OPEC

World Oil Outlook

2010

Organization of the Petroleum Exporting Countries

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OPEC is a permanent, intergovernmental organization, established in Baghdad, Iraq, 10–14 September 1960. The Organization comprises 12 Members: Algeria, Angola, Ecuador, Islamic Republic of Iran, Iraq, Kuwait, Socialist People's Libyan Arab Jamahiriya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela. The Organization has its headquarters in Vienna, Austria.

Its objective is to coordinate and unify petroleum policies among Member Countries, in order to secure a steady income to the producing countries; an efficient, economic and regular supply of petroleum to consuming nations; and a fair return on capital to those investing in the petroleum industry.

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Foreword

For the global oil market, the period since publication of the previous World Oil Outlook (WOO) has been a far more stable one than the year prior. Prices have remained relatively steady throughout 2010, generally in the $70–85/barrel range, demand growth has re-emerged, led by developing countries, and the necessary investments to meet expected future demand and maintain an adequate level of spare capacity are taking place.

OPEC remains committed to its goal of providing steady supplies of crude to the market at all times. Current investments should be enough to satisfy both demand for OPEC crude and provide a comfortable cushion of spare capacity, which already exceeds the very high level of 6 mb/d.

In addition, the numbers point to the fact that there are clearly enough resources to meet future demand. Figures continue to show us that reserve estimates are rising as improved technology offers up new ways and means of unlocking both conventional and unconventional resources. This is expected to continue in the future.

It is clear, however, that many challenges remain. These include the extent and nature of the global economic recovery, downward pressures on demand, uncertainties regarding market signals that are paramount for market stability, major energy and environment policy developments, the United Nations Millennium Development Goals (UN MDGs) and energy poverty, as well as such issues as costs and human resources.

Most analysts believe that the worst of the global financial crisis and subsequent economic downturn is behind us. The monetary and fiscal stimulus packages implemented in many countries across the world have clearly played a positive role in helping economies return to growth. A recovery is clearly underway, with the economic outlook far brighter in most parts of the world than a year or so ago.

However, there are several key constraints that could potentially impact the recovery. Firstly, it is obvious that growth is uneven. Emerging markets are leading the way, with the two most populous nations, China and India, continuing to expand their share of global GDP. On the other hand, in the OECD, particularly in the European Union where much talk has centred on sovereign debt issues, there has generally been relatively muted growth.

In addition, many regions are still witnessing tight credit conditions even though financial markets have stabilized, statistically high levels of unemployment and continuing low consumer spending. There is also increasing concern about how the recent acknowledgement by many governments of the need for austerity measures, specifically a reduction or removal of fiscal stimuli, will impact economic growth.

Moreover, it is important not to forget that this recent economic crisis was unparalleled in modern times; in terms of the financial sector losses witnessed, the resulting significant contractionary impact this had on the real economy, and the levels of fiscal stimulus initiated. The unraveling of these events still has some way to go.

All these issues are reflected in this year's WOO. At present, however, there appears to be little consensus on how these developments will play out. And it is not for OPEC to offer up answers to such core global economic questions.

This publication also emphasizes the significance of consuming country energy and environmental policies, many of which offer an unclear picture of their impact on future oil consumption levels and overall energy demand. It is essential that these are better understood, since a lack of transparency and unreliable market signals can significantly impact the oil market.

These uncertainties are reflected in the downward revisions to long-term oil demand projections that have been witnessed throughout the industry in recent years. There are also major uncertainties for future non-OPEC supply, especially given overly ambitious targets for some fuel types, such as biofuels. All of this complicates the difficult task of making appropriate investments in both the upstream and downstream sectors. Lead times are very long in this industry, and it is a complex and ongoing challenge to avoid over- or under-investing.

The industry also continues to be concerned about the availability of suitably trained manpower. It is important to remember that the training, education and retention of skilled labour is fundamental to the future health of the industry. In this regard, it is satisfying to be able to point to the efforts that are increasingly being made, particularly in OPEC Member Countries, to provide appropriate education and training. Globally, however, more needs to be done.

The issue of climate change remains, of course, a pressing one, with the next meeting of the Conference of Parties of the United Nations Framework Convention on Climate Change taking place in Cancun, Mexico, in December 2010. In this regard, it is important to recall the distinctions between the responsibilities set out for developed Annex-I countries and those for developing nations, with any future agreement needing to be comprehensive, balanced, fair and equitable. We require 'win-win' solutions that do not discriminate against one party or another.

While the worries surrounding excessive price volatility and the role of speculation have somewhat diminished over the past 12 months or so, it is essential we do not forget the price extremes that the market witnessed back in 2008. A number of steps are now being taken to introduce regulatory reforms to financial markets and commodity trading practices. Given the importance of market stability to both producers and consumers, it is crucial that these reforms eliminate the exacerbating effects of speculation when prices are trending both higher and lower.

We should also continually remind ourselves of the UN MDGs and the commitments that have been pledged. It is critical that these are met. And in terms of helping reduce poverty, we should remember that a key catalyst is the alleviation of energy poverty, particularly in terms of reducing the indoor burning of biomass that prematurely kills hundreds of thousands every year and in providing access to modern energy services.

The WOO 2010 provides all interested parties with a better understanding of how decisions, policies and trends might impact the industry's future. It is not about predictions, but a tool of reference to aid both OPEC and other industry stakeholders. Its goal, as in previous years, is to explore the potential developments for the oil market in the medium- and long-term.

In OPEC's 50th Anniversary year, we hope that this publication further underscores the Organization's enduring commitment to market stability for the benefit of producers and consumers, as well as present and future generations. And it is a means of furthering dialogue with all stakeholders with a view to understanding each other's perspectives.

Abdalla Salem El-Badri
Secretary General

Executive summary

The emergence of oil as an asset class has led to higher price swings

The appeal of investing in commodities, including oil, has increased significantly over the last five years. Previously, the paper oil market was dominated by commercials that used futures and over-the-counter markets to hedge price risk. In more recent times, however, there has been a rapid increase in the participation of non-commercials, looking for higher returns from a rise or a fall in the oil price and/or seeking diversification of their investment portfolio. The growing involvement of investment banks and funds has provided opportunities to generate returns from the performance of oil derivatives (futures, options and swaps), and, as a result, oil has evolved with other commodities into an asset class. This has been helped by the issuance of the US Commodity Modernization Act in 2000 and by low interest rates. As a consequence, the volume of money going into paper oil has increased and trading volumes have risen dramatically. A number of steps are now being taken to introduce regulatory reforms to financial markets, including commodities markets. It remains to be seen how effective these reforms are in mitigating the effects of speculation in exacerbating price fluctuations, when trending both upward and downward, and in preserving sufficient liquidity to allow markets to properly perform their price discovery and risk transfer functions.

Oil price assumptions largely reflect economic recovery and upstream costs

Making assumptions for future oil price developments is complicated by the dramatic price turbulence in 2008–2009 and the fact that this was not driven by fundamentals. The combined impacts of the global financial and economic crisis, the accompanied fall in oil prices, and with costs having settled at considerably higher levels than in the past, brought new challenges for the oil industry. With the recent gradual economic recovery, however, and a return to an upward trend in upstream and downstream full cycle costs, the low prices observed at the end of 2008, as well as those a decade ago, are now regarded as unsustainably low. Prices must be sufficiently high to provide an incentive for the incremental barrel to be developed and supplied. Equally, sustainable oil prices cannot be so high as to impair global economic growth. Noting these perceptions, the Reference Case assumes a nominal price that remains in the range $75–85/b over the years to 2020, reaching $106/b by 2030. It is important to stress that this does not reflect or imply any projection of whether such prices are likely or desirable.

Recovery from the global recession has been swifter than previously thought, but remains fragile

The global recession, which started in the US in December 2007, turned out to be the deepest and longest in more than six decades. In 2009, global gross domestic product (GDP) is estimated to have declined by 0.8%, although in the latter part of 2009, and especially in the first half of 2010, the pace of the global economic recovery exceeded expectations, with a pervasive revival in manufacturing and trade. Nevertheless, there is concern about the timing and pace of the exit from the unprecedented – and in some cases increasingly burdensome – stimulus measures. It is also unclear whether measures taken so far are sufficient to ensure that robust foundations for sustained global economic growth in the medium-term have been laid. In spite of this, there are a number of positive signs, with some strong indications that the recovery is underway and that the financial crisis has been navigated. The Reference Case builds upon the observation that recovery occurs at different speeds across world regions. For example, while both North America and the OECD Pacific are expected to grow robustly in 2010 at 2.6% and 3.2%, respectively, Western Europe's growth is more sluggish, at 1.4%. Developing countries are seen to lead the recovery, averaging growth of 6.5%. Overall, the global economy is assumed to grow by 3.9% in 2010, and then by 3.7% per annum (p.a.) in the medium-term to 2014.

Long-term economic growth is assumed to be robust

For long-term economic growth potential, as well as the prospects for future energy needs, it is essential to consider demographic trends. Growth patterns will vary across regions. Globally, world population expands in the Reference Case to 8.3 billion by 2030, an increase of 1.5 billion from 2009. Of this increase, 95% will be in developing countries. Long-term economic growth is also closely linked to productivity growth. The financial crisis and global recession, however, has raised concerns over long-term economic growth implications. Structural reforms that place a new emphasis upon regulation rather than the free market ethos may well promise greater stability, but questions remain as to whether this comes at a price in terms of economic growth. Nevertheless, the Reference Case assumes a robust average global economic growth rate of 3.5% p.a. for the period 2010–2030. South Asia and China are the fastest growing regions. Despite this, the gulf between rich and poor is likely to remain over this timeframe, with OECD regions easily retaining their position as the wealthiest nations in terms of income per capita.

Energy policies add considerable uncertainty to the outlook

Energy policies are one of the key drivers for future energy demand and supply, and one of the most uncertain areas to address. The WOO Reference Case incorporates in its projections the estimated impacts of legislation that have already been passed into law. Two key recent examples are the US Energy Independence and Security Act (EISA) and the European Union's (EU) package of implementation measures for climate change and energy objectives. These measures aim, *inter alia*, for ambitious transportation fuel efficiency and biofuels targets. The adverse impact on the need for OPEC oil of these two measures alone is likely to be around 4 mb/d by as early as 2020. The biofuels targets, in both the US and the EU, are generally regarded as overly ambitious, and have not been fully factored in to the Reference Case. An increasingly important issue has become the extent to which long-term Reference Case demand and supply projections should also reflect possible policies and measures that are linked to greenhouse gas (GHG) emission reduction or limitation targets. The Reference Case also includes road transportation efficiency gains at a global level, which reflects the massive research and development (R&D) currently underway in this sector.

Energy use will continue to rise, but energy poverty will remain

Demand for commercial energy has increased progressively, from 55 million barrels of oil equivalent per day (mboe/d) in 1960 to 227 mboe/d in 2008. Given the Reference Case assumptions, energy demand will continue to increase, as economies expand, the global population grows and living conditions across the world improve. By 2030, world energy demand will be more than 40% higher than it is today. In the future, developing countries will account for most of the demand increase. This is not only due to larger populations and future higher economic growth, but also because of the huge pent-up demand for energy use in these countries as people gradually gain access to modern energy services. Nonetheless, energy poverty will remain. Energy use per capita in developing countries has always been well below that of the OECD and this remains the case in the future: in 2030 the OECD will be using on average three and a half times as much energy per head as developing countries.

Despite renewables growth, fossil fuels remain dominant in the energy mix

In satisfying the world's energy needs, the Reference Case sees fossil fuels playing the prominent role, and though their share in the energy mix is expected to fall, it remains over 80% throughout the period to 2030. Even with the energy policies factored into the Reference Case, that to a considerable extent target oil use, oil's leading role in the energy mix will continue with its share remaining above 30%, albeit falling over time. Oil use, however, grows at the slowest rate of all fuel types. The rate of expansion in natural gas use is expected to be high, especially with the technological developments that have made economic the exploitation of unconventional resources. In the Reference Case, coal, despite having the highest CO_2 emissions per unit of energy of any fuel type, is expected to retain its importance in the energy mix as the second most important fuel. Renewable energy will grow fast, but from a low base, while both hydropower and nuclear power witness some expansion.

The rising potential of shale gas poses new questions for the future energy mix

Talk of shale gas transforming the US energy market has been gathering momentum in recent years. The figures being discussed are potentially huge. The surge in the development of US shale gas has occurred in response to a rapid increase in natural gas prices leading to many avenues being explored to alleviate tight supply. Supplies of shale gas have been known about for decades, but have until now proven difficult to exploit. However, the melding of horizontal drilling and hydraulic fracturing has lowered costs considerably. The effect has already been felt with lower natural gas prices and in the rapidly changing economics of liquefied natural gas (LNG). Interest in shale gas in Europe, as well as in China, is also beginning to gather pace. Whether shale gas is a 'game changer' remains unclear. However, its potential is undisputed.

Oil demand rises more swiftly in the medium-term due to the rapid economic recovery

Turning specifically to oil, a swifter than expected recovery from the global recession has led to positive impacts upon demand. The Reference Case now foresees demand growth of 1.0 mb/d in 2010, more than double that expected in the WOO 2009 reference case that had assumed a slower recovery. In the medium-term to 2014, world demand increases to 89.9 mb/d, an increase of 5.4 mb/d from 2009. This 2014 global figure is 0.8 mb/d higher than that expected in last year's WOO. Nevertheless, the effects of the recession mean that 2007 demand levels are not reached again until 2011. OECD oil demand falls slightly over the medium-term, with demand having peaked in 2005. Over two-thirds of growth in developing countries will come from developing Asia, with China seeing the largest expansion.

Long-term oil demand rises to 105.5 mb/d by 2030 in the Reference Case

Looking further ahead, long-term demand projections for all energy types, including oil, are subject to ever-growing uncertainties. Alternative economic growth paths may emerge, reflecting, for example, the possible rise of protectionism, varying success in coping with global imbalances, or possible long-term structural impacts relating to responses to the global financial crisis. While it could be argued that departures from current trends are becoming increasingly likely, the Reference Case sees oil demand by 2030 essentially unchanged from the WOO 2009, reaching 105.5 mb/d by 2030, an increase of 21 mb/d from 2009. The figure represents an average annual oil demand increase of 0.9% p.a., or in volume terms, 1 mb/d p.a. The relative demand growth trends seen in the medium-term are also reflected in long-term projections. OECD demand continues to fall throughout the period to 2030; a slow increase is expected in oil demand in transition economies; and the net long-term demand increase is driven by developing countries. Over the period 2009–2030, consumption in developing countries increases by more than 22 mb/d. Of the total global oil demand growth in the long-term, 75% is in developing Asia.

The transportation sector is key to oil demand growth

Globally, the only sources of net increase in demand over the past three decades have been transportation (road, aviation and marine) and the petrochemicals sector. Moving forward, it is clear that transportation will remain the main source of oil demand growth. Interestingly, however, over the projection period a decline in oil use in the OECD is expected in all sectors. In developing countries, while the increase in oil use in transportation is the largest source of growth, other sectors should also see robust expansion. The petrochemical industry is growing in importance in terms of oil demand levels, and other industrial activities such as construction, iron and steel, machinery and paper are also witnessing significant growth.

Changes to road transportation technologies will be evolutionary, not revolutionary

The pace at which alternative fuels and engine technologies will penetrate the road transportation sector is influenced by policies, as well as technological developments and resource availability. The prospects for gas-to-liquids (GTLs), coal-to-liquids (CTLs) and compressed natural gas (CNG) are likely to benefit from falling costs, but the major factors affecting oil demand are expected to be increased engine efficiencies, the more rapid introduction of hybrid-electric vehicles and an expanded biofuels use. The development of advanced hybrid and battery technologies is assumed, in the Reference Case, to be slow, as these require substantial R&D investment and the development of manufacturing and recharging infrastructure. Thus, the internal combustion engine is expected to maintain its current position as the dominant automotive technology. Overall, it is likely that the impact of alternative fuels and engine technologies in road transportation will – at least for the period up to 2030 – be more an evolutionary process, than a revolutionary one.

Supply patterns suggest little room for additional OPEC crude over the medium-term

Medium-term non-OPEC crude oil plus natural gas liquids (NGLs) supply is anticipated to remain approximately flat, at just over 46 mb/d. By 2014, however, this is higher by close to 1 mb/d when compared to the WOO 2009. The medium-term outlook for biofuels and non-conventional oil sees continued growth and is also slightly stronger than in the previous assessment. These upward revisions are, in part, a reflection of the oil prices that have been seen in 2010. Total non-OPEC supply continues to expand over the medium-term, increasing by 2.2 mb/d between 2009 and 2014. Over these years there will also be a rise of 1.6 mb/d in the amount of NGLs supplied by OPEC. As a result, the amount of crude required from OPEC rises only slowly, from 28.7 mb/d in 2009 to 30.6 mb/d by 2014. The Reference Case thereby foresees stable OPEC crude oil spare capacity of around 6–7 mb/d, around 7–8% of world demand.

The consequences of the Gulf of Mexico oil spill on future supplies is limited

In making the supply outlook assessment, attention has also been paid to the possible consequences of the Deepwater Horizon drilling rig explosion, and the subsequent oil spill, earlier this year. There are a number of possible short-, medium- and long-term implications for the offshore oil industry, particularly in the Gulf of Mexico. Of course, the moratorium on offshore exploration and drilling had already impacted ongoing projects. More stringent regulations are likely, and this could lead to increased costs, potentially less exploration, lengthier timescales before drilling and less favourable project economics. How all this will impact the industry is at the moment difficult to gauge. It is considered, however, in the Reference Case, that the impact on overall deepwater production will only be limited and short-term, and in the medium- and long-term, offshore oil continues to grow in importance as part of global oil supplies.

OPEC will increasingly be called upon to supply the incremental barrel

In the long-term, total non-OPEC liquids supply continues to grow throughout the entire period, as increases in non-crude sources are stronger than the slight crude supply declines. Non-OPEC non-conventional oil supply increases by 7.9 mb/d over the years 2009–2030, primarily through increases in Canadian oil sands and biofuels in the US, Europe and Brazil. NGLs from OPEC and non-OPEC in the Reference Case increases from just under 10 mb/d in 2009, to almost 16 mb/d by 2030. All of this means that the amount of OPEC crude needed will rise throughout the projection period, reaching 38.7 mb/d by 2030. The expanding role that non-crude forms of liquid supply will play in satisfying demand is an important feature of the Reference Case. It signifies that crude supply only needs to increase modestly. Indeed, it reaches only 75 mb/d by 2030.

World supply and demand outlook in the Reference Case *mb/d*

	2010	2015	2020	2025	2030
World oil demand	85.5	91.0	96.2	100.9	105.5
Non-OPEC supply	51.9	53.9	55.7	56.6	57.5
OPEC crude supply	29.3	30.8	33.2	36.0	38.7

The outlook points to large upstream investment requirements

The cost of adding additional capacity is highest in OECD countries, in particular in the North Sea, where it is twice as expensive to add capacity compared to average OPEC figures. Over time, this difference gets progressively larger. The upshot is that the amount of cumulative investment needed in OECD countries in the Reference Case to 2030 is more than 45% higher than in OPEC Member Countries, although OECD supply is actually falling throughout the period. By 2030, global upstream investment requirements, excluding necessary investments in additional infrastructure, such as for pipelines, amount to \$2.3 trillion in 2009 dollars. Of this figure, almost three quarters is in non-OPEC countries.

Security of demand is a genuine concern

The recent contraction in economic activity and the accompanying dramatic fall in global oil demand have highlighted the concerns surrounding the risks of over- or under-investing. Uncertainty over how much oil will be demanded in the future is also particularly affected by policies and technology, especially in the transportation sector. Lower growth and higher growth scenarios have been constructed to better understand this issue. The lower growth scenario combines a more pessimistic outlook for the global economy with an acceleration of policies that limit oil demand growth. The higher growth scenario takes a more optimistic view on economic growth. The implications for the amount of OPEC crude oil required are substantial. The higher growth scenario sees this rising by more than 14 mb/d to 2030, while the lower growth one sees essentially flat demand for OPEC crude over the next two decades. The implications for OPEC investment needs are startling: the difference between the higher and lower growth scenarios over the next decade reaches \$230 billion in real terms. This emphasizes the fact that concerns over security of demand are genuine.

Refining overcapacity will depress medium-term profitability

The substantial oil demand decline – the result of the global financial crisis and the subsequent economic downturn – combined with the wave of new refining capacity that has come on-line in the past few years, has led to a dramatic change in refining sector fundamentals. From what many have termed a 'golden age' between 2004 and mid-2008, with demand growth and refining tightness, the industry is now suffering from a severe demand collapse and surplus capacity, especially in OECD regions. On top of this, it is estimated that around 7.3 mb/d of new crude distillation capacity will likely be added to the global refining system in the period to 2015, and this will be well supported by additional secondary processes. The Asia-Pacific is expected to see the largest capacity growth, followed by the Middle East. The primary implication is that these forthcoming projects will act to sustain a period of low refinery utilizations and hence poor economics. Moreover, should the global economic recovery, and thus oil demand, prove to be slower than in the Reference Case, the medium-term capacity surplus will be markedly higher.

Capacity rationalization in the refining sector appears inevitable

Another implication relates to the increasing potential for refinery closures. In this respect, strong regional differences apply, notably between the continuing growth requirements of non-OECD regions, especially the Asia-Pacific, and the surpluses in the US, Europe and Japan, which implies possible closures. The refining industry in the US & Canada region is expected to be the most adversely affected, mainly due to a combination of an ethanol supply surge, an overall demand decline, especially for gasoline, and the availability of low-cost gasoline for export to the US, a by-product of diesel production in Europe. Refineries in Europe and Japan, however, will also suffer a large number of closures. Refineries that are small and simple, lack local crude supplies, specialty products or petrochemicals integration, and which are most reliant on export markets, are likely to be the most vulnerable.

Declining crude share leaves little room for further refining expansion

The proportion of crude oil needing to be refined per barrel of incremental product continues to decline as the percentage share of biofuels, GTLs, CTLs, NGLs and other non-crudes in total supply continues to rise. The impact is significant. Both the volume and proportion of non-crudes in total supply roughly doubles between 2005 and 2030, cutting the share of crude oil from the range of 90% to below 80%. From 2008 levels, the opportunity for growth in global crude oil refining to 2030 is only about 9 mb/d, even though oil demand is projected to rise by some 20 mb/d. For 2010–2030, the potential for incremental crude is a little better at a projected 10 mb/d, but the inexorable rise of non-crudes in total supply remains a significant factor impacting refining expansion.

A new downstream outlook is emerging

One specific aspect of this year's WOO is the evolving contrast between OECD and non-OECD regions. The latter regions are continuing to see the bulk of the world's demand growth, whereas OECD demand has already peaked. From a refining perspective, this situation has created a stark contrast between the Atlantic and Pacific Basins. Dominated by Europe and the US, the former is the centre of the refining surplus. Conversely, the latter, primarily the Asia-Pacific region, is the hub of capacity growth. It is anticipated that there will be a substantial reshaping and reordering of refining capacity and refinery ownership over the next few years. In respect to capacity, the stage is set for an extended period of intense competition for both established markets, with limited or little growth, and those markets witnessing significant expansion.

Demand patterns point to a further move to middle distillates and light products

In terms of volume, the largest future demand increases are projected for diesel/gasoil that is used in a wide range of growth sectors, including the key transport and industry sectors. Volumes of diesel/gasoil increase almost 10 mb/d by 2030, from 2009 levels. This assumes an increasing share of diesel cars in developing countries, although not to the levels seen in Europe, and the continued use of fuel oil as marine bunkers. There is, however, a major uncertainty related to marine bunker regulations. Much stricter future quality specifications for marine bunker fuel could lead to a switch away from residual fuels to diesel oil in international shipments. Overall, the demand trend clearly emphasizes a further shift towards middle distillates and light products. Around 55% of demand growth to 2030 is for middle distillates, with another 32% for gasoline and naphtha. In contrast to light products, the demand for residual fuel oil is projected to decline.

Middle distillates and light products drive capacity expansion

The future demand trend towards middle distillates and light products will be the key driver for downstream capacity expansions and future refinery configurations. To meet future demand for refined products, more than 16 mb/d of global distillation capacity additions will be required by 2030. In addition, almost 11 mb/d of conversion capacity and 20 mb/d of desulphurization units are necessary during the same period. Because of the additional barrels of middle distillates, hydro-cracking will dominate conversion capacity. And around 70% of desulphurization units will be built to produce cleaner diesel fuel.

Oil trade continues to expand

The global oil trade is projected to see growing volumes, albeit at a much slower pace than anticipated before the economic slowdown began in 2008. In the period to 2015, total oil trade is estimated to increase by almost 4 mb/d compared to 2009 levels, rising to more than 55 mb/d. However, the same period experiences a shift in the structure of this trade. Crude oil exports are expected to decline by around 1 mb/d and the trade in oil products is projected to increase by almost 5 mb/d. In the period beyond 2015, however, trade in both crude and products expands. By 2030, the inter-regional oil trade increases by more than 11 mb/d from 2015, to reach almost 66 mb/d.

Tanker market remains in oversupply for most of the decade

The tanker market appears to be oversupplied for a good part of this decade. Under market conditions characterized by lower demand for oil movements – compared to those anticipated before the economic crisis – capacity oversupply, lower scrapping rates and large order books, the medium-term is expected to witness a surplus of tonnage across all tanker categories, and in turn, depressed freight rates. In the long-term, however, the renewal of scrapping activities and anticipated inter-regional trade growth, in both crude oil and refined products, will gradually absorb this capacity oversupply and lead to a balanced market with reasonable freight rates.

Upstream and downstream face many challenges

The WOO, in its assessment of energy supply and demand patterns, in general, and oil, in particular, makes clear that a number of challenges and uncertainties lie ahead, in both the upstream and downstream. These relate not just to how much future production will be required, but also to such diverse issues as: the emergence of oil as a financial asset; upstream costs; the adequacy of the human resource skills base; the evolution of technology; the issue of sustainable development and the need to tackle energy poverty; and the future role of dialogue and cooperation in meeting the industry's challenges.

There is a need to satisfactorily address speculation

There is an emerging and broad consensus that the extreme price fluctuations and excessive volatility that characterized the oil market back in 2008 and early 2009, should be avoided in the future. It is detrimental to all parties and not in the interests of market stability. This was underscored by both producers and consumers at the 12th International Energy Forum (IEF) Ministerial Meeting in Cancun, Mexico, earlier in 2010. While some disagreement remains over what was actually behind the volatility, it has become increasingly accepted that non-fundamental factors were at play. This can be viewed in the regulatory proposals and measures now underway in financial markets to help combat extreme volatility.

Industry costs remain high

In 2009, there was a modest fall in industry costs, but this year they have begun to rise again. Concerns over this rise can be tempered, to some extent, by the realization that technology has played, and continues to play, a significant role in reducing costs and supporting the expansion of hydrocarbon resources. Nevertheless, despite such ongoing contributions from technologies to keep costs in check, there are a number of major challenges ahead. Longer term, perhaps the key issue relates to environmental protection. In particular, possible costs associated with GHG emissions can be anticipated to add to the industry's overall costs. In addition, some areas of the industry are also facing other environmental hurdles, including the degrading of surface water quality and the acidification of both soil and water, all of which could mean higher industry costs.

The human resource issue remains a key concern

The knock-on impacts of the financial crisis and the economic downturn have been felt globally through both job losses and in a lack of job creation. This has been particularly apparent in industries that require significant numbers of skilled personnel for long-term projects, such as the petroleum industry. This development comes on top of the concerns expressed over the past few years regarding the adequacy of the industry's human resource skills base. It is evident that there is a need to address this challenge globally, so that it does not impact the industry's development.

Technology challenges in the oil industry

In the years ahead, an important challenge will be ensuring that technology continues to play a critical role in the supply of petroleum to the world at large. The evolution of technologies and technological breakthroughs will be needed to help bring resources to end-users in an ever more efficient, timely, sustainable and economic manner. Technology will also be crucial in advancing the industry's activities to improve its environmental footprint, both in production and use, as well as pushing for the development and use of cleaner fossil fuel technologies, such as carbon capture & storage (CCS). More CCS demonstration projects are needed on an industrial scale. Developed countries should take the lead in the effort to make CCS commercially viable, given their historical responsibility, as well as their technological and financial capabilities.

Recognizing the historical responsibility for GHG emissions

Anthropogenic GHGs come from a wide range of activities, with about 57% of the total coming from CO_2 emitted from fossil fuel use. The rise in fossil fuel use in the Reference Case implies an increase in global CO_2 emissions of 38% from 2009–2030. On a per capita basis, by 2030, Annex I countries emit, on average, 2.6 times more CO_2 than non-Annex I countries. However, cumulative emissions are more relevant to possible impacts upon the climate. Despite stronger expected emissions growth from developing countries in the Reference Case, the cumulative contribution from Annex I countries will continue to dominate. By 2030, they account for 64% of the cumulative CO_2 emissions since 1900. This underscores the need to fully reflect the historical responsibility in reaching an agreed outcome in the current climate change negotiations.

Energy and climate change policies could substantially impact the industry

Energy and climate change legislation in Europe already exists and it is expected that this will be expanded over time. Outside of Europe, climate and energy policy legislation remains a subject of often heated debate, particularly in the developed world. This can be viewed in recent debates in the US and Australia. Nevertheless, it is expected that legislation in some form or other is very likely to move ahead, with knock-on impacts for oil demand, probably oil supply, and almost certainly to refining in the affected regions. Carbon related legislation is still at a formative stage, but the implication is that it could do as much to reshape global oil markets and refining over the next 20 years, as will regional economic and population growth. Its potential to reduce demand growth and further increase competition for product markets sends a clear signal that project developers will need to remain cautious about any investment decisions, both in the upstream and downstream.

Sustainable development is an over-arching objective

It is critical that the UN Millennium Development Goals and the commitment to reduce poverty are met. In terms of helping reduce poverty, a catalyst is access to modern energy services, particularly through reducing the burning of indoor biomass that prematurely kills hundreds of thousands every year. Sustainable development is addressed by OPEC Member Countries, through their own aid institutions, as well as through OPEC's sister organization, the OPEC Fund for International Development (OFID). Today these institutions are helping to alleviate poverty and improve energy access in many developing countries.

Dialogue and cooperation the way forward

Dialogue between producers and consumers will continue to be important for maintaining market stability, and in helping drive sustainable global economic growth. Moreover, it helps to advance understanding over such issues as demand and supply security, environmental protection, technology transfer, and education and human resource development. The global petroleum market is increasingly interdependent, and strong relations between producers and consumers are a key ingredient in achieving market stability. Indeed, the benefits of dialogue are as clear today as they have ever been. This can be viewed in OPEC's cooperation with a whole host of countries and other international organizations.

Section One

Oil supply and demand outlook to 2030

Chapter 1
World energy trends: overview of the Reference Case

Main assumptions

Oil price

When looking at future oil price assumptions, it is important to recall the dramatic turbulence in prices that was witnessed over the year before the publication of the previous World Oil Outlook (WOO) in 2009. The OPEC Reference Basket (ORB) of crudes peaked at $141/b in July 2008, fell to $33/b by the end of that year as the global financial crisis softened fundamentals, before beginning a gradual recovery in 2009.

From this period, what has been increasingly recognized is that both the rise to the record high and then the steep fall were not driven by fundamentals. The role of increased speculative activity in the price volatility has been widely acknowledged. The ad hoc Jeddah Energy Meeting of June 2008, followed by the ad hoc London Energy Meeting in December 2008, focused upon the need to reduce excessive volatility, including through the improved regulation of oil futures and over-the-counter (OTC) markets. Further follow up progress on this issue was witnessed at the 12th Meeting of the International Energy Forum (IEF), in Cancun, Mexico, in March 2010, from which a Ministerial Declaration[1] reiterated the commitment to the producer-consumer dialogue and to pursuing ways and means to help mitigate energy market volatility.

The emergence of oil as an asset class and the impact of financial markets on crude oil prices has attracted heightened attention in recent years (Box 1.1). A number of steps are now being taken to introduce regulatory reforms to financial markets, including commodities markets. While the potential impacts of these reforms remain to be seen, in particular given repeated financial innovation, a crucial test consists of how effective these reforms are in mitigating the effects of speculation in terms of exacerbating price fluctuations, both when trending higher and lower.

The financial and economic crisis has brought new challenges for the oil industry. For example, the fall in oil prices, at a time when costs had settled at considerably higher levels than in the past, placed strains on the industry's ability to invest at appropriate levels, which altered project economics and led to some cancellations and delays. In addition, debt financing became more difficult; lower earnings and stock valuations limited equity finance; a lower risk-appetite emerged in some quarters, in particular for small companies; and the demand contraction threw considerable doubt over how much investment was actually needed.

Such abnormal conditions can obviously create difficulties in developing a medium- and long-term oil price assumption. For the Reference Case, however, it is assumed that the price path will be driven by a return to fundamentals-driven market behaviour, as well as a gradual move towards healthier economic conditions.

The key perceptions for developing the Reference Case oil price assumption are:

- A gradual recovery from the global financial and economic crisis;
- OPEC Member Countries' ability and willingness to adjust their production levels according to evolving market fundamentals;
- Sufficient world oil resources and adequate spare capacity in both the upstream and downstream;
- The behaviour of marginal upstream and downstream costs; and
- An understanding that too low prices are likely to be damaging to supply prospects, while those that are too high could endanger the recovery and the subsequent sustained growth in the global economy.

A significant element in the development of an oil price assumption is the perception of the behaviour of upstream finding and development costs, a crucial component in any company's investment decisions. And of course, a central element in whether any given oil price might be considered sustainable. Upstream capital costs peaked in the third quarter of 2008, and a subsequent decline was then observed. However, the fall in costs was not particularly strong. In fact, the structural elements that pushed towards higher movements, such as expanding deepwater activity and rising iron ore prices, and hence steel prices, reacting to increasing demand in developing countries, have recently become somewhat stronger. Indeed, upstream costs are now rising again.

As has been noted, the low oil price environment at the end of 2008 and in the first quarter of 2009, the global financial crisis and the low earnings of many companies in the industry, as well as tight credit lines meant the financing of new projects became increasingly difficult. This led to a slowing down in the pace of investment in new upstream projects and, in some instances, project cancellations and delays. The expectation that future costs will be higher than in the past supports the idea that the low prices observed just a decade ago are now unsustainably low.

Costs also feed into the assessment of the sustainability of high prices, which may make significant amounts of alternatives to conventional oil economically feasible, whether they are non-conventional oils or alternative fuels. Indeed, much of the literature on longer term sustainable energy prices, for example, considers the relevance of so-called backstop technologies.

Although the pace at which such technologies can be introduced is limited by the rate of capital stock turnover, full cycle costs may provide a floor for long-term oil prices through market fundamentals, as prices must be sufficiently high to provide an incentive for the incremental barrel of supply to be developed. While there is no single break-even oil price as this varies by region and production profile, for the long-term price assumption, the significant figure is that for the marginal barrel of supply. For example, it is estimated that Canadian oil sands projects – both mining and *in situ* – require on average around \$70/b to generate a 10% real internal rate of return (IRR),[2] although a higher IRR obviously points to the need for higher prices. Coal-to-liquids (CTLs), often considered a backstop technology, have been calculated to be economic in the range of \$74–85/b.[3]

Another issue considered when making the Reference Case oil price assumption is the fact that oil prices today have a lower impact on the global economy than in the past. The lower economic impact can be traced to several factors, including lower oil intensities reducing the exposure of economies to oil prices. Oil intensities in Organisation for Economic Cooperation and Development (OECD) countries have fallen on average by almost 60% since 1970, and most developing countries are also using less oil per unit of gross domestic product (GDP).

With economic growth a significant oil demand driver, the modest impact of higher oil prices on economic growth is a crucial factor in understanding the robustness of demand in the face of any given oil price.

There are also other, more direct interpretations as to why oil prices might have a limited impact on demand. These include the fact that high levels of taxation on oil products stunt the impact of crude price movements on retail prices. Moreover, the captive transportation sector is known to have low price elasticities.

In sum, there are many factors that influence what might be considered a sustainable price that is consistent with the Reference Case. Prices that are either too low or too high are likely to give rise to feedbacks that will place pressure on prices to move away from those 'unsustainable' levels. How strong these feedbacks are, and how fast they are to impact prices, are not known for certain. Moreover, they will probably also change over time and according to circumstances. While a broad understanding of possible developments and their potential effects is emerging, in developing assumptions for future oil price developments the core idea of sustainability is inherent.

Noting these perceptions, the Reference Case, developed using OPEC's World Energy Model, OWEM, assumes a nominal price that remains in the range \$75–85/b over the years to 2020, reaching \$106/b by 2030. These prices are only assumptions and do not reflect any path that could be considered likely or desirable.

Box 1.1
The emergence of oil as an asset class

The appeal of investing in commodities, including oil, has increased significantly over the last decade. As a result, paper oil markets[4] have expanded dramatically. Activities are now more diversified and there has been a significant change in both participants and trading instruments.

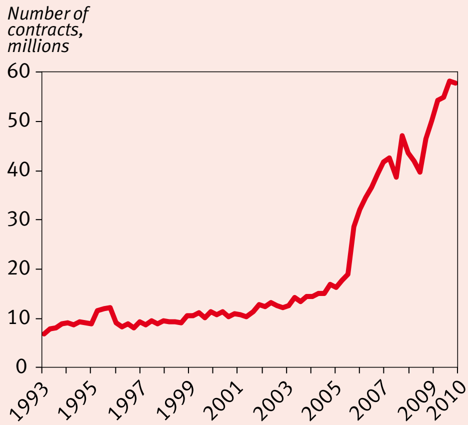
Previously, the paper oil market was dominated by commercial traders, such as producers, which leverage the futures market to hedge future production, and refiners and airline companies, which use it to hedge price risk. In recent years, however, there has been a rapid increase in the participation of non-commercial traders,[5] looking for higher returns from a rise or a fall in the oil price.

The growing involvement of investment banks and funds has resulted in a far more diversified paper oil market and the development of new instruments. This includes commodity indices, such as the S&P Goldman Sachs Commodity Index, and Exchange Traded Funds (ETFs), such as the US Oil Fund. The emergence of ETFs has made asset allocation more accessible to individual investors.

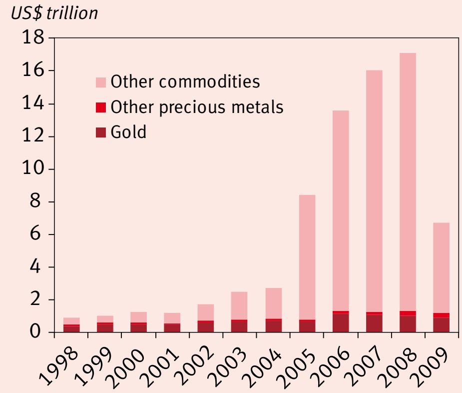
These developments and the boom in oil and other commodities have provided opportunities to invest in new assets that generate returns from the price performance of oil futures and derivatives, rather than attempting to generate returns from more traditional means, such as through capital investment into stocks of companies engaged in oil exploration, production and refining. It has meant oil has evolved with other commodities into an asset class and the oil price has become strongly correlated to developments in equities and the value of the dollar.

The introduction of these new diversified instruments, in addition to traditional ones, such as futures, options and swaps, has resulted in the market shifting from primarily being a hedge market to being both a hedge and an investment market. As a consequence, the volume of money going into paper oil has increased and trading volumes in both the organized exchanges and the unregulated OTC markets have risen dramatically (this can be viewed in the figures over the page).

Futures and options contracts outstanding on commodity exchanges, March 1993–June 2010



Notional amount of outstanding over-the-counter commodity derivatives, 1998–2009



Source: Bank for International Settlements, 2010.

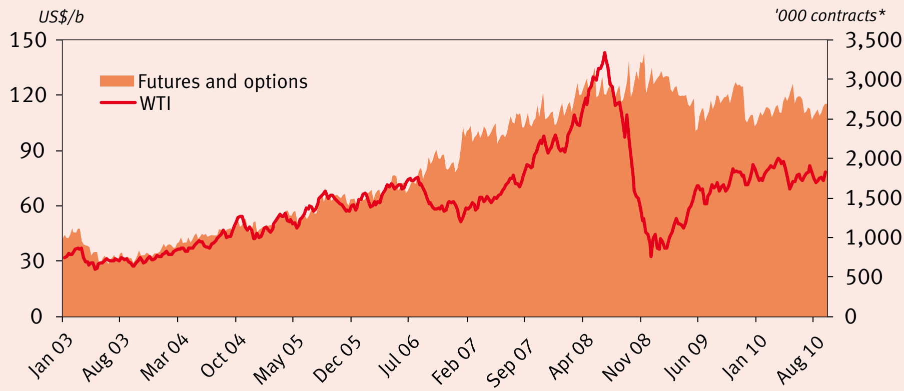
Chapter 1

A strong upward trend in volumes, particularly for futures options, has been observed on the Nymex over the last decade. Open interest in Nymex light sweet crude oil contracts (futures and options) has risen sharply, moving from an average of less than 600,000 contracts in 2000 to an average of around 1 million contracts in 2004, before surging to more than 3 million contracts in mid-2008, a few days before the West Texas Intermediate (WTI) front-month hit a record high (WTI front-month prices and open interest on Nymex are shown on the figure over the page). The rise in open interest was driven mainly by non-commercial dealers.

Available data from the US Commodity Futures Trading Commission (CFTC) shows that the involvement of money managers[6] has increased significantly recently. Consequently, the price of WTI and the net long crude oil positions of money managers on the Nymex have been moving in tandem. Since oil has emerged as an asset class, macroeconomic and financial data have become ever more important factors impacting price direction, compared to prompt supply and demand fundamentals.

Increasing activity on the exchanges and OTC markets, in line with the more diversified trading activity, raised concerns about the impacts of speculative activity as the oil price went through tremendous volatility. US crude oil prices rose from around \$18/b in mid-January 2002 to settle beyond \$145/b on 3 July 2008, before tumbling to less than \$34/b on 19 December 2008.

WTI front-month price and open interest on Nymex
January 2003–October 2010



** Each contract is 1,000 barrels.*
Source: CFTC.

In response to the upheaval caused by the financial crisis of 2008, as well as the spike in commodity prices that preceded it, world leaders at the G-20 Summit in Pittsburgh in September 2009 announced a series of reforms to strengthen the international financial regulatory system. Among these were expanding the scope of regulation and oversight to include the $615 trillion OTC derivatives market. By the end of 2012, G-20 countries are committed to standardizing OTC derivatives that are traded on exchanges or electronic platforms and cleared through central counterparties. All non-cleared contracts would have higher capital requirements. These measures would greatly enhance the ability of regulators to monitor developments in the previously opaque OTC market.

With the passage of the Dodd-Frank Wall Street Reform and the Consumer Protection Act in July 2010, the US has already put these G-20 commitments into law, although the details of the new regulations are still being written. In addition to the OTC measures, the CFTC is now authorized to impose position limits across a broad range of commodity markets, including oil. The purpose of the limits are to: diminish, eliminate or prevent excessive speculation; deter and prevent market manipulation, squeezes, and corners; ensure sufficient market liquidity for bona fide hedgers; and make certain that the price discovery function of the underlying market is not disrupted.

Outside the US, financial regulatory reform has also been moving forward. The European Commission prepared two draft laws on OTC derivatives that call for the central clearing of standardized swap contracts, new reporting requirements and the publishing of aggregate positions by class of derivative. As in the US proposal, commercial firms hedging physical risk will be exempted from centralized clearing. The new rules are expected to be operational at the end of 2012, once they have been approved by member states and the European Parliament. The proposals must be approved by the European Parliament and then the European Council of European Union (EU) leaders before they come into force.

Separately, the new UK government has announced a shake up of UK financial regulatory institutions. As part of this proposal, the CFTC's UK counterpart, the Financial Services Authority (FSA), will cease to exist and the Bank of England will take charge of financial supervision. How this might affect commodity market supervision is not yet clear.

Regulators in Asia have also been looking into reforms targeting OTC markets. Japan, India, China, Hong Kong, Singapore, South Korea and Taiwan have all created task forces to study setting up clearing operations for OTC derivatives, in line with the G-20 initiative. Such a coordinated, global approach reduces the risk of regulatory arbitrage, where financial players shift activities to the market with the least regulation and oversight. The spike in crude oil prices in 2008 has also helped consolidate the dialogue between consumer and producer nations on the impact of financial markets on the oil price. The Jeddah and London Ministerial ad hoc energy meetings held in June and December 2008 respectively, led to collaborative efforts aimed at exploring ways and means to address the issue of extreme energy market volatility. A result of this was seen in part of the Cancun Ministerial Declaration, adopted on the occasion of the 12^{th} IEF Meeting on 29–31 March 2010.

As can be seen, the events of 2008 – which include the spike in oil prices, the financial crisis and the onset of the global economic recession – have created a broad consensus among governments for the need to review the global regulatory financial market framework. And this has provided a window of opportunity to improve regulation and oversight in the financial oil markets. Given the locations of the major exchanges, these efforts will need to be carried out by the governing and regulatory bodies in consuming countries, primarily in the US and Europe. While oil producing countries will not be able to contribute directly in these efforts, they will certainly follow developments with interest and welcome any efforts to enhance oil market stability.

Medium-term economic growth

The previous WOO paid close attention to the medium-term prospects for the world economy, given the unravelling of the global financial crisis over the period of its preparation. The financial crisis was unparalleled, not only in terms of losses incurred by the financial sector, but also because of the strong contractionary effects this had on the real economy. The recession, which started in the US in December 2007 and took serious hold after the collapse of Lehmann Brothers in September 2008, turned out to be the deepest and longest[7] in more than six decades. In 2009, global GDP is estimated to have declined by 0.8% and recovery in 2010 remains shaky, with large uncertainties over the short- to medium-term. One of the most important questions that needs answering is what medium- and long-term scars will be left on the world economy, and in turn, how this will impact potential growth. In this regard, past experiences could help.[8] As a corollary, the question is to adequately assess whether the current proposed country-specific and global policies can help to heal these scars and accelerate the process of returning to trend growth rates.

There are several constraints to the recovery. These include: continuing credit tightness, even though financial markets have stabilized; a lack of confidence that is hindering investment, despite the fact that companies are in an increasingly sound financial condition; persistently high unemployment; low consumer confidence and thus spending; and the presence of too much excess capacity worldwide. On top of this lie concerns over how the fading effects of fiscal and monetary stimuli and the difficulty of renewing such macroeconomic incentives – as austerity measures in many developed countries take precedence – impact economic growth (Box 1.2). There is also particular concern over the Eurozone, specifically its sovereign debt crisis and the perceived weakness of its banking system.

There are nevertheless positive signs. In general, there are strong indications that the recovery is underway, with the monetary and fiscal stimuli helping to return economies to growth, and that the financial crisis has been navigated. For example, in the US, this is supported by the fact that the so-called 'TED-Spread' – the difference between the three-month T-bill interest rate and three-month LIBOR, which is an indicator of perceived credit risk in the general economy – is back to normal levels, having approached a massive five percentage points in 2008. Even in the EU, driven by the engine of Germany's success in exports, there is increasing evidence of some growth momentum in the real economy. Additionally, there is also a strong backlog of pent-up demand.

Looking at the overall global economic situation, in 2010 growth resumed and world trade is forecast to pick up. However, as noted by the constraints to growth, the recovery remains fragile. The handling of the recovery this year and next will lay the foundations for future medium-term growth. In particular, the timing of the exit strategies, both fiscal and monetary, is of the utmost importance. Moreover, while the massive monetary and fiscal stimuli have been greeted positively by most, they have led to a profound debt burden for many countries. It begs the questions: what are the associated risks and how might this impact future economic growth?

The Reference Case assumes that the recovery occurs at different speeds across world regions. For example, while both North America and the OECD Pacific are expected to grow robustly in 2010 at 2.6% and 3.2% respectively, Western Europe's growth is more sluggish, at 1.4%. Developing countries are seen to lead the recovery, averaging growth of 6.5% (Table 1.1). In 2011 and 2012, the recovery in the OECD continues and by 2013 is complete in all regions, with Western Europe again the slowest to recover.[9]

Compared to the WOO 2009, the recovery in 2010 is expected to be faster: world economic growth is now anticipated to be close to 2% higher than previously thought, with net growth of 3.9% for the global economy up from the 2.1% assumed last year. This is a reflection of the effect of the massive stimulus packages.[10]

The medium-term outlook for economic growth could be affected by the large increases in government debt associated with those fiscal stimuli in response to the

Table 1.1
Real GDP growth assumptions in the medium-term *% p.a.*

	2009	2010	2011	2012	2013	2014
North America	–2.9	2.6	2.5	2.5	2.5	2.5
Western Europe	–3.9	1.4	1.3	1.7	1.9	1.9
OECD Pacific	–3.3	3.2	2.1	1.9	1.9	1.9
OECD	**–3.4**	**2.2**	**2.0**	**2.1**	**2.2**	**2.2**
Latin America	0.1	5.1	3.6	3.3	3.3	3.3
Middle East & Africa	2.4	3.5	3.5	3.5	3.5	3.5
South Asia	6.3	7.2	6.9	6.7	6.5	6.3
Southeast Asia	0.5	5.1	4.3	4.0	3.8	3.8
China	8.7	9.5	8.6	8.5	8.5	8.5
OPEC	2.8	2.8	3.4	3.7	3.7	3.7
Developing countries	**4.1**	**6.5**	**5.9**	**5.8**	**5.8**	**5.8**
Russia	–8.7	4.0	3.8	3.6	3.4	3.3
Other transition economies	–5.2	2.0	3.4	3.3	3.2	3.1
Transition economies	**–7.2**	**3.0**	**3.5**	**3.4**	**3.3**	**3.2**
World	**–0.8**	**3.9**	**3.7**	**3.7**	**3.7**	**3.7**

Box 1.2
The world economic recovery: pause or double dip?

In the latter part of 2009 and especially in the first half of 2010, the pace of the global economic recovery exceeded expectations, with a pervasive revival in manufacturing and trade. On the financial front, the banking sector also moved away from the precipice with large banks reporting profits although lending remains low as deleveraging is still ongoing. However, the pace of economic expansion experienced by developed and developing countries differed substantially resulting in a two-speed world recovery. It also precipitated a debate about the timing and pace of exiting from the unprecedented, and in some cases increasingly burdensome, stimulus measures that had supported economies during the crisis.

Achieving the same level of coordination among G-20 countries when exiting the stimulus is likely to be more difficult than it was when designing these measures and this may be an influential factor in the success of the global recovery. In 2008 the real risks of a collapse in the global financial system and an economic depression concentrated the minds of policy makers. However, in the recovery phase, the clear divergence in the strength of the upturn between developed and developing markets is a major factor determining the timing of exit policies. Thus, major developing country markets have already taken steps to tighten monetary policy and in some cases to slow down overheating economies.

In early 2010, the Chinese government took measures to deflate a property bubble. The question arose as to whether these steps would succeed without derailing the strong recovery and maintain China's growing role as an engine of regional and global growth. So far, China appears to be successful in achieving a soft-landing.

Moreover, worries about debt sustainability in OECD countries in the coming years, made worse through the massive cost of fiscal and monetary rescue packages, forced governments early on to consider plans to cope with the debt burden over the medium-term. However, the luxury of time proved illusory as heavily-indebted Greece (and subsequently the whole Eurozone) was forced to address the problem head-on in spring 2010. The sovereign debt crisis in Southern Europe raised doubts about the prospects of recovery in the region this year and next. The slow, but eventually adequate response of the Eurozone to the Greek debt problem, finally calmed markets, although confidence remains shaken. However, dealing with the heavy debt burden at a faster pace could slow down growth for many years. Immediate fears of a sovereign debt default in Greece have subsided somewhat but the price being paid is a deep recession. Similarly for Ireland and Spain, painful cutbacks have become necessary.

Meanwhile, domestic consumption in OECD countries remains weak. This in turn is strongly linked to falling consumer confidence in the face of a largely 'jobless recovery'. In the US, the weak labour market is affecting confidence and contributing to the marked deterioration in the housing market. The fragility of the US recovery has led to increasing expectation of a double-dip recession, making exit strategies more difficult. Meanwhile, the deleveraging process of households is still ongoing. Households are still a long way from pre-crisis levels of debt/income and debt/total assets. Thus, US consumers are saving more than before the crisis, implying that the old paradigm of the consumer being the main engine of growth is no longer valid.

The resulting likelihood of a Japan-like scenario of a lost economic decade, characterized by stagnating growth and deflation, not only for the US, but also for Europe, has generated a heated debate on 'austerity *versus* stimulus' among and within OECD countries, with an emerging transatlantic divide between Europe and the US. The European Central Bank and large Eurozone countries advocate the wisdom of austerity and of exiting stimulus measures sooner rather than later in the belief that this is a necessary condition for sustainable medium-term growth. Policy makers in the US, however, remain cautious and many analysts advocate more quantitative monetary easing measures, and further fiscal stimulus if possible, to help avert a double-dip and a lost decade scenario. They refer to the extended economic depression in the 1930s when support is believed to have been withdrawn too soon. While further fiscal stimulus may be problematic, the US Federal Reserve remains confident that it still has enough monetary ammunition in the form of quantitative easing to rescue the recovery, if need be. However, many doubt the effectiveness of further quantitative easing.

At the same time, the calls for surplus countries like Germany, Japan and China to contribute towards global reflation and a rebalancing of the world economy by encouraging domestic private consumption are falling partly on deaf ears, particularly in Germany. It should be stressed, however, that China is gradually moving towards rebalancing its economy. Nonetheless, this global process is gradual at best and will not offer an immediate respite.

One year into the world economic recovery, many questions remain unanswered and it is unclear whether the measures taken so far are sufficient to ensure that foundations for strong sustainable growth in the medium-term have been laid. In view of past evidence indicating that growth tends to be slower and unemployment higher in years following severe financial crises, there is not much room for complacency. While it is also true that many developing and emerging markets are in a much better financial situation than OECD countries and are expected to continue to grow briskly, their growth prospects in a globalized world are not divorced completely from those of advanced economies and while they will increasingly act as motors of world growth, the process may not be smooth.

Finally, the much-heralded measures to restructure the global financial system are still a work-in-progress, given the complexity of the issues involved and the controversial nature of some of the proposed reforms. It begs the question: will the measures be sufficient to make the world safe (or safer) from new upheavals? So far, the process has been slow, both at the national and multilateral level, although some progress has been made to improve transparency and moderate reforms are expected to be implemented in the course of the next few years.

In the US, the Dodd-Frank Wall Street Reform and Consumer Protection Act has gone some way to restrict the ability of banks under federal insurance from engaging in proprietary trading. The EU has adopted a new financial supervisory structure, but the main thrust is focused on harmonizing national rules and advancing transparency. At the multilateral level, the emerging compromise on the Basel 3 banks' capital requirements and liquidity standards, to be presented to the G-20 Leaders' Summit in Seoul in November 2010, appears to be a watered-down version of initially envisaged reforms. However, this cautious approach to financial reform may itself be a reflection of widespread fears of derailing an already fragile recovery in the real economy.

It is clear that the G-20, which led the rescue of the world economy, has largely succeeded in steering the world away from the storm into quieter waters, but the global economic recovery is still far from secure.

global crisis. The International Monetary Fund (IMF), for example, estimates that debt ratios are likely to turn out to be the largest since World War II.[11] They emphasize that, while a too rapid withdrawal of the fiscal stimuli could add serious downside risk to the recovery, there are also serious concerns over sustainability of the debt. It is clearly too early to judge how this will play out.

Long-term economic growth

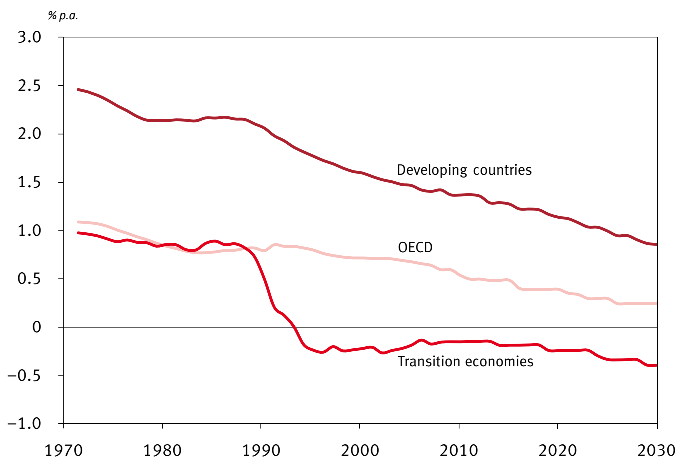
Demographics

For long-term economic growth potential, as well as the prospects for future energy needs, it is essential to consider demographic trends. While the world's population is clearly set to grow, albeit at slowing rates, growth patterns will be very different across regions. Moreover, the evolving age structure will also be important, as it is the size of the working age population that is relevant to the availability of labour. Changes in age structure will also affect the number of people who are of driving age, which has implications for the potential growth in car ownership levels.

Additionally, demographic dynamics affect the amount of spending that will be necessary on health care and state pensions. This is particularly relevant to those countries that are expected to 'age' substantially. For example, the European Commission's 2009 Ageing Report[12] emphasizes that age-related spending in the EU will need to increase rapidly, by 5% of GDP over the period 2007–2050. And social security reform has become a major focus of attention in the US under President Barack Obama, as well as in many European Countries. The global financial crisis has thrown these challenges into sharper relief, given the complications associated with the rise in government debt. For the long-term, there is concern that the fiscal adjustments needed to cater for ageing populations may have implications for sustainable real economic growth.

Figure 1.1 demonstrates historically declining population growth rates. In the OECD, average growth of 1% per annum (p.a.) was seen in the early 1970s. By 2009, the average OECD growth was down to 0.6% p.a., as fertility rates fell in Western Europe and Japan from close to two children per woman in the early 1970s to 1.6

Figure 1.1
Annual growth rates of population



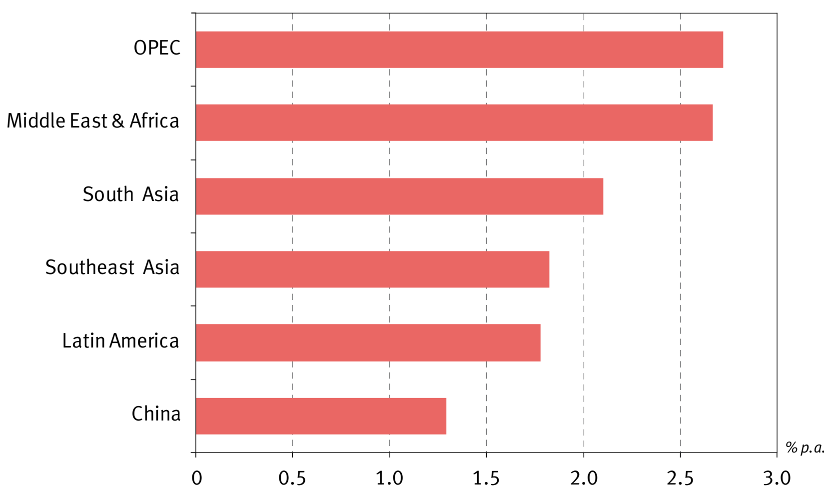
Source: Population Division of the Department of Economic and Social Affairs of the United Nations Secretariat, World Population Prospects: The 2008 Revision, http://esa.un.org/unpp.

and 1.3 respectively by the first decade of the 21st century. The pattern in North America has been different, however, with the rate remaining approximately constant at around two over the past 40 years. In the future, the United Nations (UN) does not foresee much change in fertility rates in the OECD, and population growth trends will be dominated by the ageing of populations, as the median age in the OECD increases from the current level of around 40 to over 44 years by 2030. Consequently, all OECD regions will witness declining growth rates: OECD Pacific population actually plateaus around 2013–2016, before declining; Western Europe is barely growing, at 0.1% p.a., by 2030; and North America too, exhibits declining growth, albeit with a fairly robust annual increase of 0.6% p.a. by 2030.

Developing countries have seen faster population growth than the OECD. The rate averaged almost 2.5% p.a. in 1970, although this had fallen to 1.4% p.a. by 2009. The fastest average growth over the period 1970–2009 was observed in OPEC and non-OPEC Middle East & Africa (Figure 1.2).

Birth rates have been, and continue to be, considerably higher in developing countries than in the OECD, although this figure has also seen a downward trend. For example, fertility rates in India have halved over the past four decades. A continued decline in fertility rates will lead to a further fall in average population growth rates, so that by 2030 developing country population levels will be rising by under 1% p.a.

Figure 1.2
Average annual growth of population in developing countries, 1970–2009



Compounding the effect of lower birth rates upon population growth, developing countries will also eventually start to experience an accelerated 'ageing' population process. For example, the current median age in India of under 25 years is expected to grow to almost 32 by 2030; for China the change will be from 34 to 41 years; and for Brazil, from under 29 to 38 years.

