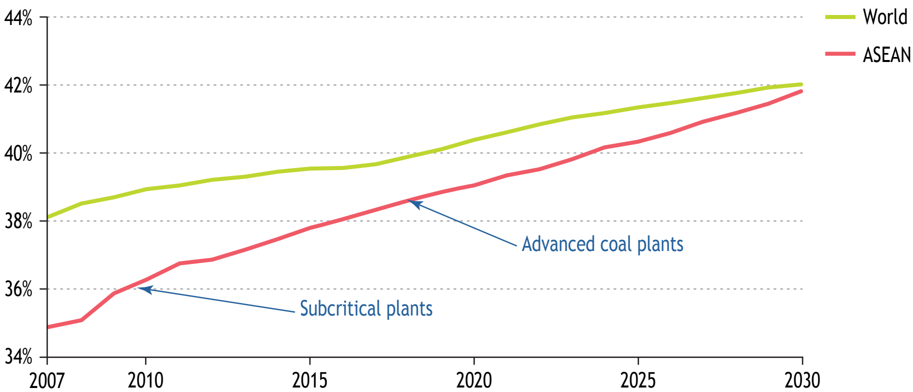
Southeast Asia's installed electricity-generating capacity was 138 GW in 2007. The region needs to add 243 GW of new capacity by 2030 in the Reference Scenario, some of which is to replace existing capacity that is retired (Figure 15.11). Coal is expected to make up 38% of the additional capacity and new gas-fired capacity 43%. Some 20 GW of additional capacity from non-hydro renewable energy sources comes online by 2030, namely geothermal, biomass, solar or wind.

**Figure 15.11** • ***ASEAN generation capacity by country and fuel in the Reference Scenario***




In the Reference Scenario, the average efficiency of power generation in Southeast Asia is set to increase. This results from the installation of new, more efficient plants, including combined-cycle gas turbines, while some older inefficient plants are retired. The average efficiency of the region's coal-fired generation is projected to increase from 35% in 2007 to slightly below 42% in 2030 (Figure 15.12). In comparison, the average efficiency of coal plants globally increases from 38% to 42% over the same period.

**Figure 15.12 • ASEAN efficiency improvements in coal-fired generation in the Reference Scenario**




## *Nuclear energy*

There are currently no nuclear power plants in Southeast Asia, other than small research reactors. But parts of the region are becoming increasingly interested in developing nuclear power as a means to help solve looming electricity shortages and to reduce growing dependence on fossil fuel imports. Philippines, Thailand and Vietnam each include the introduction of nuclear power in their medium- and long-term power development plans, while Malaysia is looking at the possible deployment of nuclear power post-2020. Indonesia had plans for the introduction of a significant nuclear programme but these were put on hold in July 2009 (Table 15.6).

**Table 15.6 • Plans for nuclear power plant construction in ASEAN by country**

| | Capacity (MW) | Year |
|---|---|---|
| Indonesia | 4 800 | 2025* |
| Philippines | 2 400 | 600 MW in 2025<br>600 MW in 2027<br>600 MW in 2030<br>600 MW in 2034 |
| Thailand | 2 000 | 2020 |
| Vietnam | 8 000 | 2 000 MW by 2020<br>Additional 2 000 MW by 2021<br>Additional 4 000 MW by 2025 |

* Plans abandoned in July 2009 but may be reinstated at a later date.

There is, of course, considerable uncertainty about the prospects for nuclear power in the region as there are many challenges to overcome, including public acceptance, financing, site selection, long-term storage of spent fuel, developing safety and security regulations, and building up human resources and technological capabilities.

In the Reference Scenario, nuclear power is projected to start making a contribution to Southeast Asia's energy needs soon after 2020 and to represent 0.5% of the region's primary energy supply by 2030. This is well behind the ambitious targets in the plans of some individual ASEAN member states. In contrast, in the 450 Scenario nuclear plays a much greater role in the region's energy mix.

In July 2009, *Indonesia* cancelled plans to build four nuclear power plants by 2025, the first of which was to have been operational by 2016. This decision was linked both to the current climate of tight credit and growing public opposition in the lead up to the presidential elections. The possibility remains that the nuclear programme will be reinstated, particularly as the government is seeking to maintain the country's nuclear expertise, in part through international co-operation.

*Philippines* developed the Bataan nuclear plant about 25 years ago, but the plant was declared unsafe and was never operated. Philippines is exploring the option of rehabilitating this nuclear plant for operation by 2025 and then to increase nuclear capacity to 2 400 MW by 2034.

*Thailand* has plans to develop 2 000 MW of nuclear power by 2020. It had originally planned for another 2 000 MW by 2021, but this increment has been deferred due to the current economic crisis, which has lowered expected future energy demand.

*Vietnam* is pursuing the introduction of nuclear energy as a means of meeting the country's energy security and sustainability objectives. The government of Vietnam has taken preparatory steps towards getting a first commercial-scale project on line by 2020 and reaching total capacity of 8 000 MW by 2025. The country has been operating a 500-kW research reactor for more than 25 years.

*Malaysia* is focusing on a "Five-Fuel Diversification" strategy, with oil, hydropower, gas, coal and renewables as the five main fuels. However, following the spike in natural gas and coal prices in 2007 and 2008, Malaysia has expressed interest in the possible deployment of nuclear power after 2020.

Although it has no formal plans for nuclear power at present, in 2008 *Cambodia* announced hopes of eventually building a nuclear power plant to reduce its dependence on diesel-powered generators. It is, however, expected that the country's immediate priority will be to expand hydropower facilities and coal-fired power plants.

### *Structure of ASEAN electricity utilities*

As is common in developing economies with geographically and demographically dispersed communities, electricity in ASEAN relies upon a mix of grid power supply, distributed power generation systems and stand-alone power generation systems. In some situations, the closest source of electricity is located across the border in a neighbouring country, creating opportunities for cross-border interconnection and electricity trading to optimise the use of energy resources within the region.



Historically, the ASEAN electricity utilities have been state-owned, vertically integrated utilities (VIUs). However, in recent decades, ASEAN governments have recognised the need to open up their electricity supply industries and electricity markets in order to attract the private-sector investment that is necessary to meet electricity demand growth on a competitive basis. Some measure of unbundling and liberalisation of state-owned utilities has already been undertaken (Table 15.7). The primary approach has been to retain state ownership of the utility but to open up the generation sector to independent power producers (IPPs), while introducing some form of regulatory framework for independent production. In Southeast Asia, a subset of IPPs exist, known as small power producers (SPPs). SPPs are producers that are privately owned or co-operatives, often based on renewable energy or co-generation, and that have the right to feed excess electricity into the national power system. Indonesia, Malaysia, Philippines and Thailand have developed SPP access frameworks and power purchase agreements (PPAs) to give SPPs access to the national grids. In many ASEAN countries, where access, reliability or quality of electricity supply is limited, auto-producers (private entities self-generating primarily for their own use) are also common. This is particularly the case for industries that are distant from the grid, such as mining and mineral processing industries, and for agricultural industries producing bio-waste, such as rice milling, timber milling and sugar production.

**Table 15.7 • *Current status of the ASEAN power utilities by country***

| | Power company | Current status |
|---|---|---|
| Brunei Darussalam | Department of Electrical Services | VIU +IPPs |
| Cambodia | Electricité du Cambodge | VIU +IPPs |
| Indonesia | PT Perusahaan Listrik Negara | VIU + IPPs |
| Laos | Electricité du Laos | VIU |
| Malaysia | Tenaga Nasional Berhad<br>Sabah Electricity Sdn. Bhd<br>80% subsidiary of TNB<br>Sarawak Electricity Supply Corporation | VIU Peninsular Malaysia +IPPs<br>VIU Sabah State +IPPs<br><br>VIU Sarawak State +IPPs |
| Myanmar | Ministry of Electric Power | VIU + small IPPs |
| Philippines | National Power Corporation<br>MERALCO<br>National Grid Corporation of the Philippines | State-owned power generation co. + IPPs<br>Largest electricity distributor<br>Privately owned company that maintains and operates the transmission network |
| Singapore | Generating companies (Gencos)<br>SP PowerGrid<br>Energy Market Company<br>Retailers | IPPs<br>T&D<br>Market Operator<br>Retailing |
| Thailand | Electricity Generating Authority of Thailand<br>Metropolitan Electricity Authority of Thailand<br>Provincial Electricity Authority of Thailand | VIU + IPPs + SPPs<br>Metropolitan distribution and retail supply<br>Provincial distribution and retail supply |
| Vietnam | Electricity of Vietnam | VIU + IPPs |

Although the situation is slowly changing, the state utilities generally remain the national monopoly system operator, retain ownership of the national transmission and distribution (T&D) networks, and enjoy a monopoly of retailing. The utility is accordingly the sole off-taker for the electricity generated by the IPPs. Electricity regulators have been established in Malaysia (Malaysian Energy Commission), Philippines (Energy Regulatory Commission), Singapore (Energy Market Authority), Thailand (Energy Regulatory Commission) and Vietnam (Electricity Regulating Authority of Vietnam).

### *Access to electricity in the ASEAN region*

In 2008, the number of people in Southeast Asia without access to electricity was 160 million — or 28% of the region's population. The bulk of those without access to electricity lived in rural areas. Rural and urban electrification rates in the region are currently around 55% and 91%, respectively.

There is great disparity throughout the region: in Myanmar the overall electrification level is only 13%, whereas in Singapore the rate is 100% (Table 15.8). Indonesia (81 million), Myanmar (43 million) and Philippines (13 million) have the greatest number of people without electricity; these collectively account for 85% of the total population without electricity in the region.

Since 2005, the number of people with access to electricity in Southeast Asia has increased by 27 million. This impressive improvement is attributable both to the success of electrification programmes (particularly in Indonesia, Malaysia, Myanmar and Philippines) and to higher urbanisation. Nonetheless, in the absence of concerted efforts, 9% of the ASEAN population, 63 million people, is projected still to lack electricity in 2030, despite more widespread prosperity and more advanced technology.

**Table 15.8 • ASEAN electricity access by country, 2008**

| | Population (millions) | Electrification rate (%) | Rural population without electricity (millions) | Urban population without electricity (millions) |
|---|---|---|---|---|
| Brunei Darussalam | 0.4 | 100 | 0.0 | 0.0 |
| Cambodia | 14.7 | 24 | 10.1 | 1.1 |
| Indonesia | 228.3 | 65 | 74.0 | 7.1 |
| Laos | 6.0 | 55 | 2.4 | 0.3 |
| Malaysia | 27.0 | 99 | 0.2 | 0.0 |
| Myanmar | 49.2 | 13 | 29.8 | 13.0 |
| Philippines | 89.5 | 86 | 10.8 | 1.7 |
| Singapore | 4.7 | 100 | 0.0 | 0.0 |
| Thailand | 64.2 | 99 | 0.4 | 0.0 |
| Vietnam | 86.1 | 89 | 9.4 | 0.1 |
| **Total** | **570.2** | **72** | **137.1** | **23.3** |

Source: IEA analysis.

## Renewables supply

Renewable energy accounted for about 27% of ASEAN total primary energy demand in 2007. By far, the main renewable energy application in Southeast Asia remains the use of traditional biomass for household cooking and rural electrification.[6] Considerable potential to expand the use of biomass exists, as many countries in the region are large producers of agricultural commodities and so have abundant feedstocks of residues, such as rice husks, straw, coconut husks, shells and bagasse.

Renewables in Southeast Asia are also increasingly being used in modern applications. Most ASEAN countries have integrated renewable energy into their overall energy policy frameworks and have introduced renewable energy targets, generally for electricity generation. Biofuel targets and blending mandates are also becoming more common in the ASEAN region (Table 15.9). Currently, the use of biomass in modern applications within the region is highest in Indonesia, Malaysia and Thailand.

**Table 15.9 • *Biofuel policies in selected ASEAN countries***

| | Numerical target | Blending mandate | Economic measures | Main feedstock |
|---|---|---|---|---|
| Indonesia | Biofuel use to represent 2% of energy mix by 2010, 3% by 2015, 5% by 2025 | Gasoline: mandatory blend of 1%-5% bioethanol; Diesel: mandatory blend of 0.25%-1% biodiesel since January 2009 | Rp 1 trillion ($110 million) set aside to help biofuel crop farmers, incentives for biofuel investors | Palm oil for biodiesel, molasses for bioethanol |
| Malaysia | | Diesel: 5% biodiesel (B5) by 2008* | Biodiesel used in selected government vehicles since February 2009 | Palm oil |
| Philippines | 5% of total annual volume of gasoline sold shall be E5 by 2009 | Gasoline: minimum 5% ethanol (E5) by 2009 & E10 by 2011; Diesel: 1% biodiesel (B1) in 2007 and B2 by 2009 | Tax incentives, financial assistance | Coconut oil for biodiesel, sugar cane for bioethanol |
| Thailand | 2022: Ethanol 9 million litres per day and biodiesel 4.5 million litres per day | Gasoline: optional use of E10, E20 and E85; Diesel: 2% palm oil (B2) from February 2008 onwards, B5 by 2011 | Taxes and levies are lowered | Palm oil for biodiesel, cane molasses for bioethanol |
| Vietnam | 2020: 500 million litres of ethanol, 50 million litres of biodiesel | Production targets: 100 000 tonnes of 5% ethanol blend; 50 000 tonnes of 5% biodiesel blend each year by 2010 | Government plans favourable conditions for biofuel development and investment promotion: tax incentives, low-interest loans | Potentials of jatropha for biodiesel, cassava and sugar cane for bioethanol |

* B5 implementation delayed due to rising palm oil prices.

Sources: ADB (2009a); Bundit (2009); APEC Biofuels website, www.biofuels.apec.org; IEA (2009); Nilkuha (2009); REN21 (2008, 2009).

6. Traditional biomass is typically fuelwood, dung and agricultural residues.

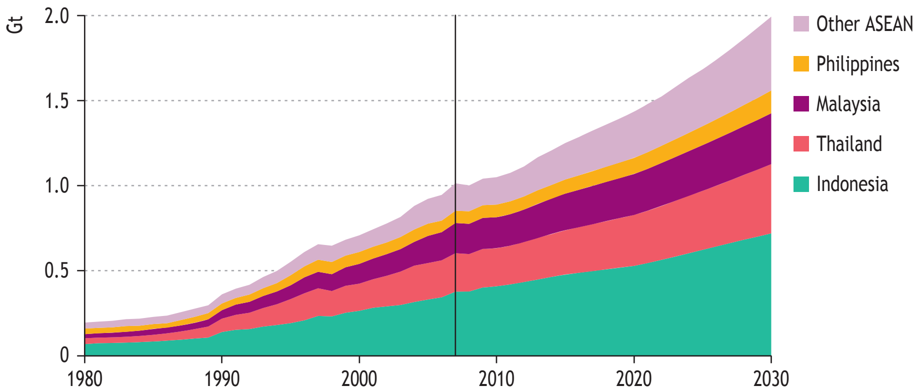
In the Reference Scenario, the use of renewables in Southeast Asia expands by 2% per annum on average through to 2030, reaching 213 Mtoe. The utilisation pattern changes considerably, with the deployment of modern renewables increasing at a much faster rate than traditional biomass. Traditional biomass consumption increases to 100 Mtoe in 2030, an average annual growth rate of 0.3%.

Renewables-based electricity generation, excluding hydropower, is projected to grow substantially in ASEAN over the coming decades, benefiting from high fossil-fuel prices, declining investment costs and government support. In the Reference Scenario, ASEAN renewable electricity generation is projected to increase from 21 TWh in 2007 to 111 TWh in 2030 and its share of total generation to increase from 4% to 7% over the same period. Renewables-based electricity generation will consume around 11 Mtoe of biomass as feedstock in 2030. ASEAN biofuels supply is projected to climb to 7 Mtoe (140 kb/d[7]) in 2030, meeting 5% of the region's total road-transport fuel demand.

## Energy-related $CO_2$ emissions and local pollution

The projected trends in energy demand in the Reference Scenario mean that energy-related $CO_2$ emissions from Southeast Asia continue to increase. Having already grown from around 360 Mt in 1990 to just over 1 000 Mt in 2007, they are projected to rise to 1 430 Mt in 2020 and 1 990 Mt in 2030, an average rate of growth of 3% per annum (Figure 15.13). Southeast Asia's share of global $CO_2$ emissions is 5% in 2030, up from around 3.5% today. Southeast Asia has been responsible for 1% of the world's cumulative emissions since 1890 but, due to the projected rapid growth in emissions in the region, the region's share of cumulative emissions is set to increase to 3.3% by 2030.

**Figure 15.13 • ASEAN energy-related $CO_2$ emissions by country in the Reference Scenario**




Between 2007 and 2030, the Reference Scenario sees a substantial reduction in energy-related $CO_2$ emissions per unit of GDP in Southeast Asia, as is typical of developing economies. The average rate of improvement is 0.8% per year over the period.

7. Calculated from an energy-equivalent basis.

In contrast, per-capita emissions of energy-related $CO_2$ in Southeast Asia show a steady increase over the remainder of the *Outlook* period, from 1.8 tonnes in 2007 to 2.8 tonnes in 2030. Although per-capita emissions in Southeast Asian countries continue to be significantly lower than in the OECD, the gap narrows through the *Outlook* period, from a factor of six in 2007 to three in 2030.

**Box 15.5 ● *Increasing the role of renewables in Southeast Asia***

Although large variations exist from country to country, the technical potential for most renewable energy sources in the ASEAN region is very large relative to current production levels, even for the most mature renewable energy technologies.

In terms of hydropower, the technical potential of the region is about 150 GW, including significant mini- and micro-hydro potentials in Indonesia, Malaysia, Cambodia and Philippines. The technical potential for bio-energy – from feedstocks such as agricultural and forestry residues, energy crops, animal residues and municipal solid waste – is also large, with the exception of the small coastal economies, such as Brunei Darussalam and Singapore.

In terms of solar energy, on average ASEAN countries receive daily insolation, a measure of solar radiation energy received, of between 4 and 7 $kWh/m^2$. This has already facilitated high penetration of solar photovoltaic in Indonesia, Philippines, Thailand and Vietnam for off-grid applications, such as water pumping, residential and street lighting, telecom networks and navigational aids. Philippines is the second-largest user worldwide of geothermal energy for power generation, followed by Indonesia. Although the latter's technical potential is substantially larger, it remains underexploited. The technical potential for wind energy is significant, at around 120 TWh, with the best locations found in Philippines and Vietnam.

In the 450 Scenario, the role of renewables in ASEAN total primary energy supply increases significantly, compared to the Reference Scenario. But for such an increased share of the region's renewable energy potential to be realised, significant barriers (not solely limited to economics) will need to be overcome, primarily through government action. The most important are:

- Electricity sector reforms, including fair and non-discriminatory grid access, fair and transparent pricing of transmission and distribution services, and unbundling of vertically integrated electricity sector services.
- Energy market distortions, especially with regard to electricity and oil product subsidies.
- Administrative hurdles in obtaining planning permission and environmental licensing.
- Absence of adequate and targeted incentives for renewables.
- The inability of the electricity grid to absorb and balance large-scale variable renewable power generation.
- Lack of awareness among decision makers and financial institutions.
- Lack of suitable financing options.

Power generation is expected to be the major source of growth in $CO_2$ emissions in Southeast Asia, accounting for over half the increase over the *Outlook* period. Transport-related $CO_2$ emissions in Southeast Asia increase by 90% to 435 Mt in 2030. This is primarily due to rising demand for individual mobility and freight, which more than offsets the expected improvements in vehicle efficiency across the region. The industrial sector (comprising manufacturing such as iron and steel, chemicals, non-metallic minerals and paper, as well as related products and processes) accounts for 14% of the projected increase in Southeast Asia's energy-related $CO_2$ emissions.

Despite improvements in recent years, local air pollution remains a major public health issue in many parts of Southeast Asia, particularly in major cities such as Jakarta, Bangkok, Manila, Kuala Lumpur and Ho Chi Minh City. This is linked primarily to rising vehicle use, rapid rates of industrialisation and urbanisation, the heavy reliance on coal and the siting of industry close to residential areas. Fossil-energy use gives rise to various toxic and noxious emissions, notably sulphur dioxide ($SO_2$), carbon monoxide, particulate matter and nitrogen oxides ($NO_x$), which in turn contributes to the formation of ground-level ozone. These emissions create health problems, urban haze and acid rain.

In the Reference Scenario, Southeast Asia's emissions of particulate matter experience modest growth, reaching 3.8 Mt in 2030, 6% higher than the level in 2007. This low rate of growth reflects changes in fuel-use patterns by households (replacement of solid fuels with other energy forms) and better controls on sources in power plants, industry and road transport. Sulphur dioxide emissions in the Reference Scenario are also projected to increase slightly, from 2.6 Mt in 2007 to 3 Mt in 2030 due primarily to stricter controls on power plants and industry (Table 15.10). $NO_x$ emissions rise from 4.5 Mt in 2007 to 5.9 Mt in 2030.

**Table 15.10 • *ASEAN emissions of major pollutants in the Reference Scenario*** (Mt)

| | 2007 | 2015 | 2020 | 2030 | 2007-2030* |
|---|---|---|---|---|---|
| $SO_2$ | 2.6 | 2.3 | 2.5 | 3.0 | 0.5% |
| $NO_x$ | 4.5 | 4.3 | 4.5 | 5.9 | 1.2% |
| PM2.5 | 3.5 | 3.7 | 3.7 | 3.8 | 0.3% |

* Compound average annual growth rate.

## Energy investment

The Reference Scenario projections call for cumulative investment in energy-supply infrastructure in Southeast Asia of $1.1 trillion over 2008-2030 (Table 15.11), or around 2% of the region's annual average GDP. This includes spending both to expand supply capacity to meet rising demand, and to replace existing and future supply facilities retired during the projection period.

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Around 55% of the required investment goes into the power sector, reflecting the rapid growth projected for electricity demand and the capital-intensive nature of power projects. The oil and gas sectors require 18% and 23% of total investment, respectively. Coal-industry investment is much smaller, amounting to 3.3% of the total, as the production of coal is much less capital intensive than that of oil, gas or electricity.

Financing power-sector investment is expected to be a major challenge, especially for the poorer countries of Southeast Asia that rely heavily on public-sector finance. It is expected that a growing share of power-sector investment will come from private domestic and foreign sources, as countries push ahead with plans to liberalise and restructure their electricity markets and gradually to phase out subsidies to adopt market-reflective tariffs.

In the Reference Scenario, it is assumed that the ongoing development of the proposed Trans-ASEAN Gas Pipeline project boosts prospects for gas exploration and production by improving market access for otherwise stranded gas resources and reducing political risks by linking suppliers and customers in long-term relationships. Similarly, in the oil sector, it is assumed that moves to reduce legal and regulatory uncertainties and to improve the tax environment boost prospects for oil-sector investment, particularly in Indonesia.

**Table 15.11 • *ASEAN cumulative investment in energy-supply infrastructure in the Reference Scenario*** *($ billion in year-2008 dollars)*

| | 2008-2020 | 2021-2030 | 2008-2030 |
|---|---|---|---|
| Coal | 19 | 19 | 38 |
| Oil | 105 | 101 | 206 |
| Gas | 137 | 127 | 263 |
| Biofules | 3 | 1 | 4 |
| Power | 259 | 376 | 635 |
| **Total** | **523** | **624** | **1 146** |
| *Share of world* | *4%* | *5%* | *4%* |

## The 450 Scenario

As ASEAN primary energy demand and reliance on fossil fuels rapidly grows, so too will regional $CO_2$ emissions. In the Reference Scenario, a 3% per annum growth in energy-related $CO_2$ emissions is projected through to 2030 (see above). For ASEAN, the challenge of greenhouse-gas emissions is immediate. The region will be both a contributor to and a particular victim of the effects of climate change as it has centres of population and economic and agricultural activities concentrated in low-lying coastal zones that are very susceptible to rising sea levels. During the 14th ASEAN Summit (Thailand, March 2009), the ASEAN Heads of State/Government recognised the importance of addressing the challenge of climate change and the need for ASEAN countries to work closely together and with other partners for a successful outcome of the negotiations at the 15th Conference of the Parties (COP) to the United Nations Framework Convention on Climate Change (UNFCCC) (December 2009, Copenhagen).

In the 450 Scenario, it is assumed that the ASEAN countries adopt, on a national basis, a comprehensive set of policies and measures designed to curb greenhouse-gas emissions across all sectors. These policies and measures can be grouped into activities aimed at improving energy efficiency, promoting renewable energy sources and increasing investment in clean energy technologies. In addition, ASEAN countries are assumed to participate in international sectoral agreements covering the iron and steel, cement and passenger vehicles sectors, with countries setting efficiency standards relative to their means and their potential for emissions reduction. The benefits of the related greenhouse-gas emission reductions are supplemented by the benefits of increased security of supply, improved energy efficiency and lower local pollution. Although the countries in the ASEAN region may not initially have quantified country-wide obligations under a post-2012 climate framework, the national policies and measures they are assumed to adopt in the 450 Scenario will be a necessary component of effective global abatement action.

In the 450 Scenario, implementation of the emission reductions policies and measures in developing countries, including those in ASEAN, is assumed to involve a degree of co-funding through international financial transfers. Financial support for mitigation measures in developing countries can be provided through a range of channels, including the international market for emission-reduction credits and international financial transfers and loans. The Clean Development Mechanism (CDM) currently enables many types of emission-reduction projects in non-Annex I Parties to earn credits that can be used by Annex I Parties to comply with their national emissions limitation commitments under the Kyoto Protocol. The Global Environment Facility, the World Bank, the Asian Developement Bank and other institutions provide financial support for mitigation measures in developing countries.

## Energy demand

In the 450 Scenario, ASEAN primary energy demand grows at an average 2.1% per year to 2030, compared with 2.5% in the Reference Scenario (Table 15.12). Demand approaches 825 Mtoe in 2030 – a reduction of about 9% relative to the Reference Scenario. By 2030 the energy saving, relative to the Reference Scenario, is comparable to the current energy consumption of Malaysia.

Energy intensity falls much faster in the 450 Scenario than in the Reference Scenario, particularly towards the end of the *Outlook* period. By 2030, primary energy intensity is 9% lower than in the Reference Scenario. The greatest challenge to realise this improvement is to encourage private consumers to invest in energy efficiency by making their homes more energy efficient – including the purchase of more efficient electrical appliances – and by driving more efficient cars.

Compared to the Reference Scenario, ASEAN demand for coal falls, in absolute terms, further than demand for any other fuel. It grows, over the projection period, by 3.0% per year on average in the 450 Scenario, compared with 4.7% per year in the Reference Scenario. Policies to promote energy efficiency, nuclear, renewables and more efficient coal-fired power plants account for the bulk of this difference in coal demand.

ASEAN oil demand rises to 3.8 mb/d in 2020 (close to 0.4 mb/d less than in the Reference Scenario) and in 2030 to 4.4 mb/d (around 0.9 mb/d less). More than half of the savings in oil demand occur in the transport sector, linked to efficiency improvements and the expansion of biofuels programmes. ASEAN demand for natural gas is projected to increase at a much slower rate in the 450 Scenario, compared to the Reference Scenario, growing at 1.1% per year.

Demand for low-carbon energy, such as hydropower, biomass and other renewables and nuclear power, increases from 141 Mtoe in 2007 to 298 Mtoe in 2030 (about 37% greater than that in the Reference Scenario). Other renewables, such as wind and solar power, receive a significant boost, rising six-fold between 2007 and 2030. Modern biomass use increases – particularly in power generation – to around 89 Mtoe in 2030. Nuclear power grows significantly faster than in the Reference Scenario, to reach nearly 18 Mtoe in 2030.

**Table 15.12 • ASEAN primary energy demand in the 450 Scenario** (Mtoe)

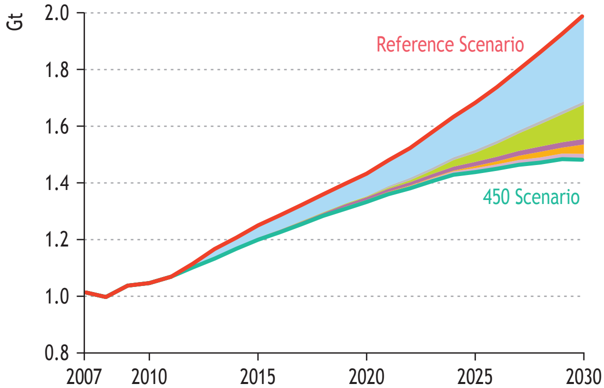
| | 2007 | 2020 | 2030 | Average annual growth rate 2007-2030 (%) | % change in 2030 from the Reference Scenario |
|---|---|---|---|---|---|
| Coal | 76 | 139 | 150 | 3.0 | -31 |
| Oil | 179 | 192 | 224 | 1.0 | -16 |
| Gas | 117 | 139 | 152 | 1.1 | -23 |
| Nuclear | 0 | 2 | 18 | n.a. | 340 |
| Hydro | 6 | 9 | 15 | 4.2 | 45 |
| Biomass | 120 | 145 | 176 | 1.7 | 11 |
| Other renewables | 15 | 30 | 89 | 8.1 | 101 |
| **Total** | **513** | **656** | **825** | **2.1** | **-9** |

## Energy-related $CO_2$ emissions

ASEAN countries still generate a significant increase in emissions in the 450 Scenario, but to a lower extent than in the Reference Scenario. In the 450 Scenario, the region's energy-related $CO_2$ emissions in 2030 are 1.5 gigatonnes (Gt), as opposed to 2.0 Gt in the Reference Scenario. Per-capita emissions also continue to increase, from 1.8 tonne of $CO_2$ in 2007 to 2.1 tonne of $CO_2$ in 2030.

In 2030, 319 Mt of avoided $CO_2$ emissions – 62% of the total reduction in the 450 Scenario – stem from efficiency improvements in the end-use sectors and in power generation. A further 33 Mt of $CO_2$ savings come from the operation of an additional 7 GW of nuclear capacity, beyond that built in the Reference Scenario (Figure 15.14).

**Figure 15.14 • ASEAN energy-related $CO_2$ emissions reduction by source in the 450 Scenario compared with the Reference Scenario**




| | Abatement ($Mt\ CO_2$) 2020 | Abatement ($Mt\ CO_2$) 2030 |
|---|---|---|
| Efficiency | 84 | 319 |
| End-use | 82 | 308 |
| Power plants | 1 | 11 |
| Renewables | 2 | 121 |
| Biofuels | 9 | 20 |
| Nuclear | 3 | 33 |
| CCS | 1 | 18 |

## Incremental investment and co-benefits

The stabilisation of greenhouse-gas emissions at 450 parts per million (ppm) will require substantial investment in low-carbon technologies and energy efficiency. For the ASEAN region, $388 billion – additional to the investment already assumed in the Reference Scenario – is invested in the energy sector in the period 2010-2030 in low-carbon technologies and energy efficiency. This sum includes capital spending by businesses and spending by individuals on cars, equipment, appliances and other energy-related items.

The largest increase in investment is in transport, most of this $222 billion goes into the purchase of more efficient vehicles. Additional investment in buildings amounts to $74 billion. Total investment in the power sector – including generation, transmission and distribution – is $54 billion higher than in the Reference Scenario. This is a result of the broader uptake of less carbon-intensive generating options at higher per-unit capital costs.

The increased demand-side investment required in the 450 Scenario is partly offset by the reduction in investment on the supply side, due to lower energy demand. In the 450 Scenario, investment in coal, oil and gas supply in ASEAN is lower than in the Reference Scenario by $124 billion over 2008-2030.



The measures taken to contain $CO_2$ emissions also contribute to the energy security of Southeast Asia and reduce local air pollution by reducing emissions of particulate matter, $NO_x$ and $SO_2$. The region's oil imports in the 450 Scenario reach 3.4 mb/d in 2030, 12% lower than in the Reference Scenario. In 2030, the net oil-import bill is reduced by nearly $51 billion, or 31%, compared with the Reference Scenario. The fuel bill as a share of regional GDP increases from 1.6% in 2007 to 4.8% in 2030 in the Reference Scenario, while it is 3.3% in 2030 in the 450 Scenario, making the economy less vulnerable to international fuel-price fluctuations.

## ASEAN energy co-operation

In 1997, the ASEAN Heads of State adopted the ASEAN 2020 Vision. This envisaged, *inter alia*, an energy-interconnected Southeast Asia, achieving economic and security gains from more efficient and diversified utilisation of regional energy resources.

The concept of an ASEAN Plan of Action for Energy Co-operation (APAEC) was initiated by ASEAN Energy Ministers in 1998, as a means of giving effect to the energy components of the ASEAN 2020 Vision. The plan for the period 1999-2004 involved, for the first time, the region-wide participation of all ten ASEAN member countries.

The ASEAN APAEC for 2010-2015 is the third in the APAEC process (Table 15.13). It recognises that a secure and sustainable energy supply is crucial to the transformation of the ASEAN region into a resilient, prosperous, rules-based and integrated economic community. It also recognises the importance of engaging internationally in the global energy policy debate. The APAEC 2010-2015 focuses on seven programme areas:

- ASEAN Power Grid (APG)
- Trans-ASEAN Gas Pipeline (TAGP)
- coal and clean coal technology
- energy efficiency and conservation
- renewable energy
- regional energy policy and planning
- civilian nuclear energy.

The "ASEAN way", characterised by consensus-based decision making and respect for the sanctity of state sovereignty, is generally viewed as essential to enhanced co-operation among the ten ASEAN member countries. However, it has also been criticised as hindering progress and the current APAEC seeks to meet this criticism by speeding up the pace of implementation of the APAEC strategies and tasks. Specifically, it strengthens arrangements for co-ordination and monitoring including a mid-term evaluation process and a scorecard to capture – at a glance – the milestones achieved.

The pace of implementation and, most importantly, the sustainability of the APAEC will hinge on the willingness of individual ASEAN countries to act to reform and liberalise their energy sectors. This particularly involves action on cost-reflective fossil-fuel pricing and electricity tariffs, and removing fuel and tariff subsidies. International experience has shown that such action is crucial to encourage sustained private-sector investment and the deployment of renewable energy, energy efficiency and clean energy technologies.

**Table 15.13 • ASEAN Plan of Action for Energy Co-operation, 2010-2015**

| Programme area | Implementing body | Strategies |
|---|---|---|
| ASEAN Power Grid (APG) | Heads of ASEAN Power Utilities and Authorities (HAPUA) | Accelerate the development of the ASEAN Power Grid Interconnection projects.<br>Optimise the generation sector *vis-à-vis* the available indigenous energy resources in the region.<br>Encourage and optimise the utilisation of ASEAN resources, such as funding, expertise and products to develop the generation, transmission and distribution sectors. |
| Trans-ASEAN Gas Pipeline (TAGP) | ASEAN Council on Petroleum (ASCOPE) | Collectively implement the ASEAN MOU on the TAGP.<br>PERTAMINA and PSC partners undertake detailed feasibility study for the East Natuna gas field development.<br>Respective member countries to implement the approved Roadmap for TAGP.<br>ASCOPE Gas Centre (AGC) to implement the approved 5-year Work Programme. |
| Coal and clean coal technology | ASEAN Forum on Coal (AFOC)<br>ASEAN Centre for Energy (ACE) as secretariat | Strengthen the institutional and policy framework and build an ASEAN coal image.<br>Promote coal and clean coal technologies.<br>Promote intra-ASEAN coal trade and investment.<br>Enhance environmental planning and assessment of coal projects. |
| Energy efficiency and conservation | Energy Efficiency and Conservation Sub-sector Network (EE&C-SSN)<br>- ACE as Secretariat | Develop energy-efficiency policy and build capacity.<br>Raise awareness and disseminate information. Facilitate energy-efficiency financing.<br>Promote good energy-management practices, especially for industrial and commercial sectors. |
| Renewable energy | Renewable Energy Sub-sector Network (RE-SSN)<br>- ACE as Secretariat | Increase the development and utilisation of RE sources to achieve the 15% target share of RE in ASEAN power-generation mix.<br>Enhance awareness and information sharing and strengthening networks.<br>Promote intra-ASEAN co-operation on ASEAN-made products and services.<br>Promote renewable energy financing scheme.<br>Promote the commercial development and utilisation of biofuels. Develop ASEAN as a hub for renewables. |
| Regional energy policy and planning | Regional Energy Policy and Planning Sub-sector Network (REPP-SSN)<br>- ACE as Secretariat | Enhance energy policy and supply security information sharing network.<br>Effectively manage the implementation of APAEC 2010-2015.<br>Conduct capacity building in energy and environmental policy planning and energy supply security assessment.<br>Prepare regional energy *Outlooks* and conduct ASEAN energy policy reviews and analysis series.<br>Strengthen collaboration and dialogues with ASEAN partners and with national, regional and global institutions. |
| Civilian nuclear energy | Nuclear Energy Co-operation Sub-sector Network | To forge ASEAN-wide nuclear energy co-operation for electricity generation. |

To establish a multi-country energy market, ASEAN countries will have to continue to expose their energy-supply industries to open competition, to unbundle vertically integrated, state-owned enterprises, and to establish independent and authoritative national regulatory agencies. A multi-country market will require harmonised technical and regulatory standards, common policies and pricing regulation, third-party grid and pipeline access, and, ultimately, the establishment of a regional regulator. These elements will demand some flexibility in pursuing the "ASEAN way".

Three key areas of the ASEAN energy co-operation agenda are examined below, namely the ASEAN Power Grid (APG), the Trans-ASEAN Gas Pipeline (TAGP) and the ASEAN Petroleum Security Agreement (APSA).

## The ASEAN Power Grid

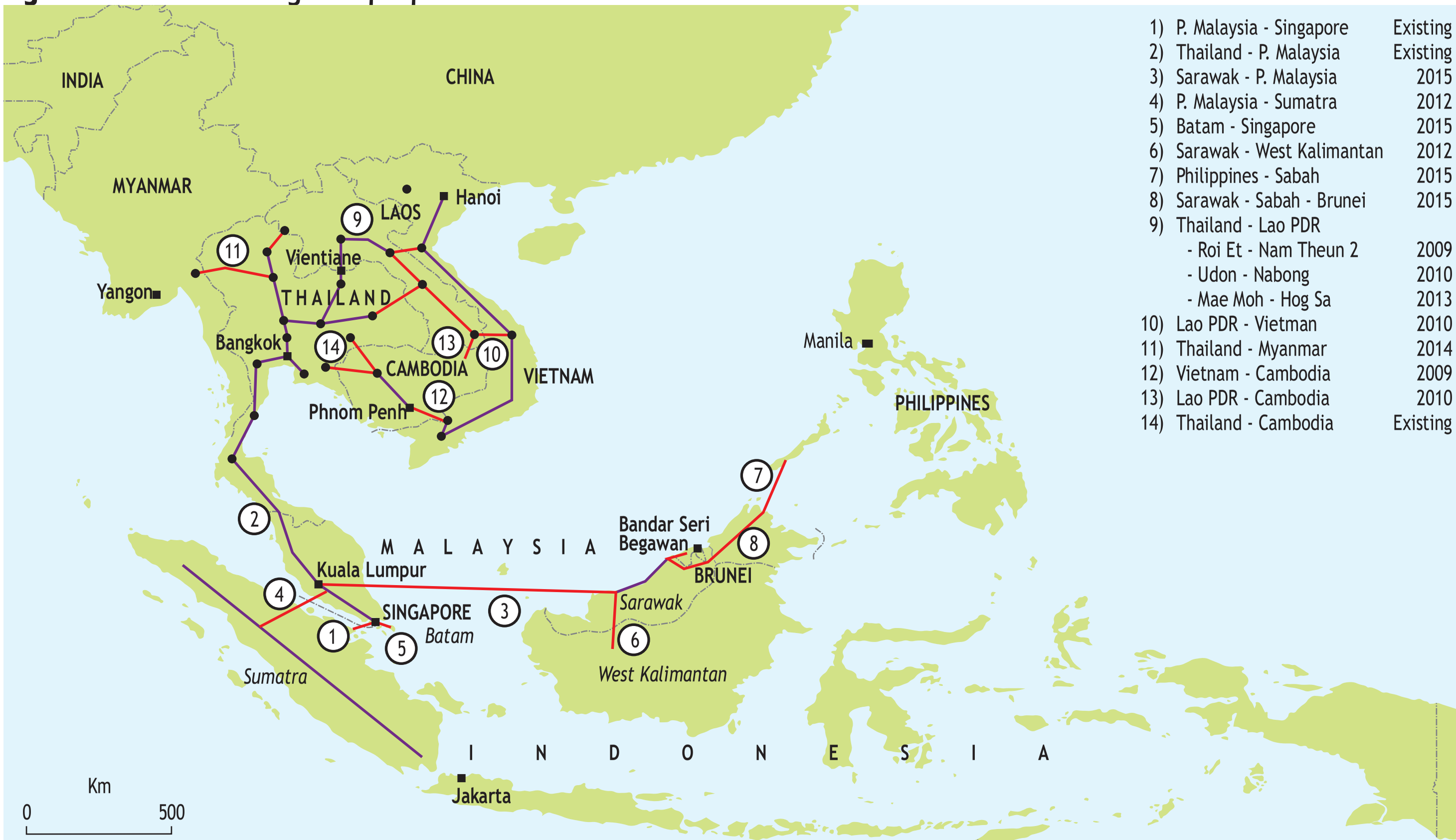
Interconnection of electricity systems in Southeast Asia began in 1971 when the Nam Ngum 1 hydropower project between Laos and Thailand commenced operation. Power-exchange agreements were later made between Thailand, Malaysia and Singapore in 1978, which involved two interconnections between Malaysia and Thailand, and between Malaysia and Singapore. In 1981, the power utilities and authorities of the ASEAN member countries established the Heads of ASEAN Power Utilities and Authorities (HAPUA). The task of the HAPUA was to establish an electricity interconnection network between the ASEAN member countries to facilitate cross-border electricity trading and to improve access to energy services. This gave rise to the concept of the ASEAN Power Grid (APG).

The APG is a flagship programme mandated in 1997 by the ASEAN Heads of States/Governments under the ASEAN Vision 2020 of ensuring regional energy security while promoting the efficient utilisation and sharing of resources. HAPUA has the task of steering the development of the APG. In 2003, the HAPUA conducted its ASEAN Interconnection Masterplan Study (AIMS) to formulate an ASEAN electricity interconnection master plan that met the needs for supply, transmission and distribution, as well as security and electricity trading between ASEAN countries.[8]

The HAPUA is now working towards 14 identified interconnection projects for the APG: initially on cross-border, bilateral terms, then gradually expanding to a sub-regional basis, particularly in the ASEAN Sub-region of Cambodia, Laos, Myanmar and Vietnam (CMLV Sub-region), and, finally to a totally integrated Southeast Asian power grid system (Figure 15.15). Currently, three interconnections are in operation, under bilateral agreements and in the ownership of the power utilities/authorities involved. An additional 11 projects are planned for interconnection through to 2015.

8. The AIMS Study is currently being revised (AIMS II) and its findings will be completed in 2010.

**Figure 15.15 • Existing and proposed ASEAN Power Grid interconnections**




The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Sources: HAPVA Secretariat

## The Trans-ASEAN gas pipeline

The Trans-ASEAN Gas Pipeline (TAGP) aims to interconnect the gas pipeline infrastructure of each of the ASEAN member countries and enable gas to be traded across their borders (Figure 15.16). The ASEAN Council of Petroleum (ASCOPE), the regional association of ASEAN member countries' national oil companies (NOCs), has the task of steering the development of the TAGP Master Plan.

Historically, the ASEAN gas utilities have been state-owned, vertically integrated monopolies held by the NOC or by their gas transmission/distribution subsidiary. Some measure of unbundling and liberalisation has been undertaken in some ASEAN countries, notably in Philippines, Singapore and, to a lesser extent, in Indonesia. However, domination of the gas supply and distribution industry by state enterprises remains the norm, which means that gas producers cannot sell directly to consumers. As in the case of the APG, limitations of the steps taken so far towards gas unbundling and liberalisation are a major hurdle to the emergence of a common multi-country system.

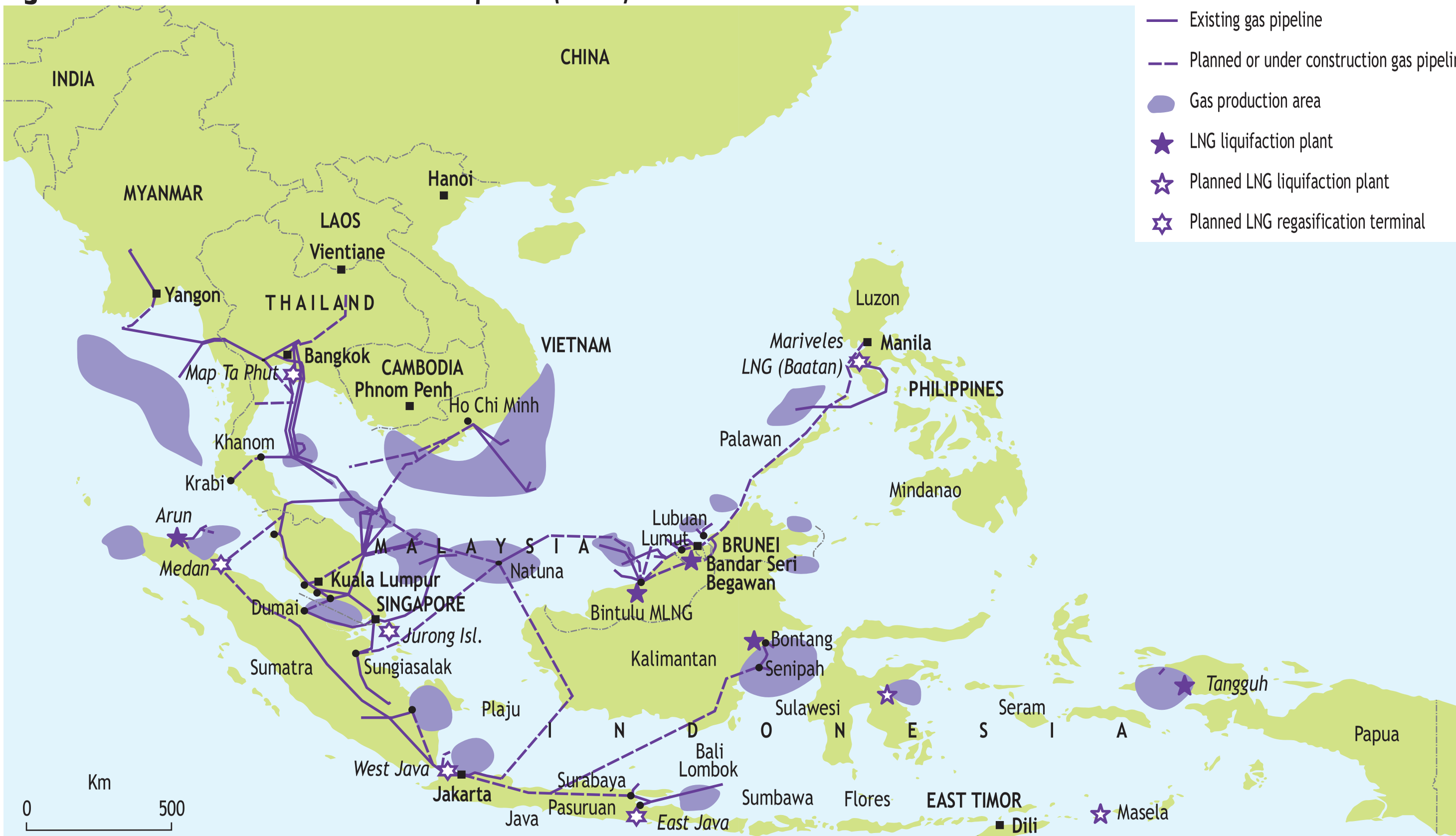
The original TAGP Masterplan 2000 aimed to develop an ASEAN regional gas grid by 2020, largely by linking the existing and planned gas pipeline networks of the ASEAN member countries. Under the revised TAGP Masterplan 2008, these interconnections are to be accelerated by 2015. They are seen as a key driver of growth for the energy-consuming sectors of the ASEAN economies.

Nine bilaterally interconnected gas pipelines, with a total length of approximately 2 600 km, are currently operating (Table 15.14). These interconnections are inter-country pipelines delivering gas on long-term contract from a main producer (often the state's NOC) to a main buyer (again, often the state NOC or the state-owned gas power company).

**Table 15.14 • *Existing bilateral gas pipeline interconnections***

| Existing interconnections | Length (km) | Commissioning date |
|---|---|---|
| 1. Peninsular Malaysia - Singapore | 5 | 1991 |
| 2. Yadana (Myanmar) - Ratchaburi (Thailand) | 470 | 1999 |
| 3. Yetagun (Myanmar) - Ratchaburi (Thailand) | 340 | 2000 |
| 4. West Natuna (Indonesia) - Singapore | 660 | 2001 |
| 5. West Natuna (Indonesia) - Duyong (Malaysia) | 100 | 2001 |
| 6. South Sumatra (Indonesia) - Singapore | 470 | 2003 |
| 7. Malaysia - Thailand Joint Development Area | 270 | 2005 |
| 8. Malaysia - Singapore | 4 | 2006 |
| 9. Malaysia - Vietnam Joint Development Area | 325 | 2007 |

**Figure 15.16** • **The Trans-ASEAN Gas Pipeline (TAGP)**




The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: ASCOPE Secretariat

Fundamental to the longer-term development of the TAGP is the bringing into commercial production of the large Indonesian offshore gas field, Natuna D-Alpha, in East Natuna. This block contains some 1.3 tcm of recoverable gas reserves (approximately 43% of Indonesia's proven reserves). However, its development has been deferred pending clarification of its commercial viability and of technical considerations related to the very high $CO_2$ content (70%) of the gas. The 50-50 venture in Natuna D-Alpha between PERTAMINA (Indonesia's state-owned petroleum company) and ExxonMobil did not survive to the stage of production; the Indonesian government terminated its contract with ExxonMobil in 2007, leaving PERTAMINA in charge. A number of potential foreign partners are being considered to develop the field in partnership with PERTAMINA. Assuming East Natuna proceeds, the updated TAGP Masterplan involves the construction of 4 500 km of pipelines, mainly undersea, worth some $7 billion (Table 15.15).

ASEAN member countries recognise that the APG and the TAGP will create economic efficiencies and stimulate investment in their energy-supply industries and trade. However, some countries are reluctant to yield any appreciable measure of control over their energy sector policy and regulation, which are often perceived as elements of national energy security.

**Table 15.15 • *Planned gas pipeline interconnections***

| Proposed interconnections | Length (km) | Commissioning date |
|---|---|---|
| 1. East Natuna (Indonesia) - Erawan (Thailand) | 1 500 | Commissioning date will be approx. Seven years from East Natuna gas supply sanction. |
| 2. East Natuna (Indonesia) - Kerteh (Malaysia) | 600 | Approximate volume to make each pipeline viable is 28 mcm/d. |
| 3. East Natuna (Indonesia) - Java (Indonesia) | 1 400 | |
| 4. East Natuna (Indonesia) - Vietnam | 900 | |
| 5. East Natuna (Indonesia) - Brunei Darussalam - Sabah (Malaysia) - Palawan (Philippines) | | This proposed interconnection, particularly with Philippines, is deferred due to commercial and technical considerations. |

To date, the existing power interconnections in ASEAN have been developed through direct government-to-government negotiation, with subsequent bilateral agreement (and ownership) by the power utilities concerned. They are inter-country connections that deliver electricity from one main producer to one main buyer on long-term contracts. Similarly, the existing nine gas pipelines are based on bilateral arrangements between two member countries, with no pipelines passing through a transit country. Consequently, neither the existing electricity nor gas model matches up to the requirements for multi-country interconnection and third-party access that characterise the APG and TAGP. They are not part of a common system shared by the member countries, featuring both term contract sales and spot-trading supply between network suppliers and consumers.

Consequently, for both the APG and the TAGP, much remains to be developed and implemented by each ASEAN member country, including:

- Establishment of independent and authoritative national electricity and gas regulators, tasked with regulating in the long-term interests of consumers and the supply industry.
- Co-operation and co-ordination between national regulators and, in the longer term, establishment of regional regulators.
- Regional harmonisation of safety and technical specifications, as well as legal and regulatory frameworks, including issues of jurisdiction and responsibility over interconnections.
- Agreement on:
  - third-party access and a transit code, including the issuance of permits and licenses;
  - some standardisation of contractual arrangements;
  - transparency and unbundling of generation and transmission pricing; and
  - unbundling and liberalisation of the supply industry to allow the entry of more players, and more flexible investment policies (upstream and downstream sector) to encourage an influx of capital.
- A co-operation and co-ordination code between national TSOs and, in the longer term, establishment of a regional TSO.
- Amendment of policies likely to deter inward investors, including consumer subsidies and obligations on producers to assign some proportion of their production to local use.

## ASEAN oil security

### *National arrangements*

All ASEAN member countries recognise the need to establish a national policy for energy emergency preparedness and to adopt measures to diminish their growing vulnerability to an oil supply disruption. This is particularly so for the large net oil-importing economies of Philippines, Thailand, Singapore and more recently, Indonesia. Within a few years, the same will also apply to Malaysia. Financial constraints have led ASEAN governments to hesitate to make commitments to strategic stocks. Instead, most ASEAN countries have some form of mandatory control over the level of operational stocks held by the petroleum refiners and importers, and of their release in times of crisis. Current national policies and measures reflect the varying economic and energy supply circumstances of the member countries:

- *Singapore* maintains an investment and regulatory regime in which the private sector will invest, diversify supply sources and maintain healthy levels of company stocks. Its obligatory crude oil stockpiling was abolished in 1983.

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- *Indonesia* imposes a mandatory stockholding obligation on its NOC, PERTAMINA. Emergency buffer reserve provisions were contained in its new *Energy Law* in August 2007, and the recently created National Energy Council, chaired by the president, is expected to formulate the country's national petroleum strategic stocks policy.
- *Malaysian* legislation endows the prime minister with authority to direct the operations of its NOC, PETRONAS, in an emergency, including full control over its operational stocks.
- *Philippines* legislation requires its oil refineries to maintain a minimum inventory level and the country has established a national Oil Contingency Plan to be implemented in the event of an oil supply disruption. It is continuing to develop its petroleum stockpiling policy.
- *Thailand*, under its current energy security legislation, the *Emergency Decree on Remedy and Prevention of Shortage of Fuel Oil, B.E. 2516 (1973)*, can control production, distribution, export and import of fuels, as well as the generation and distribution of electricity, and can impose rationing of fuels. The government also mandates levels of stocks of crude oil and petroleum products for Thai petroleum market participants. Thailand is currently reviewing its oil and gas emergency preparedness policy and measures.
- *Vietnam* is developing its Petroleum Stockpiling Master Plan. The Master Plan will examine in detail the country's long-term oil requirements, the least-cost options for oil stockpiling and distribution systems, and the structure and management of a national emergency response organisation. The country recently announced plans to invest $2.38 billion by 2015 to build a network of storage facilities for crude oil and refined products.

### *Regional co-operation*

As a regional grouping, ASEAN governments have recognised the need to go beyond their national arrangements for regionally based emergency preparedness and co-ordinated response measures. One driving force for this was growing recognition of the ASEAN region's responsibilities and vulnerabilities in relation to key Asian choke points for oil and LNG supply to the highly import-dependent economies of Southeast and Northeast Asia. In 1986, they signed the ASEAN Petroleum Security Agreement (APSA) which envisaged an ASEAN emergency petroleum-sharing scheme. However, the APSA was never activated and the shortages of crude oil and petroleum products during the late 1980s and 1990s were resolved by bilateral arrangements between ASEAN countries and through international commercial transactions.

In 1999, ASEAN energy ministers decided that the provisions of the APSA should be reviewed. As part of the review process, conducted by ASCOPE, the IEA was invited to present IEA experiences. Since that time, further input and assistance has been provided by the IEA and the ASEAN+3 (ASEAN+ China, Japan and Korea). In March 2009, the revised APSA and its Annex, the Co-ordinated Emergency Response Measures (CERM), were signed. The revised APSA seeks to provide for both short-term crisis response and for medium- and longer-term policy, including diversification of the energy mix, diversification of sources for each fuel and stimulation of energy-sector investment. Significantly, the 2009 APSA includes a crisis response mechanism called the Mechanism for the Operationalisation of the Co-ordinated Emergency Response Measures. This outlines the:

- CERM management structure;
- co-ordination provisions and lines of authority;
- trigger/activation and monitoring mechanisms; and
- arrangements for deactivation.

The functionality of the 2009 APSA/CERM will depend critically on each ASEAN member having in place its own national oil emergency response agency and response measures, especially stockpiles, and then on the development of the protocols to enable the ASCOPE Secretariat to put into effect and manage the ASEAN regional response in a timely fashion.

Some features of the revised APSA/CERM that call for further development include:

- The APSA is not triggered until an ASEAN "country(ies) in distress" has experienced a "critical shortage", namely a 10% shortfall for a continuous period of 30 days. For a member country, such as Indonesia, that consumes over 1 mb/d and has 20+ days of mandated stocks, this trigger point may be too remote.
- An ASEAN "country in distress" must also demonstrate that measures, such as demand restraint and fuel switching, have been implemented nationally before its "critical shortage" will trigger the APSA. Some ASEAN countries do not yet have the necessary legislation, implementing agency and protocols in place to take the necessary action at national level.
- A "critical shortage" can be due only to natural calamity, explosion of facilities or war. It does not appear to include shortages due to global oil supply disruption.
- The obligation on ASEAN countries is no more than to use their "best endeavours" to assist the "country in distress" and all measures are voluntary.
- Strategic oil stockpiling by each ASEAN member country is voluntary.
- There is only limited mention of pre-crisis preparation, such as data collection, establishment of national hotlines/contact points, information exchange, or consultation and co-ordination within ASEAN and co-ordination more globally.

Notwithstanding these issues, the 2009 APSA/CERM is a milestone ASEAN regional agreement. It offers a basis for further development and for potential harmonisation of responses between the IEA and the ASEAN in the event of a global oil-supply crisis.

# ASEAN-4 COUNTRY PROFILES

## Indonesia, Thailand, Malaysia and Philippines

### HIGHLIGHTS

- Indonesia, Thailand, Malaysia and Philippines currently account for 80% of ASEAN total primary energy demand. With their large populations and strong economic growth prospects, the four are projected to account for around three-quarters of incremental energy demand in ASEAN through to 2030. In the Reference Scenario, their collective oil imports quadruple to over 3 mb/d in 2030 — equivalent to the current production of the United Arab Emirates. They also add around 150 GW of new power-generation capacity by 2030 to meet growth in electricity demand.
- Indonesia is the world's fourth most-populous country and by far the biggest economy; it is also the largest energy producer and consumer in ASEAN. It is the world's leading steam coal exporter, a substantial LNG exporter and was, until 2004, a net oil exporter. Reducing energy subsidies, increasing energy sector investment and improving the electrification rate are among the key challenges facing the country. In the Reference Scenario, Indonesia accounts for 36% of the incremental energy demand in ASEAN to 2030. Indonesia remains an exporter of natural gas and coal, but is projected to import 1.3 mb/d of oil by 2030.
- Thailand is the second-largest energy consumer in ASEAN and is heavily dependent on imports — particularly oil but also natural gas, coal and electricity. A key challenge is to meet growing demand for electricity while improving the diversity of the power-generation mix. In the Reference Scenario, Thailand's energy demand grows at 2.3% per annum on average through to 2030. Thailand's dependence on oil imports rises to 82% in 2030, from 60% in 2008. Its gas imports more than double to 24 bcm in 2030 – equivalent to Algeria's LNG exports in 2007.
- Malaysia is the third-largest energy consumer in ASEAN and is heavily dependent on fossil fuels. It has significant energy resources and is a major exporter of LNG. In 2008, the country reduced energy subsidies, which were creating a significant fiscal burden. Malaysia's primary energy demand is projected to grow on average at 2.1% per year to 2030. While it is currently a net oil exporter, it is set to become a net importer soon after 2015.
- Philippines is the fifth-largest energy consumer in ASEAN (after Vietnam) and is heavily reliant on imported energy. In the Reference Scenario, energy demand in Philippines is projected to grow at 2.8% per year and double that of today by 2030. The country is seeking to reduce imports by developing renewables, including geothermal, of which it is already the world's second-largest producer. Improving electrification rates is an ongoing challenge.

# Indonesia

## Overview and assumptions

Indonesia is the world's fourth most-populous country and is spread over a large archipelago. It is by far the largest economy in ASEAN and accounted for 37% of the region's primary energy consumption and 53% of its production in 2007. Indonesia's primary energy demand increased more than three-fold between 1980 and 2007, (Table 16.1). With the exception of oil, Indonesia is self-sufficient in terms of energy supplies. The country became a net oil importer in 2004 and suspended its membership of the Organization of the Petroleum Exporting Countries (OPEC) in 2008. The frequent brownouts on the islands of Java and Bali, the result of insufficient power capacity investment, are a key energy challenge. Another challenge is to improve the electrification rate: supply currently reaches only 65% of the population.

**Table 16.1 • Key energy indicators for Indonesia**

| | Unit | 1980 | 2007 | 1980-2007** |
|---|---|---|---|---|
| Total primary energy demand* | Mtoe | 57 | 191 | 4.6% |
| Total primary energy demand per capita | toe | 0.39 | 0.84 | 2.9% |
| Energy intensity | toe/thousand dollar of GDP in PPP | 0.24 | 0.22 | -0.2% |
| Share of oil in total primary energy demand | % | 36% | 32% | n.a. |
| Energy-related $CO_2$ emissions*** | Mt | 69 | 377 | 6.5% |

* Includes traditional biomass.
** Compound average annual growth rate.
*** From fuel combustion only.

### *The political and economic outlook*

The Republic of Indonesia was established in 1945, following a long period of Dutch colonial rule. Indonesia's political system is a constitutional democracy, with a president who occupies the position of Head of State and Head of Government, and a legislature made up of a House of Representatives and a Regional Representatives' Assembly, which is mandated to deal with regional affairs. The current President, Dr. H. Susilo Bambang Yudhoyono, was elected as the sixth president of Indonesia in 2004 and re-elected for a second term in July 2009. Indonesia was one of the five original founding members of ASEAN in 1967, along with Malaysia, Philippines, Singapore and Thailand.

Indonesia has the largest economy in Southeast Asia, with a gross domestic product (GDP) of $908 billion (in purchasing power parity [PPP] terms) in 2008. GDP per capita stands at $3 978. In the midst of the Asian Financial Crisis of the late 1990s, Indonesia's GDP contracted by 13.7% and inflation rose to 77%. Over the past five years, the Indonesian economy has performed well and the government has significantly reduced the level of public debt.

The GDP of Indonesia grew at an impressive 4% in the second quarter of 2009 on a year-on-year basis, indicating that compared to its ASEAN neighbours it is holding up well through the global financial crisis. Nevertheless, the Indonesian government has taken steps to safeguard the economy by introducing a $6.3 billion dollar stimulus package, equivalent to 1.2% of the country's GDP. Around one-quarter of the package is made up of government spending, while the remainder is in the form of tax incentives. The Indonesian government expects GDP growth to slow in 2009 before picking up in 2010.

### Key assumptions

The projections in this *Outlook* assume that the Indonesian economy will grow on average by 4.7% per year from 2007 to 2015 (Table 16.2). Growth is assumed to slow thereafter as the economy matures, bringing down the average for the entire *Outlook* period to 3.7% per year. In the short term, the Indonesian economy is expected to experience slower growth due to the current financial crisis.

Indonesia's rate of population growth is declining, from 1.9% in the 1980s to 1.2% in 2007. This *Outlook* assumes that the population will increase by 0.8% per year on average to 2030, reaching 273 million. Today, around 50% of the population live in urban areas but this share is assumed to grow to 69% in 2030. In 2030, GDP per capita of Indonesia reaches $7 200.

**Table 16.2 • GDP and population growth assumptions in Indonesia in the Reference Scenario** (compound average annual growth rates)

| | 1980-2007 | 2007-2015 | 2015-2030 | 2007-2030 |
|---|---|---|---|---|
| GDP (PPP) | 4.8% | 4.7% | 3.1% | 3.7% |
| Population | 1.6% | 1.0% | 0.7% | 0.8% |
| GDP per capita | 3.2% | 3.6% | 2.4% | 2.8% |

## Energy policy

The Indonesian Ministry of Energy and Mineral Resources (MEMR) is the body responsible for the development of Indonesia's energy policy. Under the National Energy Policy, which was introduced in 2006, a target has been set to reduce the share of oil in the fuel mix to below 20% and to increase that of renewables to 17%, both by 2025. In 2007, Indonesia enacted the *Energy Law*, which is the country's first legislation on energy. Under the new law, the government gives priority to improving energy efficiency and increasing renewable energy development to enhance energy security and improve access to modern energy services.

The Indonesian government is attempting to increase the country's oil and gas output by optimising production at existing fields, including through employing enhanced oil recovery (EOR) techniques. It is also moving to open new acreages for exploration, with emphasis on deep sea and frontier regions, and to accelerate production from new fields. To improve access to natural gas, the Indonesian government is implementing the National Gas Transmission and Distribution Network Master Plan, which is aimed at transporting gas over long distances to demand centres, in particular to the largest market, on the island of Java. The Master Plan, when completed, will involve laying over 8 200 km of gas transmission pipeline for domestic supply and exports.

Indonesia is working towards reducing energy subsidies on a gradual basis and ensuring that subsidies are available only to low-income earners and small-scale industries. In October 2005, the government raised subsidised petroleum prices by around 125% in order to dampen demand and reduce budget expenditure. In May 2008, the government further increased gasoline and diesel prices by nearly 30%, and then in July 2008 raised LPG prices by 23%. In December 2008, following the drop in world oil prices, the government increased subsidies again, thereby reducing retail prices of gasoline and diesel. From May 2008 onwards, the government ceased paying subsidies to larger industrial electricity consumers. The MEMR estimated that this could save the government up to $270 million annually.

Indonesia has a programme to phase out the use of kerosene, in favour of liquefied petroleum gas (LPG), as a means to reduce government subsidy payments and harmful emissions. LPG stoves and small LPG cylinders have been distributed, free of charge, to urban households using kerosene stoves, starting with households living around the capital. There are plans to expand this programme to other cities. The objective is to eliminate the use of kerosene stoves in urban areas by the end of 2009.

The Indonesian government passed a new law on coal mining in December 2008, which allows the government to determine production levels for each commodity in each year on a province-by-province basis. Furthermore, it requires coal companies to meet domestic market obligations (DMO) before supplying export markets.

Although Indonesia has significant renewable energy potential, it remains largely under-utilised. According to the MEMR, the country's renewable potential includes 450 MW of small hydropower, 50 GW of biomass, 4.80 kWh/m$^2$/day of solar power, and good wind resources with speeds of 3-6 m/s. As of November 2008, Indonesia had over 5 GW of grid-connected renewables with an additional 86 MW under construction. While micro-hydro is still by far the largest contributor of renewable resources, the government is now actively exploring the potential to utilise wind energy. Currently, Indonesia ranks third in terms of geothermal power (1 043 MW) in the world after the United States and Philippines. Geothermal potential could be as much as 27 GW, if medium and low temperature geothermal are included.

The Indonesian government is drafting a law on new and renewable energy, which includes plans for both supply and demand, and the use of fiscal incentives. In 2008, Indonesia announced the 10 000 MW Crash Program Phase II, which aims to increase renewable generating capacity, particularly from geothermal and hydropower. Targets have been set to boost the capacity of micro-hydro power plants to 2.9 GW by 2025, geothermal plants to 9.5 GW by 2025, wind power to 0.97 GW by 2025, solar power to 0.87 GW by 2024 and biomass to 180 MW by 2020. Since January 2009, the transport, industry and power-generation sectors and fuel distributors in Indonesia have been obliged to use biofuel blends. The government has set the goal that biofuels should contribute 3% of the energy mix by 2015 and 5% by 2025. To boost the development of biomass, the Indonesian government plans to open 6 million hectares of new plantation area for sugar cane, cassava, palm and jatropha by 2025.

Indonesia lags behind many parts of ASEAN in terms of access to modern energy services. Although much progress has been made in recent years, it is estimated that 81 million people currently live without electricity. The government has set a target to increase electricity access to 93% of the population by 2025, from the current level of 65%. The challenges for rural electrification in Indonesia are significant, as the archipelago consists of 17 500 islands, of which 6 000 are inhabited. The low population densities and low average electricity consumption per capita make it difficult to achieve economies of scale in rural electricity. Many isolated and remote areas of the country have diesel generators with high operating costs. The Indonesian government has introduced programmes for the wider deployment in rural areas of renewable energies, such as solar and micro-hydro, in order to reduce dependence on diesel generators.

## Energy demand

### *Primary energy demand*

Indonesia's total primary energy demand stood at 191 million tonnes of oil equivalent (Mtoe) in 2007, the highest in the ASEAN region and the 13$^{th}$ highest in the world. Since 1980, total primary energy demand has grown rapidly (except during the Asian Financial Crisis of 1998/1999) at an average of 4.6% per year, while GDP has grown at 4.8% per year. Total primary energy demand was 0.84 toe per capita in 2007, less than one-fifth of the OECD average.

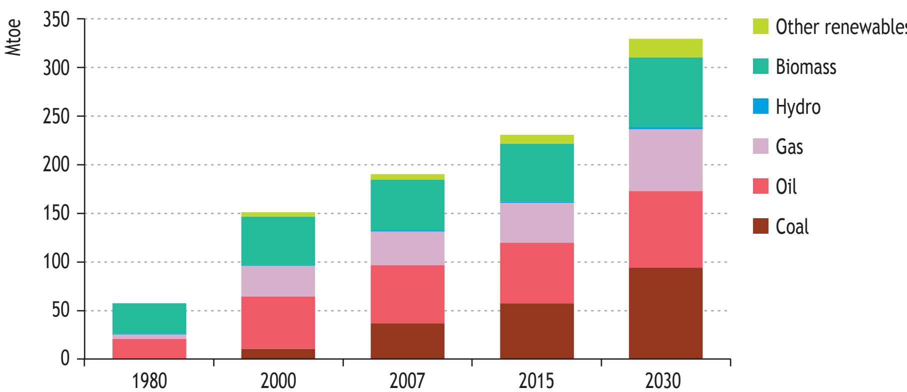
Oil demand in Indonesia almost tripled between 1980 and 2007, although the share of oil in total primary energy demand declined from 36% to 32% over the period, as a result of stronger growth in demand for coal and gas. Coal accounts for 19% of total primary energy demand and is the leading energy source in both the power sector and the industry sector. Primary demand for coal grew at a rapid 22% per year on average between 1980 and 2007. Gas demand, which currently represents 18% of total primary energy demand, also grew strongly through the period at 7% per year on average, led by demand from power generation and industry.

Despite Indonesia's significant hydro-electric potential, especially in Irian Jaya and Kalimantan, hydropower is not well developed due to geographical barriers. Indonesia is also rich in resources of geothermal energy. Its production of 7 TWh of electricity from geothermal sources in 2007 was the third-largest in the world, after the United States and Philippines (REN21, 2009). Indonesia has been studying the option of developing nuclear energy for more than 30 years, but plans to launch a significant nuclear programme were put on hold in June 2009.

In the Reference Scenario, Indonesia's primary energy demand is projected to grow at an average annual rate of 2.4%, from 191 Mtoe in 2007 to 330 Mtoe in 2030 (Figure 16.1). The share of fossil fuels in the primary energy mix rises from 69% in 2007 to 72% in 2030. Oil demand increases modestly, from 60 Mtoe in 2007 to 79 Mtoe in

2030, as robust demand growth from transport is offset by substitution away from oil in power generation. Oil's share of the energy mix declines from 32% in 2007 to 24% in 2030. Coal demand, mainly driven by power generation and industry, grows at 4.2% per year, the fastest among fossil fuels. By 2030, coal's share of primary demand reaches 29% to become the leading fuel in the energy mix. Gas demand grows from 34 Mtoe in 2007 to 63 Mtoe in 2030. Almost half of the increase in gas demand comes from power generation. The share of biomass in primary demand declines from 27% in 2007 to 22% in 2030, as living standards improve and residents use more LPG and electricity. Other renewables – a group that includes wind, geothermal and solar – grow briskly at 5.2% per year on average, their share in the energy mix increasing to 6% in 2030, from 3% today.

**Figure 16.1 • Indonesia's primary energy demand by fuel in the Reference Scenario**



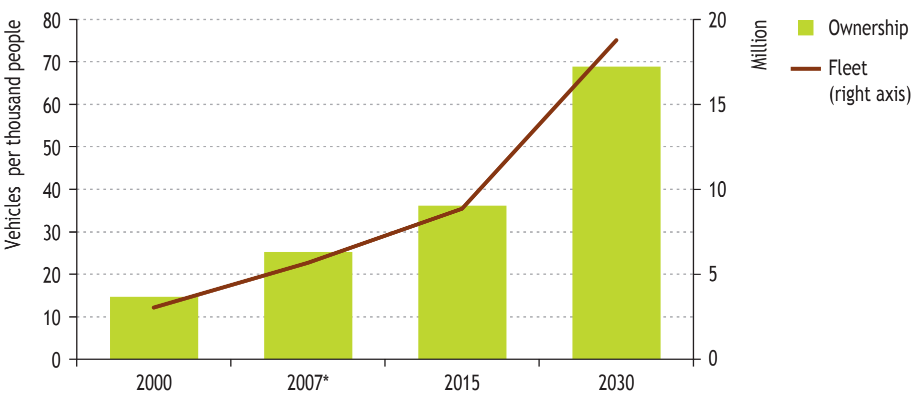

## *Final energy consumption*

Indonesia's total final energy consumption is projected to increase from 145 Mtoe in 2007 to 237 Mtoe in 2030, reflecting average growth of 2.2% per year. Final oil demand sees the largest increase in absolute terms, reflecting accounting for over one-quarter of the growth in total final energy consumption. Almost all of this increase is attributable to transport. Natural gas shows the fastest growth among fossil fuels, with an average yearly increase of 3.2%. The industry and the non-energy use sectors lead this growth. Final coal consumption (mainly by industry) increases by 2.2% per year and its share reaches nearly 15% in 2030. Electricity demand grows by 5.3% per year, with its share in final consumption rising from 7% to 14%. Consumption of biomass, mainly used in the residential sector, increases very modestly as the population growth rate slows and households switch to modern fuels as their incomes rise.

Energy demand in *industry* is projected to continue to grow strongly to 2030, at 2.7% per year, and its share in total final consumption to rise to 37% in 2030. Coal's share in industrial energy demand declines from 44% in 2007 to 40% in 2030, though coal use grows 2.2% per year to 2030. Gas demand grows at 3.8% per year, accounting for over one-quarter of industrial energy demand in 2030. The largest users of gas in Indonesia are power plants, followed by industrial users, such as fertilizer and petrochemical plants. Industrial oil demand is expected to decline at 0.7% per annum and its share of total industry energy consumption drops to 6% in 2030. Industrial electricity demand grows fastest at 4.8% per year to 2030. The share of electricity in total industrial energy consumption jumps from 8% in 2007 to 13% in 2030.

Energy demand in the *transport* sector is projected to grow at 3.3% per year. The share of transport energy demand in total final consumption is projected to rise from 17% in 2007 to 21% in 2030. In 2030, 61% of Indonesia's oil use is for transport, up from 41% in 2007. Rising incomes and the availability of affordable, locally manufactured vehicles leads to increased car ownership and driving, as well as to more freight transport. Passenger light-duty vehicle (PLDV) ownership is projected to grow from 25 vehicles per 1 000 people in 2007 to almost 70 vehicles per 1 000 people in 2030 (Figure 16.2). Indonesia becomes the biggest PLDV market in ASEAN, with a fleet amounting to 19 million vehicles in 2030. Demand for biofuels rises to 48 thousand barrels per day (kb/d) in 2030, accounting for 5% of transport oil demand.

**Figure 16.2 • Indonesia's PLDV ownership and fleet in the Reference Scenario**




*IEA estimate.

Energy demand in the *buildings* sector is projected to grow at an average annual rate of 1.3% over the *Outlook* period. Although biomass and waste, mainly used for cooking in the residential sector, together remain the biggest energy source in the sector, their use declines as residents switch to modern energy sources. Electricity demand grows at 5.5%, the fastest of all fuels. Rising living standards, rapid urbanisation and electrification programmes drive the growth in ownership of electrical appliances, particularly air conditioners. However, electricity consumption per capita in the residential sector in 2030 is still only about one-fifth of the current level in OECD countries. Growth in oil demand declines, compared with the historical rate. Within the residential and services sector, there is expected to be an ongoing switch from kerosene to LPG.

## Oil supply

### Resources and reserves

Indonesia is the largest oil producer in ASEAN and the second-largest, next to China, in Asia. Ultimately recoverable resources from discovered fields are estimated at 44 billion barrels (USGS, 2000). Indonesia has a proven reserves of 4 billion barrels (O&GJ, 2008) in 16 producing basins (out of a total of 60). The bulk of Indonesia's oil and gas reserves are located onshore and offshore in Central Sumatra and Kalimantan.

At current levels of production, Indonesia's proven reserves would sustain production for another 12 years. One of Indonesia's last undeveloped oilfields, located in East and Central Java, is the Cepu area. It contains proven reserves of 250 million barrels, and it is estimated that the area could hold up to 600 million barrels of recoverable oil.

### Production and trade

Indonesian oil production averaged around 1.0 million barrels per day (mb/d) in 2008. Output has been declining rapidly since the peak at just over 1.6 mb/d in the early 1990s, as the majority of the fields are maturing. Most of Indonesia's crude oil is produced onshore from two of the country's largest oilfields, Minas and Duri, which are in the province of Riau on the eastern coast of central Sumatra. The Duri field is the site of one of the world's largest EOR operations. Other principal oil-producing regions are South Sumatra, on and offshore East Kalimantan, offshore northeast of Java, Jambi on the east coast of central Sumatra and the Natuna area in the South China Sea. After delays due to disputes with landowners and the local government, the Cepu block project commenced production in late 2008, with peak production expected to reach 165 kb/d by 2012.

With rapidly rising oil demand and declining production, Indonesia became a net importer of crude oil and petroleum products in 2004. The country imported around 200 kb/d of oil in 2008 and suspended its membership of OPEC in the same year. Indonesia's current exports of petroleum products are limited to fuel oil and naphtha.

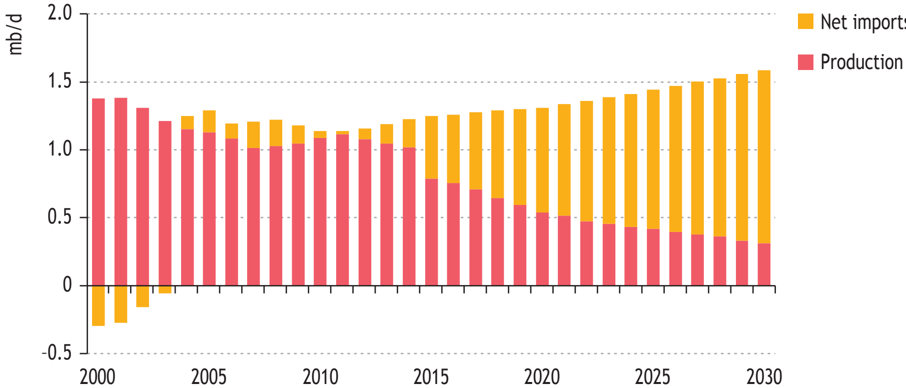
In the Reference Scenario, Indonesia's oil production is projected to fall to around 800 kb/d in 2015 and 300 kb/d in 2030 (Figure 16.3). As a result, the country relies on imports (1.3 mb/d) to meet 80% of its crude oil requirements by 2030.

### Refining capacity

As of January 2009, Indonesia had combined installed refining capacity of 1.1 mb/d at eight[1] refinery facilities. Since 2000, the refineries have maintained a combined output of around 950 kb/d. The largest refineries are the 348 kb/d Cilacap facility in Central Java, the 260 kb/d Balikpapan plant in Kalimantan and the 135 kb/d Musi Refinery in South Sumatra. Currently, Indonesia's refineries meet about two-thirds of domestic refined product demand.

1. Including six refineries (operated by PERTAMINA), one condensate splitter and one micro-refinery in Cepu.

**Figure 16.3 • *Indonesia's oil balance in the Reference Scenario***




Note: Negative numbers denote net exports.

## Natural gas supply

Indonesia, with 3 trillion cubic metres (tcm) of proven reserves of natural gas in 2008, has the largest gas reserves in the ASEAN region (O&GJ, 2008). At current levels of production, these would sustain production for another 39 years. According to the Indonesian government, more than 70% of the country's natural gas reserves are located offshore, with the largest found off Natuna Island, East Kalimantan, South Sumatra and West Papua (or Irian Jaya). Sizeable reserves were discovered in 2006 and 2007, after new exploration and development licences were issued.

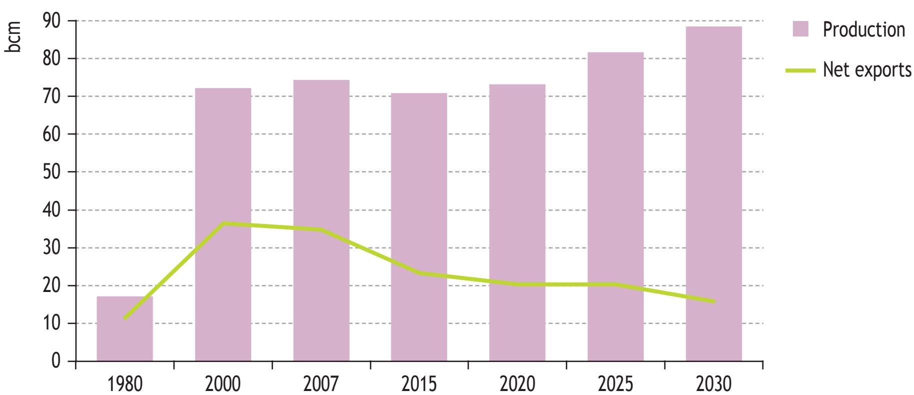
The Indonesian government has plans to develop the country's coalbed methane (CBM) resource, which is located mainly in Sumatra and Kalimantan and is estimated at 12.8 tcm. According to the plan, CBM will be supplied for local household and small power-generators. It will then be made available to other industrial, power-generation and transportation applications before finally being linked by pipeline to Java. In June 2008, the Indonesian government awarded two CBM licences in East Kalimantan and Riau province. According to the Indonesian oil and gas regulator, BPMigas, a combined $13 million will be spent developing the areas over the first three years. In August 2009, five more CBM blocks were awarded in South Sumatra and South Kalimantan, brining the total number of licensed CBM blocks to seven.

Indonesia's natural gas production reached 77 billion cubic metres (bcm) in 2008. There is a geographical mismatch between the main demand centres in Indonesia, namely Java and Bali, and the predominant supply sources in Natuna Island and South Sumatra. This gives rise to a need for extensive pipeline systems in Sumatra and Java. Other supply regions, such as Kalimantan and Papua, are not connected by pipelines with the largest consuming regions. Due to this mismatch, LNG import terminals are being considered in East Java, West Java and North Sumatra, to complement the existing and future pipelines. One of the terminals, in West Java, is currently planned to be operational by 2013, using gas supplied from Bontang and Tangguh.

Indonesia currently supplies 12% of the world's LNG from two production centres, at Arun in Aceh and Bontang in East Kalimantan. The most recent LNG project is in Tangguh, Papua, which has a capacity of 10.3 bcm and commenced production in 2009. The gas is supplied from onshore and offshore reserves in the Wiriagar and Berau Blocks. The project will initially provide exports to North America, China and Korea.

In the Reference Scenario, Indonesia's natural gas production is expected to remain broadly flat over the next decade (Figure 16.4). Beyond 2020, it is assumed that Natuna is developed, adding up to 20 bcm/year of production by 2030. This helps to temper the decline at other fields, many of which have already passed their peak. CBM is also expected to make a growing contribution in the last decade of the projection period. In total, gas production is projected to climb from 77 bcm in 2008 to close to 90 bcm in 2030.

**Figure 16.4 • *Indonesia's natural gas balance in the Reference Scenario***




## Coal supply

Indonesia has 6.8 billion tonnes of economically recoverable reserves of coal and some 85 billion tonnes of potential resources. About 41% of the reserve base is hard coal and, at current hard coal production levels, reserves would last 12 years (BGR, 2009). Indonesia's potential coal resources have grown by 34.4 billion tonnes since 2007, with 95% of the growth being hard coal (BGR, 2009). Combining both hard coal and lignite, Indonesia has a potential resource base of 92 billion tonnes, which would equate to nearly 350 years at the current rate of production. Most of Indonesia's coal reserves are located in South Sumatra and East Kalimantan; relatively smaller deposits of coal are found in West Java and in Sulawesi. Indonesian coals have a low ash and sulphur content (typically less than 1%), making them some of the cleanest coals in the world. But they are high in moisture and have a low average heating value.

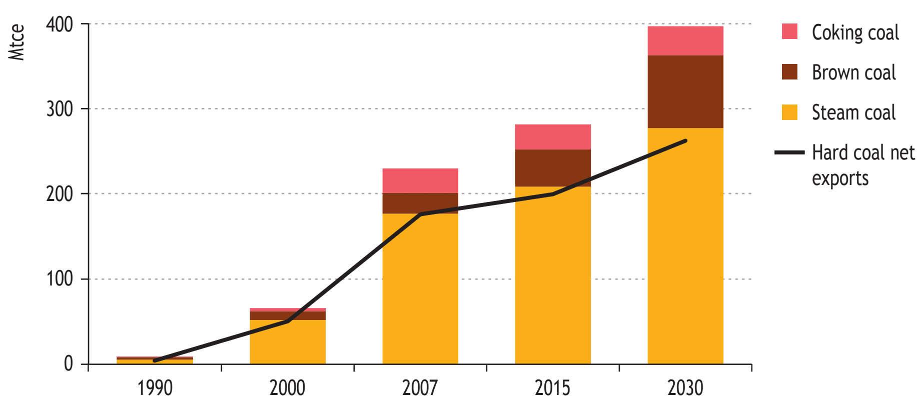
In 2007, Indonesian production reached 230 million tonnes of coal equivalent (Mtce) of coal, a level more than four times higher than 1998. Indonesia overtook Australia as the world's largest exporter of steam coal in 2005 and is projected to remain the leader over the projection period. Close to three-quarters of Indonesian coal exports have in the past gone to Asian customers, with Japan alone accounting for around 20% to 25%. Indonesia's new National Energy Policy aims to increase the share of coal in the country's energy mix. Further development and improvement of infrastructure are required to meet increasing demand, especially export demand from the emerging markets of China and India.

Indonesia has been considering the option of using lignite as a feedstock for the production of liquid fuels, and has raised the possibility that output from coal-to-liquids (CTL) plants could meet 2% of total primary oil demand by 2025. At the end of 2008, Sasol of South Africa expressed preliminary interest in developing a CTL plant in South Sumatra, with a production capacity of 1.1 mb/d by 2015.

In the Reference Scenario, Indonesia's coal production is projected to rise to 282 Mtce in 2015 and nearly 400 Mtce in 2030, representing an increase of nearly three-quarters compared to current levels (Figure 16.5). Of Indonesia's incremental coal production, 36% is from brown coal. This strong growth in brown coal reduces the share of hard coal in Indonesian production from about 90% at present to 80% by 2030. Indonesia's incremental brown coal production accounts for 70% of the increase in the world's brown coal output and, by attaining a level of 85 Mtce by 2030, Indonesia overtakes Germany to become the world's largest brown coal producer.