Population dynamics in transition economies have shown a unique trend. In the 1970s and 1980s they followed a similar downward trend in average growth to the OECD, but in 1989, following the collapse of the Soviet Union and other Communist countries, there was a startling change. From 1989 to 1993, the average population growth fell from 0.7% p.a. to no growth at all. Primarily behind this was a dramatic fall in birth rates. UN projections foresee a further decline in transition economy populations, particularly in Russia and the Ukraine.

Table 1.2 summarizes the implications of these developments for world population levels and growth. Globally, the number of people on the planet, using the

Table 1.2
Population levels and growth

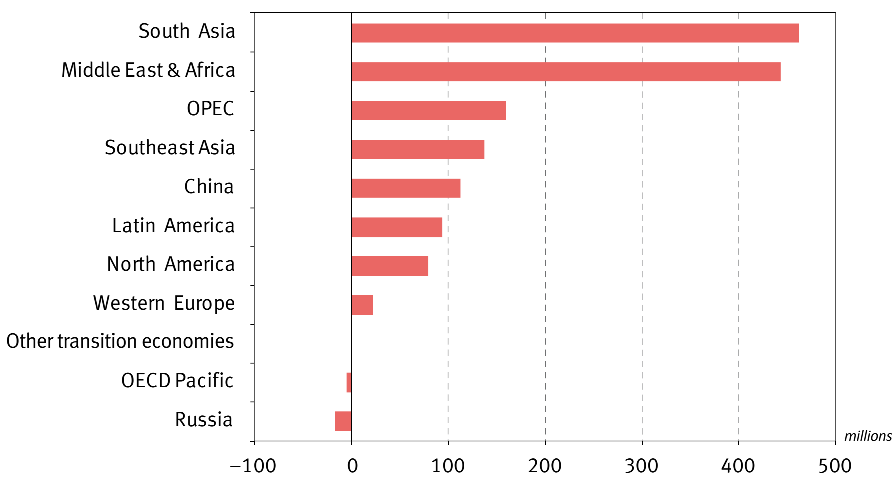
	Levels *millions*		Growth *millions*	Growth *% p.a.*		
	2009	**2030**	**2009–2030**	**2009–2030**	**2009–2020**	**2020–2030**
North America	462	542	80	0.8	0.9	0.6
Western Europe	544	566	22	0.2	0.3	0.1
OECD Pacific	201	196	–5	–0.1	0.0	–0.2
OECD	**1,207**	**1,305**	**97**	**0.4**	**0.4**	**0.3**
Latin America	428	522	94	1.0	1.1	0.8
Middle East & Africa	861	1,305	444	2.0	2.1	1.8
South Asia	1,620	2,083	463	1.2	1.5	1.0
Southeast Asia	650	787	138	0.9	1.1	0.8
China	1,345	1,458	113	0.4	0.5	0.2
OPEC	393	553	160	1.6	1.8	1.4
Developing countries	**5,296**	**6,708**	**1,412**	**1.1**	**1.3**	**1.0**
Russia	140	123	–17	–0.6	–0.6	–0.7
Other transition economies	196	196	0	0.0	0.1	–0.1
Transition economies	**337**	**320**	**–17**	**–0.2**	**–0.2**	**–0.3**
World	**6,840**	**8,332**	**1,492**	**0.9**	**1.1**	**0.8**

Source: United Nations, Department of Economic and Social Affairs, Population Division.

medium variant of projections of the UN Department of Economic and Social Affairs, grows on average by 0.9% p.a. over the years to 2030, at which time it reaches 8.3 billion, an increase of 1.5 billion from 2009. Of this increase, 95% will be in developing countries, with developing Asia accounting for close to half of the global increase (Figure 1.3).

In the discussion of demographics, focus has been upon median estimates, although the UN also provides high and low growth estimates, which is an often

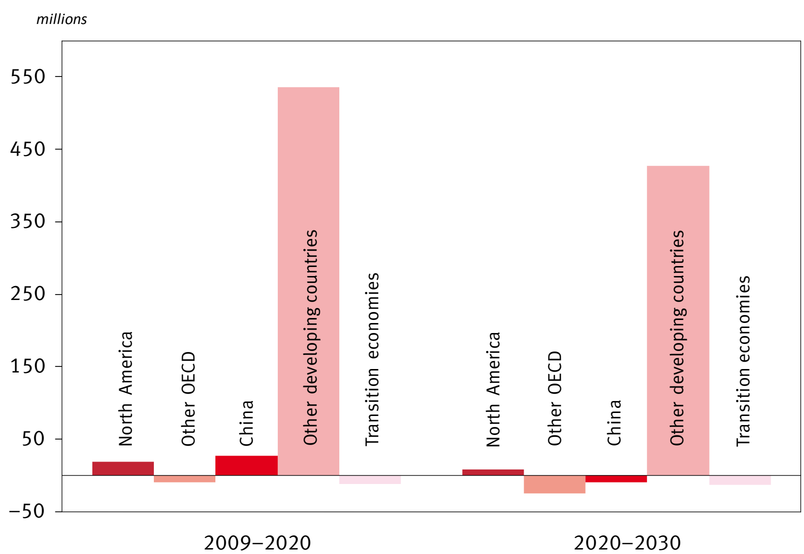
Figure 1.3
Increase in population, 2009–2030



overlooked source of uncertainty. Reference has been made to the changing age structure of populations and the impact that this will have upon the growth of working age populations, and by extension, the size of the labour force, a key determinant of potential economic growth. OECD countries have an average of 66% of the population at a working age (defined here as aged 15–64). However, this figure is already shrinking as a result of ageing populations. It means that the available labour force in Western Europe is expected to peak this year, before declining, unless changes to the retirement age are made and/or immigration inflows are increased. In Japan, the size of the working age population actually peaked in the 1990s, and in the OECD Pacific as a whole, the figure has also already begun to fall. In North America, the share of this age group in the total population will soon begin to fall, but the relatively strong total population growth will ensure a continued expansion of the size of the region's labour force for the foreseeable future. Over the years 2009–2030, the North American workforce is assumed to increase by 27 million, in contrast to the rest of the OECD, which sees a decline over that period of over 34 million people.

In developing countries, an interesting demographic is that the Chinese labour force is expected to peak around 2015, before falling by 14 million by 2030. The rest of the developing world, however, is expected to see a greater number of people entering the workforce compared to those retiring. In Asian countries alone, excluding China, an increased workforce of close to half a billion people can be expected by 2030. Transition economies will see a fall in the workforce as falling total populations combines with ageing. These developments are summarized in Figure 1.4.

Figure 1.4
Growth of labour force, 2009–2030



Beyond these aggregate demographics, the general trend towards urbanization will continue. The only growth in rural populations of any significance is expected in Africa and South Asia (Table 1.3). Otherwise, there will be much migration from rural areas to cities, as well as net additions to populations in these areas. The biggest example of relocation is expected in China, where more than 170 million people are anticipated to move from rural lands to cities over the years to 2030.

Table 1.3
Population by urban/rural classification

millions

	2009		2030		Increase 2009–2030	
	Urban	Rural	Urban	Rural	Urban	Rural
North America	379	83	472	71	93	–13
Western Europe	394	150	440	126	46	–24
OECD Pacific	147	54	154	42	7	–12
OECD	**920**	**287**	**1,066**	**238**	**146**	**–49**
Latin America	356	71	461	61	104	–10
Middle East & Africa	340	521	652	652	312	132
South Asia	491	1,129	868	1,216	376	87
Southeast Asia	316	334	491	297	175	–37
China	592	753	879	579	288	–174
OPEC	248	144	403	149	155	5
Developing countries	**2,344**	**2,953**	**3,754**	**2,954**	**1,411**	**1**
Russia	102	38	94	29	–8	–9
Other transition economies	109	87	124	72	15	–15
Transition economies	211	125	218	101	7	–24
World	**3,475**	**3,365**	**5,039**	**3,293**	**1,564**	**–72**

Source: United Nations, Department of Economic and Social Affairs, Population Division.

Economic growth

In addition to demographic trends, assumptions are also necessary for factor productivity. This is, *inter alia*, related to technological advancement. In the Reference Case, productivity growth in OECD regions is assumed to be 2% p.a. in the early years of the projection, falling to 1.5% p.a. by 2030, while higher rates are assumed for developing countries. However, the financial crisis and global recession has raised concerns over the long-term implications for economic growth. Structural reforms that place a new emphasis upon regulation rather than the free market ethos may well promise greater stability, but questions arise as to whether this might come at a price in terms of economic growth?

There is therefore considerable uncertainty concerning future productivity growth, and, consequently, economic growth. Additionally, while the Reference Case assumes the continued benefits of globalization through increased trade, even if the long-running Doha Round of trade talks do not come to fruition, the possibility of rising protectionism implies real threats to the robust economic expansion assumed in the Reference Case.

The Reference Case assumptions for economic growth appear in Table 1.4. An average global rate of 3.5% p.a. emerges for the period 2010–2030. This is higher than the assumption in the WOO 2009, firstly, due to the slightly more optimistic recovery path following the global recession, and, secondly, due to an upward revision to growth expectations in developing countries over the period to 2020. Asian growth continues to dominate economic growth performance, with South Asia and China the fastest growing regions averaging 5.4% and 6.9% p.a. respectively. OECD countries grow by an average of 2% p.a., and Russia and other transition economies at an average of 2.8% p.a.

In terms of the relative size of the regional economies, it is worth noting that, while OECD regions currently still dominate global activity, by 2030, China has become larger than either North America or Western Europe (Figure 1.5). Similarly, South Asia rises in importance, exceeding the size of the entire OECD Pacific economy by this date.

Table 1.4
Average annual real GDP growth rates in the Reference Case (PPP basis) *% p.a.*

	2010–2020	2021–2030	2010–2030
North America	2.5	2.3	2.4
Western Europe	1.8	1.6	1.7
OECD Pacific	2.0	1.5	1.7
OECD	**2.1**	**1.9**	**2.0**
Latin America	3.3	2.8	3.1
Middle East & Africa	3.4	3.2	3.3
South Asia	6.1	4.6	5.4
Southeast Asia	3.9	3.2	3.5
China	8.0	5.6	6.9
OPEC	3.6	3.3	3.5
Developing countries	**5.6**	**4.4**	**5.0**
Russia	3.3	2.5	2.9
Other transition economies	2.9	2.4	2.6
Transition economies	**3.1**	**2.5**	**2.8**
World	**3.7**	**3.2**	**3.5**

Figure 1.5
Real GDP in 2009 and 2030

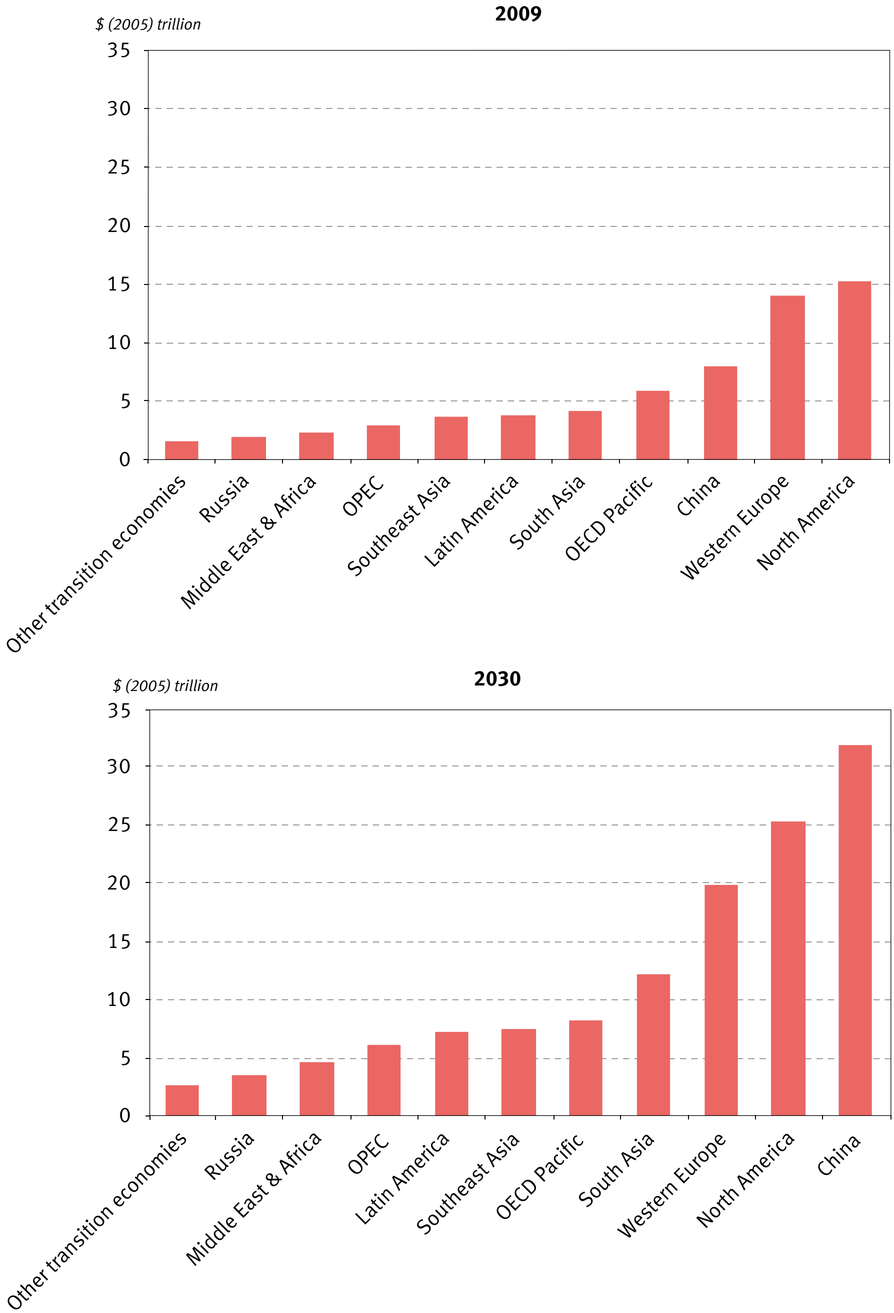
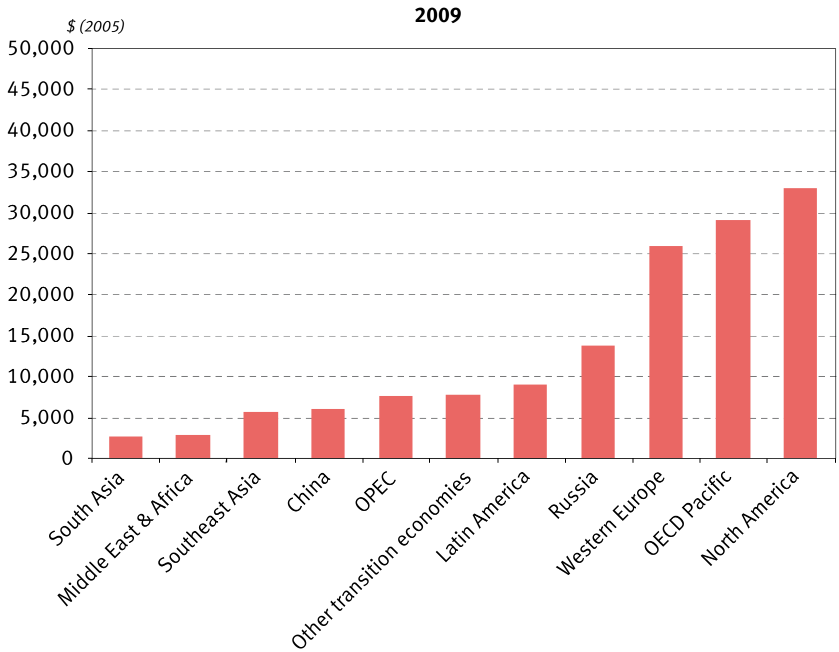
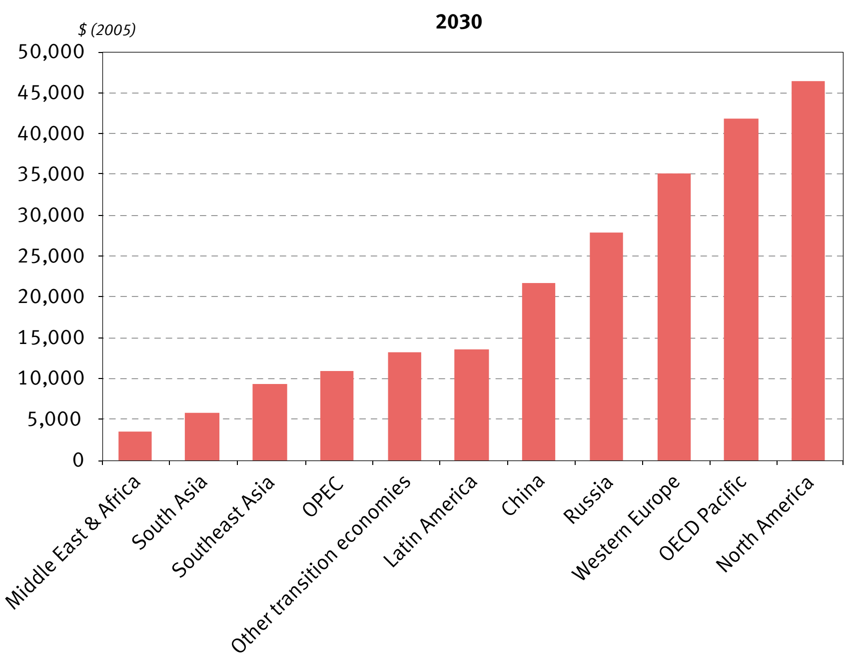


Figure 1.6
Real GDP per capita in 2009 and 2030





Chapter 1

Despite this shift towards Asia, with the region becoming increasingly important in the global economic order, the implications for GDP per capita developments suggest that the gulf between rich and poor is likely to remain over this timeframe. This can be viewed in Figure 1.6, with OECD regions easily retaining their position as the wealthiest of nations. Indeed, while China's strong economic performance raises its GDP per capita substantially, sufficient to become the wealthiest developing region per head, it still stands at well under half the value of North America by 2030. Having said that, China's GDP per capita by 2030 is as high as the levels seen in Western Europe as recently as 1990. In contrast, the poorest of these regions, namely non-OPEC Middle East and Africa – and by virtue of relative population size, predominantly the latter – is not expected to reach the GDP per capita levels that were achieved by China in 2004.

Energy policies

Energy policies are one of the key drivers for future energy demand and supply. And what is evident is that this is one of the most uncertain areas to address in making projections, especially in the long-term. The issue of understanding energy policy goals and targets is not new: attempts at developing energy outlooks have always had to consider the extent to which policies might affect the evolution of oil and energy demand. In terms of the WOO, there have always been broad trends in policies that have been accounted for in developing past reference cases. For instance, increasing taxation and other incentives to improve energy efficiency, and subsidies for certain fuel types, such as those supporting the nuclear and coal industries, are examples of such trends that have helped shape past WOO projections for energy demand and supply.

More recently, however, there has been legislation that has been passed into law. The WOO 2008 reference case already took note of the likely impact of a number of policy announcements, even if at the time they had not yet been enacted. The upshot was that even in the WOO 2008 the trend towards still higher efficiency improvements was incorporated into reference case figures.

By the time the WOO 2009 was finalized, however, some policy initiatives had actually been passed into law. The two key cases were the US Energy Independence and Security Act (EISA) and the EU's package of implementation measures for climate change and renewable energy objectives. The policy targets that were involved were thus incorporated into last year's reference case.

The US EISA Act introduces stricter Corporate Automobile Fuel Efficiency (CAFE) standards, which has been estimated to reduce demand by 1.1 mb/d in 2020, and 2.1 mb/d by 2030. This was included in last year's reference case. The Act also includes biofuels targets, which implies the use of at least 36 billion gallons of renewable and alternative fuels by 2022. However, this target has until now, generally been regarded as overly ambitious, given the specific requirements for the commercial viability of advanced biofuels. It was therefore assumed in the previous reference case that just one half of the additional biofuels required will appear by 2022, but that through the 2020s advances in technology enable the EISA targets to be met by 2030. This raises biofuels supply by 1 mb/d above the previous level by this date. The same assumption is made for the WOO 2010 Reference Case.

The EU package of measures involves: binding targets to reduce CO_2 emissions by 20% from 1990 levels by 2020; energy efficiency improvements of 20% by 2020; and a 20% share for renewable energy by that date. This led to the measures being dubbed the '20-20-20' climate and energy package. Again, last year's WOO had already factored the expected impacts of this legislation into the reference case, and this current publication makes the same assumptions. The specific changes incorporated were: the revision of the EU's Emissions Trading System results in greater efficiency in the industrial sectors of the Western European region, as well as a lower share for coal and a higher share for renewables in electricity generation; the target of 120g CO_2/km from new cars phased in over 2012–2015 leads to additional 0.5% p.a. efficiency improvements for Western Europe's transportation sector in the longer term; the 20% renewable energy target leads to a higher renewables share in the energy mix, but not to EU target levels, as this was, and still is, regarded as overly ambitious; the 10% renewables target for the transportation sector leads to higher biofuels use compared to earlier reference case outlooks, but not to the extent reflected by the EU target, as there are also doubts as to whether this level is reachable.

It might also be noted that the EU package included a legal framework for carbon capture and storage (CCS), with the intention of building at least 12 large-scale commercial demonstration CCS plants. Early in 2010, the EU agreed to incentivise the CCS demonstration through the EU Emissions Trading System (ETS), by providing funding from the auctioning of EU ETS allowances which can be used to co-finance the demonstration plants. The European Economic Recovery Plan also allocated over €1 billion to CCS demonstration projects inside the EU. However, the Reference Case does not assume that this has any tangible effect on the energy mix over the timeframe to 2030.

These specific policy developments are themselves clearly subject to uncertainties in terms of implementation. As noted, some of the targets are regarded as unrealistic. There are major uncertainties concerning spill-over, such as the longer term impact of automotive efficiency targets on truck fuel use and there may be constraints from, for example, technological developments, or feedbacks from the effects upon land-use and food prices.

However, an increasingly important issue has become the extent to which long-term Reference Case demand and supply projections should also reflect possible measures that are linked to greenhouse gas (GHG) emission reduction targets. The pace and extent to which measures are introduced, together with how corresponding technologies develop, have become key uncertainties. Kyoto Protocol targets, however, have never been incorporated into the Reference Case.

Ambitious GHG emission abatement targets are generally regarded as being unreachable unless massive amounts of existing capital are prematurely retired at huge expense. Nevertheless, there is some evidence of a growing momentum in public opinion behind the need to reduce GHG emissions, at least in some regions, which would suggest that it is becoming increasingly likely that changes are in store to the trends portrayed in the previous reference case. For this year's WOO, some further additional road transportation sector efficiency gains are assumed at a global level, reflecting the massive scale of research and development (R&D) currently underway in this sector. However, the Reference Case still does not introduce the scale of technological breakthroughs and changes in consumer behaviour that would be necessary for such targets to be met. This kind of break with the past is, however, becoming a growing possibility.

Finally, a key assumption in making energy projections relates to the existence of subsidies. Clearly, any change in policy in this regard could have significant implications for price signals to consumers. However, it must remembered that this is a very complicated issue given that the role of subsidies extends to important socio-economic objectives (Box 1.3). In the Reference Case, it is assumed that only gradual change to subsidy levels occurs in line with current policy directions.

Box 1.3
Energy subsidies: a multi-faceted issue

Energy plays an important role in moving a country through the various stages of socio-economic development. In fact, in some respects the development stage of a country can be determined by this factor. For example, cheap, abundant energy from coal, oil and natural gas has helped drive a large part of the global economy, in particular the OECD, for decades. Conversely, the lack of accessibility to modern, efficient sources of energy has hindered the advancement of the least developed world.

In looking at the issue of energy subsidies it is essential to keep in mind energy's socio-economic dimension, and in turn, resolve questions relating to definitions, measurements and just how the subject is evaluated in a global context. The key lies in appreciating the inter-linkages between the three pillars of sustainable development, namely the economic, environmental and social/poverty dimensions. For energy subsidies, this means, in particular, moving beyond the environmental context, in which they are often considered.

The role of subsidies in helping to alleviate energy poverty, promoting access to affordable modern energy services, as well as their importance in economic development, is significant. This can be witnessed in the UN Millennium Development Project, which emphasizes the close relationship between access to energy services and the Millennium Development Goals (MDGs). It is essential that the world pursues more equitable patterns of development as a failure to do so will result in missing the targets set out in the MDGs.

If the phasing-out of subsidies is proposed on grounds relating to climate change concerns, it is important to recall the principles and provisions of the United Nations Framework Convention on Climate Change (UNFCCC), in particular, the emphasis on the historical responsibility of developed countries in regard to the state of the atmosphere, as well as the principle of common, but differentiated responsibilities.

Moreover, the impact of fuel subsidies on the environment may not always be negative. This depends on whether the subsidy encourages households, or industry, to use more or less carbon-intensive energy sources. For instance, removing subsidies on kerosene or liquefied petroleum gas (LPG) can induce poorer households in certain countries to increase their reliance on firewood. The resulting negative impacts can be an increase in deforestation, much greater local pollution and a destruction of carbon sinks.

The use of 'negative' subsidies (taxes) on fossil fuel use, particularly petroleum products, should not be ignored. For example, revenues raised through taxes levied by OECD countries on energy, mainly fossil fuels for transport, have been estimated to be around US$800 billion annually between 2004 and 2009.[13]

When discussing and analyzing energy subsidies, it is also important to examine non-fossil fuel energy subsidies, which are considerable in number and have been increasing over time. A rough estimate by the Global Subsidies Initiative (GSI) indicates that around US$100 billion per year is spent to subsidize alternatives to fossil fuels. Subsidies are concentrated in OECD countries, which are responsible for the generation of over 80% of the world's nuclear and renewable electricity and two-thirds of its biofuels production. Furthermore, based on GSI figures,[14] renewable energy sources and biofuels are subsidized at a much higher rate than fossil fuels. The per unit basis subsidies for renewables and biofuels are equal to five cents per kilowatt hour (kWh), compared with 1.7 cents per kWh for nuclear power, and 0.8 cents per kWh for fossil fuels.

When considering the various types of subsidies, it is critical to make every effort to distinguish between the various forms. There is what can be deemed 'effective' subsidies that have been, and will continue to be, a policy instrument serving and supporting justified priorities within an economy. These have a permanent nature, but evolve over time. Then there are 'embedded' subsidies, which are ingrained in the socio-economic fabric of countries and cannot be treated in isolation. And there are wasteful subsidies that need to be removed with care, and with the provision of an adequate safety net.

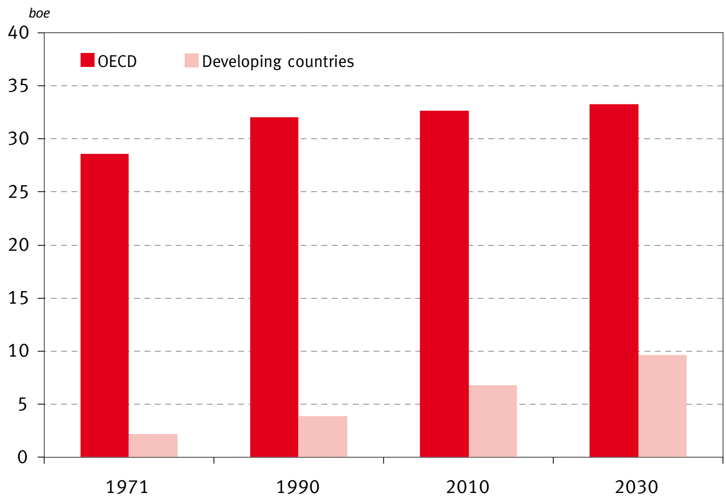
With the above in mind, it is clear that subsidies are multi-faceted in nature, covering a plethora of socio-economic issues, and are fundamentally country-specific in that they are related to national circumstances. Thus, the use, or the phasing out, of energy subsides, needs to be viewed as a decision to be taken by individual sovereign states.

Energy demand

Energy use is inextricably entwined with human history. Coal use helped fuel the industrial revolution of the 18th and 19th centuries; oil use has, *inter alia*, formed the basis of the mobility revolution of the 20th century; all fuel types have been used to increasingly provide access to electricity; and a myriad of uses allows energy services to fuel economic growth, and bring about social progress. Demand for energy has increased progressively, from 55 million barrels of oil equivalent per day (mboe/d) in 1960 to 227 mboe/d in 2008.[15] With the assumptions laid out in the first part of this Chapter, energy demand will continue to increase to 2030, as economies expand, the world population grows and people's living conditions improve.

In the Reference Case, by 2030, world energy demand increases by more than 40% compared to today's levels. By 2008, non-OECD countries were using, for the first time, more commercial energy than OECD countries. In the future, developing countries will account for most demand increases. This is not only due to higher population and economic growth, but also because of the huge pent-up demand for energy use in these countries as people gradually gain access to modern energy

Figure 1.7
Energy use per capita



services. Energy use per capita in developing countries has always been well below that of the OECD: in 1971 it was just one-thirteenth of OECD values, by 1990 it was still only one-eighth, and by 2010 it was one-fifth. This picture remains similar in the future: over the timeframe under consideration, the Reference Case sees the OECD enjoying on average three-and-a-half times as much energy per head as developing countries (Figure 1.7 and Box 1.3).

In satisfying the world's energy needs, the Reference Case sees fossil fuels playing the prominent role, and though their share in the energy mix is expected to fall, it remains over 80% throughout the period to 2030. And even with the energy policies introduced into the Reference Case, which to a considerable extent target oil use, the leading role in the energy mix will continue to be played by oil, with its share remaining above 30%, albeit falling over time (Table 1.5 and Figure 1.8). Oil use, however, grows at the slowest rate of all fuel types. The rate of expansion of the use of natural gas is expected to be high, especially with the technological developments that have allowed the rapid exploitation of unconventional resources, such as shale and tight gas and coalbed methane (Box 1.4). In the Reference Case, coal, despite having the highest CO_2 emissions per unit of energy of any fuel type, is expected to retain its position, as the second most important fuel in the energy mix. Renewable energy will grow fast, but from a low base, while both hydropower and nuclear power expand.

Table 1.5
World supply of primary energy in the Reference Case

	Levels mboe/d				Growth % p.a.	Fuel shares %			
	2008	2010	2020	2030	2008–30	2008	2010	2020	2030
Oil	80.9	80.4	89.9	97.6	0.9	35.7	35.0	32.7	30.2
Coal	64.8	66.2	80.1	92.1	1.6	28.6	28.8	29.2	28.5
Gas	51.4	52.1	64.5	79.1	2.0	22.7	22.7	23.5	24.5
Nuclear	14.4	14.7	16.9	20.7	1.7	6.3	6.4	6.2	6.4
Hydro	5.5	5.8	7.3	9.0	2.3	2.4	2.5	2.7	2.8
Biomass	8.6	9.2	12.9	17.5	3.3	3.8	4.0	4.7	5.4
Other renewables	1.3	1.5	3.2	6.8	7.8	0.6	0.7	1.2	2.1
Total	**226.8**	**229.9**	**274.8**	**322.9**	**1.6**	**100.0**	**100.0**	**100.0**	**100.0**

Coal

Coal is the most abundant fossil fuel: current reserves, in terms of energy content, amount to more than those for oil and gas combined. With the use of coal focused primarily on generating electricity, and with coal the most carbon-intensive fossil fuel, the future prospects for coal use are closely related to how climate change mitigation policies and measures evolve.

Coal reserves are particularly plentiful in the US, Russia, China, Australia and India, who between them account for 78% of the world's total. These five countries also consume for the lion's share, amounting to 74% of the total global use in 2009 (Figures 1.9 and 1.10). However, net trade patterns reveal markedly different rankings: the two major net exporters are Australia and Indonesia, followed by Russia, Colombia, US and South Africa (Figure 1.11). China is expected to become a net importer in the coming years, while in 2009 India was already importing one seventh of its coal needs.

CCS technology could be the key factor in determining the viability of long-term growth in coal use, should ambitious net GHG emission reduction targets be set for developed countries. A key development would be to render CCS projects eligible to the Kyoto Protocol's Clean Development Mechanism (CDM).

The Reference Case therefore maintains the assumption of previous outlooks that neither of the driving forces of energy security concerns on the one hand, and environmental considerations (beyond already implemented policies) on the other, are

Figure 1.8
World supply of primary energy by fuel type

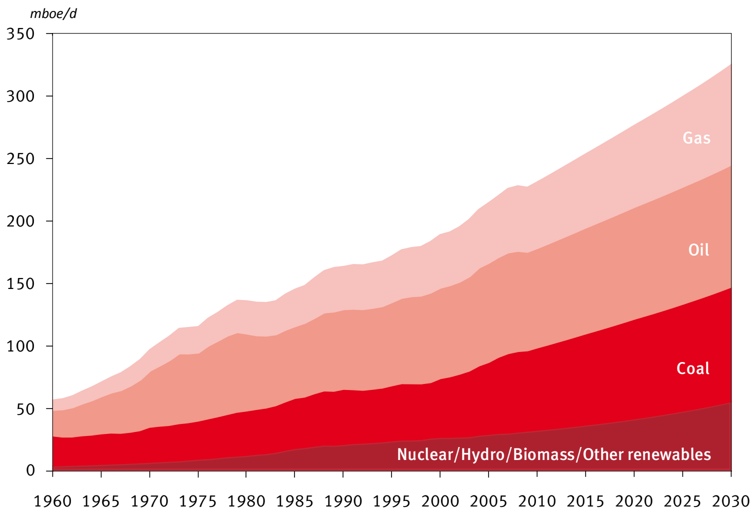
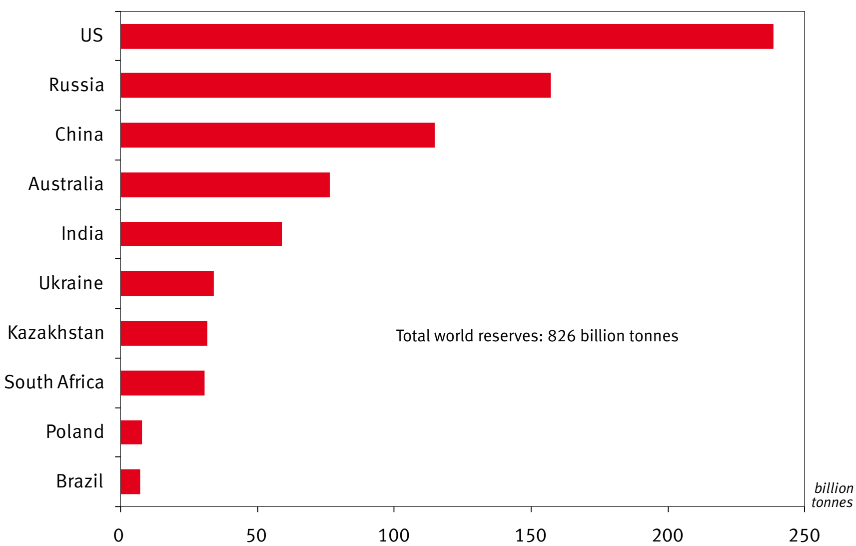


Figure 1.9
Coal reserves, end 2009 (Top 10 countries)



Source: *BP Statistical Review of World Energy, 2010.*

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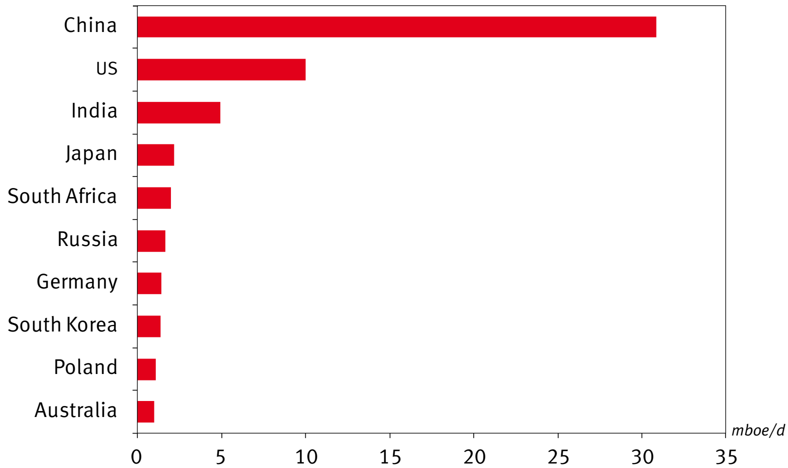
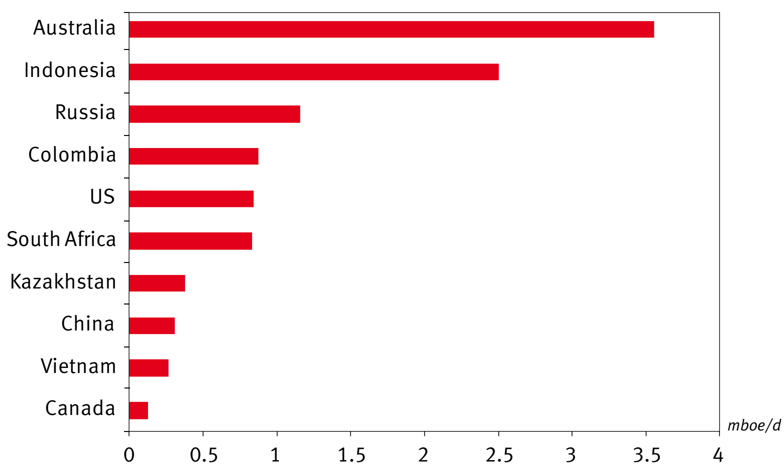
Figure 1.10
Coal demand, 2009 (Top 10 countries)



Source: BP Statistical Review of World Energy, 2010.

Figure 1.11
Coal net exports, 2009 (Top 10 countries)



Source: BP Statistical Review of World Energy, 2010.

Table 1.6
Coal and gas demand growth, 1990–2008 and 2008–2030 *% p.a.*

	Coal		Gas	
	1990–2008	2008–2030	1990–2008	2008–2030
North America	0.9	0.2	1.3	0.4
Western Europe	–1.5	–1.2	3.3	0.0
OECD Pacific	2.6	–0.8	4.2	0.5
OECD	**0.3**	**–0.4**	**2.2**	**0.3**
China	5.3	2.5	9.2	4.7
OPEC	1.0	3.3	6.0	4.4
Other developing countries	4.2	2.9	7.2	4.2
Developing countries	**4.9**	**2.7**	**6.8**	**4.4**
Russia	–3.1	0.0	0.1	1.3
Other transition economies	–2.7	0.0	–1.0	0.9
Transition economies	**–2.9**	**0.0**	**–0.3**	**1.2**
World	**2.1**	**1.6**	**2.4**	**2.0**

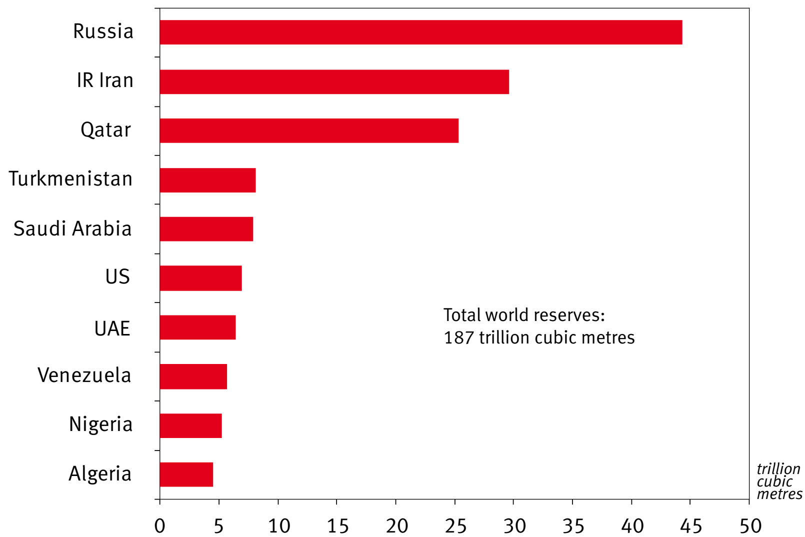
predominant. Since the Reference Case does not assume that such abatement targets are in force over the projection period to 2030, coal use is expected to continue to grow in developing countries, although at slower rates than the past. Reference Case projections for coal are shown in Table 1.6. Demand growth in developing countries rises by an average of 2.7% p.a. Key to this growth will clearly be China and India. For the OECD, there is a distinction in the prospects between regions. North American coal use grows slightly, but a steady decline is expected in both Western Europe and the OECD Pacific.

Gas

More than half of the world's gas reserves are in three countries: Russia, Iran and Qatar (Figure 1.12). However, Turkmenistan has witnessed the largest growth in reserves over the past decade. Almost three-quarters of gas trade is through pipelines, but LNG is growing in significance, although the emergence of shale gas may temper growth somewhat in the coming years. The top two consumers are by far the US and Russia (Figure 1.13).

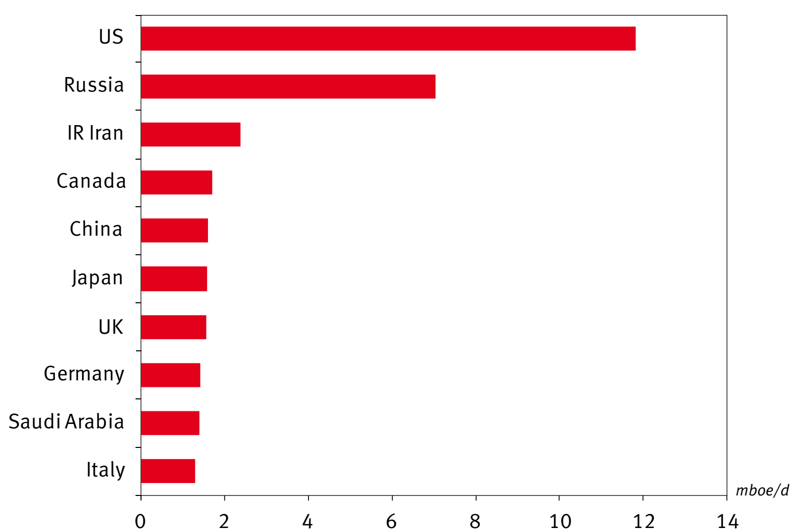
In the future, it is expected that most natural gas consumption will continue to be in the same country where the gas is produced. The major change away from historical trends will concern the rise of unconventional gas, particularly in North

Figure 1.12
Natural gas reserves, end 2009 (Top 10 countries)



Source: *BP Statistical Review of World Energy, 2010.*

Figure 1.13
Natural gas demand, 2009 (Top 10 countries)

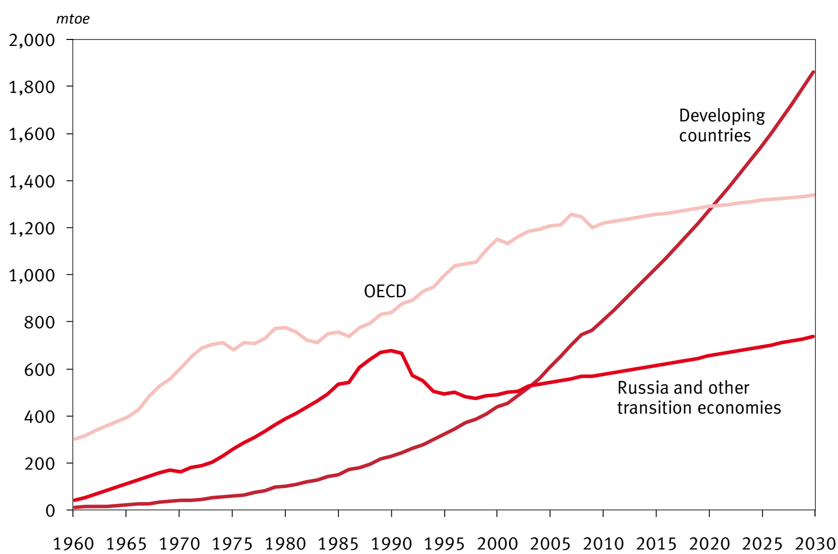


Source: *BP Statistical Review of World Energy, 2010.*

America. Over the past year or so there has been much movement in the development of shale gas (Box 1.4), with companies looking to acquire assets and develop this huge resource. In the US, it is believed that most new reserves growth will come from unconventional shale gas reservoirs. This is viewed as a potential game changer, with many voices in the US believing it to be opportunity to become self-sufficient in gas. Significant shale gas opportunities are also being explored in Europe, and in Asia, where China is making some headway in developing its shale gas reserves. The upshot is that this may have a significant impact upon international gas markets, the future economics of LNG transportation, as well as the electricity generation sectors of these countries.

The projections for the growth in natural gas use in the Reference Case appear in Table 1.6, while the level of gas demand for the OECD, developing countries and transition economies from 1960–2030 is shown in Figure 1.14. The Reference Case sees stronger gas demand growth in North America than in the previous outlook to reflect the accelerating emergence of unconventional gas as a supply source. Gas demand in Western Europe and the OECD Pacific is not expected to rise as swiftly as witnessed in the past. Total OECD gas demand increases by 6% over the projection period.

Figure 1.14
Gas demand, 1960–2030



Box 1.4
Shale gas: a game changer?

Talk of shale gas[16] transforming the US energy market has been gathering momentum in recent years. The potential figures being discussed are huge and given the recent plethora of announcements, as well as the increasing number of conferences and literature on the topic, there is growing excitement. This feeling is also spreading elsewhere, with a number of other countries looking to assess their shale gas resources. It leads to the question on many people's lips: is shale gas a game changer?

In the US gas market, the change has been quite significant. For example, according to the Energy Information Administration, unconventional gas production accounted for around 40% of total US gas production in 2008, with shale gas by far the fastest growing component. Despite higher production and lower prices, proved reserves of dry natural gas in 2008 grew by a hefty 30%, reaching 347 trillion cubic feet (Tcf), thus increasing for the tenth consecutive year. In 2000, reserves were only half of this figure, at 177 Tcf.

It is true, however, that estimating technically recoverable resources remains difficult, given the large heterogeneities in shale deposits, and the characteristics of, and differences in, basins. Moreover, there are also the issues of recovery rates and costs to consider.

The surge in the development of shale gas has occurred in response to a confluence of factors, particularly the recognition at the beginning of the last decade that the US was entering a period of tight gas supplies and a rapid increase in natural gas prices as a result of supply and demand pressures. It led to many avenues being explored to alleviate the issue, with a number of companies looking at how to liberate the supplies of shale gas that had been known about for decades, but had to then, proven difficult to exploit.

The breakthrough was the melding of two technologies – horizontal drilling and hydraulic fracturing – that finally cracked the shale rock to free greater volumes, and importantly, at a much lower unit cost than previously thought possible. This led to the development of major gas shale resources, such as those at Barnett, Fayetteville, Woodford and Marcellus.

In the US, unconventional gas is already changing the country's overall energy outlook. There is now talk of gas abundance; a major shift from the expectations envisaged just ten years ago when an increased reliance on imported liquefied natural gas (LNG) was generally projected. This has had a dramatic impact on US gas prices, with even a spill over to spot prices in EU markets. The Henry Hub natural gas spot price declined from more than $13/mBtu (million British thermal units) in 2006 to less than $4/mBtu at the end of September 2010.

Interest in unconventional gas in Europe is also beginning to gather pace. Companies have been racing to secure shale and coalbed gas acreage in countries such as Poland, Sweden, Germany, Hungary, Austria, France and the UK. To date, however, the fields are believed to be smaller than those in the US and only a few exploratory pilot projects currently exist, such as the Mako Trough in Hungary, Oldenburg in Germany and Lebien LE1 and Legowo LE1 in Northern Poland. At present, it is still too early to provide estimates of Europe's technically recoverable unconventional gas resources, although some consultants' figures have suggested there is considerable potential.

In China, Sinopec has recently initiated a programme to evaluate shale gas deposits in the southern part of the country, although there are similar considerable uncertainties surrounding the size of the potential resource in this country.

With all the hype surrounding shale gas, there has also been some discussion as to the potential impact on oil markets. There is no doubt that a lower natural gas price per unit of energy could be seen as an incentive to use more gas. For example, in the US, the April 2010 nationwide average price of compressed natural gas (CNG) was $2.12 in diesel gallon equivalent, or 90 cents lower than a gallon of diesel.[17]

There are, however, many hurdles still facing natural gas. In the power sector, the scope for displacing oil is rather limited today. As discussed in Chapter 2, oil's share in electricity generation has been falling in all regions, and this trend is expected to continue in the future. In the transportation sector, natural gas could be used either directly in internal combustion engines as compressed natural gas – or even as liquefied natural gas for heavy trucks – and indirectly in electricity-powered cars. According to the International Association for Natural Gas Vehicles, the global number of natural gas vehicles reached 10 million units in 2008, mostly in Asia and Latin America. However, this represents less than 1% of total commercial road vehicles. In the US, there are only 110,000 natural gas vehicles out of 247 million road vehicles.

Three main hurdles prevent a more widespread use of natural gas in transportation: higher vehicle costs, lower energy density and a lack of refueling stations. Government support and subsidies are unavoidable even if the CNG price premium is maintained over a long period of time. Even with such support, growth would likely be limited to the niche segment of the low driving-range and centrally-refuelled fleet vehicles. It is estimated that even if there is accelerated development of this fuel type, the level of oil replaced would not exceed 0.7 mb/d by 2030.

Similarly, the development of electric vehicles faces many obstacles, which are explained in Box 2.1 on transportation technologies. Again, even with accelerated development, their growth may lead to a replaced oil volume of less than 0.5 mb/d by 2030. However, plug-in hybrids may have further appeal should the natural gas price premium be maintained over the long-term and have a substantial impact on lowering electricity prices.

Despite all the positives lauded on shale gas, however, it is important to remember that challenges still exist.

Questions have been raised about the potential environmental dangers posed to drinking water from chemicals used in the fraccing process and these fears may be heightened by the recent oil spill from the Deepwater Horizon rig off the coast of Louisiana. With the push for shale gas being partly initiated by higher natural gas prices, what might the impact of lower prices be? Will shale gas exploitation remain economical? Infrastructure concerns, such as the need for new networks of pipelines, as well as regulatory issues, have also been raised.

Whether shale gas is a 'game changer' remains unclear. However, its potential is undisputed and its impact on the natural gas markets is already being felt worldwide.

Gas demand in developing countries grows rapidly in the Reference Case, at an average rate of over 4% p.a. By 2022, developing countries will be consuming more gas than OECD countries. Within the transition economies group, Russia is the dominant gas user. The pattern of gas demand growth has changed markedly following the collapse of the Former Soviet Union (FSU), and future gas demand increases are expected to reflect the considerable scope that remains for efficiency gains. The Reference Case sees growth averaging 1.3% p.a. in Russia.

Non-fossil fuels

Nuclear energy is assumed to grow slightly faster than in the previous reference case. At present, according to the World Nuclear Association,[18] over 50 reactors are under construction in 13 countries, with most reactors on order or planned in the Asian region, although plans exist for new units in Europe, the US and Russia.

In Asia, South Korea has plans to bring a further eight reactors into operation by around the middle of this decade, Japan has one reactor under construction and others being considered, and China also has a significant nuclear power plant building programme.

In the US, earlier this year, President Barack Obama announced more than $8 billion in federal loan guarantees to begin building the first US nuclear power stations for 30 years. It is expected that the two new plants are to be constructed in the state of Georgia by US electricity firm Southern Company.

Europe too is seeing an increase in activity. The Finnish Government has recently approved building permits for the construction of its sixth and seventh reactors. Although delays and cost overruns to the currently under construction Olkiluoto-3 reactor have raised concerns that a nuclear comeback may be somewhat less than some have anticipated. In France, the building of a new plant at Flamanville is ongoing, in Sweden earlier this year, the construction of a new nuclear plant was narrowly approved by Swedish MPs, Italy is proposing new nuclear build, in Germany the government, in its new energy programme, has decided to extend the life spans of the country's 17 nuclear plants, and in the UK there is still much talk, though no concrete decisions, about the need for new nuclear plants.

Despite these developments, however, a number of other reasons remain a cause for concern for the nuclear industry. Firstly, there is the human resource challenge, which is particularly acute for the industry, as since the late 1980s, when nuclear was viewed as being part of the past, there has been little appeal for young engineers and operators to study and take up jobs in the industry. And secondly there are a number of safety concerns, heightened by nuclear incidents in the 1980s and 1990s, as well as the fundamental issues of waste and decommissioning.

In terms of power generation, hydropower currently supplies around 16% of the world's needs. In the future it is expected that hydropower will continue to witness growth, albeit mainly in developing countries. The sustainable potential in developed countries has largely been exploited.

In recent times, significant growth in developing countries has been witnessed in Asia, particularly in China, as well as in Latin America, with countries such as Brazil. It is clear that considerable resources remain untapped in many developing countries, although environmental concerns and the impact of population resettlement could constrain the full exploitation of the available resources.

While large hydropower plants remain on the agenda in many countries, small hydropower installations are anticipated to play a greater role in the year ahead, particularly as they are easier to construct and lower capital investment is needed. In some instances, small hydropower in rural areas is being used to replace diesel generators or other small-scale power plants.

In the OECD region, where biomass pellets are becoming a common fuel, solid, liquid and gaseous biomass is burnt for a variety of applications. This includes district, domestic and commercial heating; the production of industrial process heat; electricity generation; and combined heat and power (CHP) applications. In Brazil, as well in other developing countries with a significant sugar industry, bagasse is commonly used for power and heat production. And the use of biomass for the production of transportation fuels is common in many countries.

With the exception of biofuels, electricity generation is the fastest growing application for modern biomass. Globally, 54 GW of biomass power capacity was in place by the end of 2009, with the US and Europe contributing 8.5 GW and 7 GW, respectively.[19] China's capacity rose in 2009 to just over 3 GW. In the Reference Case, global biomass use for power generation between 2008 and 2030 will expand at an average annual rate of 6.1%. Modern biomass use in applications other than transportation fuels between 2008 and 2030 will grow at a much faster pace in both OECD countries and transition economies, each at 2.9% p.a., than in developing countries, which sees growth of 0.7% p.a. This leads to a global average growth rate of 2.8% p.a.

The global financial crisis, and the ensuing credit crunch, the lower demand for energy and the moderation of energy prices, had threatened renewable energy projects, in particular wind and photovoltaics (PV) which had been growing at very fast rates, albeit from a low base. In many countries, however, the economic rescue packages included appropriations designed to stimulate renewable investment. For example, through the American Recovery and Reinvestment Act of 2009, the US Treasury gave away more than $1.5 billion to wind energy projects alone.

Solar, wind, small hydro, ocean and tidal energy are used for a number of applications including water and domestic heating, industrial process heat, but in general, their main contribution is to power generation. Their use varies across the world, and it is interesting note which countries lead the way in terms of energies and technologies. For example, China is the largest market for solar water heaters, while the US and Europe are the world leaders in wind energy and solar PV use for power generation.

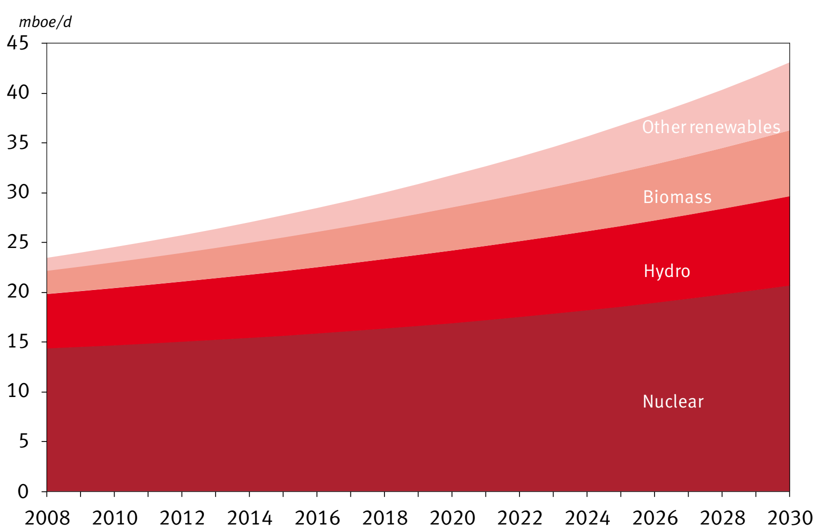
In recent years, after a relatively lengthy growth hiatus since the mid 1980s, concentrated solar thermal power has experienced a strong revival. In early 2010, over 2.4 gigawatts (GW) of capacity was either under construction or being contracted, the majority of this is in Spain. Future growth, however, is expected to be global with an additional 8 GW of capacity slated for the US by 2014, and China and the Middle East/North Africa region are anticipated to quickly become important players in this market. This is a huge growth from a mere world total of 350 megawatts (MW) in 2005.

Non-fossil fuels in power generation

Driven by continuing policy support, the potential for cost reductions, as well as climate change concerns, non-fossil fuels use in global power generation will grow in the Reference Case, at an average annual rate of 2.8% p.a. between 2008 and 2030, to reach a total of 43.2 mboe/d.

Despite the current push to develop it in a number of countries across the world, nuclear power is assumed to witness the slowest growth among non-fossil fuels for power generation at 1.6% p.a., but it will grow faster in developing countries, at 5.6% p.a. Between 2008 and 2030, global demand for hydropower in the Reference Case will expand at an annual average rate of 2.3% p.a. Developing countries will witness

Figure 1.15
Non-fossil fuels for power generation, 2008–2030



the greatest growth of 3.3% p.a., followed by the OECD with 1.2%, and transition economies with 0.8%. During the same period, the fastest growing component is other renewables, at 7.8% p.a., while biomass for power generation will increase at 4.8% p.a. Despite the relatively fast growth rates for these two components, however, the fact that they are starting from a low base makes their combined contribution to non-fossil fuel electricity production not much more than 30% by 2030.

Oil demand

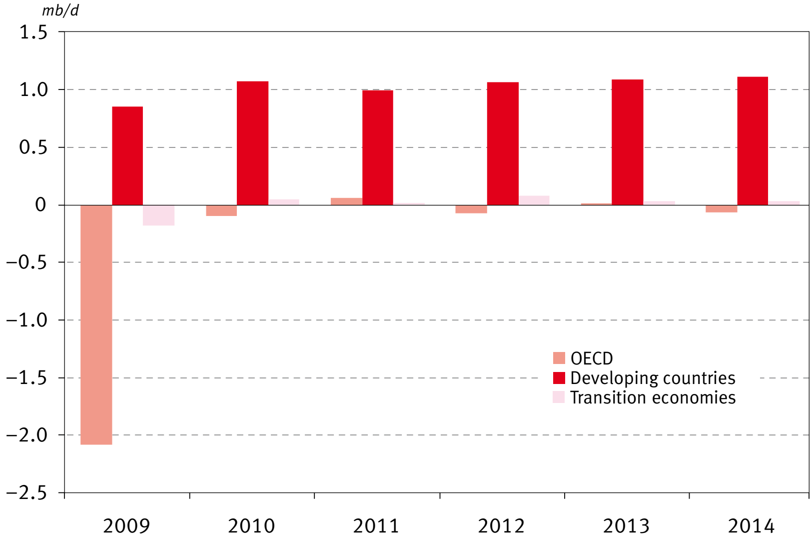
Oil demand in the medium-term

The previous WOO had already factored in the possible impact of oil price turbulence into the medium-term oil demand prospects, with the price rise to record highs in 2008 leading to some short-term demand destruction, but with such impacts being short-lived when the price subsequently fell. As already described, little has changed to medium-term oil price assumptions. The oil price is not a driver of change, in comparison to last year's report. Indeed, last year, the fundamental adjustment to demand expectations that had been necessary over the medium-term was due to lower

Table 1.7
Medium-term oil demand outlook in the Reference Case *mb/d*

	2009	2010	2011	2012	2013	2014
North America	23.3	23.6	23.8	23.8	23.9	23.8
Western Europe	14.5	14.1	14.0	14.0	13.9	13.9
OECD Pacific	7.7	7.7	7.6	7.6	7.6	7.6
OECD	**45.5**	**45.4**	**45.5**	**45.4**	**45.4**	**45.3**
Latin America	4.9	5.0	5.0	5.1	5.2	5.3
Middle East & Africa	3.4	3.5	3.5	3.6	3.7	3.8
South Asia	3.9	4.0	4.1	4.3	4.5	4.7
Southeast Asia	6.0	6.1	6.1	6.3	6.4	6.5
China	8.3	8.7	9.1	9.6	10.0	10.5
OPEC	7.9	8.2	8.4	8.6	8.7	8.9
Developing countries	**34.3**	**35.4**	**36.4**	**37.4**	**38.5**	**39.6**
Russia	3.0	3.0	3.0	3.1	3.1	3.1
Other transition economies	1.7	1.7	1.7	1.7	1.8	1.8
Transition economies	**4.7**	**4.7**	**4.8**	**4.8**	**4.9**	**4.9**
World	**84.5**	**85.5**	**86.6**	**87.6**	**88.8**	**89.9**

Figure 1.16
Annual growth of oil demand in the medium-term

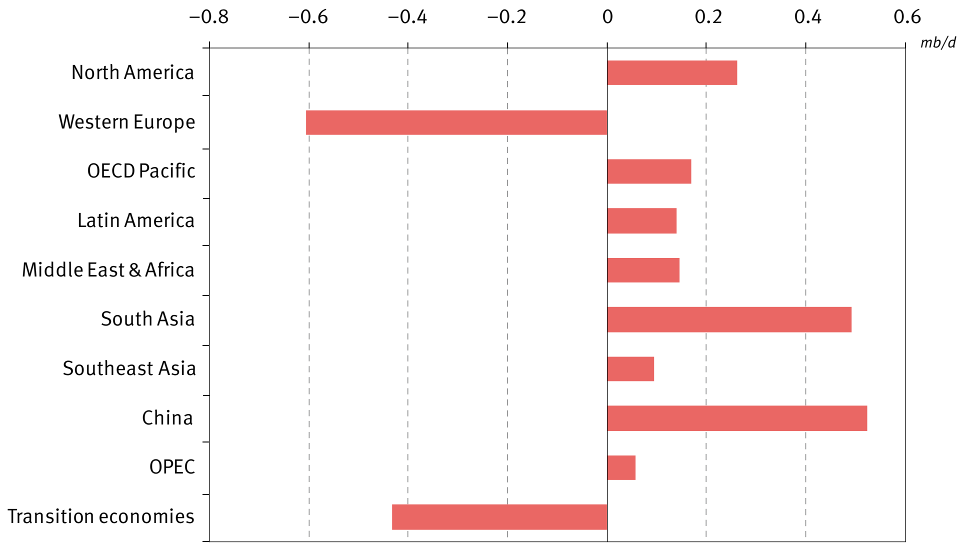


economic growth assumptions as the global financial crisis gathered pace. The assumptions for real GDP growth in this year's WOO also capture the negative impacts of the crisis, although, as we have seen, the 2010 Reference Case is more optimistic regarding the speed of economic recovery. This slight reassessment implies positive impacts on short-term demand.