In the Reference Scenario, the majority of the increase in Indonesian hard coal production goes towards satisfying demand for exports. Indonesia's coal exports rise from 176 Mtce in 2007 to 200 Mtce in 2015 and 262 Mtce in 2030, accounting for one-fifth of the increase in global hard coal trade. Coal from Indonesia becomes increasingly attractive to the prosperous coastal regions of China, potentially displacing domestic Chinese production that must be railed and shipped long distances from Shanxi, Shaanxi and Inner Mongolia. Recent investments in Indonesia by the Chinese company Shenhua are part of a growing effort by Chinese and Indian companies to secure future coal supplies, including some for steel production.

**Figure 16.5 • Indonesian coal production by type and hard coal net exports in the Reference Scenario**




16

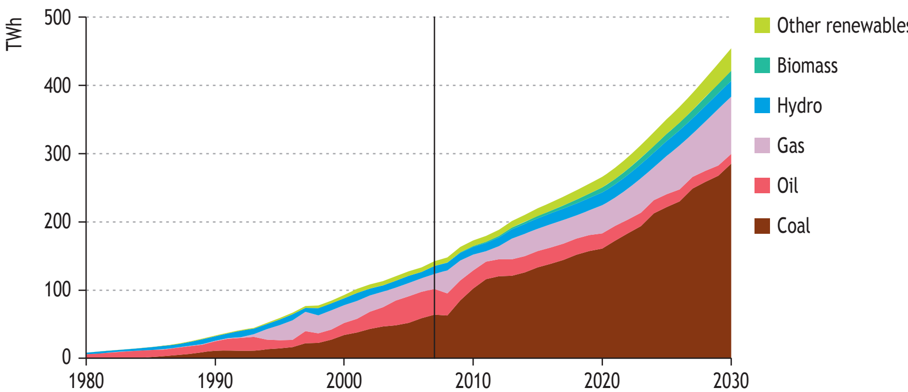
## Electricity generation

In 2007, Indonesia generated 142 TWh of electricity, of which 45% came from coal, 27% from oil, 16% from gas, 8% from hydro-electric source, and 5% from geothermal and other renewable sources. Indonesia's per-capita electricity consumption is currently only 7% of the OECD average.

Due to the current global economic crisis, electricity demand in Indonesia dropped in the fourth quarter of 2008, but it is expected to pick up rapidly, as consumer expenditure has since accelerated. Over the *Outlook* period, total generation is projected to increase by 5.2% per year, more than tripling by 2030. At 454 TWh, Indonesia's generation in 2030 is comparable to the current level of production in all the other ASEAN countries combined.

During the *Outlook* period, coal's dominance in the electricity generation mix rises still further, from 45% in 2007 to 63% in 2030 (Figure 16.6). Electricity generation from gas grows at 5.9% per year and the share of gas-fired generation increases from 16% in 2007 to 18% in 2030. Oil's share is expected to decline steadily, accounting for 3% of the generation fuel mix by the end of the *Outlook* period.

**Figure 16.6 • Indonesia's electricity generation by fuel in the Reference Scenario**




Through to 2030, the growth in electricity demand from the industrial sector is projected to increase at 4.8% annually, while the buildings sector also experiences strong growth of 4.7% per year, due to urbanisation and rising living standards. Growth in electricity demand is also boosted by government programmes aimed at ensuring 93% of all households have access to electricity by 2025. To meet this target, Indonesia needs to provide 1.3 million new connections every year.

Total installed power capacity is projected to increase almost three-fold, from 35 GW in 2007 to 101 GW in 2030 in the Reference Scenario. By 2030, coal makes up 45% of the total capacity, while 31% is gas-fired. Hydropower will represent a moderate 9% and other renewable, especially geothermal generation, make up 8%.

## Climate change and local pollution

Deforestation and land-use change are currently responsible for the bulk of Indonesia's greenhouse-gas emissions. Emissions from the energy sector remain relatively low, but are increasing rapidly. Indonesia's per-capita annual energy-related carbon dioxide ($CO_2$) emissions in 2007 reached 1.7 tonnes, compared to an average of 10.9 tonnes in the OECD. In the Reference Scenario, total energy-related $CO_2$ emissions are projected to rise by 2.8% per year on average, to 719 million tonnes (Mt) in 2030 (Table 16.3). Most of the additional emissions in Indonesia come from burning coal in power stations. Emissions from this source are 172 Mt higher in 2030 than 2007. Measured on a per-capita basis, Indonesia's emissions by 2030 reach nearly one-quarter of the current OECD average.

**Table 16.3 • *Indonesia's energy-related $CO_2$ and local air pollutant emissions in the Reference Scenario*** (Mt)

| | 1980 | 2000 | 2007 | 2015 | 2030 | 2007-2030* |
|---|---|---|---|---|---|---|
| $CO_2$ | 69 | 265 | 377 | 478 | 719 | 2.8% |
| $NO_x$ | n.a. | n.a. | 1.7 | 1.6 | 2.0 | 0.9% |
| PM2.5 | n.a. | n.a. | 1.6 | 1.7 | 1.8 | 0.4% |
| $SO_2$ | n.a. | n.a. | 1.1 | 1.0 | 1.2 | 0.5% |

* Compound average annual growth rate.

Sources: IEA analysis and IIASA (2009).

Indonesia suffers from high levels of airborne pollution, largely caused by the burning of fossil fuels in power stations, factories and vehicles. Total sulphur dioxide ($SO_2$) emissions in Indonesia reached 1.1 Mt in 2007. They come mainly from the power sector, reflecting its heavy reliance on coal- and oil-fired power plants. In the Reference Scenario, with implementation of the government's policy to switch away from oil, $SO_2$ emissions are expected to grow at just 0.5% per year between 2007 and 2030.

Emissions of nitrogen oxides ($NO_x$) come mainly from vehicles and the power sector. They are projected to rise at 0.9% per year on average in the Reference Scenario as Indonesian vehicle ownership triples. Emissions of particulate matter (PM), which come mainly from burning of biomass in households, are projected to increase from 1.6 Mt in 2007 to 1.8 Mt in 2030.

# Thailand

## Overview and assumptions

Thailand is the fourth most-populous country in the ten-member ASEAN group, with 64 million inhabitants. It has the second-largest economy in the region, or fourth largest on a per-capita basis. The country is the second-largest energy consumer in ASEAN and is heavily dependent on fossil fuels, particularly oil for transportation and natural gas for power generation (Table 16.4). Due to its limited and dwindling indigenous energy resources, Thailand is heavily dependent on imports to meet its energy needs – particularly oil, but also natural gas, coal and electricity. A key challenge the country will face over the medium and longer term is meeting growing demand for electricity while improving the diversity of the generation mix, as options such as coal and nuclear face strong public opposition.

**Table 16.4 • Key energy indicators for Thailand**

| | Unit | 1980 | 2007 | 1980-2007** |
|---|---|---|---|---|
| Total primary energy demand* | Mtoe | 22 | 104 | 5.9% |
| Total primary energy demand per capita | toe | 0.47 | 1.62 | 4.7% |
| Energy intensity | toe/thousand dollar of GDP in PPP | 0.19 | 0.19 | 0.05% |
| Share of oil in total primary energy demand | % | 49% | 40% | n.a. |
| Energy-related $CO_2$ emissions*** | Mt | 34 | 226 | 7.2% |

* Includes traditional biomass.
** Compound average annual growth rate.
*** From fuel combustion only.

## *The political and economic outlook*

Thailand is a constitutional monarchy with a Prime Minister, Abhisit Vejjajiva, as the Head of Government and a hereditary monarch, King Bhumibol, as the Head of State. King Bhumibol has limited power under the Constitution but is a symbol of national strength and is revered by Thai people. Prime Minister Vejjajiva took up duties as Thailand's 27th Prime Minister in December 2008, following a period of political and social turmoil.

After emerging from the Asian Financial Crisis, which originated in Thailand in July 1997 and soon spread to other Southeast Asian countries, Thailand enjoyed a period of relatively robust economic expansion, linked to strong growth in exports and tourism. By 2007, Thailand's GDP had reached $532 billion, in terms of purchasing power parity (PPP), ranking it the second-largest ASEAN economy after Indonesia. On a per-capita basis (in PPP terms), Thailand's GDP, at $8 340, ranks fourth in the ten-member ASEAN group, after Singapore, Brunei Darussalam and Malaysia.

The Thai economy is heavily trade focussed, with exports of goods and services accounting for around two-thirds of GDP. Manufactured products, most notably computers, hard drives, electrical goods, motor vehicles and automotive components contribute the bulk of Thailand's export earnings. Thailand is also one of the world's leading exporters of agricultural products, notably rice, fish, sugar and processed foods. The United States, Japan and China are Thailand's three largest export markets. Tourism also plays an important role in the Thai economy and is an important source of foreign exchange earnings and employment.

Thailand's economic growth weakened in 2008 to 2.6%, about half the level of 2007, due to the onset of the global economic slowdown. The contraction then became even more severe, as demand for Thailand's exports contracted in many of its key markets and tourism numbers slumped. In response, the government has launched several rounds of economic stimulus aimed at jump-starting the economy. These have included provision of low-interest loans for tourism-oriented small firms and funding for small rural enterprises. The plans include finance for investment in infrastructure projects, tax cuts, cash hand-outs for low-income earners, subsidies for transport and utilities, and expanded free education.

During the second quarter of 2009, Thailand's economy contracted by 4.9%, relative to a year earlier, although signs[2] started emerging that the economy was starting to improve. The latest estimates from the Asian Development Bank (ADB) are for a return to positive growth in Thailand in 2010.

### Key assumptions

The projections in this *Outlook* assume that Thailand's economy will grow on average by 3.3% per year from 2007 to 2030 (Table 16.5). In the near term, the economy is expected to experience slower growth, due to the current financial crisis. Thailand's rate of population growth has declined from about 1.5% in the 1980s to 0.6% in 2007. This *Outlook* assumes that the population will increase by 0.4% per year on average to 2030, reaching 70 million. Today, around 33% of the population live in urban areas, but this share is assumed to grow to 46% in 2030. In 2030, GDP per capita in Thailand is projected to reach $16 000.

**Table 16.5 • *GDP and population growth assumptions in Thailand in the Reference Scenario*** *(compound average annual growth rates)*

| | 1980-2007 | 2007-2015 | 2015-2030 | 2007-2030 |
|---|---|---|---|---|
| GDP (PPP) | 5.9% | 3.3% | 3.3% | 3.3% |
| Population | 1.2% | 0.5% | 0.3% | 0.4% |
| GDP per capita | 4.7% | 2.7% | 3.0% | 2.9% |

## Energy policy

Thailand's energy policy is based on five key objectives:

- Energy efficiency: To incentivise efficiency gains in the household, industrial, service and transportation sectors.
- Energy security: To boost investment in exploration and production of oil and natural gas, and in electricity, to enhance interconnection with energy resources in neighbouring countries, and to increase the supply of crude oil and natural gas in other countries for delivery to Thailand.
- Energy pricing: To ensure energy prices are adequate to stimulate investment in the energy industry, while maintaining affordable and high standards of quality, service and safety.



2. Thailand's gross domestic product rose a seasonally adjusted 2.3% sequentially in the second quarter, reversing from a 1.8% drop in the first quarter of 2009.

- Alternative energy: To deploy biofuels and use natural gas in the transportation and industrial sectors, and switch to domestic renewable energy sources in power generation.
- Sustainable development: To minimise the environmental impact of energy production and consumption, including through use of the Clean Development Mechanism (CDM).

The strategic vision for the development of Thailand's electricity sector is set out in the Power Development Plan (PDP 2007) which covers the period 2007-2021 and has now been revised on two occasions, due to the economic downturn. Under the plan the Electricity Generating Authority of Thailand (EGAT) – Thailand's main electric power producer/wholesaler – will continue to develop the major power generation projects, while there will be a greater role for the private sector, as purchases from small power producers (SPPs) and independent power producers (IPPs) will increase, as will imports from neighbouring countries, predominantly Laos but also Malaysia.

The PDP 2007 envisages that the country's generating capacity will increase to 58 GW in 2021. There is also a goal of supplying 2 000 MW of electricity from nuclear in 2021, with an expectation that this would be increased by a further 2 000 MW later in that decade. The plan seeks to increase the use of coal and renewables in power generation, thereby reducing dependence on natural gas so that it can be retained for value-added usage in transportation and the petrochemical Industry.

The Thai government views coal as a means to increase power system security and minimise generating costs. Nonetheless, public opposition to $NO_x$ and $SO_2$ emissions from coal-fired power plants has forced several proposed projects to switch to natural gas and/or to relocate to alternate sites. To improve public acceptance, the Thai government is encouraging the greater use of imported coal (of higher quality than local production) and the uptake of cleaner coal technologies.

The Thai government has implemented a Strategic Plan for Renewable Energy Development, which aims to increase alternative energy's share of total final energy demand to 20% by 2022. There are four key elements to the plan: energy conservation; renewable energy utilisation; human resources development; and public awareness. There is potential to increase solar and wind power, and significant prospects for small-scale hydropower systems. Although Thailand also has substantial untapped potential for large-scale hydropower, its use is limited, due to strong public opposition to large storage dams (Bundit, 2009). Current support measures for renewables include feed-in tariffs, including for biomass, small hydropower, biogas, wind and solar photovoltaic (PV).

Development and promotion of biofuels is one of the top agenda items of the Thai government. Targets have been set to expand the use of ethanol to 9 million litres per day (Ml/d) in 2022 and of biodiesel to 4.5 Ml/d in 2022. Relative to the palm oil resource utilised to produce biodiesel, resources that can be utilised to produce ethanol (such as molasses and cassava) are much more abundant.

Thailand currently has 11 ethanol plants with a total production capacity of 1.7 Ml/d, although average production is lower at 1.3 Ml/d. Various support measures are in place to promote more ethanol production. These include a tax mechanism to make ethanol cheaper than gasoline to end users, a guarantee of higher marketing margins for distributors, government support for research and development to increase feedstock yields, and a commitment to use ethanol in the state-owned vehicle fleet. Thailand has ten biodiesel plants, representing total production capacity of 2.9 Ml/d, and actual production of 1.6 Ml/d. Since April 2008, it has been mandatory to use 2% palm oil-based biodiesel in diesel sold throughout Thailand. The blending ratio is set to rise to 5% in 2011. Over 60% of Thailand's vehicles run on diesel, due to the popularity of medium-sized pick-up trucks.

Thailand's National Energy Conservation Program (ENCON) provides financial assistance and incentives for projects related to energy conservation, renewable energy, and research and development, as well as public awareness promotion and training. The programme is financed by the Energy Conservation Promotion Fund, which was set up in 1992 with the introduction of a tax (0.75 baht per litre or around $0.02 per litre in 2008) on the sale of gasoline, diesel, fuel oil and kerosene. Phase 3 of the ENCON Program, covering the period 2008-2011, is currently being implemented and aims to reduce energy demand in 2011 (as projected by the Ministry of Energy) by 10.8%. The key elements of the programme include improving and expanding public transport systems, speeding-up the introduction of energy-efficiency labelling, establishing minimum energy-performance standards, promoting combined heat and power systems, and increasing public awareness of energy efficiency.

Thailand is actively promoting the uptake of natural gas vehicles (NGVs) as a means to reduce dependence on oil in the transport sector. The target is to increase the number of NGVs on the road to 332 000 by 2012, from around 120 000 in 2008. Incentives include import duty exemptions for NGV buses and conversion kits, and a reduction in excise taxes and registration fees. Funding from ENCON is being used to encourage private transportation companies, including taxis, to convert their vehicles into NGVs.

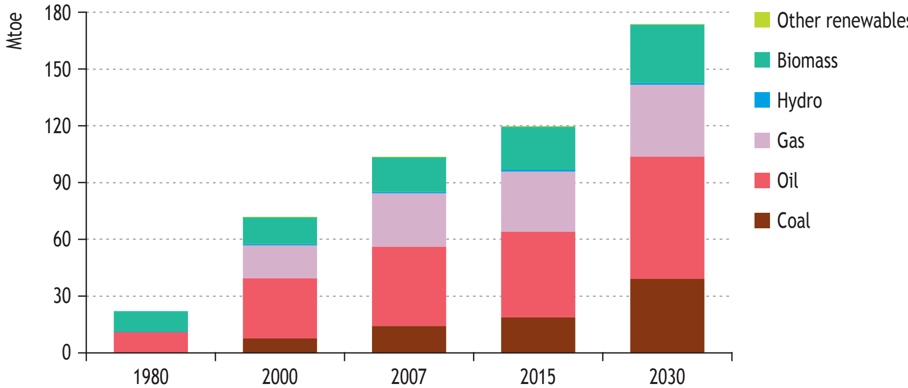
## Energy demand

### *Primary energy demand*

In 2007, Thailand's primary energy demand stood at 104 Mtoe, or 1.6 toe on a per-capita basis. In the Reference Scenario, Thailand's primary energy demand is projected to grow at an average rate of 2.3% per year through the *Outlook* period, reaching 174 Mtoe in 2030 (Figure 16.7). Demand growth remains modest in the near term, due to the current economic weakness.

Thailand consumed 42 Mtoe of oil in 2007, making oil the dominant fuel in the energy mix. Oil demand growth has slowed since 2008, due to high prices, the faltering economy and policy efforts to promote alternative fuels in transportation and to substitute natural gas for oil in the industrial sector. Nonetheless, through the *Outlook* period, oil demand is projected to grow steadily, reaching 65 Mtoe in 2030. Oil accounts for 32% of the increase in total primary energy demand over the projection period though its share declines slightly, to 37% in 2030 from 40% in 2007, as demand for other fuels grows strongly.

**Figure 16.7** • ***Thailand's primary energy demand by fuel in the Reference Scenario***




Primary natural gas consumption in Thailand totalled 28 Mtoe in 2007. By far the biggest user was the power sector, with 19 Mtoe, from which it supplied 67% of the country's total electricity. Natural gas is also used for transportation fuel, cooking gas and as petrochemical feedstock. In January 2009, Thailand's state-controlled oil and gas conglomerate, PTT Plc, reported that they expected natural gas demand in 2009 to remain close to the level of 2008 due to the economic slowdown – previously they had been forecasting growth of 5% to 7%. In the Reference Scenario, natural gas demand in Thailand is projected to grow at on average 1.3% per annum over 2007-2030, to 38 Mtoe, and its share in total primary energy demand declines from 27% in 2007 to 22% in 2030. This modest growth reflects policies to increase diversity in power generation.

Thailand's consumption of coal in 2007 totalled 14 Mtoe. The biggest user was the power sector with 7 Mtoe, supplying 21% of the country's total electricity generation. The remaining 7 Mtoe was used for industrial applications, particularly in the cement industry, and to a lesser extent pulp and paper manufacturing. In the Reference Scenario, Thailand's demand for coal is projected to grow by 4.5% per year on average, reaching 19 Mtoe in 2015 and 39 Mtoe in 2030. Coal's share in total primary energy demand increases from 14% in 2007 to 22% in 2030.

In 2007, Thailand's supply of renewable energy (including hydropower, traditional biomass and other renewables) amounted to 19.2 Mtoe, or 19% of total primary energy supply. The bulk of this was energy derived from fuel wood and agricultural residues, and was used in the residential and industrial sectors. In the Reference Scenario, the use of renewable energy in Thailand is projected to increase by 2.3% per year between 2007 and 2030. Most of this increase is in the power sector, where the share of renewables grows from 6% in 2007 to 11% in 2030, underpinned by government subsidies that encourage generation by solar, wind, biomass and biogas.

Thailand's energy intensity – the amount of energy needed to produce a unit of GDP – is projected to decline throughout the *Outlook* period at an average rate of 1.0% per-annum. Per-capita energy use continues to increase, but at a much slower rate than experienced during the last decade. By 2030, per-capita energy consumption in Thailand is around 56% of the current average level in the OECD.

### *Final energy consumption*

In the Reference Scenario, total final energy consumption in Thailand is projected to increase from 70 Mtoe in 2007 to 114 Mtoe in 2030, at an average rate of growth of 2.2% per year. This is much less than the rate from 1990 to 2007, reflecting the slower pace of overall growth and expected efficiency improvements in all end-use sectors.

Final oil demand rises by 1.9% per year and growth in oil demand accounts for 44% of the increase in total final energy consumption from 2007 to 2030. Final gas consumption expands at 2.7% per annum on average, reaching 4.4 Mtoe in 2030, with the industrial sector accounting for the bulk of the increase. The increase in industrial electricity demand accounts for 47% of the increase in the power demand for end-use sectors over the *Outlook* period, as industrialisation gathers pace.

Total final consumption of renewable energy including biomass increases from 12 Mtoe in 2007 to 20 Mtoe in 2030. Bolstered by government support programmes to promote the use of ethanol and biodiesel as petroleum product extenders (so as to reduce dependence on imported oil), the transport sector's demand for biofuels increases rapidly. Biofuels share of total transportation energy demand increase from 1% in 2007 to 10% by 2030. Total biofuels demand increases to 29 kb/d in 2015 and 67 kb/d in 2030 – at an average annual rate of growth of 15%.

## Oil supply

Thailand had proven crude oil reserves of 440 million barrels as of January 2009 (OG&J, 2008). Although the prospects for significantly boosting reserve levels are thought to be limited, a number of foreign oil companies and PTT Exploration and Production (PTTEP), a unit of PTT Plc, are actively exploring. The most prospective regions are the Gulf of Thailand (including the Joint Development Area [JDA] between Thailand and Malaysia), and the central and north onshore regions. PTTEP is also involved in upstream activities in foreign countries, including Myanmar, Bangladesh, Cambodia, Indonesia, Algeria, Egypt and Australia, with the objective of increasing supply to the Thai market.

Thailand's oil production has been increasing in recent years and averaged 344 kb/d in 2008. Offshore fields in the Gulf of Thailand are responsible for around 82% of current production. In the Reference Scenario, Thailand's total oil production is projected to decline gradually to just under 300 kb/d in 2015 and around 250 kb/d in 2030.

Thailand's total refining capacity stands at 1.2 mb/d across seven refineries. The largest facilities are the Thai Oil Public Company Limited's 275-kb/d refinery and the IRPC Public Company Limited's 215 kb/d refinery. PTT Plc has major interests in five of the seven refineries. The Thai government is interested in promoting the country as a regional oil refining and trading hub, and is offering generous tax subsidies to encourage refiners to develop additional capacity. To meet the needs of its refineries, Thailand imported 799 kb/d of crude oil in 2007. Thailand also exports a small volume of crude oil (as some domestic crude is not suitable for processing by local refineries) and some refined products to regional markets. Around 95% of Thailand's crude oil imports in 2007 came from countries in the Middle East, including the United Arab Emirates, Saudi Arabia, Oman, Qatar and Yemen.

Currently Thailand is proportionally one of Southeast Asia's largest oil importers and is expected to become even more dependent on imports through the *Outlook* period. In the Reference Scenario, petroleum imports are expected to increase to 1.2 mb/d by 2030, reaching 82% of projected consumption at that time.

## Natural gas supply

Thailand is comparatively rich in natural gas (relative to oil), with proven reserves estimated at 317 bcm in 2008 (O&GJ, 2008). The country is seeking to boost reserves through exploration, particularly in the Malaysian-Thailand Joint Development Area (JDA) in the Gulf of Thailand. Natural gas production in Thailand totalled 28.3 bcm in 2008. As with oil, the country's major gas fields are located in the Gulf of Thailand. The largest, the Bongkot field, is operated by PTTEP, with production of around 5.9 bcm/year of natural gas and 18 kb/d of condensate in 2008.

Thailand started importing natural gas from Myanmar in 1999 and is currently receiving about 9.8 bcm/year from the Yadana and Yedagun gas fields located in the Andaman Sea. This gas arrives via a 670-km pipeline that connects the Yadana gas field to a power plant operated by the EGAT in Ratchaburi province (located in the west of Thailand) and then to other users in the Bangkok area. At present, Thailand does not import LNG but it has an agreement with Qatargas to buy 1.4 bcm/year of LNG annually from 2011. It has also been in discussions with other suppliers, including Indonesia and Iran, for LNG volumes, although the recent economic downturn has lessened the urgency of finalising any agreements.

In the Reference Scenario, Thailand's natural gas production is projected to decline marginally to 24 bcm in 2030. To satisfy growing demand, domestic production is projected to be supplemented by imports of around 13 bcm in 2015, rising to 24 bcm in 2030. As a result, imports represent 50% of Thailand's natural gas demand in 2030.

## Coal supply

Thailand's economically recoverable brown coal reserves at the end of 2007 totalled 1.9 billion tonnes and are concentrated in the Province of Lampang in the north of the country (BGR, 2009). Although this is sufficient to meet current levels of demand for more than 100 years, its use is hampered by low public acceptance because of its high sulphur content. Total production of brown coal in Thailand in 2007 was 7.6 Mtce.

As prospects for significantly increasing production of high-quality coal in Thailand are limited, the country is expected to become increasingly dependent on imports. In the Reference Scenario, Thailand's coal production is projected to reach 11 Mtce in 2015 and 23 Mtce in 2030, while imports increase from 16 Mtce in 2015 to 33 Mtce in 2030.

## Electricity generation

Thailand's demand for electricity grew rapidly, at an average 6.2% per annum, between 2000 and 2007. The latest peak in electricity consumption occurred in April 2008, during the summer cooling period, at 22.6 GW. Total electricity generated and imported in 2008 was approximately 147 TWh (EGAT, 2008).

Thailand had approximately 30 GW of power generation capacity in 2007. Currently, the network is operating with a reserve capacity of around 25%. While this is well above the minimum reserve margin target of 15% set by the Ministry of Energy, it has been falling steadily since 2001, due to strong demand growth (until recently) and lower-than-planned capacity additions. Thailand's generation mix is highly dependent on fossil fuels. In 2007, natural gas represented 66% of the mix, coal 21%, hydropower 5.5%, fuel oil 2.7%, renewables 1.6% and the remaining 3% was imported from Malaysia and Laos (EGAT, 2008).

In the Reference Scenario, electricity generation is projected to grow at 3.6% per annum through the *Outlook* period, reaching 325 TWh in 2030. It is projected that Thailand needs to add an additional 45 GW of new capacity by 2030 to meet this demand. The share of natural gas in the generating mix is projected to decline considerably, from 67% in 2007 to 40% in 2030, in favour largely of coal. The share of renewables in the power-generation mix also grows strongly, to 10% in 2015 and then 12% in 2030.

### Climate change and local pollution

Thailand's per-capita energy-related $CO_2$ emissions in 2007 reached 3.5 tonnes, approximately 30% of the average level in the OECD. In the Reference Scenario, emissions are projected to rise by 2.6% per year to 406 Mt in 2030 (Table 16.6). Some 60% of the growth in emissions results from the increased share of coal in the power-generation mix. Measured on a per-capita basis, by 2030 Thailand's $CO_2$ emissions reach 61% of the current OECD level.

Thailand's $SO_2$ emissions, primarily from power plants, totalled 0.5 Mt in 2007. In the Reference Scenario, $SO_2$ emissions decrease at 0.9% per annum on average, to 0.4 Mt in 2030. Emissions of $NO_x$, primarily from vehicles and power plants, are projected to rise slightly in the Reference Scenario reaching 1.5 Mt in 2030. Emissions of particulate matter, which come mainly from the burning of biomass, are projected to decline, from 0.4 Mt in 2007 to 0.3 Mt in 2030.

**Table 16.6 • *Thailand's energy-related $CO_2$ and local air pollutant emissions in the Reference Scenario*** (Mt)

| | 1980 | 2000 | 2007 | 2015 | 2030 | 2007-2030* |
|---|---|---|---|---|---|---|
| $CO_2$ | 34 | 159 | 226 | 260 | 406 | 2.6% |
| $NO_x$ | n.a. | n.a. | 0.97 | 0.98 | 1.48 | 1.9% |
| PM2.5 | n.a. | n.a. | 0.35 | 0.34 | 0.31 | -0.5% |
| $SO_2$ | n.a. | n.a. | 0.48 | 0.33 | 0.39 | -0.9% |

* Compound average annual growth rate.

Sources: IEA analysis and IIASA (2009).

## Malaysia

### Overview and assumptions

Malaysia has 27 million inhabitants and is the third-largest energy consumer in ASEAN after Indonesia and Thailand, accounting for 14% of the region's primary consumption in 2007 (Table 16.7). The country's primary energy demand increased six-fold between

1980 and 2007. Malaysia's primary energy mix is dominated by fossil fuels, their share having increased from 86% in 1980 to 95% in 2007. The country is the second-largest energy producer in ASEAN and is a significant net exporter of natural gas, primarily in the form of LNG.

**Table 16.7 • Key energy indicators for Malaysia**

| | Unit | 1980 | 2007 | 1980-2007** |
|---|---|---|---|---|
| Total primary energy demand* | Mtoe | 12 | 73 | 6.9% |
| Total primary energy demand per capita | toe | 0.88 | 2.74 | 4.3% |
| Energy intensity | toe/thousand dollar of GDP in PPP | 0.17 | 0.20 | 0.7% |
| Share of oil in total primary energy demand | % | 67% | 35% | n.a. |
| Energy-related $CO_2$ emissions*** | Mt | 24 | 177 | 7.7% |

* Includes traditional biomass.
** Compound average annual growth rate.
*** From fuel combustion only.

### *The political and economic outlook*

Malaysia's political structure is federal. The constitutional monarch and federal Head of State, elected every five years is the Yang di-Pertuan Agong, commonly referred to as the King of Malaysia. Malaysia has two chambers of Parliament, the Senate (Dewan Negara) and the House of Representatives (Dewan Rakyat). The government is closely modelled on the Westminster parliamentary system and has been headed by Prime Minister Najib Razak since April 2009. Following independence in 1957, Malaysia has been governed by a multi-party coalition known as the Barisan Nasional or the National Front (formerly known as the Alliance).

Malaysia's economy is the fourth largest in Southeast Asia, with a GDP of $367 billion (in PPP terms) in 2007. GDP per capita (in PPP terms), at $13 826 in 2007, was the third highest in ASEAN after Singapore and Brunei Darussalam, but still below the OECD average. Annual growth in GDP declined during the Asian Financial Crisis, but rebounded sharply, led by strong growth in exports, particularly in electronics and electrical products, as well as massive public investment. Despite the strong economic growth and government policies to eradicate poverty, pockets of poverty still exist, particularly in the rural areas.

As a result of the current global economic slowdown, Malaysia's GDP contracted by 6.2% on a year-on-year basis in the first quarter of 2009, its worst performance since the third quarter of 2001. The government has since moved to stimulate the economy[3] in order to offset the decline in manufactured exports caused by weakening global demand. According to the Asian Development Bank (ADB), Malaysian GDP is likely to contract 3.1% in 2009 before growing by 4.2% in 2010 (ADB, 2009a).

3. The Malaysian government announced a RM 60 billion (approximately $17 billion) stimulus package in March 2009, on top of the RM 7 billion (approximately $2 billion) package implemented in November 2008.

### *Key assumptions*

The projections in this *Outlook* assume that the Malaysian economy will grow on average by 3.4% per year from 2007 to 2030 (Table 16.8). Growth is expected to be slower towards the end of the projection period as the economy matures. Malaysia's rate of population growth is declining, from some 2.8% per year in the 1980s to 1.7% in 2007. This *Outlook* assumes that the population will increase by 1.2% per year on average to 2030, reaching 35 million. Around 69% of the population lived in urban areas in 2007 and the rate of urban concentration in 2030 is expected to reach 82%.

**Table 16.8 • *GDP and population growth assumptions in Malaysia in the Reference Scenario*** (compound average annual growth rates)

| | 1980-2007 | 2007-2015 | 2015-2030 | 2007-2030 |
|---|---|---|---|---|
| GDP (PPP) | 6.2% | 3.6% | 3.3% | 3.4% |
| Population | 2.5% | 1.6% | 1.1% | 1.2% |
| GDP per capita | 3.6% | 2.0% | 2.2% | 2.1% |

## Energy policy

The Economic Planning Unit (EPU) and the Implementation and Coordination Unit (ICU), which report directly to the Prime Minister, devise and oversee all energy policy in Malaysia, in consultation with the Ministry of Energy, Water and Communications, which regulates the non-oil and gas and electricity sectors. The Energy Commission of Malaysia regulates energy supply activities and enforces energy supply laws.

Malaysia is currently in the process of formulating a comprehensive National Energy Plan, which will focus on intensifying energy-efficiency initiatives in order to achieve more productive and prudent use of its remaining reserves. The plan, which is scheduled to be finalised by late 2009, will increase efforts to develop alternative forms of energy, including solar, wind and biofuels, and will explore the possible use of nuclear energy.

Under the Ninth Malaysia Plan (2006-2010), the government has set a target of 350 MW[4] of grid-connected renewable electricity generation by 2010. Currently, the Small Renewable Energy Power Program (SREP), which was launched in 2001, provides for power generated from renewable resources to access the national grid. SREP developers can sell power to utilities through the Renewable Energy Power Purchase Agreement (REPPA), which gives plants a license for a period of 21 years to sell up to 10 MW to the national grid system. Under this programme, the utilisation of all types of renewable energy is permitted, including biomass, biogas, municipal solid waste, solar, small hydropower and wind.

In 2008, the Malaysian government introduced a broad package of reforms to energy subsidies, which were creating a mounting fiscal burden. The package included subsidy reductions, cash rebates, windfall taxation on certain sectors and an expansion of the social safety net. Malaysian retail gasoline prices were increased by more than

4. 300 MW in Peninsular Malaysia and 50 MW in Sabah.

40% in July 2008 and the following month the price of gas for power generation was raised by 124% in Peninsular Malaysia. In line with this increase in the gas price, the average electricity tariff for all sectors of the economy was increased by 24% (from \$0.075/kWh to \$0.093/kWh).

Malaysia introduced a Five-Fuel Diversification Policy in 2001, which aims to broaden the fuel mix and increase the share of renewables in the supply of electricity. As a result, oil's dominance in the power-generation fuel mix has been reduced significantly, in favour of natural gas and coal.

To ensure adequate, secure and cost-effective energy supplies, the Malaysian government formulated a National Depletion Policy in 1981. The policy sets a limit on the total production of crude oil of 650 kb/d and natural gas from Peninsular Malaysia of 56.6 million cubic metres (mcm) per day.

In recent years, the Malaysian government has stepped up efforts to promote energy efficiency in various sectors, including the industrial, commercial, residential and transport sectors. The 2009 budget introduced various fiscal incentives; for example, there is now an exemption from import duty and sales tax for high-efficiency motors, insulation materials and various household electronic goods.

## Energy demand

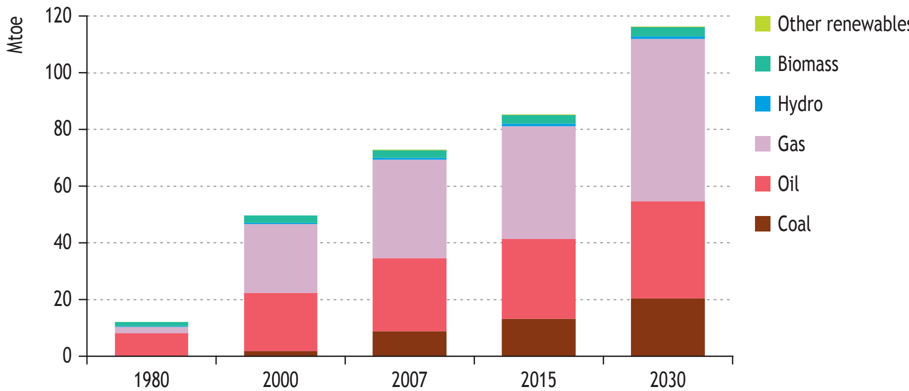
### *Primary energy demand*

The share of fossil fuels in Malaysia's energy mix increased from 86% in 1980 to 95% in 2007. The biggest increase came from gas, with its share more than doubling to 48% in 2007 – the result of government policy to diversify energy sources. Coal, which is mainly used in power generation, increased its share from less than 1% in 1980 to 12% in 2007. Oil demand grew at 4.4% per annum, though its share dropped substantially, from 67% in 1980 to 35% in 2007. The share of biomass – mostly traditional biomass used for cooking in the residential sector – declined steadily from 13% in 1980 to 4% in 2007 as urbanisation gathered pace.

In the Reference Scenario, Malaysia's primary energy demand is projected to grow at 2.1% per year, from 73 Mtoe in 2007 to 116 Mtoe in 2030 (Figure 16.8). This is considerably slower than the growth of 7% per year from 1980 to 2007. Throughout the *Outlook* period, Malaysia's energy intensity declines, by 1.3% per year, as the structure of its economy progressively approaches that of OECD countries today.

In the Reference Scenario, oil consumption increases from 26 Mtoe in 2007 to 34 Mtoe in 2030, and Malaysia becomes a net oil importer soon after 2015. Natural gas remains the dominant fuel in Malaysia's energy mix, with demand growing at a robust annual rate of 2.2%. The main uses are in industry and power generation. Malaysia remains a net gas exporter through to 2030. Coal demand increases most strongly amongst the fossil fuels, at 3.7% per year, and its share in primary demand rises from 12% in 2007 to over 17% by 2030, boosted by the government's policy to increase its use for power generation so as to reduce dependence on natural gas. The contribution of hydropower remains moderate at 1% in 2030. The share of traditional biomass continues to decline as urbanisation reaches 82% in 2030 from 69% in 2007.

**Figure 16.8 • Malaysia's primary energy demand by fuel in the Reference Scenario**




## *Final energy consumption*

In the Reference Scenario, total final energy consumption increases from 43 Mtoe in 2007 to 71 Mtoe in 2030, at an average rate of growth of 2.2% per year (Figure 16.9). This is less than the rate experienced from 1990 to 2007, reflecting expected efficiency improvements in all end-use sectors, as well as slower GDP and population growth. Final oil demand rises by 1.4% per year and oil accounts for 97% of total energy demand for transport in 2030. Final gas consumption more than doubles, reaching 19 Mtoe in 2030, with industrial demand accounting for 89% of the increase. Final coal consumption, mainly in industry, increases from 1.4 Mtoe in 2006 to 1.7 Mtoe in 2030. Final electricity consumption grows fastest, at 3.7% per year, as industrial growth and urbanisation accelerate.

Among end-use sectors, *industrial* energy demand grows most briskly, at 2.6% per year on average over the *Outlook* period. Energy intensity is expected to decline slowly, with a gradual shift to less energy-intensive industries and improvements in energy efficiency. The share of gas and electricity in industry's final consumption rise as the government promotes diversification of the fuel mix. Electricity use in industry rises the fastest, at 4.5% per year on average, and electricity accounts for 28% of industrial energy demand in 2030. The share of gas demand in industry increases modestly, to 45% by 2030, as more gas is used in the power sector.

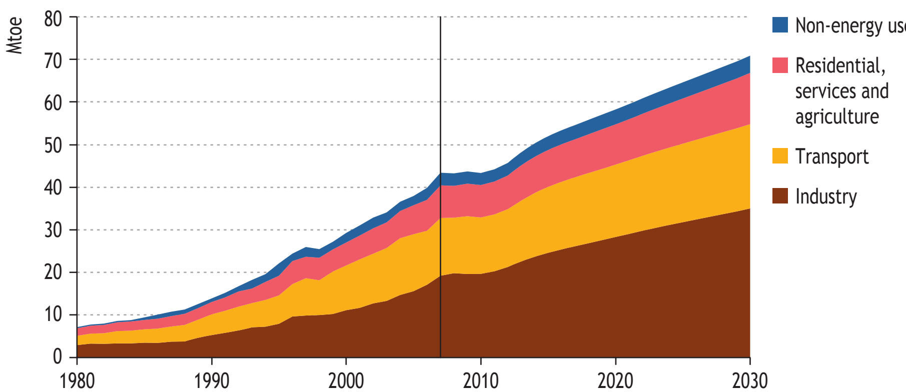
*Transport* energy demand grows at 1.7% per year. Vehicle fuel efficiency is expected to improve, but strong GDP growth over the next decade causes transport demand growth to accelerate. The share of transport energy demand in total final consumption is projected to decline slightly, from 31% in 2007 to 28% in 2030. Demand for biofuels in transport increases to 9 kb/d in 2030, accounting for 2% of total transport oil demand.

Rising incomes lead to increased car ownership and driving, as well as to more freight. Passenger car ownership in Malaysia is projected to rise to 476 per 1000 people by 2030, similar to the level of Japan today. Urban transport depends very much on passenger vehicles, since the rail infrastructure is not yet well developed. Demand for freight trucks is boosted by robust growth in manufacturing and construction. The road-vehicle stock more than doubles over the *Outlook* period. Fuel efficiency policies are expected to have a significant impact on growth in transport fuel demand. The Malaysia Vehicle Inspection programme currently requires all commercial vehicles to be inspected for safety and emissions either annually or twice per year, depending on age, and private vehicles must be inspected prior to re-sale, encouraging the uptake of more efficient models.

*Buildings sector* energy demand is projected to grow at 2% per year on average over the *Outlook* period. The Energy Labelling Programme, for refrigerators, air conditioners and electric fans, is currently encouraging the purchase of more efficient models and has achieved considerable energy savings. In addition, the Malaysian government has focused on improving building efficiency, which is expected to reduce gradually the energy intensity of commercial buildings.

Energy demand in the residential and services sector is projected to grow fastest in the first half of the period. Electricity accounts for most of the growth in demand to 2030. As appliance ownership levels increase, the share of electricity in total residential and services energy use rises from 55% in 2007 to 65% in 2030.

**Figure 16.9 • *Malaysia's final energy consumption by sector in the Reference Scenario***




## Oil supply

Malaysia is the second-largest oil producer in ASEAN, with proven reserves of 4.0 billion barrels, similar to the level of Indonesia (O&GJ, 2008). It relies on three producing basins; the Malay Basin in the west, and the Sarawak and Sabah Basins in the east. Malaysia's proven oil reserves have declined from a peak of 4.6 billion barrels in 1996. At the current rate of production, proven reserves would sustain production for another 15 years.

Malaysia's national oil company, Petroliam Nasional Berhad (PETRONAS), dominates upstream and downstream activities. It holds exclusive ownership rights to all exploration and production. All foreign and private companies must operate through production sharing contracts (PSCs) with PETRONAS. Malaysia has been intensifying the exploration of deepwater and extra-deepwater areas, a pursuit that is costly and requires substantial technical expertise. Notable discoveries include the Kikeh field in Sabah, reportedly containing recoverable reserves of 440 million barrels.

Malaysia's oil production was 771 kb/d in 2008, with net exports of 285 kb/d. Domestic production has been rising since 2002 as a result of new offshore developments. The biggest field, Tapis which contains a light grade of crude oil with low sulphur content, currently accounts for about 70% of Malaysia's total oil production. Kikeh, Malaysia's first deepwater field, came on stream in August 2007. It is located at a water depth of some 1 300 metres and was jointly developed by Murphy Oil and PETRONAS. It reached a production rate of 120 kb/d in 2008. The Shell-operated Gumusut/Kakap deepwater fields are expected to begin production in 2011, with a potential production capacity of 150 kb/d. Shell also expects to begin oil production at the deepwater Malikai field by 2012, although no production timetable is yet set. Currently, nine deepwater fields have been identified for commercial operations through to 2013.

Malaysia has invested heavily in refining activities during the last two decades and is now able to meet the country's demand for petroleum products domestically, having previously relied on imports from Singapore.

In the Reference Scenario, Malaysia's oil production is expected to decline to around 700 kb/d by 2015 and then to 400 kb/d in 2030. The country becomes a net importer soon after 2015 and its imports reach 300 kb/d in 2030. By that time Malaysia's oil import dependence is 45%.