As the results in Table 1.7 show, the Reference Case now foresees demand growth of 1 mb/d in 2010, more than double that expected in the previous reference case with the slower recovery. Figure 1.16 highlights the annual growth of demand over this medium-term period.

By 2014, world demand has increased to 89.9 mb/d, an increase of 5.4 mb/d over the five years from 2009. Because of the effects of the recession, 2007 demand levels are not reached again until 2011. OECD oil demand falls slightly over this period, with demand having peaked in 2005, while a small rise in demand is expected in the Reference Case in transition economies. Essentially this means that all of the oil demand increase over the medium-term is from developing countries. And over two-thirds of this growth will come from developing Asia, with China seeing the largest expansion. Nonetheless, over this medium-term period, total OECD oil demand continues to account for over half of the world's oil demand.

Figure 1.17
Changes to oil demand Reference Case projections in 2014 compared to WOO 2009



While the demand figures in Table 1.7 reflect an upward revision for most world regions for 2014, because of the stronger recovery that is now assumed, expectations for transition economies have fallen because of the unexpectedly sharp downward impact upon demand in 2009 (Figure 1.17). On aggregate, the global figure of 89.9 mb/d in 2014 is 0.8 mb/d higher than in the previous reference case.

Oil demand in the long-term

Long-term demand projections for all energy types, including oil, are subject to ever-growing uncertainties. Alternative economic growth paths may emerge, reflecting, for example, the possible rise of protectionism, the varying success in coping with global imbalances, or the possible long-term structural impacts relating to responses to the global financial crisis. Nevertheless, the greatest uncertainty over the health of economies and the corresponding potential impacts upon oil demand is arguably primarily in the short- to medium-term. Over the long-term there are considerable – and natural – divergent views over two other major drivers: policies and technology. While scenarios later in this report will look at the various possible impacts of different assumptions for these, the Reference Case involves only slight modifications to the assumptions for these drivers, when compared to the WOO 2009.

Slight additional efficiency improvements have, however, combined with stronger economic growth assumptions for some developing country regions and led to an essentially unchanged level for oil demand in the Reference Case. This reaches 105.5 mb/d by 2030, an increase of 21 mb/d from 2009 (Table 1.8). The figure represents an average annual oil demand increase over 2009–2030 of 0.9% p.a., or, in volume terms, an average increase of 1 mb/d p.a. This is far lower than the rate of growth forecast just a few years ago.

The relative demand growth patterns seen in the medium-term are also reflected in long-term projections: OECD demand continues to fall throughout the period to 2030; a slow increase is expected in oil demand in transition economies; and, consequently, the net increase in Reference Case global demand in the long-term is essentially driven by the pace of developing country demand growth. Over 2009–2030, consumption in these countries increases by over 22 mb/d, reaching almost 57 mb/d by the end of the projection period (Figure 1.18). Of the net growth in global oil

Table 1.8
World oil demand outlook in the Reference Case

mb/d

	2009	2010	2015	2020	2025	2030
North America	23.3	23.6	23.8	23.6	23.2	22.8
Western Europe	14.5	14.1	13.9	13.7	13.5	13.2
OECD Pacific	7.7	7.7	7.6	7.4	7.2	7.0
OECD	**45.5**	**45.4**	**45.3**	**44.7**	**44.0**	**43.1**
Latin America	4.9	5.0	5.3	5.7	6.0	6.3
Middle East & Africa	3.4	3.5	3.9	4.3	4.7	5.2
South Asia	3.9	4.0	4.9	5.9	7.0	8.3
Southeast Asia	6.0	6.1	6.7	7.4	8.2	9.0
China	8.3	8.7	10.9	13.1	15.0	16.7
OPEC	7.9	8.2	9.0	9.8	10.6	11.4
Developing countries	**34.3**	**35.4**	**40.8**	**46.3**	**51.5**	**56.8**
Russia	3.0	3.0	3.1	3.3	3.3	3.4
Other transition economies	1.7	1.7	1.8	1.9	2.0	2.1
Transition economies	**4.7**	**4.7**	**5.0**	**5.2**	**5.4**	**5.6**
World	**84.5**	**85.5**	**91.0**	**96.2**	**100.9**	**105.5**

Figure 1.18
Growth in oil demand, 2009–2030

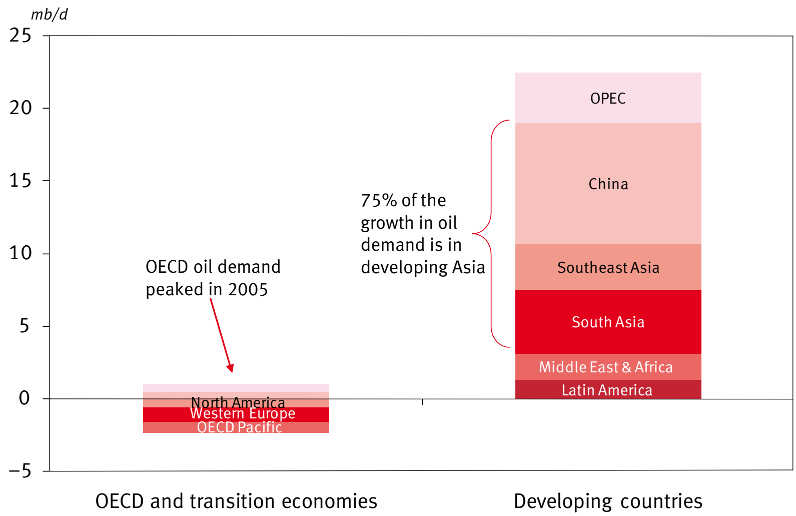


Figure 1.19
OECD and non-OECD oil demand

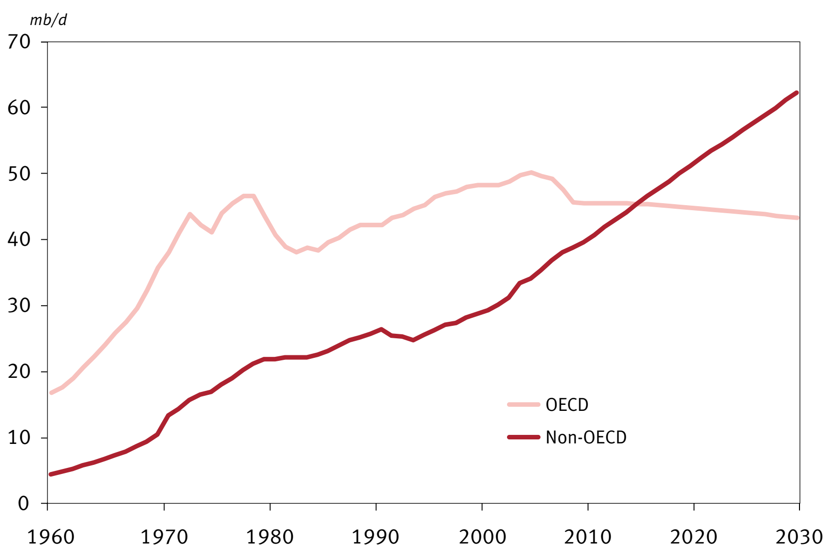


Figure 1.20
Oil use per capita in 2030

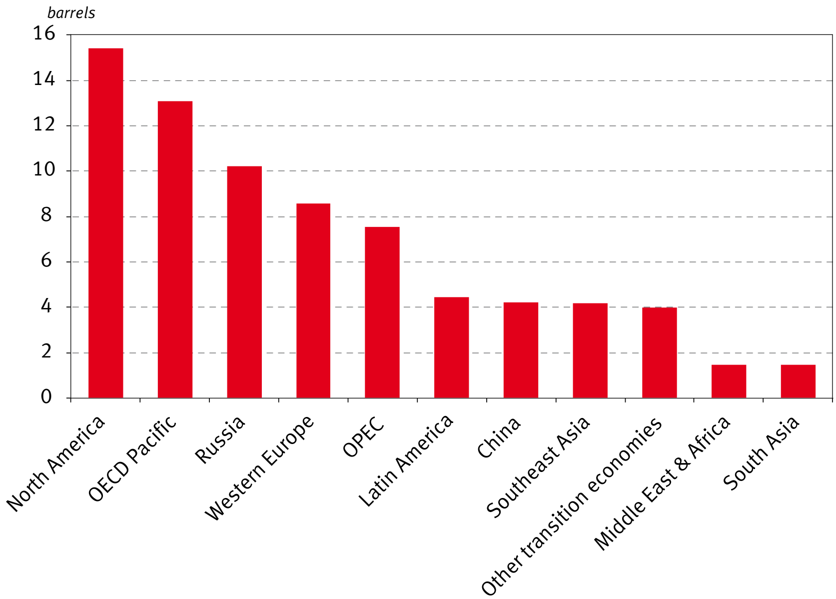


Figure 1.21
Annual global growth in oil demand by sector

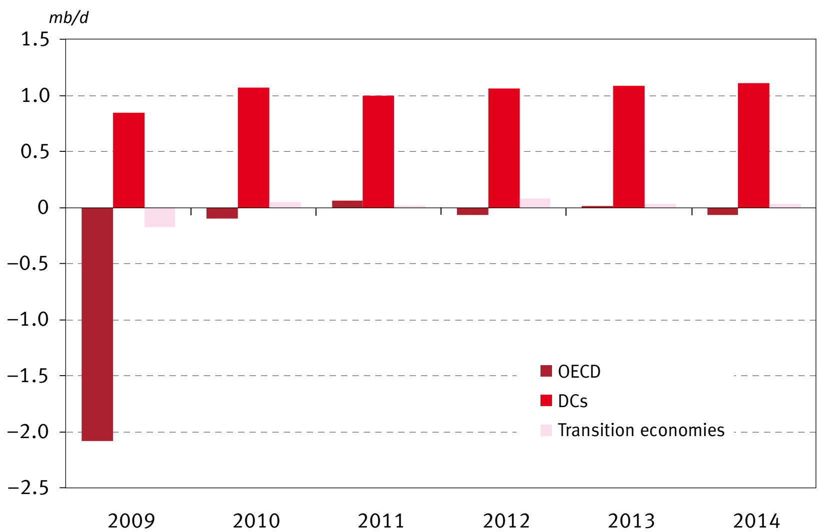


Figure 1.22
Annual growth in oil demand by sector in OECD countries

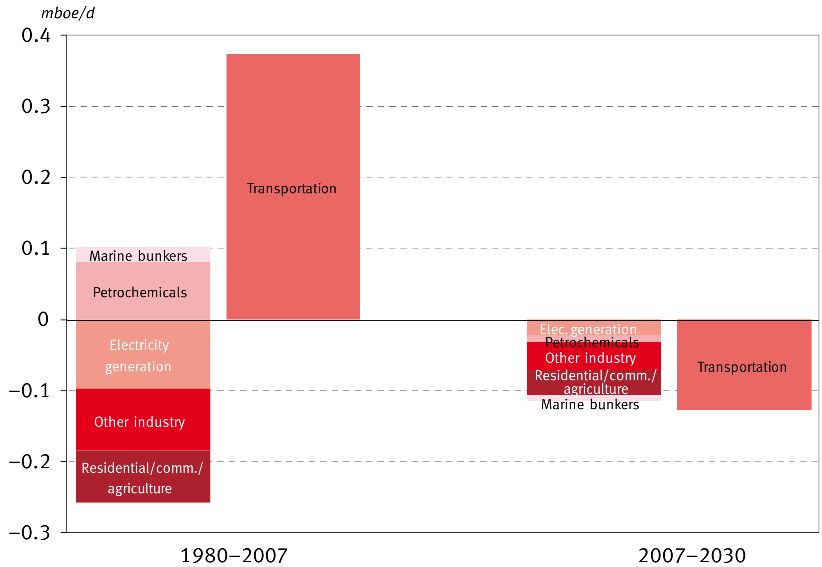


Figure 1.23
Annual growth in oil demand by sector in developing countries

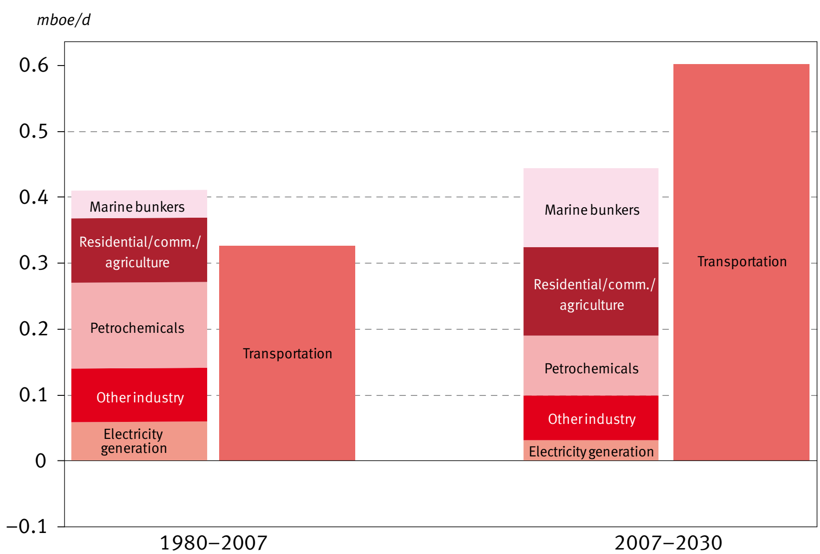
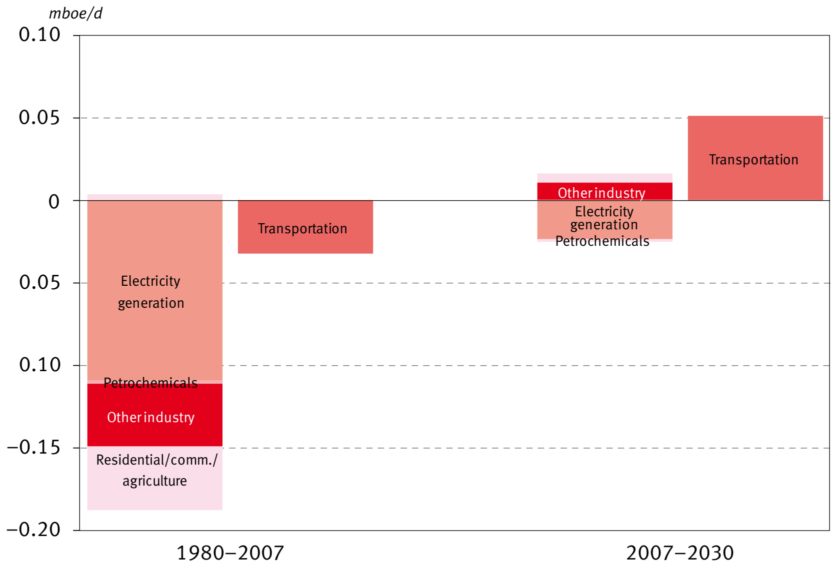


Figure 1.24
Annual growth in oil demand by sector in transition economies



demand from 2009–2030, 75% is in developing Asia. These developments suggest that non-OECD oil demand will overtake OECD oil demand in 2016 (Figure 1.19).

However, per capita oil use in developing countries will still be well below OECD levels throughout the projection period. Oil use per person by 2030 in developing countries will be just one-quarter of the rate of use in OECD countries. On an individual regional basis, the differences are even starker: in 2030, North American per capita oil use will be eleven times that of South Asia (Figure 1.20).

The detailed sectoral outlook for oil demand is described in Chapter 2, and the Reference Case projection is summarized in Figures 1.21–1.24. Globally, the only sources of net demand increase over the past three decades have been transportation (road, aviation and marine) and the petrochemicals sector. And moving forward, it is clear that transportation will remain the main source of oil demand growth. Interestingly, however, over the projection period a decline in oil use in the OECD is expected in all sectors. In developing countries, while the increase in oil use in transportation is the largest source of demand growth, other sectors should also see robust growth. Transition economies will see a modest increase in oil demand in transportation.

Oil supply

Oil supply in the medium-term

A bottom-up approach is used to estimate medium-term prospects for upstream supply, while longer term sustainability and consistency is ensured by evaluating impacts upon resource availability. Medium-term oil supply projections are based upon an assessment of net average additions by country, with estimated incremental volumes from new fields adjusted for declines. A bottom-up approach is also undertaken for biofuels and other non-conventional oil supplies. A more detailed description of these projections is presented in Chapter 3.

Table 1.9
Medium-term oil supply outlook in the Reference Case *mb/d*

	2009	2010	2011	2012	2013	2014
US & Canada	11.3	11.6	11.7	11.7	11.8	11.8
Mexico	3.0	2.9	2.8	2.8	2.7	2.7
Western Europe	4.7	4.4	4.3	4.2	4.2	4.1
OECD Pacific	0.6	0.6	0.6	0.6	0.7	0.7
OECD	**19.6**	**19.6**	**19.4**	**19.4**	**19.3**	**19.2**
Latin America	4.4	4.7	5.0	5.0	5.2	5.4
Middle East & Africa	4.4	4.5	4.5	4.5	4.4	4.4
Asia	3.7	3.7	3.7	3.8	3.8	3.9
China	3.9	4.0	4.0	4.1	4.1	4.1
DCs, excl. OPEC	**16.4**	**16.9**	**17.2**	**17.4**	**17.6**	**17.7**
Russia	9.9	10.1	10.1	10.1	10.2	10.3
Other transition economies	3.2	3.3	3.4	3.6	3.7	3.9
Transition economies	**13.1**	**13.3**	**13.5**	**13.7**	**13.8**	**14.2**
Processing gains	2.0	2.1	2.1	2.1	2.2	2.2
Non-OPEC	**51.1**	**51.9**	**52.2**	**52.6**	**52.9**	**53.3**
of which: non-conventional	3.4	3.7	4.0	4.3	4.6	4.8
NGLs	5.7	5.8	6.0	6.1	6.2	6.4
OPEC NGLs	**4.2**	**4.7**	**5.2**	**5.5**	**5.7**	**5.9**
OPEC GTLs*	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**
OPEC crude	**28.7**	**29.3**	**29.2**	**29.6**	**30.2**	**30.6**
World supply	**84.2**	**86.0**	**86.8**	**87.8**	**89.0**	**90.1**

* *Includes MTBE. Future growth is expected to be dominated by GTLs.*

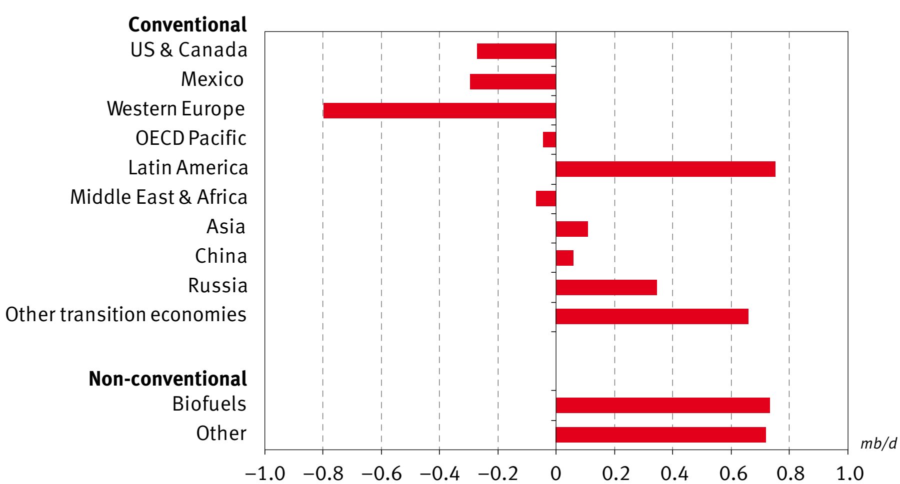
The initial focus is upon the prospects for non-OPEC supply, before looking at the implications for the amount of oil OPEC will be expected to supply in the Reference Case, given the demand outlook described.

Looking firstly at conventional supply, non-OPEC crude oil plus natural gas liquids (NGLs) production is expected to remain approximately flat in the medium-term, at just over 46 mb/d. This figure is higher by close to 1 mb/d compared to the aggregate non-OPEC conventional supply outlook in the WOO 2009.

The medium-term outlook for biofuels and non-conventional oil is slightly higher than in the previous assessment. Main sources of growth are Canada's oil sands, increasing to 2 mb/d by 2014, and increases in biofuels in the US and Brazil.

The medium-term developments for all non-OPEC liquids, namely crude, NGLs, biofuels and other non-conventional oil, are shown in Table 1.9, while the growth over the period 2009–2014 is summarized in Figure 1.25. Table 1.9 also includes the call on OPEC oil, derived from the Reference Case demand and non-OPEC supply outlook. Total non-OPEC supply continues to grow over the medium-term, increasing by 2.2 mb/d over the period 2009–2014. Over these years there will also be a rise of 1.6 mb/d in the amount of NGLs supplied by OPEC. As a result, the amount of crude that will be required from OPEC rises slowly, from 28.7 mb/d in

Figure 1.25
Growth in non-OPEC supply, 2009–2014



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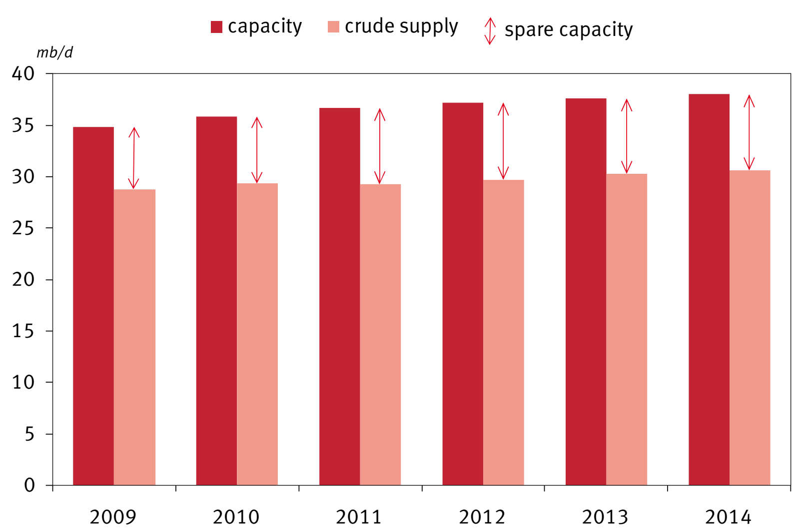
2009 to 30.6 mb/d by 2014. The medium-term call on OPEC crude throughout the period is slightly lower than in the previous assessment.

In line with expectations that OPEC Member Countries will, under Reference Case conditions, be relied upon increasingly to supply additional oil to satisfy growing demand, as well as the Organization's aim to "offer an adequate level of spare capacity", investments are being undertaken to expand upstream capacity. The expected call on OPEC crude in the Reference Case is combined with production capacity estimates in Figure 1.26. The fall in oil demand in 2009, together with both rising non-OPEC supply and an increase in OPEC's total capacity meant that spare crude capacity more than doubled in that year. Throughout the medium-term, the Reference Case foresees a stable OPEC crude oil spare capacity of around 6–7 mb/d. This represents around 7–8% of total world demand over this period, and reflects the Reference Case assumption that sufficient investment is being made to provide ample spare capacity. It also, however, reflects the assumption that over-investment is avoided. Downside demand risks for OPEC oil are substantial, suggesting that rising levels of unused capacity are a real concern.

Oil supply in the long-term

While medium-term Reference Case supply paths are derived from a database of fields and investment projects, long-term supply paths for conventional oil are necessarily

Figure 1.26
OPEC crude oil capacity and supply in the medium-term



linked to what is realistically feasible, given the resource base. To this end, the mean estimates from the US Geological Survey (USGS) of ultimately recoverable reserves (URR) of crude oil plus NGLs are used. The approach is described in more detail in Chapter 3.

Supply projections to 2030 are presented in Table 1.10. Non-OPEC liquids supply, including crude, NGLs, and non-conventional oil, continues to grow throughout the entire period, as increases in non-crude sources are stronger than the slight crude supply declines (Figure 1.27). Non-OPEC non-conventional oil supply increases by

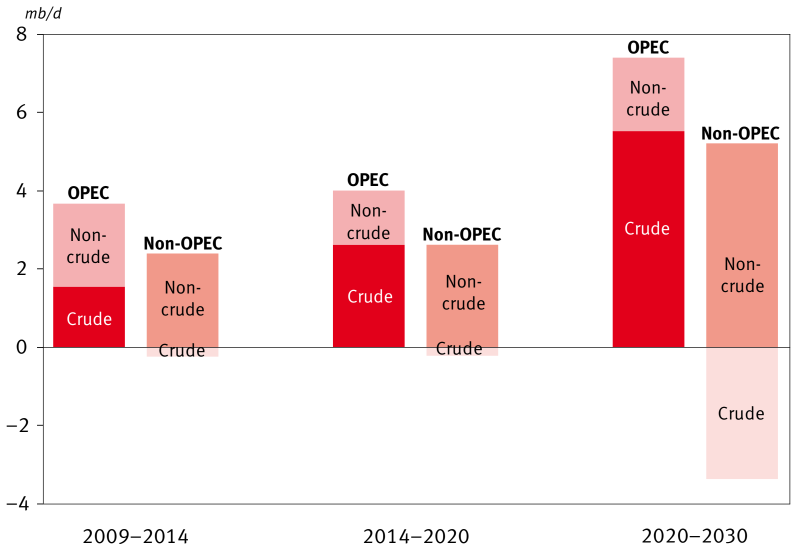
Table 1.10
World oil supply outlook in the Reference Case

mb/d

	2009	2010	2015	2020	2025	2030
US & Canada	11.3	11.6	11.9	12.3	13.0	13.9
Mexico	3.0	2.9	2.6	2.4	2.2	2.0
Western Europe	4.7	4.4	4.0	3.8	3.7	3.6
OECD Pacific	0.6	0.6	0.7	0.7	0.7	0.7
OECD	**19.6**	**19.6**	**19.2**	**19.2**	**19.5**	**20.2**
Latin America	4.4	4.7	5.6	6.5	6.9	6.9
Middle East & Africa	4.4	4.5	4.4	4.3	4.1	3.9
Asia	3.7	3.7	3.9	4.1	3.9	3.7
China	3.9	4.0	4.1	4.1	4.1	4.3
DCs, excl. OPEC	**16.4**	**16.9**	**18.0**	**19.0**	**19.1**	**18.7**
Russia	9.9	10.1	10.4	10.7	10.7	10.7
Other transition economies	3.2	3.3	3.9	4.3	4.6	5.0
Transition economies	**13.1**	**13.3**	**14.4**	**15.0**	**15.3**	**15.7**
Processing gains	2.0	2.1	2.3	2.5	2.7	2.9
Non–OPEC	**51.1**	**51.9**	**53.9**	**55.7**	**56.6**	**57.5**
of which: non-conventional	3.4	3.7	5.2	6.8	8.9	11.3
NGLs	5.7	5.8	6.4	6.7	6.9	7.1
OPEC NGLs	**4.2**	**4.7**	**6.2**	**7.2**	**8.0**	**8.9**
OPEC GTLs*	**0.1**	**0.1**	**0.3**	**0.4**	**0.5**	**0.6**
OPEC crude	**28.7**	**29.3**	**30.8**	**33.2**	**36.0**	**38.7**
World supply	**84.2**	**86.0**	**91.2**	**96.4**	**101.1**	**105.7**

* *Includes MTBE. Future growth is expected to be dominated by GTLs.*

Figure 1.27
Incremental OPEC and non-OPEC supply in the Reference Case



7.9 mb/d over the years 2009–2030, primarily through increases in Canadian oil sands and biofuels in the US, Europe and Brazil. An increasingly important element of liquids supply is NGLs: the combined supply from OPEC and non-OPEC in the Reference Case increases from just under 10 mb/d in 2009 to almost 16 mb/d by 2030.

Together with Reference Case demand growth, the expectations for non-OPEC supply and the increase in non-crude OPEC supply mean that the amount of OPEC crude needed will rise throughout the projection period, reaching 38.7 mb/d by 2030. The calculation also allows for a small amount of additional supply necessary for stocks. This level of supply is 2.4 mb/d lower than in the WOO 2009 reference case. The share of OPEC crude in total supply by 2030 is 37% (Figure 1.28).

The growing role that non-crude forms of liquid supply will play in satisfying demand is an important feature of the WOO. It signifies that crude supply only needs to increase modestly, indeed, it reaches just 75 mb/d by 2030. Figure 1.29 clearly shows the relative importance of non-crude in supplying future oil needs. It is worth stressing that this slow growth in crude supply is not the result of a resource constraint: it is simply the result of the displacement by other sources.

Figure 1.28
OPEC crude and other sources of liquids supply in the Reference Case

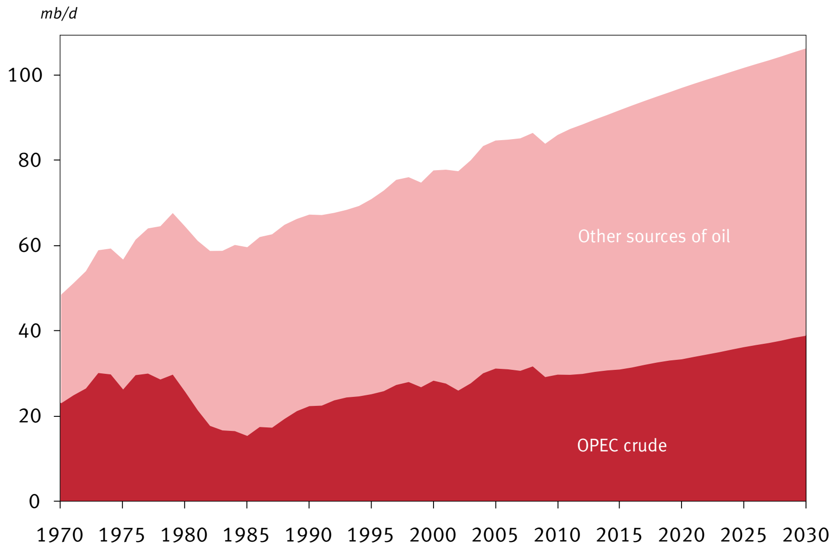


Figure 1.29
Incremental crude and non-crude oil supply in the Reference Case

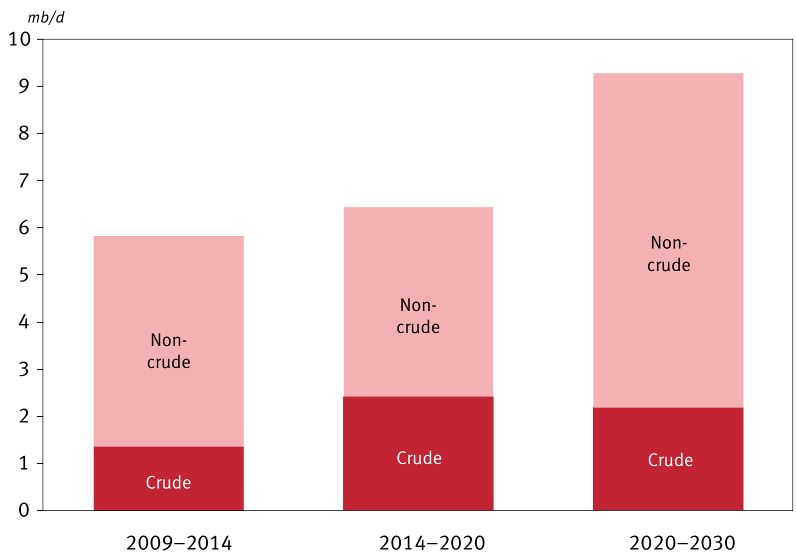


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Figure 1.30
Non-OPEC oil supply, OECD regions

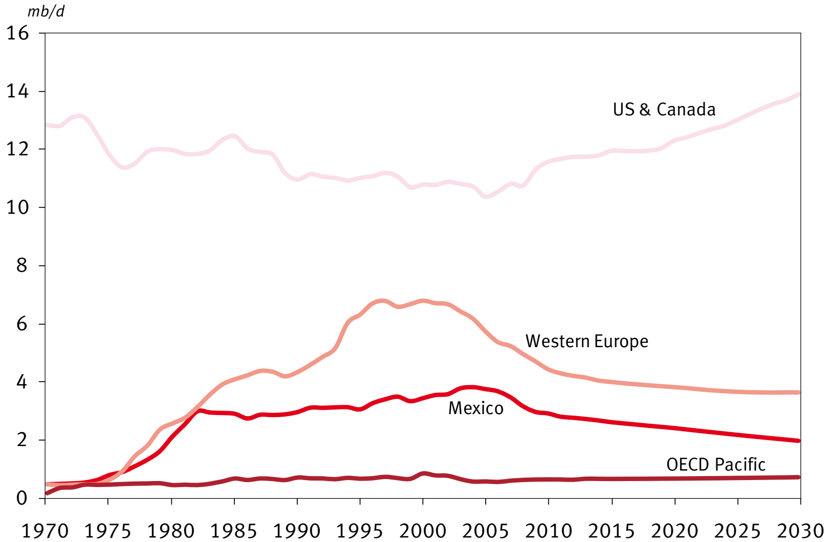


Figure 1.31
Non-OPEC oil supply, developing country regions

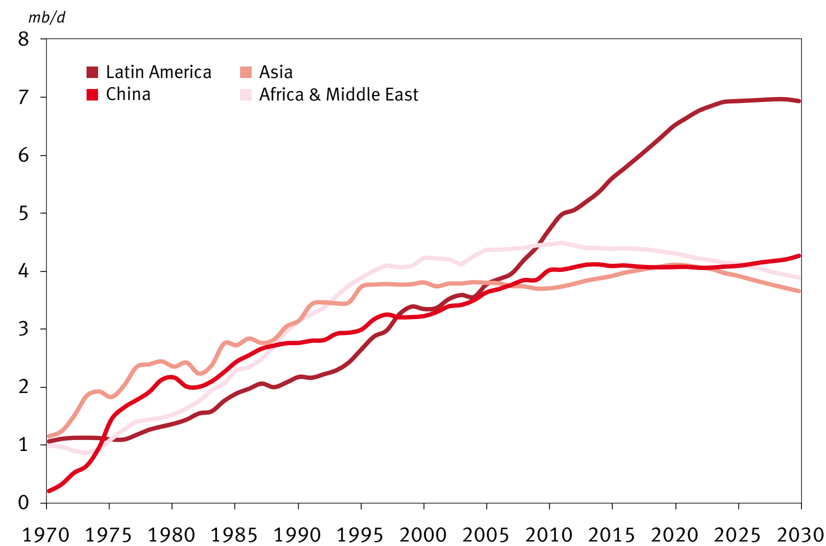
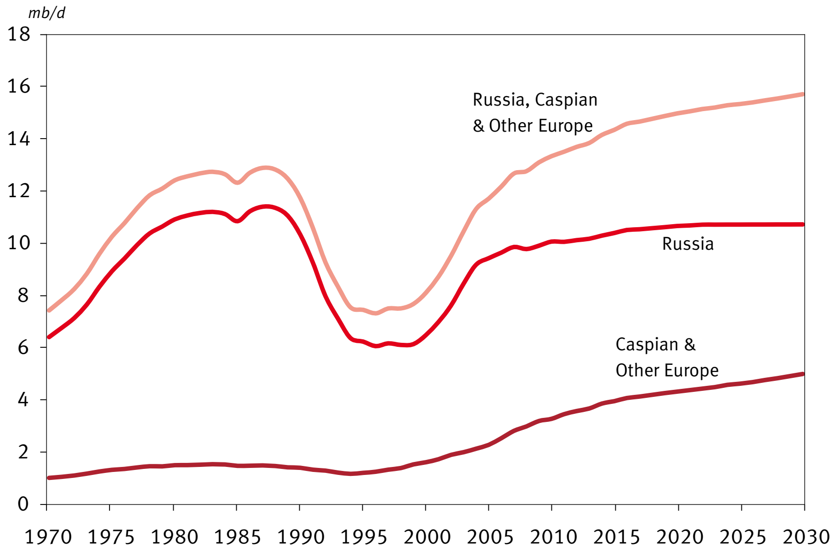


Figure 1.32
Non-OPEC oil supply, transition economies



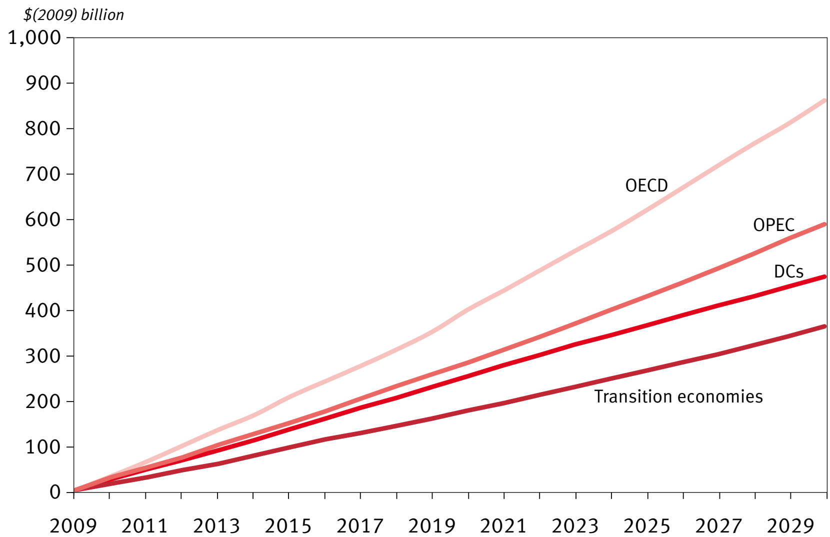
Figures 1.30 to 1.32 present the liquids supply paths in the Reference Case, on a regional basis.

Upstream investment

Upstream capital costs more than doubled from the first quarter of 2004 to the third quarter of 2008. In the wake of the global financial crisis and the associated fall in oil demand, upstream costs began to fall. However, the decline has not been as rapid or as great as some had expected. This is in part explained by robust rig rates, especially in expensive ultra-deep water, and some expected rebound in raw material prices as the recovery from the recession continues.[20]

In calculating upstream investment requirements that are implied by Reference Case volumes, assumptions need to be made for future unit costs of capacity, as well as decline rates. These calculations exclude the necessary investment in additional infrastructure, such as for pipelines. The cost of adding additional capacity is at its highest in OECD countries, in particular in the North Sea, where it is twice as expensive to add capacity compared to the OPEC region, and this difference gets progressively larger over time. The average cost in non-OPEC countries is assumed

Figure 1.33
Cumulative upstream investment requirements in the Reference Case, 2009–2030



to rise gradually to over \$20,000 per b/d of additional conventional oil capacity. On top of this, natural decline rates in non-OPEC country producing fields are greater than for OPEC. The upshot is that, as Figure 1.33 highlights, the amount of cumulative investment needed in OECD countries in the Reference Case up to 2030, is more than 45% higher than in OPEC countries, although OECD supply is actually falling throughout the period. By 2030, global upstream investment requirements amount to \$2.3 trillion, in 2009 dollars, of which 73% is in non-OPEC countries.

CO_2 emissions

It is important that this WOO's energy outlook is interpreted in terms of future GHG emissions. Anthropogenic GHGs come from a wide range of activities, and less than 57% of the total comes from CO_2 emitted from the use of fossil fuels. The rise in fossil fuel use in the Reference Case implies an increase in global CO_2 emissions of 38% from 2009–2030. The fastest growth in emissions will come from developing countries: by 2013 non-Annex I emissions will exceed those of Annex I countries. By 2030, Annex I emissions are 0.1% below their 1990 levels. Nevertheless, on a per capita basis, by 2030, Annex I countries emit, on average, 2.6 times more CO_2 than non-Annex I countries (Figure 1.34).

Figure 1.34
Per capita CO_2 emissions

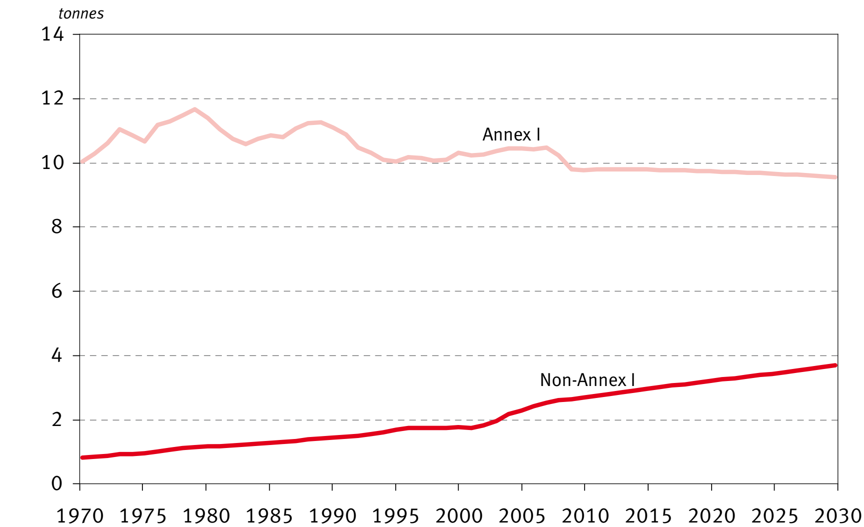
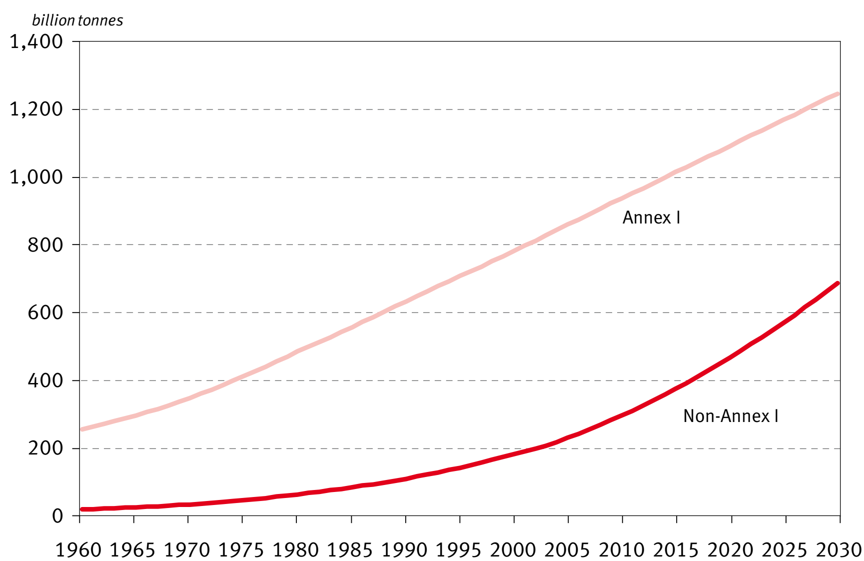


Figure 1.35
Cumulative CO_2 emissions from 1900, 1960–2030



Source for historical cumulative emissions: World Resources Institute.

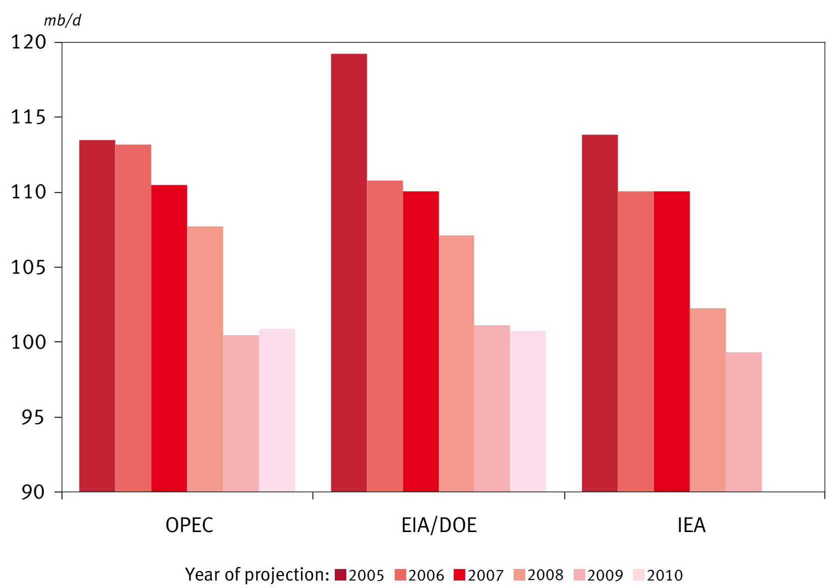
However, cumulative emissions are more relevant to possible impacts upon the climate. Despite stronger expected emissions growth from developing countries in the Reference Case, the cumulative contribution from Annex I countries will continue to dominate. By 2030, they account for 64% of the cumulative CO_2 emissions since 1900 (Figure 1.35). This underscores the need to fully reflect the historical responsibility in reaching an agreed outcome in the current climate change negotiations.

Oil demand projections have been falling

A comparison of oil demand projections for the medium- and long-term has been made using the main assumptions and results from OPEC, the Energy Information Administration of the US Department of Energy (EIA/DOE) and the International Energy Agency (IEA).

Making oil demand projection comparisons is complicated by differences in the definitions of regions, variations in technical granularity, as well as disparities in other technical definitions, such as whether to include biofuels in oil demand. In order to better facilitate a useful comparison, adjustments to published figures typically need to be made to attempt to portray a 'level playing field'.

Figure 1.36
Changing world oil demand projections for 2025



Looking long-term there is a considerable degree of agreement over global demand prospects, with the three institutions covering a rather narrow range. This is remarkable when compared to the large ranges that have been witnessed in the past. For example, as recent as 2001, the range for demand in the year 2020 – a similar two decade-ahead projection – went from as low as 105 mb/d to as high as almost 120 mb/d. This is a clear reflection of the process of downward revisions to demand. Recent adjustments have incorporated, for example, the impacts of the US EISA and the EU energy and climate change package of measures that led to substantial downward revisions, as well as the effects of the recent economic downturn. As a demonstration of this process of downward revision, Figure 1.36 compares the changing demand expectations for the year 2025.

There is also an emerging perception that a lowering of demand expectations will continue, for example, if climate change concerns lead to further downward pressures upon oil demand. This leads to a fundamental question: to what extent should targets and objectives, as set out in policy statements, or even signed into law, already be incorporated into future reference case projections?

Chapter 2

Oil demand by sector

There are evidently different drivers at play across the various sectors where oil is consumed. It is therefore important to inspect demand behaviour with sufficient granularity to understand the drivers and the consequent trends. And with data from both OECD and non-OECD countries continuing to improve in terms of quality and comprehensiveness, it has become ever more feasible to make appropriate distinctions across sectors of the various impacts of, for example, economic trends, demographics, policies, prices, costs and the development and penetration of technology.

This year's WOO continues this process by disaggregating the industrial sector into two components: oil use in the petrochemical sector, and other industry use. The assessment has been made possible by the marked improvement in data for this sector, particularly for developing countries. It is important that this process of data improvement continues, since considerable question marks still surround the reliability of available information on energy consumption in some sectors.

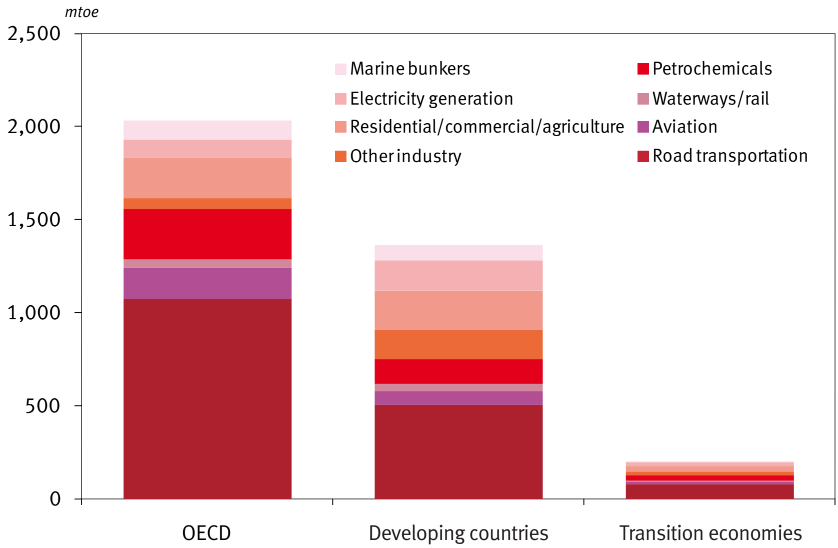
The level of oil consumption in 2007 by sector for the OECD, developing countries and transition economies is presented in Figure 2.1. The shares in demand are shown in Figure 2.2. Globally, road transportation accounted for 46% of oil consumption in this year, and total transportation had a 56% share. The share of road transportation is highest in OECD countries, but saturation and policy effects are likely to limit future growth, while, in contrast, there is large potential for growth in developing countries. The breakdown of the industry sector into two components reveals oil use in petrochemicals to be the second largest source of oil consumption worldwide, although it should be noted that in developing countries non-petrochemical oil use in industry is slightly higher than in the petrochemical sector. With these sectoral patterns in mind, this Chapter considers the prospects for oil demand.

Road transportation

Passenger car ownership

The contrast between car ownership in developed countries and developing countries is apparent in Table 2.1 and Figure 2.3. Of a global total of 823 million cars in 2007, less than 22% were in developing countries. For developing countries as a whole, there were 35 cars per 1,000 inhabitants in 2007. The lowest rates of ownership are found in Bangladesh and Ethiopia, with an average of one car for every thousand people. This

Figure 2.1
Oil demand by sector in 2007



Source: *OECD/IEA Energy Balances of OECD/non-OECD countries, 2009 (used throughout this Chapter).*

Figure 2.2
The distribution of oil demand across sectors in 2007

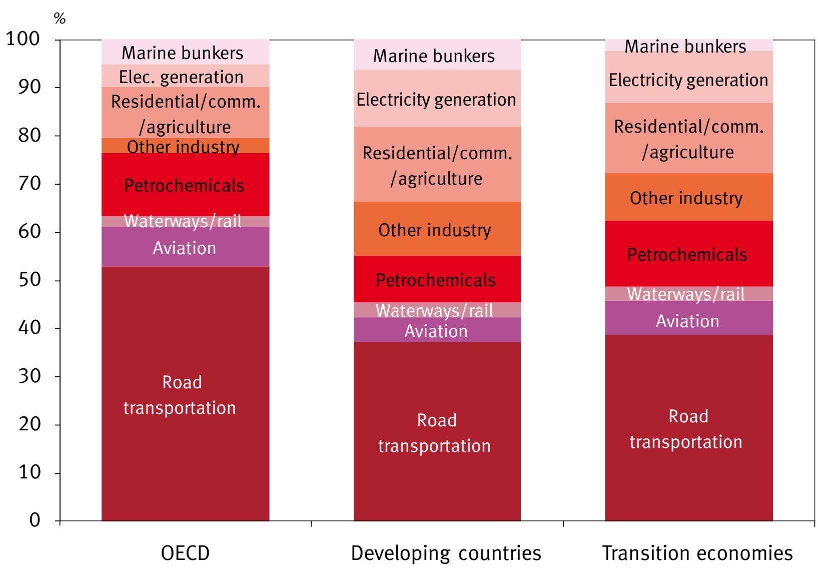


Table 2.1
Vehicle and passenger car ownership in 2007

	Population *millions*	Vehicles *millions*	Cars *millions*	Cars *per 1,000*
North America	450.7	293.2	259.3	575.2
Canada	32.9	19.3	18.6	565.4
Mexico	107.5	25.7	17.5	163.1
USA	308.7	247.3	222.2	719.8
Western Europe	540.9	276.1	238.9	441.7
Austria	8.3	4.6	4.2	511.1
Belgium	10.5	5.7	5.0	475.4
France	61.7	37.1	30.7	497.5
Germany	82.3	51.3	46.6	565.6
Greece	11.1	6.1	4.8	431.8
Hungary	10.0	3.5	3.0	300.3
Italy	59.3	40.2	35.7	601.6
Luxembourg	0.5	0.2	0.2	445.5
Netherlands	16.5	8.2	7.2	439.3
Poland	38.1	17.2	14.6	382.6
Portugal	10.6	5.5	5.3	502.2
Spain	44.1	27.0	21.8	494.0
Turkey	73.0	9.7	6.5	88.7
UK	60.9	32.1	28.2	463.5
OECD Pacific	201.1	111.1	86.0	427.7
Australia	20.9	14.3	11.5	549.6
Japan	127.4	77.0	59.6	468.2
New Zealand	4.2	3.1	2.6	620.0
South Korea	48.0	16.4	12.0	250.6
OECD	**1,192.7**	**680.3**	**584.2**	**489.8**
Latin America	420.6	70.3	56.0	133.0
Argentina	39.5	12.4	9.8	247.0
Brazil	190.1	38.0	30.3	159.3
Chile	16.6	2.7	1.7	102.3
Colombia	44.4	2.9	1.7	37.7
Peru	28.5	1.4	0.9	32.2
Uruguay	3.3	0.7	0.6	175.0
Middle East & Africa	803.8	33.3	21.9	27.2
Egypt	80.1	4.5	2.7	33.8
Ethiopia	78.6	0.2	0.1	0.9
Ghana	23.5	0.8	0.5	21.0
Jordan	5.9	0.8	0.5	90.3
Kenya	37.8	0.8	0.6	14.9
Morocco	31.2	2.2	1.6	52.7
South Africa	49.2	7.6	5.2	105.0
Sudan	40.4	0.7	0.5	12.9
Syria	20.5	1.0	0.4	21.8

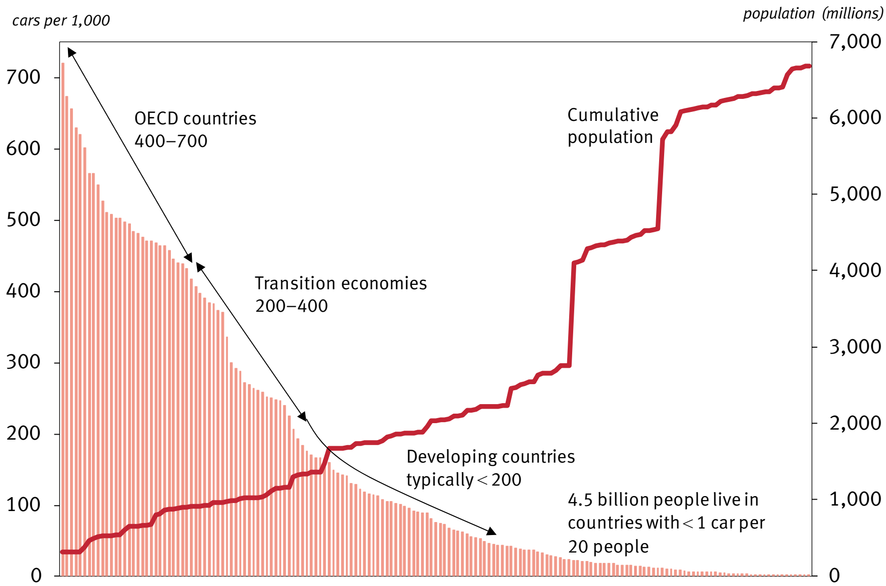
Table 2.1 (continued)
Vehicle and passenger car ownership in 2007

	Population *millions*	Vehicles *millions*	Cars *millions*	Cars *per 1,000*
South Asia	1,567.2	22.4	15.2	9.7
Bangladesh	157.8	0.4	0.2	1.0
India	1,164.7	18.6	12.7	10.9
Pakistan	173.2	1.8	1.4	8.3
Sri Lanka	19.9	1.2	0.4	18.2
Southeast Asia	630.3	49.6	31.8	50.4
Indonesia	225.6	17.1	9.5	42.1
Malaysia	26.6	8.6	7.6	287.0
Philippines	88.7	2.9	0.9	10.6
Singapore	4.5	0.7	0.5	115.3
Taiwan	22.7	6.9	5.7	252.1
China	1,328.8	42.5	29.6	22.3
OPEC	377.6	35.7	24.3	58.0
Algeria	33.5	3.6	2.2	65.3
Angola	17.0	0.7	0.6	37.0
Ecuador	13.6	0.8	0.5	37.3
Iran	70.4	7.0	5.7	80.8
Iraq	29.0	2.4	0.8	27.3
Kuwait	2.9	1.3	0.8	263.3
Libya	6.2	1.8	1.4	225.4
Nigeria	148.1	6.2	3.0	20.6
Qatar	0.8	0.6	0.4	469.9
Saudi Arabia	24.2	6.0	4.7	192.4
United Arab Emirates	4.4	1.4	1.3	292.0
Venezuela	27.5	4.0	3.0	107.4
Developing countries	**5,128.2**	**253.9**	**178.7**	**34.8**
Russia	141.7	34.8	29.3	206.5
Other transition economies	196.0	34.0	30.9	157.8
Belarus	9.7	2.7	2.3	239.5
Bulgaria	7.6	2.3	2.0	258.0
Kazakhstan	15.5	2.6	2.2	141.0
Romania	21.5	4.2	3.7	170.6
Ukraine	46.3	6.5	5.9	128.3
Transition economies	**337.6**	**68.8**	**60.2**	**178.3**
World	**6,658.5**	**1,003.0**	**823.0**	**123.6**

Sources: International Road Federation, World Road Statistics, various editions, OPEC Secretariat database.

is compared to average ownership rates of 490 per 1,000 in OECD countries, with the highest rate in the US at 720. When looking at these numbers, it is striking that 4.5 billion people live in countries with an average of less than 1 car for every 20 people.

Figure 2.3
Passenger car ownership per 1,000, 2007



Sources: International Road Federation, World Road Statistics, various editions, OPEC Secretariat database.

With this disparity in ownership levels, it is unsurprising that there has been and continues to be strong growth in the number of cars in developing countries. Over the period 2000–2007, the number of cars globally increased from just over 650 million to 823 million (Figure 2.4), with an additional 73 million cars appearing on the roads in developing countries. Yet despite the high levels of car ownership in the OECD, growth here also continues, with a further 78 million cars on the road in OECD countries in 2007, compared to 2000.

Having said that, five of the fastest six growing car populations over the period 2000–2007 were in non-OECD countries, with China increasing by 21 million over that period, easily the fastest rate (Figure 2.5). More recently, the growth in Chinese car volumes has accelerated further. In 2009 the number of new car sales increased by close to 50%, with nearly 13 million light vehicles purchased, making China the largest auto market in the world.

In the longer term, saturation effects will increasingly become evident in OECD countries, with average ownership levels already close to one car for every two people.

Figure 2.4
Global passenger car ownership, 2000–2007

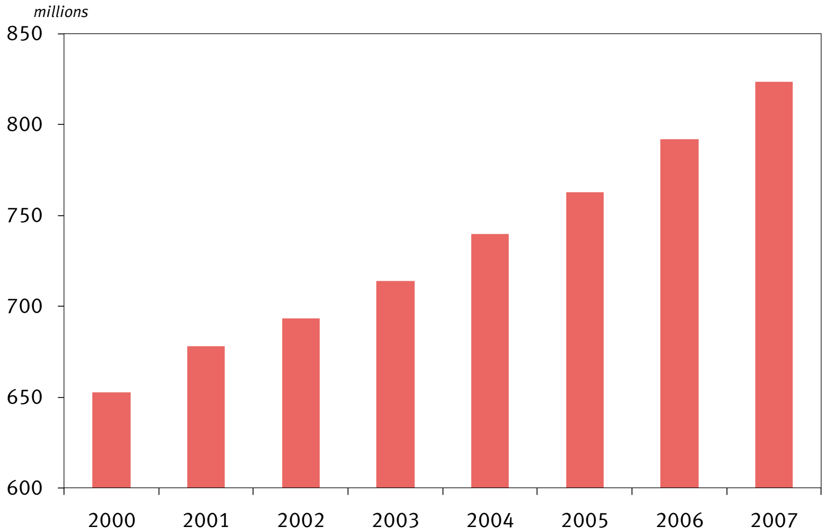
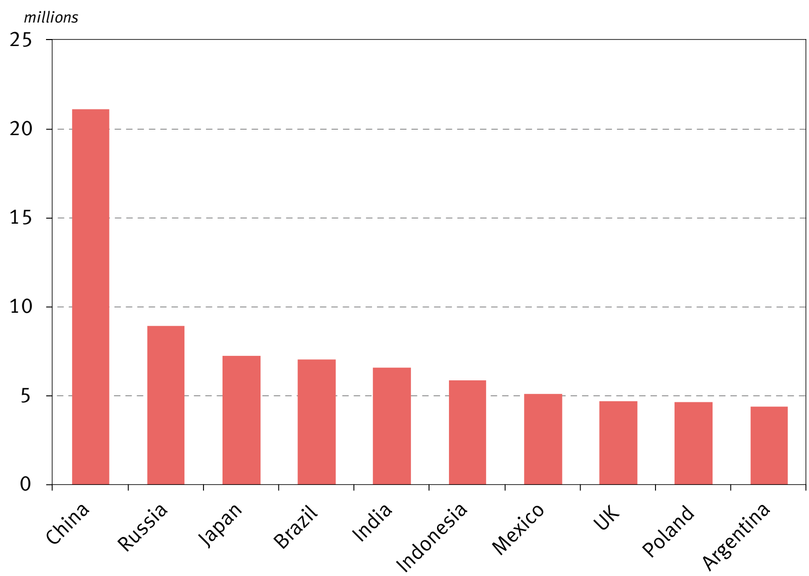


Figure 2.5
Growth in passenger cars, 2000–2007



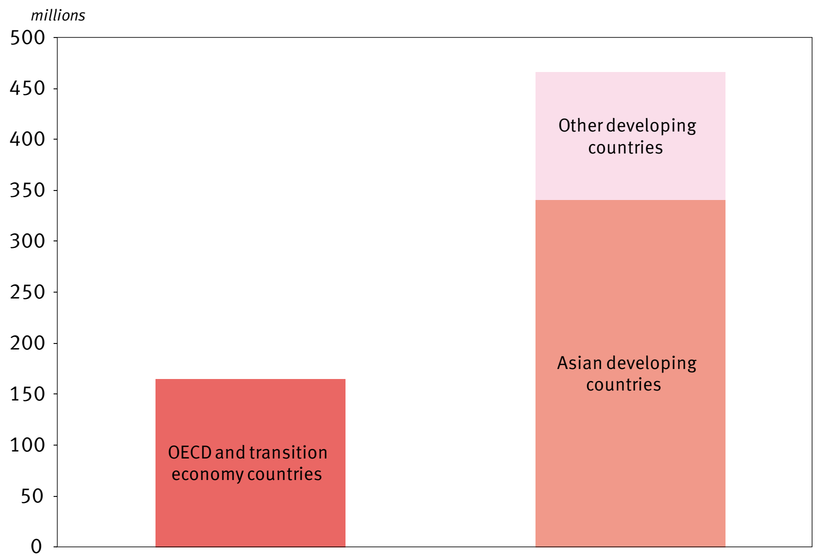
In order to capture the corresponding expected growth slowdown in the number of cars, the modelling framework needs to allow explicitly for a non-linear relationship between rising wealth and the number of cars per capita. Saturation assumptions are therefore needed. It is assumed that developing countries will head towards lower saturation levels than OECD countries. It is, however, broadly recognized that countries at low levels of passenger car ownership will not experience such saturation for a long time, and that other constraints to growth will be increasingly relevant, which might include congestion, available infrastructure, public transportation, taxation and local pollution. Other stimuli to growth may be regarded as essentially short-term in nature. For example, the extremely rapid growth in new car purchases that has recently been observed in China has been partly induced by government tax breaks on small cars.

Projections for the number of passenger cars in the Reference Case are shown in Table 2.2, with the increase summarized in Figure 2.6. For the OECD as a whole, there

Table 2.2
Projections of passenger car ownership to 2030

	Cars *per 1,000*				Cars *million*				Car growth *% p.a.*
	2007	**2010**	**2020**	**2030**	**2007**	**2010**	**2020**	**2030**	**2007–2030**
North America	575	555	581	601	261	259	295	326	1.0
Western Europe	442	436	462	489	238	238	259	277	0.7
OECD Pacific	428	437	484	517	86	88	97	101	0.7
OECD	**490**	**482**	**513**	**540**	**585**	**585**	**651**	**704**	**0.8**
Latin America	133	138	163	187	55	60	78	98	2.5
Middle East & Africa	27	31	41	52	22	27	45	68	5.0
South Asia	10	12	26	50	15	20	48	104	8.7
Southeast Asia	50	57	88	127	32	38	64	100	5.1
China	22	30	80	147	30	41	114	214	9.0
OPEC	58	59	80	106	22	24	38	59	4.4
Developing countries	**34**	**39**	**64**	**96**	**177**	**209**	**388**	**642**	**5.8**
Russia	207	200	296	379	29	28	39	47	2.1
Other trans. economies	158	176	239	302	31	35	47	59	2.9
Transition economies	**178**	**186**	**262**	**332**	**60**	**62**	**86**	**106**	**2.5**
World	**123**	**124**	**147**	**174**	**821**	**856**	**1,126**	**1,452**	**2.5**

Figure 2.6
Increase in number of passenger cars, 2007–2030



will be an additional 119 million cars by 2030, compared to 2010 levels. For developing countries, however, the increase will be far greater, rising by more than 430 million cars over that period, representing almost three-quarters of the global increase. Developing Asia will be the key to this increase, with over half of the global rise in passenger cars occurring in that region.

On a per capita basis, car ownership in the Reference Case clearly rises fastest in developing countries because of the huge growth potential, increasing from a current average of below 40 per 1,000 to 96 per 1,000 by 2030, yet this average rate is still well below OECD rates. The most dramatic rise in the Reference Case is for China, increasing from an estimated 30 cars per 1,000 in 2010 to 147 per 1,000 by 2030. The latter figure is comparable to average rates seen in Western Europe in the 1960s. Of the developing country regions, only Latin America approaches recent OECD ownership levels. By 2030, the region reaches 187 cars per 1,000, similar to rates in Norway in 1970, Japan in 1978, Greece in 1993, and South Korea in 2001. Southeast Asia sees similar ownership rates to China by 2030, but South Asia and Africa will still have only one car per 20 people by then. The OPEC car ownership rate rises sharply from just under 60 to 106 per 1,000 over the period.

Commercial vehicles

The global stock of commercial vehicles[21] rose by more than 41 million over the seven years from 2000 to reach over 179 million in 2007. Commercial vehicle use is closely linked to industrial output. And over the past three decades approaching 90% of the global increase in industrial output has been in developing countries. It is therefore understandable that the number of trucks per dollar of GDP has been falling for OECD countries, while it has been rising in developing countries.

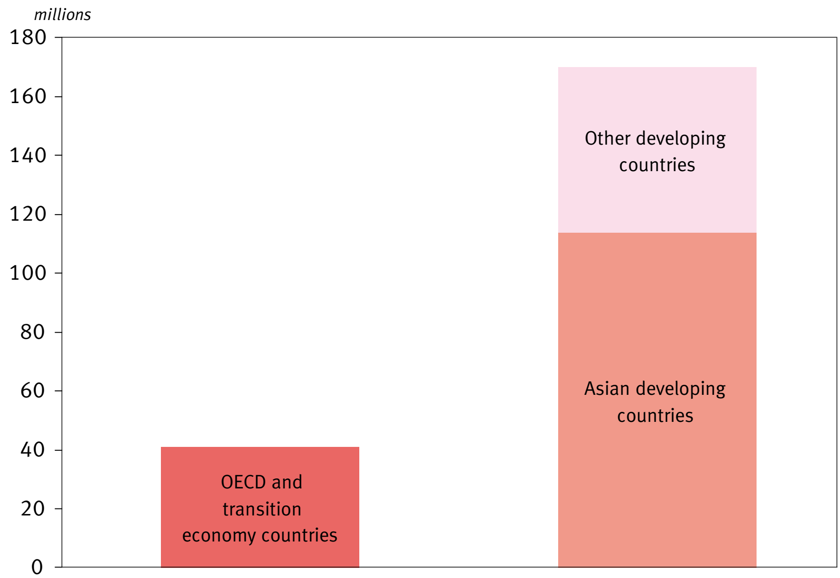
The Reference Case projection for trucks and buses is shown in Table 2.3. The strongest growth is in developing countries with the ongoing impact of higher growth

Table 2.3
The volume of commercial vehicles in the Reference Case *millions*

	2007	2010	2015	2020	2025	2030	Growth % p.a. 2007–2030
North America	34	34	36	39	42	44	1.2
Western Europe	37	39	43	49	56	62	2.3
OECD Pacific	25	26	26	26	26	27	0.2
OECD	**96**	**98**	**105**	**114**	**123**	**133**	**1.4**
Latin America	14	17	20	24	27	31	3.5
Middle East & Africa	11	14	20	27	35	46	6.3
South Asia	7	10	16	24	35	48	8.5
Southeast Asia	18	21	27	35	44	54	5.0
China	13	15	20	26	33	40	5.1
OPEC	11	12	15	18	21	25	3.6
Developing countries	**75**	**90**	**119**	**154**	**195**	**245**	**5.3**
Russia	6	6	6	6	7	7	0.8
Other transition economies	3	3	4	4	5	6	2.7
Transition economies	**9**	**9**	**10**	**11**	**12**	**12**	**1.6**
World	**179**	**198**	**234**	**279**	**330**	**390**	**3.4**

in industrial output. Total volumes in 2030, at 245 million, are close to triple current levels. And, once again, developing Asia is the dominant source of growth, reaching 142 million by 2030, and accounting for half of the global increase in the Reference Case (Figure 2.7).

Figure 2.7
Increase in volume of commercial vehicles, 2007–2030



Oil use per vehicle

Oil use per vehicle is affected by many factors, but is particularly sensitive to policy and technological developments. In this regard, consumer government policies can strongly influence the behaviour of this variable. For example, the incorporation of impacts of the US EISA and the EU package of energy and climate change measures led to revised assumptions for this variable in the WOO 2009. The US EISA raised CAFE standards from 25 miles per gallon (mpg) to 35 mpg by 2020, and this increase in new car efficiencies fed directly into the assumption for this variable. Similarly, the EU legislation that introduces a binding target of 120g CO_2/km by 2015 affects average efficiencies. Government policy can also influence driving mileage and a consumer's choice of public or private transport.

Over the next two decades, although the market share of conventional internal combustion engine powered vehicles will be challenged by the development and penetration of other technologies, the Reference Case sees conventional combustion engines remaining the most important vehicle technology, given that it is an established, but still evolving technology with a well developed network of service and fuelling stations. Improvements in conventional vehicles will deal with more efficient combustion, based upon improvements in spark-ignition and compressed ignition engine technologies, in transmissions, tyres, the use of lightweight materials and improved aerodynamics. The key alternative technologies to conventional engines over the projection period are likely to be hybrid-electric power-trains, including plug-in hybrids, but the huge financial investment expected to be required for R&D to bring down costs, build capacity and expand production, is expected to delay the penetration of these technologies to the back-end of the Reference Case timescale (Box 2.1).

At the global level, average efficiency improvements are 2.1% p.a. Nevertheless, it is important to remain aware of the uncertainties that dominate this important variable. For example, policy measures that support the development of alternative technologies can affect the timing of when these technologies become economic. It is also worth noting that the economics of these alternative technologies will be closely affected by oil price developments and price spreads with other alternative fuels.

Box 2.1
Road transportation technology: evolution or revolution?

The pace at which alternative fuels and engine technologies will penetrate the global market for light duty vehicles in road transportation, as well as the extent to which they will affect demand growth for petroleum-based fuels, is influenced by a number of factors. These include government policies and the price of oil, as well as technological barriers and resource availability for these alternatives. Three areas are significant in this regard, namely non-agricultural fuels, biofuels and vehicle efficiency technologies.

Non-agricultural alternative fuels such as GTLs and CTLs from Fischer-Tropsch synthesis, as well as CNG, are likely to witness growth in countries that benefit from high coal and natural gas endowments. Historically, they have been employed as part of policies reflecting resource nationalism, energy security, or as a means to improve air quality, for example, in some large Indian cities. It is likely, however, that climate change mitigation policies, if implemented, will hinder their growth, as many of these technologies have a high carbon footprint and require the use of costly offsets or sinks, such as carbon reduction permits or the technology of CCS.

The prospects for biofuels growth, whether derived from agricultural products in the form of first- and second- generation ethanol or biodiesel, or as more advanced biomass-derived synthetic fuels, are related to the pace of technology development, as well as concerns about their sustainability. The types of biofuels and technologies used, and the feedstocks employed, vary according to a particular country's resource endowment. In general, first generation biofuels are being developed globally.

Second generation fuels and biomass-to–liquids (BTLs) are more complex technologies and are making most progress in OECD countries and in partnerships with major non-OECD producers.

Vehicle efficiency technologies, such as improvements in spark ignition and compression ignition engines, as well as the increased presence of hybrid electric powertrains and battery electric vehicles, will see some advancement. However, growth rates are expected to vary between the technologies, given the substantial financial investment required to build capacity.

While improvements in vehicle engine efficiencies will take place across the world, the development of advanced hybrid and battery technologies will be more regional, specifically in the OECD. Moreover, their expansion will be slower. This category of technology remains expensive relative to others as it requires substantial R&D investment and the creation of manufacturing and recharging infrastructure. Additionally, India and China are expected to leverage their substantial industrial production capacity to create small, low-cost vehicles, including those for export, and to improve domestic fuel efficiencies.

The extent to which efficiency improvements and the development and penetration of alternative fuels should already be incorporated into central benchmark projections – such as the WOO Reference Case – is an important element to consider, given their potential to significantly impact future demand. For example, the WOO 2008 assessment demonstrated that alone, US and EU policies focused on improving automotive efficiencies and higher biofuels use could displace between 4 and 9 mb/d of OPEC crude by 2030.

In fact, considerable amounts of previously expected future oil requirements have already been displaced, for example, by the more rapid expansion of biofuels use and advancements in fuel economy standards. This displacement is set to continue.

Furthermore, different emergence rates for alternative fuel types and engine technologies are distinctly feasible in a situation where there is accelerated development. While governments can play a major role in creating opportunities for technologies that might not naturally become economic over the period to 2030, in an era of constrained government budgets, priorities are likely to emerge.

Naturally, falling costs in emerging technologies will affect the economics of alternative fuels, with breakthrough years likely to come earliest for CNG, GTLs and CTLs. Even with such accelerated technological development, however, the major impacts on oil demand are likely to continue to come from improved vehicle efficiencies and higher biofuels penetration. Efficiency improvements are likely to be most affected by increased engine efficiencies and the more rapid introduction of hybrid-electric vehicles. By 2030, at least another 5 mb/d of oil demand could be 'destroyed' under such a development path.

Looking further ahead, of the whole spectrum of technologies, it is breakthroughs in battery technology for electric cars, and catalyst, feedstock, or industrial biofuel production technology that could pave the way for significant changes. However, battery electric storage is already a mature technology, having been around for more than a century, and its take-up to date has been rather slow.

It is clear that the internal combustion engine (ICE) will maintain its current position as the dominant automotive technology, at least up to 2030. It is expected that automotive manufacturers will increase the efficiency of ICE vehicles through improvements in such areas as vehicle weight, rolling resistance, aerodynamic drag and accessory loads. In addition, opportunities also exist for manufacturers to further improve ICE vehicle design and technology to respond to CO_2 regulations and efficiency requirements. These two key parameters will remain a priority for the industry in the years ahead.

As a result, future oil use in the road transportation sector will be 'avoided' or 'replaced' predominantly through improved vehicle efficiencies and increased ethanol use. Following these are developments in hybrid electric vehicles and growth in biodiesel. Other alternative fuels and technologies including BTLs, CTLs, CNG, plug–in hybrids, battery electric vehicles, GTLs and hydrogen are expected to have relatively minor roles in relation to avoided or replaced oil use in the transportation sector – at least for the period up to 2030.

Overall, it is therefore likely that the impact of alternative fuels and engine technologies on petroleum products demand in road transportation will be more an evolutionary process, than a revolutionary one.

Road transportation demand projections

Passenger car ownership and commercial vehicle projections together with an understanding of efficiency gains lead to estimating projected road transportation oil demand levels (Table 2.4). Overall global demand rises by 8.5 mboe/d over the period 2008–2030. OECD road transportation demand, however, is projected to fall in the Reference Case throughout the entire period, having peaked in 2007. Figure 2.8 shows that 87% of the net increase in road transportation oil demand takes place in developing Asia. By 2025, developing countries consume more oil in this sector than OECD countries. Nevertheless, per capita oil use for road transportation in developing countries in 2030 is still less than one quarter of that in the OECD.

Aviation

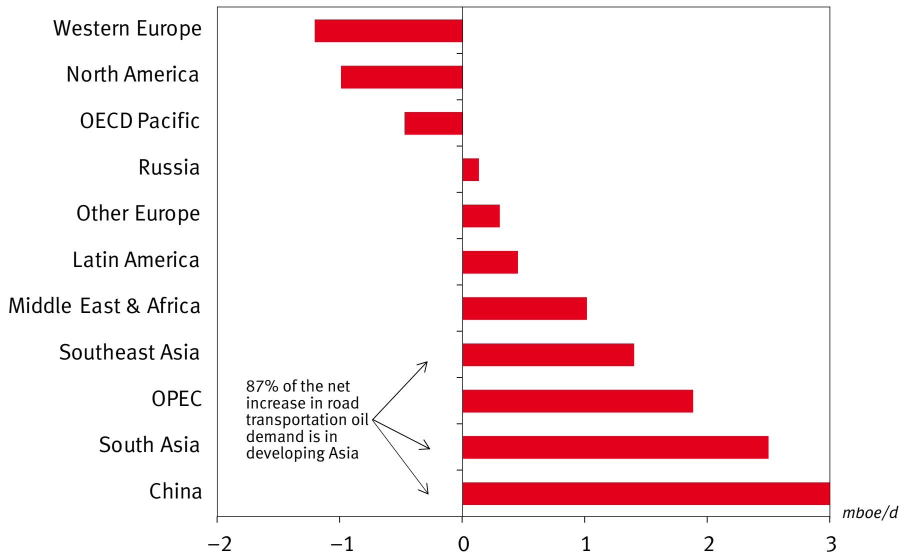
Aviation represents around 12% of the fuel consumption for the entire transportation sector. This compares to 80% for road transport. Aviation oil demand in 2007 accounted for a little over 6% of world demand. The OECD currently accounts for around two-thirds of world aviation oil demand. The US alone accounts for over one-third of this. Growth rates in aviation oil demand in OECD countries have typically been outpacing those in the road transportation sector, with the exception of the US.

Table 2.4
Oil demand in road transportation in the Reference Case *mboe/d*

	Levels				Growth
	2008	**2010**	**2020**	**2030**	**2008–2030**
North America	11.9	11.7	11.5	10.9	–1.0
Western Europe	6.5	5.8	5.6	5.3	–1.2
OECD Pacific	2.6	2.5	2.4	2.1	–0.5
OECD	**21.0**	**20.0**	**19.5**	**18.3**	**–2.7**
Latin America	2.0	2.0	2.3	2.5	0.5
Middle East & Africa	1.2	1.4	1.8	2.3	1.0
South Asia	1.0	1.1	2.2	3.5	2.5
Southeast Asia	1.9	2.1	2.7	3.3	1.4
China	2.0	2.4	4.5	5.5	3.5
OPEC	2.6	2.8	3.7	4.5	1.9
Developing countries	**10.8**	**11.8**	**17.1**	**21.5**	**10.7**
Russia	0.8	0.8	0.9	1.0	0.1
Other transition economies	0.7	0.7	0.8	1.0	0.3
Transition economies	**1.5**	**1.4**	**1.7**	**2.0**	**0.4**
World	**33.3**	**33.2**	**38.4**	**41.8**	**8.5**

Both passenger numbers and freight loads have increased dramatically over recent years. For example, by 2007, the number of airplane passengers had quadrupled compared to 1980. Freight expanded at a similar rate. However, despite this growth, the increase in aviation fuel demand has been more modest, expanding at around half the

Figure 2.8
Growth in oil consumption in road transportation, 2007–2030



rate of passenger and freight traffic. This has been a result of the sector's considerable efficiency gains, with the biggest contribution coming from improved aircraft design, materials and engines. Other factors include load factors and economies of scale. Further efficiency and technology improvements are clearly expected in this sector.

The greatest percentage oil demand growth rates in this sector have been in emerging economies, particularly in Asian developing countries. The single highest growth registered over the period 1980–2007 was by China, which witnessed an average annual rate of 14%, although this increase was from a low base. Nonetheless, OECD oil use in the aviation sector in 2007 still accounted for two-thirds of global consumption.

Economic growth obviously plays a central role in the expansion of the aviation sector. Increases in personal income and an expanding economy will affect the demand for both air freight and passenger transportation, whether for private or business travel. Consequently, a close connection between economic activity and oil demand in this sector is expected. This has been particularly visible in the context of the global financial crisis and subsequent economic downturn.

It should be noted, however, that aviation fuel intensity decreased appreciably over the past three decades, at an average annual rate of close to 3%. While

7.6 barrels of oil equivalent (boe) were needed to perform one million tonnes-kilometre in 1980, only 3.4 boe were necessary in 2006. Around one-third of this decline came from aircraft design and enhancements in materials and engines. The rest is due to a number of other contributing factors, such as advancements in passenger occupancy and freight load factors, traffic management and economies of scale.

Further technological advances in the aviation industry can be expected to bring about more efficiency-related improvements. This includes the continued development and introduction of new materials, such as lighter composite materials. Engine design is also expected to witness ongoing technological advancements and efficiency enhancements, such as through the use of ultra-high by-pass ratio engines for subsonic airplanes. Projects aimed at improving computer-based simulation systems are also anticipated to help reduce energy consumption and waste in the design process, as well as lower test facility costs and lesser test flight hours.

In the Reference Case, the sector's demand increase over the period 2008–2030 approaches 2 mboe/d. In contrast to road transportation, there is still expected to be scope for growth in OECD countries, though expansion in developing countries will be faster in both percentage and absolute terms (Table 2.5), with China witnessing the largest growth.

However, while in the Reference Case OECD countries are expected to still use more oil in this sector than non-OECD countries, there are a number of downside risks to this projection, including the possible impact of saturation effects, and congestion. For developing countries there may be infrastructural constraints.

Other transportation: domestic waterways and rail

Beyond road and aviation, the remaining use of oil in the transportation sector is primarily for rail and domestic navigation – a small amount is also used for pipeline transport – with both sub-sectors each using just under 1 mboe/d. Demand in OECD countries has been largely static over the past two decades in the rail industry, whereas developing countries have seen a steady increase. The key increase has been in China, which, together with the US, is the main user of oil in railways, with these two countries accounting for 63% of oil use in this sub-sector.

As with railways, the only significant increase in oil use in domestic navigation over the past two decades has been in China. Here waterways are an important part of the infrastructure for the domestic transportation of goods, prior to them being exported. The expectation of a continued escalation in trade between China and the

Table 2.5
Oil demand in aviation in the Reference Case *mboe/d*

	Levels				Growth
	2008	2010	2020	2030	2008–2030
North America	1.8	1.8	1.9	2.0	0.2
Western Europe	1.2	1.1	1.2	1.3	0.1
OECD Pacific	0.4	0.4	0.5	0.5	0.1
OECD	**3.3**	**3.3**	**3.6**	**3.8**	**0.5**
Latin America	0.2	0.2	0.2	0.2	0.1
Middle East & Africa	0.2	0.2	0.3	0.3	0.1
South Asia	0.1	0.1	0.2	0.2	0.1
Southeast Asia	0.4	0.4	0.5	0.6	0.2
China	0.3	0.3	0.5	0.7	0.4
OPEC	0.3	0.3	0.3	0.4	0.1
Developing countries	**1.5**	**1.6**	**2.0**	**2.5**	**1.0**
Russia	0.2	0.2	0.3	0.4	0.2
Other transition economies	0.1	0.1	0.1	0.1	0.0
Transition economies	**0.3**	**0.3**	**0.4**	**0.5**	**0.2**
World	**5.1**	**5.2**	**6.0**	**6.8**	**1.7**

rest of the world indicates that more oil will be needed to help power the transport on China's domestic waterways.

The Reference Case outlook for oil use in rail and domestic navigation is shown in Table 2.6.

Other sectors

Petrochemicals

Petroleum product use in the industrial sector is the second largest source of oil demand. The OECD has dominated demand for oil in this sector, accounting for 61% of global use in 1990, rising to 68% by 2007 (see Figures 2.9 and 2.10).

What is also interesting to observe is that a number of changes have occurred over the past two decades. Firstly, although the OECD continues to account for more than half of this sector's total consumption, it has only seen growth in the

Table 2.6
Oil demand in domestic waterways and railways in the Reference Case *mboe/d*

				Levels	Growth
	2008	2010	2020	2030	2008–2030
North America	0.4	0.4	0.4	0.3	–0.1
Western Europe	0.3	0.2	0.2	0.2	–0.1
OECD Pacific	0.2	0.2	0.2	0.2	0.0
OECD	**0.9**	**0.8**	**0.7**	**0.7**	**–0.2**
Latin America	0.1	0.1	0.2	0.2	0.1
Middle East & Africa	0.0	0.0	0.0	0.0	0.0
South Asia	0.1	0.1	0.1	0.1	0.1
Southeast Asia	0.1	0.1	0.1	0.1	0.0
China	0.6	0.8	1.2	1.6	0.9
OPEC	0.0	0.0	0.0	0.0	0.0
Developing countries	**0.9**	**1.1**	**1.6**	**2.1**	**1.2**
Russia	0.1	0.1	0.1	0.1	0.0
Other transition economies	0.0	0.0	0.0	0.0	0.0
Transition economies	**0.1**	**0.1**	**0.1**	**0.2**	**0.0**
World	**1.9**	**2.0**	**2.5**	**3.0**	**1.0**

petrochemical sector, while net use in other industrial sectors has declined. Secondly, oil use in developing countries' industry sector has risen swiftly for both petrochemical use and other industrial processes, partly due to a transfer of these energy-intensive industries from the OECD to developing countries. And thirdly, transition economies have witnessed a net decline in non-petrochemical use, following the collapse of the Soviet Union at the tail-end of the 1980s.

As with the transportation sector, the varying regional prospects for future demand are the key to understanding how oil demand patterns might emerge, in particular as developing countries expand their industrial base. It is also important to distinguish between the major components of demand in this sector. In this regard, the regional prospects for demand in the petrochemical sector are first assessed. This is followed by a closer look at demand in other industrial sectors.

In OECD countries, petroleum product use in the petrochemical sector, mainly naphtha and NGLs, has been steadily rising for the past 25 years. However, the growth has been slowing. Over the ten years between 1987–1997, oil use in the

Figure 2.9
Oil demand in industry, 1990

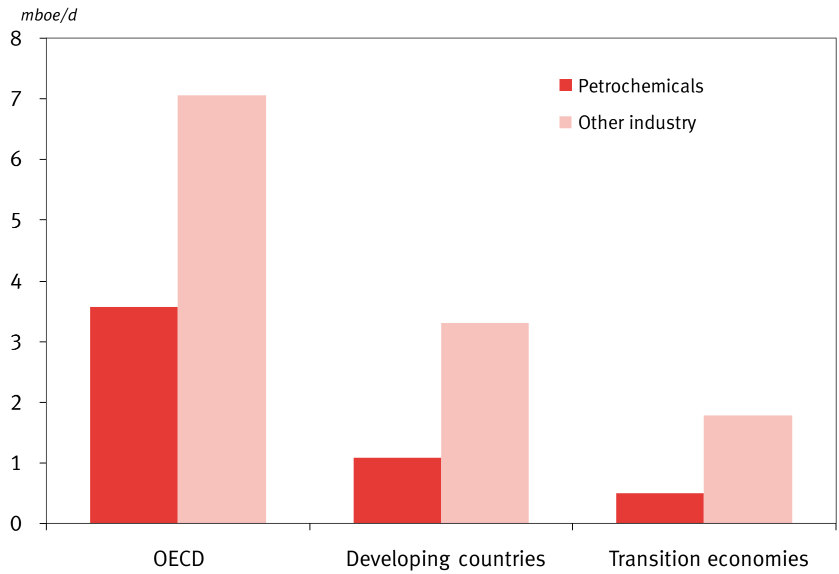
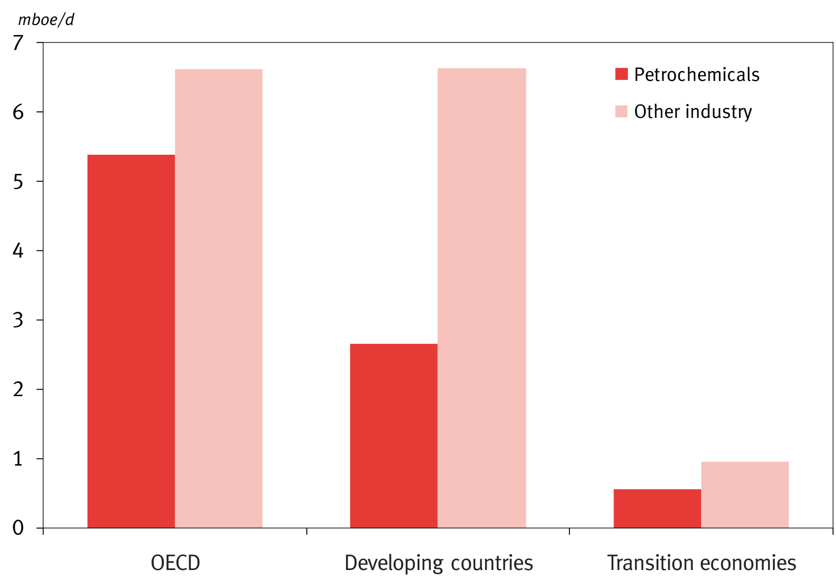


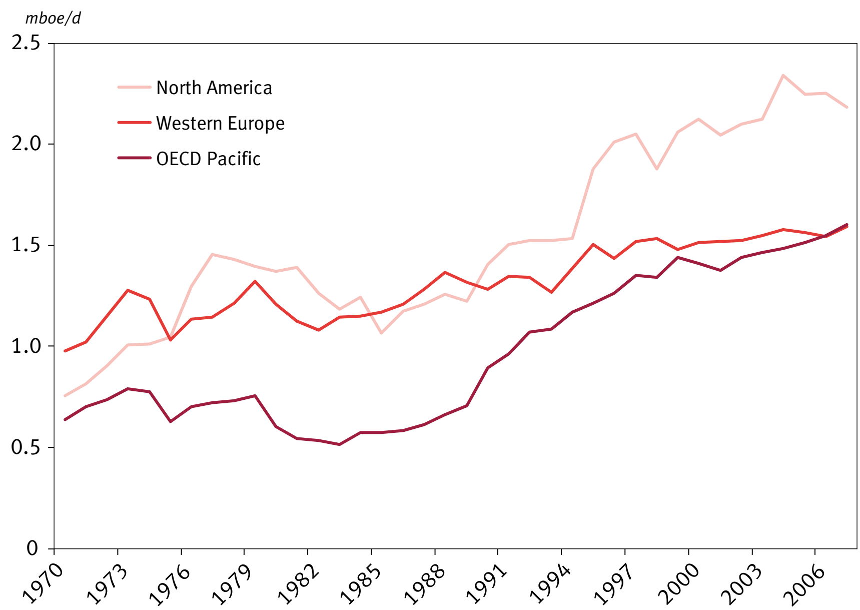
Figure 2.10
Oil demand in industry, 2007



petrochemical sector grew by 70%, 19% and 120% in North America, Western Europe and the OECD Pacific respectively. In the following ten years, however, the increase was only 6%, 5% and 18% respectively (Figure 2.11). This slowdown has reflected a gradual shift in global petrochemical production patterns. For example, OPEC Member Countries have developed a wave of petrochemical projects and there has also been strong demand growth for petrochemical materials in emerging Asian markets, such as China and India.

The linkage between economic activity and petrochemical feedstock needs in OECD countries is therefore not straightforward. There are clear indications of a very close link in the short-term between fluctuations in GDP – or more precisely, fluctuations in output or demand in the appropriate sector, such as transportation, manufacturing and construction – and feedstock needs, as this reflects changes in the demand for end products. Thus the global recession hit oil demand in the petrochemicals sector particularly severely. Looking longer term, trends are strongly affected by the continued growth in the trade of petrochemical products, largely from Asia to the OECD. Thus there is an ongoing decoupling between economic activity in OECD countries and domestic petrochemicals supply, and, consequently, the demand for feedstocks.

Figure 2.11
Oil demand in the petrochemical sector in OECD regions



The Reference Case outlook for oil use in North America's petrochemicals sector underlines the close linkage between oil use in this sector and industrial activity, reflecting the continuing impact of domestic economic expansion on the need to provide such products as plastics, synthetic fibres, synthetic rubber, paints, adhesives and aerosols. However, it also reflects the gradual shift in end-use product manufacture to other regions. Although North America is currently a net exporter of ethylene, for example, there has been a slowdown in the addition of new capacity, as well as some closures, as the higher production costs have changed North American competitiveness with other world regions. The sector is also very sensitive to economic fluctuations – petrochemical oil use in North America in 2009 is actually estimated to have declined by close to 5%. While demand will continue to grow over the medium- to long-term, it will be at declining rates.

Petrochemical oil use in Western Europe has seen the slowest growth of all the OECD regions. While petrochemical oil use is strongly affected by fluctuations in industrial activity, the long-term growth potential appears limited. As the economic recovery gets underway, some modest increase in oil use can be expected, but with ethylene demand and production capacity already close to peaking in this region, it is expected that oil use in the Western European petrochemicals sector will also stagnate.

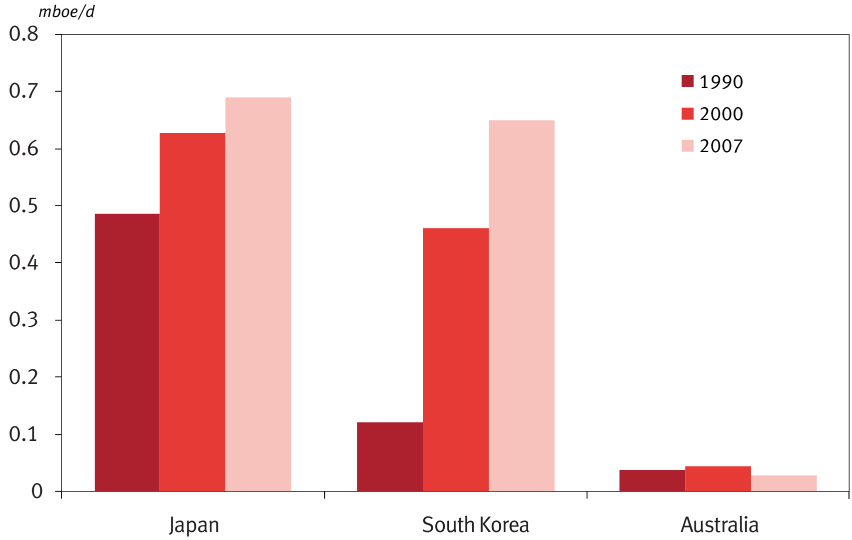
The petrochemical industry in the OECD Pacific region has witnessed two distinct patterns. While Japan and Australia have seen fairly flat ethylene production, or even declining, and with no significant increases in ethylene production capacity planned, South Korea has exhibited strong growth, to the extent that it is now the region's largest ethylene producer. In line with this, oil use as a feedstock in South Korea has been growing rapidly. Over the period 1990–2007 it rose by an average rate of more than 10% p.a. (Figure 2.12).

This affects the outlook for this sector's oil demand in the OECD Pacific as a whole. Oil feedstocks have been growing faster than the region's industrial value-added, but the rapid expansion in South Korea shows signs of slowing, and the net growth for the region should, over the medium- and long-term, fall below that of industrial activity. The medium-term expansion plans that are on the table are modest.

Of the non-OECD regions, the most important for future petrochemical petroleum product demand growth will be OPEC and China. Many OPEC Member Countries have ambitious plans to expand their petrochemical industries, taking advantage of low-cost feedstocks, while China is investing heavily to satisfy its rapid ethylene demand growth.

The income elasticity in China for petrochemical feedstocks with regard to industrial activity is strong, but falling. This not only reflects the continued strong

Figure 2.12
Petroleum product feedstocks in the petrochemical sector



growth in domestic ethylene capacity, but also the growing level of imports of ethylene derivatives from the Middle East. In the Reference Case, while robust growth is expected for petrochemical feedstocks in China, this is expected to gradually slow, in part, as the share of industry in total GDP continues to decline.

The growth of the petrochemical industry in OPEC over the past two decades has been based upon a steady rise in the use of both petroleum products and natural gas as feedstocks. Although oil use in this sector actually fell over the period 2005–2007, existing petrochemical expansion projects point to a resumption in the steady growth of the use of petroleum products as feedstocks. Moreover, the crude prices assumed in the Reference Case may positively affect the capital available to this sector.

Of the remaining developing countries, the only growth of note in oil use as a feedstock is expected in Asia, where the two main players are Chinese Taipei and India, followed by Singapore, Indonesia and Thailand. Total Southeast Asia oil use in this sector has been rising considerably faster than economic activity, and even if elasticities begin to fall, demand growth is still expected to be robust. Similarly, oil use in India, accounting for all of the South Asian demand in this sector, is expected to continue rising, especially given the increasing demand for petrochemical products such as plastics and chemicals. In Latin America, where Brazil is the main producer of ethylene, only a modest petrochemical industry growth is expected, and the need to import ethylene and ethylene derivatives is likely to increase. Oil use in this sector for the Middle East and Africa is expected to remain minimal.

In Russia, oil use as a feedstock in the sector has been roughly flat since the turn of the century. While new projects have been announced, delays have been witnessed, in part because of financing issues. The Reference Case sees some growth, but slowing in line with a decline in the assumed importance of the industry sector in GDP. For other transition economies, oil use in the petrochemical sector is primarily in Romania and Ukraine, but only minor increases in demand are expected.

Projections for oil use in the petrochemical sector are shown in Table 2.7. The main source of increase is in developing countries, which sees demand 1.5 mboe/d higher in 2030 than in 2008. The strongest increase comes from developing Asia and OPEC. Of the net increase in oil use in the petrochemicals over the period 2008–2030, 62% is in non-OECD Asia. Oil use in this sector in the OECD and transition economy regions is expected to stay approximately flat.

Table 2.7
Oil demand in petrochemicals in the Reference Case *mboe/d*

				Levels	Growth
	2008	2010	2020	2030	2008–2030
North America	2.1	1.9	2.1	2.2	0.1
Western Europe	1.5	1.4	1.4	1.4	–0.1
OECD Pacific	1.6	1.5	1.6	1.6	0.0
OECD	**5.2**	**4.9**	**5.1**	**5.2**	**–0.1**
Latin America	0.3	0.3	0.3	0.4	0.1
Middle East & Africa	0.0	0.0	0.0	0.0	0.0
South Asia	0.3	0.4	0.4	0.6	0.2
Southeast Asia	0.7	0.7	0.9	1.0	0.3
China	0.9	1.0	1.2	1.3	0.4
OPEC	0.5	0.5	0.7	0.9	0.4
Developing countries	**2.7**	**2.9**	**3.6**	**4.2**	**1.5**
Russia	0.5	0.5	0.5	0.5	0.1
Other transition economies	0.1	0.1	0.1	0.1	0.0
Transition economies	**0.6**	**0.6**	**0.6**	**0.6**	**0.1**
World	**8.6**	**8.3**	**9.3**	**10.0**	**1.5**

Other industry sectors

Oil use in the other industry sectors covers a wide range of activities, including construction, glass manufacture, cement production, the food and tobacco industries, mining and quarrying, and the paper pulp and printing industries.

As mentioned, the OECD has seen a decline in oil use in other industry sectors (Figure 2.13). The most pronounced period of decline was following the rise in oil prices in the 1970s and early 1980s. However, the drop off has continued since.

The three major products in use in this sector are gas/diesel oil, heavy fuel oil and bitumen. In response to the high oil prices of 2008, in every region there was a significant fall in the use of heavy fuel oil, as well as, to a lesser extent, diesel. In North America and Western Europe the decline has continued, largely as fuel oil is replaced by natural gas. In Western Europe, where the decline has been the most dramatic, the fall occurred across all industries, but particularly notably in the iron and steel industry, the non-metallic mineral industries, such as glass and cement and in refineries themselves. Nevertheless, the scope for further declines in demand for these products is expected to be limited.

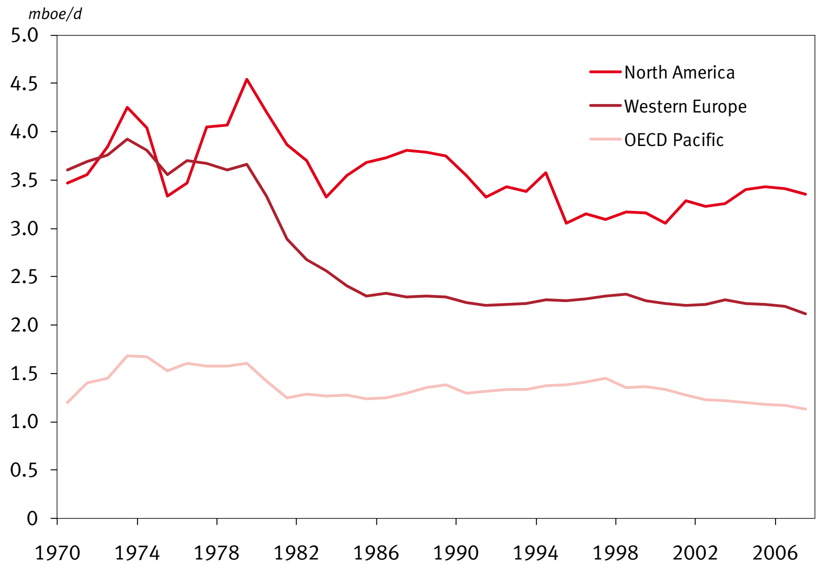
At the same time, however, the use of bitumen has been steadily expanding, at least in North America and Western Europe. Otherwise known as asphalt, this is used for road surfacing, as well as for roofing material. Notwithstanding ongoing research into possible alternatives, such as rapeseed oil, demand for bitumen has been robust as road networks have matured and regular maintenance is undertaken.

The prospects in OECD regions for aggregate oil use in other industry, outside of petrochemicals, are thus subject to complex and, in part, opposing trends and drivers. While the use of heavy fuel oil is likely to continue to fall, the substitution possibilities have already been largely exploited. Diesel use has been approximately flat for the past two decades. Moreover, although the share of industry in GDP for these regions has for a number of decades been on a downward trend, for the past ten years it has been relatively stable across most of the OECD. At the same time, bitumen demand is likely to remain fairly constant, as for the most part in the OECD, road surfacing will be dominated by maintenance.

As a result, the net impact upon oil use in the OECD other industry sector is set for a continued decline, but this will be slightly below historical rates.

Of developing countries, the main user of oil in this sector is China (Figure 2.14). Indeed, this sector accounted for something like one-third of the rapid increase in

Figure 2.13
Oil demand in other industry in OECD regions



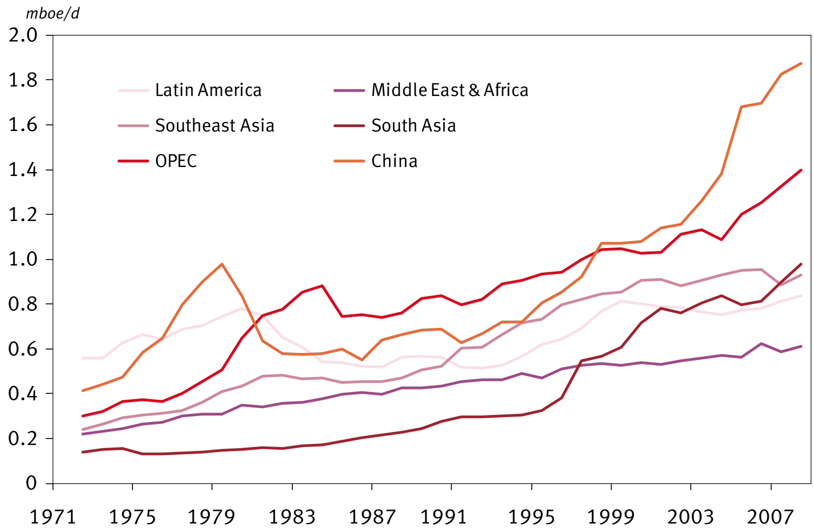
Chinese oil demand in 2004, which was one of the factors behind the upward price pressure that year. Other developing countries also exhibit continued upward trends in oil use in this sector.

For China, the rapid increase in oil use has been associated with growing industrial activity, as well as significant investments in infrastructure. The three key rises in demand from 2000–2007 have been for bitumen in road building, gas/diesel in construction and heavy fuel oil in glass and cement production. Demand for these products has increased at above 10% p.a. over this period. Prospects for oil demand growth are clearly contingent upon the future pace of investment activity, but also upon the extent to which substitution patterns affect the fuel mix in this sector. In particular, the key fuels for this sector continue to be coal and coal-based electricity, accounting for a combined total of more than 80% of energy use. Despite this dominance, and the fact that the share of industry in Chinese GDP is probably set to fall, in accordance with the country's 11th Five Year Plan, oil demand in this sector is still expected to grow steadily, although not at the rapid rates experienced over the past years.

Projections for oil use in other industry are shown in Table 2.8. The only source of growth is in developing countries, which sees demand increase by almost 2 mboe/d

Chapter 2

Figure 2.14
Oil demand in other industry in developing countries



by 2030 compared to 2008. Again, the strongest increase comes from developing Asia and OPEC, together accounting for almost all of the net increase. Oil use in this sector in the OECD is expected to gradually fall.

Residential/commercial/agriculture

The evolution of oil use in the residential, commercial and agriculture sectors has been one of contrasting trends across world regions. While OECD and transition economies have witnessed static or falling demand, developing countries' oil use for these sectors has continued to rise over the past four decades (Figure 2.15). By 2007, developing countries' oil use in these three sectors was, for the first time, greater than in the OECD. This development highlights the importance of better understanding sectors beyond the transportation and industry sectors, in order to obtain a clearer picture of future oil demand prospects.

Of these three sub-sectors, residential oil use continues to be the most significant, accounting for close to half the sector's demand. Moreover, there have been robust upward trends for residential oil use in developing countries as traditional fuels have been replaced by commercial energy, largely as a result of increasing

Table 2.8
Oil demand in other industry in the Reference Case *mboe/d*

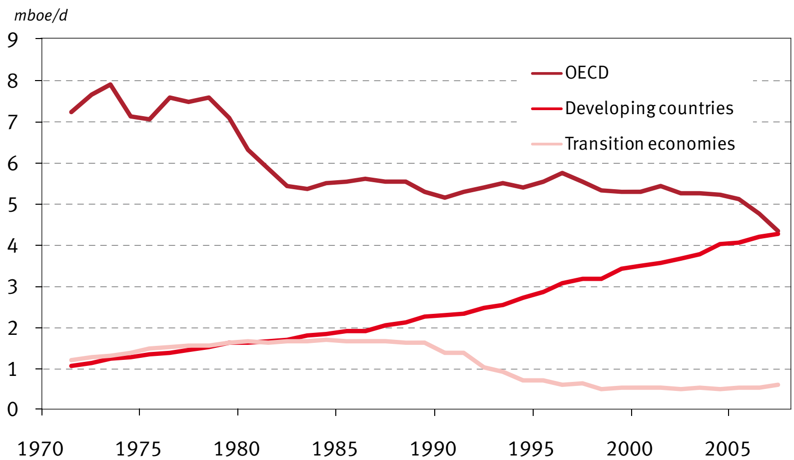
	Levels				Growth
	2008	2010	2020	2030	2008–2030
North America	3.2	3.2	3.1	2.9	–0.3
Western Europe	2.2	2.0	1.9	1.8	–0.3
OECD Pacific	1.1	1.0	0.9	0.9	–0.2
OECD	**6.4**	**6.2**	**5.9**	**5.7**	**–0.8**
Latin America	0.9	0.9	0.9	0.9	0.1
Middle East & Africa	0.6	0.6	0.7	0.8	0.2
South Asia	1.0	1.0	1.3	1.5	0.5
Southeast Asia	0.9	1.0	1.1	1.1	0.2
China	1.9	1.9	2.2	2.3	0.4
OPEC	1.5	1.7	1.8	1.9	0.4
Developing countries	**6.9**	**7.1**	**8.0**	**8.7**	**1.8**
Russia	0.6	0.6	0.7	0.7	0.1
Other transition economies	0.4	0.4	0.4	0.4	0.0
Transition economies	**1.0**	**1.0**	**1.0**	**1.1**	**0.1**
World	**14.2**	**14.2**	**15.0**	**15.5**	**1.2**

urbanization. India and China are the key users, accounting for 40% of developing country demand. On the other hand, oil use in OECD households has steadily declined, although it still accounts for around 2 mboe/d of demand, with the US being the largest single OECD user.

Although residential oil consumption retains its prominence in this sector, oil demand prospects are also increasingly affected by the use of products in the agricultural sector, particularly in developing countries, where consumption doubled over the period 1990–2007.

The projections for this grouping are shown in Table 2.9. Oil demand in developing countries is seen to increase in the Reference Case by 3 mboe/d over the period 2008–2030, confirming the importance of the sector. Nevertheless, this is in part negated by declines in oil use elsewhere, in particular through an expected continued decline in residential oil use in the OECD and transition economies. Global oil use in the residential, commercial and agriculture sectors is thereby expected to rise by just over 2 mboe/d by 2030.

Figure 2.15
The evolution of oil demand in residential/commercial/agriculture sectors



Electricity generation

It is well documented that electricity demand growth in developing countries is typically at least as strong as economic growth. And in developed countries, it is also a form of energy that exhibits a strong link between demand and GDP. In the OECD, despite limited requirements for additional basic services from electricity, there is still a growing demand for electrical appliances that underpins the need for more electricity. On the flip side, however, improved efficiency standards in new electrical products are already impacting average electricity needs, and as the present stock turns over, there should be considerable scope for further efficiency gains.

The story is, of course, very different in developing countries, where the key statistic remains the fact that there are still 1.4 billion people who do not have access to electricity. As can be seen from Figure 2.16, although the demand growth rate in developing countries has been swifter, it has been from a low base. On average, per capita electricity use in the residential sector in developing countries is still less than one-ninth of that in the OECD. The ratio has, however, improved dramatically since 1971, when per capita use in the OECD was forty times higher than in developing countries.

The role of oil in meeting the expected future electricity demand will continue to be reduced, as further switching towards other fuels occurs. Thus, despite the

Table 2.9
Oil demand in residential/commercial/agricultural sectors in the Reference Case *mboe/d*

	Levels				Growth
	2008	2010	2020	2030	2008–2030
North America	1.6	1.6	1.5	1.4	–0.2
Western Europe	1.7	1.6	1.4	1.3	–0.4
OECD Pacific	0.9	0.9	0.8	0.8	–0.1
OECD	**4.2**	**4.0**	**3.8**	**3.5**	**–0.7**
Latin America	0.6	0.6	0.8	1.0	0.5
Middle East & Africa	0.5	0.5	0.7	0.8	0.3
South Asia	0.6	0.7	0.9	1.2	0.5
Southeast Asia	0.6	0.6	0.6	0.7	0.1
China	1.3	1.4	2.0	2.5	1.2
OPEC	0.7	0.8	1.0	1.1	0.4
Developing countries	**4.4**	**4.6**	**6.0**	**7.4**	**3.0**
Russia	0.3	0.3	0.2	0.2	–0.1
Other transition economies	0.3	0.3	0.3	0.3	–0.1
Transition economies	**0.6**	**0.6**	**0.5**	**0.5**	**–0.1**
World	**9.2**	**9.2**	**10.3**	**11.3**	**2.1**

expected growth in electricity demand, no global increase is expected for oil used in electricity generation (Table 2.10). The only scope for a slight rise in oil use will come from remote areas in developing regions where, for example, diesel-powered generators can provide access to electricity more readily than other means that require more expensive infrastructure.

Marine bunkers

Throughout the last century and the early part of this, the shipping industry has witnessed an expansion in the amount of trade it carries. This has been fuelled by increased industrialization, a growing demand for consumer products and the general advancement of globalization. It has led to the sea lanes of the world becoming the global highways for trade; from crude oil in vast oil tankers and iron ore in huge bulk carriers, to containerships full of every conceivable consumer good.

Today, more than 90% of world trade is carried by sea. By 2008, carried cargoes by sea amounted to more than 8.1 billion tonnes, equivalent to a total volume of world trade by sea of over 33,000 billion tonne-miles. And it is anticipated that the

Figure 2.16
Average annual per capita electricity use in the residential sector, 1971–2007

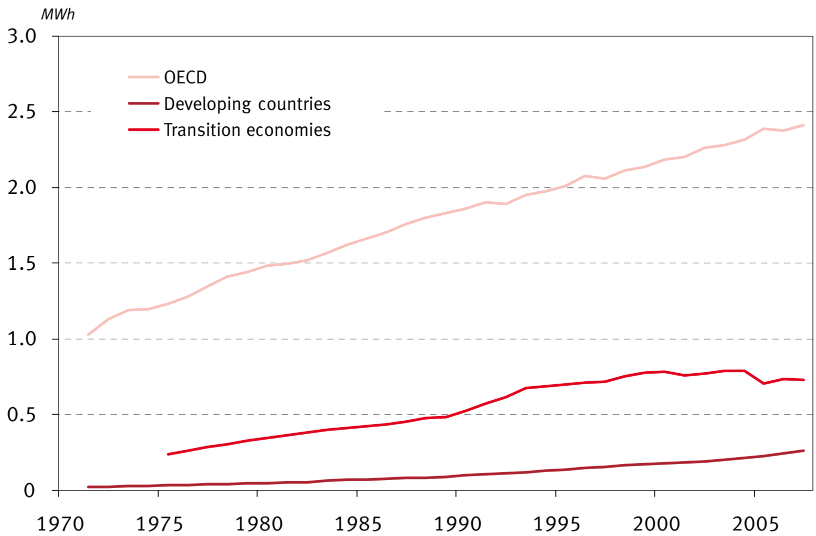


Table 2.10
Oil demand in electricity generation in the Reference Case

mboe/d

	Levels				Growth
	2008	2010	2020	2030	2008–2030
North America	0.7	0.7	0.7	0.7	0.1
Western Europe	0.5	0.4	0.4	0.3	–0.2
OECD Pacific	0.7	0.7	0.5	0.4	–0.3
OECD	**1.9**	**1.8**	**1.6**	**1.4**	**–0.5**
Latin America	0.5	0.5	0.5	0.5	0.0
Middle East & Africa	0.5	0.5	0.6	0.8	0.3
South Asia	0.3	0.4	0.5	0.6	0.3
Southeast Asia	0.4	0.4	0.4	0.4	0.0
China	0.2	0.2	0.2	0.2	–0.1
OPEC	1.4	1.4	1.5	1.5	0.0
Developing countries	**3.4**	**3.4**	**3.6**	**3.9**	**0.5**
Russia	0.3	0.3	0.2	0.1	–0.1
Other transition economies	0.1	0.1	0.1	0.1	–0.1
Transition economies	**0.4**	**0.4**	**0.3**	**0.2**	**–0.2**
World	**5.7**	**5.6**	**5.6**	**5.5**	**–0.2**

growth in sea trade will continue as the world's population continues to rise and demand for goods from developing countries increases.

It has all meant that fuel demand in this sector has grown significantly. Indeed, in recent years the annual growth rate of global fuel consumption has been around 3.3%, which is higher than that for the transportation sector as a whole. However, fuel consumption per carried cargo has been declining, at an average rate of 0.7% p.a. during the period 1988–2008.

One of the important challenges facing the shipping industry, as described in the WOO 2009, concerns the growth of emissions limits and the need to use cleaner products. Regulations for securing improved standards for safety at sea and marine pollution are mandated by two conventions: the SOLAS (Safety of Life at Sea) and MARPOL (Marine Pollution). The first concerns the safety of merchant ships and the second covers the prevention of pollution of the marine environment by ships from operational or accidental causes. In recent years, the major impact of these conventions on the shipping and refining industries has been the amendments to the MARPOL Convention with regard to emissions limits. This includes strengthening and extending the concepts of Emission Controlled Areas (ECAs) when considering SOx, NOx and particulate matters.

For a number of years, the Baltic Sea, the North Sea and the English Channel have been considered ECAs by the International Maritime Organization (IMO), which means ships effectively have to switch to much cleaner fuels when operating in these waters. Looking ahead, specific areas of the US and Canada will become ECAs by 2012. And it is expected that ECAs will in the future be expanded to other areas such as the Norwegian and Barents Sea, the Mediterranean Sea and Japanese waters. The upshot is that an expansion in the number of ECAs signifies a greater need for cleaner fuels.

However, there are huge uncertainties concerning the impacts of MARPOL regulations on marine bunker fuels, international maritime transportation and the refinery industry. This stems from the uncertainties on the penetration of scrubbing, refinery investment in cracking technologies and new ECA areas, something that is explored in more detail in Chapter 6. What is apparent, however, is that these moves towards more stringent emission limits will bring with them additional cost burdens for ship operators. It points to the expectation that efficiency gains of the past will at least continue into the future, and probably accelerate.

Although there is the expectation that efficiency gains will continue, the increase in oil demand in marine bunkers in the Reference Case remains strong, approaching 3 mboe/d over the period 2008–2030 (Table 2.11), with close to 80% of that growth in developing Asia.

Demand by product

The key findings related to sectoral oil demand underscore the importance of the transportation sector, which accounts for more than 40% of current oil demand. Moreover, this sector is seen as the main segment for future demand growth. Within the transportation sector, the growth will primarily occur in road transportation, followed by aviation. Marine bunkers will also significantly contribute to future demand, although they are accounted for separately. Another key observation underscores the growing importance of the petrochemical industry in terms of oil demand levels and growth. Other industrial activities such as construction, iron and steel, machinery and paper are also witnessing oil demand growth. Additionally, divergent regional trends for oil use in electricity generation and in the residential/commercial/agriculture sector will also affect future product demand.

These developments in specific oil demand sectors determines to a great extent the current and future demand structure in respect to the product slate. Observed

Table 2.11
Oil demand in marine bunkers in the Reference Case *mboe/d*

	Levels				Growth
	2008	2010	2020	2030	2008–2030
North America	0.6	0.5	0.5	0.5	–0.1
Western Europe	1.0	1.0	1.1	1.2	0.2
OECD Pacific	0.2	0.2	0.2	0.1	0.0
OECD	**1.8**	**1.7**	**1.8**	**1.9**	**0.1**
Latin America	0.1	0.1	0.2	0.2	0.1
Middle East & Africa	0.1	0.1	0.1	0.1	0.0
South Asia	0.0	0.0	0.0	0.0	0.0
Southeast Asia	0.8	0.7	1.1	1.6	0.8
China	0.2	0.3	0.7	1.7	1.5
OPEC	0.4	0.4	0.5	0.7	0.3
Developing countries	**1.6**	**1.6**	**2.5**	**4.3**	**2.7**
Russia	0.0	0.0	0.1	0.1	0.1
Other transition economies	0.1	0.1	0.1	0.1	0.0
Transition economies	**0.1**	**0.1**	**0.2**	**0.2**	**0.1**
World	**3.5**	**3.4**	**4.5**	**6.4**	**2.9**

key trends in sectoral demand are clearly reflected in projections of global product demand, as presented in Table 2.12 and in Figure 2.17.