### Natural gas supply

Malaysia held 2.4 tcm of proven natural gas reserves as of January 2009 (14 billion barrels of oil equivalent) – more than three times the size of its oil reserves (O&GJ, 2008). Of its natural gas reserves, about 50% are located offshore Sarawak, 41% offshore the east coast of Peninsular Malaysia and 9% offshore Sabah. Most of the country's undiscovered gas resources are in offshore areas (USGS, 2000).

Malaysia's natural gas production has risen steadily in recent years, reaching 61.5 bcm in 2008, up 22% since 2000. Although the country is a significant exporter of natural gas, it is also facing a potential gas shortage as production at the fields that supply the domestic market are struggling to match the strong demand from industry. As with oil, domestic supply in Malaysia comes largely from three main sources: offshore Terengganu (Malay Basin) to cater for domestic demand in Peninsular Malaysia, Sabah offshore fields for Sabah's domestic gas consumption, and offshore Sarawak mainly for LNG exports (IEA, 2009). Malaysia's gas exploration and production activities will continue to focus on offshore areas, increasingly on deepwater blocks. Associated gas production at the Kikeh field in offshore Sabah has commenced and gas was transported to PETRONAS' Labuan Gas Terminal in December 2008. Production from Kikeh is expected to reach a stabilised rate of 1.2 bcm/year, possibly expanding in the future. Another major new development is PETRONAS Carigali's Block SK-309, which started producing 1.3 bcm/year in early 2009.

**Box 16.1 • *The important role of PETRONAS in the Malaysian economy***

Petroliam Nasional Berhad (PETRONAS), the national oil company of Malaysia, was established in 1974 in response to the first oil shock, which prompted the Malaysian government to take control of its own hydrocarbon resources. It is wholly owned by the government and has the exclusive right to explore, develop and produce petroleum resources within the country. While foreign and private oil companies are also able to operate in Malaysia, they must do so through production sharing contracts with PETRONAS. The company also has a significant presence in the downstream sector in Malaysia, where it competes with other multinational oil companies.

PETRONAS is generally considered to be one of the world's most successful oil companies, including both national oil companies (NOCs) and international oil companies (IOCs). In 2008, it was ranked by Fortune Magazine as the eight most profitable company in the world and the most profitable in Asia. This success has stemmed from its ability to grow reserve levels and production within Malaysia, and from its achievement in forging a presence in foreign markets, making use of its technical expertise. It has operations in more than 30 countries, and production from its overseas assets accounted for 58% of its total oil production and 50% of its overall gas production in 2008.

PETRONAS plays a huge role in the economy of Malaysia and this has been expanding in recent years. In 2008, payments made by PETRONAS – including dividends, taxes, royalty and export duties – represented 45% of the Malaysian government's total revenues, or RM 72.5 billion (approximately $21 billion). However, as Malaysia is faced with declining oil production the share of oil and gas revenues in GDP will taper off, increasing the importance of diversifying the economy.

LNG accounted for 9.6% of Malaysia's total exports in the first quarter of 2009 and was the second-largest export commodity (Malaysian Department of Statistics, 2009). In 2008, Malaysia exported just under 31 bcm of LNG, mostly to Japan, Korea and Chinese Taipei. Demand for LNG exports is expected to be a key factor driving the development of Malaysia's natural gas industry. The Sabah Oil and Gas Terminal (SOGT) was opened in 2007 and is capable of receiving 5.2 bcm and 7.2 bcm/year of gas from the Kinabalu and Kebabangan fields, respectively. This development will complement the existing Labuan Gas Terminal and Sabah Gas Terminal. In addition, the 500-km Sabah-Sarawak Gas Pipeline (SSGP) project is expected to deliver gas from Kimanis in Sabah to PETRONAS' massive LNG complex in Bintulu (East Malaysia) from 2012. The offshore fields of Sarawak will continue to be the main source of supply to the LNG plants in Bintulu (with gas from Sabah, via SSGP, to complement supply). The de-bottlenecking of the MLNG Dua facility, which is one of the three facilities in Bintulu, is scheduled to be completed by the end of 2009. Upon completion, each of the three trains will be capable of producing 4.1 bcm/year. In total, the Bintulu complex's annual production capacity will rise to 33 bcm.

In the Reference Scenario, Malaysia's gas production grows to 64 bcm in 2015 and to 74 bcm in 2030. Although Malaysia is projected to remain a net exporter of natural gas, rising domestic demand will mean that the country's gas exports as a share of production will fall from 36% in 2007 to 9% in 2030.

## Coal supply

Malaysia's economically recoverable coal reserves, predominately located in Sarawak, stood at 180 Mt in 2007 and the nation's potential resources are 1.5 billion tonnes (BGR, 2009). More than three-quarters of the reserves are hard coal. Malaysia's coal production increased on average by 18% per year from 2000 to 2007 and the reserves-to-production ratio in 2007 was close to 170 years. The power sector currently consumes 85% of the country's total coal consumption. Tenaga Nasional Berhad, the largest electricity utility in Malaysia, plans to decrease the use of natural gas at its power plants and increase the use of coal, because of limited availabilities in the supply of natural gas for the domestic market.

Although Malaysia's coal reserves are significant, currently 94% of coal used in the country is imported, due to the high extraction cost of locally sourced coal. In 2007, Malaysia imported a total of 12 Mtce of coal, mostly from Australia, China, South Africa and Indonesia. Most of Malaysia's coal deposits are located in the interior areas, where the infrastructure is poor. To exploit these mostly deep deposits would require major investments in underground mines and new infrastructure. In the Reference Scenario, Malaysia's coal production is expected to reach 1.6 Mtce in 2015 and 3 Mtce in 2030, while coal imports rise from 17 Mtce to 26 Mtce over the same period.

## Electricity generation

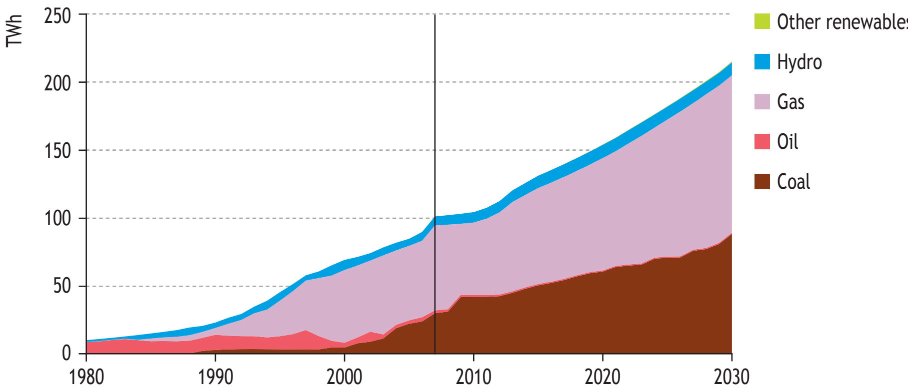
Malaysia has the third-largest electricity market in ASEAN, behind Indonesia and Thailand. The country's per-capita electricity consumption is approximately 43% of the OECD average. Predominantly gas-fired, total electricity generation reached 101 TWh in 2007. Electricity demand dipped during the Asian Financial Crisis but growth resumed at around 5.6% per annum between 2000 and 2007. The growth in electricity demand in this period came predominantly from the industrial sector. Due to the recent credit crunch, electricity demand dropped in the fourth quarter of 2008, but is expected to pick up once the economy recovers.

In the Reference Scenario, total generation is projected to increase by 3.3% per year, more than doubling by 2030. At 216 TWh, Malaysia's generation in 2030 is comparable to the current level of production in Mexico (Figure 16.10). The dominance of natural gas in the electricity generation mix continues, but its share falls to 54% in 2030 from 62% in 2007. Electricity generation from coal grows at 4.8% per year and the share of coal-fired generation increases from 30% in 2007 to 41% in 2030. Hydropower is expected to account for 4% of Malaysia's generation fuel mix by 2030.



Malaysia's installed capacity stood at 26 GW in 2008. Malaysia plans to reduce the excess reserve capacity from the current level of 43% to 25%. To meet projected demand growth over the *Outlook* period, Malaysia's installed capacity reaches 47 GW by 2030 in the Reference Scenario. By 2030, it is projected that 31% of the installed capacity will be coal-fired, 56% gas-fired and 8% from renewables. Although there remains untapped hydropower potential in some parts of the country, most of the potential sites in Peninsular Malaysia have already been developed. The most immediate addition is expected to be the Bakun Hydro-electric Project, which is currently being developed in Sarawak and should come on line soon after 2011.

**Figure 16.10 • *Malaysia's electricity generation by fuel in the Reference Scenario***




## Climate change and local pollution

Through the *Outlook* period, Malaysia's energy-related $CO_2$ emissions are projected to rise by 2.3% per year on average, reaching 300 Mt in 2030 (Table 16.9). Most of the growth in emissions comes from coal-fired power plants. Malaysia's per-capita annual energy-related $CO_2$ emissions in 2007 stood at 6.7 tonnes, compared to an average of 10.9 tonnes in the OECD. By 2030, measured on a per-capita basis, Malaysia's emissions reach nearly 80% of the current OECD level.

Several cities in Malaysia are badly affected by airborne pollution, largely caused by the burning of fossil fuels in power stations, factories and vehicles. Total $SO_2$ emissions in Malaysia reached 228 000 tonnes in 2007. In the Reference Scenario, with the government's policy to switch away from oil in favour of gas, and with greater deployment of advanced emission control systems, $SO_2$ emissions are expected to decline by 0.2% per annum on average. Emissions of $NO_x$, mainly from vehicles and the power sector, are projected to decline slightly through the *Outlook* period, while emissions of particulate matter, mainly from biomass burning in households, are set to decline at an average annual rate of 1.1%.

**Table 16.9 • Malaysia's energy-related $CO_2$ and local air pollutant emissions in the Reference Scenario** (Mt)

| | 1980 | 2000 | 2007 | 2015 | 2030 | 2007-2030* |
|---|---|---|---|---|---|---|
| $CO_2$ | 24 | 116 | 177 | 215 | 299 | 2.3% |
| $NO_x$ | n.a. | n.a. | 0.60 | 0.58 | 0.59 | -0.0% |
| PM2.5 | n.a. | n.a. | 0.15 | 0.14 | 0.11 | -1.1% |
| $SO_2$ | n.a. | n.a. | 0.23 | 0.21 | 0.22 | -0.2% |

* Compound average annual growth rate.

Sources: IEA analysis and IIASA (2009).

# Philippines

## Overview and assumptions

Philippines, with a population of 90 million in 2008, is the fifth-largest energy consumer in Southeast Asia after Indonesia, Thailand, Malaysia and Vietnam. Philippine primary energy demand doubled between 1980 and 2007, while the economy expanded by 225% over the same period (Table 16.10). Fossil fuels make up 57% of the country's energy mix, with renewables and biomass responsible for the remainder. Philippine reliance on imported energy is high and the country faces serious challenges in attracting investment to overcome electricity shortages. Improving the electrification rate is an ongoing challenge, with around 13 million people currently lacking access.

**Table 16.10 • Key energy indicators for Philippines**

| | Unit | 1980 | 2007 | 1980-2007** |
|---|---|---|---|---|
| Total primary energy demand* | Mtoe | 22 | 40 | 2.3% |
| Total primary energy demand per capita | toe | 0.46 | 0.45 | -0.0% |
| Energy intensity | toe/thousand dollar of GDP in PPP | 0.16 | 0.13 | -0.8% |
| Share of oil in total primary energy demand | % | 49% | 34% | n.a. |
| Energy-related $CO_2$ emissions*** | Mt | 33 | 72 | 2.9% |

* Includes traditional biomass.
** Compound average annual growth rate.
*** From fuel combustion only.

### *The political and economic outlook*

Philippines is a multi-party democratic republic with a presidential system. The national government is made up of three branches: an executive branch, a legislative branch and a judicial branch. The executive branch consists of cabinet members headed by the president, who is the chief of state and the head of the government. President Gloria Macapagal Arroyo has been the President of Philippines since 2004.

Philippines is the fifth-largest economy in ASEAN, with a GDP of $306 billion (in PPP terms) in 2007, or $3 484 on a per-capita basis. The services sector dominates the economy, representing 55% of GDP in 2007, followed by the industrial sector (31%) and then agriculture, fisheries and forestry (14%). In 2008, growth in Philippine GDP slowed to 4.6% from 7.2% in 2007, largely reflecting weakening global demand for exports (ADB, 2009b). Merchandise exports fell by 2.6% in 2008, the first contraction since 2001. In January 2009, the government announced a $6.9-billion economic stimulus package to expand labour-intensive infrastructure projects and provide tax breaks. In June 2009, as a result of weak exports and slow consumer spending, the Philippine government scaled down its official economic growth estimates for 2009. The Asian Development Bank forecasts GDP growth will slow to 1.6% in 2009 and pick up in 2010 to 3.3% (ADB, 2009a).

### *Key assumptions*

The projections in this *Outlook* assume that the Philippine economy will grow at a rate of 3.5% per year to 2015 before increasing to 4.0% per year between 2015 and 2030 (Table 16.11). The population of Philippines grew at 2.2% annually between 1980 and 2008, reaching 90 million. In the Reference Scenario, the average rate of population growth to 2030 slows to 1.5% per year, reaching 123 million. Today, around 64% of the population live in urban areas, but this share is assumed to grow to 77% in 2030. In 2030, GDP per capita in Philippines is projected to reach around $5 900.

**Table 16.11 • *GDP and population growth assumptions in Philippines in the Reference Scenario*** *(compound average annual growth rates)*

| | 1980-2007 | 2007-2015 | 2015-2030 | 2007-2030 |
|---|---|---|---|---|
| GDP (PPP) | 3.0% | 3.5% | 4.0% | 3.8% |
| Population | 2.3% | 1.7% | 1.3% | 1.5% |
| GDP per capita | 0.8% | 1.8% | 2.6% | 2.3% |

## Energy policy

The Philippine government has adopted an energy independence agenda, which comprises efforts to accelerate exploration, development and use of indigenous energy resources, intensify renewable energy resource development, increase the use of alternative fuels, and enhance energy efficiency and conservation. To increase the utilisation of renewable energy, President Arroyo signed the *Renewable Energy Act* in December 2008. This new law provides various fiscal incentives for investment in renewables, including a seven-year tax holiday, tax exemption for carbon credits generated from renewable energy sources, and a 10% corporate income tax instead of the standard 30%. Non-fiscal incentives include the establishment of renewable portfolio standards, a feed-in-tariff system, a green energy option, net metering and a renewable energy market.

The Alternative Fuels Programme (AFP) is one of the key elements of the Philippine drive to reach a goal of 60% energy self-sufficiency by 2010. The AFP has four major sub-programmes: a) the Biodiesel Programme; b) the Bioethanol Programme; c) the

Natural Gas Vehicle Programme for Public Transport (NGVPPT); and d) the Autogas Programme. The programme is also supporting the introduction of hybrid, fuel cell, hydrogen and electric vehicles (Philippine DOE, 2009a).

The Philippines *Biofuels Act* of 2007 established various requirements for ethanol and biodiesel. These included a minimum blend of 5% bioethanol by 2009, to increase to 10% in 2011, and an initial minimum blend of 1% biodiesel, which was increased to 2% in 2009. There are two existing ethanol plants in Philippines with combined production capacity of 39 Ml/year. A further ten projects are under development, utilising sugar cane, cassava or sorghum as feedstocks. Philippines currently has 12 biodiesel production plants, with a production capacity of 370 Ml/year. Coconuts are the primary feedstock, as the coconut industry is the dominant in the agricultural sector. Philippines is also planning the cultivation of jatropha as a feedstock for biodiesel.

The Autogas Programme promotes the use of LPG as an alternative transport fuel. The aim is to diversify the country's fuel sources, while diminishing the problems of air pollution created by vehicle emissions. As of February 2009, over 17 500 taxis had been converted to use of LPG and as of April 2009, 180 LPG dispensing pumps had been installed nationwide (Philippine DOE, 2009b). The NGVPPT includes various measures to encourage the use of natural gas in public transport, such as infrastructure development, financial assistance, and the development of standards and codes of practice.

The Philippine Department of Energy has set up a project to study the development of nuclear power as a long-term power option and has set a target of 600 MW of nuclear capacity by 2025, rising to 2 400 MW in 2034. Philippines completed the construction of Bataan-1, a 620 MW pressurised water reactor in 1984, but it was never operated due to safety concerns linked to its proximity to a major earthquake fault line. The Philippine National Power Corporation and Korea Electric Power Corp are currently undertaking a joint 18-month feasibility study to explore the possibility of restarting the Bataan nuclear power plant.

The Philippine National Power Corporation (NPC), which was an integrated state-owned monopoly, is currently being privatised to facilitate competition in the power sector. The National Transmission Corporation, the state-owned company established to assume the transmission functions of the NPC, turned over its functions to the private National Grid Corporation of Philippines in January 2009. Philippines has also started the operation of a wholesale electricity spot market on the island of Luzon.

With the Philippines Energy Efficiency Project (PEEP), the government is aiming to reduce peak demand for power and defer the need for power-generation capacity additions, reduce oil imports and acquire revenue from the Clean Development Mechanism (CDM) under the United Nations Framework Convention on Climate Change (UNFCCC). The PEEP action plan includes measures such as replacement of incandescent light bulbs, the implementation of energy-efficiency standards for buildings and utilities, a ban on the importation of inefficient second-hand vehicles and the establishment of an energy-efficiency and conservation testing centre.

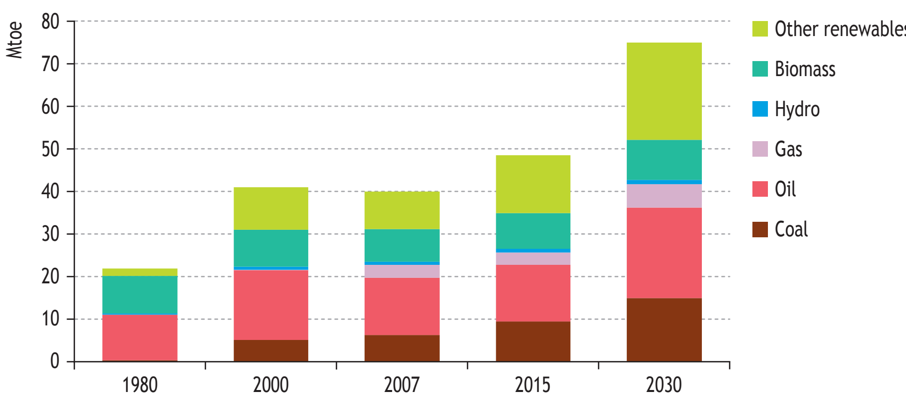
With its 2009-2018 Missionary Electrification Plan, the Philippine government intends to expand electricity generation capacity in approximately 200 non-electrified areas through subsidies and private sector participation programmes. Philippine rural electrification programmes started more than 30 years ago and the results have been impressive, with millions of households gaining access to electricity. By 2008, 97% of the urban population had access to electricity. The figure for service to the rural population was only 65%, but the geography of Philippines poses many problems for rural electrification. The country is a large and dispersed group of 7 100 islands, of which 2 800 are inhabited, leading to an extremely fragmented rural electrification landscape with more than 100 rural electric co-operatives. Active volcanoes, periodic typhoons and the mountainous landscape further complicate the challenge of rural electrification.

Despite the current financial crisis, the Philippine government is making efforts to maintain energy investment, with biofuels, renewable generation capacity, and oil and gas infrastructure identified as the priority areas. The government intends to offer more than 30 contracts for oil, gas and coal investment in 2009, and to attract finance for 4 000 MW of generation capacity over the period 2008 to 2014.

## Energy demand

In 2007, Philippine primary energy demand stood at 40 Mtoe, or 0.5 toe on a per capita basis. In the Reference Scenario, Philippine primary energy demand is projected to grow at an average rate of 2.8% per year from 2007 to 2030. The growth rate is expected to be slower in the near term, due to the global financial crisis (Figure 16.11).

**Figure 16.11 • Philippine primary energy demand by fuel in the Reference Scenario**




Oil accounted for 34% of Philippine total primary energy consumption in 2007. Other renewables (mainly geothermal) was the second most important element in the energy mix with a share of 22%, followed by biomass and waste at 19%, and coal at 16%. The large use of biomass and waste is linked to the significant proportion of the population living in rural areas and the large agro-industry base.

Primary oil demand in Philippines stood at 13 Mtoe in 2007. Oil demand growth has slowed in recent years, due to high prices, the increase in consumption of indigenous gas and the government's policy of reducing dependence on oil imports. In the Reference Scenario, oil demand is projected to grow steadily, reaching 21 Mtoe in 2030, while its share of primary energy demand declines slightly to 28%.

Philippine primary natural gas consumption totalled 3 Mtoe in 2007. More than 90% was used for power generation, with a small portion used in transportation and as petrochemical feedstock. In the Reference Scenario, natural gas demand in Philippines is projected to grow at an average annual rate of 2.7% over 2007-2030, reaching 5.6 Mtoe. The share of gas in power generation declines, as the use of coal and geothermal energy rise.

Philippine consumption of coal in 2007 totalled 6.3 Mtoe. Around 70% of the coal was used as fuel for power generation, with the remainder going to cement production and industrial applications. Use of coal for power generation has increased significantly since 1996 and is expected to continue to do so, based on its cost advantage. In the Reference Scenario, Philippine demand for coal is projected to advance by 3.8% per year, reaching 15 Mtoe in 2030.

Philippines is well endowed in terms of renewable energy resources. It is the world's second-largest geothermal power producer (behind the United States) with production of 10 TWh from geothermal sources in 2007. It also has high wind and solar potential, as well as abundant hydropower and biomass resources. In the Reference Scenario, demand for renewable energy, including biomass, grows at an average annual rate of 2.9% over 2007-2030, reaching 33 Mtoe. Its share of total primary energy demand is 44% in 2030, just slightly lower than today. The bulk of the increase is in power generation, underpinned by the government's goal to encourage generation by geothermal, hydropower and other renewables.

In the Reference Scenario, total final consumption grows from 23 Mtoe in 2007 to 38 Mtoe in 2030. The share of the transport sector increases the most, from 38% to 43%. Demand for biofuels is projected to increase to 1.3 Ml/d by 2015 and 2.2 Ml/d by 2030, by which time they represent 4.5% of transportation fuel demand. Total final electricity consumption more than doubles, from 4 Mtoe to 9 Mtoe.

## Oil supply

Philippines had 140 million barrels of proven oil reserves as of January 2009 (O&GJ, 2008). The country's oil production in 2008 was 23 kb/d. Most of the current production is from the Malampaya and Palawan fields in the South China Sea. To encourage upstream oil exploration, the government has provided various incentives, including tax exemptions, profit-sharing agreements and allowances for repatriation of profits.

The Philippine downstream oil industry is dominated by two major oil refining and marketing companies; Petron and Pilipinas Shell. A third oil refiner, Caltex Philippines Inc., converted its facility into an import terminal in 2003 and is now operating as a marketing and distribution company. Petron is jointly owned by the Philippine National Oil Company (PNOC), Saudi Aramco and the public. Petron operates a 180 kb/d refinery and over 1 200 gasoline stations nationwide; Pilipinas Shell has a 110 kb/d refinery and about 800 gasoline stations; Caltex/Chevron has two import terminals and around 850 retail gas stations.

As Philippine total oil demand was 234 kb/d in 2008, imports of 211 kb/d were required. In the Reference Scenario, Philippine total oil production is projected to decline gradually throughout the *Outlook* period to around 10 kb/d in 2030. Imports rise to 235 kb/d in 2015 and 400 kb/d in 2030.

### Natural gas supply

Philippine proven reserves of natural gas stood at 99 bcm as of December 2008 (O&GJ, 2008). Gas production commenced in 2001, with the commercialisation of the offshore Malampaya gas in the South China Sea, and has since increased substantially, allowing gas to become the leading fuel for electricity generation. In 2008, Philippine gas production reached 3.7 bcm.

As with oil, the government has provided incentives, such as tax exemptions, duty exemptions and low-interest funding, to encourage natural gas exploration and production. In the Reference Scenario, gas production is projected to increase to 4.1 bcm in 2030.

### Coal supply

Philippine economically recoverable coal reserves amounted to 316 Mt in 2007, of which two-thirds are hard coal (BGR, 2009). Potential coal resources are nearly six times greater than the current reserve base. The coal produced in Philippines is mainly lignite or sub-bituminous and is of poor quality, so it is typically blended with higher grade imported coal to improve its burning characteristics. Coal deposits are located in many parts of Philippines, with the largest on Semirara Island, Antique. Sizeable deposits are located also in Cebu, Zamboanga Sibuguey, Albay, Surigao and Negros provinces. Incentives, such as tax exemptions, duty exemptions on equipment and ease of entrance for foreign technical personnel, have been provided by the government to bolster coal production.

In addition to indigenous coal production of 2.3 Mtce in 2007, Philippines imported 6.7 Mtce of coal. Coal imports have been rising over the years, in line with increased demand. In the Reference Scenario, Philippine coal production is projected to reach 4.2 Mtce in 2015 and 7.9 Mtce in 2030. Imports are projected to reach 9.4 Mtce in 2015 and 13.4 Mtce in 2030.

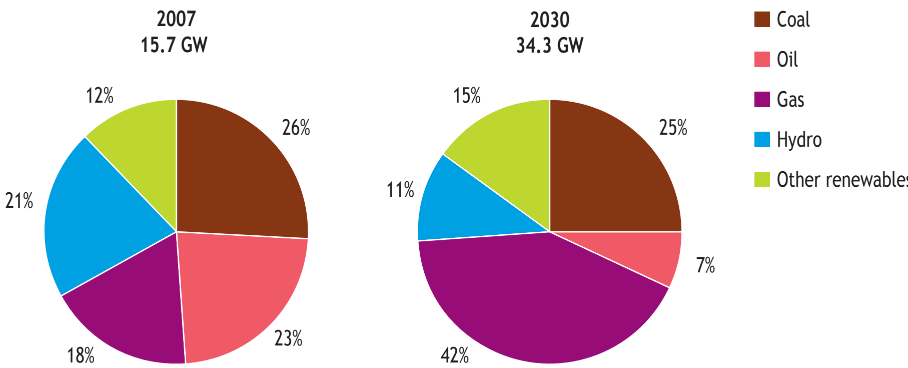
### Electricity generation

Philippine total installed generation capacity in 2007 was 15.7 GW. Coal-fired power plants accounted for the largest share, contributing 4.2 GW. Oil-based power plants accounted for 3.6 GW and hydro-electric power plants for 3.2 GW. Natural gas-fired power plants amounted to 2.8 GW and geothermal power plants to 1.8 GW.

In 2007, power production in Philippines totalled 60 TWh. Natural gas accounted for 33% of total generation, followed by coal at 28%, geothermal at 17%, hydro-electricity at 14% and oil at 8%. Philippines has gradually reduced the use of oil for power generation, with its share declining by more than 50% since 1980. Philippine per-capita electricity consumption is currently only 8% of the OECD average.

In the Reference Scenario, Philippine electricity demand is projected to grow at an average rate of 2.8% per annum until 2015 and then 3.7% between 2015 and 2030. To meet this demand, installed capacity is projected to expand to more than 34 GW by 2030 (Figure 16.12). In the Reference Scenario, electricity generation in Philippines increases by 3.4% per year, reaching 129 TWh in 2030. Coal remains the dominant fuel in power generation, with a share of 42% of total electricity produced by 2030. Nuclear energy does not appear in the timeframe of the Reference Scenario.

**Figure 16.12 • *Philippine installed electricity generation capacity in the Reference Scenario***




**Box 16.2 • *Geothermal in Philippines***

Philippines is the second-largest producer of geothermal power in the world, with estimated potential reserves of 4 800 MW. As of 2007, Philippine geothermal installed capacity was 1 800 MW, mostly located in the central island of Visayas, and accounted for 17% of the country's electricity production.

Philippines aims to be the world leader in geothermal energy and intends to commission 700 MW of new capacity between 2010 and 2014 (Philippine DOE, 2008). The government sees the expansion of geothermal as a means not only of increasing power-generation capacity but also of developing tourism through attractions such as hot springs, spas and resorts.

To promote geothermal exploration and development, several incentives have been put in place, including exemptions from taxes and duties, faster depreciation of capital equipment and easier remittance of earnings. The government hopes to attract $0.9 billion in private investments in the geothermal sector in the next five years.

However, the utilisation of geothermal power is not without its challenges. In addition to attracting private investment and securing project financing, social issues such as the encroachment on ancestral land, resettlement and relocation have to be addressed and technical constraints need to be overcome, such as dealing with equipment corrosion by acidic geothermal fluids. To help overcome the social challenges, the Philippine government is stepping up public awareness campaigns and implementing community programmes to fund and support local education, health and infrastructure construction.

## Climate change and local pollution

Philippine energy-related $CO_2$ emissions in 2007 totalled 72 Mt. On a per-capita basis, in 2007 the country's emissions were less than 10% of the average level in the OECD. In the Reference Scenario, emissions are projected to increase at an average rate of 2.8% per year, to 134 Mt in 2030 (Table 16.12). Emissions of major local pollutants – $NO_x$, $SO_x$ and PM2.5 – are expected to decrease slightly throughout the *Outlook* period, with the wider deployment of advanced emission control systems.

**Table 16.12 • *Philippine energy-related $CO_2$ and local air pollutant emissions in the Reference Scenario*** (Mt)

| | 1980 | 2000 | 2007 | 2015 | 2030 | 2007-2030* |
|---|---|---|---|---|---|---|
| $CO_2$ | 33 | 70 | 72 | 83 | 134 | 2.8% |
| $NO_x$ | n.a. | n.a. | 0.4 | 0.3 | 0.4 | -0.3% |
| PM2.5 | n.a. | n.a. | 0.2 | 0.2 | 0.2 | -0.4% |
| $SO_2$ | n.a. | n.a. | 0.3 | 0.2 | 0.3 | -0.5% |

* Compound average annual growth rate.

Sources: IEA analysis and IIASA (2009).

# ANNEXES

# TABLES FOR REFERENCE SCENARIO PROJECTIONS

## General note to the tables

The tables show projections of energy demand, electricity generation and capacity, and carbon dioxide ($CO_2$) emissions from fuel combustion for the following regions/countries: World, OECD, OECD North America, the United States, OECD Europe, the European Union, OECD Pacific, Japan, non-OECD, Eastern Europe/Eurasia, Russia, non-OECD Asia, China, India, the Association of Southeast Asian Nations (ASEAN), the Middle East, Africa and Latin America.

For OECD and non-OECD countries, the energy demand, electricity generation and $CO_2$ emissions from fuel combustion data up to 2007, are based on IEA statistics, published in *Energy Balances of OECD Countries*, *Energy Balances of Non-OECD Countries*, and *$CO_2$ Emissions from Fuel Combustion*.

The definitions for regions, fuels and sectors can be found in Annex C.

Both in the text of this book and in the tables, rounding may cause some differences between the total and the sum of the individual components. Growth rates are calculated on a compound average annual basis and are marked "n.a." when the base year is zero or the value exceeds 200%.

## Definitional note to the tables

*Total primary energy demand* is equivalent to *power generation* plus *other energy sector* excluding electricity and heat, plus *total final consumption* excluding electricity and heat. *Total primary energy demand* does not include ambient heat from heat pumps or electricity trade. *Power generation* includes electricity and heat production by main activity producers and auto-producers. *Other sectors* includes final consumption in the residential, services, agricultural and non-specified sectors. Total $CO_2$ emissions include emissions from *other energy sector*, as well as from *power generation* and *total final consumption* (as shown in the tables). $CO_2$ emissions and energy demand from international marine and aviation[1] bunkers are included only at the global transport level. $CO_2$ emissions do not include emissions from industrial waste and non-renewable municipal waste.

1. In October 2008, the IEA hosted the 3rd meeting of InterEnerStat during which it decided to align its energy statistics and balances with most other international organisations and to treat international aviation bunkers in the same way as international marine bunkers. Compared to previous editions, in the *WEO-2009* international aviation bunkers are reported at the world level rather than at country/regional level.

## **Reference Scenario:** World

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **8 761** | **12 013** | **13 488** | **14 450** | **15 611** | **16 790** | **100** | **100** | **1.5** |
| Coal | 2 221 | 3 184 | 3 828 | 4 125 | 4 522 | 4 887 | 27 | 29 | 1.9 |
| Oil | 3 219 | 4 093 | 4 234 | 4 440 | 4 691 | 5 009 | 34 | 30 | 0.9 |
| Gas | 1 671 | 2 512 | 2 801 | 3 035 | 3 299 | 3 561 | 21 | 21 | 1.5 |
| Nuclear | 526 | 709 | 810 | 851 | 921 | 956 | 6 | 6 | 1.3 |
| Hydro | 184 | 265 | 317 | 346 | 374 | 402 | 2 | 2 | 1.8 |
| Biomass and waste | 904 | 1 176 | 1 338 | 1 428 | 1 512 | 1 604 | 10 | 10 | 1.4 |
| Other renewables | 36 | 74 | 160 | 224 | 292 | 370 | 1 | 2 | 7.3 |
| **Power generation** | **2 981** | **4 557** | **5 338** | **5 823** | **6 420** | **7 042** | **100** | **100** | **1.9** |
| Coal | 1 228 | 2 167 | 2 631 | 2 871 | 3 174 | 3 481 | 48 | 49 | 2.1 |
| Oil | 376 | 284 | 220 | 199 | 183 | 167 | 6 | 2 | -2.3 |
| Gas | 576 | 988 | 1 093 | 1 202 | 1 318 | 1 464 | 22 | 21 | 1.7 |
| Nuclear | 526 | 709 | 810 | 851 | 921 | 956 | 16 | 14 | 1.3 |
| Hydro | 184 | 265 | 317 | 346 | 374 | 402 | 6 | 6 | 1.8 |
| Biomass and waste | 59 | 84 | 128 | 160 | 200 | 257 | 2 | 4 | 5.0 |
| Other renewables | 32 | 60 | 138 | 194 | 251 | 314 | 1 | 4 | 7.4 |
| **Other energy sector** | **880** | **1 212** | **1 399** | **1 498** | **1 612** | **1 682** | **100** | **100** | **1.4** |
| *of which electricity* | *183* | *287* | *342* | *379* | *420* | *461* | *24* | *27* | *2.1* |
| **Total final consumption** | **6 293** | **8 273** | **9 201** | **9 838** | **10 599** | **11 405** | **100** | **100** | **1.4** |
| Coal | 761 | 727 | 846 | 878 | 918 | 961 | 9 | 8 | 1.2 |
| Oil | 2 607 | 3 527 | 3 732 | 3 961 | 4 254 | 4 581 | 43 | 40 | 1.1 |
| Gas | 957 | 1 292 | 1 419 | 1 510 | 1 619 | 1 728 | 16 | 15 | 1.3 |
| Electricity | 833 | 1 413 | 1 752 | 1 963 | 2 217 | 2 488 | 17 | 22 | 2.5 |
| Heat | 333 | 273 | 292 | 301 | 314 | 322 | 3 | 3 | 0.7 |
| Biomass and waste | 797 | 1 029 | 1 139 | 1 194 | 1 236 | 1 270 | 12 | 11 | 0.9 |
| Other renewables | 4 | 13 | 22 | 30 | 41 | 55 | 0 | 0 | 6.6 |
| **Industry** | **1 800** | **2 266** | **2 650** | **2 836** | **3 067** | **3 302** | **100** | **100** | **1.7** |
| Coal | 470 | 581 | 677 | 706 | 745 | 789 | 26 | 24 | 1.3 |
| Oil | 327 | 320 | 328 | 336 | 346 | 355 | 14 | 11 | 0.5 |
| Gas | 355 | 460 | 510 | 544 | 584 | 622 | 20 | 19 | 1.3 |
| Electricity | 379 | 596 | 786 | 881 | 991 | 1 103 | 26 | 33 | 2.7 |
| Heat | 150 | 120 | 128 | 131 | 135 | 139 | 5 | 4 | 0.6 |
| Biomass and waste | 117 | 189 | 220 | 238 | 263 | 292 | 8 | 9 | 1.9 |
| Other renewables | 0 | 0 | 1 | 1 | 1 | 2 | 0 | 0 | 7.0 |
| **Transport** | **1 578** | **2 297** | **2 530** | **2 753** | **3 019** | **3 331** | **100** | **100** | **1.6** |
| Oil | 1 485 | 2 161 | 2 337 | 2 524 | 2 764 | 3 052 | 94 | 92 | 1.5 |
| *of which marine bunkers* | *113* | *192* | *199* | *214* | *228* | *244* | *8* | *7* | *1.1* |
| *of which aviation bunkers* | *85* | *138* | *152* | *168* | *184* | *204* | *6* | *6* | *1.7* |
| Biofuels | 6 | 34 | 77 | 104 | 120 | 133 | 1 | 4 | 6.1 |
| Other fuels | 87 | 101 | 116 | 125 | 135 | 146 | 4 | 4 | 1.6 |
| **Other sectors** | **2 440** | **2 941** | **3 185** | **3 377** | **3 603** | **3 830** | **100** | **100** | **1.2** |
| Coal | 254 | 110 | 117 | 116 | 113 | 108 | 4 | 3 | -0.1 |
| Oil | 437 | 453 | 458 | 472 | 491 | 505 | 15 | 13 | 0.5 |
| Gas | 456 | 613 | 647 | 689 | 741 | 796 | 21 | 21 | 1.1 |
| Electricity | 433 | 794 | 936 | 1 046 | 1 186 | 1 338 | 27 | 35 | 2.3 |
| Heat | 183 | 153 | 163 | 171 | 179 | 183 | 5 | 5 | 0.8 |
| Biomass and waste | 674 | 806 | 842 | 853 | 854 | 845 | 27 | 22 | 0.2 |
| Other renewables | 4 | 12 | 21 | 30 | 40 | 53 | 0 | 1 | 6.5 |
| **Non-energy use** | **475** | **770** | **836** | **873** | **911** | **942** | **100** | **100** | **0.9** |

## **Reference Scenario:** World

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **11 814** | **19 756** | **24 352** | **27 232** | **30 670** | **34 292** | **100** | **100** | **2.4** |
| Coal | 4 424 | 8 216 | 10 461 | 11 744 | 13 457 | 15 259 | 42 | 44 | 2.7 |
| Oil | 1 332 | 1 117 | 859 | 776 | 717 | 665 | 6 | 2 | -2.2 |
| Gas | 1 727 | 4 126 | 4 982 | 5 620 | 6 270 | 7 058 | 21 | 21 | 2.4 |
| Nuclear | 2 013 | 2 719 | 3 107 | 3 263 | 3 532 | 3 667 | 14 | 11 | 1.3 |
| Hydro | 2 144 | 3 078 | 3 692 | 4 027 | 4 352 | 4 680 | 16 | 14 | 1.8 |
| Biomass and waste | 131 | 259 | 408 | 522 | 654 | 839 | 1 | 2 | 5.2 |
| Wind | 4 | 173 | 678 | 1 010 | 1 289 | 1 535 | 1 | 4 | 9.9 |
| Geothermal | 36 | 62 | 97 | 121 | 146 | 173 | 0 | 1 | 4.6 |
| Solar | 1 | 5 | 67 | 146 | 248 | 402 | 0 | 1 | 21.2 |
| Tide and wave | 1 | 1 | 2 | 3 | 5 | 13 | 0 | 0 | 14.6 |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **4 509** | **5 728** | **6 284** | **7 026** | **7 821** | **100** | **100** | **2.4** |
| Coal | 1 440 | 1 897 | 2 108 | 2 408 | 2 705 | 32 | 35 | 2.8 |
| Oil | 445 | 422 | 345 | 300 | 268 | 10 | 3 | -2.2 |
| Gas | 1 168 | 1 464 | 1 573 | 1 749 | 1 972 | 26 | 25 | 2.3 |
| Nuclear | 371 | 411 | 427 | 459 | 475 | 8 | 6 | 1.1 |
| Hydro | 923 | 1 099 | 1 196 | 1 289 | 1 382 | 20 | 18 | 1.8 |
| Biomass and waste | 46 | 71 | 91 | 114 | 146 | 1 | 2 | 5.2 |
| Wind | 96 | 295 | 422 | 522 | 600 | 2 | 8 | 8.3 |
| Geothermal | 11 | 16 | 19 | 22 | 26 | 0 | 0 | 4.0 |
| Solar | 9 | 53 | 102 | 162 | 244 | 0 | 3 | 15.3 |
| Tide and wave | 0 | 1 | 1 | 1 | 3 | 0 | 0 | 11.5 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **20 941** | **28 826** | **32 306** | **34 526** | **37 311** | **40 226** | **100** | **100** | **1.5** |
| Coal | 8 308 | 12 220 | 14 677 | 15 796 | 17 228 | 18 641 | 42 | 46 | 1.9 |
| Oil | 8 823 | 10 888 | 11 311 | 11 910 | 12 707 | 13 618 | 38 | 34 | 1.0 |
| Gas | 3 810 | 5 718 | 6 317 | 6 820 | 7 376 | 7 966 | 20 | 20 | 1.5 |
| **Power generation** | **7 471** | **11 896** | **13 819** | **14 953** | **16 344** | **17 824** | **100** | **100** | **1.8** |
| Coal | 4 929 | 8 681 | 10 556 | 11 504 | 12 680 | 13 873 | 73 | 78 | 2.1 |
| Oil | 1 196 | 900 | 701 | 633 | 579 | 530 | 8 | 3 | -2.3 |
| Gas | 1 346 | 2 315 | 2 562 | 2 817 | 3 085 | 3 421 | 19 | 19 | 1.7 |
| **Total final consumption** | **12 454** | **15 493** | **16 842** | **17 817** | **19 049** | **20 409** | **100** | **100** | **1.2** |
| Coal | 3 241 | 3 290 | 3 806 | 3 941 | 4 108 | 4 288 | 21 | 21 | 1.2 |
| Oil | 7 061 | 9 311 | 9 887 | 10 531 | 11 358 | 12 300 | 60 | 60 | 1.2 |
| *of which transport* | *4 399* | *6 435* | *6 959* | *7 518* | *8 235* | *9 092* | *42* | *45* | *1.5* |
| *of which marine bunkers* | *358* | *613* | *636* | *685* | *731* | *780* | *4* | *4* | *1.1* |
| *of which aviation bunkers* | *252* | *405* | *448* | *494* | *543* | *600* | *3* | *3* | *1.7* |
| Gas | 2 152 | 2 892 | 3 149 | 3 345 | 3 583 | 3 821 | 19 | 19 | 1.2 |