In terms of volume, the largest increase in future demand is projected for diesel/gasoil, with an increase of almost 10 mb/d by 2030, from 2009 levels. This is because diesel/gasoil is used in a wide range of growth sectors, including the key transport and industry sectors. Within the product group of diesel/gasoil, it is diesel for transport that is growing most rapidly in the majority of countries, whereas gasoil for heating is being negatively impacted by the shift towards the increased use of natural gas and/or electricity and renewable energy for heating. The declining gasoil share is also supported by the tightening quality specifications for this product, especially in Europe, as this encourages a switch either to diesel from gasoil in the residential sector, or to alternative fuels. A combination of these trends results in a projection for future average diesel/gasoil growth of 2% p.a. This is double the average and above the levels of other major transport fuels.

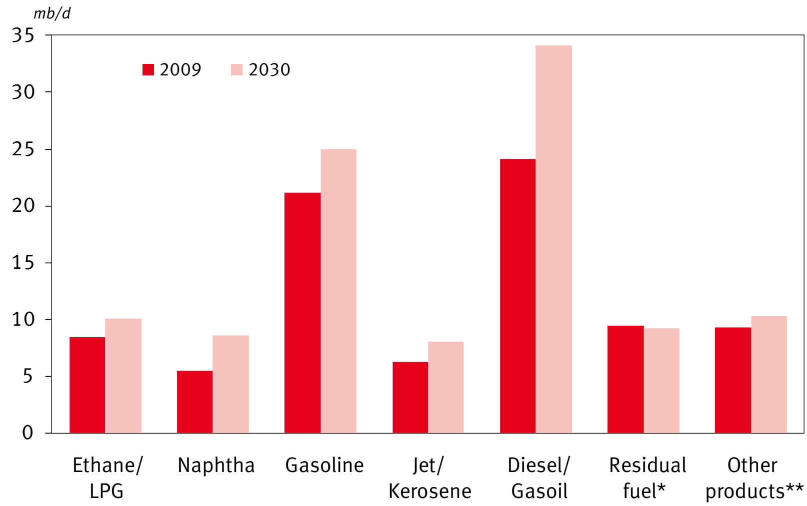
Nevertheless, there are two key issues that could potentially alter this view. The first one is the penetration level of diesel cars in expanding markets. The projections

Table 2.12
Global product demand, shares and growth

	Global demand mb/d					Growth rates % p.a.		Shares %	
	2009	**2015**	**2020**	**2025**	**2030**	**2009–2015**	**2015–2030**	**2009**	**2030**
Light products									
Ethane/LPG	8.5	9.0	9.4	9.7	10.1	1.1	0.7	10.0	9.5
Naphtha	5.5	6.2	6.9	7.7	8.4	2.1	2.1	6.5	8.0
Gasoline	21.2	22.4	23.4	24.2	25.0	0.9	0.7	25.1	23.7
Middle distillates									
Jet/kerosene	6.3	6.8	7.2	7.6	8.0	1.3	1.1	7.4	7.6
Gasoil/diesel	24.3	27.4	29.8	32.0	34.1	2.0	1.5	28.7	32.4
Heavy products									
Residual fuel*	9.5	9.4	9.4	9.2	9.1	–0.1	–0.2	11.2	8.6
Other**	9.3	9.8	10.2	10.5	10.7	0.7	0.6	11.1	10.1
Total	**84.5**	**91.0**	**96.2**	**100.9**	**105.5**	**1.2**	**1.0**	**100.0**	**100.0**

* *Includes refinery fuel oil.*
** *Includes bitumen, lubricants, waxes, still gas, coke, sulphur, direct use of crude oil, etc.*

Figure 2.17
Global product demand, 2009 and 2030



assume an increasing share of diesel cars in developing countries, although not to the levels experienced in Europe. The reality, however, could deviate in either direction depending on the progress in engine technologies and the taxation policies of these countries. The second issue relates to marine bunker regulations. Much stricter future quality specifications for marine bunker fuel could potentially lead to a partial, or even a total switch from residual fuels to diesel oil in international shipments. Needless to say, this could dramatically increase future diesel demand, with substantial implications for the refining sector.

Another growing middle distillates product group is jet fuel and kerosene. Similar to the case of diesel/gasoil, demand for jet fuel is on the rise, but kerosene for residential use – mostly for lighting and heating/cooking – will continue to be displaced by alternative fuels in most regions. Kerosene demand is projected to decline steadily. This makes overall growth lower than it would have been if jet fuel/kerosene was considered alone. In total, jet fuel/kerosene demand is projected to grow on average by 1.3% p.a. for the entire forecast period. This corresponds to an increase of close to 2 mb/d by 2030. Moreover, growth in this product group is much faster in developing countries, up to 5% p.a. in some regions, while demand in OECD regions is flat to marginally declining.

While gasoil/diesel is foreseen to record the highest volume gain within the forecast period, it is naphtha that will be the fastest growing product on a percentage basis, especially in developing Asia. Despite a temporary naphtha demand decline for in 2009, the growth is expected to resume in 2010 and to continue in both the medium- and long-term, with average growth rates at 2.1% p.a. This is driven mainly by high petrochemicals demand growth, volume increases in Asia, as well as expanding demand in most developing countries, albeit from a lower volume base. These increases more than compensate for the stagnant or declining naphtha demand in OECD regions. Moreover, naphtha demand growth helps partially offset a moderate projected global growth rate for gasoline of 0.9% p.a. over the forecast period as it represents a significant portion of the gasoline boiling range when crude oil is distilled. The overall gasoline growth rate is low because of the importance of North America and Europe in total gasoline demand. The two regions comprised 56% of global gasoline demand in 2009. Therefore, demand declines in these regions have a large impact on the global picture, offsetting increases in other regions, with rates ranging between 1% and 4% p.a.

Looking at these product categories as a whole, the future demand trend clearly emphasizes a further shift towards middle distillates and light products. The numbers speak for themselves: out of 21 mb/d of additional demand by 2030, compared to 2009 levels, around 55% is for middle distillates and another 32% is for gasoline and naphtha.

Contrary to light products, the demand for residual fuel oil is projected to decline, while other products, mostly heavy, will expand moderately. The picture here is, however, a little bit more complicated than the overall figures suggest. In particular, fuel oil is typically consumed for electricity generation, in the industry sector, as a bunker fuel and for a refinery's internal use. The use of fuel oil in industry and refineries faces competition from natural gas, as fuel oil for electricity generation does in most regions. However, the result of this 'competition' varies across regions. On a global scale, demand decreases in these sectors are expected to be broadly compensated by growth in international shipments, thus there is an increased demand for bunkering. In the Reference Case projections, residual ('intermediate') fuel oil remains the major bunker fuel. However, as mentioned earlier, tightening product specifications for international bunkers could further reduce demand for fuel oil.

The last group of products, labelled 'other products', consists of a mixture of streams, such as asphalt, lubricants, petroleum coke, refinery gas, sulphur, paraffin waxes and white spirit. It also includes the direct use of crude oil. Overall growth in these petroleum products is projected to be approximately 0.7% p.a., when 2009 and 2030 are compared. Within the group, somewhat stronger growth is assumed for lubricants and asphalt due to the expected expansion of road transportation, including the building of the required infrastructure. Generally, products such as asphalt, lubricants, waxes and solvents are strongly linked to economic growth, and the production of still gas, coke and sulphur is very much a function of refining activity growth. Therefore, there are regional variations in projected demand changes for these products. These range between declining demand in Western Europe and North America, to strong increases in Africa and the Asia-Pacific, particularly China.

Chapter 3

Oil supply

The overview of the oil supply outlook presented in Chapter 1 underscores that an eventual small decline in non-OPEC crude and NGLs will be more than compensated by increases in supply from biofuels and oil sands. At the same time, OPEC NGLs production is expected to see robust growth. The longer term implications of these developments is that there will be a growing need for OPEC crude in the Reference Case, although in the medium-term this increase is slow to take hold.

This Chapter explores in more detail the components of the supply outlook. It begins with an assessment of non-OPEC crude oil and NGLs in the medium- and long-term. These two time spans imply the need for two distinct methodologies: the medium-term assessment to 2014 takes advantage of a comprehensive database of upstream projects, while the long-term outlook relates to the availability of remaining resources. The outlook for non-conventional oil and biofuels is then discussed. As with demand, it is important to bear in mind that there are considerable uncertainties surrounding the outlooks for both conventional and non-conventional oil. The Chapter finishes with a closer look at OPEC upstream investment.

Medium-term non-OPEC crude and NGLs

The potential short- and medium-term adverse impact on oil supplies of the economic crisis, the debt financing difficulties and the low oil price environment has now eased. The global upstream investment level, after a 22% decline in 2009 has returned to an upward trend. It is expected to rise by 8% to $353 billion in 2010.[22]

One of the most destabilizing forces to affect non-OPEC supply in recent times has been oil price volatility. In the summer of 2008 the oil price reached record levels, before collapsing significantly to just above $30/b by the end of the year. This movement inevitably focused attention upon the possible impacts of low oil prices on the industry, as projects were cancelled or delayed (Box 3.1). In the second half of 2009 and in 2010, however, oil prices have recovered to over $70/b and in recent months credit markets have eased.

In fact, recent production figures from some key areas have been above expectations and the supply outlook in the short- and medium-term is encouraging, leading to an upward revision to last year's WOO.

By 2014, non-OPEC crude plus NGLs supply is expected to be more than 1 mb/d higher than in the WOO 2009 reference case. Total non-OPEC crude and NGLs supply is expected to reach 46.2 mb/d in 2014 (Table 3.1). The main growth in non-OPEC supply will come from Brazil deepwater and pre-salt, Russia, Kazakhstan, Colombia, Azerbaijan, India, Malaysia and Congo. Mature areas such as the UK, Norway and Mexico will dominate the declines.

The Deepwater Horizon explosion, and the subsequent Gulf of Mexico oil spill, clearly has implications for oil supply (Box 3.2). For example, the moratorium that followed has some immediate impacts, including project delays. Moving forward, however, the effects are still far from clear. It is expected, however, that costs will rise, as regulations become stricter, at least in the US, but the actual extent of these increases remains uncertain. New regulations are still being discussed and debated, and knock-on effects to other world regions are a major unknown. For the medium-term outlook, however, it should be noted that the spill has occurred in the context of a rapid expansion of production in the area. In 2009, many projects in the deepwater Gulf of Mexico began, adding over 300,000 b/d in gross capacity. During 2010–2014 many more are scheduled to come on stream, adding over 600,000 b/d in gross capacity. The new big deepwater projects include Knotty Head, Cascade and Chinook, Puma, Droshky and Great White, with a number of smaller fields coming on stream too. By 2014, US Gulf of Mexico production is expected to reach close to 2 mb/d, from around 1.2 mb/d in 2009.

In the US too, and for the first time since 2002, Alaska will be adding production capacity over the medium-term. However the gross addition is only around 100,000 b/d by 2014, mainly from Liberty and Prudhoe Bay Western Region developments.

Despite the expected growth in production levels in the Gulf of Mexico, declines elsewhere, together with a relatively stable supply from Canada, means that US & Canada crude oil plus NGLs production will begin to decline from 2011, at an annual rate of around 0.1 mb/d, reaching 8.8 mb/d by 2014.

While Mexico succeeded in slowing its decline rate during 2009, as production fell by 190,000 b/d against a 290,000 b/d drop in 2008, there remain significant uncertainties ahead, mainly due to the continuing decline in the giant Cantarell field. The gradual decline in crude plus NGLs production from Mexico is expected to remain, with it falling to 2.7 mb/d by 2014 from 3 mb/d in 2009.

In Western Europe, crude and NGLs production fell by 250,000 b/d in 2009. This was mainly from the North Sea. Moreover, North Sea oil production is expected to decline further in the coming years as the basin matures and following a reduction

Table 3.1
Medium-term non-OPEC crude oil and NGLs supply outlook in the Reference Case *mb/d*

	2009	2010	2011	2012	2013	2014
United States	7.2	7.3	7.1	7.0	6.9	6.9
Canada	1.9	1.9	2.0	2.0	2.0	1.9
US & Canada	**9.1**	**9.2**	**9.1**	**9.0**	**8.9**	**8.8**
Mexico	**3.0**	**2.9**	**2.8**	**2.8**	**2.7**	**2.7**
Norway	2.3	2.2	2.1	2.1	2.0	1.9
United Kingdom	1.5	1.3	1.3	1.3	1.2	1.2
Denmark	0.3	0.3	0.2	0.2	0.2	0.2
Western Europe	**4.4**	**4.1**	**3.9**	**3.8**	**3.7**	**3.6**
Australia	0.5	0.5	0.6	0.6	0.5	0.5
OECD Pacific	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**
OECD	**17.1**	**16.8**	**16.5**	**16.2**	**15.9**	**15.7**
Argentina	0.7	0.7	0.7	0.7	0.7	0.7
Brazil	2.0	2.2	2.3	2.4	2.5	2.6
Colombia	0.7	0.8	0.8	0.8	0.8	0.8
Latin America	**3.9**	**4.1**	**4.3**	**4.4**	**4.5**	**4.6**
Oman	0.8	0.8	0.8	0.8	0.8	0.8
Syrian Arab Republic	0.4	0.4	0.4	0.4	0.3	0.3
Yemen	0.3	0.3	0.3	0.3	0.2	0.2
Middle East	**1.7**	**1.7**	**1.7**	**1.7**	**1.6**	**1.6**
Congo	0.3	0.3	0.3	0.3	0.3	0.3
Egypt	0.7	0.7	0.6	0.6	0.6	0.6
Equatorial Guinea	0.4	0.3	0.4	0.4	0.4	0.4
Gabon	0.3	0.3	0.3	0.3	0.2	0.2
Sudan	0.5	0.5	0.5	0.5	0.5	0.5
Africa	**2.6**	**2.6**	**2.6**	**2.6**	**2.6**	**2.6**
India	0.8	0.8	0.9	0.9	1.0	1.0
Indonesia	1.0	1.0	1.0	1.0	1.0	1.0
Malaysia	0.7	0.7	0.6	0.7	0.7	0.8
Thailand	0.4	0.3	0.3	0.3	0.4	0.4
Vietnam	0.4	0.4	0.4	0.4	0.4	0.4
Asia	**3.7**	**3.7**	**3.7**	**3.8**	**3.8**	**3.8**
China	**3.8**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**
DCs, excl. OPEC	**15.6**	**16.0**	**16.2**	**16.2**	**16.4**	**16.5**
Russia	**9.9**	**10.1**	**10.1**	**10.1**	**10.2**	**10.3**
Kazakhstan	1.5	1.6	1.7	1.8	1.8	2.0
Azerbaijan	1.0	1.2	1.2	1.3	1.3	1.3
Other transition economies	**3.2**	**3.3**	**3.4**	**3.6**	**3.6**	**3.8**
Transition economies	**13.1**	**13.3**	**13.5**	**13.7**	**13.8**	**14.1**
Total non-OPEC crude & NGLs	**45.7**	**46.1**	**46.1**	**46.1**	**46.1**	**46.2**

in exploration and appraisal spending. As a result, West European crude oil and NGLs production is expected to fall to 3.6 mb/d in 2014, down from 4.4 mb/d in 2009, driven mainly by field declines in the mature North Sea.

Norwegian production fell to 2.3 mb/d in 2009. This was despite the fact the Alvheim-Vilje field reached its plateau rate of 120,000 b/d in 2009 and Tyritans, a condensate field, was brought on stream. Production is expected to decline further in 2010. Nevertheless, the fall may be smaller than 2009, as the Snohvit condensate field has recently come back on stream. Declines in mature fields and uncertainties surrounding new investments, due to higher costs, have increased the medium-term risk.

In the UK, crude and NGLs production fell by around 80,000 b/d during 2009, as a number of fields within the Forties complex, including the Buzzard field, shut down for extensive maintenance. Production is expected to decline further in 2010, following a reduction in exploration and appraisal spending and significant declines in existing fields; only 78 exploration and appraisal wells were drilled on the UK's continental shelf during 2009, down by around 35% compared with the previous year. A further slowdown in investments is expected in 2010, which is expected to have an additional adverse impact on the decline rate. Nevertheless, a number of fields were put on stream during the last year including Jacky, West Don, Don South West and Shelley. With all this in mind, crude oil and NGLs production in the UK is expected to continue its steady decline, falling from around 1.5 mb/d in 2009 to 1.2 mb/d in 2014. This fall reflects the fact that most fields are now well into their decline phase. Some of this decline is compensated by a number of substantial new developments including Lochranza, Athena, Fyne, Causeway Phase I, Cheviot, Huntington, Perth, Lyell (redevelopment), Bugle, Golden Eagle Area, Clair Phase II and Laggan-Tormore.

The production of crude and NGLs in Latin America in the Reference Case is expected to steadily rise over the medium-term, reaching 4.6 mb/d in 2014, up from 3.9 mb/d in 2009, mainly due to increases in Brazil. The Urugua-Tambua, Mexilhao, Pinauna, Golfinho Module 3, Peregrino, Marlim Sul Module 3, Cavalo Marinho, as well as the Tupi pre-salt pilot production in the Santos Basin, are set to add at least 450,000 b/d of capacity by 2011. A further ten major projects – Jubarte Phase 2, Marlim Sul Module 4, Whale Park fields, Guara, Papa-Terra, Roncador P-55, Espadarte Module 3, Roncador P-62, Iara and Oliva & Atlanta – with a total production capacity in excess of 1.1 mb/d, will further contribute to the medium-term growth. It should be noted, however, that the production test of Tupi that began in May 2009 and which was planned to continue for 15 months, was halted only two months later due to technical difficulties.

The other source of medium-term growth in this region is Colombia. Its crude oil and NGLs production is expected to increase from about 670,000 b/d in 2009 to 750,000 b/d in 2014. Increased production depends on new capacity from fields that are currently in development or under appraisal. The main growth will come from the redevelopments of the Rubiales heavy oil field and the construction of the Oleoducto de Los Llanosa heavy oil pipeline that will eliminate bottlenecks. Other major projects contributing to future capacity increases include the Tibu phase III development and the Llanos Basin heavy crude project.

Non-OPEC Middle East & Africa crude oil and NGLs production over the medium-term is expected to stay approximately flat, at just over 4.2 mb/d.

In the Middle East region, Oman will depend on heavy oil developments and enhanced oil recovery (EOR) projects to offset decline rates and sustain a production level of around 0.8 mb/d. In this regard, good results have already been achieved at the Mukhanizana field using steam injection. Production at this field is expected to increase from 90,000 b/d in 2009 to around 150,000 b/d by 2012. In addition, Oman will add 10,000 b/d from the Marmul polymer injection project, 40,000 b/d from miscible gas injection at the Harweel field and another 40,000 b/d from steam injection at Qarn Alam field. On the other hand, production from Yemen and Syria is expected to decline slowly over the medium-term. For Syria, increasing water production becomes an ever more serious problem in mature and depleting fields. Crude oil and NGLs production in the non-OPEC Middle East is expected to fall slightly from 1.7 mb/d in 2009 to 1.5 mb/d in 2014.

In non-OPEC Africa, some growth is expected, mainly from Sudan and Congo. In recent years, considerable growth has occurred in Sudan, although this has not been as quick as anticipated just a few years ago. Looking ahead, the start-up of the Gumry and Meleta fields is set to add around 100,000 b/d of capacity by 2012. Consequently, Sudan's crude oil and NGLs production is expected to increase from about 470,000 b/d in 2009 to 540,000 b/d in 2014. Production from Congo is expected to increase over the medium-term, mainly due to increased investments in a new onshore development and the ramp-up in production from deepwater projects, including the M'Boundi Upgrade, Moho/Bilondo, Haute Mer N'Kossa and Azurite. As a result, Congo's crude oil and NGLs production is anticipated to increase from about 270,000 b/d in 2009 to 340,000 b/d in 2014. Other countries contributing to the medium-term growth include Ghana, driven by the Jubilee phase 1 (120,000 b/d) development, which is expected to be on stream in late 2010. On the other hand, Egypt is projected to decline steadily from almost 700,000 b/d in 2009 to less than 600,000 b/d in 2014. This is driven by a production decline in the Gulf of Suez, which accounts for the majority of Egypt's oil production. The rate of decline, however, is expected to be limited by the emergence of the Western Desert as a new oil producing region and by growing condensate production. In the Reference Case, crude oil and NGLs production in non-OPEC Africa remains fairly flat between 2009 and 2014 at around 2.6 mb/d.

Crude oil and NGLs in non-OPEC Asian countries, excluding China, grows only very slowly over the medium-term, reaching 3.8 mb/d by 2014, about 100,000 b/d higher than 2009 levels. India is projected to grow strongly in the next few years, driven by the start-up of the onshore Rajasthan project, which is targeting peak production of around 175,000 b/d in 2011. Further projects including Bhagyam, Saraswati/Raageshwari and the Krishna-Godavari Cluster fields, with a total production capacity in excess of 240,000 b/d, will also support India's medium-term output growth. As a result, Indian crude oil and NGLs production is expected to increase from about 800,000 b/d in 2009 to 970,000 b/d in 2014. In Malaysia, production is anticipated to increase by around 50,000 b/d, from 710,000 b/d in 2009 to 760,000 b/d in 2014, as many fields, including Gumusut-Kakap, Sumandak and Malikai, with over 200,000 b/d capacity are expected to come on stream over the next five years. Vietnam's production is forecast to decline in 2010, but from 2011 mature field declines will be offset by the Nam Rong/Doi Moi, Su Tu Den, Chim Sao & Dua fields, as well as the Te Giac Trang group of fields. Further projects are also expected to come on stream, including the Te Giac Trang, Hai Su Den, Hai Su Trang and Su Tu Trang fields. Elsewhere, supply is not expected to grow in Indonesia, Brunei, Papua New Guinea, Pakistan and Thailand. In Indonesia the production of crude and NGLs will stay approximately flat at around 1 mb/d. Decline in the mature fields will be offset by new production, as many fields including the Tuban Block Expansion, Gendalo, Kangean Expansion, Jeruk, Gehem-Ranggas, Bukit Tua and Sadewa with over 210,000 b/d capacity are slated to come on stream over the next five years. In addition, the giant Banyu Urip field, which came on stream last year, will reach 165,000 b/d around 2011, up from 20,000 b/d today.

In China, the giant Daqing, Shengli and Liaohe fields will continue to be the main source of supply, despite the fact that their production is in slow decline. Many new fields, including Bozhong, Yuedong, Weizhou & Weizhou South, Chunxiao and Xinbei, are expected to come on stream over the next five years. These are slated to add 85,000 b/d. In addition, phase 1 of the Nanpu field in Bhai Bay is anticipate to come on stream in 2010, adding 200,000 b/d once it reaches its plateau. Further developments in this field will add another 300,000 b/d over the next decade. Crude oil and NGLs production over the medium-term in China stays flat in the Reference Case at 3.9 mb/d.

Even with the investment cutbacks witnessed in late 2008 and early 2009 as a result of the financial crisis, particularly in the three largest producing countries, Russia, Azerbaijan and Kazakhstan, the transition economies region will continue to lead total non-OPEC medium-term volume growth. The crude oil and NGLs production in this group of producers is anticipated to grow from around 13.1 mb/d in 2009 to 14.1 mb/d by 2014.

Although oil production in Russia fell in 2008, growth returned in 2009 and further expansion is expected over the medium-term. The growth of Russian supply during 2009 can be attributed to the improved export revenue streams for oil companies, the fiscal measures that were put in place in late 2008/early 2009 to stimulate investment in remote regions and the start-up of new projects from investments made earlier. The main fields that came on stream during 2009 and which are now building towards their plateau include Salym, Vankorskoye, South Khylchuyuskoye, Urna, Ust-Tegus, Verkhnechonskoye and the Northern Hub of the Kamennoye oil field. These fields are expected to add around 650,000 b/d. Although the Volga-Urals region will continue to see an output decline, there are a number of new projects scheduled to start over the next few years including Yuri Korchagin, Kuyumbinskoye, Srednebotuobinskoye, Dulisminskoye (Phase I), Prirazlomnoye, Pyakyakhinskoye, Kolvinskoye, Dulisminskoye (Phase II), Vladimir Filanovsky, East & West Messoyakhskoye and Yurubcheno-Tokhomskoye (Phase I). The production capacity of these fields totals around 900,000 b/d. Production in East Siberia and the Far East (Sakhalin Island) is also expected to rise. With all of these developments, crude oil and NGLs production in Russia increases gradually in the Reference Case from 9.9 mb/d in 2009 to 10.3 mb/d in 2014.

In the other transition economy countries, crude oil and NGLs production, with Azerbaijan and Kazakhstan the major producers, is expected to increase from 3.2 mb/d in 2009 to around 3.9 mb/d by 2014. In Azerbaijan the bulk of this expansion comes from the deepwater Azeri Chirag Guneshli (ACG) project, as the country continues its development of the ACG complex of fields, where peak production is anticipated to be just below 1 mb/d in 2012. However, production growth did slow slightly in 2009, due to technical problems (gas leakage) at the ACG complex. Azerbaijan's crude oil and NGLs production increases from about 1 mb/d in 2009 to 1.3 mb/d in 2014. Expected increases in Kazakhstan are primarily the result of expansions at the Tengiz and Karachaganak fields. The current development of the Tengiz field is anticipated to increase its total production to around 750,000 b/d by 2011/early 2012. However, the final expansion of this field, which is slated to start producing two years later, will only help in offsetting the decline elsewhere and maintain a production plateau of 750,000 b/d for nine-to-ten years. Phase III of the Karachaganak project is expected to start production in 2012. The start-up of the Kashagan early production is also anticipated in the medium-term, although this has now been pushed back to 2013. Crude oil and NGLs production in Kazakhstan increases from 1.5 mb/d in 2009 to 2 mb/d in 2014 in the Reference Case.

Long-term non-OPEC crude and NGLs

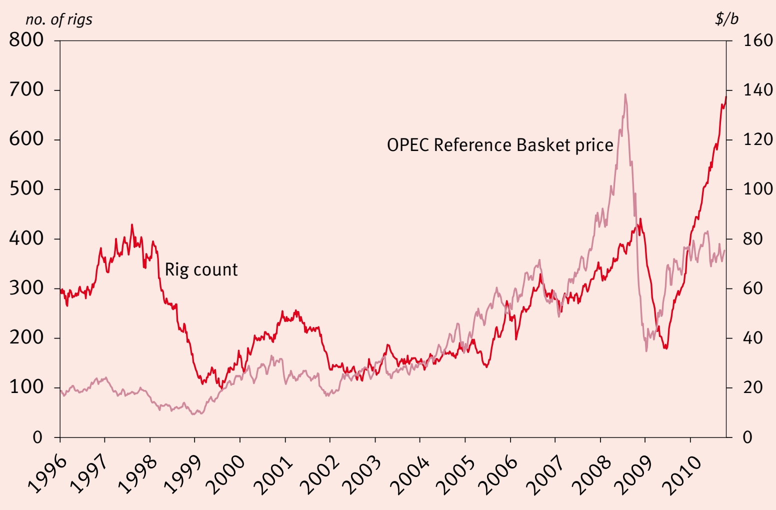
Long-term non-OPEC crude and NGL supply levels will be affected by a range of factors, including the oil price, the evolution of costs, fiscal conditions, investment

Box 3.1
Oil supply: lessons from low prices

The oil price turbulence of the recent past has drawn attention to several important issues. One relates to the possible non-OPEC oil supply implications of the price collapse in the second half of 2008, with the OPEC Reference Basket falling from around $140/b at the beginning of July to just $33/b by the end of the year. This development brought with it new challenges for the oil industry. The fall in oil prices, at a time when costs had settled at considerably higher levels than in the past, placed strains on the industry's ability to invest at appropriate levels. The changed economics and the uncertainties resulting from wide price fluctuations led to project cancellations and delays, although many of these have now been reactivated. It is important, therefore, to derive lessons from this episode.

It is broadly accepted that actual production levels are typically insensitive to falling oil prices in the short-term. Indeed, in some instances lower prices could lead to higher short-term output, when oil companies seek to compensate for the effect of lower prices on cash flows by overproducing wells and/or postponing maintenance and some investments in mature fields. However, the medium- and long-term responsiveness to low oil prices is generally much higher than in the short-term, as changes to exploration and development investment translate into future

US oil rig count and the OPEC Reference Basket price



Source: Baker Hughes, OPEC Secretariat.

production levels. This can be viewed in the fact that the exploration and development rig count has responded closely to price movements in the past, particularly in the OECD (see figure for US rig count).

The experience of the low oil price environment demonstrated that, in the medium-term, projects at an advanced development stage are likely to proceed. It is the projects that have not yet been approved or sanctioned that are at risk of being postponed or cancelled as a result of low prices. The projects considered most at risk at the end of 2008 following the price crash – and, in some cases, due to the impacts of other effects attendant to the global financial crisis, such as debt financing difficulties – were those with high costs and/or in a harsh environment, despite the fact that oil companies were in a healthy financial state as a result of the previous high price environment. This included deepwater projects in the Gulf of Mexico and Brazil, EOR projects and those in the Canadian oil sands.

OPEC supply prospects are also affected by low oil prices. If such prices emerge, for example, in the face of a demand contraction, the concern about investing in unneeded capacity is clearly more acute.

Furthermore, low oil prices have significant implications for more expensive non-conventional oil. In the medium- to long-term, most of the world's non-conventional oil supply (excluding biofuels) will come in the form of oil extracted from the Alberta oil sands. Although a number of large projects are planned to be developed over the next five-to-seven years, the oil price decline was one of the factors that led to project cancellations and delays. The prospects for biofuels production growth were also revised in the face of lower oil prices, especially when coupled with higher input commodity prices, such as corn prices in the case of US ethanol.

Of course, the adverse impact of the low oil price environment on oil supplies eased during 2009 as prices recovered. Indeed, the performance of non-OPEC producers in this price environment has been surprisingly strong. This is reflected, for example, in the steady upward revision to supply expectations as prices have more recently remained at comfortable levels. For 2010, expectations for conventional non-OPEC oil production in September 2010 had increased, when compared to the beginning of the year, by around 600,000 b/d. But not all of this has been driven by the current healthy price levels: in Russia, fiscal terms mean that producers are not fully exposed to international prices due to export taxes. Biofuel production in both the US and Brazil has also been stronger than previously anticipated.

Recent behaviour has shown that oil prices continue to matter for supply. The low prices witnessed at the end of 2008 led to a revision in investment plans; and if prices had remained that low, the implications for supply moving forward, both in OPEC and non-OPEC countries, could have been substantial. This, in turn, is a reflection of the lesson that low oil prices can sow the seeds of higher ones, and that security of supply is improved by security of demand.

activity, technology, the natural decline rates of existing fields, environmental regulation and the size of the resource base.

Technological developments have been key to expanding the resource base, making frontier oil commercially available and improving the recovery rates in existing fields. For example, just four decades ago, all offshore oil was considered an unconventional resource. However, this portion of global supply has since grown to account for 30% of the total. Cost developments will also depend on the outcome of the 'tug-of-war' between technology and resource depletion. For some countries, above-ground issues tend to be the main influence on the supply path. All of these elements, in addition to price and taxation, can add significant uncertainty to the level of non-OPEC supply that can be expected in the future. And this, in turn, adds to the uncertainty over how much oil will be required from OPEC Member Countries.

The long-term supply paths of non-OPEC crude oil and NGLs in the Reference Case are linked to the resource base using mean estimates of URR from the USGS to ensure that feasible, long-term sustainable paths are projected. In some cases, above-ground constraints dominate the paths. The feasibility is monitored beyond the projection period (up to 2050) to ensure that supply is consistent with smooth transitions to lower production paths as resources gradually deplete, rather than requiring any abrupt changes to supply at some point in the future. The approach, therefore, does not assume that the resource base is sufficient to satisfy expected world oil demand growth: it is a result of the methodology employed.

Estimates from the USGS assessment in 2000 of URR practically doubled since the early 1980s, from just under 1.7 trillion barrels to over 3.3 trillion barrels, while cumulative production during this period has been less than one-third of this increase. Improved technology, successful exploration and enhanced recovery from existing fields have enabled the world to increase its resource base to levels well above past expectations. This process continues today, and is expected to continue in the future.

Technology has, for example, revolutionized the information available about the features of a geological structure. This, in turn, has enhanced the likelihood of finding oil. The successful application of a remarkable array of technologies, such as 3-D and 4-D seismic and horizontal drilling, has extended the reach of the industry to new frontier areas, improved oil recovery and reserve growth, and reduced the industry's environmental footprint. Technological innovation remains central to further improving sub-surface imaging of deep and complex horizons, and improving recovery from existing fields.

Table 3.2 documents the estimated cumulative production, current proved reserves and the remaining reserves of conventional oil to be added, which come from two sources, namely reserves growth and discoveries yet to be made. The total original recoverable resources, estimated at 3.465 trillion barrels, are higher than the USGS figures in their World Petroleum Assessment 2000. This is because values have been adjusted to reflect a number of countries in Asia and Africa that are now producing oil, but in fact were not included in the USGS figures.

Table 3.2
Estimates of world crude oil and NGLs resources

billion barrels

	OPEC	Non-OPEC	Total world
Cumulative production to 2008 (a)	420	610	1,030
Proved reserves (b)	1,027	270	1,295
Reserves to be added ultimately (c)	**607**	**533**	**1,140**
Of which:			
Reserves growth	347	163	510
Discoveries yet to be made	260	370	630
Original Endowment (a) + (b) + (c)	2,054	1,413	3,465

Sources: USGS World Petroleum Assessment 2000, OPEC Annual Statistical Bulletin, July 2009, IHS PEPS database, Secretariat estimates.

Note should also be taken of the recent discoveries offshore Angola and Ghana and the USGS upward revision of undiscovered oil and gas north of the Arctic Circle by 412 billion boe of which 84% is expected to be offshore.

The non-OPEC region has 40% of the world's original endowment, against 60% for OPEC, and has produced more than 40% of this amount, against 20% for OPEC. The OECD countries as a group have produced more than 50% of their original endowment.

In the coming years, advances in technology, improvements in scientific knowledge and in upstream economics, will be the major drivers for increases in oil reserves.

Table 3.3 presents the long-term outlook for crude oil plus NGLs supply by region. Following the medium-term patterns, all OECD regions are set to see a continued decline to 2030, falling by 5 mb/d from 17.1 mb/d in 2009. Developing countries production initially rises for the first decade of the projection, largely due to increases in Brazilian production. Once supply plateaus in Latin America, however, a gradual decline in other developing regions means that the total developing country supply of crude and NGLs falls to 15.6 mb/d by 2030, the same level as in 2009. Over the entire projection period, Russia and other transition economies continue to increase their supply. Total non-OPEC production of crude oil and NGLs thereby stays approximately flat for much of the projection period, declining slightly in the latter years of the Reference Case.

Table 3.3
Long-term non-OPEC crude oil and NGLs supply outlook in the Reference Case *mb/d*

	2009	2010	2015	2020	2025	2030
US & Canada	9.1	9.2	8.8	8.2	7.6	7.1
Mexico	3.0	2.9	2.6	2.4	2.2	2.0
Western Europe	4.4	4.1	3.5	3.1	2.7	2.5
OECD Pacific	0.6	0.6	0.5	0.5	0.6	0.6
OECD	**17.1**	**16.8**	**15.4**	**14.3**	**13.1**	**12.1**
Latin America	3.9	4.1	4.8	5.6	5.8	5.6
Middle East & Africa	4.3	4.3	4.2	4.1	3.9	3.6
Asia	3.6	3.6	3.8	3.9	3.6	3.3
China	3.8	3.9	3.8	3.6	3.4	3.2
DCS, excl. OPEC	**15.6**	**16.0**	**16.6**	**17.2**	**16.7**	**15.6**
Russia	9.9	10.1	10.4	10.6	10.6	10.6
Other transition economies	3.2	3.3	3.9	4.3	4.6	5.0
Transition economies	**13.1**	**13.3**	**14.3**	**14.9**	**15.2**	**15.6**
Non-OPEC	**45.7**	**46.1**	**46.3**	**46.4**	**45.0**	**43.3**

The long-term outlook for the US does not factor in any persistent impacts from the Gulf of Mexico oil spill (Box 3.2). Nevertheless, it is possible that this assumption will need to be revisited in the future. In Alaska, the development of small fields and heavy oil, as well as the liquid production from gas/condensate fields, will

Box 3.2
After Deepwater Horizon: implications for the industry

The Deepwater Horizon drilling rig explosion earlier this year – and the subsequent oil spill – was a tragic event. Its impact and the aftermath have been felt by many: the 11 workers who died and their families, those that live along the Gulf of Mexico coast, the companies involved, the oil industry, in general, and deep offshore drilling, in particular.

While the spill has now been contained and the well permanently 'killed', the clean up goes on, and within the oil industry, much talk is now turning to the potential consequences for the offshore oil industry in the years ahead, particularly in the Gulf of Mexico. There are many questions that feed into this, such as: What actually caused the explosion? How safe is offshore drilling? What will it take to stop this from happening again? Is offshore deepwater[23] drilling really necessary, and why? Why was the oil industry not better prepared to handle such an incident? And what are the implications for the future?

It is impossible to fully assess all the potential consequences, with investigations into the actual causes and discussions about new regulations ongoing. What is evident, however, is that the context for deepwater exploration and production has changed, and that there are a number of possible short-, medium- and long-term implications, specifically those broad in scope, that can be explored.

In the short-term to date, in terms of changes to the business, what the US Government has put in place is a restructuring of its Minerals Management Service (MMS), as well as a moratorium on offshore exploration and drilling, although this has now been lifted.

The MMS restructuring divides the service into three independent functions: one for oversight of safety and environmental protection in all offshore energy activities, another will take care of leasing federal waters for conventional and renewable energy resources, and the third will collect and distribute revenues. It is anticipated that there will be more stringent regulations, more frequent inspections and the need for more elaborate reporting. This will naturally lead to increased costs, potentially less exploration, lengthier timescales before drilling and less favorable project economics, everything else being equal.

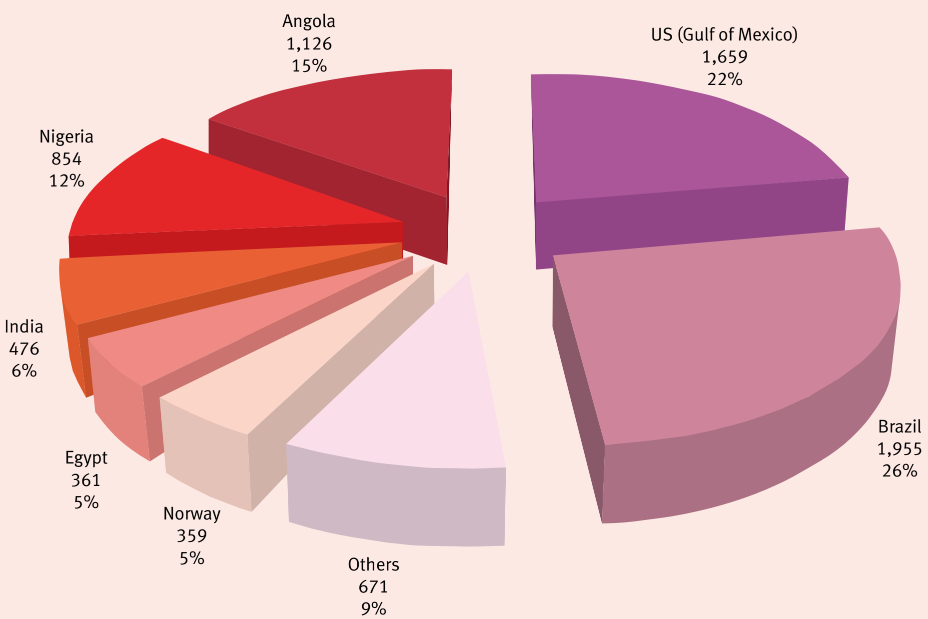
Of course, the moratorium has already impacted the ongoing projects. According to Wood Mackenzie's press release from 17 September 2010, drilling on 33 wells was suspended at the first safe stopping point, drilling offshore Alaska was postponed until at least 2011, the Western Gulf of Mexico Lease Sale 215 and the proposed Virginia Lease Sale 220 have also been cancelled and three other leases are subject to review.

Moreover, it is evident that the public's confidence has been knocked in regard to the offshore oil industry. How this impacts the sector, and plays on the minds of politicians, is at the moment difficult to gauge.

Some of these issues may also have implications for the medium- and long-terms. Thus, it is essential for the industry to look to restore public confidence, develop better safety technology and more effective deepwater intervention technologies, revisit current business models, and explore the issue of partnering, with both other industry players and governments. The industry needs to learn from what happened and implement the required changes to make sure the necessary investment goes in to create a sustainable deepwater business.

The importance of this should not be under-estimated. In this year's WOO, demand for oil is set to rise in the Reference Case by 25% by 2030, from 2009

Deepwater oil and gas production (>500m) in mid-2010 *1,000 boe/d*



Source: Wood Mackenzie, 2010 oil and gas production; water depth >500m.

levels, and to meet this it is clear that supply will be required from a wide variety of sources, including deepwater areas.

Over the last couple of decades, deepwater has rapidly become an important part of the world's oil supply. Globally, oil supplies from deepwater have risen from 1.5 mb/d in 2000 to 5 mb/d by 2009, around 5% of total world oil production. Brazil leads the way, followed by the US Gulf of Mexico, with the US alone seeing around 25% of its production coming from deepwater, and then there are OPEC Member Countries Angola and Nigeria (see figure for deepwater oil and gas production).

Looking ahead, there is also significant future potential for deepwater production, as has been most recently witnessed in the large finds off Brazil and West Africa (since 2000, 40% of discovered reserves have been in deepwater).

While the implications of the Deepwater Horizon spill will be significant for the industry, in terms of such issues as new regulations, improved emergency response measures, new business models and additional costs, it is anticipated that the impact on overall deepwater production will only be limited and short-term. In the long-term, it is expected that any new regulations will become routine practice, new technologies will continue to improve project economics and the oil and gas industry will continue to learn its lessons, develop and emerge stronger.

help to offset the decline from the mature Prudhoe Bay and Kuparuk fields. In the Lower 48 states, there is substantial potential for increasing recovery in areas where rates are low, such as in California's heavy oil fields, by using EOR methods and advanced drilling technology. Total crude and NGLs supply in the US & Canada falls steadily over the long-term, reaching just over 7 mb/d by 2030, some 2 mb/d below current levels.

By 2015, Mexico will have produced more than half of its original endowment of oil resources. Thus, despite the relatively buoyant production levels that are currently being observed, it is inevitable that the longer term will witness a gradual decline, unless substantial upward revisions to its endowment are registered, which remains a possibility. The total supply of crude and NGLs in the Reference Case falls from 3 mb/d in 2009 to 2 mb/d by 2030.

Similarly, resource availability will dominate the long-term pattern of crude and NGLs supply in Western Europe. Already by 2012, more than half of the URR of the region will have been produced. Some potential exists for production in the environmentally sensitive areas of frontier provinces, such as the Lofoten Islands, Tromso, Nordaland and the Barents Sea, but these areas are unlikely to offset the decline in mature fields. By 2030, the Reference Case sees crude and NGLs supply from this region falling to 2.5 mb/d from the 2009 level of 4.4 mb/d.

The rapid expansion of crude and NGLs supply in Latin America over the next decade is primarily due to increases in Brazilian production. The pre-salt Santos Basin – Libra, Franco, Tupi, Jupiter, Carioca, Guara, Parati, Caramba, Bem Te Vi, Iara, Azulao, and Iguacu fields – is central to future growth. Additionally, there are pre-salt discoveries located under existing fields to the north of the Campos Basin, including: offshore Espirito Santo-Cachalote; Baleia Franca-pre-salt; Baleia Ana-pre-salt; Baleia Azul-pre-salt; Jubarte-pre-salt; Cachareu; and Pirambu. Argentina also has some potential to offset the decline in its mature fields through the use of secondary and tertiary recovery techniques and developing the heavy oil reserves of the Neuquén Basin. In Colombia, the production of crude and NGLs is expected to stay approximately flat until 2020, thereafter declining, to average around 0.4 b/d by the end of the projection period. The increases from its heavy oil fields will not be sufficient to offset the decline rate of the mature fields such as Cusiana/Cupiagua and Cano Limón. Overall, Latin American crude and NGLs production rises from 3.9 mb/d in 2009 to 5.5 mb/d by 2020, staying approximately flat in the decade following.

In non-OPEC Middle East & Africa countries, the flat medium-term production of crude and NGLs eventually turns into a steady decline. It falls to 3.6 mb/d in 2030, from the current levels of 4.3 mb/d. In Oman, there have been no major discoveries in recent years and this trend is expected to continue. In Egypt, exploration activities in the Gulf of Suez and Western Desert, as well as increases in NGLs production, have helped reduce its decline. However, the production of crude and NGLs is forecast to fall from 0.7 mb/d in 2009 to just 0.3 mb/d by 2030. In Sudan, the second largest non-OPEC producer in Africa, crude and NGLs production is expected to remain steady, around 0.5 mb/d over the projection period.

Asian countries have produced less than one third of their original endowment of crude plus NGLs, and longer term prospects see production levels at current levels of 3.6 mb/d or higher for the next 15 years. By 2030, production will, however, be in slight decline, falling to 3.3 mb/d. Indonesia, at 1 mb/d, is the largest producer in this region and there is good potential from reserves growth in existing fields and from gas projects. NGLs volumes are expected to increase throughout the forecast period, but these will not be enough to reverse the long-term decline of crude oil production. Consequently, the production of crude and NGLs in Indonesia is expected to fall gradually after 2020. India, accounting for close to 25% of the region's supply, has high exploration potential with new discoveries in the Krishna-Godavari and Rajasthan Basins. NGLs are also expected to contribute to production over the long-term. As a result, production of crude and NGLs in India remains close to current levels for the entire projection period. Malaysia has good deepwater exploration potential, although large discoveries are unlikely and most of the yet-to-find resources in this area will be located in small finds. Gas has greater potential and NGLs supply is expected to play a larger role in Malaysia's long-term production. Malaysian crude and NGLs production is slated to be around 0.7 mb/d in 2030, approximately equivalent to current levels.

In China, cumulative production of crude oil plus NGLs is currently around one half of its URR. While EOR projects will help arrest the decline, it is yet-to-find resources in the East China and South China Seas, as well as reserves growth in existing fields, that will provide the main production volumes in the future. As a result, after a medium-term supply plateau of around 3.8 mb/d, a gradual fall in China's production of crude and NGLs is expected after 2015, with output falling in the Reference Case to 3.2 mb/d in 2030.

The Russian resource base remains considerable: by 2009 only 30% of the estimated URR had been produced. Prospects for supply over the long-term continue to be dominated by above-ground issues, including fiscal conditions and infrastructure availability. The construction of new infrastructure has recently been proposed to promote the upstream developments in West Siberia and the northern part of Krasnoyarsk in the Yamal-Nenets area, where a significant amount of oil reserves is awaiting development. This should allow crude production from this area to reach 1.5 mb/d by 2020, in addition to over 0.8 mb/d of NGLs. Moreover, significant increases in crude oil and NGLs are expected in East Siberia, mainly from the giant Vankorskoye oil and gas field, where production is expected to plateau near 0.5 mb/d after 2015. Russia's production of crude and NGLs in the Reference Case rises to 10.6 mb/d within a decade, before it plateaus out from 2020.

The Caspian region, which constitutes the bulk of supply from the other transition economies, is similarly well-endowed with oil, with just 15% of its original resource base so far produced. As with Russia, resource availability will therefore not be a constraint to supply potential. In the Reference Case, crude plus NGLs supply rises from 3.2 mb/d in 2009 to 5 mb/d by 2030. Close to 90% of this increase will come from Kazakhstan, where production is expected to increase to more than 3 mb/d by 2030, as the Karachaganak and Kashagan fields reach their final phases of development. In addition, new discoveries in the Turgay Basin and the offshore regions of the north Caspian blocks are anticipated to contribute to future supply. In Azerbaijan, growth beyond 2015 is likely to be limited. The ACG oil field is expected to reach a production plateau of 1 mb/d by 2020. Other large contributors to Azerbaijan's oil production growth over the next decade include the shallow water Guneshli field and Shah Deniz.

Table 3.4
Medium-term non-OPEC non-conventional oil supply outlook (excluding biofuels) in the Reference Case *mb/d*

	2009	2010	2011	2012	2013	2014
US & Canada	1.5	1.5	1.7	1.9	1.9	2.0
Western Europe	0.1	0.1	0.1	0.1	0.1	0.1
OECD Pacific	0.0	0.0	0.0	0.0	0.1	0.1
OECD	**1.6**	**1.7**	**1.8**	**2.0**	**2.1**	**2.2**
Middle East & Africa	0.2	0.1	0.2	0.2	0.2	0.2
China	0.0	0.0	0.1	0.1	0.1	0.1
Developing countries, excl. OPEC	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**
Non-OPEC	**1.8**	**1.9**	**2.0**	**2.2**	**2.4**	**2.5**

Non-conventional oil (excluding biofuels)

The overview of the oil supply Reference Case emphasized the growing importance of non-conventional oil, in both the medium- and long-terms. In this regard, the single most important source of this form of liquids supply, other than biofuels, is oil sands, but there are also growing quantities of oil coming from other sources, in particular GTLs and CTLs. Table 3.4 shows that, over the medium-term, a steady rise in non-conventional oil supply is expected, reaching 2.5 mb/d by 2014 in the Reference Case, up from 1.8 mb/d in 2009.

Canadian oil sands constitute the lion's share of this supply and the expected future growth. High costs, nonetheless, make this form of supply particularly sensitive to oil price levels. This was most recently viewed when oil prices declined at the end of 2008, which combined with funding difficulties associated with the global financial crisis, slowed down developments in oil sands projects. The recovery in prices, however, has led to a cautious revision of growth prospects. A number of projects began in 2009 including the 110,000 b/d Horizon mining project and the 22,000 b/d Christina Lake Regional Project. Many companies are also planning to increase their capital spending in oil sands projects, including Suncor, EnCana, Imperial Oil, Shell and Devon. In this connection, Imperial Oil recently resumed the first 110,000 b/d phase of the Kearl Lake project; the 100,000 b/d Jackpine mine of Shell is expected to come on stream in 2010, together with the nearby 100,000 b/d expansion of the Scotford upgrader; and at least another 20 projects with a total capacity of around 700,000 b/d are scheduled to come on stream over the next five years. As a result, in the medium-term Reference Case, oil sands production is anticipated to increase from 1.3 mb/d in 2009 to around 1.9 mb/d in 2014.

In the long-term, several constraints to growth are likely to emerge for Canadian oil sands, such as the availability of transportation infrastructure, human resource issues, concerns over water supplies, natural gas availability and possible costs associated with GHG emissions. In the Reference Case, however, it is assumed that GHG policies do not hamper oil sands growth. The expansion will be supported by advances in technology that will make oil sands developments competitive with commercially economic oil. The long-term Reference Case outlook sees supply from Canadian oil sands rising to over 4 mb/d by 2030.

In addition, oil from shale oil, as well as GTLs and CTLs are anticipated to increase. By 2030, this accounts for close to 2 mb/d of supply.

It is worth noting that the impact of liquids production from wet unconventional natural gas, such as wet shale gas, as well as organic-matter-rich shales, may turn out to be significant in the future.

Table 3.5
Long-term non-OPEC non-conventional oil supply outlook (excluding biofuels) in the Reference Case

mb/d

	2009	2010	2015	2020	2025	2030
US & Canada	1.5	1.5	2.2	2.9	3.9	5.0
Western Europe	0.1	0.1	0.1	0.1	0.1	0.1
OECD Pacific	0.0	0.0	0.1	0.1	0.1	0.1
OECD	**1.6**	**1.7**	**2.4**	**3.1**	**4.1**	**5.2**
Latin America	0.0	0.0	0.0	0.0	0.1	0.1
Middle East & Africa	0.2	0.1	0.2	0.2	0.2	0.2
Asia	0.0	0.0	0.1	0.1	0.1	0.1
China	0.0	0.0	0.1	0.2	0.4	0.7
DCS, excl. OPEC	**0.2**	**0.2**	**0.4**	**0.5**	**0.8**	**1.0**
Russia	0.0	0.0	0.0	0.0	0.1	0.1
Non-OPEC	**1.8**	**1.9**	**2.8**	**3.6**	**4.9**	**6.3**

In sum, supply from non-OPEC non-conventional oil (excluding biofuels) increases in the Reference Case by 4.5 mb/d over the period 2009–2030, reaching 6.3 mb/d by 2030 (Table 3.5).

Biofuels

With the recent oil price stability, the potential adverse impacts on global biofuels supply underscored in last year's WOO have substantially eased. As a result, the Reference Case sees global biofuels supply growing in 2010 by 0.21 mb/d, compared to a prediction of just 0.13 mb/d last year.

In the US, data from the Renewable Fuels Association[24] indicate record-breaking ethanol production for each month of the first half of 2010. This, however, has led to an ethanol oversupply, which means prices remained suppressed. The US is currently approaching the ethanol 'blend wall' with ethanol demand close to hitting the maximum ceiling of a 10% blend rate. A decision by the US Environmental Protection Agency (EPA) to increase the ethanol content of gasoline to 15% has been repeatedly postponed due to concerns about the possible negative effects of the higher ethanol concentration on engines and fuel lines, as well as on refuelling station equipment. It is likely that the introduction of higher gasoline blends will be made gradually, spread out over the next few years.

In a move a designed to help implement the EU's requirements that biofuels must be produced sustainably, the European Commission decided in June 2010 to encourage industry, governments and non-governmental organizations (NGOs) to set up certification schemes for all types of biofuels, including those imported into the EU. The rules for the certification scheme are part of a set of guidelines explaining how the Renewable Energy Directive, coming into effect in December 2010, should be implemented. However, whether the sustainability goal of the new certification scheme can be made compatible with the quantitative biofuels targets stipulated in the

Table 3.6
Medium-term biofuel supply outlook in the Reference Case *mb/d*

	2009	2010	2011	2012	2013	2014
US & Canada	0.8	0.9	0.9	0.9	1.0	1.0
Western Europe	0.2	0.3	0.3	0.3	0.3	0.4
OECD	**1.0**	**1.1**	**1.2**	**1.2**	**1.3**	**1.4**
Latin America	0.5	0.6	0.6	0.6	0.6	0.6
Asia	0.0	0.1	0.1	0.1	0.1	0.1
China	0.0	0.1	0.1	0.1	0.1	0.1
Developing countries, excl. OPEC	**0.6**	**0.7**	**0.7**	**0.8**	**0.8**	**0.9**
Non-OPEC	**1.6**	**1.8**	**1.9**	**2.1**	**2.2**	**2.3**

Table 3.7
Long-term biofuel supply outlook in the Reference Case *mb/d*

	2009	2010	2015	2020	2025	2030
US & Canada	0.8	0.9	1.0	1.3	1.5	1.9
Western Europe	0.2	0.3	0.4	0.6	0.8	1.1
OECD	**1.0**	**1.1**	**1.5**	**1.9**	**2.4**	**3.0**
Latin America	0.5	0.6	0.7	0.8	1.0	1.2
Middle East & Africa	0.0	0.0	0.0	0.0	0.1	0.1
Asia	0.0	0.1	0.1	0.1	0.2	0.3
China	0.0	0.1	0.2	0.2	0.3	0.4
DCS, excl. OPEC	**0.6**	**0.7**	**0.9**	**1.2**	**1.6**	**2.0**
Non-OPEC	**1.6**	**1.8**	**2.4**	**3.1**	**4.0**	**5.1**

Directive remains to be seen. At least in the UK, the Committee on Climate Change, the government climate advisors, said in July 2010 that a goal to obtain 10% of transport fuel from renewable sources, and mostly biofuels, was too high given sustainability concerns. The committee supported an alternative, 8% target.

In Latin America, strong demand for transportation oil coupled with the introduction, especially in Argentina and Brazil, of higher biodiesel blending requirements, indicates robust biofuels growth.

Since publication of last year's WOO, there has been no compelling evidence to reconsider the view that first-generation technologies will continue to supply the vast bulk of biofuels over the medium-term, and that sustainability issues place a limitation on how much first-generation biofuels can be produced. Therefore, the Reference Case sees global biofuels supply expand in the medium-term, to 2.3 mb/d in 2014, up from 1.6 mb/d in 2009 (Table 3.6).

Second-generation biofuels are assumed to contribute increasingly to global supply from 2020 onwards. Further down the line, beyond the forecasting period, algae-based biofuels – a third-generation biofuels technology – could potentially provide huge amounts of supply and be what some are calling a 'game changer'. To 2030, however, despite the reliance of the instituted biofuels policy targets on advanced technologies in both the EU and the US, the Reference Case sees it as unlikely that these targets will be met in full. Global biofuels supply increases by 3.5 mb/d from 2009–2030, reaching 5.1 mb/d by the end of the period (Table 3.7).

OPEC upstream investment activity

Chapter 1 noted that OPEC spare capacity is set to rise. Indeed, by the end of 2009, total OPEC crude production capacity had already reached more than 35 mb/d, well over the average production of 29.2 mb/d for the first half of 2010. This means spare capacity is close to 6 mb/d. This has emerged from OPEC's absorption of the lower oil demand that accompanied the global financial crisis – global demand in 2009 was 1.8 mb/d lower than in 2007 – as well as actual capacity increases in Member Countries.

Adjusting investment plans to suit emerging supply and demand conditions is obviously a difficult task, given the industry's long-lead times and high upfront costs. Moreover, the investment challenge has recently been further complicated by the fact that as prices softened towards the end of 2008, the high cost environment persisted. It was, of course, understandable that OPEC Member Countries were concerned that investments were being made in capacity that might not be needed.

At the time of the release of the WOO 2009, some projects that had previously been considered to contribute capacity additions were slated to be delayed or even postponed until after 2013. However, by the end of 2009, after the oil price improved, the global economy began its turnaround and growth was back on the agenda in many regions, around 10 projects, with a total capacity of 1.2 mb/d, were returned to being 'back on track'. These are now expected to be on stream before 2014. The start-up dates of the majority of the remaining delayed projects are now re-scheduled for the next five-to-seven years, with very few now seen as being on-hold.

Over the period to 2014 there are around 140 projects expected to come on stream in OPEC Member Countries. These projects will result in net crude oil capacity additions of around 3 m/d by the end of 2014. On top of this, over 2 mb/d of net NGL capacity additions is anticipated. The estimated required investment over this time is around $155 billion.

The increase in capacity reflects the significant efforts made by OPEC Member Countries to support market stability. And it is a clear reflection of OPEC's policy laid down in both its Statute and Long-Term Strategy (LTS), in particular that "supporting security of supply to consumers", by expanding production capacity in such a way as to not only meet the increased demand for its oil, but to also "offer an adequate level of spare capacity".

Chapter 4

Upstream challenges

Having considered the Reference Case outlook for supply and demand of energy it becomes clear that a number of challenges lie ahead. A major one facing the oil industry, in general, and OPEC, in particular, relates to the significant uncertainties over how much future production will be required. This stems from such issues as the lack of clarity regarding the energy and environmental policies of a number of major consuming countries, as well as the impact of the recent economic downturn and the implications this will have on the oil market in the future. This, in turn, has a significant impact on producers and investors as they look to make sure the world has a steady and secure supply of oil, and a comfortable level of spare capacity.

Moreover, alongside this concern, there are various other challenges that are today, and in the future, expected to have a role in how the industry's future pans out. This includes the emergence of oil as a financial asset; upstream costs; the adequacy of the human resource skills base; the technology evolution, and in some cases, revolution; the issue of sustainable development and the need to tackle energy poverty; and the future role of dialogue and cooperation in meeting the industry's challenges.

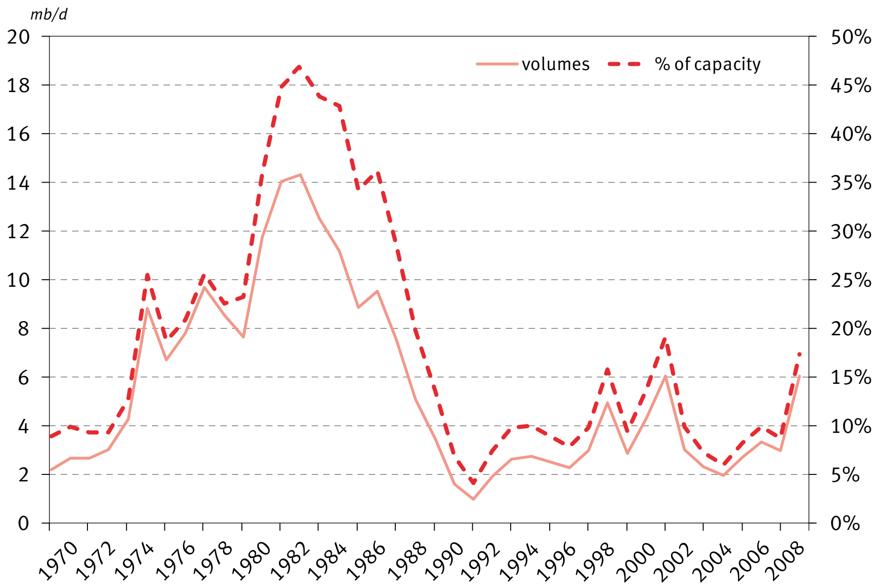
These issues are all explored in more detail in this Chapter.