# **Reference Scenario:** OECD

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **4 476** | **5 496** | **5 458** | **5 553** | **5 681** | **5 811** | **100** | **100** | **0.2** |
| Coal | 1 065 | 1 158 | 1 112 | 1 094 | 1 106 | 1 103 | 21 | 19 | -0.2 |
| Oil | 1 851 | 2 110 | 1 930 | 1 898 | 1 868 | 1 853 | 38 | 32 | -0.6 |
| Gas | 840 | 1 259 | 1 283 | 1 350 | 1 394 | 1 453 | 23 | 25 | 0.6 |
| Nuclear | 450 | 592 | 623 | 612 | 638 | 653 | 11 | 11 | 0.4 |
| Hydro | 101 | 108 | 117 | 121 | 125 | 127 | 2 | 2 | 0.7 |
| Biomass and waste | 141 | 221 | 295 | 342 | 377 | 414 | 4 | 7 | 2.8 |
| Other renewables | 29 | 47 | 100 | 137 | 172 | 208 | 1 | 4 | 6.7 |
| **Power generation** | **1 703** | **2 281** | **2 343** | **2 396** | **2 488** | **2 591** | **100** | **100** | **0.6** |
| Coal | 749 | 937 | 923 | 915 | 917 | 918 | 41 | 35 | -0.1 |
| Oil | 151 | 99 | 54 | 40 | 34 | 33 | 4 | 1 | -4.7 |
| Gas | 175 | 437 | 446 | 480 | 501 | 537 | 19 | 21 | 0.9 |
| Nuclear | 450 | 592 | 623 | 612 | 638 | 653 | 26 | 25 | 0.4 |
| Hydro | 101 | 108 | 117 | 121 | 125 | 127 | 5 | 5 | 0.7 |
| Biomass and waste | 52 | 67 | 92 | 108 | 123 | 142 | 3 | 5 | 3.3 |
| Other renewables | 25 | 40 | 89 | 121 | 151 | 180 | 2 | 7 | 6.8 |
| **Other energy sector** | **389** | **440** | **436** | **445** | **456** | **459** | **100** | **100** | **0.2** |
| *of which electricity* | *105* | *121* | *125* | *131* | *136* | *140* | *27* | *30* | *0.6* |
| **Total final consumption** | **3 084** | **3 771** | **3 731** | **3 816** | **3 904** | **3 991** | **100** | **100** | **0.2** |
| Coal | 230 | 135 | 117 | 112 | 107 | 102 | 4 | 3 | -1.2 |
| Oil | 1 584 | 1 874 | 1 747 | 1 738 | 1 730 | 1 721 | 50 | 43 | -0.4 |
| Gas | 590 | 738 | 739 | 754 | 773 | 789 | 20 | 20 | 0.3 |
| Electricity | 548 | 795 | 842 | 886 | 941 | 997 | 21 | 25 | 1.0 |
| Heat | 40 | 68 | 73 | 75 | 79 | 82 | 2 | 2 | 0.8 |
| Biomass and waste | 89 | 154 | 203 | 234 | 254 | 272 | 4 | 7 | 2.5 |
| Other renewables | 4 | 7 | 11 | 16 | 21 | 27 | 0 | 1 | 6.0 |
| **Industry** | **820** | **872** | **867** | **874** | **886** | **894** | **100** | **100** | **0.1** |
| Coal | 158 | 115 | 101 | 97 | 94 | 90 | 13 | 10 | -1.1 |
| Oil | 168 | 129 | 111 | 106 | 102 | 98 | 15 | 11 | -1.2 |
| Gas | 225 | 259 | 257 | 258 | 260 | 259 | 30 | 29 | 0.0 |
| Electricity | 220 | 270 | 282 | 289 | 297 | 303 | 31 | 34 | 0.5 |
| Heat | 14 | 27 | 27 | 28 | 28 | 28 | 3 | 3 | 0.3 |
| Biomass and waste | 36 | 71 | 89 | 96 | 104 | 114 | 8 | 13 | 2.0 |
| Other renewables | 0 | 0 | 1 | 1 | 1 | 2 | 0 | 0 | 6.7 |
| **Transport** | **936** | **1 237** | **1 224** | **1 248** | **1 256** | **1 263** | **100** | **100** | **0.1** |
| Oil | 909 | 1 181 | 1 138 | 1 142 | 1 143 | 1 148 | 95 | 91 | -0.1 |
| Biofuels | 0 | 23 | 50 | 67 | 72 | 73 | 2 | 6 | 5.1 |
| Other fuels | 27 | 33 | 37 | 39 | 40 | 42 | 3 | 3 | 1.0 |
| **Other sectors** | **1 039** | **1 272** | **1 288** | **1 346** | **1 416** | **1 493** | **100** | **100** | **0.7** |
| Coal | 69 | 17 | 14 | 13 | 11 | 10 | 1 | 1 | -2.4 |
| Oil | 255 | 212 | 183 | 178 | 174 | 170 | 17 | 11 | -1.0 |
| Gas | 311 | 421 | 422 | 435 | 452 | 470 | 33 | 31 | 0.5 |
| Electricity | 320 | 515 | 549 | 585 | 630 | 680 | 40 | 46 | 1.2 |
| Heat | 27 | 42 | 45 | 48 | 50 | 53 | 3 | 4 | 1.1 |
| Biomass and waste | 53 | 59 | 65 | 71 | 78 | 85 | 5 | 6 | 1.6 |
| Other renewables | 3 | 7 | 10 | 15 | 20 | 26 | 1 | 2 | 6.0 |
| **Non-energy use** | **289** | **391** | **352** | **348** | **346** | **342** | **100** | **100** | **-0.6** |

# Reference Scenario: OECD

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **7 568** | **10 641** | **11 239** | **11 825** | **12 512** | **13 215** | **100** | **100** | **0.9** |
| Coal | 3 055 | 3 957 | 3 896 | 3 968 | 4 102 | 4 241 | 37 | 32 | 0.3 |
| Oil | 692 | 434 | 237 | 175 | 149 | 145 | 4 | 1 | -4.7 |
| Gas | 771 | 2 307 | 2 430 | 2 656 | 2 785 | 2 962 | 22 | 22 | 1.1 |
| Nuclear | 1 725 | 2 273 | 2 389 | 2 347 | 2 449 | 2 506 | 21 | 19 | 0.4 |
| Hydro | 1 170 | 1 258 | 1 355 | 1 408 | 1 448 | 1 478 | 12 | 11 | 0.7 |
| Biomass and waste | 123 | 217 | 306 | 366 | 423 | 492 | 2 | 4 | 3.6 |
| Wind | 4 | 150 | 512 | 728 | 910 | 1 068 | 1 | 8 | 8.9 |
| Geothermal | 29 | 40 | 58 | 70 | 82 | 92 | 0 | 1 | 3.7 |
| Solar | 1 | 5 | 54 | 102 | 160 | 220 | 0 | 2 | 18.3 |
| Tide and wave | 1 | 1 | 2 | 3 | 5 | 12 | 0 | 0 | 14.3 |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **2 472** | **2 766** | **2 852** | **3 009** | **3 174** | **100** | **100** | **1.1** |
| Coal | 648 | 661 | 655 | 662 | 663 | 26 | 21 | 0.1 |
| Oil | 226 | 195 | 130 | 100 | 85 | 9 | 3 | -4.2 |
| Gas | 720 | 804 | 826 | 868 | 931 | 29 | 29 | 1.1 |
| Nuclear | 308 | 315 | 307 | 318 | 325 | 12 | 10 | 0.2 |
| Hydro | 436 | 461 | 476 | 488 | 496 | 18 | 16 | 0.6 |
| Biomass and waste | 38 | 53 | 64 | 74 | 86 | 2 | 3 | 3.6 |
| Wind | 81 | 222 | 303 | 368 | 417 | 3 | 13 | 7.4 |
| Geothermal | 7 | 10 | 11 | 13 | 14 | 0 | 0 | 3.0 |
| Solar | 8 | 45 | 80 | 118 | 155 | 0 | 5 | 13.5 |
| Tide and wave | 0 | 1 | 1 | 1 | 3 | 0 | 0 | 11.3 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **11 033** | **12 916** | **12 358** | **12 366** | **12 413** | **12 494** | **100** | **100** | **-0.1** |
| Coal | 4 103 | 4 465 | 4 322 | 4 260 | 4 259 | 4 234 | 35 | 34 | -0.2 |
| Oil | 5 009 | 5 504 | 5 046 | 4 979 | 4 931 | 4 907 | 43 | 39 | -0.5 |
| Gas | 1 920 | 2 947 | 2 990 | 3 126 | 3 224 | 3 353 | 23 | 27 | 0.6 |
| **Power generation** | **3 912** | **5 129** | **4 951** | **4 948** | **4 962** | **5 033** | **100** | **100** | **-0.1** |
| Coal | 3 026 | 3 791 | 3 732 | 3 696 | 3 683 | 3 673 | 74 | 73 | -0.1 |
| Oil | 477 | 314 | 173 | 128 | 108 | 105 | 6 | 2 | -4.6 |
| Gas | 409 | 1 024 | 1 045 | 1 124 | 1 171 | 1 254 | 20 | 25 | 0.9 |
| **Total final consumption** | **6 524** | **7 105** | **6 725** | **6 718** | **6 715** | **6 713** | **100** | **100** | **-0.2** |
| Coal | 1 015 | 592 | 513 | 489 | 467 | 444 | 8 | 7 | -1.2 |
| Oil | 4 165 | 4 815 | 4 511 | 4 493 | 4 469 | 4 451 | 68 | 66 | -0.3 |
| *of which transport* | *2 668* | *3 481* | *3 354* | *3 368* | *3 370* | *3 385* | *49* | *50* | *-0.1* |
| Gas | 1 344 | 1 698 | 1 701 | 1 736 | 1 780 | 1 819 | 24 | 27 | 0.3 |

## **Reference Scenario:** OECD North America

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **2 243** | **2 793** | **2 778** | **2 834** | **2 909** | **2 974** | **100** | **100** | **0.3** |
| Coal | 486 | 593 | 590 | 587 | 611 | 621 | 21 | 21 | 0.2 |
| Oil | 914 | 1 109 | 1 018 | 1 009 | 990 | 985 | 40 | 33 | -0.5 |
| Gas | 516 | 668 | 672 | 691 | 709 | 733 | 24 | 25 | 0.4 |
| Nuclear | 180 | 245 | 256 | 263 | 282 | 285 | 9 | 10 | 0.7 |
| Hydro | 51 | 55 | 58 | 59 | 60 | 61 | 2 | 2 | 0.4 |
| Biomass and waste | 78 | 102 | 140 | 164 | 182 | 200 | 4 | 7 | 3.0 |
| Other renewables | 19 | 20 | 44 | 61 | 75 | 89 | 1 | 3 | 6.7 |
| **Power generation** | **851** | **1 121** | **1 164** | **1 198** | **1 249** | **1 298** | **100** | **100** | **0.6** |
| Coal | 419 | 537 | 544 | 543 | 551 | 560 | 48 | 43 | 0.2 |
| Oil | 47 | 34 | 19 | 15 | 12 | 11 | 3 | 1 | -5.0 |
| Gas | 95 | 210 | 212 | 221 | 228 | 244 | 19 | 19 | 0.7 |
| Nuclear | 180 | 245 | 256 | 263 | 282 | 285 | 22 | 22 | 0.7 |
| Hydro | 51 | 55 | 58 | 59 | 60 | 61 | 5 | 5 | 0.4 |
| Biomass and waste | 41 | 22 | 35 | 42 | 49 | 60 | 2 | 5 | 4.4 |
| Other renewables | 18 | 18 | 41 | 55 | 67 | 78 | 2 | 6 | 6.7 |
| **Other energy sector** | **185** | **228** | **229** | **234** | **243** | **246** | **100** | **100** | **0.3** |
| *of which electricity* | *57* | *60* | *64* | *68* | *71* | *73* | *26* | *30* | *0.9* |
| **Total final consumption** | **1 538** | **1 908** | **1 874** | **1 916** | **1 961** | **2 004** | **100** | **100** | **0.2** |
| Coal | 59 | 36 | 31 | 29 | 27 | 25 | 2 | 1 | -1.5 |
| Oil | 807 | 1 000 | 931 | 931 | 932 | 936 | 52 | 47 | -0.3 |
| Gas | 360 | 392 | 385 | 388 | 394 | 397 | 21 | 20 | 0.1 |
| Electricity | 271 | 390 | 410 | 432 | 460 | 488 | 20 | 24 | 1.0 |
| Heat | 3 | 8 | 8 | 8 | 8 | 7 | 0 | 0 | -0.3 |
| Biomass and waste | 37 | 80 | 105 | 122 | 133 | 139 | 4 | 7 | 2.4 |
| Other renewables | 0 | 2 | 3 | 6 | 8 | 11 | 0 | 1 | 6.7 |
| **Industry** | **357** | **378** | **376** | **375** | **377** | **377** | **100** | **100** | **-0.0** |
| Coal | 49 | 34 | 29 | 27 | 26 | 24 | 9 | 6 | -1.4 |
| Oil | 60 | 43 | 35 | 34 | 33 | 32 | 11 | 8 | -1.3 |
| Gas | 138 | 145 | 140 | 139 | 139 | 137 | 38 | 36 | -0.2 |
| Electricity | 94 | 107 | 110 | 111 | 112 | 113 | 28 | 30 | 0.2 |
| Heat | 1 | 6 | 7 | 7 | 7 | 7 | 2 | 2 | 0.2 |
| Biomass and waste | 16 | 44 | 55 | 57 | 61 | 64 | 12 | 17 | 1.7 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2.8 |
| **Transport** | **560** | **744** | **737** | **752** | **759** | **767** | **100** | **100** | **0.1** |
| Oil | 541 | 707 | 685 | 687 | 689 | 697 | 95 | 91 | -0.1 |
| Biofuels | 0 | 15 | 29 | 42 | 47 | 47 | 2 | 6 | 5.0 |
| Other fuels | 19 | 22 | 23 | 23 | 23 | 24 | 3 | 3 | 0.4 |
| **Other sectors** | **477** | **594** | **591** | **619** | **655** | **692** | **100** | **100** | **0.7** |
| Coal | 10 | 2 | 1 | 1 | 1 | 0 | 0 | 0 | -6.0 |
| Oil | 82 | 81 | 62 | 62 | 61 | 60 | 14 | 9 | -1.3 |
| Gas | 185 | 206 | 202 | 207 | 213 | 219 | 35 | 32 | 0.3 |
| Electricity | 177 | 281 | 299 | 320 | 345 | 373 | 47 | 54 | 1.2 |
| Heat | 2 | 2 | 1 | 1 | 1 | 1 | 0 | 0 | -3.1 |
| Biomass and waste | 21 | 21 | 21 | 23 | 25 | 28 | 3 | 4 | 1.3 |
| Other renewables | 0 | 2 | 3 | 6 | 8 | 11 | 0 | 2 | 6.9 |
| **Non-energy use** | **143** | **191** | **170** | **170** | **170** | **168** | **100** | **100** | **-0.5** |

## **Reference Scenario:** OECD North America

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **3 809** | **5 219** | **5 515** | **5 815** | **6 168** | **6 521** | **100** | **100** | **1.0** |
| Coal | 1 790 | 2 266 | 2 266 | 2 341 | 2 450 | 2 569 | 43 | 39 | 0.5 |
| Oil | 217 | 140 | 81 | 65 | 51 | 47 | 3 | 1 | -4.7 |
| Gas | 406 | 1 082 | 1 135 | 1 196 | 1 255 | 1 349 | 21 | 21 | 1.0 |
| Nuclear | 687 | 941 | 981 | 1 010 | 1 084 | 1 093 | 18 | 17 | 0.7 |
| Hydro | 593 | 645 | 677 | 686 | 695 | 704 | 12 | 11 | 0.4 |
| Biomass and waste | 90 | 83 | 131 | 159 | 189 | 229 | 2 | 4 | 4.5 |
| Wind | 3 | 38 | 193 | 281 | 337 | 392 | 1 | 6 | 10.7 |
| Geothermal | 21 | 24 | 37 | 45 | 53 | 59 | 0 | 1 | 4.0 |
| Solar | 1 | 1 | 14 | 32 | 55 | 79 | 0 | 1 | 22.6 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 18.1 |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **1 223** | **1 307** | **1 354** | **1 429** | **1 502** | **100** | **100** | **0.9** |
| Coal | 354 | 354 | 371 | 390 | 393 | 29 | 26 | 0.5 |
| Oil | 96 | 79 | 48 | 34 | 31 | 8 | 2 | -4.8 |
| Gas | 438 | 458 | 465 | 485 | 517 | 36 | 34 | 0.7 |
| Nuclear | 115 | 120 | 123 | 132 | 133 | 9 | 9 | 0.7 |
| Hydro | 183 | 186 | 188 | 190 | 192 | 15 | 13 | 0.2 |
| Biomass and waste | 13 | 21 | 26 | 31 | 38 | 1 | 3 | 4.9 |
| Wind | 19 | 75 | 106 | 124 | 141 | 2 | 9 | 9.1 |
| Geothermal | 4 | 5 | 6 | 8 | 8 | 0 | 1 | 3.7 |
| Solar | 1 | 9 | 20 | 34 | 49 | 0 | 3 | 16.9 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 13.5 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **5 570** | **6 752** | **6 540** | **6 558** | **6 633** | **6 721** | **100** | **100** | **-0.0** |
| Coal | 1 905 | 2 278 | 2 283 | 2 275 | 2 325 | 2 352 | 34 | 35 | 0.1 |
| Oil | 2 478 | 2 914 | 2 692 | 2 677 | 2 666 | 2 675 | 43 | 40 | -0.4 |
| Gas | 1 187 | 1 560 | 1 565 | 1 606 | 1 643 | 1 695 | 23 | 25 | 0.4 |
| **Power generation** | **2 014** | **2 715** | **2 700** | **2 704** | **2 730** | **2 787** | **100** | **100** | **0.1** |
| Coal | 1 640 | 2 111 | 2 140 | 2 138 | 2 160 | 2 184 | 78 | 78 | 0.1 |
| Oil | 151 | 114 | 64 | 51 | 38 | 35 | 4 | 1 | -5.0 |
| Gas | 222 | 490 | 496 | 516 | 531 | 568 | 18 | 20 | 0.6 |
| **Total final consumption** | **3 203** | **3 647** | **3 442** | **3 442** | **3 450** | **3 464** | **100** | **100** | **-0.2** |
| Coal | 262 | 152 | 130 | 121 | 114 | 106 | 4 | 3 | -1.6 |
| Oil | 2 114 | 2 593 | 2 429 | 2 429 | 2 431 | 2 445 | 71 | 71 | -0.3 |
| *of which transport* | *1 579* | *2 072* | *2 007* | *2 013* | *2 019* | *2 041* | *57* | *59* | *-0.1* |
| Gas | 827 | 901 | 883 | 892 | 905 | 913 | 25 | 26 | 0.1 |



A

## **Reference Scenario:** United States

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **1 913** | **2 337** | **2 291** | **2 316** | **2 360** | **2 396** | **100** | **100** | **0.1** |
| Coal | 458 | 554 | 549 | 548 | 571 | 581 | 24 | 24 | 0.2 |
| Oil | 757 | 910 | 822 | 806 | 782 | 772 | 39 | 32 | -0.7 |
| Gas | 438 | 538 | 522 | 522 | 526 | 533 | 23 | 22 | -0.0 |
| Nuclear | 159 | 218 | 225 | 231 | 246 | 248 | 9 | 10 | 0.6 |
| Hydro | 23 | 21 | 23 | 24 | 24 | 24 | 1 | 1 | 0.5 |
| Biomass and waste | 62 | 82 | 116 | 138 | 153 | 167 | 4 | 7 | 3.1 |
| Other renewables | 14 | 13 | 34 | 47 | 59 | 70 | 1 | 3 | 7.5 |
| **Power generation** | **750** | **963** | **994** | **1 016** | **1 054** | **1 091** | **100** | **100** | **0.5** |
| Coal | 396 | 502 | 507 | 509 | 516 | 525 | 52 | 48 | 0.2 |
| Oil | 27 | 18 | 10 | 7 | 5 | 6 | 2 | 1 | -4.9 |
| Gas | 90 | 173 | 167 | 167 | 168 | 175 | 18 | 16 | 0.0 |
| Nuclear | 159 | 218 | 225 | 231 | 246 | 248 | 23 | 23 | 0.6 |
| Hydro | 23 | 21 | 23 | 24 | 24 | 24 | 2 | 2 | 0.5 |
| Biomass and waste | 40 | 19 | 31 | 37 | 44 | 53 | 2 | 5 | 4.6 |
| Other renewables | 14 | 11 | 31 | 42 | 51 | 60 | 1 | 6 | 7.7 |
| **Other energy sector** | **149** | **174** | **165** | **162** | **164** | **159** | **100** | **100** | **-0.4** |
| *of which electricity* | *49* | *46* | *49* | *52* | *53* | *54* | *26* | *34* | *0.8* |
| **Total final consumption** | **1 292** | **1 588** | **1 538** | **1 563** | **1 588** | **1 614** | **100** | **100** | **0.1** |
| Coal | 54 | 30 | 26 | 24 | 23 | 21 | 2 | 1 | -1.5 |
| Oil | 683 | 835 | 762 | 754 | 746 | 743 | 53 | 46 | -0.5 |
| Gas | 303 | 321 | 311 | 313 | 316 | 318 | 20 | 20 | -0.0 |
| Electricity | 226 | 329 | 343 | 359 | 380 | 402 | 21 | 25 | 0.9 |
| Heat | 2 | 7 | 7 | 7 | 7 | 6 | 0 | 0 | -0.4 |
| Biomass and waste | 23 | 63 | 85 | 101 | 110 | 114 | 4 | 7 | 2.6 |
| Other renewables | 0 | 2 | 3 | 5 | 8 | 10 | 0 | 1 | 6.5 |
| **Industry** | **283** | **292** | **284** | **280** | **276** | **271** | **100** | **100** | **-0.3** |
| Coal | 45 | 28 | 25 | 23 | 22 | 21 | 10 | 8 | -1.3 |
| Oil | 44 | 31 | 24 | 22 | 21 | 20 | 11 | 7 | -1.9 |
| Gas | 110 | 111 | 105 | 103 | 101 | 98 | 38 | 36 | -0.5 |
| Electricity | 75 | 80 | 79 | 78 | 77 | 74 | 27 | 27 | -0.3 |
| Heat | 0 | 6 | 6 | 6 | 6 | 6 | 2 | 2 | 0.1 |
| Biomass and waste | 9 | 36 | 45 | 47 | 49 | 52 | 12 | 19 | 1.7 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2.7 |
| **Transport** | **488** | **636** | **620** | **628** | **628** | **629** | **100** | **100** | **-0.0** |
| Oil | 472 | 605 | 577 | 572 | 567 | 568 | 95 | 90 | -0.3 |
| Biofuels | 0 | 15 | 27 | 39 | 44 | 44 | 2 | 7 | 4.8 |
| Other fuels | 16 | 16 | 17 | 17 | 17 | 17 | 2 | 3 | 0.4 |
| **Other sectors** | **403** | **502** | **495** | **518** | **548** | **580** | **100** | **100** | **0.6** |
| Coal | 10 | 2 | 1 | 1 | 1 | 0 | 0 | 0 | -5.9 |
| Oil | 62 | 56 | 39 | 38 | 37 | 35 | 11 | 6 | -1.9 |
| Gas | 164 | 180 | 176 | 179 | 184 | 189 | 36 | 33 | 0.2 |
| Electricity | 152 | 248 | 263 | 280 | 302 | 326 | 49 | 56 | 1.2 |
| Heat | 2 | 2 | 1 | 1 | 1 | 1 | 0 | 0 | -3.7 |
| Biomass and waste | 14 | 13 | 13 | 15 | 17 | 18 | 3 | 3 | 1.6 |
| Other renewables | 0 | 2 | 3 | 5 | 7 | 10 | 0 | 2 | 6.7 |
| **Non-energy use** | **119** | **158** | **138** | **136** | **136** | **133** | **100** | **100** | **-0.7** |

## **Reference Scenario:** United States

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **3 203** | **4 322** | **4 526** | **4 748** | **5 008** | **5 277** | **100** | **100** | **0.9** |
| Coal | 1 700 | 2 118 | 2 111 | 2 194 | 2 291 | 2 402 | 49 | 46 | 0.5 |
| Oil | 131 | 78 | 44 | 31 | 26 | 27 | 2 | 1 | -4.6 |
| Gas | 382 | 915 | 904 | 915 | 927 | 968 | 21 | 18 | 0.2 |
| Nuclear | 612 | 837 | 863 | 885 | 942 | 951 | 19 | 18 | 0.6 |
| Hydro | 273 | 250 | 272 | 274 | 276 | 279 | 6 | 5 | 0.5 |
| Biomass and waste | 86 | 72 | 117 | 142 | 169 | 206 | 2 | 4 | 4.7 |
| Wind | 3 | 35 | 175 | 243 | 284 | 325 | 1 | 6 | 10.2 |
| Geothermal | 16 | 17 | 27 | 34 | 40 | 45 | 0 | 1 | 4.4 |
| Solar | 1 | 1 | 13 | 30 | 52 | 74 | 0 | 1 | 22.5 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | n.a. |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **1 039** | **1 096** | **1 125** | **1 185** | **1 239** | **100** | **100** | **0.8** |
| Coal | 333 | 332 | 349 | 367 | 368 | 32 | 30 | 0.4 |
| Oil | 73 | 59 | 30 | 21 | 21 | 7 | 2 | -5.4 |
| Gas | 400 | 403 | 400 | 410 | 429 | 39 | 35 | 0.3 |
| Nuclear | 101 | 104 | 107 | 114 | 115 | 10 | 9 | 0.6 |
| Hydro | 100 | 100 | 101 | 101 | 102 | 10 | 8 | 0.1 |
| Biomass and waste | 11 | 19 | 23 | 28 | 34 | 1 | 3 | 5.1 |
| Wind | 17 | 68 | 92 | 105 | 118 | 2 | 10 | 8.8 |
| Geothermal | 3 | 4 | 5 | 6 | 6 | 0 | 1 | 4.0 |
| Solar | 1 | 9 | 19 | 32 | 46 | 0 | 4 | 16.7 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 13.5 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **4 845** | **5 742** | **5 494** | **5 466** | **5 494** | **5 535** | **100** | **100** | **-0.2** |
| Coal | 1 792 | 2 115 | 2 115 | 2 119 | 2 165 | 2 194 | 37 | 40 | 0.2 |
| Oil | 2 042 | 2 382 | 2 170 | 2 136 | 2 110 | 2 104 | 41 | 38 | -0.5 |
| Gas | 1 011 | 1 245 | 1 209 | 1 211 | 1 219 | 1 238 | 22 | 22 | -0.0 |
| **Power generation** | **1 848** | **2 441** | **2 418** | **2 414** | **2 430** | **2 472** | **100** | **100** | **0.1** |
| Coal | 1 550 | 1 975 | 1 995 | 2 003 | 2 021 | 2 045 | 81 | 83 | 0.2 |
| Oil | 88 | 61 | 33 | 22 | 18 | 19 | 3 | 1 | -5.0 |
| Gas | 210 | 405 | 390 | 390 | 391 | 408 | 17 | 17 | 0.0 |
| **Total final consumption** | **2 725** | **3 029** | **2 811** | **2 785** | **2 765** | **2 757** | **100** | **100** | **-0.4** |
| Coal | 239 | 127 | 108 | 101 | 95 | 88 | 4 | 3 | -1.6 |
| Oil | 1 788 | 2 163 | 1 986 | 1 964 | 1 943 | 1 937 | 71 | 70 | -0.5 |
| *of which transport* | *1 376* | *1 772* | *1 690* | *1 676* | *1 661* | *1 664* | *58* | *60* | *-0.3* |
| Gas | 697 | 739 | 717 | 720 | 728 | 732 | 24 | 27 | -0.0 |

# Reference Scenario: OECD Europe

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **1 602** | **1 826** | **1 788** | **1 811** | **1 844** | **1 894** | **100** | **100** | **0.2** |
| Coal | 442 | 337 | 294 | 283 | 274 | 265 | 18 | 14 | -1.0 |
| Oil | 603 | 634 | 589 | 586 | 583 | 579 | 35 | 31 | -0.4 |
| Gas | 258 | 448 | 454 | 485 | 508 | 535 | 25 | 28 | 0.8 |
| Nuclear | 204 | 241 | 226 | 194 | 183 | 184 | 13 | 10 | -1.2 |
| Hydro | 38 | 43 | 47 | 51 | 53 | 54 | 2 | 3 | 1.1 |
| Biomass and waste | 53 | 102 | 132 | 151 | 165 | 180 | 6 | 10 | 2.5 |
| Other renewables | 5 | 21 | 46 | 62 | 79 | 96 | 1 | 5 | 6.9 |
| **Power generation** | **611** | **759** | **746** | **751** | **771** | **807** | **100** | **100** | **0.3** |
| Coal | 270 | 246 | 218 | 211 | 207 | 202 | 32 | 25 | -0.9 |
| Oil | 47 | 26 | 16 | 12 | 10 | 10 | 3 | 1 | -4.0 |
| Gas | 40 | 148 | 151 | 173 | 187 | 204 | 19 | 25 | 1.4 |
| Nuclear | 204 | 241 | 226 | 194 | 183 | 184 | 32 | 23 | -1.2 |
| Hydro | 38 | 43 | 47 | 51 | 53 | 54 | 6 | 7 | 1.1 |
| Biomass and waste | 8 | 38 | 48 | 56 | 62 | 69 | 5 | 8 | 2.6 |
| Other renewables | 3 | 17 | 40 | 55 | 70 | 84 | 2 | 10 | 7.1 |
| **Other energy sector** | **147** | **148** | **142** | **141** | **141** | **141** | **100** | **100** | **-0.2** |
| *of which electricity* | *38* | *44* | *43* | *44* | *45* | *47* | *30* | *33* | *0.2* |
| **Total final consumption** | **1 115** | **1 287** | **1 284** | **1 323** | **1 359** | **1 397** | **100** | **100** | **0.4** |
| Coal | 121 | 56 | 47 | 45 | 42 | 40 | 4 | 3 | -1.4 |
| Oil | 516 | 565 | 529 | 529 | 527 | 522 | 44 | 37 | -0.3 |
| Gas | 204 | 281 | 283 | 292 | 302 | 312 | 22 | 22 | 0.5 |
| Electricity | 190 | 263 | 277 | 293 | 311 | 331 | 20 | 24 | 1.0 |
| Heat | 37 | 55 | 59 | 62 | 64 | 68 | 4 | 5 | 0.9 |
| Biomass and waste | 45 | 64 | 83 | 95 | 103 | 112 | 5 | 8 | 2.5 |
| Other renewables | 2 | 4 | 5 | 7 | 9 | 12 | 0 | 1 | 5.4 |
| **Industry** | **319** | **323** | **317** | **322** | **328** | **334** | **100** | **100** | **0.1** |
| Coal | 70 | 41 | 35 | 33 | 32 | 31 | 13 | 9 | -1.2 |
| Oil | 57 | 45 | 40 | 38 | 36 | 34 | 14 | 10 | -1.2 |
| Gas | 78 | 92 | 92 | 93 | 94 | 95 | 29 | 29 | 0.1 |
| Electricity | 86 | 107 | 110 | 114 | 118 | 121 | 33 | 36 | 0.5 |
| Heat | 13 | 17 | 17 | 18 | 18 | 18 | 5 | 5 | 0.2 |
| Biomass and waste | 14 | 20 | 23 | 26 | 29 | 33 | 6 | 10 | 2.2 |
| Other renewables | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 8.3 |
| **Transport** | **266** | **348** | **347** | **360** | **365** | **369** | **100** | **100** | **0.3** |
| Oil | 260 | 332 | 318 | 326 | 329 | 332 | 95 | 90 | -0.0 |
| Biofuels | 0 | 8 | 19 | 24 | 24 | 25 | 2 | 7 | 5.1 |
| Other fuels | 6 | 8 | 10 | 11 | 12 | 13 | 2 | 3 | 1.8 |
| **Other sectors** | **432** | **497** | **512** | **535** | **562** | **593** | **100** | **100** | **0.8** |
| Coal | 50 | 13 | 11 | 10 | 9 | 8 | 3 | 1 | -2.3 |
| Oil | 116 | 84 | 77 | 74 | 71 | 68 | 17 | 12 | -0.9 |
| Gas | 112 | 174 | 176 | 184 | 192 | 202 | 35 | 34 | 0.7 |
| Electricity | 99 | 149 | 160 | 171 | 185 | 201 | 30 | 34 | 1.3 |
| Heat | 24 | 38 | 42 | 44 | 47 | 49 | 8 | 8 | 1.1 |
| Biomass and waste | 30 | 36 | 41 | 45 | 50 | 54 | 7 | 9 | 1.8 |
| Other renewables | 2 | 3 | 5 | 7 | 9 | 11 | 1 | 2 | 5.2 |
| **Non-energy use** | **99** | **118** | **108** | **105** | **103** | **101** | **100** | **100** | **-0.7** |

# Reference Scenario: OECD Europe

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **2 632** | **3 575** | **3 716** | **3 914** | **4 144** | **4 398** | **100** | **100** | **0.9** |
| Coal | 1 011 | 1 013 | 917 | 914 | 934 | 946 | 28 | 22 | -0.3 |
| Oil | 203 | 110 | 68 | 51 | 44 | 43 | 3 | 1 | -4.0 |
| Gas | 167 | 802 | 825 | 958 | 1 029 | 1 103 | 22 | 25 | 1.4 |
| Nuclear | 782 | 925 | 869 | 743 | 700 | 707 | 26 | 16 | -1.2 |
| Hydro | 443 | 498 | 547 | 588 | 616 | 633 | 14 | 14 | 1.1 |
| Biomass and waste | 21 | 108 | 142 | 169 | 191 | 216 | 3 | 5 | 3.0 |
| Wind | 1 | 105 | 301 | 419 | 529 | 614 | 3 | 14 | 8.0 |
| Geothermal | 4 | 10 | 13 | 15 | 17 | 19 | 0 | 0 | 3.1 |
| Solar | 0 | 4 | 34 | 56 | 81 | 108 | 0 | 2 | 15.7 |
| Tide and wave | 1 | 1 | 1 | 2 | 4 | 9 | 0 | 0 | 13.4 |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **847** | **1 005** | **1 035** | **1 095** | **1 162** | **100** | **100** | **1.4** |
| Coal | 196 | 203 | 181 | 168 | 166 | 23 | 14 | -0.7 |
| Oil | 68 | 58 | 43 | 33 | 24 | 8 | 2 | -4.3 |
| Gas | 184 | 218 | 221 | 238 | 262 | 22 | 23 | 1.6 |
| Nuclear | 130 | 122 | 103 | 97 | 98 | 15 | 8 | -1.2 |
| Hydro | 185 | 206 | 218 | 227 | 232 | 22 | 20 | 1.0 |
| Biomass and waste | 20 | 26 | 31 | 35 | 40 | 2 | 3 | 2.9 |
| Wind | 57 | 138 | 185 | 227 | 253 | 7 | 22 | 6.7 |
| Geothermal | 2 | 3 | 3 | 3 | 4 | 0 | 0 | 1.9 |
| Solar | 5 | 30 | 48 | 65 | 81 | 1 | 7 | 12.9 |
| Tide and wave | 0 | 0 | 1 | 1 | 2 | 0 | 0 | 10.5 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **3 890** | **4 020** | **3 747** | **3 768** | **3 773** | **3 788** | **100** | **100** | **-0.3** |
| Coal | 1 676 | 1 300 | 1 137 | 1 094 | 1 059 | 1 022 | 32 | 27 | -1.0 |
| Oil | 1 640 | 1 687 | 1 564 | 1 556 | 1 544 | 1 534 | 42 | 40 | -0.4 |
| Gas | 574 | 1 032 | 1 047 | 1 118 | 1 170 | 1 232 | 26 | 33 | 0.8 |
| **Power generation** | **1 349** | **1 447** | **1 305** | **1 317** | **1 320** | **1 334** | **100** | **100** | **-0.4** |
| Coal | 1 105 | 1 020 | 902 | 875 | 852 | 828 | 70 | 62 | -0.9 |
| Oil | 151 | 82 | 50 | 38 | 33 | 32 | 6 | 2 | -4.0 |
| Gas | 93 | 345 | 353 | 405 | 435 | 475 | 24 | 36 | 1.4 |
| **Total final consumption** | **2 365** | **2 379** | **2 255** | **2 270** | **2 277** | **2 282** | **100** | **100** | **-0.2** |
| Coal | 533 | 247 | 206 | 194 | 184 | 173 | 10 | 8 | -1.5 |
| Oil | 1 374 | 1 486 | 1 396 | 1 402 | 1 397 | 1 388 | 62 | 61 | -0.3 |
| *of which transport* | *768* | *994* | *950* | *973* | *984* | *991* | *42* | *43* | *-0.0* |
| Gas | 458 | 646 | 652 | 673 | 696 | 720 | 27 | 32 | 0.5 |

## **Reference Scenario:** European Union

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **1 633** | **1 757** | **1 711** | **1 723** | **1 743** | **1 781** | **100** | **100** | **0.1** |
| Coal | 455 | 330 | 281 | 260 | 248 | 233 | 19 | 13 | -1.5 |
| Oil | 603 | 607 | 563 | 557 | 551 | 545 | 35 | 31 | -0.5 |
| Gas | 295 | 432 | 437 | 463 | 484 | 508 | 25 | 29 | 0.7 |
| Nuclear | 207 | 244 | 228 | 202 | 188 | 192 | 14 | 11 | -1.0 |
| Hydro | 25 | 27 | 30 | 33 | 34 | 35 | 2 | 2 | 1.2 |
| Biomass and waste | 46 | 101 | 133 | 154 | 169 | 183 | 6 | 10 | 2.6 |
| Other renewables | 3 | 16 | 39 | 54 | 69 | 84 | 1 | 5 | 7.5 |
| **Power generation** | **644** | **740** | **718** | **717** | **730** | **760** | **100** | **100** | **0.1** |
| Coal | 286 | 250 | 216 | 201 | 195 | 185 | 34 | 24 | -1.3 |
| Oil | 61 | 27 | 16 | 12 | 10 | 10 | 4 | 1 | -4.1 |
| Gas | 54 | 140 | 142 | 161 | 175 | 191 | 19 | 25 | 1.4 |
| Nuclear | 207 | 244 | 228 | 202 | 188 | 192 | 33 | 25 | -1.0 |
| Hydro | 25 | 27 | 30 | 33 | 34 | 35 | 4 | 5 | 1.2 |
| Biomass and waste | 8 | 38 | 49 | 58 | 64 | 70 | 5 | 9 | 2.7 |
| Other renewables | 3 | 14 | 36 | 50 | 63 | 76 | 2 | 10 | 7.5 |
| **Other energy sector** | **149** | **146** | **138** | **136** | **134** | **133** | **100** | **100** | **-0.4** |
| *of which electricity* | *39* | *43* | *40* | *41* | *42* | *42* | *29* | *32* | *-0.0* |
| **Total final consumption** | **1 126** | **1 224** | **1 220** | **1 251** | **1 278** | **1 307** | **100** | **100** | **0.3** |
| Coal | 119 | 43 | 35 | 31 | 28 | 25 | 4 | 2 | -2.3 |
| Oil | 501 | 538 | 503 | 501 | 495 | 488 | 44 | 37 | -0.4 |
| Gas | 228 | 276 | 278 | 286 | 294 | 303 | 23 | 23 | 0.4 |
| Electricity | 185 | 244 | 256 | 268 | 283 | 300 | 20 | 23 | 0.9 |
| Heat | 54 | 58 | 62 | 65 | 68 | 71 | 5 | 5 | 0.8 |
| Biomass and waste | 38 | 63 | 84 | 96 | 104 | 113 | 5 | 9 | 2.6 |
| Other renewables | 1 | 2 | 3 | 4 | 6 | 8 | 0 | 1 | 7.0 |
| **Industry** | **341** | **304** | **298** | **301** | **305** | **308** | **100** | **100** | **0.1** |
| Coal | 68 | 31 | 24 | 22 | 20 | 18 | 10 | 6 | -2.3 |
| Oil | 57 | 45 | 40 | 38 | 36 | 34 | 15 | 11 | -1.2 |
| Gas | 98 | 93 | 93 | 94 | 95 | 96 | 31 | 31 | 0.1 |
| Electricity | 85 | 99 | 101 | 104 | 107 | 110 | 33 | 36 | 0.5 |
| Heat | 19 | 17 | 17 | 17 | 17 | 17 | 6 | 6 | 0.1 |
| Biomass and waste | 14 | 20 | 23 | 26 | 30 | 33 | 7 | 11 | 2.3 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 23.0 |
| **Transport** | **259** | **335** | **335** | **346** | **349** | **350** | **100** | **100** | **0.2** |
| Oil | 253 | 318 | 305 | 311 | 312 | 312 | 95 | 89 | -0.1 |
| Biofuels | 0 | 8 | 20 | 25 | 26 | 26 | 2 | 7 | 5.2 |
| Other fuels | 6 | 8 | 10 | 11 | 11 | 12 | 2 | 4 | 1.8 |
| **Other sectors** | **428** | **470** | **483** | **503** | **526** | **553** | **100** | **100** | **0.7** |
| Coal | 50 | 11 | 9 | 8 | 7 | 6 | 2 | 1 | -2.7 |
| Oil | 110 | 76 | 69 | 66 | 64 | 62 | 16 | 11 | -0.9 |
| Gas | 115 | 166 | 169 | 175 | 182 | 190 | 35 | 34 | 0.6 |
| Electricity | 95 | 139 | 148 | 157 | 168 | 181 | 30 | 33 | 1.1 |
| Heat | 35 | 41 | 45 | 48 | 50 | 53 | 9 | 10 | 1.1 |
| Biomass and waste | 24 | 35 | 40 | 45 | 49 | 54 | 7 | 10 | 1.9 |
| Other renewables | 1 | 2 | 3 | 4 | 6 | 7 | 0 | 1 | 6.7 |
| **Non-energy use** | **97** | **115** | **104** | **101** | **99** | **96** | **100** | **100** | **-0.8** |

# Reference Scenario: European Union

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **2 568** | **3 325** | **3 432** | **3 587** | **3 765** | **3 968** | **100** | **100** | **0.8** |
| Coal | 1 050 | 1 024 | 907 | 870 | 876 | 862 | 31 | 22 | -0.7 |
| Oil | 221 | 112 | 69 | 51 | 43 | 43 | 3 | 1 | -4.1 |
| Gas | 191 | 725 | 746 | 861 | 929 | 995 | 22 | 25 | 1.4 |
| Nuclear | 795 | 935 | 874 | 773 | 721 | 736 | 28 | 19 | -1.0 |
| Hydro | 286 | 309 | 351 | 381 | 400 | 408 | 9 | 10 | 1.2 |
| Biomass and waste | 20 | 105 | 143 | 172 | 191 | 212 | 3 | 5 | 3.1 |
| Wind | 1 | 104 | 300 | 412 | 508 | 581 | 3 | 15 | 7.8 |
| Geothermal | 3 | 6 | 8 | 9 | 11 | 13 | 0 | 0 | 3.6 |
| Solar | 0 | 4 | 34 | 56 | 80 | 107 | 0 | 3 | 15.7 |
| Tide and wave | 1 | 1 | 1 | 2 | 4 | 9 | 0 | 0 | 13.4 |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **804** | **951** | **973** | **1 019** | **1 067** | **100** | **100** | **1.2** |
| Coal | 200 | 207 | 182 | 167 | 158 | 25 | 15 | -1.0 |
| Oil | 74 | 61 | 45 | 34 | 25 | 9 | 2 | -4.6 |
| Gas | 175 | 207 | 208 | 223 | 242 | 22 | 23 | 1.4 |
| Nuclear | 132 | 123 | 108 | 101 | 103 | 16 | 10 | -1.1 |
| Hydro | 140 | 156 | 166 | 172 | 175 | 17 | 16 | 1.0 |
| Biomass and waste | 20 | 27 | 32 | 35 | 39 | 2 | 4 | 3.0 |
| Wind | 57 | 138 | 183 | 220 | 241 | 7 | 23 | 6.5 |
| Geothermal | 1 | 1 | 2 | 2 | 2 | 0 | 0 | 2.7 |
| Solar | 5 | 30 | 48 | 65 | 81 | 1 | 8 | 12.9 |
| Tide and wave | 0 | 0 | 1 | 1 | 3 | 0 | 0 | 10.5 |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **4 042** | **3 886** | **3 588** | **3 553** | **3 534** | **3 516** | **100** | **100** | **-0.4** |
| Coal | 1 737 | 1 269 | 1 082 | 1 002 | 954 | 897 | 33 | 26 | -1.5 |
| Oil | 1 647 | 1 624 | 1 503 | 1 487 | 1 469 | 1 452 | 42 | 41 | -0.5 |
| Gas | 659 | 992 | 1 003 | 1 064 | 1 111 | 1 167 | 26 | 33 | 0.7 |
| **Power generation** | **1 492** | **1 450** | **1 280** | **1 250** | **1 243** | **1 238** | **100** | **100** | **-0.7** |
| Coal | 1 171 | 1 039 | 897 | 834 | 803 | 762 | 72 | 62 | -1.3 |
| Oil | 195 | 86 | 52 | 39 | 33 | 33 | 6 | 3 | -4.1 |
| Gas | 127 | 326 | 331 | 376 | 406 | 443 | 22 | 36 | 1.4 |
| **Total final consumption** | **2 379** | **2 251** | **2 129** | **2 131** | **2 123** | **2 114** | **100** | **100** | **-0.3** |
| Coal | 529 | 198 | 157 | 141 | 127 | 114 | 9 | 5 | -2.4 |
| Oil | 1 336 | 1 420 | 1 333 | 1 332 | 1 320 | 1 304 | 63 | 62 | -0.4 |
| *of which transport* | *749* | *954* | *913* | *929* | *932* | *932* | *42* | *44* | *-0.1* |
| Gas | 513 | 633 | 639 | 657 | 676 | 696 | 28 | 33 | 0.4 |