Making appropriate investment decisions in the face of supply, demand and price uncertainties

A key challenge for the oil industry, in general, and OPEC, in particular, relates to the uncertainties surrounding future demand for oil. These can hinder appropriate and timely investments in OPEC Member Countries; the implication being that there are substantial and tangible risks associated with both under- and over-investment. History demonstrates that these concerns are justified. Perhaps the most alarming example of investment in unneeded upstream capacity occurred in the early 1980s, when shrinking oil demand led to OPEC spare capacity rising to a peak of 14.6 mb/d in 1983 (Figure 4.1). It meant that 46% of OPEC's available production capacity at that time was simply not being used.

More recently, the rapid expansion of the global economy over the years 2002–2007 led to an oil demand surge and, with non-OPEC supply stagnating, a corresponding rise in OPEC supply to satisfy the growing requirements. While average OPEC crude production in 2002 was 25.5 mb/d, by 2008 it had risen to an average

Figure 4.1
OPEC spare production capacity, volumes and as a percentage of capacity, 1970–2009



of 31.2 mb/d, an increase of 5.7 mb/d, with the level of spare capacity falling to 2–3 mb/d. In response, large investment plans were devised and their implementation accelerated despite surging Engineering, Procurement and Construction (EPC) costs.

Another relevant episode is currently being played out. Following the onset of the global financial crisis and the resulting sharp contraction in economic activity, particularly in OECD countries, there was an accompanying dramatic fall in global oil demand. For the fist time since the early 1980s, world oil demand declined in two consecutive years by a cumulative 1.9 mb/d. This, compounded with new capacity that was being brought on stream, led to a rapid rise in unused capacity that reached over 6 mb/d by the second quarter of 2009.

These experiences highlight the concerns surrounding the risks of over- or under-investing. This, however, is not only specific to oil. The recent happenings in natural gas markets are a clear illustration of such risks.

A key unknown in understanding how the required volumes of OPEC crude oil might develop is the evolution of oil demand. In general, this is affected by three broad factors that are, to a considerable degree, inter-related: economics, policies and technology.

The significance of economic growth uncertainties has been brought into sharp focus by the recent global financial crisis. The global economy in 2009 contracted for the first time in six decades. Indeed, the 2009 WOO reported that the "current contraction cycle could already be characterized as the deepest and the mostly widespread since the Second World War". The impact is clearly reflected in the fact that demand in this year's WOO for the year 2009 is 4 mb/d below what was estimated just two years ago.

Moreover, this is further underlined given that there remain substantial risks for the global economy. These stem, in particular, from a further deterioration in the financial strength of banks in advanced economies, and the lower business and consumer confidence, which, together with deflation risks, could lead to the postponement of private investment and spending plans. In addition to these current concerns, medium- to long-term economic growth is subject to a host of uncertainties that could easily lead to higher – or lower – expansion.

The next identified uncertainty for future oil demand concerns how policies evolve. This is particularly important the further forward we look. This challenge not only affects the range of feasible oil demand for the coming years, but also the central level of expectations that are already incorporated into the Reference Case. For example, in the WOO 2008 two sets of policies were analyzed in terms of how they might affect future oil demand relative to the reference case: namely, the US EISA, and the EU's energy and climate change legislative package. Their adverse impact on the need for OPEC oil was estimated to be in the order of 4 mb/d as early as 2020. Since then, however, the former has been passed into law, while the latter's directives have been adopted by both the EU Council and the European Parliament. Consequently, these two policies were incorporated into the WOO 2009 reference case.

The implications for future oil demand as a result of new policies are uncertain: key questions will always arise, such as how might policy goals evolve in the longer term, or even how realistic some agreed policy targets are, such as those relating to biofuels in the EU.

Another major uncertainty, possibly the greatest one in the long-term, concerns the extent to which climate change policies will be introduced and the exact nature of these.

Many of the technological uncertainties are closely related to policy discussions. In particular, technological developments in the transportation sector will fundamentally affect the prospects for future oil demand, both as they relate to conventional drive trains and fuels, as well as to the commercial viability of alternative engines and energy sources.

There are also significant uncertainties regarding the prospects for non-OPEC supply and how this in turn will impact the market for OPEC oil. Investment, as well as short-term supply levels, are affected by a range of factors, such as the oil price, fiscal conditions, the evolution of costs, the natural decline of existing fields, environmental regulation, the size of the resource base and technology.

Technological developments have been a key in expanding the resource base and making previously inaccessible oil commercially available. Cost developments will also depend, at least partially, on the outcome of the 'tug-of-war' between technology and resource depletion. For some countries, above-ground issues tend to have a significant influence on the possible future supply path. All of these elements can add significant uncertainties to the expected levels for future non-OPEC supply. And this, in turn, adds to the uncertainty over how much oil will be required in the future from OPEC Member Countries.

As seen in Box 3.1, another major factor adding to the uncertainty is the different perceptions of how the evolution of oil prices will affect investment activity, in general, and individual OPEC Member Countries, in particular. There is an inevitable direct link between evolving prices and OPEC investment. However, differences in expectations for the medium-term price evolution are also likely to add further uncertainty to possible investment activity, which in turn complicates the process of attempting to make the 'appropriate' levels of investment in an industry that is characterized by long-lead times and payback periods.

The time a project takes to complete depends on its size, complexity and location. In general, the range is from a few years to a decade or more. For example, the quickest type of project is perhaps the redevelopment or expansion of a large oil field in the Middle East, with a time scale of two-and-a-half years involved. A typical large offshore project takes at least seven years from its appraisal phase to first production. For instance, the Buzzard field in the UK's North Sea took seven years from its discovery in 2001 to first production in 2007. And the Azeri Chirage Guneshli development in the Caspian Sea, offshore Azerbaijan, took ten years to come on stream (1996–2005).

Much of the new capacity that will become available between now and 2015 is under development, but given the long-lead times for the exploration and development of new oil fields, a slowdown in investment today will be felt in production capacity levels in the coming years.

An attempt to quantify the possible impact of these uncertain oil supply and demand paths has been made by developing lower growth and higher growth scenarios.

The lower growth scenario reflects the downside risks to demand stemming from the uncertainties outlined. It is still generally thought that these risks are greater than the upside potential. In this scenario, average oil use per vehicle declines more rapidly than in the Reference Case, particularly over the longer term. This is a reflection of the development and introduction of more efficient cars and trucks, and the effects this would have upon average efficiencies as the capital stock turns over. On top of this, in line with ongoing concerns about economic recovery, as well as longer term possible constraints to GDP growth, the assumption is made that the world economy suffers from a more protracted recession compared to the Reference Case. Moreover, in the longer term, annual growth rates are assumed to be 0.5% lower than the Reference Case.

In the higher growth scenario, the upside potential for economic growth is considered, with an even swifter recovery than that assumed in the Reference Case. This also involves a more optimistic view over the long-term sustainable rates of GDP increases. In this scenario, it is assumed that economic growth is half a percentage point higher throughout the projection period, compared to the Reference Case.

Tables 4.1 and 4.2 show the results for the two scenarios.

Table 4.1
Global oil demand – differences from the Reference Case in the lower growth and higher growth scenarios

mb/d

	2015	2020	2025	2030
Lower growth	–3.8	–6.6	–9.5	–12.6
Higher growth	1.6	3.4	5.4	7.6

The impacts upon demand in the lower growth scenario are significant. As early as 2015, global oil demand is almost 4 mb/d lower than in the Reference Case and by 2030 demand is more than 12 mb/d lower. The average annual demand growth in this scenario to 2030 is under 0.4 mb/d. The lower demand is assumed to be accompanied by oil prices that are lower than in the Reference Case, which could mean lower non-OPEC supply. It is, however, also assumed that OPEC absorbs most of the weakness in demand by adjusting production and investment plans accordingly. Nevertheless, the amount of OPEC crude oil that is required in this scenario is considerably lower than that in the Reference Case. Indeed, there is barely scope for an increase in supply throughout the entire period 2015–2030.

Table 4.2
OPEC crude and non-OPEC oil supply – differences from the Reference Case in the lower growth and higher growth scenarios *mb/d*

	2015	2020	2025	2030
Lower growth				
Non-OPEC	–0.5	–1.2	–1.7	–2.1
OPEC crude	–3.3	–5.4	–7.8	–10.6
Higher growth				
Non-OPEC	0.5	1.2	1.8	2.1
OPEC crude	1.2	2.2	3.6	5.5

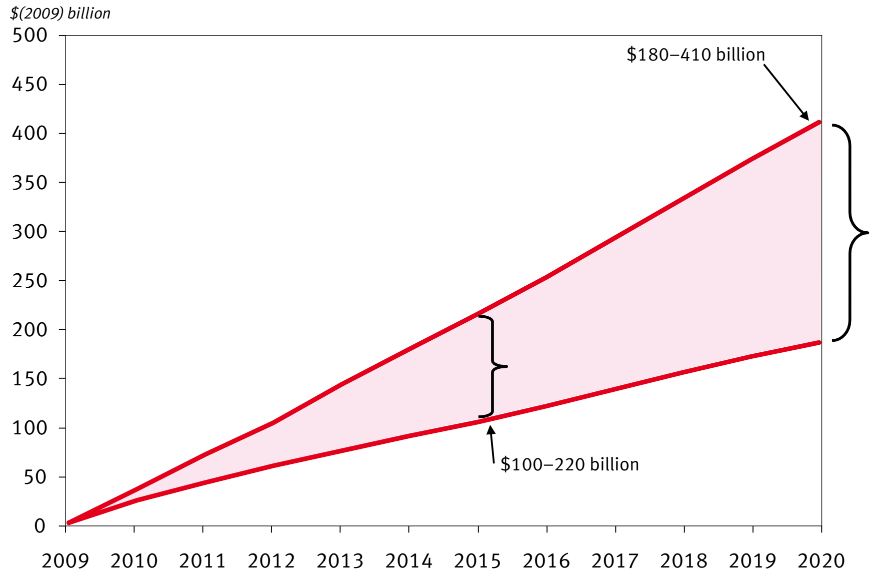
In the higher growth scenario, oil demand increases by 1.4 mb/d annually, reaching 113 mb/d by 2030, almost 8 mb/d more than in the Reference Case. It is assumed that some of the demand increase would be satisfied by stronger growth in more expensive non-OPEC oil, both conventional and non-conventional, which is consistent with higher oil prices. Nevertheless, the scenario assumes that the key supply response is from OPEC, which accelerates additional capacity investment to satisfy demand and ensure that the market is well supplied at all times. The amount of OPEC crude oil required by 2020 is more than 2 mb/d higher than in the Reference Case, and more than 5 mb/d higher by 2030.

These calculations demonstrate the genuine concern over making the appropriate investment decisions in the face of supply, demand and price uncertainties. The scenarios clearly underline the wide range of possible volumes of crude oil that OPEC might need to supply in the future.

These results have also been interpreted in terms of upstream investment requirements in OPEC Member Countries. Given the approximately flat OPEC crude supply that is implied by the lower growth scenario, investment in this instance would be required only to compensate for production declines in existing facilities. On the other hand, the higher growth scenario requires both additional capacity, as well as the compensation for declines. The assumptions for decline rates and unit costs change between the scenarios, a reflection of the higher costs associated with the higher growth scenario. Additionally, since the maintenance of capacity is cheaper than the addition of new capacity, the lower growth scenario involves lower unit costs.

The results are portrayed in Figure 4.2. The projections are limited to the timeframe of 2020, as longer term uncertainties typically have little effect upon current investment decisions. The difference between the higher and lower growth scenarios

Figure 4.2
Cumulative OPEC investment requirements: how much is needed?



by 2020 reaches $230 billion in real terms. And over the period to 2015, where many investment commitments have already been locked in, the scenarios suggest that upstream investment requirements could lie in the wide range of $100–220 billion.

These scenarios demonstrate the evident severity of the challenge of making large investments in an environment of uncertainty.

Oil as a financial asset

There is an emerging broad consensus that the extreme price fluctuations and excessive volatility that characterized the oil market back in 2008 and early 2009 should not be allowed to return to the market. These types of happenings are detrimental to all parties, and not in the interests of market stability. This was underscored by both producers and consumers at the 12th International Energy Forum (IEF) Ministerial Meeting in Cancun, Mexico, earlier in 2010.

While some disagreement remains over what was actually behind the volatility, over the past year or so it has become increasingly accepted that non-fundamental factors were at play. This can be viewed in the regulatory proposals and measures now underway in financial markets to help combat extreme volatility. The emergence of oil as a financial asset traded through a diversity of instruments in futures exchanges and OTC markets helped fuel excessive speculation that drove price movements and stirred up volatility. It led to a situation where futures prices were, to a certain extent, detached from the supply and demand fundamentals of the underlying commodity.

Addressing this concern has been to the fore of OPEC's thinking. In fact, a better understanding of the interlinkages between physical and financial markets and evolving market regulation has been agreed upon as an area of cooperation between the IEF, the International Energy Agency (IEA) and OPEC. OPEC has also conducted a number of joint workshops with the EU on financial markets, illustrating the greater attention paid to the challenges posed by the functioning of these markets today.

Costs remain high

In 2009, there was a general trend towards falling industry costs. This drop, however, was relatively modest as can be viewed in the IHS/CERA's Upstream Capital Costs Index for June 2010 (Figure 4.3). The Index rose 0.2% during the first three months of 2010, having declined in the previous three months. IHS/CERA expectations for the rest of 2010 (dotted line in Figure 4.3) suggests a continued upward trajectory.

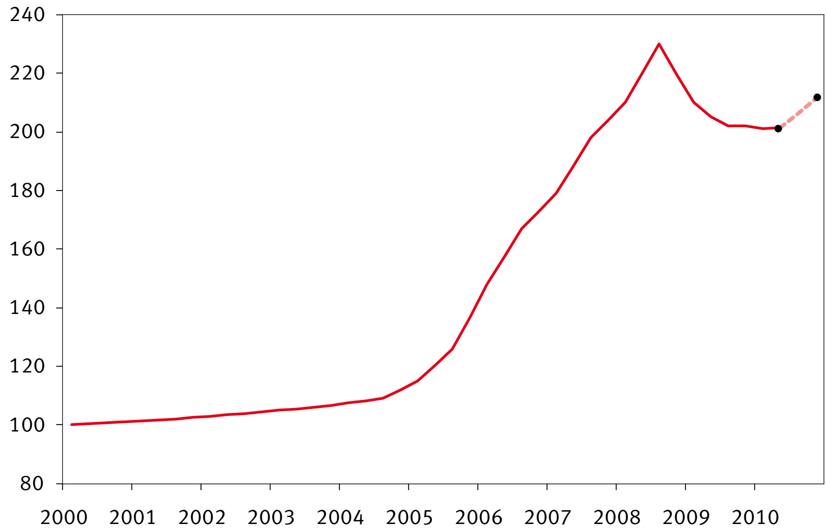
It should be noted that the recent downward trend was not industry wide. The price of steel, yards and fabrication costs, as well as onshore costs have all risen. On the other hand, offshore rig costs have been witnessing a downward movement.

Looking ahead, the issue of costs will continue to be a major challenge, and represent another key uncertainty for the industry.

In the short-term, one specific issue is the possible knock-on impacts of the accident at BP's Deepwater Horizon oil rig in the Gulf of Mexico (Box 3.2). The spectre of increased costs has been much discussed following the incident, and there is also the potential for higher insurance costs.

Despite increasing attention being paid to the recent rise in upstream costs, it is important to also keep in mind the major role that technology has played and continues to play in reducing costs and supporting the expansion of hydrocarbon resources. Technical progress has increased exploration efficiency progressively: worldwide, success rates have risen from about one in 10 in the 1960s to more than one in five today. And technology also helps reduce the cost of the marginal barrel; for example, the oil sands industry continues to look for ways to make *in situ* production cheaper.

Figure 4.3
IHS/CERA upstream capital costs index (UCCI), 2000 = 100



Source: IHS/Cambridge Energy Research Associates.

Nevertheless, despite such ongoing contributions from technologies to keep costs in check, there are a number of major challenges ahead. Longer term, perhaps the key issue is that of environmental protection. As underlined later in this Chapter, technology has, and will continue to help meet the challenge of reducing the environmental footprint of exploration and production activities. Nonetheless, possible costs associated with GHG emissions can be anticipated to add to the industry's overall costs. This is evident throughout the supply chain, including the downstream, as highlighted in Chapter 9. In addition, some areas of the industry are also facing other environmental hurdles, including the degrading of surface water quality and the acidification of both soil and water.

Human resources

The knock-on impacts of the financial crisis and the economic downturn have been widespread, not only in regard to falling GDP and larger budget deficits, but also in terms of job losses and in a lack of job creation. This has been particularly apparent in industries that require significant numbers of skilled personnel for long-term projects, such as the petroleum industry. Moreover, this comes on top of the concerns expressed over the past few years regarding the adequacy of the human resource skills base. It is evident that there is a need for the industry to address this challenge so that it does not impact its development.

Alongside the current global economic climate, the human resource challenges include the large scale downsizing that led to a lack of recruitment into the energy sector during the 1980s and 1990s. At this time many universities cut back drastically on the number of people taking energy disciplines because the industry did not need graduates in such numbers. In recent years, there has also been a dramatic expansion in the service and emerging knowledge economies, which has led to fierce competition for talent. And additionally, there is a sizeable section of the industry's workforce, particularly the large numbers that entered the industry in the 1970s, that are rapidly approaching retirement.

Yet as has already been made clear in this year's WOO, the world needs more energy, and the petroleum industry is expected to be faced with new and more complex technical challenges in the future. It all points to the need for additional know-how and expertise. The industry needs the human dimension to thrive; it is and will continue to be the cog that drives it forward.

It is apparent that there are no real short-term solutions, which means the industry must look beyond the next few years and see people as long-term assets. This means making the industry more attractive to prospective graduates and employees from across the world and broadening the ways and means available to keep talented people in the industry.

For OPEC, both the Caracas and Riyadh OPEC Summits of 2000 and 2007 respectively, underscored the vital role of scientific and technical research, establishing and facilitating links between research centres in Member Countries, and obviously closely linked to these is the value of the human resource. OPEC appreciates the benefits of promoting the exchange of expertise, knowledge sharing and international best practice, particularly through universities and research institutions.

Technology and R&D

Throughout the history of the petroleum industry, technology has continually helped push back the boundaries to enable a continuous expansion in production, improvements in recovery rates and facilitate increases in the estimates of the global URR.

In the years to come, an important challenge will be to ensure that technology continues to play a critical role in the supply of petroleum to the world at large.

Though resources are plentiful, oil companies today are now moving into more challenging, more remote and more expensive locations to explore for and produce energy. In many instances, this will require technological breakthroughs and the evolution of current technologies to help bring these resources, in fact, all resources, to end-users in an ever more efficient, timely, sustainable and economic manner. Some key technologies are related to remote sensing, sub-surface visualization, intelligent drilling and completions, automation and data integration.

Technology will also be crucial in helping solve another challenge – that of continually advancing the industry's activities to improve its environmental footprint. Even small advancements can have major benefits in environmental performance and, ultimately, business performance. This means advancing the environmental credentials of oil, both in production and use; improving operational efficiencies and recovery rates, and pushing for the development and use of cleaner fossil fuel technologies.

The petroleum industry, in fact, has a long history of successfully reducing its environmental footprint, for example, in drilling, gas flaring reduction and cutting plant emissions. And the automotive industry, as well as the refining industry, has a good track record in continuously reducing the pollutant emissions of vehicles.

As for technologies, perhaps the best available to reduce net CO_2 emissions in this respect is CCS in deep geological formations. The Intergovernmental Panel on Climate Change (IPCC) has stressed that CCS has a large economic mitigation potential and could contribute to meeting up to 55% of the global cumulative mitigation effort by 2100. While its potential is huge, it still faces many hurdles. This includes its high cost; the impact on plant efficiency; and public acceptance.

Some industrial applications do exist, such as In Salah in Algeria, Weyburn-Midale in Canada and Sleipner and Snøhvit in Norway. But it is clear that more demonstration projects are needed. A 'win-win' approach could be to associate CO_2 storage with enhanced oil recovery. This is envisaged for projects proposed in several regions, including OPEC Member Countries Saudi Arabia and the UAE. It is, however, developed countries who should take the lead in the effort to make CCS commercially viable, given their historical responsibility, as well as their technological and financial capabilities.

Sustainable development

It is important to recall that the very first UN MDG is poverty eradication. Every six seconds a child dies because of hunger and related causes, and over 1 billion people do not have enough to eat – more than the populations of the US and the EU combined.

It is critical that the UN MDGs and the commitment to reduce poverty are met. And in terms of helping reduce poverty, a catalyst is access to modern energy services, particularly by reducing the burning of indoor biomass that prematurely kills hundreds of thousands every year.

In the developing world, 1.4 billion people have no access to electricity and 2.7 billion do not have adequate energy services. To enhance living standards, it is essential that everyone has access to reliable, affordable, economically viable, socially acceptable and environmentally sound energy services. This issue needs the urgent and critical attention of world leaders, much as the attention given to climate change.

The issue of sustainable development is also addressed by OPEC Member Countries, through their own aid institutions, as well as OPEC's sister organization, the OPEC Fund for International Development (OFID), which are today helping to alleviate poverty and improve energy access in many developing countries. OFID, which was set up in 1976, has to the end of July 2010, provided help to 127 countries from the developing world and its cumulative development assistance stands at over $12 billion.

In September this year, the UN Summit on the Millennium Development Goals concluded with the adoption of a global action plan to achieve the eight anti-poverty goals by their 2015 target date.

Dialogue & Cooperation

The importance of energy dialogue between producers and consumers in addressing such challenges was stressed at all three OPEC Summits, in Algiers in 1975, Caracas in 2000, and in Riyadh in 2007. Dialogue will continue to remain an effective channel of communication between producers and consumers for maintaining market stability, transparency and the sustainable growth of the world economy. Dialogue also helps to advance understanding over such issues as demand and supply security, environmental protection, technology transfer, and education and human resource development.

The global petroleum market is interdependent, and strong relations between producers and consumers are a key ingredient in achieving market stability. Indeed, the benefits of dialogue are as clear today as they ever have been. This can be viewed in OPEC's cooperation with a whole host of countries and other international organizations, such as the European Union, the IEA, the IEF, China, Russia, the UN, the World Bank, the International Monetary Fund and the WTO.

The development of the producer-consumer dialogue was furthered earlier this year with the Cancun Ministerial Declaration that was issued at the 12th Meeting of the IEF in March 2010.

Section Two

Oil downstream outlook to 2030

Chapter 5

Distillation capacity requirements

The substantial oil demand decline that resulted from the global financial crisis and the subsequent economic downturn, combined with the wave of new refining capacity that has come on-line in the past few years, has led to a dramatic change in refining sector fundamentals. Whereas projections only two years ago were for global oil demand to reach almost 90 mb/d in 2010 and surpass 92 mb/d in 2012, the latest figures are for 85.5 mb/d in 2010 and 87.6 mb/d in 2012. This is a dramatic downward revision in the range of 5 mb/d for 2012. At the same time, major refinery projects – many of which had plans finalized before the global recession hit – continue to be implemented, bringing substantial new capacity on stream. Set alongside trends that have been in place for some time, such as the rising supply of NGLs and biofuels and a continuing drive toward lighter and cleaner products, in general, and diesel fuel, in particular, refiners are under pressure to reassess the viability of further investments and rethink the industry's future.

Central to their short-, medium- and long-term concerns is how to deal with the challenge of severe overcapacity in combination with the contrasting demand evolution across regions. Further closures are inevitable and arguably those that have occurred to date are just the beginning. There are also major regional differences to take into account. The Atlantic Basin, with its flat to declining demand and over-capacity in the US and Europe, is far worse affected than the Pacific Basin where more capacity is needed to meet sustained products demand growth. Moreover, in the industrialized regions, there is a growing likelihood – or presence – of energy and climate change legislation that could raise refiners' costs, as well as further curtail crude-derived product demand.

This raises several key issues. Initially, new refining projects and plans for the next few years need to be carefully evaluated as they will essentially impact future refining balances and economics, especially in the short- to medium-term. In the longer term, refining balances will increasingly be impacted by growing non-crude supplies that effectively bypass the refining system and reduce the proportion of crude oil that needs to be processed. This declining share of crude supply, combined with upward revisions for condensates/NGLs, rising ethanol production and declining naphtha/gasoline demand in the Atlantic Basin, will also amplify the problem of the naphtha/gasoline surplus. On top of this, declining gasoline demand in the US will provide fewer outlets for Europe's gasoline surplus, thus exacerbating the regional imbalance created by the increasing diesel share in Europe's demand.

Changes are also likely to materialize in respect to the overall quality of the crude slate, which will affect future conversion and hydro-treating capacity requirements. For example, the medium-term decline in heavy crude production coincides with a large increase in coking capacity which, it is projected, will lead to a continuation of the coking surplus that has already become evident. Therefore, the structure of the future crude slate will likely remain a concern for refiners.

Understandably, changes in the composition of the crude slate must be viewed in conjunction with the projected changes in the demand structure. As already discussed in Chapter 2, future demand increases are projected almost entirely for light products and middle distillates, with almost no change to the heavy part of the refined barrel. This move will necessitate some changes in refinery configurations by putting pressure on the need for conversion and hydro-treating capacity additions.

This Section examines and projects how these developments are likely to impact the global downstream and what the implications of these projections signal in terms of the need for further changes in product demand and/or refinery process technology. To do so, the World Oil Refining Logistics and Demand (WORLD[25]) model was used, which integrates analysis using all the relevant parameters/variables within one analytical framework. In OPEC's modelling system, WORLD is closely linked to OWEM, which constitutes the quantitative basis for Section One. However, because of trade flows, the regional formation is based on geographic rather than institutional definitions. The WORLD model breaks the world into 18 regions, which, for reporting purposes, are aggregated into the seven major regions defined in Annex C. It is also important to note that in this Section, the phrase 'medium-term' covers the period to 2015.

Assessment of refining capacity expansion – review of existing projects

Cyclicality has of course been a regular feature of the refining industry, which is evidently supported by developments over the past decade. From surplus and modest margins in 2001/2002, the industry moved to a relatively tighter refining situation and extreme margins in the period 2005 through to mid-2008, before seeing a return to widespread spare capacity and poor margins. This is where the industry finds itself at present.

Looking back further, the refining industry has recorded several cycles of excess and tight capacity. In the 1970s, the industry experienced periods of rapid expansion fuelled initially by rising demand and anticipated sustained growth. The 1980s was a period of industry consolidation. Falling demand in the first half of the period led to a series of refinery closures which meant that global capacity declined to the level of 73 mb/d at the end of the decade, from more than 82 mb/d at its beginning.

With demand growing in the 1990s, this initially absorbed the available refining capacity and improved utilization rates. In the second half of the decade, the industry responded with another wave of capacity additions, which once the Asian economic crisis hit in the late 1990s, created a new surplus at the turn of the century. The industry's response post-2000, however, lagged behind the emerging demand structure changes, notably a shift from fuel oil to light products, in particular middle distillates. This lack of investment resulted in a capacity deficit, especially in respect to upgrading processes, which became more apparent after a surge in the consumption of refined products in 2004 and 2005. As demand for light products and middle distillates accelerated and stricter product specifications in developed countries came on board, a much tighter refining sector was seen, which led to increased margins and profitability. Margins, however, were to some extent exacerbated by the changing dynamics of the oil market at that time.

The upshot of this was the refining industry experienced what some have termed a 'golden period' between 2004 and 2008. Many investors were attracted to the industry and refiners began to consider numerous options for further capacity expansion, with some now in existence.

By the end of 2008 and into 2009, however, the industry was witnessing a change once again. It was a major turning point for the industry. By 2009 particularly, refiners faced the triple impact of the highest demand loss for refined products in decades, across almost all regions, a number of major new refining projects coming on stream, as well as a major drop in crude oil prices, which alone tended to collapse refining margins. The combination of these factors led to a rapid capacity surplus build-up and, in turn, significantly reduced margins and profitability. Consequently, many new projects either for the expansion of existing facilities or for new plants were put on hold or rescheduled. This was also exacerbated by stubbornly high construction costs.

Moreover, the contrasting prospects for the refining industry in developed and developing countries have become more apparent. The demand decline materialized predominantly in developed regions, which has a high installed refining capacity base. However, the bulk of the future medium- and long-term demand growth is expected in developing countries. With the global economic recovery underway in 2010, this contrast is becoming even more pronounced. An early signpost to this is the revived interest in new refining projects, especially in the Asia-Pacific and the Middle East, while OECD regions are going through a period of capacity rationalization.

These facts are demonstrated in the list of announced capacity expansion projects. Today, several major institutions[26] report that up to 38 mb/d of additional crude distillation capacity could be added if all announced projects are successfully implemented, with the majority of these projects in developing countries. Indeed, the Asia-Pacific typically accounts for around 40% of the announced projects, the Middle East 20% and Africa and Latin America around 10% each. While this picture is not new, what is new is the further shift towards Asia-Pacific and Middle East projects, in particular, and away from the OECD regions.

Nevertheless, given the current situation of a still relatively fragile economic recovery, alongside the prospects for relatively weak demand in the medium-term, it would be unrealistic to presume that many of the announced or considered projects will be implemented by 2015. Global demand in the Reference Case by then is slated to only be around 5 mb/d higher than in the pre-crisis year of 2008. Moreover, between today and 2015 – in fact, even beyond this timeframe – the continued supply growth projected for biofuels and other non-crude streams will further reduce demand for the refinery processing of crude oil. On top of this, some capacity increases will be achieved through debottlenecking in existing refineries, which further reduces the need for new projects.

Another factor bringing an additional element of uncertainty to refiners is the recent evolution of downstream construction costs. In the period between 2004 and 2008, the downstream industry experienced significant construction cost increases. Based on the IHS/CERA index, they rose by over 60% from 2004 to the third quarter of 2008. A similar trend was recorded by the Nelson-Farrar[27] refinery construction index, although the increase here was less pronounced. The reason is that the Nelson-Farrar index is tied to developments in the US where cost escalation has not been as dramatic as in other regions. The IHS/CERA index covers a wider range of projects across world regions.

It should be noted, however, that both indexes show a temporary decline in construction costs toward the end of 2008 and in the first half of 2009. According to IHS/CERA, the downstream construction cost started declining in the third quarter of 2008 and accelerated in the first quarter of 2009, losing around 10% from its highest levels before returning to an upward trend in the remaining quarters of 2009. A similar pattern can be observed in the Nelson-Farrar index.

In last year's WOO, it was concluded that "the prospect of costs continuing to drop in the near-term has also served to influence refiners to delay projects." In other words, the investors' perception was that if they waited their costs would be lower. Today, however, costs are back on an upward trajectory again, which is anticipated to be the trend in the medium-term, although it is not assumed that the sharp cost acceleration prior to 2008 returns. Wherever a firm decision for project implementation has already been made, the expectation of cost increases accelerates development.

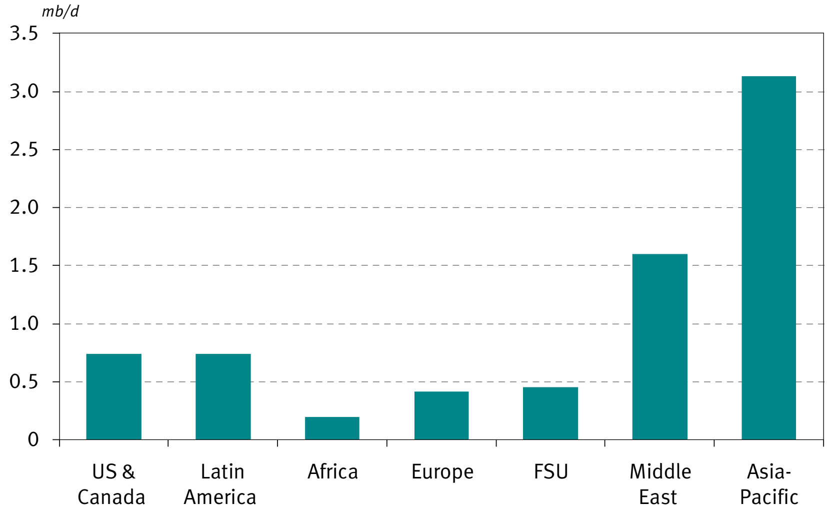
In respect to projects where no firm decision has been made, in addition to the cost and demand uncertainties that favour cautiousness in terms of project implementation and timing, several other factors need to be considered. This is especially true in the US and Europe, where the situation for refiners is becoming ever more complicated and uncertain, in light of the adopted or pending mandates for biofuels supply, transport fleet efficiencies and emissions, alternative vehicles and carbon regimes.

Elsewhere, however, capacity expansion in several emerging markets is being supported by policy incentives and favourable treatment. This is the case in India where export-oriented refineries commissioned before April 2012 enjoy tax holidays and duty free crude oil imports. Similarly, Chinese refineries benefit from competitive advantages in the form of a large stimulus plan to support both capacity expansion and the upgrading of existing facilities to produce lighter and cleaner products. Moreover, in December 2008, the Chinese government introduced a new pricing regime that effectively guarantees a minimum of 5% profit for refiners when crude prices are below $80/b.[28] The implication of these policies is two-fold. Firstly, they provide a strong incentive for a rapid expansion of the refining sectors in those two countries. Secondly, they allow for high utilization rates even at times when other markets suffer from substantial overcapacity. This will place added pressure on refineries that are exposed to market prices, thus increasing the likelihood of further closures.

All of the factors underlined, alongside a careful evaluation of the current status of each refining project, including commitments undertaken by investors and regional and domestic conditions supporting or discouraging their execution, were considered in arriving at the best estimation of expected refining capacity additions to 2015. The results of these calculations indicate that around 7.3 mb/d of new crude distillation capacity will likely be added to the global refining system in the period to 2015, including capacity creep[29] (Figure 5.1).

The Asia-Pacific is expected to see the largest capacity growth. The anticipated high proportion of capacity additions in the region is a continuation of the trend observed in recent years whereby the biggest refining projects have come on stream in China and India. This is certainly the case in China, where refining capacity is undergoing a period of rapid evolution. Largely centrally planned by the government, a primary objective has been to expand capacity sufficiently to keep up with domestic products demand, which is rising at an average of 4–5% p.a. Where refining was once predominantly concentrated in small inland facilities, including the 'social' or 'teapot' refineries, and processing was primarily of domestic sweet crude oil, the emphasis today is on large, complex installations in both inland and coastal centres. New coastal refinery complexes, like the ones at Qingdao, Dalian and Fujian, have been principally designed to process foreign medium sour crudes. The expansion of crude oil supplies

Figure 5.1
Distillation capacity additions from existing projects, including capacity creep, 2010–2015



Box 5.1
China's refining capacity: a need for better understanding

In assessing developments in China's refining sector it is important to underscore the challenges in accurately calculating the nation's refining capacity. There is evidence that figures from various sources, both from within China and outside, offer significant divergences in the amount of actual refining capacity in China.

The table over the page underlines these differences. First, there is the data from C1 Energy, which is an in-country China specialist. This data is that it explicitly distinguishes between major and independent companies. It counts a total of 177 refineries and a combined capacity of just over 10.7 mb/d at the end of 2009.

Allowing for the potentially low utilizations of the smaller 'social' refineries, sometimes referred to as 'teapot' refineries, its total capacity appears fairly realistic given that the country's refinery crude throughput is estimated at around 8 mb/d by the end of 2009.

From other sources highlighted, only Purvin & Gertz records sufficient capacity to allow processing at this level, with the Oil & Gas Journal the furthest away, reporting around 6.8 mb/d at the start of this year. It is interesting to note, however, that the Oil & Gas Journal only records data from 54 refineries.

What is clear is that there are gaps and discrepancies relating to information about secondary processing capacity across all sources. This underlines the importance of individual refinery checks, where feasible, and the use of aggregate 'best estimate' totals for each unit type. This may help reduce some of the uncertainties surrounding China's refining capacity.

China's refining capacity according to several sources, 2009

mb/d

	C1 Energy			Oil & Gas Journal	Purvin & Gertz	Hart Energy
	Four majors(1)	Independents(2)	Total			
Number of reported refineries	78	99	177	54	–	–
Crude distillation	**8.9**	**1.8**	**10.7**	**6.8**	**9.3**	**7.7**
Vacuum distillation				0.2	4.0	
Coking	1.2	0.3	1.6	0.2	0.8	1.0
Thermal cracking					0.1	
Fluid catalytic cracking	2.2	0.7	2.9	0.6	1.8	2.2
Hydro-cracking	1.2	0.3	1.5	0.2	1.0	0.7
Catalytic reforming	0.7	0.0	0.7	0.2	0.6	0.7
Total desulphurization	2.1	0.0	2.1	0.5	1.9	3.3
Alkylation			0.02	0.02	0.03	0.02
MTBE/oxygenates	0.03	0.01	0.05	0.00	0.00	
Aromatics			0.41	0.02	0.06	
Lubes				0.02		
Asphalt (bitumen)	0.06	0.19	0.26		0.13	
Coke (tons/d)				4,020		
Sulphur (tons/d)				1,362	3,325	
Hydrogen (million SCF/d)					989	

(1) Sinopec, CNPC, CNOOC, Shaanxi Yangchang.
(2) Independents include 'social' refineries.
– Not reported.

Chapter 5

via pipelines from Kazakhstan and Russia will likely lead to refinery capacity expansions in the inland north-western and north-eastern parts of China too.

In respect to ownership, China's refining sector can be divided into major and independent refineries. According to in-country data,[30] the former dominated capacity in 2009, with 8.9 mb/d at 78 refineries. The independent sector had more refineries, at 99, but on average these were much smaller with an estimated total capacity of 1.8 mb/d in 2009. They include the small 'social' refineries, together with the somewhat larger refineries that are privately-owned or are divisions of state-run enterprises whose main business is not focused on oil refining, for example, ChemChina and SinoChem.

The major refineries used to consist solely of those owned by China Petrochemical Corporation (Sinopec) and China National Petroleum Corporation (CNPC or Petrochina). These two entities still control almost 75% of the national refining capacity, with Sinopec around 43% and CNPC at 31%, but those involved in the 'majors' sector is expanding. It is now considered to include two more companies, China National Offshore Oil Corporation (CNOOC) and Shaanxi Yanchang Petroleum Group, and diversification may expand further in the future. CNOOC now controls some 6% of the national capacity and Shaanxi around 3%, leaving a balance of close to 17% for independent refiners. China does not currently possess any mega-scale refineries, but it is moving toward progressively larger facilities. The largest 24 refineries comprise almost 55% of the total national capacity, which includes five facilities with a capacity in the 300,000–460,000 b/d range and 19 in the 160,000–300,000 b/d range. These figures exclude interests in refineries outside China, for instance CNPC's activities in Kazakhstan, Sudan, and elsewhere in Africa.

A review of the largest Chinese refining companies is instructive in gaining a sense of how significant they are becoming as competitive global players. The top two Chinese companies in 2008 ranked among the global leaders in terms of refining capacity.[31] Sinopec (4.2 mb/d) ranked second to ExxonMobil (5.4 mb/d), but ahead of Shell (4 mb/d), BP (3.2 mb/d) and ConocoPhillips (2.8 mb/d). CNPC (2.6 mb/d) then ranked seventh, just behind PDVSA (2.6 mb/d), but ahead of Valero (2.4 mb/d) and Saudi Aramco (2 mb/d). Since that time, Sinopec and CNPC have both expanded their capacity. Current rankings would likely appear to be two and five, respectively.

Looking at Chinese projects, two major refineries have come on stream in 2010, namely Tianjin and Qinzhou, with both adding 200,000 b/d of new capacity. Sinopec's refining and petrochemical complex in Tianjin started its commercial operations in May 2010. The Qinzhou refinery of Petrochina, which includes a 70,000 b/d fluid catalytic cracking (FCC) unit and a 44,000 b/d hydro-cracker and reformer, went on stream in September 2010. These came on top of two expansion projects located in Qilu and Gaoqiao, which were finalized in the first half of 2010, as well as three major refineries completed in 2009 – CNOOC's Huizhou Refinery, Sinopec's Fujian Refinery and PetroChina's Dushanzi Refinery.

Looking ahead, the construction of Maoming and Huizhou are also at an advanced stage, likely to be completed by 2011. Further out toward 2015, expansion projects and grassroot refineries in several locations such as Quanzhou, Jieyang, Sichuan and Huabei, among others, are currently underway. Some projects are also likely to be developed as joint ventures with partners from OPEC Member Countries. In fact, Saudi Aramco partnered with Sinopec in construction of the Qingdao refinery, as well as in the Fujian project, jointly with Sinopec and ExxonMobil. In addition, environmental clearance and approval of the technical review has already been granted to a major refinery and petrochemical joint venture between Sinopec and Kuwait Petroleum, while Saudi Aramco and PDVSA have also reported further interest and negotiations with Chinese partners. In summary, estimations indicate that expansion of the Chinese refining sector will reach around 1.8 mb/d of additional distillation capacity by 2015, compared to the 2009 base.

As already highlighted, the other country in the Asia-Pacific that is expected to see significant refining capacity additions is India. Its refining industry can be divided into two sub-sectors, namely the public sector, which came into being in the mid-1970s, and the private sector, which was ushered into existence after the Indian Government enacted laws in the mid-1990s that allowed privately-owned refineries.

Consisting of four companies,[32] total public sector capacity stood at around 2 mb/d in 2009. The currently listed projects for future development total another 2 mb/d. These emphasize coking, hydro-cracking, catalytic reforming, limited FCC and significant hydro-treating to comply with tightening sulphur specifications and the availability of mainly medium gravity crude oils. Of the total, some 0.8 mb/d are realistically estimated to be online by 2015. These expansions should come close to matching product demand increases in the country.

While the public refining sector in India is experiencing some growth, it is the private sector that is changing the perception of Indian refining. Following the mid 1990s government laws allowing private refining companies, Reliance Industries has constructed a large-scale 550,000 b/d refinery at the Jamnagar Special Economic Zone. This refinery has since been expanded to 660,000 b/d and a second 580,000 b/d refinery was added in 2009.[33] Essar Oil started up a refinery at Vadinar in 2006–2007, initially with 210,000 b/d capacity, which has since been expanded to

280,000 b/d. A further two-phase expansion is planned for this refinery, initially to 360,000 b/d by mid-2011 and then a doubling to 720,000 b/d by 2013. In looking at this expansion, it is assessed that the first phase is considered firm, and is thus included in the projects expected to go ahead. The subsequent doubling to 720,000 b/d, however, was considered more speculative and thus excluded, although Essar – and Reliance – have a history of delivering on their project plans.

What is significant is that the total combined capacity for these three refineries located on India's west coast exceeds 1.5 mb/d. This is higher than Singapore's 1.4 mb/d capacity. Should Essar move ahead with both phases of its planned expansion, the combined capacity will essentially total 2 mb/d.

Moreover, these are large scale, complex, sophisticated and primarily export-oriented. They are convenient for processing crude oils from the Middle East, and secondarily North and West Africa. As their capacity rises, they will become greater crude oil consumers, including for heavy and difficult-to-process grades that could otherwise be difficult to place. Additionally, since most of their output is intended for export markets, and they do, or will have the capability to meet the most advanced product specifications with low operating costs, they will increasingly be viewed as competitors in the global downstream sector.

India's contribution to the capacity expansion of the Rest of Asia region will be supplemented by refining projects in other countries too. In the period to 2015, some additions are expected from the Korangi project in Pakistan, the Petrovietnam project in Nghi Son, Vietnam and from the expansion of the Chittagong refinery in Bangladesh. Combined with the Indian projects, this region is projected to add about 1.2 mb/d of capacity by 2015.

A long list of projects, totalling almost 9 mb/d of distillation capacity, has been announced by countries in the Middle East. It is unlikely, however, that all of them will come to fruition. The contribution from the Middle East is projected to be 1.6 mb/d of additional capacity between 2010 and 2015. The biggest portion of this is expected to come from new grassroots projects. Among several announcements, the most likely projects are Jubail and Yanbu in Saudi Arabia – possibly Jizan too – and the Ruwais refinery in the UAE.

In June 2010, Total and Saudi Aramco signed a deal to finance the 400,000 b/d Jubail refinery, which is scheduled to become operational in 2013. Saudi Aramco had also intended to partner with ConocoPhillips for a project in Yanbu, which is expected to be the same size as Jubail. In April 2010, however, ConocoPhillips withdrew from the project. Nonetheless, Saudi Aramco appears to be moving forward with the project. There is less certainty regarding the third Saudi project, originally to be sited at the Jizan Economic City, both in terms of location and size. In September 2010, Saudi Aramco had indicated that it might change the location and scale down its size to around a 100,000 b/d topping facility. It was originally envisaged to be a 250,000–400,000 b/d refinery with associated petrochemical units and scheduled to be on stream by 2015. With these changes, it is likely that the project will be delayed beyond 2015.

The UAE's Ruwais project is a 400,000 b/d grassroots refinery of crude distillation capacity with all the associated secondary processes. It will be constructed alongside the existing 120,000 b/d facility, which is located some 240 km west of Abu Dhabi. The project is tentatively scheduled to be completed by 2014.

Elsewhere in the region, a question mark still remains over Kuwait's huge Al-Zour project. It had been cancelled, but is now being re-considered. And in Qatar, the Mesaieed (Al-Shaheen) refinery in Qatar has now been put on hold. Due to the size of these projects and the uncertainties, it is unlikely that they will be finalized before 2015. In addition to grassroots refineries, several expansion projects are also underway in the region, in particular in Iran (Abadan, Bandar Abbas and Lavan) and Iraq (Basra and Daura). Both countries have also announced plans for several grassroots refineries that are needed to cover domestic demand. Similarly to the Al-Zour and Mesaieed refineries, it is expected that the implementation of these projects will be delayed until after 2015.

North America, dominated by developments in the US refining sector, will be the third biggest contributor to global capacity additions. Here, around 0.7 mb/d of new capacity will be achieved through the expansion of existing facilities, though some of the projects are actually the size of new world-scale refineries, notably the Motiva project in Port Arthur, Texas, and Marathon's expansion at its Garyville refinery in Louisiana. The Motiva project will add 325,000 b/d of distillation capacity and is expected to be on stream by 2012. Although construction of Marathon's 180,000 b/d project at Garyville was completed in December 2009, it has been in the process of full integration to the original refinery operations. Thus, it was kept in the list of projects with an effective start-up date of 2010 since its impact on the market will be felt only during 2010. The remaining capacity additions will come from smaller projects such as the expansion of the Wood River refinery by ConocoPhillips/Encana, BP's project in Whiting and the Consumers' Co-Operative Refineries expansion of the Regina complex in Canada, among others. Moreover, many of the US projects are geared to configuring refineries to receive increasing amounts of Canadian syncrudes, which means switching from light sweet or sour crude feedstock toward heavier ones.

Despite the high number of announcements, there are not many projects in other regions with a real chance of implementation before 2015. In total, all other regions will likely add around 1.8 mb/d of new distillation capacity. The biggest portion, 0.7 mb/d, is slated for Latin America. This is mainly through expansion projects in existing refineries in Caripito and Santa Ines in Venezuela, Barrancabermeja in Colombia, Esmeraldas in Ecuador and Guamare in Brazil. In addition to the expansion of crude distillation units, several projects in Latin America focus on increasing capabilities to produce diesel fuel, particularly in Brazil, where the gasoline market has little margin potential because of ever-expanding ethanol production. Several countries in the region, led by Brazil, Venezuela and Argentina and followed by some smaller Caribbean states, have plans for major grassroots refineries. For example, Brazil's Petrobras recently announced an ambitious plan to build 1.3 mb/d of new refining capacity in order to add value to its expanding upstream sector. Despite these declarations, however, it is envisaged that only a portion of these projects will be operational before 2015.

In Africa, the outlook is similar. There are more than 20 new refinery projects on the table, but with the exception of a couple of very small projects and potentially Angola's Lobito refinery, none of them is expected to be built by 2015. This is reflected in the projection that only 0.2 mb/d of distillation capacity will be added in this region.

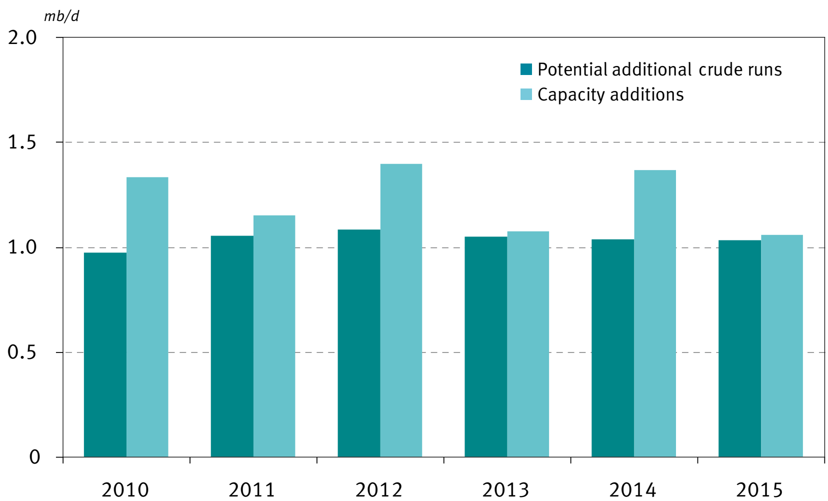
The remaining two regions, Europe and countries of the FSU, are projected to expand their refining systems by 0.4 mb/d and 0.5 mb/d of distillation capacity, respectively.

In Europe, the main projects are located in Southern Europe. Expansion will be achieved by two projects in Spain – Huelva and Cartagena – expansion of the Porto refinery in Portugal and the Corinth and Thessaloniki refineries in Greece. In Northern Europe, one significant project is expected. The Grupa Lotos facility in Gdansk, Poland is slated to add 90,000 b/d of new capacity.

For the FSU this year, there is an increase in projected capacity, compared to last year. These are scattered through several existing refineries in Russia and Belarus, the major ones being the expansion of the Tuapse refinery by Rosneft, the Nizhnekamsk refinery by CJSC Nizhnekamsk, the Kirishi plant by Surgutneftegaz and another two facilities in Belarus. Moreover, many projects in these two regions are oriented toward adding conversion and hydro-treating capacity to match the rising demand for middle distillates and to meet required quality specifications. Russia has also recently announced that it intends to add significant refinery capacity on its Pacific coast, fed by the newly operational Eastern Siberia Pacific Ocean (ESPO) pipeline from Eastern Siberia. However, this project is at too early a stage to be considered for 2015 start-up.

Figure 5.2 presents the yearly increments of distillation capacity resulting from both existing projects and capacity creep. It also shows estimates of the potential for additional crude runs, based on those annual capacity increases and taking into account average utilization rates, as well as the fact that new capacity gradually becomes available for production over this timeframe. While the figures for capacity additions represent total increases at the end of each year, the potential for additional crude runs reflects the yearly average capacity that contributes to the supply of refined products. By 2015, the potential for additional crude runs could increase by 6.3 mb/d, considering the average utilization rates for available capacity. Moreover, despite the fact that capacity additions measured at the end of each year appear to be coming on stream 'in waves', measured in terms of the potential yearly crude runs, they create rather stable increases of slightly more than 1 mb/d each year, except for 2010 where the increase is moderately lower.

Figure 5.2
Additional distillation capacity and crude runs from existing projects, including capacity creep



In addition to crude distillation capacity, it is equally important to assess the expansion of secondary process units before any conclusion on the adequacy or inadequacy of new projects can be made. A significant proportion of additions to secondary refining processes materialize through smaller upgrading projects in existing facilities. These projects are less costly and have shorter lead times. In respect to conversion

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capacity, the trend toward the increasing share of lighter products, especially diesel, in total demand, has led to a higher proportion of conversion capacity additions compared to distillation units. Historically, this proportion was in the range of 40–50%, but this has been significantly higher in the past few years. A review of the current projects, however, indicates that this proportion will decrease from the recent highs of almost 80%, so that for projects coming on stream in the period to 2015 it is expected to be around 65%.

Similar trends could also be observed in respect to sulphur removal processes. Moves toward ultra low sulphur fuels in the OECD, combined with tightening sulphur content specifications in several major developing countries, have necessitated a substantial expansion in global hydro-treating capacity over the past decade. This trend is likely to continue in the future and is visible in the number of projects expected to be constructed in the period to 2015, with total hydro-treating capacity additions broadly matching those for distillation units.

Table 5.1 provides an indication of what is expected in respect to secondary processes for the period to 2015. Out of a total of 4.2 mb/d of conversion capacity, the majority will come in the form of hydro-cracking units (1.8 mb/d) followed by coking (1.5 mb/d) and FCC units (1 mb/d). Hydro-crackers will be built mainly in regions with a growing diesel demand, which includes both Europe and North America. Comparatively high additions are projected for the FSU region, driven by the prospects for higher diesel/gasoil exports to Europe, which needs, and will continue to need imports of this product. The largest coking capacity additions are expected in the US and India, followed by the Middle East and China. New projects in South Europe will also include coking units while expansion of this process type in other regions will be fairly limited. Gasoline demand growth in the Middle East and China justifies the lead these regions are taking in expanding their catalytic cracking capacity. To a lesser extent, this will also be seen in the Rest of Asia region and the FSU. In contrast, no FCC expansion is foreseen in Europe, Africa and the OECD Pacific. The remaining parts of the world will likely experience only limited additions of FCC units.

Increases in desulphurization capacity are projected to be realized in relatively stable annual increments of around 1 mb/d for the entire period 2010–2015. This marks a total increase of 6.2 mb/d by the end of 2015, compared to the existing levels at the end of 2009. Most of the new capacity should be added in Asia and the Middle East, with 2 mb/d and 1.9 mb/d respectively. There are several reasons for this. Firstly, these regions will continue their move toward cleaner products by adopting mostly European standards for product quality specifications, albeit with different timeframes. Secondly, some of the projects in these two regions are export-oriented refineries targeting the markets where low or ultra-low sulphur products are mandated.

Table 5.1
Estimation of secondary process additions from existing projects *mb/d*

	By process		
	Conversion	Desulphurization	Octane units
2010	0.7	1.0	0.4
2011	0.8	1.1	0.3
2012	0.9	1.1	0.3
2013	0.6	0.8	0.2
2014	0.6	1.2	0.2
2015	0.5	1.0	0.2
	By region		
	Conversion	**Desulphurization**	**Octane units**
US & Canada	0.8	0.6	0.3
Latin America	0.3	0.8	0.2
Africa	0.2	0.1	0.1
Europe	0.6	0.4	0.1
FSU	0.5	0.3	0.1
Middle East	0.6	1.9	0.5
Asia-Pacific	1.3	2.0	0.6
World	4.2	6.2	1.8

Therefore, part of the desulphurization capacity will be built for this reason. Last, but not least, these are also regions with high domestic supply growth and, consequently, additional volumes of refined products output warrant capacity increases.

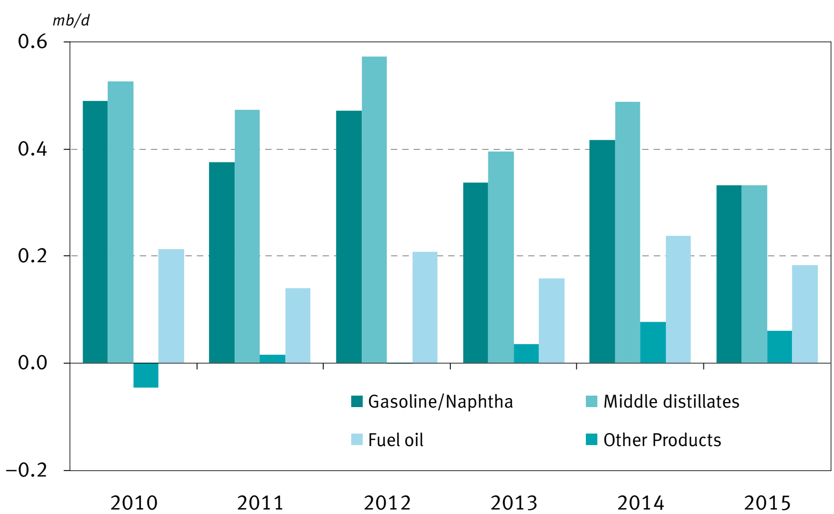
Both parts of the American continent, the US & Canada and Latin America, will also add significant volumes of desulphurization capacity (1.4 mb/d combined). The remaining capacity additions are seen in Europe (0.4 mb/d), the FSU (0.3 mb/d) and Africa (0.1 mb/d). Additions in North America and Europe relate mainly to the completion of modifications to comply with ultra-low sulphur gasoline and diesel standards that are slated to be fully in place by 2010/2011. These two regions see limited additions, however, as many refineries have already added and/or revamped capacity. Within Europe, the majority will be added in the south and eastern parts of the continent, as the northern part is already at full compliance.

The last category of capacity additions, referred to as octane units, relates to the quality of finished gasoline and comprises mainly catalytic reforming, isomerization and alkylation. Projections indicate that around 1.7 mb/d of these processes will be added to the global refining system in the period between 2009 and 2015. Out of this, catalytic reforming will account for the majority, 1.4 mb/d globally. Lesser amounts of isomerization (0.3 mb/d) and alkylation (0.2 mb/d) units appear in proposed refinery configurations and these units will be constructed in regions where gasoline demand increases are expected.

The combination of crude distillation capacity additions and the increases in secondary units determines the limits to which refiners will be able to react to changing future demand levels and the structure of the crude slate. On the one hand, additional secondary units provide some flexibility in steering refinery output toward the required product slate through adjusting process unit operating modes. In addition, refiners also have the option to alter the feedstock composition and can chose crudes that yield higher percentages of specific products. On the other hand, however, this flexibility is limited by both the available capacity in specific units and the availability of specific crude streams.

Bearing this in mind, Figure 5.3 summarizes the potential for the incremental output of refined products resulting from existing projects and grouped into major product categories. In total, the assessed implementation of current projects allows for around 6.5 mb/d of additional products to be available by 2015, compared to 2009

Figure 5.3
Potential incremental product output from existing projects



levels. In line with the expected demand structure shift, the changing refining configuration will allow for larger increases in the production of middle distillates (2.8 mb/d) and gasoline/naphtha yields (2.4 mb/d). The potential for additional fuel oil production depends on the region. It is declining in OECD regions, the FSU and in North Africa, but elsewhere it is increasing. Globally, it will be rather flat in the next three years and is expected to increase marginally toward the end of the considered period with new projects in the Middle East coming on stream. The divergent geographical structure also applies for 'other products'. However, increases in the Asia-Pacific and the Middle East more than offset the decline in some regions, so that in total these products have a potential to increase by around 1.1 mb/d.

Compared to last year's assessment, there is a shift in that more future refining capacity is to be placed in developing countries, especially the Middle East and the Asia-Pacific. Moreover, capacity additions are spread more uniformly over the years to 2015 and average annual capacity additions are higher than last year. If there is a situation of rather moderate demand increases then this will certainly put additional pressure on already low industry utilization rates and margins, thus adversely affecting the economics of existing and newly constructed facilities. The question remains, therefore, as to what extent and for how long will refiners – especially smaller refineries in OECD regions – sustain low utilization rates and margins? In other words, will refiners be forced to shut their operations? This leads to further questions. Is there an option for a 'relatively smooth' transition until demand increases eliminate excess capacity, or is some kind of significant capacity rationalization unavoidable? And what kind of implications might this situation have in the long-term?