## **Reference Scenario:** OECD Pacific

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **631** | **877** | **892** | **908** | **927** | **943** | **100** | **100** | **0.3** |
| Coal | 137 | 227 | 228 | 225 | 221 | 217 | 26 | 23 | -0.2 |
| Oil | 335 | 367 | 323 | 303 | 295 | 288 | 42 | 31 | -1.0 |
| Gas | 66 | 143 | 156 | 173 | 178 | 185 | 16 | 20 | 1.1 |
| Nuclear | 66 | 106 | 141 | 155 | 173 | 184 | 12 | 20 | 2.4 |
| Hydro | 11 | 10 | 11 | 12 | 12 | 12 | 1 | 1 | 0.9 |
| Biomass and waste | 10 | 16 | 23 | 26 | 30 | 34 | 2 | 4 | 3.2 |
| Other renewables | 5 | 6 | 11 | 14 | 18 | 23 | 1 | 2 | 5.7 |
| **Power generation** | **241** | **400** | **432** | **447** | **467** | **485** | **100** | **100** | **0.8** |
| Coal | 60 | 155 | 162 | 160 | 158 | 156 | 39 | 32 | 0.0 |
| Oil | 56 | 39 | 19 | 13 | 12 | 12 | 10 | 3 | -4.9 |
| Gas | 40 | 79 | 83 | 86 | 86 | 89 | 20 | 18 | 0.5 |
| Nuclear | 66 | 106 | 141 | 155 | 173 | 184 | 26 | 38 | 2.4 |
| Hydro | 11 | 10 | 11 | 12 | 12 | 12 | 2 | 3 | 0.9 |
| Biomass and waste | 3 | 6 | 9 | 10 | 12 | 13 | 2 | 3 | 3.0 |
| Other renewables | 3 | 5 | 8 | 11 | 14 | 18 | 1 | 4 | 5.7 |
| **Other energy sector** | **56** | **64** | **65** | **70** | **72** | **73** | **100** | **100** | **0.6** |
| *of which electricity* | *11* | *17* | *18* | *19* | *19* | *20* | *26* | *27* | *0.8* |
| **Total final consumption** | **431** | **577** | **573** | **577** | **584** | **589** | **100** | **100** | **0.1** |
| Coal | 49 | 43 | 39 | 38 | 38 | 37 | 8 | 6 | -0.7 |
| Oil | 261 | 310 | 286 | 278 | 271 | 263 | 54 | 45 | -0.7 |
| Gas | 26 | 65 | 71 | 74 | 77 | 80 | 11 | 14 | 0.9 |
| Electricity | 86 | 142 | 155 | 162 | 170 | 177 | 25 | 30 | 1.0 |
| Heat | 0 | 5 | 6 | 6 | 6 | 7 | 1 | 1 | 1.1 |
| Biomass and waste | 7 | 10 | 14 | 16 | 18 | 21 | 2 | 4 | 3.3 |
| Other renewables | 2 | 1 | 2 | 3 | 4 | 5 | 0 | 1 | 6.2 |
| **Industry** | **144** | **170** | **174** | **177** | **181** | **183** | **100** | **100** | **0.3** |
| Coal | 39 | 41 | 37 | 36 | 36 | 35 | 24 | 19 | -0.7 |
| Oil | 51 | 41 | 36 | 35 | 34 | 32 | 24 | 18 | -1.1 |
| Gas | 10 | 22 | 25 | 26 | 27 | 27 | 13 | 15 | 0.9 |
| Electricity | 40 | 56 | 62 | 64 | 67 | 68 | 33 | 37 | 0.9 |
| Heat | 0 | 3 | 3 | 3 | 4 | 4 | 2 | 2 | 0.8 |
| Biomass and waste | 5 | 8 | 11 | 12 | 14 | 17 | 5 | 9 | 3.4 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 6.6 |
| **Transport** | **110** | **145** | **141** | **136** | **131** | **127** | **100** | **100** | **-0.6** |
| Oil | 109 | 141 | 135 | 130 | 124 | 120 | 98 | 94 | -0.7 |
| Biofuels | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 9.4 |
| Other fuels | 2 | 3 | 5 | 5 | 5 | 6 | 2 | 4 | 2.5 |
| **Other sectors** | **130** | **180** | **185** | **191** | **199** | **207** | **100** | **100** | **0.6** |
| Coal | 10 | 2 | 2 | 2 | 1 | 1 | 1 | 1 | -1.4 |
| Oil | 57 | 48 | 44 | 43 | 42 | 41 | 27 | 20 | -0.7 |
| Gas | 15 | 41 | 43 | 45 | 47 | 49 | 23 | 24 | 0.8 |
| Electricity | 44 | 84 | 90 | 95 | 100 | 106 | 47 | 51 | 1.0 |
| Heat | 0 | 2 | 2 | 3 | 3 | 3 | 1 | 1 | 1.5 |
| Biomass and waste | 2 | 2 | 2 | 2 | 3 | 3 | 1 | 1 | 1.6 |
| Other renewables | 1 | 1 | 2 | 3 | 3 | 4 | 1 | 2 | 6.1 |
| **Non-energy use** | **46** | **82** | **73** | **73** | **73** | **72** | **100** | **100** | **-0.5** |

# Reference Scenario: OECD Pacific

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **1 128** | **1 848** | **2 007** | **2 096** | **2 200** | **2 296** | **100** | **100** | **0.9** |
| Coal | 254 | 679 | 713 | 714 | 719 | 726 | 37 | 32 | 0.3 |
| Oil | 271 | 184 | 88 | 59 | 54 | 55 | 10 | 2 | -5.1 |
| Gas | 199 | 423 | 469 | 502 | 500 | 509 | 23 | 22 | 0.8 |
| Nuclear | 255 | 407 | 540 | 595 | 665 | 706 | 22 | 31 | 2.4 |
| Hydro | 133 | 116 | 131 | 134 | 138 | 141 | 6 | 6 | 0.9 |
| Biomass and waste | 12 | 26 | 33 | 38 | 43 | 47 | 1 | 2 | 2.6 |
| Wind | 0 | 7 | 17 | 28 | 44 | 62 | 0 | 3 | 10.3 |
| Geothermal | 4 | 6 | 9 | 11 | 12 | 13 | 0 | 1 | 3.2 |
| Solar | 0 | 0 | 6 | 14 | 24 | 33 | 0 | 1 | 29.4 |
| Tide and wave | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | n.a. |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **402** | **454** | **464** | **486** | **511** | **100** | **100** | **1.0** |
| Coal | 97 | 103 | 103 | 103 | 104 | 24 | 20 | 0.3 |
| Oil | 62 | 58 | 38 | 33 | 30 | 16 | 6 | -3.1 |
| Gas | 99 | 128 | 140 | 144 | 153 | 25 | 30 | 1.9 |
| Nuclear | 64 | 74 | 80 | 89 | 94 | 16 | 18 | 1.7 |
| Hydro | 68 | 69 | 70 | 71 | 72 | 17 | 14 | 0.3 |
| Biomass and waste | 4 | 6 | 6 | 7 | 8 | 1 | 2 | 2.5 |
| Wind | 5 | 9 | 12 | 17 | 23 | 1 | 4 | 6.9 |
| Geothermal | 1 | 1 | 2 | 2 | 2 | 0 | 0 | 3.0 |
| Solar | 2 | 6 | 12 | 19 | 25 | 1 | 5 | 11.3 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **1 573** | **2 144** | **2 070** | **2 039** | **2 006** | **1 985** | **100** | **100** | **-0.3** |
| Coal | 522 | 887 | 901 | 890 | 875 | 861 | 41 | 43 | -0.1 |
| Oil | 892 | 903 | 790 | 746 | 721 | 699 | 42 | 35 | -1.1 |
| Gas | 159 | 355 | 379 | 403 | 410 | 426 | 17 | 21 | 0.8 |
| **Power generation** | **548** | **967** | **945** | **927** | **913** | **912** | **100** | **100** | **-0.3** |
| Coal | 281 | 660 | 690 | 683 | 672 | 662 | 68 | 73 | 0.0 |
| Oil | 174 | 118 | 58 | 40 | 37 | 38 | 12 | 4 | -4.8 |
| Gas | 94 | 189 | 197 | 204 | 204 | 212 | 20 | 23 | 0.5 |
| **Total final consumption** | **956** | **1 079** | **1 028** | **1 006** | **988** | **968** | **100** | **100** | **-0.5** |
| Coal | 221 | 192 | 177 | 173 | 169 | 164 | 18 | 17 | -0.7 |
| Oil | 676 | 736 | 686 | 662 | 640 | 618 | 68 | 64 | -0.8 |
| *of which transport* | *321* | *416* | *398* | *382* | *367* | *352* | *39* | *36* | *-0.7* |
| Gas | 59 | 151 | 165 | 171 | 179 | 186 | 14 | 19 | 0.9 |

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## **Reference Scenario:** Japan

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **438** | **514** | **489** | **485** | **487** | **488** | **100** | **100** | **-0.2** |
| Coal | 75 | 115 | 108 | 105 | 100 | 98 | 22 | 20 | -0.7 |
| Oil | 250 | 230 | 186 | 169 | 160 | 152 | 45 | 31 | -1.8 |
| Gas | 44 | 83 | 85 | 86 | 87 | 92 | 16 | 19 | 0.4 |
| Nuclear | 53 | 69 | 87 | 99 | 109 | 113 | 13 | 23 | 2.2 |
| Hydro | 8 | 6 | 8 | 8 | 8 | 8 | 1 | 2 | 1.1 |
| Biomass and waste | 5 | 7 | 10 | 11 | 13 | 14 | 1 | 3 | 2.9 |
| Other renewables | 3 | 4 | 6 | 8 | 9 | 11 | 1 | 2 | 5.0 |
| **Power generation** | **174** | **232** | **237** | **244** | **253** | **262** | **100** | **100** | **0.5** |
| Coal | 25 | 64 | 64 | 62 | 58 | 57 | 28 | 22 | -0.5 |
| Oil | 51 | 31 | 15 | 9 | 9 | 10 | 13 | 4 | -5.0 |
| Gas | 33 | 54 | 54 | 54 | 55 | 58 | 23 | 22 | 0.4 |
| Nuclear | 53 | 69 | 87 | 99 | 109 | 113 | 30 | 43 | 2.2 |
| Hydro | 8 | 6 | 8 | 8 | 8 | 8 | 3 | 3 | 1.1 |
| Biomass and waste | 2 | 5 | 5 | 6 | 6 | 7 | 2 | 3 | 1.6 |
| Other renewables | 1 | 3 | 5 | 6 | 8 | 9 | 1 | 4 | 5.2 |
| **Other energy sector** | **36** | **37** | **34** | **33** | **32** | **31** | **100** | **100** | **-0.8** |
| *of which electricity* | *7* | *10* | *10* | *10* | *10* | *11* | *26* | *34* | *0.4* |
| **Total final consumption** | **300** | **342** | **319** | **314** | **311** | **307** | **100** | **100** | **-0.5** |
| Coal | 33 | 31 | 28 | 27 | 27 | 26 | 9 | 9 | -0.7 |
| Oil | 184 | 187 | 160 | 150 | 141 | 133 | 55 | 43 | -1.5 |
| Gas | 15 | 34 | 34 | 35 | 36 | 37 | 10 | 12 | 0.4 |
| Electricity | 64 | 87 | 91 | 94 | 98 | 101 | 25 | 33 | 0.7 |
| Heat | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1.8 |
| Biomass and waste | 3 | 3 | 5 | 6 | 7 | 8 | 1 | 2 | 4.5 |
| Other renewables | 1 | 1 | 1 | 1 | 1 | 2 | 0 | 1 | 3.8 |
| **Industry** | **103** | **99** | **97** | **97** | **97** | **97** | **100** | **100** | **-0.1** |
| Coal | 31 | 30 | 27 | 26 | 26 | 25 | 30 | 26 | -0.7 |
| Oil | 37 | 30 | 25 | 24 | 22 | 21 | 30 | 22 | -1.4 |
| Gas | 4 | 8 | 9 | 10 | 11 | 11 | 8 | 11 | 1.4 |
| Electricity | 29 | 29 | 31 | 32 | 32 | 32 | 29 | 33 | 0.5 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 3 | 3 | 4 | 5 | 6 | 7 | 3 | 7 | 4.2 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| **Transport** | **72** | **82** | **72** | **65** | **59** | **53** | **100** | **100** | **-1.9** |
| Oil | 70 | 81 | 70 | 62 | 56 | 50 | 98 | 95 | -2.1 |
| Biofuels | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | n.a. |
| Other fuels | 1 | 2 | 2 | 2 | 2 | 2 | 2 | 5 | 1.7 |
| **Other sectors** | **91** | **118** | **115** | **118** | **121** | **125** | **100** | **100** | **0.2** |
| Coal | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0.5 |
| Oil | 43 | 35 | 31 | 30 | 30 | 30 | 29 | 24 | -0.7 |
| Gas | 11 | 25 | 24 | 24 | 25 | 25 | 21 | 20 | 0.0 |
| Electricity | 34 | 56 | 58 | 60 | 63 | 66 | 48 | 53 | 0.7 |
| Heat | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1.8 |
| Biomass and waste | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2.5 |
| Other renewables | 1 | 1 | 1 | 1 | 1 | 2 | 1 | 1 | 3.8 |
| **Non-energy use** | **35** | **42** | **36** | **34** | **34** | **33** | **100** | **100** | **-1.1** |

## Reference Scenario: Japan

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **836** | **1 123** | **1 175** | **1 215** | **1 260** | **1 302** | **100** | **100** | **0.6** |
| Coal | 117 | 311 | 312 | 303 | 290 | 283 | 28 | 22 | -0.4 |
| Oil | 248 | 156 | 73 | 47 | 45 | 46 | 14 | 4 | -5.2 |
| Gas | 167 | 290 | 324 | 335 | 335 | 348 | 26 | 27 | 0.8 |
| Nuclear | 202 | 264 | 333 | 380 | 418 | 435 | 23 | 33 | 2.2 |
| Hydro | 89 | 74 | 87 | 90 | 93 | 96 | 7 | 7 | 1.1 |
| Biomass and waste | 11 | 23 | 27 | 29 | 32 | 34 | 2 | 3 | 1.7 |
| Wind | 0 | 3 | 10 | 18 | 27 | 34 | 0 | 3 | 11.7 |
| Geothermal | 2 | 3 | 4 | 5 | 5 | 5 | 0 | 0 | 2.5 |
| Solar | 0 | 0 | 4 | 9 | 16 | 20 | 0 | 2 | 40.5 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **263** | **288** | **290** | **300** | **310** | **100** | **100** | **0.7** |
| Coal | 44 | 45 | 44 | 42 | 41 | 17 | 13 | -0.3 |
| Oil | 56 | 51 | 33 | 29 | 26 | 21 | 9 | -3.2 |
| Gas | 62 | 81 | 89 | 91 | 96 | 24 | 31 | 1.9 |
| Nuclear | 46 | 48 | 54 | 58 | 60 | 17 | 19 | 1.2 |
| Hydro | 48 | 49 | 49 | 50 | 51 | 18 | 16 | 0.3 |
| Biomass and waste | 4 | 4 | 5 | 5 | 6 | 1 | 2 | 1.8 |
| Wind | 2 | 4 | 7 | 10 | 12 | 1 | 4 | 9.2 |
| Geothermal | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 2.2 |
| Solar | 2 | 5 | 9 | 15 | 17 | 1 | 6 | 10.1 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **1 064** | **1 232** | **1 101** | **1 046** | **1 005** | **984** | **100** | **100** | **-1.0** |
| Coal | 294 | 445 | 428 | 416 | 399 | 389 | 36 | 40 | -0.6 |
| Oil | 655 | 578 | 463 | 417 | 391 | 369 | 47 | 37 | -1.9 |
| Gas | 115 | 209 | 211 | 213 | 216 | 226 | 17 | 23 | 0.3 |
| **Power generation** | **363** | **506** | **457** | **431** | **415** | **418** | **100** | **100** | **-0.8** |
| Coal | 128 | 283 | 282 | 272 | 256 | 249 | 56 | 60 | -0.6 |
| Oil | 157 | 94 | 45 | 28 | 28 | 29 | 19 | 7 | -4.9 |
| Gas | 78 | 129 | 130 | 130 | 131 | 140 | 25 | 33 | 0.4 |
| **Total final consumption** | **656** | **682** | **605** | **576** | **553** | **530** | **100** | **100** | **-1.1** |
| Coal | 151 | 145 | 129 | 127 | 125 | 123 | 21 | 23 | -0.7 |
| Oil | 470 | 459 | 397 | 368 | 344 | 321 | 67 | 61 | -1.5 |
| *of which transport* | *208* | *238* | *206* | *184* | *165* | *148* | *35* | *28* | *-2.1* |
| Gas | 35 | 78 | 79 | 81 | 83 | 85 | 11 | 16 | 0.4 |

## **Reference Scenario:** Non-OECD

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **4 087** | **6 187** | **7 679** | **8 515** | **9 516** | **10 529** | **100** | **100** | **2.3** |
| Coal | 1 156 | 2 026 | 2 716 | 3 031 | 3 416 | 3 784 | 33 | 36 | 2.8 |
| Oil | 1 170 | 1 653 | 1 954 | 2 160 | 2 410 | 2 709 | 27 | 26 | 2.2 |
| Gas | 832 | 1 254 | 1 519 | 1 686 | 1 905 | 2 108 | 20 | 20 | 2.3 |
| Nuclear | 76 | 117 | 187 | 239 | 283 | 303 | 2 | 3 | 4.2 |
| Hydro | 84 | 157 | 201 | 225 | 250 | 275 | 3 | 3 | 2.5 |
| Biomass and waste | 763 | 955 | 1 043 | 1 087 | 1 133 | 1 188 | 15 | 11 | 1.0 |
| Other renewables | 7 | 26 | 60 | 88 | 120 | 162 | 0 | 2 | 8.2 |
| **Power generation** | **1 278** | **2 277** | **2 995** | **3 427** | **3 932** | **4 451** | **100** | **100** | **3.0** |
| Coal | 478 | 1 230 | 1 708 | 1 956 | 2 257 | 2 562 | 54 | 58 | 3.2 |
| Oil | 226 | 185 | 166 | 159 | 149 | 134 | 8 | 3 | -1.4 |
| Gas | 401 | 551 | 647 | 722 | 817 | 926 | 24 | 21 | 2.3 |
| Nuclear | 76 | 117 | 187 | 239 | 283 | 303 | 5 | 7 | 4.2 |
| Hydro | 84 | 157 | 201 | 225 | 250 | 275 | 7 | 6 | 2.5 |
| Biomass and waste | 7 | 17 | 36 | 53 | 77 | 115 | 1 | 3 | 8.7 |
| Other renewables | 7 | 21 | 49 | 73 | 100 | 134 | 1 | 3 | 8.5 |
| **Other energy sector** | **491** | **772** | **963** | **1 053** | **1 156** | **1 223** | **100** | **100** | **2.0** |
| *of which electricity* | *77* | *166* | *217* | *248* | *284* | *322* | *21* | *26* | *2.9* |
| **Total final consumption** | **3 011** | **4 172** | **5 120** | **5 640** | **6 282** | **6 965** | **100** | **100** | **2.3** |
| Coal | 532 | 592 | 729 | 766 | 811 | 860 | 14 | 12 | 1.6 |
| Oil | 825 | 1 323 | 1 634 | 1 841 | 2 111 | 2 412 | 32 | 35 | 2.6 |
| Gas | 366 | 554 | 680 | 755 | 846 | 938 | 13 | 13 | 2.3 |
| Electricity | 286 | 618 | 910 | 1 077 | 1 277 | 1 490 | 15 | 21 | 3.9 |
| Heat | 293 | 205 | 219 | 226 | 235 | 241 | 5 | 3 | 0.7 |
| Biomass and waste | 708 | 875 | 937 | 961 | 981 | 996 | 21 | 14 | 0.6 |
| Other renewables | 0 | 6 | 11 | 15 | 20 | 28 | 0 | 0 | 7.2 |
| **Industry** | **979** | **1 394** | **1 784** | **1 962** | **2 181** | **2 409** | **100** | **100** | **2.4** |
| Coal | 312 | 466 | 577 | 609 | 652 | 699 | 33 | 29 | 1.8 |
| Oil | 159 | 191 | 217 | 229 | 244 | 257 | 14 | 11 | 1.3 |
| Gas | 130 | 201 | 253 | 286 | 325 | 363 | 14 | 15 | 2.6 |
| Electricity | 159 | 325 | 504 | 592 | 695 | 801 | 23 | 33 | 4.0 |
| Heat | 137 | 93 | 101 | 103 | 107 | 110 | 7 | 5 | 0.7 |
| Biomass and waste | 82 | 117 | 131 | 142 | 159 | 178 | 8 | 7 | 1.8 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 27.0 |
| **Transport** | **444** | **730** | **955** | **1 123** | **1 349** | **1 618** | **100** | **100** | **3.5** |
| Oil | 377 | 651 | 848 | 1 000 | 1 208 | 1 456 | 89 | 90 | 3.6 |
| Biofuels | 6 | 11 | 28 | 36 | 46 | 58 | 1 | 4 | 7.6 |
| Other fuels | 61 | 68 | 79 | 86 | 94 | 104 | 9 | 6 | 1.8 |
| **Other sectors** | **1 402** | **1 669** | **1 897** | **2 031** | **2 187** | **2 338** | **100** | **100** | **1.5** |
| Coal | 184 | 93 | 103 | 103 | 102 | 99 | 6 | 4 | 0.2 |
| Oil | 182 | 241 | 275 | 294 | 317 | 335 | 14 | 14 | 1.4 |
| Gas | 145 | 192 | 225 | 253 | 289 | 327 | 11 | 14 | 2.3 |
| Electricity | 113 | 279 | 387 | 461 | 555 | 659 | 17 | 28 | 3.8 |
| Heat | 156 | 111 | 118 | 123 | 129 | 130 | 7 | 6 | 0.7 |
| Biomass and waste | 621 | 747 | 778 | 782 | 776 | 760 | 45 | 33 | 0.1 |
| Other renewables | 0 | 6 | 10 | 14 | 20 | 28 | 0 | 1 | 7.1 |
| **Non-energy use** | **186** | **379** | **484** | **525** | **565** | **601** | **100** | **100** | **2.0** |

# **Reference Scenario:** Non-OECD

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **4 245** | **9 114** | **13 114** | **15 407** | **18 158** | **21 077** | **100** | **100** | **3.7** |
| Coal | 1 370 | 4 258 | 6 564 | 7 776 | 9 354 | 11 019 | 47 | 52 | 4.2 |
| Oil | 640 | 683 | 622 | 600 | 568 | 520 | 7 | 2 | -1.2 |
| Gas | 956 | 1 819 | 2 552 | 2 964 | 3 485 | 4 097 | 20 | 19 | 3.6 |
| Nuclear | 288 | 446 | 717 | 915 | 1 083 | 1 162 | 5 | 6 | 4.2 |
| Hydro | 975 | 1 820 | 2 337 | 2 619 | 2 904 | 3 202 | 20 | 15 | 2.5 |
| Biomass and waste | 8 | 41 | 102 | 156 | 232 | 346 | 0 | 2 | 9.7 |
| Wind | 0 | 24 | 167 | 282 | 379 | 468 | 0 | 2 | 13.8 |
| Geothermal | 8 | 22 | 39 | 50 | 65 | 81 | 0 | 0 | 5.9 |
| Solar | 0 | 0 | 13 | 44 | 88 | 182 | 0 | 1 | 35.0 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | n.a. |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **2 037** | **2 962** | **3 432** | **4 017** | **4 647** | **100** | **100** | **3.7** |
| Coal | 792 | 1 236 | 1 453 | 1 746 | 2 042 | 39 | 44 | 4.2 |
| Oil | 219 | 227 | 215 | 200 | 183 | 11 | 4 | -0.8 |
| Gas | 448 | 659 | 747 | 881 | 1 041 | 22 | 22 | 3.7 |
| Nuclear | 63 | 96 | 121 | 141 | 150 | 3 | 3 | 3.8 |
| Hydro | 487 | 638 | 720 | 802 | 886 | 24 | 19 | 2.6 |
| Biomass and waste | 8 | 18 | 27 | 40 | 61 | 0 | 1 | 9.2 |
| Wind | 15 | 74 | 119 | 154 | 183 | 1 | 4 | 11.4 |
| Geothermal | 4 | 6 | 8 | 10 | 12 | 0 | 0 | 5.4 |
| Solar | 1 | 8 | 23 | 43 | 90 | 0 | 2 | 22.5 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **9 298** | **14 892** | **18 864** | **20 981** | **23 623** | **26 351** | **100** | **100** | **2.5** |
| Coal | 4 205 | 7 755 | 10 356 | 11 536 | 12 969 | 14 407 | 52 | 55 | 2.7 |
| Oil | 3 203 | 4 366 | 5 181 | 5 752 | 6 502 | 7 331 | 29 | 28 | 2.3 |
| Gas | 1 890 | 2 771 | 3 327 | 3 693 | 4 152 | 4 613 | 19 | 18 | 2.2 |
| **Power generation** | **3 559** | **6 767** | **8 868** | **10 005** | **11 382** | **12 791** | **100** | **100** | **2.8** |
| Coal | 1 902 | 4 890 | 6 824 | 7 808 | 8 996 | 10 199 | 72 | 80 | 3.2 |
| Oil | 719 | 586 | 528 | 505 | 471 | 425 | 9 | 3 | -1.4 |
| Gas | 937 | 1 292 | 1 516 | 1 692 | 1 915 | 2 167 | 19 | 17 | 2.3 |
| **Total final consumption** | **5 319** | **7 370** | **9 033** | **9 921** | **11 060** | **12 315** | **100** | **100** | **2.3** |
| Coal | 2 226 | 2 698 | 3 293 | 3 453 | 3 641 | 3 845 | 37 | 31 | 1.6 |
| Oil | 2 286 | 3 478 | 4 292 | 4 859 | 5 615 | 6 468 | 47 | 53 | 2.7 |
| *of which transport* | *1 120* | *1 935* | *2 520* | *2 971* | *3 591* | *4 327* | *26* | *35* | *3.6* |
| Gas | 807 | 1 193 | 1 448 | 1 608 | 1 803 | 2 002 | 16 | 16 | 2.3 |



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## **Reference Scenario:** Eastern Europe/Eurasia

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **1 546** | **1 114** | **1 161** | **1 217** | **1 296** | **1 354** | **100** | **100** | **0.9** |
| Coal | 365 | 210 | 215 | 223 | 243 | 261 | 19 | 19 | 0.9 |
| Oil | 475 | 228 | 236 | 249 | 256 | 260 | 20 | 19 | 0.6 |
| Gas | 604 | 555 | 569 | 579 | 614 | 642 | 50 | 47 | 0.6 |
| Nuclear | 61 | 77 | 86 | 101 | 111 | 108 | 7 | 8 | 1.5 |
| Hydro | 23 | 25 | 28 | 30 | 32 | 34 | 2 | 3 | 1.4 |
| Biomass and waste | 18 | 18 | 23 | 27 | 31 | 35 | 2 | 3 | 2.8 |
| Other renewables | 0 | 1 | 4 | 7 | 10 | 14 | 0 | 1 | 14.8 |
| **Power generation** | **747** | **558** | **580** | **602** | **639** | **669** | **100** | **100** | **0.8** |
| Coal | 203 | 146 | 151 | 158 | 175 | 191 | 26 | 29 | 1.2 |
| Oil | 127 | 22 | 20 | 18 | 16 | 13 | 4 | 2 | -2.1 |
| Gas | 329 | 283 | 282 | 277 | 282 | 294 | 51 | 44 | 0.2 |
| Nuclear | 61 | 77 | 86 | 101 | 111 | 108 | 14 | 16 | 1.5 |
| Hydro | 23 | 25 | 28 | 30 | 32 | 34 | 4 | 5 | 1.4 |
| Biomass and waste | 4 | 5 | 8 | 10 | 12 | 15 | 1 | 2 | 5.1 |
| Other renewables | 0 | 0 | 4 | 7 | 10 | 13 | 0 | 2 | 15.8 |
| **Other energy sector** | **191** | **169** | **173** | **176** | **185** | **187** | **100** | **100** | **0.4** |
| *of which electricity* | *36* | *41* | *43* | *44* | *46* | *48* | *25* | *26* | *0.6* |
| **Total final consumption** | **1 086** | **719** | **753** | **798** | **853** | **895** | **100** | **100** | **1.0** |
| Coal | 115 | 41 | 40 | 41 | 42 | 43 | 6 | 5 | 0.2 |
| Oil | 283 | 175 | 183 | 198 | 212 | 220 | 24 | 25 | 1.0 |
| Gas | 267 | 236 | 249 | 262 | 281 | 297 | 33 | 33 | 1.0 |
| Electricity | 128 | 102 | 116 | 128 | 142 | 155 | 14 | 17 | 1.8 |
| Heat | 279 | 152 | 151 | 153 | 158 | 160 | 21 | 18 | 0.2 |
| Biomass and waste | 13 | 13 | 15 | 16 | 18 | 19 | 2 | 2 | 1.7 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 6.3 |
| **Industry** | **392** | **217** | **224** | **235** | **250** | **263** | **100** | **100** | **0.8** |
| Coal | 58 | 31 | 29 | 30 | 31 | 32 | 14 | 12 | 0.2 |
| Oil | 53 | 22 | 23 | 24 | 25 | 27 | 10 | 10 | 0.8 |
| Gas | 80 | 55 | 59 | 63 | 68 | 72 | 26 | 28 | 1.2 |
| Electricity | 76 | 49 | 56 | 61 | 67 | 73 | 23 | 28 | 1.7 |
| Heat | 126 | 58 | 55 | 55 | 56 | 56 | 27 | 21 | -0.2 |
| Biomass and waste | 0 | 2 | 2 | 2 | 2 | 3 | 1 | 1 | 2.4 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 9.8 |
| **Transport** | **169** | **140** | **155** | **172** | **187** | **197** | **100** | **100** | **1.5** |
| Oil | 123 | 90 | 101 | 114 | 126 | 134 | 65 | 68 | 1.7 |
| Biofuels | 0 | 0 | 1 | 2 | 2 | 2 | 0 | 1 | 13.1 |
| Other fuels | 46 | 49 | 54 | 56 | 59 | 61 | 35 | 31 | 0.9 |
| **Other sectors** | **461** | **292** | **304** | **318** | **339** | **356** | **100** | **100** | **0.9** |
| Coal | 57 | 8 | 8 | 8 | 9 | 9 | 3 | 2 | 0.3 |
| Oil | 69 | 29 | 26 | 25 | 24 | 23 | 10 | 6 | -1.0 |
| Gas | 129 | 105 | 112 | 119 | 129 | 138 | 36 | 39 | 1.2 |
| Electricity | 40 | 44 | 49 | 54 | 61 | 68 | 15 | 19 | 1.9 |
| Heat | 153 | 94 | 96 | 98 | 102 | 104 | 32 | 29 | 0.4 |
| Biomass and waste | 13 | 11 | 12 | 12 | 13 | 14 | 4 | 4 | 1.0 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 6.3 |
| **Non-energy use** | **63** | **70** | **70** | **74** | **77** | **79** | **100** | **100** | **0.5** |

## **Reference Scenario:** Eastern Europe/Eurasia

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **1 924** | **1 685** | **1 868** | **2 012** | **2 198** | **2 375** | **100** | **100** | **1.5** |
| Coal | 448 | 400 | 427 | 472 | 546 | 622 | 24 | 26 | 1.9 |
| Oil | 271 | 47 | 41 | 37 | 30 | 23 | 3 | 1 | -3.1 |
| Gas | 706 | 651 | 723 | 724 | 759 | 829 | 39 | 35 | 1.1 |
| Nuclear | 231 | 293 | 328 | 388 | 425 | 413 | 17 | 17 | 1.5 |
| Hydro | 269 | 291 | 325 | 350 | 375 | 397 | 17 | 17 | 1.4 |
| Biomass and waste | 0 | 2 | 12 | 19 | 25 | 32 | 0 | 1 | 11.9 |
| Wind | 0 | 0 | 7 | 16 | 27 | 44 | 0 | 2 | 22.6 |
| Geothermal | 0 | 0 | 4 | 6 | 8 | 11 | 0 | 0 | 14.4 |
| Solar | 0 | 0 | 0 | 1 | 3 | 5 | 0 | 0 | n.a. |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **413** | **443** | **467** | **497** | **523** | **100** | **100** | **1.0** |
| Coal | 111 | 115 | 117 | 124 | 123 | 27 | 24 | 0.5 |
| Oil | 31 | 27 | 22 | 16 | 13 | 7 | 3 | -3.5 |
| Gas | 139 | 150 | 156 | 168 | 185 | 34 | 35 | 1.3 |
| Nuclear | 41 | 45 | 53 | 57 | 55 | 10 | 11 | 1.3 |
| Hydro | 90 | 101 | 108 | 115 | 121 | 22 | 23 | 1.3 |
| Biomass and waste | 1 | 3 | 4 | 5 | 6 | 0 | 1 | 7.7 |
| Wind | 0 | 3 | 5 | 9 | 15 | 0 | 3 | 17.3 |
| Geothermal | 0 | 1 | 1 | 1 | 2 | 0 | 0 | 12.3 |
| Solar | 0 | 0 | 1 | 2 | 4 | 0 | 1 | n.a. |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **4 036** | **2 650** | **2 723** | **2 817** | **2 997** | **3 152** | **100** | **100** | **0.8** |
| Coal | 1 366 | 831 | 845 | 877 | 958 | 1 033 | 31 | 33 | 1.0 |
| Oil | 1 260 | 577 | 601 | 640 | 674 | 688 | 22 | 22 | 0.8 |
| Gas | 1 410 | 1 243 | 1 277 | 1 300 | 1 365 | 1 430 | 47 | 45 | 0.6 |
| **Power generation** | **1 997** | **1 340** | **1 361** | **1 373** | **1 448** | **1 536** | **100** | **100** | **0.6** |
| Coal | 823 | 604 | 634 | 662 | 734 | 804 | 45 | 52 | 1.3 |
| Oil | 405 | 72 | 67 | 60 | 52 | 44 | 5 | 3 | -2.1 |
| Gas | 769 | 664 | 661 | 651 | 662 | 689 | 50 | 45 | 0.2 |
| **Total final consumption** | **1 925** | **1 192** | **1 230** | **1 306** | **1 396** | **1 460** | **100** | **100** | **0.9** |
| Coal | 531 | 219 | 203 | 208 | 217 | 222 | 18 | 15 | 0.1 |
| Oil | 788 | 447 | 471 | 512 | 551 | 573 | 37 | 39 | 1.1 |
| *of which transport* | *364* | *266* | *296* | *336* | *372* | *393* | *22* | *27* | *1.7* |
| Gas | 606 | 526 | 557 | 586 | 628 | 665 | 44 | 46 | 1.0 |

## Reference Scenario: Russia

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **871** | **665** | **700** | **735** | **783** | **812** | **100** | **100** | **0.9** |
| Coal | 182 | 102 | 116 | 128 | 144 | 159 | 15 | 20 | 1.9 |
| Oil | 264 | 132 | 138 | 146 | 146 | 146 | 20 | 18 | 0.4 |
| Gas | 367 | 366 | 367 | 371 | 392 | 403 | 55 | 50 | 0.4 |
| Nuclear | 31 | 42 | 52 | 59 | 67 | 65 | 6 | 8 | 1.9 |
| Hydro | 14 | 15 | 16 | 17 | 17 | 17 | 2 | 2 | 0.6 |
| Biomass and waste | 12 | 7 | 7 | 8 | 10 | 12 | 1 | 1 | 2.4 |
| Other renewables | 0 | 0 | 3 | 5 | 7 | 9 | 0 | 1 | 14.4 |
| **Power generation** | **444** | **365** | **386** | **403** | **429** | **446** | **100** | **100** | **0.9** |
| Coal | 105 | 76 | 90 | 102 | 117 | 132 | 21 | 30 | 2.4 |
| Oil | 62 | 14 | 15 | 14 | 13 | 11 | 4 | 3 | -0.9 |
| Gas | 228 | 214 | 207 | 202 | 202 | 204 | 59 | 46 | -0.2 |
| Nuclear | 31 | 42 | 52 | 59 | 67 | 65 | 12 | 15 | 1.9 |
| Hydro | 14 | 15 | 16 | 17 | 17 | 17 | 4 | 4 | 0.6 |
| Biomass and waste | 4 | 4 | 4 | 5 | 6 | 7 | 1 | 2 | 2.7 |
| Other renewables | 0 | 0 | 3 | 5 | 7 | 9 | 0 | 2 | 14.4 |
| **Other energy sector** | **118** | **103** | **108** | **110** | **116** | **118** | **100** | **100** | **0.6** |
| *of which electricity* | *21* | *26* | *27* | *27* | *28* | *30* | *25* | *25* | *0.6* |
| **Total final consumption** | **625** | **430** | **447** | **472** | **500** | **519** | **100** | **100** | **0.8** |
| Coal | 55 | 18 | 17 | 17 | 17 | 17 | 4 | 3 | -0.3 |
| Oil | 145 | 100 | 103 | 111 | 117 | 118 | 23 | 23 | 0.8 |
| Gas | 143 | 131 | 138 | 146 | 157 | 166 | 31 | 32 | 1.0 |
| Electricity | 71 | 60 | 70 | 76 | 84 | 92 | 14 | 18 | 1.8 |
| Heat | 203 | 119 | 116 | 118 | 121 | 122 | 28 | 24 | 0.1 |
| Biomass and waste | 8 | 3 | 3 | 3 | 4 | 4 | 1 | 1 | 2.1 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| **Industry** | **210** | **128** | **131** | **137** | **145** | **151** | **100** | **100** | **0.7** |
| Coal | 16 | 13 | 12 | 12 | 12 | 12 | 10 | 8 | -0.2 |
| Oil | 25 | 13 | 12 | 13 | 13 | 13 | 10 | 9 | 0.2 |
| Gas | 30 | 27 | 29 | 31 | 34 | 37 | 21 | 25 | 1.4 |
| Electricity | 41 | 30 | 36 | 39 | 42 | 45 | 24 | 30 | 1.8 |
| Heat | 98 | 45 | 42 | 42 | 42 | 42 | 35 | 28 | -0.3 |
| Biomass and waste | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 2.3 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| **Transport** | **116** | **93** | **101** | **111** | **119** | **124** | **100** | **100** | **1.3** |
| Oil | 73 | 50 | 55 | 63 | 69 | 72 | 54 | 58 | 1.6 |
| Biofuels | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 1 | n.a. |
| Other fuels | 43 | 42 | 45 | 48 | 50 | 52 | 46 | 42 | 0.9 |
| **Other sectors** | **259** | **162** | **166** | **172** | **182** | **188** | **100** | **100** | **0.6** |
| Coal | 39 | 4 | 5 | 4 | 4 | 4 | 3 | 2 | -0.4 |
| Oil | 28 | 14 | 12 | 11 | 10 | 8 | 9 | 4 | -2.2 |
| Gas | 57 | 45 | 47 | 50 | 55 | 59 | 28 | 31 | 1.1 |
| Electricity | 21 | 22 | 25 | 28 | 31 | 34 | 14 | 18 | 1.8 |
| Heat | 105 | 74 | 75 | 76 | 79 | 80 | 46 | 43 | 0.3 |
| Biomass and waste | 8 | 2 | 2 | 3 | 3 | 3 | 1 | 2 | 1.2 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| **Non-energy use** | **40** | **47** | **49** | **52** | **54** | **55** | **100** | **100** | **0.7** |

## **Reference Scenario:** Russia

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **1 082** | **1 013** | **1 141** | **1 220** | **1 323** | **1 424** | **100** | **100** | **1.5** |
| Coal | 157 | 170 | 212 | 258 | 310 | 372 | 17 | 26 | 3.5 |
| Oil | 129 | 17 | 22 | 22 | 20 | 18 | 2 | 1 | 0.2 |
| Gas | 512 | 487 | 513 | 504 | 510 | 541 | 48 | 38 | 0.5 |
| Nuclear | 118 | 160 | 198 | 226 | 257 | 248 | 16 | 17 | 1.9 |
| Hydro | 166 | 177 | 187 | 194 | 199 | 203 | 17 | 14 | 0.6 |
| Biomass and waste | 0 | 2 | 3 | 5 | 7 | 11 | 0 | 1 | 7.7 |
| Wind | 0 | 0 | 3 | 7 | 12 | 21 | 0 | 1 | 41.7 |
| Geothermal | 0 | 0 | 3 | 5 | 7 | 8 | 0 | 1 | 13.2 |
| Solar | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | n.a. |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **223** | **244** | **256** | **272** | **288** | **100** | **100** | **1.1** |
| Coal | 52 | 58 | 63 | 69 | 73 | 23 | 25 | 1.5 |
| Oil | 6 | 7 | 8 | 9 | 9 | 3 | 3 | 1.9 |
| Gas | 97 | 101 | 100 | 102 | 111 | 43 | 39 | 0.6 |
| Nuclear | 22 | 27 | 30 | 34 | 32 | 10 | 11 | 1.7 |
| Hydro | 46 | 49 | 50 | 51 | 52 | 20 | 18 | 0.6 |
| Biomass and waste | 1 | 1 | 1 | 2 | 2 | 0 | 1 | 4.1 |
| Wind | 0 | 1 | 2 | 4 | 6 | 0 | 2 | 29.4 |
| Geothermal | 0 | 0 | 1 | 1 | 1 | 0 | 0 | 12.5 |
| Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **2 180** | **1 574** | **1 644** | **1 726** | **1 839** | **1 928** | **100** | **100** | **0.9** |
| Coal | 688 | 428 | 481 | 532 | 599 | 661 | 27 | 34 | 1.9 |
| Oil | 625 | 326 | 340 | 361 | 374 | 375 | 21 | 19 | 0.6 |
| Gas | 866 | 821 | 823 | 832 | 866 | 892 | 52 | 46 | 0.4 |
| **Power generation** | **1 162** | **866** | **914** | **953** | **1 013** | **1 077** | **100** | **100** | **1.0** |
| Coal | 432 | 319 | 382 | 434 | 499 | 562 | 37 | 52 | 2.5 |
| Oil | 198 | 46 | 49 | 46 | 41 | 37 | 5 | 3 | -1.0 |
| Gas | 532 | 501 | 483 | 473 | 473 | 477 | 58 | 44 | -0.2 |
| **Total final consumption** | **961** | **633** | **647** | **686** | **726** | **749** | **100** | **100** | **0.7** |
| Coal | 254 | 106 | 95 | 95 | 96 | 95 | 17 | 13 | -0.5 |
| Oil | 389 | 239 | 248 | 270 | 285 | 290 | 38 | 39 | 0.8 |
| *of which transport* | *217* | *147* | *163* | *186* | *203* | *211* | *23* | *28* | *1.6* |
| Gas | 318 | 288 | 303 | 321 | 344 | 364 | 45 | 49 | 1.0 |