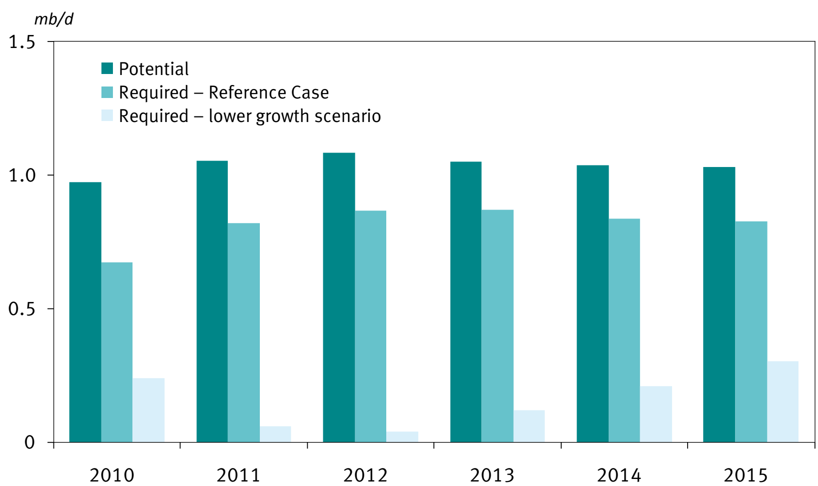
Medium-term outlook

To shed some light on the global refining sector's medium-term prospects, several factors need to be considered. Global crude throughputs will be affected by a combination of demand volumes for liquids and the supply structure. The supply side of this equation is marked by an expected rise in NGLs, condensates and biofuels, which reduces required refinery throughputs. NGLs and condensates expansion stem from a rise in the number of condensates projects, mainly across countries in the Middle East and North Africa, arising from natural gas production increases. The upward revisions in projected biofuels production stem mainly from advances in alternative fuels legislation in the US and Europe.

Given the demand projections detailed in Section One, and assuming the drivers behind the increase in light products and tighter specifications remain, the primary shift in the downstream outlook relates to the total refining capacity requirements. It is evident that there is the possibility that medium-term demand could be lower than that projected in the Reference Case. Thus, an alternative scenario, denominated the 'lower growth' scenario, explores the effects of a lower economic growth recovery following the global recession. In this scenario, for ease of reference, global oil demand rebuilds from 84.5 mb/d in 2009 to only 85.6 mb/d in 2012, 2 mb/d lower than in the Reference Case, and to 87.2 mb/d by 2015, again much below the level of 91 mb/d for the Reference Case. This situation of lower demand, compared to the Reference Case, is then sustained through to 2020 and beyond to 2030.

One specific effect of these factors is presented in Figure 5.4. This compares the potential achievable crude runs – based on expected project distillation capacity additions – with required incremental refinery crude runs from 2010–2015. The required crude runs are derived from the Reference Case and lower growth demand and supply projections. Two observations are worth noting. Firstly, after a reduction of around 1.3 mb/d in 2009 *versus* 2008, global refinery crude runs grow again in the Reference Case and are expected to continue this trend at levels of 0.8 mb/d to 0.9 mb/d p.a. However, in the lower growth scenario, increases in crude runs are significantly lower. Secondly, the potential for additional crude runs in the Reference Case consistently increases faster than the required levels, creating additional surplus capacity of around 0.2 mb/d each year.

Figure 5.4
Incremental global refinery crude runs, required and potential*

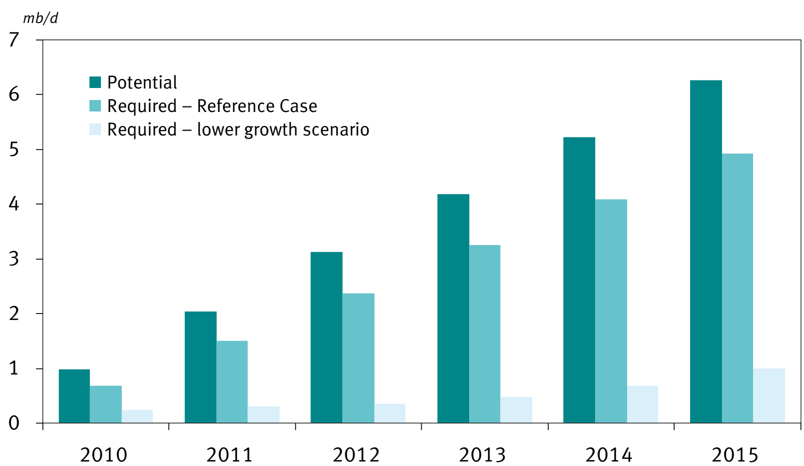


* *Potential: based on expected distillation capacity expansion.*
Required: based on projected demand increases.

Figure 5.5 puts the same information into another perspective by illustrating the cumulative effect of the additions to potential crude runs against what is projected to be required. The steady increases in potential crude runs from projects outpace the required runs every year through to 2015. This results in a cumulative surplus from projects over requirements that widens from 0.3 mb/d in 2010 to almost 1 mb/d by 2013 and then over 1.3 mb/d by 2015. It is critical to recognize that this projected growing medium-term surplus builds on top of a surplus that was created in 2009 when refining capability from finished projects increased by 1.1 mb/d, whilst required runs dropped by 1.3 mb/d. This created a gap or surplus for 2009 of 2.4 mb/d. Thus, the total refining surplus by 2015, based on developments from 2009–2015 is projected to be around 4 mb/d.

Moreover, should the global economic recovery, and thus oil demand, prove to be slower than in the Reference Case, the medium-term capacity surplus will be markedly higher. In this lower growth scenario, the required incremental refinery runs remain only minimally into positive territory on a cumulative basis by 2015, marking only 1 mb/d increase over these six years. Therefore, essentially very few of the total 6.2 mb/d of potential additional refining capability would be needed to 2015, looking at the figures on an overall global basis. The increase in the refining surplus to 2015

Figure 5.5
Additional cumulative refinery crude runs, required and potential*



* *Potential: based on expected distillation capacity expansion.*
Required: based on projected demand increases.

would be more than 5 mb/d, as against somewhat over 1.3 mb/d in the Reference Case. And added to this should be the 2.4 mb/d surplus increase from 2009.

Several implications can be concluded from this medium-term assessment. Primarily, the implication is that forthcoming projects will act to sustain a period of low refinery utilizations and hence poor economics. Moreover, the refining capacity overhang that has rapidly developed and the current difficulties in financing projects will almost certainly act to deter a number of future project developments.

Another implication relates to increasing potential for refinery closures. While this medium-term assessment considers additions *versus* requirements on an aggregate global basis, strong regional differences will apply, notably between the continuing growth requirements in non-OECD regions, especially Asia, and the surpluses in the US, Europe and Japan, which implies possible closures, as highlighted in Box 5.2.

Box 5.2
Outlook for refinery closures: a drama in three acts?

For the global oil market, a key consequence of the recent global downturn was the loss of several million barrels a day of future oil products demand. In addition, non-crude supplies have continued to grow, further eating into the required refinery output levels. For 2012, the reduction is in the range of 5 mb/d *versus* what had been projected just before the crisis.

At the same time, however, the combined capacity of the listed refinery projects has risen to 38 mb/d. This is far above recent historical levels and reflects the incentives that were seen in refining during its 'golden age' of tightness and high margins from 2004 through to 2008. While many of these projects will not go ahead, it is nonetheless estimated that 7.3 mb/d of new capacity will be added by 2015, including creep. This includes major new refinery and expansion projects in the US, China, India and the Middle East that, in the main, were authorized before the onset of the recession.

It is clearly evident that these two sides of the refinery equation do not add up. The refining sector is expected to face much upheaval in the coming years.

As is apparent in the Reference Case, this combination of factors has led to a marked reduction in refinery utilizations, to arguably unsustainably low levels. In 2008, the global utilization level was 84%, but this has since fallen significantly to almost 80% in 2009, and it is expected to be as low as 75% by 2015.

With utilization rates of at least 80% (and preferably 85%) considered necessary for a refinery's viability, the implication is that the industry is heading toward a period when substantial closures will be needed. An examination in last year's WOO indicated that at least 7 mb/d of global capacity would need to be closed worldwide to bring 2015 utilizations back to workable levels. This would have restored the global utilization rate to about 82%.

A similar modelling analysis was undertaken again this year to gauge the level of refinery closures needed to restore both refinery utilizations and margins. This led to comparable conclusions; namely that 5 mb/d of closures concentrated in the US and Europe would modestly raise both utilizations and margins, but that 7 mb/d of closures is needed to produce a more marked improvement in both. In the modelling analyses, the first 3 mb/d of closures were seen as applying to simpler, more cracking/gasoline-oriented refineries and so, to a large extent, were anticipated to do little more than remove surplus capacity, both primary and secondary. Reductions only start to 'bite' once more than 3 mb/d of 'simpler' capacity has been removed.

It is tempting to see a target of 7 mb/d of closures as being too large to contemplate in a five-year period. However, closures on such a scale would not be a first. During the 1980s, global refining capacity dropped from 82 mb/d to 73 mb/d, a fall of 9 mb/d. Given this history, and the fact that refining margins have been poor, and are expected – at least in the Atlantic Basin – to remain poor, it is perhaps surprising that, as of the third quarter of 2010, few actual closures have occurred.

The US East Coast is a case in point. Most of the refineries in this region are older units. To date, two have been permanently closed, Sunoco, Eagle Point, New Jersey and the smaller Western Refining unit in Yorktown, Virginia. However, two Valero refineries – Paulsboro, New Jersey and Delaware City, Delaware – that were either closed or were scheduled for closure, have apparently been purchased by an investment group that would appear to be aiming to restore their operations. On the US Gulf Coast only one small refinery has closed, although Chevron has also been considering a refinery closure there.

Similarly, in Europe, Petroplus' Teeside refinery in the UK and Total's Dunkirk refinery in France have been closed or are scheduled to close, but these represent the total so far, though several refineries are for sale. In Japan, the situation is once again similar. There is discussion of the need for major closures, but little has actually happened.

The limited number of refinery closures, and the talk of re-openings, appears to contradict the stark realities of refining, especially in the industrialized regions of the world.

It appears the present situation may represent part of the first act in what looks likely to become a two or three act play. ExxonMobil, Shell, Chevron, ConocoPhillips and others have all declared their intention to reduce their involvement in refining. It seems the underlying rationale is that greater 'value-added' for the corporations and their shareholders lies in focusing on exploration, production and potentially new ventures and fuels.

Yet, apart from the few closures mentioned, the initial actions taken to achieve a degree of 'disintegration' have centred on attempts to sell refineries rather than close them. As of the third quarter of 2010, there are at least 15 refineries reportedly for sale. Yet, with one or two exceptions, for instance, India's Essar, which is reported to be in discussions to buy part of Shell's European refining assets, there are few takers. This sets the scene for 'act two'.

On the assumption that few buyers come forward, and that the refining surplus is not saved by what would have to be a huge upsurge in post-recession demand, millions of barrels a day of refining capacity must sooner or later be closed. To some the future is akin to 'who blinks first'. A refiner that can hold out may end up with a greater market share as competitors are forced to close. It is anticipated that 'act two' will see an array of closures, possibly some sales, and based on history, the period could last several years.

In the US, the East Coast region is likely to remain a focus for potential closures given the intense competition there. The US Gulf Coast refineries could also be vulnerable. US refineries are being impacted by the flattening of domestic gasoline demand in parallel with rising ethanol supplies. One factor, however, working to their benefit is the increasing level of product exports. From around 1 mb/d in 2005, these have doubled to 2 mb/d in 2010, and continue to rise. The complexity and the production of higher quality products at US refineries enables them to compete in global markets and could help minimize the region's closures.

European refineries face the combined challenges of declining regional oil demand, the continuing gasoline/diesel imbalance and the imposition of carbon costs to part of their GHG emissions, potentially from 2013. A dozen refineries are reported to be for sale in Europe although analysts have estimated that up to 30 refineries – out of 132 in total – could be candidates for closure.

In Japan, it is widely believed that more 1 mb/d of capacity closures are needed to restore the country's supply and demand balance. A new rule by the Ministry of Economy, Trade & Industry (METI) requires Japanese refineries to increase their upgrading capacity as a percentage of crude runs. This will likely lead to some combination of distillation capacity reductions and upgrading additions, with the former more likely as refiners face a shrinking domestic market.

In addition, the ongoing investments in large, efficient, new refineries in the Middle East, India and elsewhere are acting to increase global competition and drive down supply costs for refined products. China could also be a factor in the global fuels product market, but its primary challenge is to build enough refining capacity to keep up with domestic demand. Opportunities for exporting products may be limited to periods when new start-up capacity allows China to temporarily 'get ahead' of domestic demand growth. This wave of competition will add to the pressures on existing refineries.

Declining demand, rising biofuels supply, an increase in non-crudes, more competition and actual or potential carbon mandates are all acting to reduce the need for, and the attractiveness of, refineries in industrialized regions.

Those that are small, simple, and lack local crude supplies, specialty products or petrochemicals integration, and that are most reliant on export markets, are likely to be the most vulnerable. As of just a few years ago, such refineries were often viewed as those with less than 100,000 b/d of capacity. Today, that no longer applies. It is evident from recent and possible closures that even a 200,000 b/d refinery is not necessarily safe. The potential wave of closures over the next few years will further 'raise the bar' in terms of what constitutes a secure, viable refinery.

For this, however, we need to wait for 'act three'. From the current perspective, this act remains an unknown, but it is likely to change the face of the refining sector, with oil majors likely to play less of a role in the future.

Long-term distillation capacity outlook

The key drivers for the long-term downstream industry developments are in general a continuation of the ones determining the medium-term prospects. The elimination of the existing capacity surplus – one that will likely be extended in the medium-term – will certainly pose a challenge for the industry for some time to come. Similarly, the further expansion of non-crude supplies in the long-term will likely be even more protracted with additional streams of GTLs, CTLs, biofuels and NGLs. Moreover, one of the key messages of this year's WOO is a further demand shift from developed to developing countries, primarily in the Asia-Pacific where major demand increases are projected.

These trends are clearly visible in the estimation of required distillation capacity additions to 2030, which are presented in Table 5.2. These estimations take into account long-term Reference Case demand and supply projections detailed in Section One. Moreover, for a better understanding of these numbers it is important to bear in mind the fact that the model used to derive them balances future capacity requirements with demand. It does not, however, take into account possible capacity rationalization. Recognizing this, estimations suggest that almost no additional distillation capacity will be needed in the medium-term beyond what is expected to be constructed from assessed projects. In the period to 2020, around 3 mb/d of new capacity will be required and a further 2.8 mb/d and 3.3 mb/d are projected for the time horizon of 2025 and 2030, respectively.

It is also important to note the fact that the annualized pace of total capacity additions needed from 2015–2030 averages in the order of 0.6 to 0.7 mb/d p.a. This is only half of the 1.2 mb/d rate for 2009–2015. This is yet another illustration that current projects are more reflective of recent history and pre-recession investment decisions. Thus, today's projects potentially represent a substantial proportion of the total additions that will be needed over the next 10–15 years. Needless to say that under the lower growth scenario requirements would be curtailed further, especially in the period to 2020.

Table 5.2
Global demand growth and refinery distillation capacity additions by period
Reference Case

mb/d

	Global demand	Distillation capacity additions			
	growth	Known projects*	New units	Total	Annualized
2009–2015	6.5	7.3	0.2	7.5	1.3
2015–2020	5.2	0.0	2.9	2.9	0.6
2020–2025	4.7	0.0	2.8	2.8	0.6
2025–2030	4.5	0.0	3.3	3.3	0.7

	Global demand	Distillation capacity additions			
	growth	Known projects*	New units	Total	Annualized
2009–2015	6.5	7.3	0.2	7.5	1.3
2009–2020	11.8	7.3	3.1	10.4	0.9
2009–2025	16.5	7.3	5.9	13.2	0.8
2009–2030	21.0	7.3	9.2	16.5	0.8

* *Known projects include additions resulting from capacity creep.*

Table 5.2 shows that cumulative refinery capacity additions are ahead of global demand growth through to 2015 – again driven by project additions – but then fall progressively below demand growth in the period from somewhere between 2015 and 2020 through to 2030. The underlying reason for this trend whereby refining additions increasingly fall behind demand growth over the longer term is that non-crude supplies – NGLs, biofuels, CTLs/GTLs, petrochemical returns – expand faster than demand and thus as a proportion of total supply. Therefore, less refining is needed per barrel of total liquids demand. In the time period from 2015 onwards, new refining capacity additions run at an average of about two-thirds of the level of total oil demand growth.

Table 5.3 presents the outlook in terms of refinery crude throughputs and utilizations. Demand destruction, a consequence of the economic crisis, higher efficiency improvements that reduce future demand growth and rising non-crude supplies act to depress global refinery crude throughputs for the entire forecast period. The pattern, however, is not the same in all regions, with similar trends to demand projections observed.

Table 5.3
Total distillation unit throughputs
Reference Case

mb/d

	US & Canada	Latin America	Africa	Europe	FSU	Middle East	Asia-Pacific	Global
2008	16.0	6.6	2.8	13.5	6.1	5.9	22.0	72.9
2015	14.4	6.3	3.0	12.4	6.1	6.8	21.9	70.9
2020	14.5	6.8	3.4	11.6	6.5	7.1	24.3	74.2
2025	14.1	7.3	3.6	11.7	6.6	7.5	26.3	77.0
2030	13.4	7.4	3.9	11.6	6.6	7.9	28.5	79.4

The two extreme sides of the regional differences are the Asia-Pacific and the US & Canada. Between 2008 and 2030, crude distillation throughputs in the Asia-Pacific are set to increase by 6.5 mb/d while those in the US & Canada are projected to decrease by 2.6 mb/d.

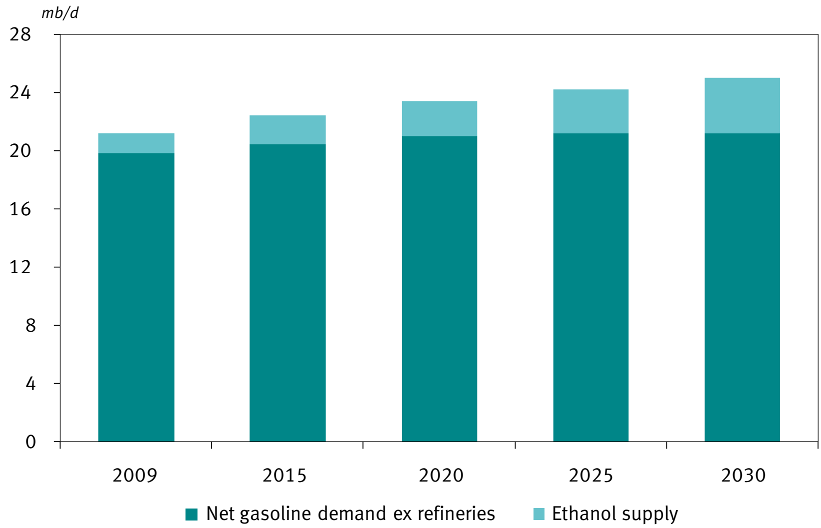
These figures highlight that the refining industry in the US & Canada region will be the most adversely affected, mainly because of a combination of a surge in ethanol supply and an overall demand decline, especially for gasoline. On top of these domestic reasons are the continuing effects of European dieselization, which will support the production of low-cost gasoline – a 'by-product' of diesel production – that will be available for export to the US. Based on the Reference Case outlook, not only do US & Canada crude throughputs never recover to 2008 levels, they also steadily decline in the period to 2030. Crude throughputs in all US and Canadian regions are expected to decline gradually, although the US Gulf Coast refineries are likely to see greater impacts than those in the interior. The latter are more protected from international competition and have the benefit of growing crude supplies from Canadian oil sands.

The rapidly growing ethanol supply plays a significant role in the US & Canada situation. Reference Case projections foresee ethanol production in the US & Canada rising from 0.7 mb/d in 2008, to 1 mb/d in 2015 and then to 1.9 mb/d by 2030.[34] As a result of the ethanol supply increases, the net demand for gasoline ex-refineries[35] peaked at around 9.4 mb/d in 2006. It was already down to 8.8 mb/d by 2008 and thus contributed to the regional gasoline surplus and depressed margins relative to crude oil. Ex-refinery gasoline requirements continue to decline to 2030 as ethanol supplies increase and improved vehicle efficiencies cut consumption. Under the Reference Case, the decline is to around 8 mb/d ex-refinery by 2020 and to 7 mb/d by 2030. Put another way, the decline for ex-refinery gasoline runs are 55,000 b/d each year to 2020, with the level then doubling annually from 2020–2030. Based on this projection, it is strikingly clear that US refining throughputs have peaked and they will need to adjust to a progressive demand decline.

Moreover, Figure 5.6 illustrates how projected global ethanol supply growth – not just regional – impacts gasoline. Driven by the US and Brazil, the main supply sources, global ethanol supply is projected to rise from 1.4 mb/d in 2009 to 2.4 mb/d by 2020 and then to 3.8 mb/d by 2030. The net increase by 2030 is 2.4 mb/d. Over the same period from 2009–2030, worldwide gasoline consumption is projected to rise from 21.2 mb/d to 25 mb/d, an increase of 3.8 mb/d. Thus, ethanol comprises 6.5% of total global gasoline consumption in 2009, almost 10% by 2020 and nearly 15% by 2030. Extrapolating out these figures shows that ethanol supply growth comprises 60% of the incremental gasoline demand growth to 2030, leaving only 40%, or 1.4 mb/d for gasoline supplied from refineries.

While the emphasis in refinery projects has shifted to distillates, every refinery expansion inevitably increases the potential gasoline and naphtha production. There is currently no such thing as a 'zero naphtha/gasoline' refinery. The NGLs and ethanol supply increases, the potential refinery increments and the moderate consumption increases – at least for gasoline – are the major factors that combine to sustain a future

Figure 5.6
Global gasoline demand and ethanol supply



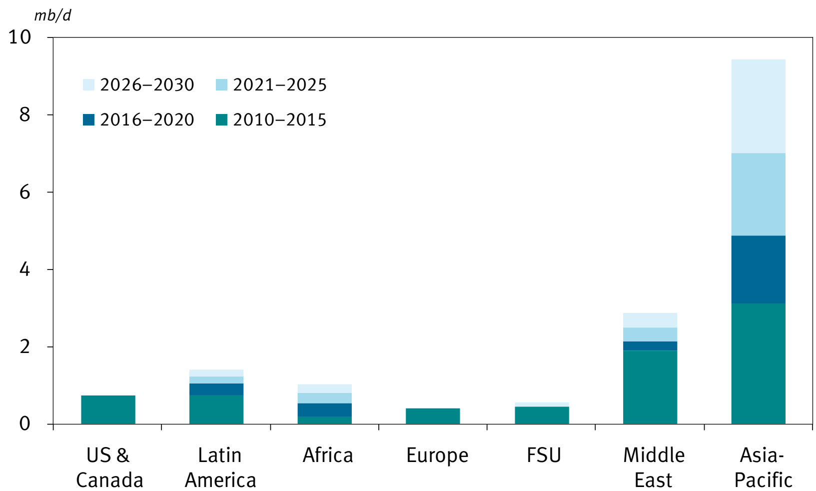
gasoline and naphtha surplus, with consequences for imbalances and depressed margins, as discussed later in this Section.

A scenario similar to that for the US & Canada is expected for Europe. Flat demand and the impact of additional biofuels supply in the range of 1 mb/d means that no refinery capacity expansion beyond current projects is projected as required by 2030. Rather, as in the US & Canada, regional refinery throughputs are projected to drop relative to recent highs of around 13.5 mb/d. The figure is 12.4 mb/d by 2015, with this then dropping below 12 mb/d through to 2030.

Although not shown directly in the summary charts, a flat to declining demand creates a similar situation in the Pacific Industrialized region (Japan and Australasia). No new refinery capacity is anticipated to be needed through to 2030 and utilizations – barring closures – are in the range of 70%.

Prospects for the FSU's downstream industry stand somewhere between those for industrialized and those for developing countries. As presented in Figure 5.7, the refining industry in this region will experience some future expansion although capacity requirements beyond the assessed projects are very limited. Projected increases in distillation throughputs between 2015 and 2020 result from gradual improvements in utilization rates, which benefit partially from domestic demand, but also from export

Figure 5.7
Crude distillation capacity additions in the Reference Case by period, 2010–2030



options to neighbouring regions. However, although utilizations gradually increase, they do not exceed 75% over the entire forecast period. Moreover, FSU refining capacity growth may also be vulnerable to, and constrained by, European demand, which is currently the major destination for Russian product exports.

The picture changes when reviewing prospects for developing countries. Latin America is expected to add 0.7 mb/d of refining capacity to 2015 and then another 0.7 mb/d by 2030. This compares to the total oil demand increase of 1.8 mb/d between 2009 and 2030. Obviously, capacity increases alone will not be sufficient to cover incremental demand. However, this will be achieved by gradually rising utilization rates in combination with growing regional non-crude streams.

In broad terms, the same picture applies to Africa, albeit the process is more dynamic. Africa is projected to experience relatively rapid demand growth. Very few projects are under construction in the region at present – approximately 0.2 mb/d – and so appreciable additions of 0.4 mb/d are projected from 2015–2020 and 0.3 mb/d from 2020–2025. Nonetheless, total additions of 1 mb/d – including assessed projects – to 2030 fall well below the regional demand increase of 2.2 mb/d. This evidently indicates that this region's refining sector faces a range of challenges.[36] On the plus side, there is growing domestic and regional crude oil production, mainly good quality, and expanding local demand. On the other side, however, many of the region's refineries, especially sub-Saharan, face the challenges of being small scale, old, relatively low in complexity and low in energy efficiency. In addition, there is intense and growing competition to import products into Africa from Europe, the Mediterranean region, the Middle East, India and even the US, which limits any substantial expansion of refining capacity for the foreseeable future.

The two remaining regions, the Asia-Pacific and the Middle East, will be where the vast majority of the refining capacity expansions to 2030 are needed. The bulk of the global total of almost 17 mb/d of required capacity expansion by 2030 will be placed in the Asia-Pacific, at more than 9 mb/d, and close to 3 mb/d will be constructed in the Middle East.

Around half of the Asia-Pacific expansions will take place in China. The exact level of future refinery expansion in China, however, is a matter of some uncertainty. This analysis was conducted on the premise that China would not – over the long-term – match all its domestic demand growth via internal refinery expansion projects. As a consequence of this, refined products imports will remain significant. Given the potential for surplus capacity worldwide, it is expected that some level of continued product imports is likely. Utilizations in China are projected to be above 90% as the country works to add capacity to keep up with demand growth and remains a net product importer.

In the Middle East, sustained demand growth at 1.7% p.a. is projected over the period to 2030. The medium-term increase to 2015 is 0.8 mb/d and long-term growth from 2015–2030 is 2 mb/d. Total capacity additions to 2030 are projected to be 2.9 mb/d. Of these, 1.9 mb/d are projects estimated to be on stream by 2015. Thus, project additions are 'front loaded' within the region. Beyond 2015, steady capacity increases totalling a further 1 mb/d are projected to be needed by 2030. Crude throughputs are anticipated to expand from 5.9 mb/d in 2009 to 7.9 mb/d in 2030. The potential for expansion – currently some 9 mb/d of Middle East projects are listed – will be driven in part by regional demand growth, but also by the potential to export increasing volumes of refined products.

Chapter 6

Conversion and desulphurization capacity requirements

A necessary prerequisite for the effective functioning of the refining sector is sufficient distillation capacity, supported by conversion and product quality related capacity that play vital roles in processing raw crude fractions into increasingly advanced finished products. The importance of these 'secondary' processes, which deliver most of a refinery's 'value-added', has been enhanced as the general trend toward lighter products and more stringent quality specifications has increased. However, the severe demand reduction for clean products has brought with it a significant fall in refinery distillation capacity requirements. This leads to the question: does the need for much less crude distillation capacity mean there will be significantly reduced requirements for secondary processing?

As already mentioned, in addition to the future demand levels and mix, there are two other important parameters impacting future capacity requirements for secondary refining processes. These are the expected quality of the global crude slate and the quality specifications for finished fuels. For example, in principle, heavier crude oil would require increased conversion capacity to produce a higher portion of light products. Changes in sulphur content of the feedstock would require adjustments to the capacity of hydro-treating units, as well as those to supply the required volumes of hydrogen and for sulphur recovery. Similarly, more stringent quality specifications in respect to other parameters, such as octane and cetane numbers, will require modifications to the range of other secondary processes to meet the given parameters.

Crude quality

The total oil supply comprises a mix of various streams, each with differing expectations for their future developments. It is expected that over the forecast period a structural change in the global liquid fuels supply will materialize, which in turn affects the future structure of the refining sector. These streams comprise crude oil production, condensates and NGLs, petrochemical return streams, biomass (ethanol and biodiesel), methanol for methyl tetra-butyl ether (MTBE), CTLs, GTLs, hydrogen and processing gains. In respect to crude oil production, the results presented in this WOO are based on a detailed analysis of around 150 crude streams covering the full spectrum of gravity and sulphur content, including the key streams in all producing regions.

From a refining point of view, the major observation in respect to the structure of the future oil supply is a shift towards an increasing share for non-crude. By 2030, it is expected that the total supply of 105.7 mb/d in the Reference Case will be met by less than 83 mb/d of crude oil supplies, with more than 23 mb/d from non-crudes, including processing gains. Non-crude in the total supply increases from 15% in 2009 to 22% by 2030. Moreover, this shift is faster in the first half of the forecast period primarily due to the expected strong expansion of NGLs, an expansion of biofuels and an increase in CTLs/GTLs production. The continuation of this trend post-2020 results from a combination of projected developments in all these streams, although growth is slower, especially in respect to NGLs.

Figures 6.1 and 6.2 present the expected quality changes in the oil supply streams that are typically used as a refinery feedstock.

At the global level, a detailed analysis of the expected structure of crude supply – and other streams – indicates a relatively stable future crude slate, especially in respect to API gravity. The figure is projected to improve to around 34.2° API by 2015 and then move back to around 33.9° API by 2030, a similar level to the present one. Figure 6.1 also underscores that the global average for the entire forecast period is anticipated to remain in a fairly narrow range of less than 1° API. In respect to sulphur

Figure 6.1
Crude quality outlook in terms of API gravity

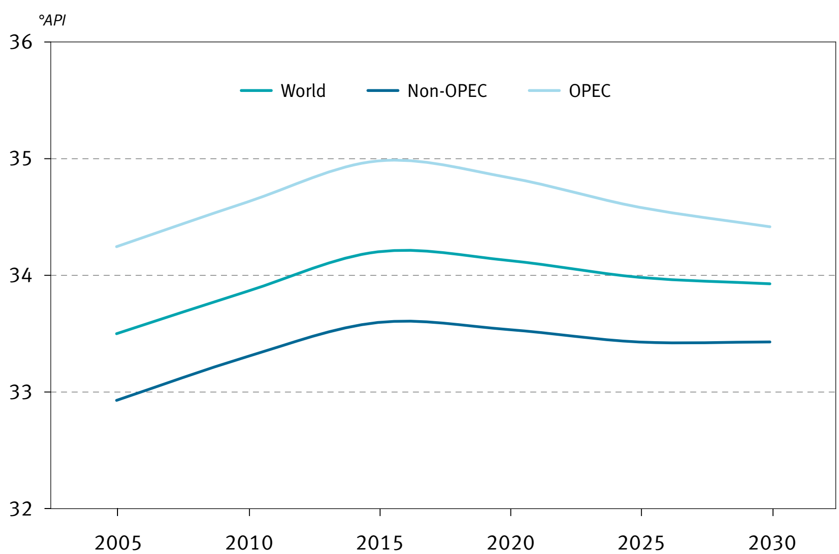
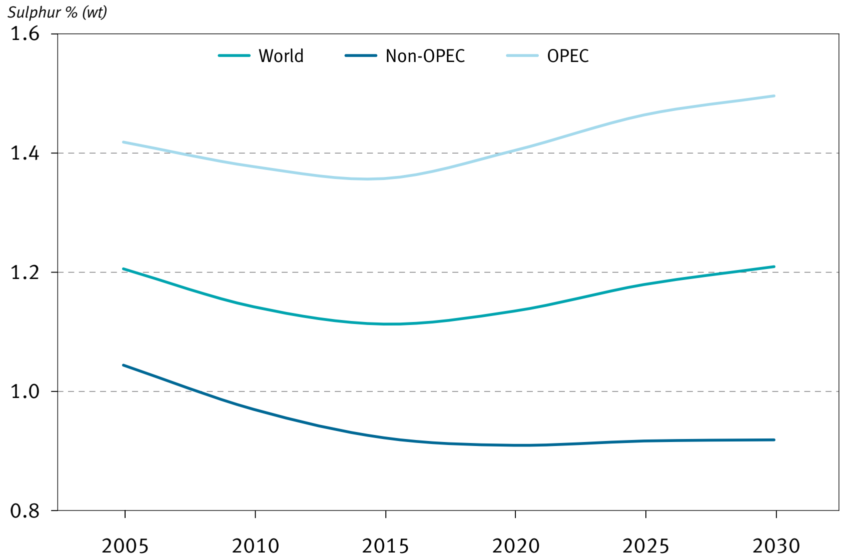


Figure 6.2
Crude quality outlook in terms of sulphur content



content, the expected variations are somewhat wider, but still less than 10%. Driven mainly by increases in syncrudes, condensates and light crude oils, it is projected that the global crude slate will get sweeter in the period to 2015, reaching 1.1% (wt)[37] average sulphur content from 1.2% (wt) in 2005. The trend then reverses towards a sourer slate, with the sulphur content slightly above 1.2% (wt) by 2030.

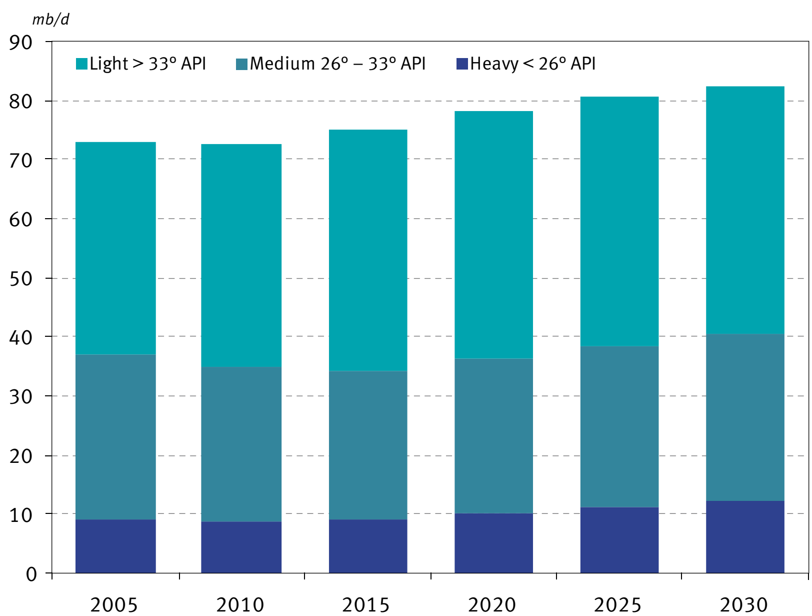
Similar patterns are observed when countries are clustered into non-OPEC and OPEC groups, although some differences do exist. In the case of non-OPEC, the average crude quality is anticipated to improve only marginally compared to the current slate, with the average API gravity increasing from an estimated 33.3° API in 2010 to around 33.4° API by 2030, and the average sulphur content declining from 1% (wt) to 0.9% (wt). A shift towards better quality is projected to occur mainly in the next few years, with a peak in quality of 33.6° API and 0.9% (wt) sulphur content around 2015. Thereafter, up to 2030, the quality of the overall non-OPEC crude slate will likely remain fairly stable.

For OPEC Member Countries, the quality of the crude slate will improve by almost 0.5° API in the period to 2015, compared to the 2010 average. It rises to 35° API by 2015. During the same period, the average sulphur content will also be lower, declining from an estimated 1.38% (wt) in 2010 to 1.35% (wt) by 2015. In the period after 2015, however, a decline in OPEC's crude quality is expected. It falls to 34.4° API by the end of the forecast period, which is slightly below the current average. Additionally, the average sulphur content is expected to be somewhat higher than today, at around 1.5% (wt).

Figure 6.3 sheds some light on the key drivers that support these projections, with more details in Section One. Between 2010 and 2030, the largest volume increases are projected in the category of light crude screams, at almost 5 mb/d. A noteworthy improvement in the crude slate should be witnessed in the FSU region, driven by new production in Caspian fields and supported by developments in Sakhalin and Siberia. This will contribute to an increase in light and sweet crude streams. Other regions seeing an expansion of these streams are Africa, the Middle East and some countries of Latin America. Combined, this growth will more than compensate for the declining supply of this crude category in the North Sea.

Moderate increases in the category of medium (mostly sour) crudes of around 2 mb/d between 2010 and 2030 are primarily due to developments in the Middle

Figure 6.3
Global crude oil, condensates and synthetic crude production by category



East, Latin America and Russia. Projected declines in some of these streams, such as the Russian Urals, are compensated by increases in others, for instance, in Brazil and the Middle East.

The composition of the category of heavy (and typically sour crudes) is determined by developments in both parts of the American continent. In total, production of these crudes is expected to increase by more than 3 mb/d by 2030, compared to the estimated levels for 2010. The main increases are from Canada, Venezuela and Brazil, supported by some streams in the Middle East and high TAN crudes from Africa. These should outweigh the dwindling production from Mexican Maya crude, as well as some minor streams in North America.

Refined products quality developments

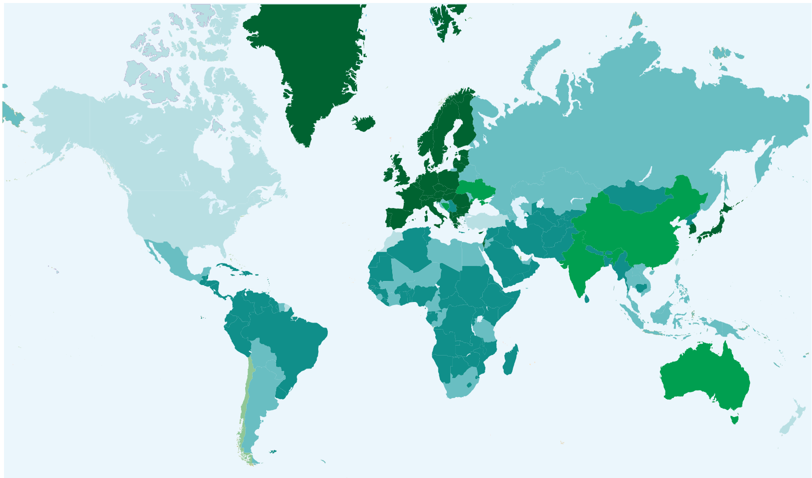
The quality specifications of finished products are a significant factor affecting future downstream investment requirements. Refiners worldwide have invested billions of dollars to comply with tightening refined product quality specifications. Throughout the 1980s and 1990s, regulators focused on lead content in gasoline. After a gradual shift to unleaded gasoline in most countries — although the worldwide completion of the process is still underway — the focus turned to the sulphur content, especially in Europe, Japan and the US. It has meant that the quality requirements of diesel fuel and gasoil, alongside gasoline, have also started to be targeted worldwide.

Globally, the current aim is to produce fuels with sulphur content below 10 parts per million (ppm), that will in turn, enable the development of advanced vehicle technology to further reduce emissions. The next step, which has already begun in a number of countries, is to extend stricter sulphur specifications beyond on-road transportation to other products, particularly jet fuel, marine bunkers and fuel oil, and to turn attention to other parameters, such as the cetane number, aromatics and benzene content. It should also be noted that at the same time, many countries have added biofuels to their fuel mix, which is creating new challenges for refiners and blenders.

This next step, however, has no coordination at the global level, and little at a regional one. Therefore, improved quality specifications for refined products have not fully spread to all regions and relatively wide variations in quality specifications still exist. This is clearly demonstrated in Figures 6.4 and 6.5, which show maximum legislatively permitted sulphur content worldwide in gasoline and on-road diesel fuel, respectively – these may differ from actual market levels – as of September 2010.

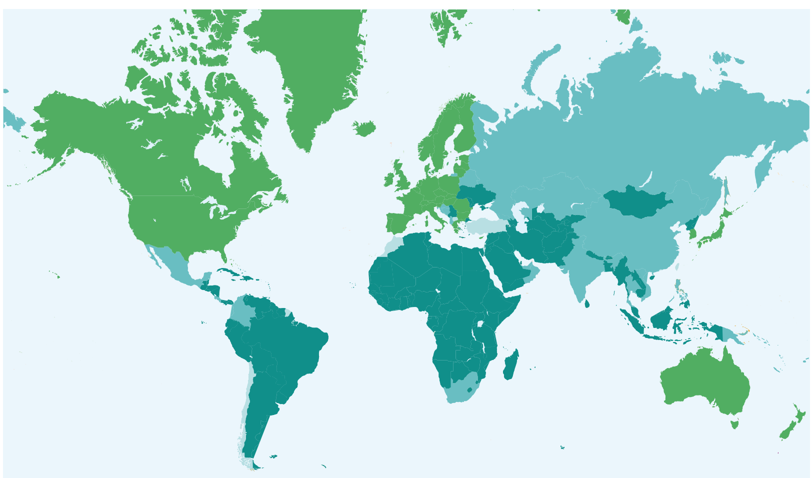
The trend in developed countries is toward the widespread use of ultra-low sulphur gasoline. The US ultra-low sulphur gasoline programme – with an 80 ppm per

Figure 6.4
Maximum gasoline sulphur limit, September 2010



Source: *Hart's International Fuel Quality Centre (IFQC), September 2010.*

Figure 6.5
Maximum on-road diesel sulphur limit, September 2010



Source: *IFQC, September 2010.*

gallon cap and a 30 ppm annual average – was phased in as of 2004. Starting in 2010, the US is limited to the 30 ppm maximum standard for all refiners. It has to be noted that California has its own stricter specifications set at a 15 ppm maximum average. Canada implemented a 30 ppm sulphur limit in 2005. Effective as of January 2009, the EU requires fuels containing 10 ppm maximum sulphur content. And Japan has required 10 ppm gasoline since January 2008, but this level had already been reached in 2005.

Despite significant improvements in a number of developing nations, in general. These countries lag somewhat behind. The gasoline sulphur limit in China was reduced from 500 ppm to a nationwide 150 ppm in December 2009. However, stricter quality requirements of 50 ppm are imposed in Beijing and Shanghai, as well as in the southern province of Guangdong. China is expected to lower the nationwide limits to 50 ppm by 2013. A similar type of policy is being applied in India too. From April 2010, selected urban centres (13 large cities) were required to follow the 50 ppm gasoline standard, while the rest of the country was at 150 ppm. The national implementation was carried out in September 2010.

Significant improvements in gasoline quality specifications are also ongoing in other major consumer countries in the Asia-Pacific, as well as in other regions and countries, especially the Middle East and Russia, albeit from much softer existing requirements.

Diesel fuel specifications not only vary between countries and regions, but also often between sectors. In the EU, the European Fuel Quality Directive has required on-road diesel fuel sulphur content to be set at 10 ppm since 2009, with off-road diesel sulphur at the same level from 2011. Sulphur limits of 10 ppm for on-road diesel fuel are also in place in Japan, Hong Kong, Australia, New Zealand and South Korea. In the US, except for California, where sulphur limits are already at 15 ppm for both on-road and off-road diesel, a move to 15 ppm sulphur diesel started in 2006 and is expected to be completed by December 2010 for on-road transport, and by 2012 for off-road diesel from the current limit of 500 ppm. In Canada, a switch to 15 ppm for on-road diesel happened in June 2006 and off-road diesel is expected to be fully aligned by October 2010.

Major developing countries could again be viewed as being behind in this process, but it should be noted that improvements hare have also been significant. China reduced its on-road diesel sulphur in January 2010, when the limit in automotive diesel was reduced to 350 ppm. It is worth stating that this was the first official differentiation between on-road and off-road diesel requirements in China. Due to the size of the country, the nationwide implementation of the 350 ppm limit is not expected before mid-2011. The diesel sulphur limit for Beijing, Shanghai and Guangdong is set at a maximum of 50 ppm. Further reductions in on-road diesel quality in major Chinese cities is planned to happen in 2012, when 10 ppm is expected to be imposed. India is following a similar path. It currently has a 350 ppm level for on-road diesel nationwide, with 50 ppm in selected cities, which was fully implemented in September 2010.

Similar improvements in on-road diesel quality are reported for countries such as Indonesia, Malaysia, Philippines, Thailand, Russia, Kuwait, Qatar, South Africa, Brazil, Chile, Colombia and Mexico.

The region that requires a major shift in future specifications is Africa, as in most countries sulphur content is in the range of 2,000 to 3,000 ppm for on-road diesel, and much higher for off-road diesel fuel. The exceptions are for South Africa and the North African sub-region, which is upgrading its refineries with a specific focus on the potential export market in Europe.

Looking at long-term assumptions, the expectations for future product quality specifications are lower for developing regions – Africa, the Asia-Pacific and Latin America – compared to last year's WOO, particularly as a result of delays in refinery upgrades due to the global financial crisis. In respect to gasoline, future quality initiatives will focus primarily on sulphur, benzene and aromatics. Projected gasoline qualities for 2010–2030 are shown in Table 6.1.

Table 6.1
Expected regional gasoline sulphur content*

ppm

Region	2010	2015	2020	2025	2030
US & Canada	30	30	<10	<10	<10
Latin America	680	260	130	70	40
Europe	15	10	<10	<10	<10
Middle East	690	180	70	40	40
FSU	430	110	50	20	15
Africa	840	440	300	170	100
Asia-Pacific	220	120	60	30	20

* *Estimated regional weighted average sulphur content is based on volumes of fuel corresponding to country specific legislated requirements as well as expected market quality.*

Source: Hart's World Refining & Fuels Services (WRFS) and IFQC.

It is diesel sulphur that presents the greatest challenge to the sector due mainly to the fact that it is expected to have the greatest need for refinery processing additions. Table 6.2 summarizes regional diesel fuel quality from 2010–2030 for on-road diesel and shows a significant slowdown in diesel quality improvements in all developing regions. For Europe and North America, on-road and off-road ultra low sulphur programmes will require sulphur diesel to be below 15 ppm for most of the diesel market (10 ppm in Europe). By 2015, on-road diesel is projected to be below 500 ppm in all regions except Africa and Latin America. While Latin America will pick up the pace in sulphur content reduction after 2015 due to planned new refinery projects, Africa is not projected to reduce sulphur levels near to 500 ppm before 2025. In the developing regions, the off-road diesel requirements will lag significantly behind the ones for on-road diesel.

Table 6.2
Expected regional on-road diesel sulphur content* *ppm*

Region	2010	2015	2020	2025	2030
US & Canada	15	15	15	10	10
Latin America	1,270	460	180	50	35
Europe	15	10	10	10	10
Middle East	1,820	460	280	110	80
FSU	490	130	50	15	10
Africa	3,260	2,210	1,230	560	210
Asia-Pacific	480	260	190	100	90

* *Estimated regional weighted average sulphur content is based on volumes of fuel corresponding to country specific legislated requirements as well as expected market quality.*
Source: Hart's WRFS and IFQC.

Since there is little room for further improvements in conventional product specifications for developed countries, the major shifts will occur in most of the developing world. China and India are currently leading the introduction of clean fuels in the developing world, followed by Latin American countries and others. Plans have been announced to progressively adopt tighter standards for both diesel and gasoline. This includes constraints on benzene (gasoline), aromatics (both fuels), gravity (diesel), cetane (diesel), although the main focus is on sulphur. This will necessitate substantial investments in hydro-treating capacity. Part of this capacity is already on the way, led by investments in the Asia-Pacific and the Middle

Chapter 6

East. However, more will be needed across all regions if the proposed targets are to be met.

It is also evident that other products, such as heating oil, jet kerosene and fuel oil, are becoming targets for tighter requirements. Sulphur content in Europe's heating oil was reduced from 2,000 ppm to 1,000 ppm on 1 January 2008, and some countries, for example, Germany, provide tax incentives for 50 ppm heating oil production and use. Parts of North America plan to reduce the sulphur level in heating oil to 15 ppm by 2020. Elsewhere, some progress will be made in reducing the levels of sulphur in heating oil, but not to very low levels.

Currently, jet fuel sulphur specifications allow for sulphur content as high as 3,000 ppm, although market products run well below this limit at approximately 1,000 ppm. It is expected that jet fuel standards will be tightened to 350 ppm in industrialized regions by 2020, with these advanced standards in other regions by 2025. Sulphur levels in the industrialized regions are assumed to be further reduced to 50 ppm by 2025.

Regarding sulphur content limits for fuel oil used as marine bunkers an important change was adopted by the Marine Environment Protection Committee (MEPC) of the IMO in October 2008. It is a development that has potentially far-reaching implications. The IMO decided on a gradual reduction of the sulphur content in bunker fuel from the current 4.5% (wt) to 3.5% (wt) in 2012 and 0.5% (wt) in 2020. The decision also covered the reduction of sulphur content in ECAs to 1% (wt) by July 2010 and 0.1% (wt) by 2015. A further key point was an allowance to use higher sulphur bunkers under the condition that a reduction in sulphur emissions would be achieved through smoke scrubbers. Since then, the North American ECA has been established along the coast of the US and Canada and the enactment of the ECA requirements will happen here in July 2012. At the same time, the US EPA has submitted a proposal to the IMO to also designate the waters adjacent to the coasts of the Commonwealth of Puerto Rico and the US Virgin Islands as ECAs.

In addition to the basic fuel quality parameters, there is currently another factor determining fuel quality specifications in the EU. Namely, fuels became an element of the discussion about the European strategy on climate change mitigation. The strong push for the development of measures that may help reduce GHG emissions and increase the share of renewable energies also affects the fuel quality properties by increasing in volumes of bio-components blended to gasoline and diesel. The latest directive constitutes part of the EU energy and climate change package of measures, adopted by the European Union in April 2009. Its aim is to reduce GHG emissions by 20%, increase renewable energies in the total energy mix to 20% – 10% in the transportation sector – and improve energy efficiency by 20%. All of this would be achieved by 2020.

The European Fuel Quality Directive (Directive 98/70/EC as amended by two subsequent directives – Directive 2003/17/EC and Directive 2009/30/EC) poses an obligation on fuel suppliers to reduce GHG emissions from transport fuels by 6% compared with the 2010 baseline. As a consequence of these policies, the ethanol content of gasoline and the fatty-acid methyl ester (FAME) content of diesel have been increased from 5% (vol)[38] to 10% (vol) for ethanol and from 5% (vol) to 7% (vol) for FAME. Similarly in the US, climate change policies based on reducing GHG emissions will place new demands on transportation that will impact sources, composition, manufacturing, costs and the efficiency of fuels. One of the current fuel quality aspects discussed is the possible increase of the ethanol content in conventional gasoline to a maximum 15% (vol) level to help meet the 36 billion gallons renewable fuel target required by 2022.

Capacity requirements

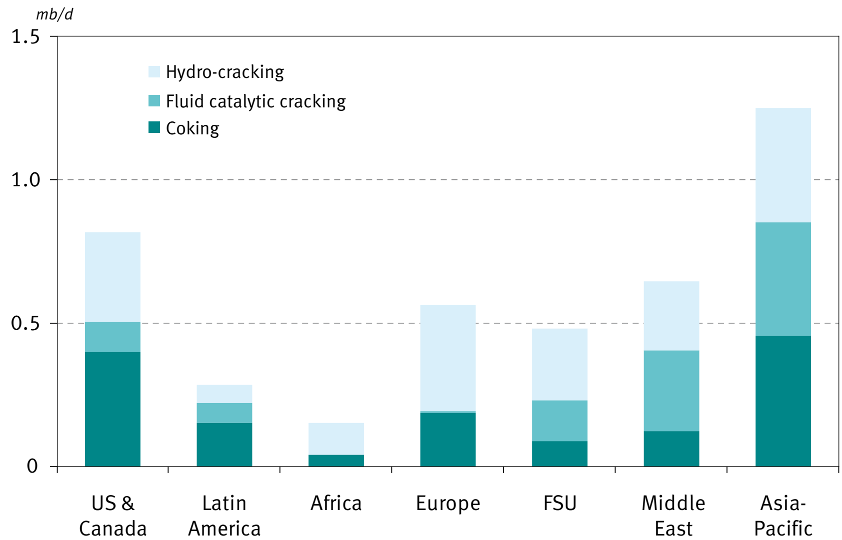
Medium-term outlook

As discussed in Chapter 5, a total of 4.2 mb/d of new conversion capacity will be added to the existing global refining base in the period 2010–2015. As presented in Figure 6.6, driven primarily by expanding diesel demand, most of this capacity will come from hydro-cracking units (1.7 mb/d), followed by coking (1.5 mb/d) and FCC units (1 mb/d).

To a significant extent, the placement of these processes will reflect the location of distillation capacity as in most cases they are part of the same expansion projects. It should be recognized, however, that in some instances the conversion capacity additions are more geared to altering refinery configuration, than to expanding capacity.

The Asia-Pacific region comprises the largest concentration of existing conversion projects, with some 1.3 mb/d set to be located in the region. This reflects the general demand growth for light products, including gasoline, and the need to incrementally process mainly medium sour crude oils. Hence, the relatively even distribution of additions across the three conversion processes. In line with distillation capacity additions, the majority of the conversion projects are located in China and India. Smaller scale conversion projects are also taking place in South Korea, Japan, Pakistan and Vietnam.

Figure 6.6
Estimation of conversion capacity additions by region based on existing projects, 2010–2015



Conversion additions in the Middle East reflect both a general move to a lighter domestic and export product slate and the region's gasoline deficit, thus the emphasis on FCC capacity. The main conversion additions are in the large Saudi Aramco projects at Jubail and Yanbu, as well as projects in Iran and potentially the UAE.

Projects in the US, mainly in the Midwest and Gulf Coast, centre on either major expansions or revamps, for example, ConocoPhillips/Encana at Wood River and Borger, BP at Whiting and Toledo and Husky at Lima. The revamps are geared to processing heavy crude oils, mainly from the Canadian oil sands production and entail joint ventures and/or long term supply agreements. These projects encompass substantial coking capacity to deal with the heavy crude oils, as well as hydro-cracking to increase distillate yields. The shift away from the traditional US emphasis on FCC capacity means the yields from these projects will comprise nearly 50% distillate. They will, however, still yield around 40% gasoline in a region where demand is flat and ethanol supplies are rising.

In Latin America, a series of projects for refinery upgrades and new facilities in Mexico, Colombia, Brazil, Ecuador and Venezuela mainly emphasize increases in heavy crude oil processing and the associated coking capacity additions. The Pemex Minatitlan project in Mexico is noteworthy as it creates 100,000 b/d of new capacity for processing Mayan heavy crude, although it is at a time when this crude's production is on a downward trend. This development highlights that, while most projects in the Americas are geared to local needs, such as processing more oil sands, the combination of recent and new coking additions with overall short- to medium-term net declines in heavy crude production is helping to sustain a coking surplus.

In Africa, the main conversion emphasis is on hydro-cracking through projects that are underway in Egypt, Libya and potentially Angola. FSU projects are generally geared toward the need to raise conversion capacity across the region. Again, the emphasis is on hydro-cracking, but also on appreciable FCC and coking additions.

Hydro-cracking capacity additions in Europe are among the highest, comparable to those coming on stream in the Asia-Pacific. This reflects Europe's shift toward diesel that began almost 20 years ago as governments became increasingly concerned with improving fuel economies and reducing CO_2 emissions. The move was initially aided by government policies that taxed diesel fuel at a lower rate than gasoline, as well as indirectly by taxes on engine capacity that were introduced in a number of countries. The transition has certainly had an impact on the market. Today, Europe's current road diesel consumption is more than double that for gasoline. This ratio is foreseen to increase further and reach 2.5 by 2015. In fact, when the total diesel consumption is considered, the diesel/gasoline ratio is expected to approach three by 2015. It then increases gradually to pass three around 2025.

Box 6.1
Dieselization in Europe: what are the refiners' options?

The process of dieselization is having a significant impact on the refining industry by distorting the traditional demand structure for transport fuels. And alongside this, the declining gasoline demand in North America, the main outlet for Europe's excess gasoline, adds a further challenge. How can European refiners improve their diesel yield while reducing that of gasoline? There are several potential options.

Most of Europe's oil refineries are more geared towards producing gasoline as the major conversion process is FCC. In this type of refinery configuration, diesel is mainly formulated from the straight run diesel (SRD) that is obtained from the crude unit and the light cycle oil (LCO) produced by the FCC plant. Other streams can also be obtained, when available, from the hydro-cracker units, the coking units and the visbreaker units, as well as minor streams from the hydro-treating units. If refiners are required to increase diesel production, it is essential to enhance the diesel yields from these streams. This can be done by selecting crude oil with higher distillate yields, adjusting the cut points, modifying the yield of process units and adding conversion and agglomeration units.

Selecting the appropriate crude slate to maximize a refinery's net income is obviously one of the most important short-term planning activities. When diesel production needs to be maximized, crude oils with high middle distillate yield are preferentially selected. The choice is usually constrained by the crude price differentials, the refinery configuration and the prevailing product prices. Widening the cut points of diesel blending streams through separation enhancement and the tuning of distillation towers can help increase diesel production. Operating the FCC unit in the distillate mode by lowering the reaction severity can increase a refinery's diesel production by up to 5%, and at the same time reduce gasoline production. These options are considered the low hanging fruits and are already being leveraged by most refiners.

FCC units are traditionally gasoline producing plants, and thus, for diesel production, it is important to look at the role of side-products. LCO is one such side-product being blended for diesel production after treatment, so maximizing the LCO yield while reducing that of gasoline is viewed as a key option for enhancing a refinery's diesel production. Achieving this through conversion reduction is limited, however, as reducing the conversion results in a lower overall yield. In recent years, FCC licensors have specifically focused on how to enhance the LCO yield at high conversions and several enhancements are now available to refiners. These include: multiple feed injection points; the double riser reactor configuration; an improved catalyst formulation; the use of catalyst poisoning additives; and adding provisions for recycling heavy cycle oil. Employing these technologies can increase the diesel yield in an FCC based refinery. These options nevertheless require additional investment and can increase operating costs.

Refiners can also add more vacuum gas oil or residue conversion units. These units can be resid-hydro-crackers or coking plants, which minimize or eliminate fuel oil production. The addition of deep conversion units enables refiners to process heavier, less expensive crudes while maximizing light fuels production. These types of improvements, however, require major investments.

To avoid the undesirable coke production and the reduced distillate yield associated with carbon rejection processes, such as delayed cokers, some technology providers are offering high conversion slurry hydro-cracking technology for residue and heavy oil conversion. The Uniflex from UOP, the Eni slurry technology (EST) of Eni and the Veba Combi-Cracker from KBR fall into this category. It is claimed that these processes can attain over 95% conversion with high yields of naphtha and gasoil, as well as other lighter products. In terms of costs, some of these processes are claimed to be more economical than traditional cokers, when the crude oil price exceeds $50/b. A commercial-scale plant based on EST technology is being built at Eni's Sannazzaro refinery in Italy. Start-up of this facility is scheduled for 2012. The other two technologies are claimed to be commercially proven and ready for licensing. These can play a significant role in converting resids and heavy crude oils into desirable high quality distillate products.

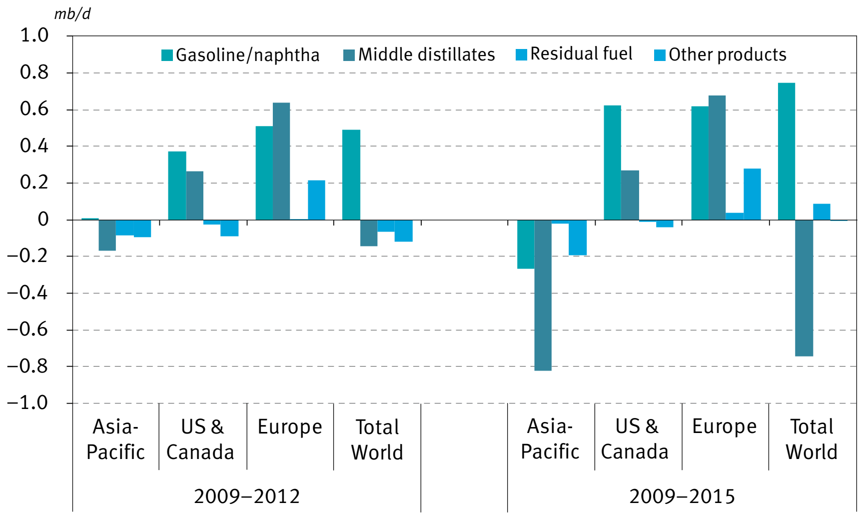
At less cost, other diesel enhancement units can be added. These include dewaxers, deasphalters and LCO hydro-treaters. To increase the refinery diesel to gasoline ratio, units that convert LPG, naphtha and olefins to diesel range materials can be introduced. The thermal cracking process, the prime process for light olefins production is also being improved to allow the blending of gasoline in petrochemicals feedstocks. All these processes can increase the gasoil available for further conversion and blending, while reducing the gasoline yield.

It is evident that the dieselization of transportation fuels poses a major challenge to oil refiners, especially in Europe. To meet this challenge, refiners are adjusting their processing units, tuning their blending schemes and selecting appropriate crude slates to maximize diesel production while minimizing that of gasoline. Processing and conversion process enhancements are becoming increasingly available. These enhancements can further help refiners to maximize diesel production, albeit at increased operating costs and with the need for additional investments.