## Reference Scenario: Non-OECD Asia

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **1 591** | **3 346** | **4 468** | **5 048** | **5 735** | **6 456** | **100** | **100** | **2.9** |
| Coal | 697 | 1 677 | 2 346 | 2 646 | 2 990 | 3 324 | 50 | 51 | 3.0 |
| Oil | 311 | 758 | 951 | 1 082 | 1 259 | 1 476 | 23 | 23 | 2.9 |
| Gas | 71 | 261 | 379 | 451 | 533 | 616 | 8 | 10 | 3.8 |
| Nuclear | 10 | 32 | 90 | 120 | 151 | 173 | 1 | 3 | 7.6 |
| Hydro | 24 | 64 | 95 | 108 | 122 | 135 | 2 | 2 | 3.3 |
| Biomass and waste | 472 | 532 | 562 | 576 | 595 | 625 | 16 | 10 | 0.7 |
| Other renewables | 6 | 21 | 46 | 65 | 85 | 107 | 1 | 2 | 7.3 |
| **Power generation** | **330** | **1 272** | **1 871** | **2 206** | **2 582** | **2 974** | **100** | **100** | **3.8** |
| Coal | 229 | 1 006 | 1 460 | 1 694 | 1 957 | 2 231 | 79 | 75 | 3.5 |
| Oil | 45 | 50 | 41 | 38 | 35 | 32 | 4 | 1 | -2.0 |
| Gas | 16 | 99 | 136 | 170 | 209 | 250 | 8 | 8 | 4.1 |
| Nuclear | 10 | 32 | 90 | 120 | 151 | 173 | 3 | 6 | 7.6 |
| Hydro | 24 | 64 | 95 | 108 | 122 | 135 | 5 | 5 | 3.3 |
| Biomass and waste | 0 | 5 | 13 | 22 | 39 | 69 | 0 | 2 | 12.3 |
| Other renewables | 6 | 17 | 37 | 53 | 69 | 85 | 1 | 3 | 7.3 |
| **Other energy sector** | **166** | **368** | **502** | **567** | **637** | **687** | **100** | **100** | **2.8** |
| *of which electricity* | *24* | *85* | *126* | *151* | *179* | *207* | *23* | *30* | *3.9* |
| **Total final consumption** | **1 220** | **2 207** | **2 888** | **3 226** | **3 647** | **4 111** | **100** | **100** | **2.7** |
| Coal | 390 | 523 | 661 | 697 | 739 | 786 | 24 | 19 | 1.8 |
| Oil | 239 | 640 | 835 | 966 | 1 148 | 1 362 | 29 | 33 | 3.3 |
| Gas | 33 | 119 | 195 | 231 | 271 | 312 | 5 | 8 | 4.3 |
| Electricity | 85 | 353 | 583 | 707 | 852 | 1 006 | 16 | 24 | 4.7 |
| Heat | 14 | 52 | 69 | 73 | 77 | 81 | 2 | 2 | 1.9 |
| Biomass and waste | 459 | 515 | 537 | 541 | 543 | 542 | 23 | 13 | 0.2 |
| Other renewables | 0 | 5 | 8 | 12 | 16 | 22 | 0 | 1 | 7.2 |
| **Industry** | **393** | **857** | **1 184** | **1 319** | **1 480** | **1 651** | **100** | **100** | **2.9** |
| Coal | 234 | 414 | 527 | 558 | 598 | 643 | 48 | 39 | 1.9 |
| Oil | 52 | 89 | 102 | 106 | 111 | 116 | 10 | 7 | 1.2 |
| Gas | 10 | 57 | 86 | 102 | 119 | 137 | 7 | 8 | 3.9 |
| Electricity | 51 | 215 | 370 | 444 | 526 | 612 | 25 | 37 | 4.7 |
| Heat | 11 | 35 | 46 | 48 | 51 | 54 | 4 | 3 | 1.9 |
| Biomass and waste | 36 | 47 | 54 | 61 | 74 | 89 | 5 | 5 | 2.8 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| **Transport** | **113** | **288** | **422** | **525** | **678** | **870** | **100** | **100** | **4.9** |
| Oil | 100 | 277 | 397 | 492 | 635 | 816 | 96 | 94 | 4.8 |
| Biofuels | 0 | 1 | 10 | 15 | 21 | 28 | 0 | 3 | 13.8 |
| Other fuels | 13 | 10 | 15 | 18 | 22 | 27 | 4 | 3 | 4.3 |
| **Other sectors** | **639** | **859** | **1 001** | **1 076** | **1 159** | **1 238** | **100** | **100** | **1.6** |
| Coal | 124 | 79 | 89 | 89 | 87 | 85 | 9 | 7 | 0.3 |
| Oil | 50 | 127 | 157 | 173 | 192 | 207 | 15 | 17 | 2.1 |
| Gas | 5 | 29 | 46 | 59 | 76 | 93 | 3 | 8 | 5.3 |
| Electricity | 34 | 135 | 205 | 253 | 314 | 379 | 16 | 31 | 4.6 |
| Heat | 3 | 17 | 22 | 25 | 27 | 26 | 2 | 2 | 1.9 |
| Biomass and waste | 423 | 467 | 473 | 464 | 448 | 426 | 54 | 34 | -0.4 |
| Other renewables | 0 | 5 | 8 | 11 | 16 | 22 | 1 | 2 | 7.1 |
| **Non-energy use** | **75** | **203** | **281** | **306** | **331** | **353** | **100** | **100** | **2.4** |

# **Reference Scenario:** Non-OECD Asia

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **1 273** | **5 095** | **8 233** | **9 962** | **11 979** | **14 101** | **100** | **100** | **4.5** |
| Coal | 730 | 3 521 | 5 709 | 6 846 | 8 239 | 9 737 | 69 | 69 | 4.5 |
| Oil | 162 | 194 | 162 | 153 | 143 | 127 | 4 | 1 | -1.8 |
| Gas | 59 | 465 | 698 | 878 | 1 086 | 1 302 | 9 | 9 | 4.6 |
| Nuclear | 39 | 123 | 344 | 460 | 581 | 663 | 2 | 5 | 7.6 |
| Hydro | 275 | 741 | 1 100 | 1 261 | 1 416 | 1 573 | 15 | 11 | 3.3 |
| Biomass and waste | 2 | 12 | 39 | 69 | 120 | 209 | 0 | 1 | 13.2 |
| Wind | 0 | 21 | 145 | 236 | 304 | 349 | 0 | 2 | 13.0 |
| Geothermal | 7 | 17 | 28 | 35 | 43 | 52 | 0 | 0 | 4.9 |
| Solar | 0 | 0 | 7 | 24 | 48 | 89 | 0 | 1 | 31.8 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **1 087** | **1 792** | **2 165** | **2 606** | **3 071** | **100** | **100** | **4.6** |
| Coal | 629 | 1 045 | 1 255 | 1 526 | 1 810 | 58 | 59 | 4.7 |
| Oil | 69 | 71 | 66 | 60 | 54 | 6 | 2 | -1.1 |
| Gas | 126 | 214 | 264 | 329 | 399 | 12 | 13 | 5.1 |
| Nuclear | 18 | 44 | 58 | 73 | 83 | 2 | 3 | 7.0 |
| Hydro | 225 | 336 | 387 | 437 | 487 | 21 | 16 | 3.4 |
| Biomass and waste | 2 | 6 | 11 | 21 | 37 | 0 | 1 | 13.7 |
| Wind | 14 | 66 | 104 | 129 | 144 | 1 | 5 | 10.7 |
| Geothermal | 3 | 4 | 5 | 7 | 8 | 0 | 0 | 4.5 |
| Solar | 1 | 5 | 14 | 25 | 48 | 0 | 2 | 19.4 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **3 523** | **8 970** | **12 239** | **13 880** | **15 845** | **17 939** | **100** | **100** | **3.1** |
| Coal | 2 535 | 6 484 | 8 985 | 10 102 | 11 366 | 12 663 | 72 | 71 | 3.0 |
| Oil | 852 | 1 928 | 2 453 | 2 819 | 3 341 | 3 957 | 21 | 22 | 3.2 |
| Gas | 136 | 558 | 801 | 959 | 1 138 | 1 318 | 6 | 7 | 3.8 |
| **Power generation** | **1 078** | **4 368** | **6 244** | **7 241** | **8 356** | **9 510** | **100** | **100** | **3.4** |
| Coal | 897 | 3 976 | 5 791 | 6 718 | 7 751 | 8 821 | 91 | 93 | 3.5 |
| Oil | 143 | 159 | 132 | 123 | 113 | 101 | 4 | 1 | -1.9 |
| Gas | 38 | 233 | 321 | 400 | 492 | 588 | 5 | 6 | 4.1 |
| **Total final consumption** | **2 284** | **4 225** | **5 495** | **6 080** | **6 849** | **7 738** | **100** | **100** | **2.7** |
| Coal | 1 577 | 2 353 | 2 968 | 3 121 | 3 297 | 3 492 | 56 | 45 | 1.7 |
| Oil | 647 | 1 629 | 2 141 | 2 500 | 3 012 | 3 621 | 39 | 47 | 3.5 |
| *of which transport* | *298* | *825* | *1 182* | *1 466* | *1 892* | *2 429* | *20* | *31* | *4.8* |
| Gas | 60 | 243 | 386 | 458 | 541 | 625 | 6 | 8 | 4.2 |

## Reference Scenario: China

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **872** | **1 970** | **2 783** | **3 116** | **3 486** | **3 827** | **100** | **100** | **2.9** |
| Coal | 534 | 1 293 | 1 843 | 2 040 | 2 248 | 2 397 | 66 | 63 | 2.7 |
| Oil | 114 | 358 | 490 | 557 | 646 | 758 | 18 | 20 | 3.3 |
| Gas | 13 | 61 | 119 | 147 | 176 | 202 | 3 | 5 | 5.3 |
| Nuclear | 0 | 16 | 59 | 84 | 107 | 127 | 1 | 3 | 9.4 |
| Hydro | 11 | 42 | 63 | 73 | 82 | 90 | 2 | 2 | 3.4 |
| Biomass and waste | 200 | 195 | 191 | 187 | 191 | 205 | 10 | 5 | 0.2 |
| Other renewables | 0 | 5 | 17 | 28 | 37 | 47 | 0 | 1 | 10.2 |
| **Power generation** | **181** | **836** | **1 300** | **1 509** | **1 721** | **1 908** | **100** | **100** | **3.7** |
| Coal | 153 | 755 | 1 126 | 1 283 | 1 444 | 1 571 | 90 | 82 | 3.2 |
| Oil | 16 | 11 | 13 | 12 | 10 | 10 | 1 | 1 | -0.6 |
| Gas | 1 | 10 | 24 | 32 | 39 | 46 | 1 | 2 | 6.7 |
| Nuclear | 0 | 16 | 59 | 84 | 107 | 127 | 2 | 7 | 9.4 |
| Hydro | 11 | 42 | 63 | 73 | 82 | 90 | 5 | 5 | 3.4 |
| Biomass and waste | 0 | 1 | 3 | 6 | 16 | 35 | 0 | 2 | 15.6 |
| Other renewables | 0 | 1 | 10 | 18 | 24 | 29 | 0 | 2 | 17.1 |
| **Other energy sector** | **94** | **224** | **321** | **364** | **407** | **428** | **100** | **100** | **2.9** |
| *of which electricity* | *12* | *51* | *77* | *91* | *104* | *115* | *23* | *27* | *3.5* |
| **Total final consumption** | **668** | **1 256** | **1 730** | **1 910** | **2 128** | **2 353** | **100** | **100** | **2.8** |
| Coal | 315 | 412 | 519 | 533 | 545 | 557 | 33 | 24 | 1.3 |
| Oil | 86 | 315 | 454 | 524 | 624 | 736 | 25 | 31 | 3.8 |
| Gas | 10 | 46 | 88 | 106 | 127 | 147 | 4 | 6 | 5.2 |
| Electricity | 43 | 234 | 406 | 485 | 568 | 646 | 19 | 27 | 4.5 |
| Heat | 13 | 52 | 68 | 72 | 76 | 79 | 4 | 3 | 1.9 |
| Biomass and waste | 200 | 193 | 188 | 181 | 175 | 170 | 15 | 7 | -0.6 |
| Other renewables | 0 | 4 | 7 | 10 | 13 | 18 | 0 | 1 | 6.5 |
| **Industry** | **242** | **575** | **814** | **885** | **968** | **1 053** | **100** | **100** | **2.7** |
| Coal | 177 | 319 | 403 | 412 | 423 | 436 | 56 | 41 | 1.4 |
| Oil | 21 | 41 | 48 | 48 | 49 | 51 | 7 | 5 | 1.0 |
| Gas | 3 | 19 | 31 | 37 | 43 | 50 | 3 | 5 | 4.3 |
| Electricity | 30 | 161 | 285 | 336 | 388 | 440 | 28 | 42 | 4.5 |
| Heat | 11 | 35 | 46 | 48 | 50 | 54 | 6 | 5 | 1.9 |
| Biomass and waste | 0 | 0 | 2 | 4 | 12 | 22 | 0 | 2 | n.a. |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| **Transport** | **38** | **140** | **238** | **295** | **382** | **487** | **100** | **100** | **5.6** |
| Oil | 28 | 134 | 224 | 277 | 359 | 458 | 95 | 94 | 5.5 |
| Biofuels | 0 | 1 | 5 | 7 | 10 | 13 | 1 | 3 | 11.3 |
| Other fuels | 10 | 6 | 9 | 11 | 13 | 16 | 4 | 3 | 4.6 |
| **Other sectors** | **345** | **433** | **520** | **560** | **596** | **622** | **100** | **100** | **1.6** |
| Coal | 109 | 64 | 72 | 71 | 68 | 64 | 15 | 10 | -0.0 |
| Oil | 18 | 67 | 90 | 102 | 113 | 121 | 15 | 19 | 2.6 |
| Gas | 2 | 18 | 32 | 42 | 54 | 65 | 4 | 10 | 5.7 |
| Electricity | 13 | 70 | 115 | 141 | 170 | 194 | 16 | 31 | 4.5 |
| Heat | 2 | 16 | 22 | 24 | 26 | 25 | 4 | 4 | 1.8 |
| Biomass and waste | 200 | 192 | 182 | 169 | 153 | 134 | 44 | 22 | -1.5 |
| Other renewables | 0 | 4 | 7 | 10 | 13 | 18 | 1 | 3 | 6.4 |
| **Non-energy use** | **43** | **108** | **158** | **170** | **182** | **192** | **100** | **100** | **2.5** |

## **Reference Scenario:** China

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **650** | **3 318** | **5 622** | **6 692** | **7 810** | **8 847** | **100** | **100** | **4.4** |
| Coal | 471 | 2 685 | 4 391 | 5 119 | 5 928 | 6 639 | 81 | 75 | 4.0 |
| Oil | 49 | 34 | 44 | 41 | 34 | 32 | 1 | 0 | -0.2 |
| Gas | 3 | 41 | 113 | 156 | 200 | 253 | 1 | 3 | 8.2 |
| Nuclear | 0 | 62 | 227 | 322 | 409 | 487 | 2 | 6 | 9.4 |
| Hydro | 127 | 485 | 734 | 848 | 950 | 1 046 | 15 | 12 | 3.4 |
| Biomass and waste | 0 | 2 | 9 | 19 | 50 | 109 | 0 | 1 | 18.3 |
| Wind | 0 | 9 | 98 | 168 | 204 | 225 | 0 | 3 | 15.1 |
| Geothermal | 0 | 0 | 1 | 2 | 3 | 4 | 0 | 0 | n.a. |
| Solar | 0 | 0 | 5 | 17 | 31 | 52 | 0 | 1 | 30.4 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **706** | **1 215** | **1 460** | **1 707** | **1 936** | **100** | **100** | **4.5** |
| Coal | 502 | 827 | 970 | 1 134 | 1 275 | 71 | 66 | 4.1 |
| Oil | 20 | 21 | 19 | 16 | 16 | 3 | 1 | -1.0 |
| Gas | 24 | 69 | 88 | 105 | 125 | 3 | 6 | 7.4 |
| Nuclear | 8 | 28 | 40 | 50 | 60 | 1 | 3 | 8.9 |
| Hydro | 145 | 220 | 255 | 287 | 316 | 21 | 16 | 3.4 |
| Biomass and waste | 1 | 2 | 4 | 9 | 21 | 0 | 1 | 17.6 |
| Wind | 6 | 44 | 74 | 88 | 95 | 1 | 5 | 12.8 |
| Geothermal | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 12.2 |
| Solar | 0 | 3 | 9 | 16 | 27 | 0 | 1 | 27.6 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **2 244** | **6 071** | **8 610** | **9 583** | **10 657** | **11 615** | **100** | **100** | **2.9** |
| Coal | 1 914 | 5 033 | 7 074 | 7 791 | 8 523 | 9 101 | 83 | 78 | 2.6 |
| Oil | 304 | 906 | 1 289 | 1 486 | 1 770 | 2 097 | 15 | 18 | 3.7 |
| Gas | 26 | 132 | 248 | 306 | 364 | 417 | 2 | 4 | 5.1 |
| **Power generation** | **652** | **3 060** | **4 592** | **5 235** | **5 874** | **6 389** | **100** | **100** | **3.3** |
| Coal | 598 | 2 996 | 4 488 | 5 115 | 5 745 | 6 244 | 98 | 98 | 3.2 |
| Oil | 52 | 38 | 45 | 41 | 35 | 33 | 1 | 1 | -0.6 |
| Gas | 2 | 25 | 59 | 78 | 95 | 112 | 1 | 2 | 6.7 |
| **Total final consumption** | **1 507** | **2 789** | **3 714** | **4 001** | **4 373** | **4 783** | **100** | **100** | **2.4** |
| Coal | 1 265 | 1 898 | 2 376 | 2 431 | 2 479 | 2 527 | 68 | 53 | 1.3 |
| Oil | 225 | 803 | 1 176 | 1 372 | 1 659 | 1 982 | 29 | 41 | 4.0 |
| *of which transport* | *83* | *399* | *665* | *822* | *1 066* | *1 358* | *14* | *28* | *5.5* |
| Gas | 17 | 88 | 162 | 197 | 235 | 274 | 3 | 6 | 5.1 |

## Reference Scenario: India

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **318** | **595** | **764** | **901** | **1 073** | **1 287** | **100** | **100** | **3.4** |
| Coal | 106 | 242 | 305 | 378 | 468 | 586 | 41 | 45 | 3.9 |
| Oil | 61 | 141 | 186 | 223 | 274 | 341 | 24 | 26 | 3.9 |
| Gas | 10 | 33 | 67 | 80 | 97 | 113 | 6 | 9 | 5.4 |
| Nuclear | 2 | 4 | 14 | 19 | 24 | 28 | 1 | 2 | 8.3 |
| Hydro | 6 | 11 | 15 | 16 | 19 | 22 | 2 | 2 | 3.1 |
| Biomass and waste | 133 | 162 | 173 | 178 | 183 | 189 | 27 | 15 | 0.7 |
| Other renewables | 0 | 1 | 5 | 6 | 7 | 10 | 0 | 1 | 9.7 |
| **Power generation** | **73** | **217** | **288** | **358** | **444** | **554** | **100** | **100** | **4.2** |
| Coal | 58 | 177 | 216 | 269 | 333 | 419 | 82 | 76 | 3.8 |
| Oil | 4 | 9 | 9 | 9 | 8 | 8 | 4 | 1 | -0.7 |
| Gas | 3 | 13 | 28 | 35 | 45 | 55 | 6 | 10 | 6.5 |
| Nuclear | 2 | 4 | 14 | 19 | 24 | 28 | 2 | 5 | 8.3 |
| Hydro | 6 | 11 | 15 | 16 | 19 | 22 | 5 | 4 | 3.1 |
| Biomass and waste | 0 | 1 | 3 | 5 | 8 | 15 | 1 | 3 | 11.8 |
| Other renewables | 0 | 1 | 4 | 5 | 6 | 8 | 0 | 1 | 9.3 |
| **Other energy sector** | **19** | **55** | **81** | **96** | **115** | **136** | **100** | **100** | **4.0** |
| *of which electricity* | *7* | *22* | *33* | *42* | *54* | *67* | *40* | *49* | *4.9* |
| **Total final consumption** | **251** | **391** | **506** | **589** | **698** | **833** | **100** | **100** | **3.3** |
| Coal | 42 | 47 | 67 | 83 | 106 | 134 | 12 | 16 | 4.7 |
| Oil | 52 | 119 | 156 | 190 | 237 | 300 | 30 | 36 | 4.1 |
| Gas | 6 | 18 | 36 | 42 | 48 | 54 | 5 | 6 | 4.9 |
| Electricity | 18 | 47 | 77 | 100 | 132 | 169 | 12 | 20 | 5.7 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 133 | 161 | 170 | 173 | 175 | 175 | 41 | 21 | 0.4 |
| Other renewables | 0 | 0 | 0 | 1 | 1 | 2 | 0 | 0 | 11.6 |
| **Industry** | **70** | **113** | **158** | **192** | **235** | **287** | **100** | **100** | **4.1** |
| Coal | 29 | 36 | 55 | 72 | 93 | 121 | 32 | 42 | 5.4 |
| Oil | 10 | 21 | 25 | 28 | 30 | 32 | 18 | 11 | 1.9 |
| Gas | 0 | 7 | 12 | 15 | 17 | 20 | 6 | 7 | 4.4 |
| Electricity | 9 | 21 | 37 | 49 | 65 | 83 | 19 | 29 | 6.2 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 23 | 28 | 28 | 28 | 29 | 30 | 25 | 11 | 0.4 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| **Transport** | **27** | **41** | **61** | **85** | **121** | **175** | **100** | **100** | **6.5** |
| Oil | 24 | 38 | 56 | 78 | 111 | 161 | 94 | 92 | 6.4 |
| Biofuels | 0 | 0 | 2 | 4 | 5 | 8 | 0 | 4 | 19.2 |
| Other fuels | 3 | 2 | 3 | 4 | 5 | 7 | 5 | 4 | 4.9 |
| **Other sectors** | **143** | **198** | **228** | **246** | **267** | **290** | **100** | **100** | **1.7** |
| Coal | 11 | 10 | 12 | 12 | 12 | 13 | 5 | 4 | 0.9 |
| Oil | 12 | 30 | 35 | 39 | 44 | 49 | 15 | 17 | 2.3 |
| Gas | 0 | 1 | 2 | 3 | 4 | 6 | 0 | 2 | 8.9 |
| Electricity | 9 | 25 | 39 | 50 | 65 | 83 | 13 | 29 | 5.4 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 111 | 133 | 140 | 141 | 140 | 137 | 67 | 47 | 0.1 |
| Other renewables | 0 | 0 | 0 | 1 | 1 | 2 | 0 | 1 | 11.6 |
| **Non-energy use** | **12** | **39** | **59** | **67** | **75** | **82** | **100** | **100** | **3.3** |

# Reference Scenario: India

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **289** | **792** | **1 271** | **1 650** | **2 147** | **2 737** | **100** | **100** | **5.5** |
| Coal | 192 | 537 | 810 | 1 095 | 1 471 | 1 935 | 68 | 71 | 5.7 |
| Oil | 10 | 36 | 36 | 36 | 35 | 33 | 4 | 1 | -0.3 |
| Gas | 10 | 66 | 150 | 189 | 243 | 299 | 8 | 11 | 6.8 |
| Nuclear | 6 | 17 | 52 | 73 | 91 | 106 | 2 | 4 | 8.3 |
| Hydro | 72 | 124 | 172 | 188 | 220 | 251 | 16 | 9 | 3.1 |
| Biomass and waste | 0 | 2 | 6 | 10 | 17 | 29 | 0 | 1 | 12.5 |
| Wind | 0 | 12 | 45 | 56 | 64 | 72 | 1 | 3 | 8.2 |
| Geothermal | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | n.a. |
| Solar | 0 | 0 | 1 | 2 | 4 | 11 | 0 | 0 | 31.8 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **150** | **263** | **335** | **444** | **571** | **100** | **100** | **6.0** |
| Coal | 78 | 141 | 191 | 268 | 364 | 52 | 64 | 6.9 |
| Oil | 7 | 8 | 8 | 8 | 8 | 5 | 1 | 0.2 |
| Gas | 16 | 32 | 41 | 53 | 65 | 11 | 11 | 6.3 |
| Nuclear | 4 | 8 | 11 | 13 | 14 | 3 | 3 | 6.0 |
| Hydro | 36 | 51 | 56 | 67 | 78 | 24 | 14 | 3.4 |
| Biomass and waste | 0 | 1 | 2 | 3 | 5 | 0 | 1 | 11.9 |
| Wind | 8 | 21 | 26 | 29 | 31 | 5 | 5 | 6.2 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 11.5 |
| Solar | 0 | 0 | 1 | 2 | 6 | 0 | 1 | 23.2 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **589** | **1 327** | **1 753** | **2 161** | **2 685** | **3 362** | **100** | **100** | **4.1** |
| Coal | 406 | 896 | 1 138 | 1 417 | 1 765 | 2 219 | 68 | 66 | 4.0 |
| Oil | 164 | 360 | 474 | 572 | 712 | 897 | 27 | 27 | 4.1 |
| Gas | 19 | 71 | 141 | 171 | 208 | 245 | 5 | 7 | 5.5 |
| **Power generation** | **245** | **747** | **929** | **1 151** | **1 424** | **1 778** | **100** | **100** | **3.8** |
| Coal | 226 | 688 | 836 | 1 042 | 1 292 | 1 624 | 92 | 91 | 3.8 |
| Oil | 11 | 28 | 27 | 27 | 26 | 24 | 4 | 1 | -0.7 |
| Gas | 8 | 30 | 66 | 82 | 106 | 130 | 4 | 7 | 6.5 |
| **Total final consumption** | **328** | **535** | **751** | **927** | **1 168** | **1 478** | **100** | **100** | **4.5** |
| Coal | 175 | 205 | 298 | 371 | 469 | 591 | 38 | 40 | 4.7 |
| Oil | 144 | 295 | 385 | 475 | 604 | 779 | 55 | 53 | 4.3 |
| *of which transport* | *72* | *116* | *168* | *234* | *336* | *484* | *22* | *33* | *6.4* |
| Gas | 9 | 35 | 68 | 81 | 94 | 108 | 7 | 7 | 5.0 |

## Reference Scenario: ASEAN

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **243** | **513** | **612** | **687** | **788** | **903** | **100** | **100** | **2.5** |
| Coal | 12 | 76 | 121 | 145 | 177 | 220 | 15 | 24 | 4.7 |
| Oil | 90 | 179 | 191 | 211 | 238 | 267 | 35 | 30 | 1.8 |
| Gas | 33 | 117 | 134 | 150 | 173 | 199 | 23 | 22 | 2.3 |
| Nuclear | 0 | 0 | 0 | 0 | 4 | 4 | 0 | 0 | n.a. |
| Hydro | 2 | 6 | 8 | 8 | 9 | 10 | 1 | 1 | 2.5 |
| Biomass and waste | 99 | 120 | 136 | 144 | 151 | 159 | 23 | 18 | 1.2 |
| Other renewables | 6 | 15 | 23 | 29 | 36 | 44 | 3 | 5 | 4.9 |
| **Power generation** | **38** | **128** | **176** | **213** | **267** | **333** | **100** | **100** | **4.2** |
| Coal | 7 | 38 | 75 | 95 | 122 | 161 | 30 | 48 | 6.4 |
| Oil | 16 | 14 | 8 | 8 | 7 | 6 | 11 | 2 | -3.5 |
| Gas | 6 | 54 | 58 | 67 | 80 | 97 | 42 | 29 | 2.6 |
| Nuclear | 0 | 0 | 0 | 0 | 4 | 4 | 0 | 1 | n.a. |
| Hydro | 2 | 6 | 8 | 8 | 9 | 10 | 5 | 3 | 2.5 |
| Biomass and waste | 0 | 1 | 4 | 6 | 8 | 11 | 1 | 3 | 10.3 |
| Other renewables | 6 | 15 | 23 | 29 | 36 | 43 | 12 | 13 | 4.8 |
| **Other energy sector** | **41** | **71** | **82** | **86** | **92** | **98** | **100** | **100** | **1.4** |
| *of which electricity* | *2* | *6* | *9* | *10* | *12* | *15* | *9* | *15* | *3.8* |
| **Total final consumption** | **177** | **362** | **423** | **472** | **535** | **606** | **100** | **100** | **2.3** |
| Coal | 4 | 37 | 45 | 49 | 54 | 58 | 10 | 10 | 1.9 |
| Oil | 66 | 145 | 157 | 176 | 202 | 231 | 40 | 38 | 2.1 |
| Gas | 8 | 30 | 40 | 47 | 55 | 63 | 8 | 10 | 3.2 |
| Electricity | 11 | 43 | 60 | 74 | 94 | 119 | 12 | 20 | 4.5 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 87 | 107 | 120 | 126 | 131 | 135 | 30 | 22 | 1.0 |
| Other renewables | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | n.a. |
| **Industry** | **37** | **108** | **138** | **157** | **180** | **201** | **100** | **100** | **2.7** |
| Coal | 4 | 36 | 43 | 47 | 51 | 54 | 33 | 27 | 1.8 |
| Oil | 14 | 20 | 20 | 21 | 22 | 22 | 18 | 11 | 0.6 |
| Gas | 3 | 21 | 29 | 34 | 40 | 45 | 19 | 23 | 3.5 |
| Electricity | 5 | 18 | 28 | 35 | 43 | 52 | 17 | 26 | 4.7 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 11 | 14 | 18 | 21 | 24 | 27 | 13 | 13 | 2.9 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| **Transport** | **33** | **77** | **89** | **105** | **128** | **154** | **100** | **100** | **3.0** |
| Oil | 33 | 77 | 86 | 100 | 121 | 146 | 99 | 95 | 2.8 |
| Biofuels | 0 | 0 | 3 | 4 | 6 | 7 | 0 | 5 | 17.5 |
| Other fuels | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 4.2 |
| **Other sectors** | **95** | **144** | **160** | **170** | **185** | **205** | **100** | **100** | **1.5** |
| Coal | 0 | 1 | 2 | 2 | 3 | 3 | 1 | 2 | 3.9 |
| Oil | 13 | 24 | 25 | 26 | 27 | 29 | 17 | 14 | 0.8 |
| Gas | 0 | 1 | 2 | 2 | 3 | 5 | 1 | 2 | 6.5 |
| Electricity | 6 | 24 | 32 | 39 | 51 | 66 | 17 | 32 | 4.4 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 76 | 93 | 99 | 100 | 101 | 101 | 65 | 49 | 0.3 |
| Other renewables | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | n.a. |
| **Non-energy use** | **12** | **32** | **36** | **39** | **43** | **46** | **100** | **100** | **1.5** |

## Reference Scenario: ASEAN

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **156** | **568** | **800** | **977** | **1 230** | **1 554** | **100** | **100** | **4.5** |
| Coal | 28 | 156 | 331 | 431 | 572 | 783 | 27 | 50 | 7.3 |
| Oil | 65 | 61 | 36 | 35 | 32 | 28 | 11 | 2 | -3.4 |
| Gas | 26 | 262 | 306 | 355 | 422 | 496 | 46 | 32 | 2.8 |
| Nuclear | 0 | 0 | 0 | 0 | 16 | 16 | 0 | 1 | n.a. |
| Hydro | 28 | 68 | 88 | 98 | 108 | 120 | 12 | 8 | 2.5 |
| Biomass and waste | 2 | 4 | 13 | 20 | 28 | 39 | 1 | 2 | 10.1 |
| Wind | 0 | 0 | 1 | 2 | 6 | 12 | 0 | 1 | 26.0 |
| Geothermal | 7 | 17 | 26 | 33 | 40 | 47 | 3 | 3 | 4.5 |
| Solar | 0 | 0 | 0 | 3 | 7 | 13 | 0 | 1 | 46.7 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **138** | **192** | **232** | **288** | **362** | **100** | **100** | **4.3** |
| Coal | 28 | 52 | 67 | 88 | 119 | 20 | 33 | 6.5 |
| Oil | 24 | 24 | 22 | 21 | 18 | 17 | 5 | -1.3 |
| Gas | 60 | 79 | 98 | 125 | 157 | 44 | 43 | 4.2 |
| Nuclear | 0 | 0 | 0 | 2 | 2 | 0 | 1 | n.a. |
| Hydro | 22 | 30 | 33 | 37 | 41 | 16 | 11 | 2.8 |
| Biomass and waste | 1 | 2 | 3 | 4 | 6 | 0 | 2 | 10.5 |
| Wind | 0 | 0 | 1 | 2 | 4 | 0 | 1 | 27.3 |
| Geothermal | 3 | 4 | 5 | 6 | 7 | 2 | 2 | 4.1 |
| Solar | 1 | 1 | 2 | 4 | 7 | 0 | 2 | 10.8 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **361** | **1 013** | **1 250** | **1 432** | **1 683** | **1 992** | **100** | **100** | **3.0** |
| Coal | 47 | 300 | 476 | 570 | 697 | 867 | 30 | 44 | 4.7 |
| Oil | 256 | 467 | 491 | 544 | 617 | 699 | 46 | 35 | 1.8 |
| Gas | 59 | 246 | 283 | 318 | 369 | 427 | 24 | 21 | 2.4 |
| **Power generation** | **95** | **322** | **460** | **556** | **693** | **882** | **100** | **100** | **4.5** |
| Coal | 28 | 152 | 297 | 375 | 482 | 637 | 47 | 72 | 6.4 |
| Oil | 52 | 45 | 26 | 25 | 23 | 20 | 14 | 2 | -3.5 |
| Gas | 15 | 126 | 137 | 156 | 188 | 226 | 39 | 26 | 2.6 |
| **Total final consumption** | **217** | **602** | **689** | **772** | **880** | **997** | **100** | **100** | **2.2** |
| Coal | 18 | 146 | 177 | 193 | 212 | 228 | 24 | 23 | 1.9 |
| Oil | 183 | 391 | 425 | 477 | 549 | 633 | 65 | 63 | 2.1 |
| *of which transport* | *97* | *227* | *254* | *298* | *359* | *433* | *38* | *43* | *2.8* |
| Gas | 15 | 64 | 87 | 102 | 119 | 137 | 11 | 14 | 3.4 |

## **Reference Scenario:** Middle East

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **220** | **546** | **702** | **804** | **913** | **1 030** | **100** | **100** | **2.8** |
| Coal | 3 | 10 | 11 | 14 | 18 | 23 | 2 | 2 | 3.7 |
| Oil | 141 | 288 | 366 | 408 | 449 | 486 | 53 | 47 | 2.3 |
| Gas | 73 | 244 | 316 | 371 | 431 | 500 | 45 | 49 | 3.2 |
| Nuclear | 0 | 0 | 2 | 2 | 3 | 3 | 0 | 0 | n.a. |
| Hydro | 1 | 2 | 3 | 3 | 4 | 4 | 0 | 0 | 3.0 |
| Biomass and waste | 1 | 1 | 2 | 3 | 4 | 5 | 0 | 1 | 6.7 |
| Other renewables | 0 | 1 | 2 | 3 | 5 | 9 | 0 | 1 | 10.7 |
| **Power generation** | **63** | **178** | **206** | **241** | **283** | **332** | **100** | **100** | **2.8** |
| Coal | 2 | 9 | 10 | 12 | 16 | 21 | 5 | 6 | 3.9 |
| Oil | 29 | 65 | 66 | 67 | 67 | 65 | 37 | 19 | -0.0 |
| Gas | 32 | 102 | 124 | 154 | 188 | 231 | 58 | 70 | 3.6 |
| Nuclear | 0 | 0 | 2 | 2 | 3 | 3 | 0 | 1 | n.a. |
| Hydro | 1 | 2 | 3 | 3 | 4 | 4 | 1 | 1 | 3.0 |
| Biomass and waste | 0 | 0 | 1 | 2 | 2 | 3 | 0 | 1 | 34.7 |
| Other renewables | 0 | 0 | 0 | 1 | 3 | 6 | 0 | 2 | 30.8 |
| **Other energy sector** | **20** | **67** | **94** | **104** | **114** | **120** | **100** | **100** | **2.6** |
| *of which electricity* | *4* | *12* | *15* | *17* | *20* | *24* | *18* | *20* | *3.0* |
| **Total final consumption** | **157** | **363** | **485** | **557** | **635** | **720** | **100** | **100** | **3.0** |
| Coal | 0 | 1 | 1 | 1 | 1 | 2 | 0 | 0 | 3.4 |
| Oil | 107 | 201 | 280 | 318 | 355 | 393 | 56 | 55 | 2.9 |
| Gas | 32 | 109 | 134 | 154 | 176 | 202 | 30 | 28 | 2.7 |
| Electricity | 17 | 49 | 68 | 81 | 98 | 119 | 14 | 17 | 3.9 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 1 | 1 | 1 | 2 | 2 | 2 | 0 | 0 | 3.8 |
| Other renewables | 0 | 1 | 1 | 2 | 2 | 3 | 0 | 0 | 4.9 |
| **Industry** | **45** | **90** | **115** | **133** | **154** | **177** | **100** | **100** | **3.0** |
| Coal | 0 | 1 | 1 | 1 | 1 | 2 | 1 | 1 | 3.4 |
| Oil | 22 | 37 | 45 | 50 | 55 | 60 | 41 | 34 | 2.1 |
| Gas | 20 | 42 | 56 | 66 | 77 | 90 | 47 | 51 | 3.3 |
| Electricity | 3 | 9 | 13 | 16 | 20 | 25 | 11 | 14 | 4.3 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2.3 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| **Transport** | **50** | **104** | **153** | **179** | **203** | **228** | **100** | **100** | **3.5** |
| Oil | 50 | 103 | 152 | 177 | 200 | 225 | 99 | 99 | 3.4 |
| Biofuels | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | n.a. |
| Other fuels | 0 | 1 | 1 | 1 | 2 | 2 | 1 | 1 | 3.8 |
| **Other sectors** | **41** | **112** | **136** | **153** | **175** | **202** | **100** | **100** | **2.6** |
| Coal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -100.0 |
| Oil | 23 | 31 | 34 | 35 | 37 | 40 | 28 | 20 | 1.1 |
| Gas | 3 | 39 | 45 | 50 | 57 | 65 | 35 | 32 | 2.2 |
| Electricity | 14 | 40 | 55 | 65 | 78 | 94 | 36 | 46 | 3.8 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1.2 |
| Other renewables | 0 | 1 | 1 | 2 | 2 | 3 | 1 | 1 | 4.9 |
| **Non-energy use** | **21** | **57** | **81** | **93** | **103** | **113** | **100** | **100** | **3.0** |

## **Reference Scenario:** Middle East

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **240** | **715** | **967** | **1 144** | **1 376** | **1 656** | **100** | **100** | **3.7** |
| Coal | 10 | 37 | 45 | 56 | 79 | 105 | 5 | 6 | 4.6 |
| Oil | 114 | 250 | 262 | 263 | 269 | 263 | 35 | 16 | 0.2 |
| Gas | 104 | 404 | 614 | 763 | 945 | 1 176 | 57 | 71 | 4.8 |
| Nuclear | 0 | 0 | 8 | 8 | 10 | 10 | 0 | 1 | n.a. |
| Hydro | 12 | 23 | 32 | 38 | 43 | 45 | 3 | 3 | 3.0 |
| Biomass and waste | 0 | 0 | 3 | 5 | 7 | 9 | 0 | 1 | 34.3 |
| Wind | 0 | 0 | 3 | 7 | 11 | 17 | 0 | 1 | 22.7 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Solar | 0 | 0 | 1 | 5 | 12 | 31 | 0 | 2 | n.a. |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **186** | **269** | **287** | **329** | **389** | **100** | **100** | **3.2** |
| Coal | 5 | 7 | 9 | 12 | 16 | 3 | 4 | 5.1 |
| Oil | 64 | 72 | 70 | 69 | 65 | 34 | 17 | 0.1 |
| Gas | 107 | 173 | 186 | 219 | 267 | 57 | 69 | 4.1 |
| Nuclear | 0 | 1 | 1 | 1 | 1 | 0 | 0 | n.a. |
| Hydro | 10 | 14 | 17 | 19 | 20 | 6 | 5 | 2.9 |
| Biomass and waste | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 19.3 |
| Wind | 0 | 1 | 2 | 3 | 6 | 0 | 1 | 28.9 |
| Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Solar | 0 | 0 | 2 | 4 | 12 | 0 | 3 | 35.6 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **588** | **1 375** | **1 730** | **1 970** | **2 228** | **2 495** | **100** | **100** | **2.6** |
| Coal | 12 | 38 | 44 | 53 | 71 | 89 | 3 | 4 | 3.8 |
| Oil | 414 | 786 | 997 | 1 104 | 1 208 | 1 297 | 57 | 52 | 2.2 |
| Gas | 163 | 550 | 689 | 813 | 950 | 1 108 | 40 | 44 | 3.1 |
| **Power generation** | **172** | **476** | **535** | **617** | **714** | **818** | **100** | **100** | **2.4** |
| Coal | 9 | 34 | 39 | 47 | 64 | 81 | 7 | 10 | 3.8 |
| Oil | 89 | 203 | 207 | 208 | 211 | 202 | 43 | 25 | -0.0 |
| Gas | 74 | 239 | 289 | 361 | 439 | 535 | 50 | 65 | 3.6 |
| **Total final consumption** | **367** | **776** | **1 026** | **1 169** | **1 318** | **1 476** | **100** | **100** | **2.8** |
| Coal | 2 | 3 | 4 | 5 | 6 | 7 | 0 | 0 | 3.5 |
| Oil | 298 | 539 | 734 | 833 | 932 | 1 032 | 69 | 70 | 2.9 |
| *of which transport* | *150* | *306* | *450* | *524* | *593* | *666* | *39* | *45* | *3.4* |
| Gas | 68 | 235 | 288 | 331 | 380 | 437 | 30 | 30 | 2.7 |

## **Reference Scenario:** Africa

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **388** | **630** | **716** | **763** | **822** | **873** | **100** | **100** | **1.4** |
| Coal | 74 | 106 | 110 | 110 | 121 | 127 | 17 | 15 | 0.8 |
| Oil | 87 | 132 | 136 | 142 | 154 | 171 | 21 | 20 | 1.1 |
| Gas | 30 | 85 | 120 | 137 | 151 | 156 | 13 | 18 | 2.7 |
| Nuclear | 2 | 3 | 3 | 5 | 5 | 7 | 0 | 1 | 3.8 |
| Hydro | 5 | 8 | 11 | 14 | 17 | 21 | 1 | 2 | 4.1 |
| Biomass and waste | 190 | 295 | 331 | 349 | 364 | 376 | 47 | 43 | 1.1 |
| Other renewables | 0 | 1 | 3 | 6 | 9 | 16 | 0 | 2 | 12.7 |
| **Power generation** | **69** | **131** | **166** | **183** | **207** | **230** | **100** | **100** | **2.5** |
| Coal | 39 | 62 | 68 | 69 | 80 | 87 | 47 | 38 | 1.5 |
| Oil | 11 | 18 | 13 | 13 | 10 | 8 | 14 | 4 | -3.3 |
| Gas | 11 | 38 | 62 | 69 | 75 | 77 | 29 | 33 | 3.1 |
| Nuclear | 2 | 3 | 3 | 5 | 5 | 7 | 2 | 3 | 3.8 |
| Hydro | 5 | 8 | 11 | 14 | 17 | 21 | 6 | 9 | 4.1 |
| Biomass and waste | 0 | 1 | 6 | 9 | 12 | 15 | 0 | 6 | 14.8 |
| Other renewables | 0 | 1 | 3 | 5 | 9 | 15 | 1 | 6 | 12.5 |
| **Other energy sector** | **57** | **90** | **103** | **110** | **116** | **119** | **100** | **100** | **1.2** |
| *of which electricity* | *6* | *10* | *12* | *13* | *15* | *16* | *11* | *14* | *2.3* |
| **Total final consumption** | **289** | **463** | **516** | **547** | **589** | **628** | **100** | **100** | **1.3** |
| Coal | 19 | 17 | 16 | 16 | 16 | 16 | 4 | 3 | -0.1 |
| Oil | 70 | 112 | 122 | 130 | 146 | 163 | 24 | 26 | 1.6 |
| Gas | 9 | 29 | 34 | 36 | 39 | 43 | 6 | 7 | 1.7 |
| Electricity | 21 | 43 | 57 | 64 | 75 | 87 | 9 | 14 | 3.1 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 169 | 261 | 287 | 300 | 311 | 319 | 56 | 51 | 0.9 |
| Other renewables | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 18.7 |
| **Industry** | **61** | **85** | **96** | **101** | **109** | **118** | **100** | **100** | **1.4** |
| Coal | 13 | 9 | 9 | 9 | 10 | 10 | 11 | 8 | 0.1 |
| Oil | 14 | 14 | 16 | 17 | 18 | 19 | 17 | 16 | 1.1 |
| Gas | 5 | 15 | 19 | 20 | 22 | 23 | 18 | 20 | 1.8 |
| Electricity | 12 | 20 | 24 | 26 | 30 | 34 | 23 | 28 | 2.4 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 16 | 26 | 27 | 29 | 30 | 33 | 30 | 28 | 1.0 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| **Transport** | **37** | **68** | **75** | **83** | **96** | **111** | **100** | **100** | **2.1** |
| Oil | 36 | 66 | 72 | 79 | 92 | 106 | 97 | 96 | 2.1 |
| Biofuels | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | n.a. |
| Other fuels | 1 | 2 | 2 | 3 | 3 | 3 | 3 | 3 | 2.7 |
| **Other sectors** | **180** | **296** | **330** | **349** | **368** | **384** | **100** | **100** | **1.1** |
| Coal | 3 | 6 | 6 | 6 | 6 | 5 | 2 | 1 | -0.4 |
| Oil | 15 | 25 | 27 | 27 | 29 | 31 | 9 | 8 | 0.9 |
| Gas | 1 | 6 | 6 | 7 | 8 | 9 | 2 | 2 | 1.8 |
| Electricity | 9 | 23 | 32 | 37 | 45 | 53 | 8 | 14 | 3.6 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 152 | 236 | 259 | 271 | 279 | 285 | 80 | 74 | 0.8 |
| Other renewables | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 18.7 |
| **Non-energy use** | **11** | **14** | **15** | **15** | **16** | **16** | **100** | **100** | **0.7** |

# **Reference Scenario:** Africa

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **316** | **615** | **798** | **897** | **1 044** | **1 200** | **100** | **100** | **2.9** |
| Coal | 165 | 267 | 292 | 294 | 357 | 402 | 43 | 34 | 1.8 |
| Oil | 43 | 68 | 48 | 49 | 38 | 33 | 11 | 3 | -3.1 |
| Gas | 43 | 170 | 290 | 328 | 364 | 382 | 28 | 32 | 3.6 |
| Nuclear | 8 | 11 | 11 | 18 | 18 | 27 | 2 | 2 | 3.8 |
| Hydro | 56 | 96 | 131 | 161 | 195 | 242 | 16 | 20 | 4.1 |
| Biomass and waste | 0 | 1 | 15 | 24 | 34 | 43 | 0 | 4 | 19.1 |
| Wind | 0 | 1 | 4 | 8 | 15 | 24 | 0 | 2 | 13.8 |
| Geothermal | 0 | 1 | 3 | 4 | 5 | 8 | 0 | 1 | 9.3 |
| Solar | 0 | 0 | 4 | 10 | 19 | 38 | 0 | 3 | 36.7 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **128** | **181** | **204** | **236** | **273** | **100** | **100** | **3.4** |
| Coal | 41 | 53 | 53 | 62 | 68 | 32 | 25 | 2.2 |
| Oil | 23 | 26 | 25 | 22 | 19 | 18 | 7 | -0.8 |
| Gas | 38 | 62 | 71 | 81 | 89 | 30 | 33 | 3.8 |
| Nuclear | 2 | 2 | 3 | 3 | 4 | 2 | 2 | 3.5 |
| Hydro | 23 | 32 | 40 | 49 | 61 | 18 | 22 | 4.3 |
| Biomass and waste | 0 | 3 | 4 | 5 | 7 | 0 | 3 | 17.4 |
| Wind | 0 | 1 | 3 | 5 | 8 | 0 | 3 | 12.9 |
| Geothermal | 0 | 0 | 1 | 1 | 1 | 0 | 0 | 7.0 |
| Solar | 0 | 2 | 4 | 8 | 16 | 0 | 6 | 36.1 |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **546** | **886** | **998** | **1 054** | **1 165** | **1 247** | **100** | **100** | **1.5** |
| Coal | 236 | 314 | 333 | 336 | 380 | 405 | 35 | 33 | 1.1 |
| Oil | 248 | 391 | 406 | 429 | 468 | 514 | 44 | 41 | 1.2 |
| Gas | 62 | 181 | 259 | 289 | 316 | 327 | 20 | 26 | 2.6 |
| **Power generation** | **213** | **386** | **449** | **468** | **517** | **543** | **100** | **100** | **1.5** |
| Coal | 152 | 239 | 265 | 268 | 311 | 337 | 62 | 62 | 1.5 |
| Oil | 35 | 57 | 40 | 39 | 30 | 26 | 15 | 5 | -3.4 |
| Gas | 25 | 89 | 144 | 161 | 176 | 179 | 23 | 33 | 3.1 |
| **Total final consumption** | **302** | **452** | **486** | **513** | **569** | **623** | **100** | **100** | **1.4** |
| Coal | 83 | 74 | 69 | 68 | 69 | 68 | 16 | 11 | -0.4 |
| Oil | 201 | 320 | 350 | 373 | 420 | 468 | 71 | 75 | 1.7 |
| *of which transport* | *106* | *196* | *215* | *234* | *273* | *314* | *43* | *50* | *2.1* |
| Gas | 18 | 57 | 68 | 72 | 79 | 87 | 13 | 14 | 1.8 |

## Reference Scenario: Latin America

| | Energy demand (Mtoe) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total primary energy demand** | **343** | **551** | **633** | **683** | **749** | **816** | **100** | **100** | **1.7** |
| Coal | 17 | 23 | 34 | 38 | 44 | 49 | 4 | 6 | 3.4 |
| Oil | 156 | 247 | 264 | 279 | 293 | 316 | 45 | 39 | 1.1 |
| Gas | 53 | 108 | 134 | 147 | 175 | 194 | 20 | 24 | 2.6 |
| Nuclear | 2 | 5 | 7 | 11 | 13 | 13 | 1 | 2 | 4.0 |
| Hydro | 31 | 58 | 64 | 70 | 75 | 81 | 10 | 10 | 1.5 |
| Biomass and waste | 82 | 108 | 124 | 131 | 139 | 147 | 20 | 18 | 1.4 |
| Other renewables | 1 | 3 | 5 | 7 | 10 | 16 | 0 | 2 | 8.1 |
| **Power generation** | **69** | **138** | **173** | **194** | **220** | **246** | **100** | **100** | **2.5** |
| Coal | 5 | 8 | 20 | 23 | 28 | 33 | 6 | 13 | 6.3 |
| Oil | 14 | 30 | 26 | 23 | 20 | 16 | 22 | 7 | -2.6 |
| Gas | 14 | 28 | 43 | 51 | 63 | 75 | 21 | 31 | 4.3 |
| Nuclear | 2 | 5 | 7 | 11 | 13 | 13 | 4 | 5 | 4.0 |
| Hydro | 31 | 58 | 64 | 70 | 75 | 81 | 42 | 33 | 1.5 |
| Biomass and waste | 2 | 7 | 8 | 10 | 12 | 13 | 5 | 5 | 3.2 |
| Other renewables | 1 | 3 | 4 | 6 | 9 | 14 | 2 | 6 | 7.8 |
| **Other energy sector** | **57** | **79** | **91** | **95** | **105** | **110** | **100** | **100** | **1.4** |
| *of which electricity* | *8* | *18* | *21* | *23* | *25* | *27* | *22* | *24* | *1.8* |
| **Total final consumption** | **259** | **420** | **477** | **513** | **558** | **610** | **100** | **100** | **1.6** |
| Coal | 7 | 11 | 11 | 11 | 12 | 12 | 3 | 2 | 0.6 |
| Oil | 126 | 195 | 213 | 229 | 249 | 274 | 46 | 45 | 1.5 |
| Gas | 25 | 61 | 68 | 73 | 79 | 85 | 15 | 14 | 1.4 |
| Electricity | 35 | 69 | 87 | 97 | 110 | 124 | 16 | 20 | 2.6 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 67 | 84 | 97 | 102 | 108 | 113 | 20 | 19 | 1.3 |
| Other renewables | 0 | 0 | 0 | 1 | 1 | 2 | 0 | 0 | 11.1 |
| **Industry** | **88** | **145** | **164** | **175** | **188** | **200** | **100** | **100** | **1.4** |
| Coal | 7 | 10 | 11 | 11 | 12 | 12 | 7 | 6 | 0.7 |
| Oil | 20 | 29 | 31 | 33 | 35 | 36 | 20 | 18 | 1.0 |
| Gas | 15 | 31 | 34 | 36 | 38 | 41 | 21 | 20 | 1.3 |
| Electricity | 17 | 32 | 40 | 45 | 51 | 58 | 22 | 29 | 2.5 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 29 | 43 | 48 | 50 | 52 | 54 | 30 | 27 | 0.9 |
| Other renewables | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| **Transport** | **74** | **130** | **149** | **164** | **186** | **212** | **100** | **100** | **2.2** |
| Oil | 68 | 115 | 126 | 138 | 154 | 176 | 88 | 83 | 1.9 |
| Biofuels | 6 | 9 | 16 | 18 | 22 | 26 | 7 | 12 | 4.6 |
| Other fuels | 0 | 6 | 8 | 8 | 10 | 11 | 5 | 5 | 2.6 |
| **Other sectors** | **81** | **111** | **126** | **136** | **147** | **158** | **100** | **100** | **1.6** |
| Coal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1.1 |
| Oil | 25 | 29 | 31 | 33 | 34 | 35 | 26 | 22 | 0.9 |
| Gas | 6 | 13 | 15 | 17 | 19 | 21 | 12 | 14 | 2.2 |
| Electricity | 17 | 37 | 46 | 52 | 58 | 66 | 33 | 42 | 2.6 |
| Heat | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |
| Biomass and waste | 32 | 32 | 33 | 34 | 34 | 34 | 29 | 22 | 0.3 |
| Other renewables | 0 | 0 | 0 | 1 | 1 | 2 | 0 | 1 | 11.1 |
| **Non-energy use** | **17** | **35** | **37** | **38** | **39** | **39** | **100** | **100** | **0.6** |

# Reference Scenario: Latin America

| | Electricity generation (TWh) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total generation** | **492** | **1 005** | **1 247** | **1 392** | **1 561** | **1 745** | **100** | **100** | **2.4** |
| Coal | 16 | 33 | 92 | 108 | 133 | 153 | 3 | 9 | 6.9 |
| Oil | 51 | 125 | 109 | 99 | 88 | 75 | 12 | 4 | -2.2 |
| Gas | 45 | 128 | 227 | 271 | 331 | 407 | 13 | 23 | 5.1 |
| Nuclear | 10 | 20 | 26 | 42 | 48 | 48 | 2 | 3 | 4.0 |
| Hydro | 363 | 669 | 749 | 809 | 875 | 944 | 67 | 54 | 1.5 |
| Biomass and waste | 7 | 26 | 33 | 40 | 47 | 54 | 3 | 3 | 3.2 |
| Wind | 0 | 1 | 7 | 14 | 23 | 34 | 0 | 2 | 16.7 |
| Geothermal | 1 | 3 | 4 | 5 | 8 | 11 | 0 | 1 | 5.9 |
| Solar | 0 | 0 | 1 | 4 | 8 | 19 | 0 | 1 | n.a. |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | Capacity (GW) | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total capacity** | **223** | **276** | **309** | **348** | **391** | **100** | **100** | **2.5** |
| Coal | 6 | 16 | 18 | 21 | 24 | 3 | 6 | 6.1 |
| Oil | 32 | 32 | 32 | 32 | 32 | 14 | 8 | -0.0 |
| Gas | 38 | 60 | 71 | 85 | 101 | 17 | 26 | 4.3 |
| Nuclear | 3 | 4 | 6 | 6 | 6 | 1 | 2 | 3.6 |
| Hydro | 138 | 155 | 168 | 183 | 197 | 62 | 50 | 1.6 |
| Biomass and waste | 5 | 6 | 7 | 8 | 9 | 2 | 2 | 2.9 |
| Wind | 0 | 2 | 5 | 7 | 11 | 0 | 3 | 14.8 |
| Geothermal | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 6.1 |
| Solar | 0 | 1 | 2 | 4 | 10 | 0 | 3 | n.a. |
| Tide and wave | 0 | 0 | 0 | 0 | 0 | 0 | 0 | n.a. |

| | $CO_2$ emissions (Mt) | | | | | | Shares (%) | | CAAGR (%) |
|---|---|---|---|---|---|---|---|---|---|
| | 1990 | 2007 | 2015 | 2020 | 2025 | 2030 | 2007 | 2030 | 2007-2030 |
| **Total $CO_2$ emissions** | **604** | **1 011** | **1 174** | **1 260** | **1 389** | **1 518** | **100** | **100** | **1.8** |
| Coal | 57 | 89 | 149 | 168 | 195 | 216 | 9 | 14 | 3.9 |
| Oil | 429 | 683 | 724 | 760 | 811 | 873 | 68 | 58 | 1.1 |
| Gas | 118 | 239 | 301 | 333 | 383 | 429 | 24 | 28 | 2.6 |
| **Power generation** | **99** | **198** | **280** | **306** | **347** | **384** | **100** | **100** | **2.9** |
| Coal | 21 | 36 | 96 | 112 | 137 | 156 | 18 | 41 | 6.5 |
| Oil | 46 | 96 | 82 | 73 | 64 | 52 | 48 | 14 | -2.6 |
| Gas | 32 | 66 | 102 | 120 | 146 | 176 | 33 | 46 | 4.3 |
| **Total final consumption** | **440** | **725** | **796** | **852** | **928** | **1 017** | **100** | **100** | **1.5** |
| Coal | 32 | 48 | 49 | 51 | 53 | 55 | 7 | 5 | 0.7 |
| Oil | 352 | 544 | 597 | 641 | 700 | 774 | 75 | 76 | 1.5 |
| *of which transport* | *202* | *342* | *376* | *411* | *460* | *524* | *47* | *52* | *1.9* |
| Gas | 55 | 133 | 150 | 161 | 174 | 188 | 18 | 19 | 1.5 |

# SENSITIVITY ANALYSIS

## Introduction

The Reference Scenario projections are derived from a large-scale mathematical model, the World Energy Model (WEM), which is underpinned by exogenous assumptions about a range of factors that drive energy demand and supply. Chief among these are macroeconomic trends, energy prices, population growth, technological developments and government policies. Although the assumptions used in the Reference Scenario are based on the most up-to-date information available, the uncertainty surrounding several of these variables is much greater at present than is usually the case.

The level of economic activity, as measured by the rate of growth in gross domestic product (GDP), is the principal driver of demand for energy. As a result, the energy projections in the *Outlook* are highly sensitive to the underlying assumptions about GDP growth. There are acute uncertainties at present about the timing and pace of the global economic recovery and, therefore, the pace and extent of the rebound in energy demand. These uncertainties also bear on the pattern of future investments in energy infrastructure. Future exchange rates also remain highly uncertain.

Energy prices are another key assumption and they have ridden a veritable roller-coaster over the past year, demonstrating the pace at which market conditions and perceptions can change. The price of oil, for example, had reached very nearly $150/barrel in July 2008, fell to around $35/barrel in February 2009 and then recovered to $65 to $70 per barrel by mid-year. While there is always uncertainty linked to energy price assumptions, the outlook at present is more uncertain than usual.

In view of these uncertainties, this annex presents the results of sensitivity analyses of the Reference Scenario figures, based on alternative assumptions about GDP growth and energy prices. The sensitivity analyses presented here are not scenarios. They provide projections that are differentiated by changes to only a single sensitivity parameter in the WEM. All other assumptions and the policy framework remain unchanged. Scenario analysis, in contrast, considers alternative *sets* of conditions in a coherent context.

## Sensitivity cases

Four separate sensitivity cases have been analysed, two related to economic activity and two to energy prices:

1. The Higher GDP Case (HGC)
2. The Lower GDP Case (LGC)
3. The Higher Prices Case (HPC)
4. The Lower Prices Case (LPC)

## Economic growth sensitivity cases

The Higher GDP Sensitivity Case (HGC) assumes a recovery from the current economic downturn in 2010, resulting in world GDP growing by an average of 0.5% per year more than in the Reference Scenario over the period 2007-2030 (*i.e.* 3.6% versus 3.1%). The Lower GDP Sensitivity Case (LGC) assumes the downturn is prolonged until 2012, resulting in world GDP growing by an average of 0.5% per year less than in the Reference Scenario over the period 2007-2030 (*i.e.* 2.6% versus 3.1%). In both the HGC and the LGC, after the assumed date of recovery, annual growth rates gradually converge to the rates set out in the Reference Scenario. The assumed trajectories for GDP in the economic growth sensitivity cases (and the Reference Scenario for comparison) are summarised in Table B.1.

**Table B.1 ● World real GDP growth in the Reference Scenario and Sensitivity Cases** (compound average annual growth rates)

| | 2007-2015 | 2015-2030 | 2007-2030 |
|---|---|---|---|
| Reference Scenario | 3.3% | 3.0% | 3.1% |
| Higher GDP Sensitivity Case | 4.2% | 3.4% | 3.6% |
| Lower GDP Sensitivity Case | 2.4% | 2.8% | 2.6% |

Note: Calculated based on GDP expressed in year-2008 dollars using purchasing power parity terms.

## Energy price sensitivity cases

The Higher Prices Sensitivity Case (HPC) and the Lower Prices Sensitivity Case (LPC) assume that the average IEA crude oil import price, a proxy for international prices, is 30% higher and lower, respectively, than in the Reference Scenario in 2030. Similarly, prices for coal in 2030 are 30% higher and lower, as are natural gas prices (which are indexed to oil) in Europe and the Pacific. Natural gas prices in North America change by a more modest 20%, as prices in this market are driven directly by supply/demand fundamentals. The assumed trajectories for international fossil-energy prices in the energy price sensitivity cases (and the Reference Scenario for comparison) are summarised in Tables B.2, B.3 and B.4.

**Table B.2 ● Fossil-fuel price assumptions in the Reference Scenario** (year-2008 dollars per unit)

| | Unit | 2000 | 2008 | 2015 | 2020 | 2025 | 2030 |
|---|---|---|---|---|---|---|---|
| IEA crude oil imports | barrel | 34.30 | 97.19 | 86.67 | 100.00 | 107.50 | 115.00 |
| Natural gas imports | | | | | | | |
| *United States* | MBtu | *4.74* | *8.25* | *7.29* | *8.87* | *10.04* | *11.36* |
| *Europe* | MBtu | *3.46* | *10.32* | *10.46* | *12.10* | *13.09* | *14.02* |
| *Japan LNG* | MBtu | *5.79* | *12.64* | *11.91* | *13.75* | *14.83* | *15.87* |
| OECD steam coal imports | tonne | 41.22 | 120.59 | 91.05 | 104.16 | 107.12 | 109.40 |

**Table B.3 • Fossil-fuel price assumptions in the Lower Prices Sensitivity Case** (year-2008 dollars per unit)

| | Unit | 2000 | 2008 | 2015 | 2020 | 2025 | 2030 |
|---|---|---|---|---|---|---|---|
| IEA crude oil imports | barrel | 34.30 | 97.19 | 67.56 | 72.00 | 76.00 | 80.00 |
| Natural gas imports | | | | | | | |
| *United States* | MBtu | *4.74* | *8.25* | *6.75* | *7.83* | *8.43* | *9.09* |
| *Europe* | MBtu | *3.46* | *10.32* | *8.23* | *8.78* | *9.27* | *9.77* |
| *Japan LNG* | MBtu | *5.79* | *12.64* | *9.32* | *9.94* | *10.49* | *11.05* |
| OECD steam coal imports | tonne | 41.22 | 120.59 | 70.98 | 75.00 | 75.73 | 76.11 |

**Table B.4 • Fossil-fuel price assumptions in the Higher Prices Sensitivity Case** (year-2008 dollars per unit)

| | Unit | 2000 | 2008 | 2015 | 2020 | 2025 | 2030 |
|---|---|---|---|---|---|---|---|
| IEA crude oil imports | barrel | 34.30 | 97.19 | 110.56 | 130.00 | 140.00 | 150.00 |
| Natural gas imports | | | | | | | |
| *United States* | MBtu | *4.74* | *8.25* | *7.94* | *10.14* | *11.75* | *13.63* |
| *Europe* | MBtu | *3.46* | *10.32* | *13.31* | *15.70* | *17.05* | *18.28* |
| *Japan LNG* | MBtu | *5.79* | *12.64* | *15.17* | *17.86* | *19.31* | *20.70* |
| OECD steam coal imports | tonne | 41.22 | 120.59 | 116.15 | 135.41 | 139.50 | 142.70 |

## Results of Sensitivity Cases

The implications of each of the sensitivity cases for world primary energy demand and energy-related $CO_2$ emissions are summarised in Table B.5. The HGC sees global primary energy demand rising by 1.7% per year on average in 2007-2030 – an overall increase of 48%, compared with an increase of 40% in the Reference Scenario. Higher GDP growth leads to higher demand for all primary fuels. Compared to the Reference Scenario, by 2030, the share of oil in the primary energy mix decreases slightly, that of nuclear remains essentially unchanged, while that of coal and gas increases at the expense of renewable sources. The slower growth of renewables is largely due to reduced demand for traditional biomass as incomes rise and households switch from biomass to modern fuels.

The LGC sees global primary energy demand rising by 1.2% per year on average in 2007-2030 – an overall increase of 32%, compared with the increase of 40% in the Reference Scenario. Lower GDP leads to lower demand for all primary fuels. The reduction is greatest for coal, as this is the fuel for which demand increases the most in the Reference Scenario. Renewables and nuclear experience the smallest reduction, relative to the Reference Scenario, as their deployment is more closely linked to policy interventions, which remain constant. Their share increases moderately in 2030.

## Table B.5 • World primary energy demand by fuel and energy-related $CO_2$ emissions by sensitivity case

| | Reference Scenario | | | GDP – Higher | | | GDP – Lower | | | Prices – Higher | | | Prices – Lower | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2030 | 2007-2030* | 2015 | 2030 | 2007-2030* | 2015 | 2030 | 2007-2030* | 2015 | 2030 | 2007-2030* | 2015 | 2030 | 2007-2030* |
| **Total demand** (Mtoe) | **13 488** | **16 790** | **1.5%** | **13 967** | **17 810** | **1.7%** | **12 967** | **15 910** | **1.2%** | **13 217** | **16 241** | **1.3%** | **13 725** | **17 515** | **1.7%** |
| Coal | 3 828 | 4 887 | 1.9% | 4 059 | 5 326 | 2.3% | 3 589 | 4 511 | 1.5% | 3 718 | 4 570 | 1.6% | 3 931 | 5 263 | 2.2% |
| Oil | 4 234 | 5 009 | 0.9% | 4 335 | 5 238 | 1.1% | 4 124 | 4 804 | 0.7% | 4 142 | 4 837 | 0.7% | 4 313 | 5 204 | 1.0% |
| Gas | 2 801 | 3 561 | 1.5% | 2 933 | 3 821 | 1.8% | 2 646 | 3 337 | 1.2% | 2 714 | 3 404 | 1.3% | 2 864 | 3 788 | 1.8% |
| Nuclear | 810 | 956 | 1.3% | 810 | 994 | 1.5% | 810 | 929 | 1.2% | 810 | 996 | 1.5% | 810 | 927 | 1.2% |
| Renewables | 1 815 | 2 376 | 2.0% | 1 829 | 2 431 | 2.1% | 1 799 | 2 329 | 1.9% | 1 833 | 2 433 | 2.1% | 1 807 | 2 333 | 1.9% |
| *Modern renewables* | *1 092* | *1 680* | *3.2%* | *1 115* | *1 757* | *3.4%* | *1 068* | *1 622* | *3.0%* | *1 107* | *1 729* | *3.3%* | *1 090* | *1 656* | *3.1%* |
| $CO_2$ emissions (Mt) | 32 306 | 40 226 | 1.5% | 33 778 | 43 115 | 1.8% | 30 734 | 37 686 | 1.2% | 31 451 | 38 157 | 1.2% | 33 035 | 42 668 | 1.7% |
| | | | | | | Change versus the Reference Scenario | | | | | | | | | |
| **Total demand** | | | | **3.5%** | **6.1%** | **0.3%** | **-3.9%** | **-5.2%** | **-0.2%** | **-2.0%** | **-3.3%** | **-0.1%** | **1.8%** | **4.3%** | **0.2%** |
| Coal | | | | 6.0% | 9.0% | 0.4% | -6.2% | -7.7% | -0.4% | -2.9% | -6.5% | -0.3% | 2.7% | 7.7% | 0.3% |
| Oil | | | | 2.4% | 4.6% | 0.2% | -2.6% | -4.1% | -0.2% | -2.2% | -3.4% | -0.2% | 1.8% | 3.9% | 0.2% |
| Gas | | | | 4.7% | 7.3% | 0.3% | -5.6% | -6.3% | -0.3% | -3.1% | -4.4% | -0.2% | 2.2% | 6.4% | 0.3% |
| Nuclear | | | | 0.0% | 3.9% | 0.2% | 0.0% | -2.9% | -0.1% | 0.0% | 4.2% | 0.2% | 0.0% | -3.0% | -0.1% |
| Renewables | | | | 0.8% | 2.3% | 0.1% | -0.9% | -2.0% | -0.1% | 1.0% | 2.4% | 0.1% | -0.4% | -1.8% | -0.1% |
| *Modern renewables* | | | | *2.1%* | *4.6%* | *0.2%* | *-2.1%* | *-3.5%* | *-0.2%* | *1.4%* | *2.9%* | *0.1%* | *-0.2%* | *-1.5%* | *-0.1%* |
| $CO_2$ emissions | | | | 4.6% | 7.2% | 0.3% | -4.9% | -6.3% | -0.3% | -2.6% | -5.1% | -0.2% | 2.3% | 6.1% | 0.3% |

* Compound average annual growth rate.

The HPC sees global primary energy demand rising by 1.3% per year on average in 2007-2030 – an overall increase of 35%, compared with the increase of 40% in the Reference Scenario. Higher fossil-fuel prices lead to higher electricity prices and to lower energy demand in all sectors. Renewable and nuclear power generation are increasingly favoured over fossil fuels, as their cost-competiveness improves. This leads to an increase in demand for renewables and nuclear, and an increase in their shares of the total primary fuel market by 2030, as the share of fossil fuels falls. Coal experiences the sharpest reduction, as it loses its rapid gains in the Reference Scenario.

The LPC sees global primary energy demand rising by 1.7% per year on average in 2007-2030 – an overall increase of 46%, compared with the increase of 40% in the Reference Scenario. Lower fossil-fuel prices lead to lower electricity prices and to higher energy demand, with fossil fuels the preferred choice of primary fuel in most cases. In 2030, relative to the Reference Scenario, the share of coal and gas in the primary energy mix increases at the expense of renewables and nuclear. The reduction in modern renewables is limited, due to the retention of the support mechanisms assumed in the Reference Scenario.

# ABBREVIATIONS, DEFINITIONS AND CONVERSION FACTORS

This annex provides general information on abbreviations, fuel, process and regional definitions, and country groupings used throughout *WEO-2009*. General conversion factors for energy are also included. Readers interested in obtaining more detailed information about IEA statistics should consult www.iea.org/statistics.

## Unit abbreviations

| | | |
|---|---|---|
| Area | Ha | hectare |
| | GHa | giga-hectare (1 hectare × $10^9$) |
| Coal | Mtce | million tonnes of coal equivalent |
| Emissions | ppm | parts per million by volume |
| | Gt $CO_2$-eq | gigatonnes of carbon-dioxide equivalent (using 100 year global warming potentials for different greenhouse gases) |
| | g $CO_2$/km | grammes of carbon dioxide per kilometre |
| | g $CO_2$/kWh | grammes of carbon dioxide per kilowatt-hour |
| Energy | toe | tonne of oil equivalent |
| | Mtoe | million tonnes of oil equivalent |
| | MBtu | million British thermal units |
| | GJ | gigajoule (1 joule × $10^9$) |
| | EJ | exajoule (1 joule × $10^{18}$) |
| | kWh | kilowatt-hour |
| | MWh | megawatt-hour |
| | GWh | gigawatt-hour |
| | TWh | terawatt-hour |
| Gas | mcm | million cubic metres |
| | bcm | billion cubic metres |
| | tcm | trillion cubic metres |
| Mass | kt | kilotonnes (1 tonne × $10^3$) |
| | Mt | million tonnes (1 tonne × $10^6$) |
| | Gt | gigatonnes (1 tonne × $10^9$) |
| Monetary | $ million | 1 US dollar × $10^6$ |
| | $ billion | 1 US dollar × $10^9$ |
| | $ trillion | 1 US dollar × $10^{12}$ |

| | | |
|---|---|---|
| Oil | b/d | barrels per day |
| | kb/d | thousand barrels per day |
| | mb/d | million barrels per day |
| | mpg | miles per gallon |
| Oil and Gas | mD | milliDarcy |
| Power | W | Watt (1 joule per second) |
| | kW | kilowatt (1 Watt $\times$ $10^3$) |
| | MW | megawatt (1 Watt $\times$ $10^6$) |
| | GW | gigawatt (1 Watt $\times$ $10^9$) |
| | TW | terawatt (1 Watt $\times$ $10^{12}$) |

## Fuel definitions

### Biodiesel

Biodiesel is a diesel-equivalent, processed fuel made from the transesterification (a chemical process which removes the glycerine from the oil) of both vegetable oils and animal fats.

### Biofuels

Biofuels includes ethanol and biodiesel.

### Biogas

A mixture of methane and $CO_2$ produced by bacterial degradation of organic matter and used as a fuel.

### Biomass and waste

Solid biomass, gas and liquids derived from biomass, industrial waste and the renewable part of municipal waste. Includes both traditional and modern biomass.

### Brown coal

Includes lignite and sub-bituminous coal where lignite is defined as non-agglomerating coal with a gross calorific value less than 4 165 kcal/kg and sub-bituminous coal is defined as non-agglomerating coal with a gross calorific value between 4 165 kcal/kg and 5 700 kcal/kg.

### Clean coal technologies

Clean coal technologies are designed to enhance the efficiency and the environmental acceptability of coal extraction, preparation and use.

## Coal

Coal includes both primary coal (including hard coal and lignite) and derived fuels (including patent fuel, brown-coal briquettes, coke-oven coke, gas coke, coke-oven gas, blast-furnace gas and oxygen steel furnace gas). Peat is also included.

## Coalbed methane (CBM)

Methane found in coal seams. Coalbed methane is a source of unconventional natural gas. Known as coal seam methane in Australia.

## Coal-to-liquids

Coal-to-liquids (CTL) refers to both coal gasification, combined with Fischer-Tropsch synthesis to produce liquid fuels, and the less developed direct-coal liquefaction technologies.

## Condensates

Condensates are liquid hydrocarbon mixtures recovered from non-associated gas reservoirs. They are composed of C4 and higher carbon number hydrocarbons and normally have an API between 50° and 85°.

## Dimethyl ether

Clear, odourless gas currently produced by dehydration of methanol from natural gas, but which can also be produced from biomass or coal.

## Ethanol

Ethanol is an alcohol made by fermenting any biomass high in carbohydrates. Today, ethanol is made from starches and sugars, but second generation technologies will allow it to be made from cellulose and hemicellulose, the fibrous material that makes up the bulk of most plant matter.

## Gas

Gas includes natural gas (both associated and non-associated with petroleum deposits but excluding natural gas liquids) and gas-works gas.

## Gas-to-liquids

Fischer-Tropsch technology is used to convert natural gas into synthesis gas (syngas) and then, through catalytic reforming or synthesis, into very clean conventional oil products. The main fuel produced in most GTL plants is diesel.

## Hard coal

Coal of gross calorific value greater than 5 700 kcal/kg on an ash-free but moist basis. Hard coal can be further disaggregated into anthracite, coking coal and other bituminous coal.

## Heavy petroleum products

Heavy petroleum products include heavy fuel oil.

## Hydropower

Hydropower refers to the energy content of the electricity produced in hydropower plants, assuming 100% efficiency. It excludes output from pumped storage, tide and wave plants.

## Light petroleum products

Light petroleum products include liquefied petroleum gas (LPG), naphtha and gasoline.

## Middle distillates

Middle distillates include jet fuel, diesel and heating oil.

## Modern biomass

Includes all biomass with the exception of traditional biomass.

## Modern renewables

Includes all types of renewables with the exception of traditional biomass.

## Natural gas liquids

Natural gas liquids (NGLs) are the liquid or liquefied hydrocarbons produced in the manufacture, purification and stabilisation of natural gas. These are those portions of natural gas which are recovered as liquids in separators, field facilities, or gas processing plants. NGLs include but are not limited to ethane, propane, butane, pentane, natural gasoline and condensates.

## Nuclear

Nuclear refers to the primary heat equivalent of the electricity produced by a nuclear plant with an average thermal efficiency of 33%.

## Oil

Oil includes crude oil, condensates, natural gas liquids, refinery feedstocks and additives, other hydrocarbons (including emulsified oils, synthetic crude oil, mineral oils extracted from bituminous minerals such as oil shale, bituminous sand and oils from coal liquefaction) and petroleum products (refinery gas, ethane, LPG, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirit, lubricants, bitumen, paraffin waxes and petroleum coke).

## Renewables

Includes biomass and waste, geothermal, hydropower, solar PV, concentrating solar power, wind and tide and wave energy for electricity and heat generation.

### Traditional biomass

Traditional biomass refers to the use of fuelwood, animal dung and agricultural residues in stoves with very low efficiencies.

## Process definitions

### Electricity generation

Electricity generation is the total amount of electricity generated by power plants. It includes own use and transmission and distribution losses.

### Greenfield

The construction of plants or facilities in new areas or where no previous infrastructure exists.

### International aviation bunkers

International aviation bunkers includes deliveries of aviation fuels to aircraft for international aviation. Fuels used by airlines for their road vehicles are excluded. The domestic/international split should be determined on the basis of departure and landing locations and not by the nationality of the airline. For many countries this incorrectly excludes fuels used by domestically owned carriers for their international departures.

### International marine bunkers

International marine bunkers covers those quantities delivered to ships of all flags that are engaged in international navigation. The international navigation may take place at sea, on inland lakes and waterways, and in coastal waters. Consumption by ships engaged in domestic navigation is excluded. The domestic/international split is determined on the basis of port of departure and port of arrival, and not by the flag or nationality of the ship. Consumption by fishing vessels and by military forces is also excluded and included in residential, services and agriculture.

### Lower heating value

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

### Natural decline rate

The base production decline rate of an oil or gas field without intervention to enhance production.

### Observed decline rate

The production decline rate of an oil or gas field after all measures have been taken to maximise production. It is the aggregation of all the production increases and declines of new and mature oil or gas fields in a particular region.

## Other energy sector

Other energy sector covers the use of energy by transformation industries and the energy losses in converting primary energy into a form that can be used in the final consuming sectors. It includes losses by gas works, petroleum refineries, coal and gas transformation and liquefaction. It also includes energy used in coal mines, in oil and gas extraction and in electricity and heat production. Transfers and statistical differences are also included in this category

## Residential, services and agriculture

The residential, services and agriculture sector include energy used in residential, commercial and institutional buildings, for agricultural production and in non-specified sectors. Building energy use includes space heating and cooling, water heating, lighting, appliances and cooking equipment. Agriculture energy use includes all energy used on farms, in forestry and fishing.

## Power generation

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

## Total final consumption

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

## Total primary energy demand

Total primary energy demand represents domestic demand only and is broken down into power generation, other energy sector and total final consumption.

# Regional definitions and country groupings

## Africa

Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, Central African Republic, Chad, Comoros, Congo, Democratic Republic of Congo, Côte d'Ivoire, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Namibia, Niger, Nigeria, Reunion, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Sudan, Swaziland, United Republic of Tanzania, Togo, Tunisia, Uganda, Zambia and Zimbabwe.

## Annex I Parties to the United Nations Framework Convention on Climate Change

Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, the Netherlands, New Zealand, Norway, Poland, Portugal, Romania, the Russian Federation, the Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey, Ukraine, the United Kingdom and the United States.

## ASEAN

Brunei Darussalam, Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Thailand and Vietnam.

## China

Refers to the People's Republic of China, including Hong Kong.

## Eastern Europe/Eurasia

Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, the former Yugoslav Republic of Macedonia, the Republic of Moldova, Romania, Russian Federation, Serbia,[1] Slovenia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan. For statistical reasons, this region also includes Cyprus, Gibraltar and Malta.

## European Union

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

## Latin America

Antigua and Barbuda, Aruba, Argentina, Bahamas, Barbados, Belize, Bermuda, Bolivia, Brazil, the British Virgin Islands, the Cayman Islands, Chile, Colombia, Costa Rica, Cuba, Dominica, the Dominican Republic, Ecuador, El Salvador, the Falkland Islands, French Guyana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Montserrat, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, St. Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, St. Vincent and the Grenadines, Suriname, Trinidad and Tobago, the Turks and Caicos Islands, Uruguay and Venezuela.

1. Serbia includes Montenegro until 2004 and Kosovo until 1999.

## Middle East

Bahrain, the Islamic Republic of Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, the United Arab Emirates and Yemen. It includes the neutral zone between Saudi Arabia and Iraq.

## Non-OECD Asia

Afghanistan, Bangladesh, Bhutan, Brunei Darussalam, Cambodia, China, Chinese Taipei, the Cook Islands, East Timor, Fiji, French Polynesia, India, Indonesia, Kiribati, the Democratic People's Republic of Korea, Laos, Macau, Malaysia, Maldives, Mongolia, Myanmar, Nepal, New Caledonia, Pakistan, Papua New Guinea, the Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Thailand, Tonga, Vietnam and Vanuatu.

## North Africa

Algeria, Egypt, Libyan Arab Jamahiriya, Morocco and Tunisia.

## OECD

Includes OECD Europe, OECD North America and OECD Pacific regional groupings.

## OECD Asia

Japan and Korea.

## OECD Europe

Austria, Belgium, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, the Slovak Republic, Spain, Sweden, Switzerland, Turkey and the United Kingdom.

## OECD North America

Canada, Mexico and the United States.

## OECD Oceania

Australia and New Zealand.

## OECD Pacific

Includes OECD Asia and Oceania.

## OECD+

OECD regional grouping and those countries that are members of the European Union but not of the OECD.

## Other Major Economies

Brazil, China, Russia, South Africa and the countries of the Middle East.

## Other Countries

Comprises all countries not included in OECD+ and Other Major Economies regional groupings, including India, Indonesia, the African countries (excluding South Africa), the countries of Latin America (excluding Brazil), and the countries of non-OECD Asia (excluding China) and the countries of Eastern Europe/Eurasia (excluding Russia).

## Organization of the Petroleum Exporting Countries

Algeria, Angola, Ecuador, the Islamic Republic of Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates and Venezuela.

## Other Asia

Non-OECD Asia regional grouping excluding China and India.

## Sub-Saharan Africa

Africa regional grouping excluding South Africa and North Africa regional grouping.

# General conversion factors for energy

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

# ANNEX D

## ACRONYMS

| | |
|---|---|
| **AEC** | ASEAN Economic Community |
| **AGP** | Arab Gas Pipeline |
| **APAEC** | ASEAN Plan of Action for Energy Cooperation |
| **APG** | ASEAN Power Grid |
| **APSA** | ASEAN Petroleum Security Agreement |
| **ASCOPE** | ASEAN Council of Petroleum |
| **ASEAN** | Association of Southeast Asian Nations |
| **CAAGR** | compound average annual growth rate |
| **CAFE** | Corporate Average Fuel Economy (standards in the US) |
| **CBM** | coalbed methane |
| **CCGT** | combined-cycle gas turbine |
| **CCS** | carbon capture and storage |
| **CDM** | Clean Development Mechanism (under the Kyoto Protocol) |
| **CER** | certified emission reduction |
| **$CH_4$** | methane |
| **CHP** | combined heat and power; when referring to industrial CHP, the term co-generation is sometimes used |
| **CNG** | compressed natural gas |
| **CNOOC** | China National Offshore Oil Corporation |
| **CNPC** | China National Petroleum Corporation |
| **$CO_2$** | carbon dioxide |
| **$CO_2$-eq** | carbon dioxide equivalent |
| **COP** | Conference of the Parties to the United Nations Framework Convention on Climate Change |
| **CSP** | concentrating solar power |
| **CTL** | coal-to-liquids |
| **EU** | European Union |
| **EU ETS** | European Union Emissions Trading System |
| **EUA** | European Union allowances |

| | |
|---|---|
| **FCV** | fuel cell vehicle |
| **FOB** | free on board |
| **GDP** | gross domestic product |
| **GHG** | greenhouse gas |
| **GTL** | gas-to-liquids |
| **HAPUA** | Heads of ASEAN Power Utilities and Authorities |
| **HDV** | heavy-duty vehicle |
| **IAEA** | International Atomic Energy Agency |
| **ICE** | internal combustion engine |
| **IEA** | International Energy Agency |
| **IGCC** | integrated gasification combined cycle |
| **IMF** | International Monetary Fund |
| **IOC** | international oil company |
| **IPCC** | Intergovernmental Panel on Climate Change |
| **IPP** | independent power producer |
| **LDV** | light-duty vehicle |
| **LNG** | liquefied natural gas |
| **LPG** | liquefied petroleum gas |
| **LRMC** | long-run marginal cost |
| **LULUCF** | land use, land-use change and forestry |
| **MAGICC** | Model for the Assessment of Greenhouse-gas Induced Climate Change |
| **MER** | market exchange rate |
| **$N_2O$** | nitrous oxide |
| **NAMA** | nationally appropriate mitigation action |
| **NBP** | national balancing point (United Kingdom) |
| **NEA** | Nuclear Energy Agency (an agency within the OECD) |
| **NGL** | natural gas liquids |
| **NOC** | national oil company |
| **$NO_x$** | nitrogen oxides |

| | |
|---|---|
| **OC** | Other Countries |
| **OCGT** | open-cycle gas turbine |
| **OECD** | Organisation for Economic Co-operation and Development |
| **OECD+** | OECD countries, plus EU countries not in the OECD |
| **OME** | Other Major Economies |
| **ONGC** | Oil and Natural Gas Corporation Limited (state-owned Indian company) |
| **OPEC** | Organization of the Petroleum Exporting Countries |
| **PLDV** | passenger light-duty vehicle |
| **PM2.5** | particulate matter with an aerodynamic diameter of less than 2.5 μm |
| **ppm** | parts per million |
| **PPP** | purchasing power parity |
| **PV** | photovoltaics |
| **R&D** | research and development |
| **RD&D** | research, development and demonstration |
| **RDD&D** | research, development, demonstration and deployment |
| **$SO_2$** | sulphur dioxide |
| **SUV** | sport utility vehicle |
| **T&D** | transmission and distribution |
| **TAGP** | Trans-ASEAN Gas Pipeline |
| **TFC** | total final consumption |
| **UAE** | United Arab Emirates |
| **UK** | United Kingdom |
| **UNFCCC** | United Nations Framework Convention on Climate Change |
| **US** | United States |
| **USGS** | United States Geological Survey |
| **WAGP** | West Africa Gas Pipeline |
| **WEO** | World Energy Outlook |
| **WEM** | World Energy Model |
| **WTI** | West Texas Intermediate |

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