The ongoing developments and improvements in the fuel efficiencies of gasoline engines, which are now approaching those for diesel engines, may, however, increase gasoline demand. This trend is becoming more visible, especially in the southern and eastern parts of Europe that are traditionally more gasoline-oriented. Therefore, some coking capacity is being added to the refining system in these regions. Moreover, the tightening of sulphur specifications in bunker fuels could put more pressure on refiners to produce more gasoil, because residue cracking may be more feasible for refiners than residue desulphurization.

Figure 6.7 shows the results of comparing the potential additional regional output by major product groups against projected incremental regional demands. The results are presented as net surplus or deficits by product group, by region and worldwide. The outcome is striking. Data for 2009–2012 indicates that only the Asia-Pacific is close to a balance for incremental refined output from projects *versus* incremental demand. The region shows only minor deficits, mainly for middle distillates. In

Figure 6.7
Expected surplus/deficit of incremental product output from existing refining projects



contrast, and as commented on previously, projects in other regions, notably the US & Canada and Europe, generate surpluses for gasoline and middle distillates relative to incremental demand. These help to ease Europe's underlying distillate deficit and creates the possibility for distillate exports from the US & Canada to Europe. On a global aggregate basis, incremental distillate output still falls slightly below incremental demand. The main imbalance relates to the projected incremental global surplus of around 0.5 mb/d for gasoline/naphtha, implying a continued gasoline/naphtha price weakness relative to crude oil. In addition, incremental residual fuel is shown as slightly short – if all the upgrading projects are completed. The implication here is that the resid to crude differential remains relatively narrow.

Between 2009 and 2015, the incremental gasoline surplus is sustained in the US & Canada and Europe, with implications for the Atlantic Basin. In contrast, based on assessed projects alone, a large distillate deficit opens up in the Asia-Pacific, and also to some degree, for gasoline and other products. The consequence is that, beyond 2012, additional capacity over and above the projects outlined is needed in the Asia-Pacific.

Overall, the medium-term outlook is for a sustained requirement in the incremental capability to produce more middle distillates, a continuing surplus for naphtha/gasoline and a relative balance for residual fuels.

Long-term outlook

Requirements for major refinery upgrading units – coking, cat-cracking and hydro-cracking – continue to be significant in the long-term, with hydro-cracking projected to take a progressively larger role. This is driven by a projected continuing demand shift for light products, in general, and for middle distillates, in particular. This is underscored in Table 6.3 that summarizes global capacity requirements, and is supported by Figures 6.8 through to 6.11.

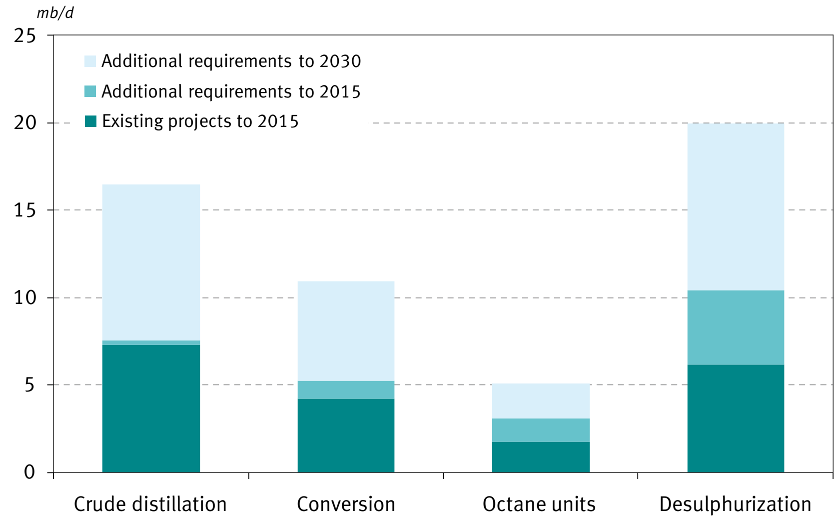
Table 6.3 shows that out of 5.7 mb/d of additional conversion capacity requirements between 2015 and 2030, some 4.8 mb/d are for incremental hydro-cracking, with only around 1 mb/d of combined coking and catalytic cracking needed during the same period. In fact, this ratio is much lower if the entire period of 2009–2030 is considered as some coking and cat-cracking capacity will be built in the next few years.

The trend towards hydro-cracking units is due to the fact that this process is the preferred choice for maximizing incremental distillate output after straight runs of

Table 6.3
Global capacity requirements by process, 2009–2030 *mb/d*

	Existing projects	Additional requirements	
	to 2015	to 2015	to 2030
Crude distillation	**7.3**	**0.2**	**9.0**
Conversion	**4.2**	**1.0**	**5.7**
Coking/Visbreaking	1.5	0.0	0.4
Catalytic cracking	1.0	0.1	0.6
Hydro-cracking	1.7	0.9	4.7
Desulphurization	**6.2**	**4.2**	**9.5**
Vacuum gasoil/Fuel oil	0.2	0.2	0.9
Distillate	4.5	2.8	6.9
Gasoline	1.4	1.2	1.7
Octane units	**1.8**	**1.3**	**2.0**
Catalytic reforming	1.3	0.8	1.1
Alkylation	0.2	0.0	0.0
Isomerization	0.3	0.5	0.9
Lubes	**0.1**	**0.7**	**0.6**

Figure 6.8
Global capacity requirements by process, 2009–2030



crude oil. However, the need to keep investing in additional hydro-cracking capacity, with its high process energy and hydrogen costs, will likely increase distillate margins relative to crude oil, as well as to other light products. In recent years, distillate margins have softened substantially because of the impacts on economic activity as a result of the global downturn. However, the longer term drive toward sustained distillate growth and the need for continuing hydro-cracking additions to produce incremental distillate is projected to reassert wider crack spreads, and differentials.

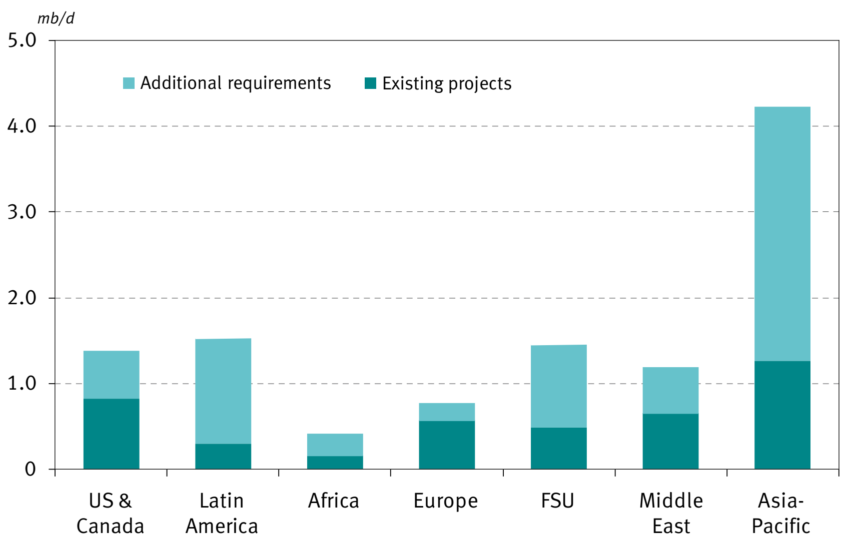
Conversely, recent substantial coking capacity additions, together with a declining supply of heavy sour crudes in the medium-term are leading to a coking surplus. This can be viewed in the absence of capacity additions needed to 2015 and the limited further additions (0.4 mb/d) projected as needed from 2015–2030. Catalytic cracking is adversely impacted by the declining gasoline demand growth and rising ethanol supply, especially in the Atlantic Basin. Consequently, projected increases beyond current projects are seen as minimal until after 2015. They are then concentrated in non-OECD regions where there is gasoline demand growth, especially the Asia-Pacific. Generally FCC units suffer, followed by coking units, as these two comprise the 'swing' units for gasoline production. It means that the long-term average utilizations of these units will be relatively depressed, partly as a result of the relatively high additions from projects that are currently under construction or in an advanced planning stage.

Figure 6.9 presents the regional breakdown of future conversion capacity requirements. Not surprisingly, beyond the conversion capacity additions that are expected to come from existing projects before 2015, future requirements will be dominated by the Asia-Pacific. This region sees around 45% or 3 mb/d of future additions. Of these, China alone is projected to require 1.8 mb/d and another 0.7 mb/d will be needed in the Rest of Asia region. While less than 0.1 mb/d of the expansion is projected for OECD Asia-Pacific countries, the remaining 0.4 mb/d will likely occur in non-OECD Industrializing countries of the Asia-Pacific region.

In terms of additions, following the Asia-Pacific is Latin America. Here, a significant increase in conversion capacity should take place (1.2 mb/d) as demand for light products is expected to grow. Another factor in this region is the projected growth in heavy crude supplies in several countries. The only other region where capacity additions are in the range of at least 1 mb/d is the FSU.

Longer term conversion capacity additions across most regions are in general biased toward hydro-cracking. This comes from the projection that distillates will comprise the main global growth product and also that the medium-term gasoline/naphtha surplus, and hence FCC, will moderate longer term needs for new FCC capacity. Additionally, because of the medium-term improvement in the global

Figure 6.9
Conversion capacity requirements by region, 2009–2030



crude slate quality and the current coking over-capacity, further coking additions are only projected to occur after 2020.

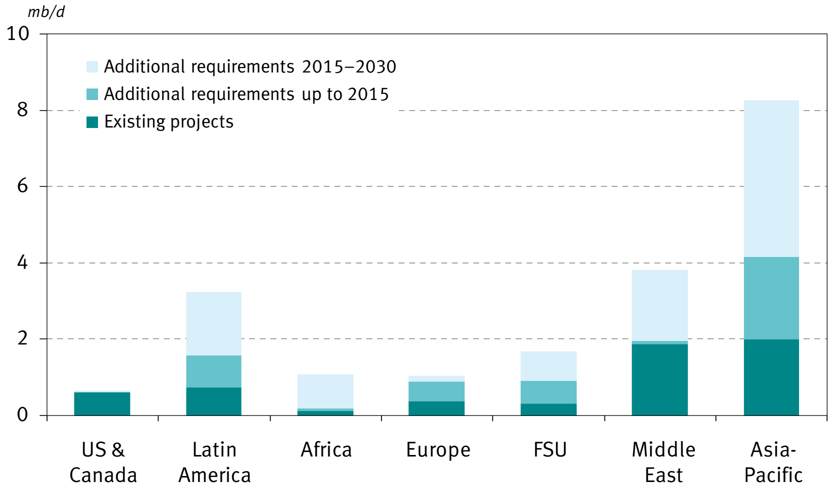
In respect to octane units, catalytic reforming requirements to 2030 are projected to be significant – above 3 mb/d in total – as are those for (C5/C6) isomerisation, with 1.8 mb/d for the entire forecast period. Conversely, minimal additional requirements are foreseen for alkylation capacity. The underlying reason for this is the projected substantial growth in the supply of condensates. These comprise large proportions of light naphtha, which is attractive for isomerizing as a means to improve its octane as a gasoline blendstock, and for heavy naphtha, which is suitable for reforming to provide incremental gasoline volumes and octane. Given that these two processes provide significant supplies of gasoline blendstocks and octane, there is little need for additional alkylation.

In terms of absolute numbers for secondary processes, it is desulphurization capacity that requires the largest increase. Over the period 2009–2030, about 20 mb/d of new desulphurization units are believed to be required globally. Out of this, some 6 mb/d are likely to be added based on known projects, an additional 4.2 mb/d are estimated as required by 2015 and another 9.5 mb/d should be constructed before 2030. Most of this capacity will be necessary in developing countries to meet the progressively stricter domestic specifications for sulphur content – often following the Euro III/IV/V standards – and to build export capacity to meet advanced ultra low sulphur (ULS) standards in export target regions.

As seen in Figure 6.10, the bulk of these units are projected in the Asia-Pacific (8.3 mb/d) and the Middle East (3.8 mb/d), driven by an expansion of the refining base, increased demand and tighter quality specifications for both domestic and exported products. Significant volumes are also expected to be added to the Latin American refining system (3.3 mb/d). The lowest desulphurization capacity additions – beyond existing projects – are foreseen for the US & Canada and Europe where almost all transport fuels are already at ULS standards. In other regions, due to the limited existing capacity, even modest sulphur reduction implies considerable capacity additions.

A summary of desulphurization capacity additions for the key product groups in major regions is presented in Figure 6.11. Except for Europe, the majority of the new desulphurization capacity requirements are driven by the need to reduce the sulphur content of middle distillates. There are two reasons for this. The first, and obvious one, is the largest volume increase in additional demand for this product category. The second one stems from the expected changes in product specifications in developing countries. While a reduction in the sulphur content of gasoline has been a target of

Figure 6.10
Desulphurization capacity requirements by region, 2009–2030

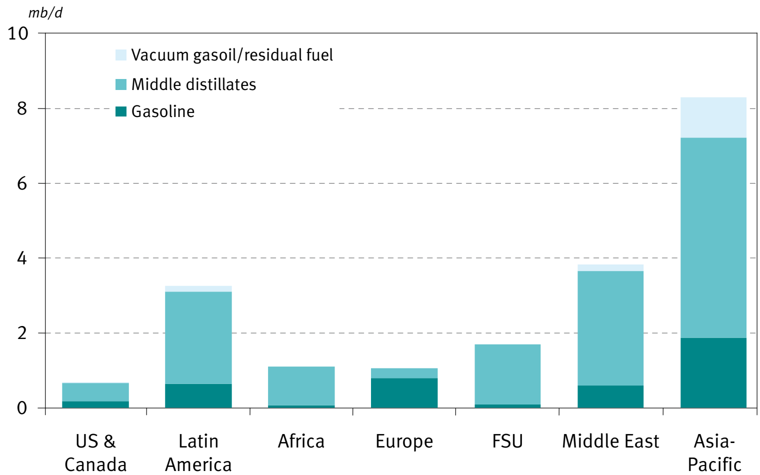


stricter regulation for some time, as discussed earlier in this Chapter, diesel oil in the transport sector of many developing countries will follow the path of reduced sulphur content. A combination of these two factors results in a projection that more than 14 mb/d – out of total of 20 mb/d – of additional desulphurization capacity is related to middle distillates.

The bulk of the remainder (4.3 mb/d) is for gasoline sulphur reduction,[39] with some 1.4 mb/d needed because of vacuum gas oil (VGO) and residual fuel oil. The latter volume, however, has the potential to be substantially higher if there are further changes in marine bunkers regulations beyond the reduction to 3.5% sulphur content on 1 January 2012; a move to 0.5% could potentially occur on 1 January 2020. The 2020 regulation requires a study to be completed by 2018 to assess whether sufficient fuels can be produced by the global refining system at the 0.5% sulphur level. It allows for a deferral of the implementation date to 2025 if major difficulties are envisaged.

The prevailing industry view at this time is that refiners would be reluctant to enter into the major investments required to produce such a low sulphur product. Rather, refiners would prefer to make incremental investments to install either residual hydro-cracking or coking plus gasoil hydro-cracking to be in a position to produce more distillates. A shift to marine distillate would, however, substantially increase

Figure 6.11
Desulphurization capacity requirements by product and region, 2009–2030



requirements for hydro-cracking, coking, desulphurization, hydrogen and sulphur recovery relative to the Reference Case projections and further augment the global shift to distillates.

Crude and product pricing and differentials

Before presenting any results on crude and product pricing it is important to stress that the modelling system used, by nature of the optimization technique, suggests capacity additions that are sufficient for the given demand and thus extreme price differentials tend not to exist. Thus, for instance, it does not fully reflect cycles or volatility that is inherited in the behaviour of crude and product prices. It does, however, capture the effects of trends such as increasing distillates in total demand, tightening sulphur standards and a lighter or heavier crude supply.

Under a scenario of sustained growth for distillates, which in turn requires ongoing investments in hydro-crackers that operate at or close to their capacity limits, distillate price differentials relative to crude and other products reflect the associated high opportunity cost of producing incremental distillate barrels. Conversely, where streams such as naphtha/gasoline are in surplus, and associated key units, notably catalytic cracking are running well below maximum utilizations, the price differentials reflect the industry's relative difficulty in finding a home for these products and streams. Consequently, these differentials are narrower.

There are several other factors that interplay in the price formation process of refined products. One is the issue of costs in both the upstream and downstream sectors. Higher capital costs for process investments typically push in the direction of wider differentials between light and heavy products and also between low sulphur and high sulphur products. Similarly, higher upstream costs drive crude prices higher, which again typically support wider light/heavy and sweet/sour crude differentials and, in turn, for products. The opposite is generally true for lower costs.

Another factor relates to operational costs. Higher crude and natural gas prices raise the variable costs of fuel, steam and power and thus the costs of the lighter, cleaner products that require more processing. Again, lower prices tend to reduce processing costs and hence the light/heavy differentials. High prices for crude oil relative to natural gas and coal – hence, fuel grade petroleum coke – on an energy basis tend to make it relatively more attractive to add hydrogen from natural gas and less attractive to reject carbon via catalytic cracking and coking.[40]

Bearing in mind the limitations of any modelling system, especially when addressing price projections, the various noted effects are reflected in the crude and product price differentials indicated by the WORLD model. However, they must be considered as price signals only; indicators of certain trends that reflect future market fundamentals rather than actual projections. In other words, they represent future 'equilibrium levels' based on an assumption that over the longer term, differentials and thus margins and profitability need to average around long-run levels. Otherwise refiners would either make such small returns on capital that they would be out of business or returns would be so high that arguably additional capacity would be attracted to the market.

In respect to crude price differentials, 'price signals' from the model for 2015 indicate a recovery from the extremely narrow differentials witnessed in 2009. This is a reflection of the expected global economic recovery, and hence oil demand. By 2015, however, they return to the more moderate differentials observed in the period between 2000 and 2004, where the global refining sector is neither too tight nor too slack. This year's results have been impacted by the level of expected refinery closures. The 1.2 mb/d of capacity closures embodied in this year's capacity base, against no closures last year, plus a slightly stronger demand recovery, contribute to the slightly better medium-term outlook in respect to crude price differentials.

In the period after 2015, crude differentials remain moderate to 2030 as the low rate of product demand growth combined with continuing increases in the supply of non-crudes helps to maintain moderate capacity utilizations and a surplus capacity in the industrialized regions (US & Canada, Europe, Japan and Australasia). Of course, this is subject to revisions if any further closures beyond the 1.2 mb/d occur. The actual pace of rationalization and closure will have an appreciable impact on crude and product differentials and margins in both the short- and long-terms.

Another observation to note in regard to crude differentials is that over the longer term, the negative differentials for heavy sour crude grades widens. This reflects the absence of residual fuel demand growth in the outlook, a projected longer term increase in the production of heavier grades and the continuing global trend toward tighter sulphur standards for transport fuels.

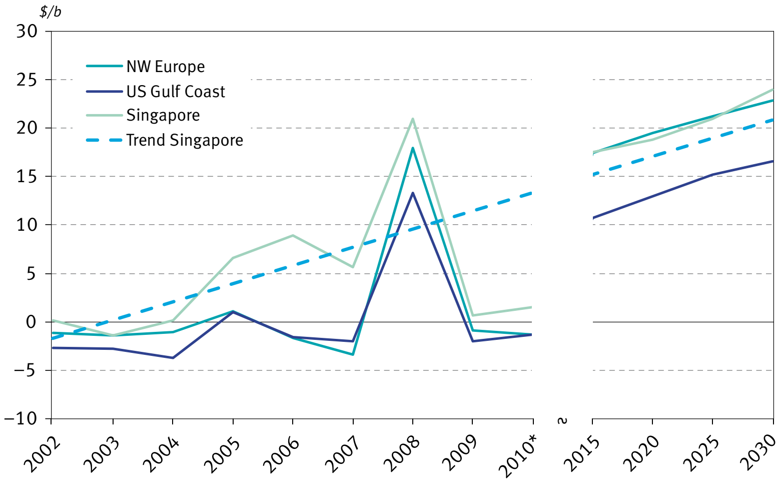
While price differentials that are developed from modelling horizons 10 and 20 years ahead should be viewed with a sense of caution and seen as indicative. Figure 6.12 highlights what is expected to be the major global trend in product differentials, namely the impact of a continuing shift toward a gasoline surplus. The figure shows the annual gasoil/diesel minus gasoline price differentials for major markets, from 2002–2009, together with projections for 2015–2030. The spike in the diesel premium over gasoline in 2008 reflected the refining tightness that occurred as economic activity continued to grow and the refiners' ability to produce incremental diesel was limited and 'tight'.

The collapse in the diesel premium over gasoline (and crude) in 2009 reflected the slowdown in economic activity, trade, transport and construction, resulting from the recession. Distillate demand was particularly hard hit, which led to significant volumes of diesel/gasoil being stored in tankers as of late 2009/early 2010. The basis of this current projection is that diesel/gasoil demand will rebuild in line with the economic recovery and at the same time gasoline remains in relative surplus. It is expected that there will be a longer term strengthening in distillate differentials *versus* gasoline. This has been the general trend since 2004, with the tightness in 2008 being offset by the collapse in 2009.

The trend towards strong economics for distillates is also visible in the projected margins for key products *versus* crude. This is shown in Figure 6.13 for the Rotterdam market compared with Brent prices. The diesel/gasoil premium *versus* crude will likely re-establish itself, although not to the level experienced in 2008. Conversely, the outlook is for poor to even severely negative margins for naphtha and gasoline *versus* crude because of the surpluses in that range of the barrel. It should also be noted that a similar picture is broadly valid for all markets.

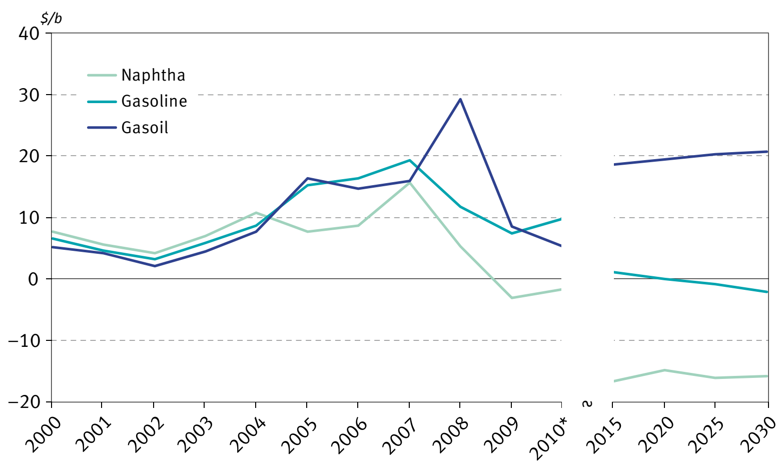
Looking ahead, these trends and differentials raise questions as to what changes might occur in the downstream sector as markets, governments and consumers look to moderate these effects:

Figure 6.12
Gasoil-gasoline price differentials in major markets, historical and projected



* *Year-to-date average week ending 8 October 2010.*

Figure 6.13
Price differentials for major products,** historical and projected



* *Based on weekly averages up to the week ending 8 October 2010.*
** *Price differentials are for the Rotterdam market calculated versus Brent.*

Chapter 6

- To what degree will governments and consumers respond over time to the higher pump prices for diesel *versus* gasoline by shifting taxes/subsidies and/or vehicle ownership – and thus demand – back toward gasoline? There is already some evidence of this in Europe;
- What potential exists to 'soak up' more naphtha as a petrochemical feedstock? This may be limited as significant growth has already been catered for in Reference Case demand projections. Additionally, since most of the steam cracker feedstock in the world's growth areas is already naphtha, the potential for the displacement of other feedstocks may be limited; and
- With price differentials between gasoil/diesel and naphtha/gasoline streams ranging up to or beyond $20/b, what is the potential for the industry to react and exploit these through processes that convert gasoline/naphtha (or C3/C4) boiling range fractions into diesel components?

It is to be assumed that these price differential outlooks provide a signal that new developments within the industry are needed and are likely to occur. For instance, it will act to spur changes ranging from demand patterns to refinery processing technology. Despite this, a central message is that these trends are not some short-term phenomenon that will quickly vanish. They are clearly set to alter the fundamental balances within the global refining system, and thus will exert a significant influence on future refining and supply economics.

Whereas the proportion of gasoline to distillate yield was of little concern to a refiner only four or five years ago, because average prices for the products were similar, in the future, it will be a major factor in determining a refinery's margins. It is expected that the industry will redress or reduce the imbalances foreseen in this WOO, but of course, major changes will take time. The upshot is that refiners are anticipated to proceed with caution and conservatism given the refining economics expected for the next few years, with distillates production representing arguably the one area with positive potential.

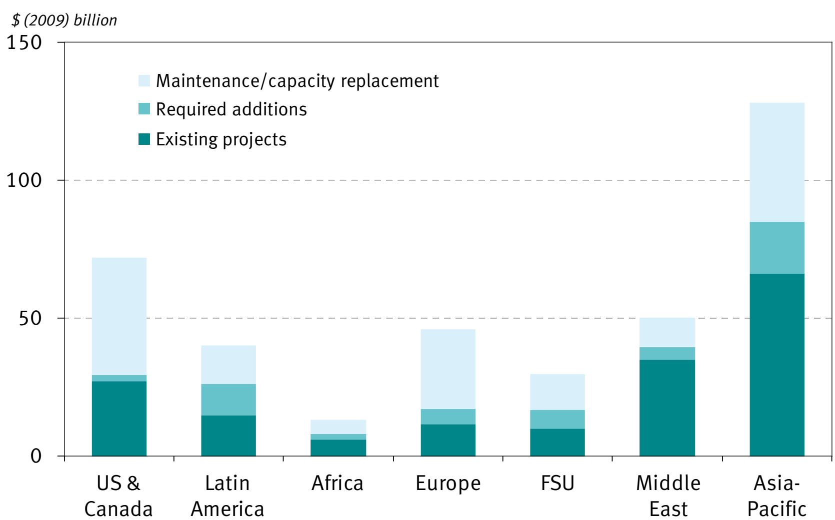
Chapter 7

Downstream investment requirements

The projected expansion and maintenance of the global refining system will of course require considerable capital investments. For the entire forecast period to 2030, investment requirements in the Reference Case are estimated to be around $860 billion. This excludes related infrastructure investments beyond the refinery gate, such as port facilities, storage and pipelines. Compared to last year's estimation, this represents an increase of around $80 billion. This rise is primarily the result of higher regional construction and maintenance costs that have been reassessed in the light of recent movements in downstream construction cost indexes.

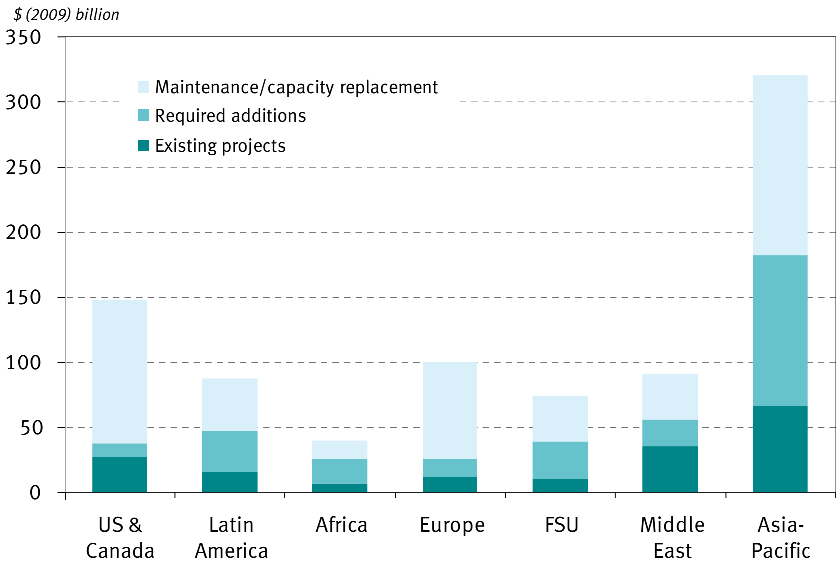
The investment requirements consist of three major components. These are presented in Figures 7.1 and 7.2 for the periods to 2015 and 2030 respectively, over and above a 2009 base. The first category of investment relates to the identified projects that are judged to go ahead. The second category, required additions, comprises the cost of capacity additions that are projected as needed for the adequate functioning of the refining sector on top of known projects. The third category of investment, maintenance and capacity replacement, relates to the ongoing annual investments required to maintain and gradually replace the installed stock of process units.

Figure 7.1
Refinery investments in the Reference Case, 2010–2015



Chapter 7

Figure 7.2
Refinery investments in the Reference Case, 2010–2030



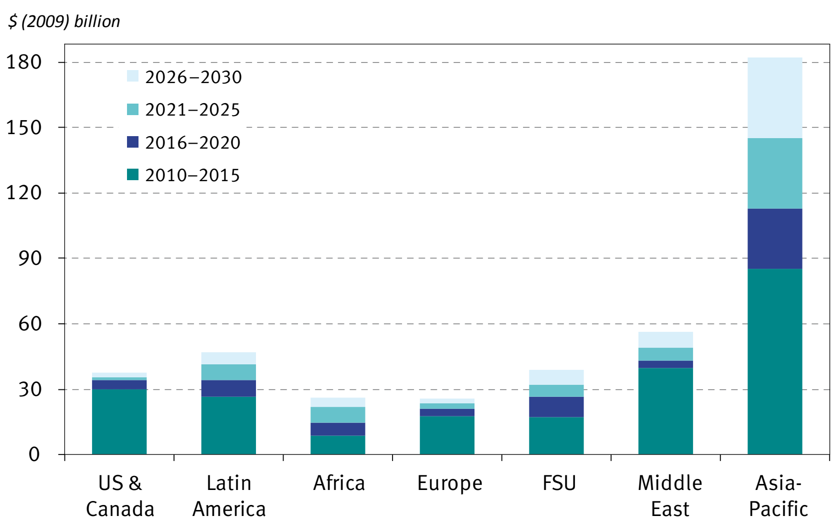
Following industry norms, the maintenance and replacement level was set at 2% p.a. of the installed base.

Consequently, up to 2015, the total required investment is expected to reach $380 billion, of which around $170 billion will cover the cost of known projects, $50 billion will be needed for additional units and $160 billion is for ongoing maintenance. Maintenance costs are highest in the US & Canada and the Asia-Pacific as almost 50% of existing capacity is located in these two regions. Asia-Pacific is also the region that will attract the highest level of investment in new units to 2015, with almost $70 billion for known projects and $20 billion for additional requirements.

After the Asia-Pacific, the region with the highest investments for capacity expansion is the Middle East, which is projected to require total capital investments of $50 billion. Of this, however, a much higher proportion is for new facilities than for replacement. In Europe, the situation is the other way around. Here, almost $30 billion will be needed to maintain the refining system in place, while less than $20 billion will be used for capacity expansion. Expansion will focus mainly on desulphurization for diesel and some distillation and conversion. Comparable total investments will also be required in Latin America, which is projected to receive investment of around $40 billion. Out of this, around $15 billion is directed to existing projects and more than $10 billion will be required to expand capacity to projected levels. Moderately lower investments of around $30 billion are expected to take place in the FSU. In the FSU, this investment is more equally distributed in terms of the expansion of all major process units. In Latin America, it is likely that the distillation base will be expanded, including for desulphurization. And in Africa, it is projected that refining sector investments will total almost $15 billion for the period to 2015. Most of this will be leveraged for capacity expansion due to the region's low existing installed capacity base.

Looking further ahead to 2030, the overall picture is not too dissimilar to the one painted for the period to 2015. This can be viewed in Figure 7.2, which further underscores the ever-expanding significance of the Asia-Pacific region. It is evident that this region will continue to attract the highest portion of future downstream investments driven by the region's strong demand growth. Almost 40% of required future global investments, or $320 billion out of $860 billion by 2030, should be invested in the Asia-Pacific. This figure also amplifies the projected falling levels of investments required in OECD regions for capacity expansion, with far more now needed for capacity maintenance. In fact, the challenge for the industry in these regions will be capacity rationalization, rather than expansion, with any investment beyond existing projects almost exclusively related to compliance on the quality of growing middle distillates volumes. Compared to the period 2009–2015, investment requirements in other regions expand considerably in all categories.

Figure 7.3
Projected refinery direct investments by region*, 2010–2030



* *Excludes maintenance/replacement costs.*

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For the entire forecast period, total global refining investments of $860 billion will comprise investment in existing projects of around $170 billion, required additions of about $240 billion and maintenance and replacement costs close to $450 billion.

Figure 7.3 shows future direct investments, excluding maintenance and replacement costs, which is broken down to major regions and time periods. The figures underline how relatively little investment is required in the US & Canada and the European refining systems, especially the further the timescale moves beyond 2015. Although not illustrated directly here, the same is also true of the OECD Pacific. It is the developing regions, led by China and India in the Asia-Pacific, and followed by the Middle East and Latin America, that exhibit the need for sustained refining investments to 2030 in order to satisfy growing product demand.

Furthermore, it is also worth noting that more than 40% of the total required direct investments to 2030 are already underway in the form of existing or scheduled projects that should be on stream before 2015. After this period, investments are expected to slow down as demand increases are partially satisfied by the existing surplus capacity. Additional investments will then mainly be required because of the demand reallocation from developed to developing countries, especially those in the Asia-Pacific.

Chapter 8

Oil movements

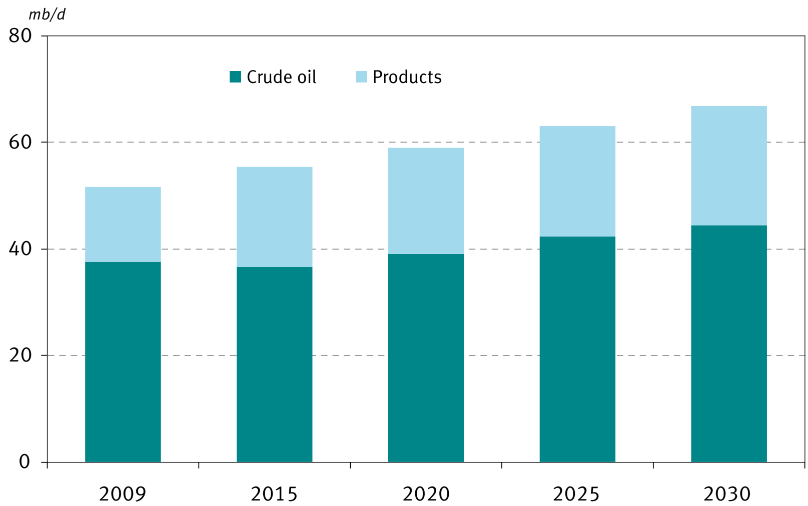
The global oil trade trend is projected to see growing volumes, albeit at a much slower pace than anticipated before the economic slowdown began in 2008. There are two key factors underlying this. The first is growing oil demand. And the second is the fact that the bulk of oil will continue to be consumed outside of the regions where the main increases in oil production take place.

While the trend for growing oil trade volumes is relatively predictable, there is less certainty regarding the split between crude and products. This relates to the uncertainty surrounding where future refining capacity will actually be located. The fact that transporting crude oil is less expensive than moving products leads, in general, to future refining capacity being placed in consuming regions, unless construction costs for building the required capacity outweigh the advantage of transport costs. Oil producing countries, however, might look to increase domestic refining capacity and benefit from the 'value-added' of oil refining.

Moreover, projections presented in this Chapter are based on an assumption that crude or products move to regions where it is most efficiently used, irrespective of ownership interests. In reality, however, oil can sometimes gravitate to places based on ownership interests, not on its optimal use. Considering this, and due to the fact that oil is a fungible commodity traded on global markets, there is a great level of uncertainty associated with any projections concerning future movements. Therefore, traded volumes presented in the WOO should be considered an indicator of certain trends and future options for resolving regional supply and demand imbalances, rather than projections of specific movements.

The overall trend in global oil[41] movements is presented in Figure 8.1. The volumes here represent the trade between all 18 model regions. In the period to 2015, the total oil trade is projected to increase by almost 4 mb/d compared to 2009 levels, rising to more than 55 mb/d. However, the same period experiences a shift in the structure of this trade. Crude oil exports are expected to decline by around 1 mb/d and the trade in oil products is projected to increase by almost 5 mb/d. This represents a substantial increase in product movements; a structural medium-term change that will likely happen as a result of several factors. These include refining capacity increases in the Middle East and the Asia-Pacific, part of which is designed for product exports; demand declines in Europe, North America and the Pacific OECD regions that makes refining capacity available for exports; growing non-crude supplies; and relatively stagnant crude oil production.

Figure 8.1
Inter-regional crude oil and products exports



Nevertheless, this trend will be reversed in the period beyond 2015 as trade in both crude and products grows. By 2030, the inter-regional oil trade increases by more than 11 mb/d from 2015 to reach almost 66 mb/d. Oil trade movements will be around 59 mb/d in 2020 and 63 mb/d in 2025. Within this period, crude exports are set to grow faster than products, which in absolute numbers means they see bigger volumes than those projected for products. If the entire period of 2009–2030 is considered, however, by the end of the forecast period crude exports will be 7 mb/d higher than in 2009, while the exports of refined products will see an increase of more than 8 mb/d. The projected total global demand increase for this period is 21 mb/d.

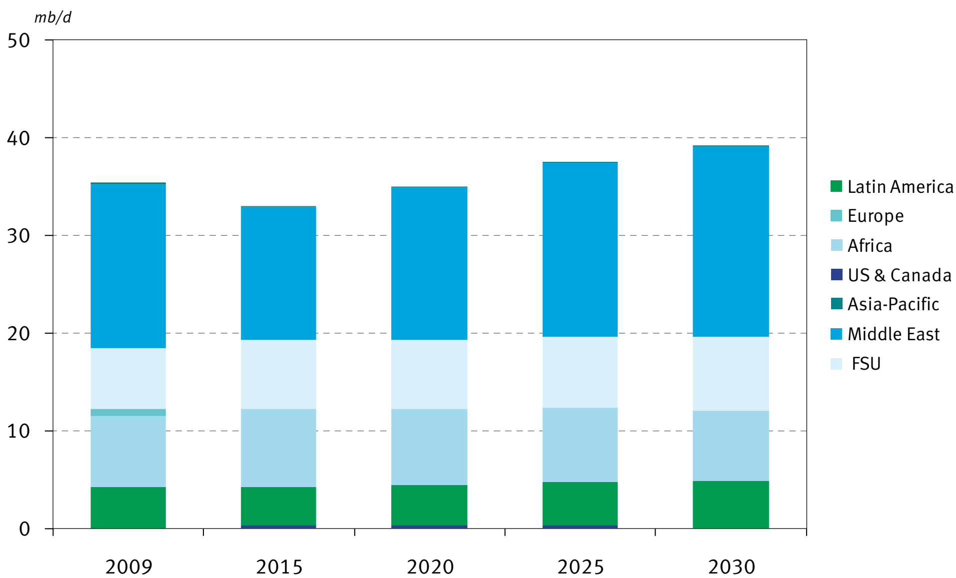
Crude oil

For the purpose of this Chapter, and to better distinguish the key trade movements, only the major seven regions of the WORLD modelling system are considered. Since, in this case, some movements are eliminated, for example, between sub-regions in the US & Canada and intra-trade in Latin America, Africa and Asia, total trade volumes are lower than reported earlier. Nonetheless, the key trends, as well as the reasons behind them are also valid for this regional configuration. In respect to the medium-term crude oil trade, movements between the major regions are projected to decline by 2.5 mb/d, from 35.5 mb/d in 2009 to 33 mb/d by 2015 (Figure 8.2). Although growth in the global crude oil trade will resume after 2015, by 2020 the traded volumes will still be lower than they were in 2009, at 35 mb/d. By 2025, these volumes are projected to exceed 37 mb/d and stand at around 39 mb/d by 2030.

Figure 8.2 also signifies the growing importance of the three producing regions that will progressively increase their contribution to the global crude trade, namely the Middle East, the FSU and Latin America. The biggest volume increase will come from the Middle East, at almost 3 mb/d between 2009 and 2030, followed by the FSU at 1.3 mb/d and Latin America at 0.7 mb/d. African crude exports are set to fluctuate around the current level, while crude exports from Europe are likely to become almost non-existent.

From the perspective of major exporters, the key changes in the flow of crude oil between 2009 and 2030 are presented in Figure 8.3. Not surprisingly, this figure highlights the future role of the Middle East as the major crude oil exporter, as well as the share of Asian imports from this region. Indeed, between 2009 and 2030, the Asia-Pacific will increase its crude imports from the Middle East by almost 5 mb/d. Moreover, this region will also increase its share in exports from Africa, Russia and Latin

Figure 8.2
Global crude oil exports by origin*



* *Only trade between major regions is considered.*

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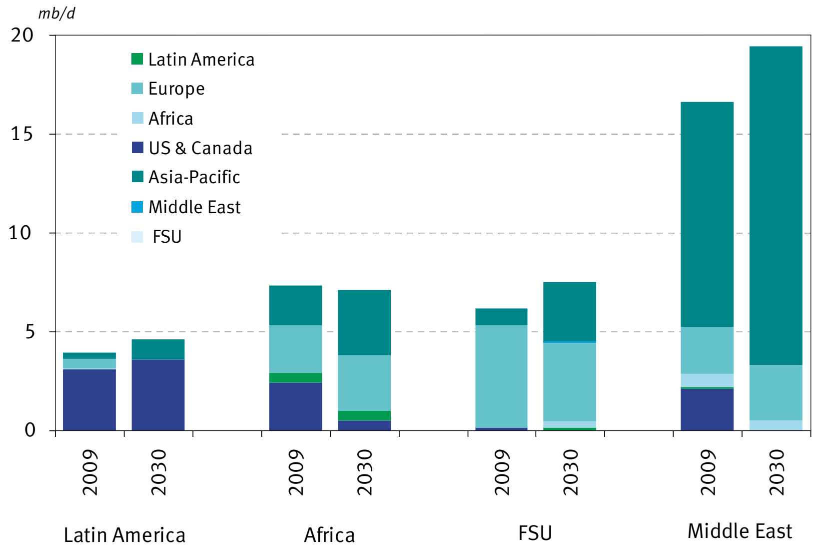
Figure 8.3
Major crude exports by destination, 2009 and 2030



America. In fact, Russia will more than triple its crude exports to the Asia-Pacific as new pipelines to China and the Russian east coast are assumed to be fully operational. A significant change in the direction of crude exports is also projected for Africa. Although the total level will broadly remain the same, there is expected to be a switch with barrels available for export redirected from the US East and Gulf coast to the Asia-Pacific. African exports to Europe are expected to remain approximately the same.

Crude oil imports for the key consuming regions in the Atlantic Basin – the US & Canada and Europe – are projected to decline over time. In the case of the US & Canada, the decline is in the range of 4 mb/d. This is mainly driven by a combination of lower demand, the expansion of non-crude supplies and higher increases in synthetic crude production from Canada. The decline in crude imports for Europe is less dramatic, projected at slightly more than 1 mb/d between 2009 and 2030. However, the decline is almost 2 mb/d if the period 2009–2020 is considered. In the last ten years of the forecast period, European crude imports will rise moderately, mainly to compensate for domestic crude supply loss.

Turning to the Middle East, by far the most dominant flow in future crude trade will be its exports to the Asia-Pacific. The Middle East, with its large existing resource base, will likely accentuate its role of key crude exporting region. After a temporary decline in its crude exports to less than 14 mb/d by 2015, from close to 17 mb/d in 2009, export volumes from this region are projected to be almost 16 mb/d by 2020 and above 19 mb/d by 2030.

As detailed in Figure 8.4, by 2030 the Asia-Pacific will account for more than 16 mb/d of these Middle East exports. Exports to other regions will gradually decline or even cease as crude movements from this region progressively become more eastward-orientated. An exception to this trend is Europe, for reasons discussed earlier in this Chapter. With sufficient desulphurization and conversion capacity in Europe at the time of its expected reversal in total crude imports, which is around 2020, Europe is projected to take advantage of price differentials for mostly medium sour with some proportion of light sour crude from the Middle East. However, increases in imports are limited to the range of 1 mb/d. This means Europe's total crude imports from the Middle East are broadly comparable to volumes in 2009.

Looking at the key crude movements from the perspective of the Asia-Pacific, the growing importance of its relationship with the Middle East is clearly demonstrated in Figure 8.5. By 2030, demand in the Asia-Pacific will increase by around 15 mb/d, compared to 2009. However, crude production will decline by 1.5 mb/d during the same period. Therefore, the growing gap between demand and local production in this region has to be filled by imports, primarily in the form of crude oil

Figure 8.4
Destination of Middle East crude oil exports and local supply, 2009–2030

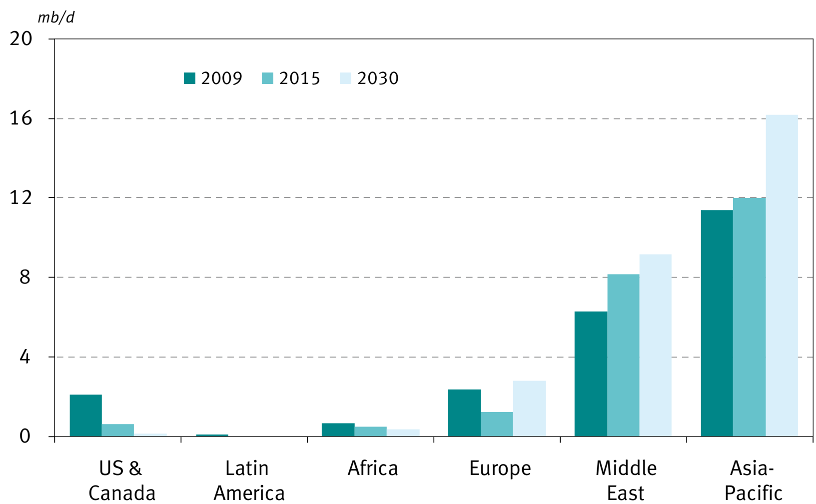
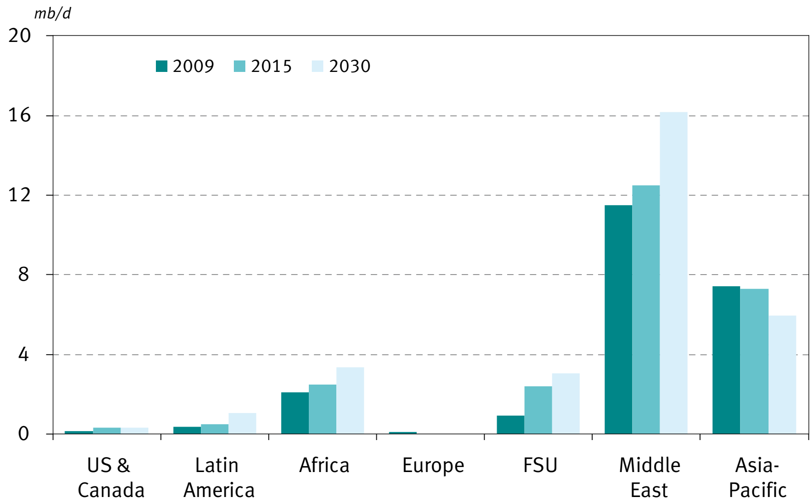


Figure 8.5
Asia-Pacific crude oil imports and local supply, 2009–2030



from all producing regions, but mainly from the Middle East, followed by Russia, Caspian, Africa and marginally crudes from both parts of America (Figure 8.5). By 2030, the Middle East will be supplying around 16 mb/d of Asian crude demand, Africa is projected to provide 3.3 mb/d of crude exports, predominantly from West Africa, and the FSU region 3 mb/d.

Oil products

The movement of oil products plays an increasingly important role in providing the required products and in solving regional imbalances between demand structures, existing refinery configurations and available crude streams. An example of this can be seen in the Atlantic Basin where a shortage of diesel oil in Europe is to a great extent covered by imports from the US, and Europe's gasoline surplus finds its home in US markets.

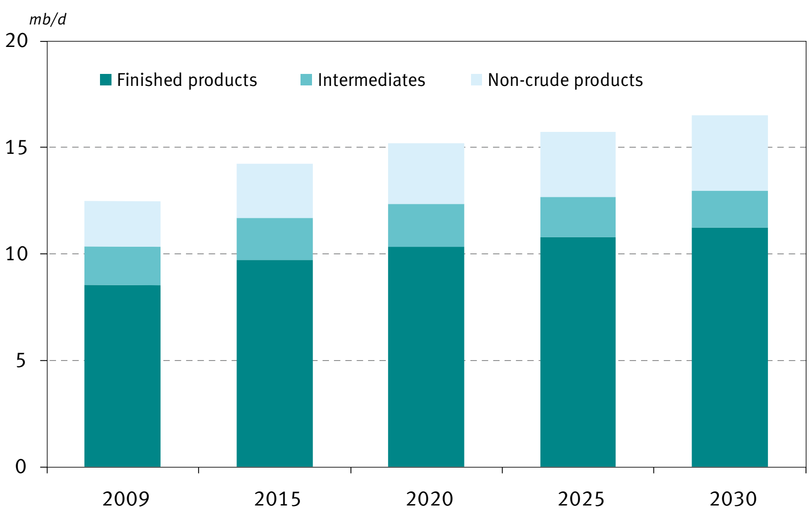
Although the traded volumes for refined products are much lower than for crude oil, they constitute an integral (and important) part of the functioning of the downstream sector. Looking ahead, future product movements will be determined by factors and issues discussed in previous Chapters. These include the future placement of new refining capacity; the growing global demand for middle distillates; the projected demand increase for petrochemical naphtha, especially in Asia; the continuing gasoline and diesel imbalance in the Atlantic Basin; the existing spare refining capacity in regions with falling demand, in particular the US and Europe; and the potential for refinery closures.

Looking at the most aggregated numbers, as presented in Figure 8.1, the trade of refined products, intermediates and non-crude based products reaches a level of more than 22 mb/d by 2030, if trade between all 18 model regions is considered. By that time, trade in products will reach 50% of the traded crude oil volumes. This represents an increase of more than 10% compared to 2009.

Similar to the analysis of crude oil movements, a more detailed analysis of product movements is restricted to the seven major regions. In this case, major inter-regional movements of liquid products will rise to 16.5 mb/d by 2030, an increase of 4 mb/d compared to 2009 (Figure 8.6).

Besides the rising volumes of finished products, discussed in more detail later in this Chapter, another key observation relates to the growing trade of non-crude based products. There are two main reasons for this: the growing production of NGLs and the related product output from gas plants supplemented by projected increases in GTLs production. The global increase in this category of liquid products is projected to be 1.4 mb/d between 2009 and 2030, rising from 2.1 mb/d in 2009 to 3.5 mb/d by 2030. CTLs and biofuels production are also projected to in-

Figure 8.6
Global exports of liquid products



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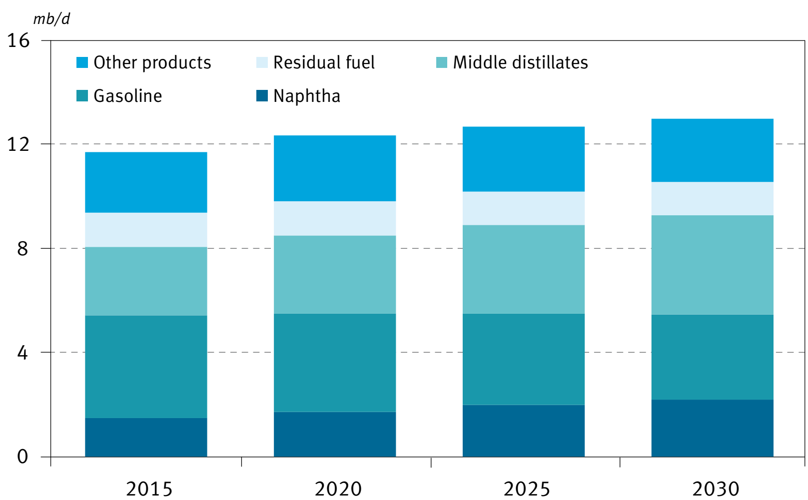
crease substantially, but this will materialize mainly in consuming regions and thus will not affect traded volumes.

Another dominant feature of future product trade is expected to be the expansion in middle distillates and naphtha – primarily for petrochemical use – that is associated with declining volumes of traded gasoline. This is underscored in Figure 8.7. The trade in middle distillates will record the highest increase, with 1.2 mb/d added between 2015 and 2030. The corresponding increase in naphtha trade is in the range of 0.7 mb/d. However, while imports of middle distillates are spread among Asia-Pacific, Europe, Africa and Latin America, naphtha will be almost entirely absorbed by Asia-Pacific, driven by a rapid expansion of the petrochemical industry in China, India and several other countries in the region.

The trade in fuel oil is projected to remain relatively stable, while gasoline is expected to decline by 0.6 mb/d. Moreover, the regional pattern of gasoline flows is likely to change. In terms of volume, the largest shift will be a reduction in US gasoline imports. This will force European refiners to find alternative outlets for their surplus gasoline, the major one expected to be Africa. In the latter part of the forecast period, Latin America will also see gasoline coming from Europe. These shifts are the result of increased competition in international gasoline markets as both Europe and the US

Figure 8.7
Global imports of refined products*



* *Includes both finished products and intermediates.*

face the problem of a gasoline surplus because of a high installed capacity for gasoline production, falling demand and increased ethanol supplies. Consequently, this will depress gasoline prices and impact future refining capacity additions in regions where gasoline is projected to grow.

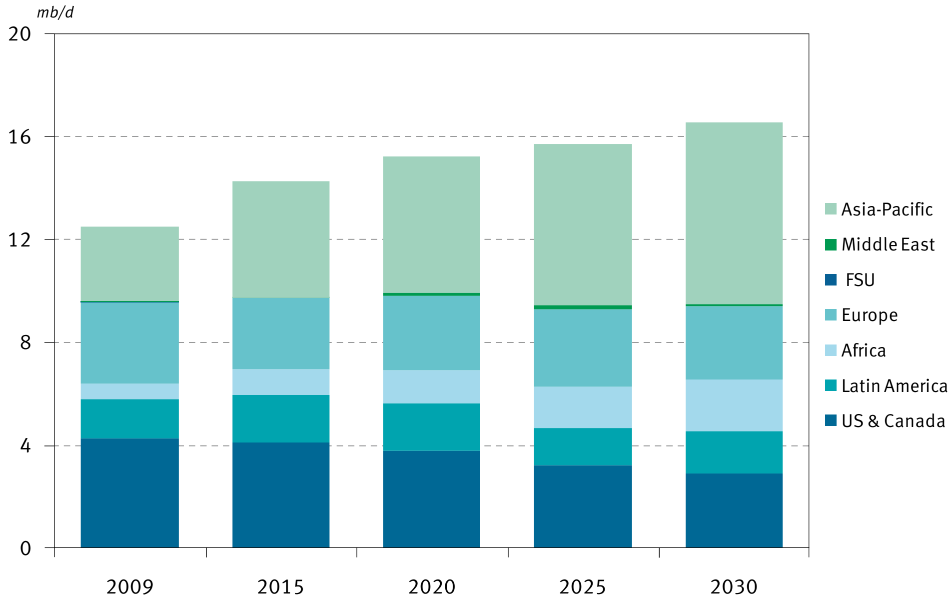
It should be emphasized, however, that these conclusions are based on a set of assumptions which, if altered, could result in a somewhat different picture. In respect to gasoline movements, the key unknowns are the extent of refinery shutdowns in Europe and the US and the pace of the dieselisation process in key consuming regions. Due to the complexity of the downstream sector, these parameters usually need to be adjusted simultaneously, since one simple change typically does not solve the problem. For example, reduced crude throughputs in Europe that are aimed at eliminating the problem of a gasoline surplus would exacerbate the problem of a distillates shortage.

In respect to other products, the corresponding trade flows could be significantly impacted by the actual placement of new refining capacity. For example, current model runs for 2030 show almost 3 mb/d of product imports into China, some 2 mb/d of product imports into the Rest of Asia region and 2 mb/d of African imports. And if these regions build more refinery capacity it will cut other regions' refinery throughputs and utilizations further. Obviously, there is a trade off here as – in shipping crude somewhere else and then processing it and shipping products to, say, China – there is a lot of transport inefficiencies *versus* shipping crude straight to refineries in China. It is a complex issue, one that needs to take into account the costs related to transportation, on one hand, and the building of new refineries, on the other. Moreover, the role of energy security should also be added into the equation.

The regional pattern of product imports is shown in Figures 8.8 and 8.9. The first figure presents total regional imports of liquid products, while the second depicts the corresponding volumes for net imports/exports between 2015 and 2030. The most evident trend resulting from these two figures is the Asia-Pacific's growing product imports in terms of both total and net imports. By 2030, total imports for this region will be more than 7 mb/d comprising mainly cargos from the Middle East, at almost 5 mb/d. Moreover, the Asia-Pacific will also be the single largest net importer of liquid products, at almost 6 mb/d of net imports.

Growing product imports are also projected for Africa, from 0.6 mb/d in 2009 to 2 mb/d by 2030. The change in the region's net imports is smaller, around 1 mb/d for the same period. This represents an important shift for Africa as this region will move from the position of being a net product exporter, with exports around 0.5 mb/d in 2009, to a net importer of similar product volumes in 2030. Similar to

Figure 8.8
Global imports of liquid products by region

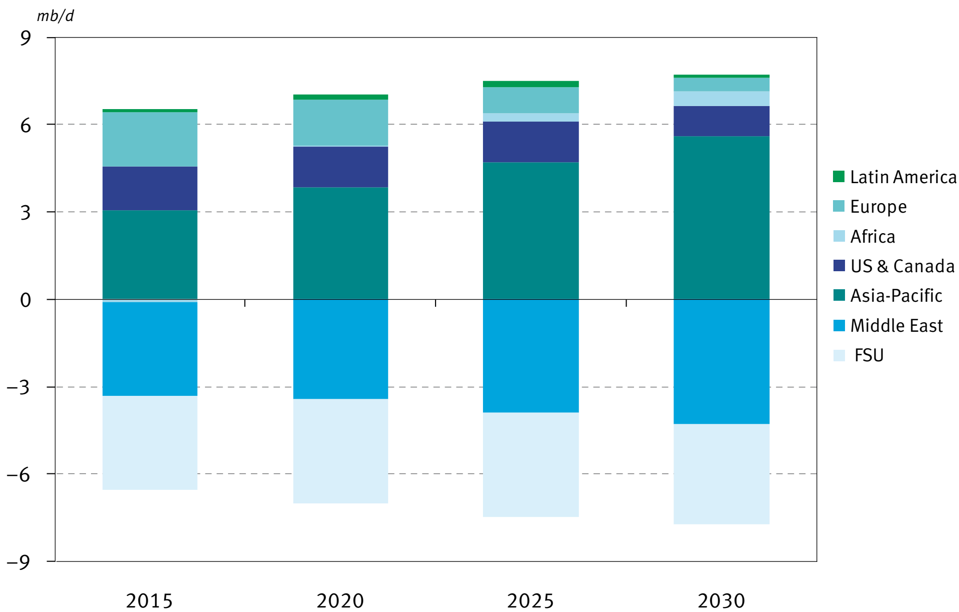


Africa, but to a much lesser extent, Latin America will also see growing product imports as demand increases are faster than the projected refining capacity additions.

The US & Canada will gradually reduce their product imports from levels of more than 4 mb/d in 2009 to 3.8 mb/d by 2020 and 2.9 mb/d by 2030. The net product imports of the region will also decrease by around 1.5 mb/d by 2030, compared to 2009. A similar pattern of declining product imports is expected in Europe.

On the other side of the product trade equation are net exporters. Given regional definitions, these are represented by the Middle East and the FSU region. These two regions are not only projected to keep their status as net product exporters during the entire forecast period, but also to increase exported volumes from current levels. The major increase for both regions will likely happen within the next few years as new refining capacity comes on stream. In the case of the FSU, this will be driven by additional conversion and desulphurisation capacity that will allow refiners in the region to primarily produce more middle distillates for export to Europe, alongside other products. It means that product exports are almost 1 mb/d higher in the medium-term. In the period after 2015, FSU net exports will be relatively stable moving within a range of 3.2–3.6 mb/d.

Figure 8.9
Net imports of liquid products by region



So the only region with continued growth in net product exports will be the Middle East, adding around 2.3 mb/d to its net exports by 2030 compared to current levels. Almost half of this increase will take place after the completion of the region's new major grassroots refineries that are projected to be operational around 2015. Since these new projects are very complex refineries, they will be able to provide products that are competitive in all major markets. Contrary to the FSU region, a further expansion of this region's refining sector is projected in the years beyond 2015. Consequently, total product exports from the Middle East are projected to reach 5.5 mb/d by 2030 and, in terms of net exports, the corresponding number is 4.3 mb/d.

Tanker capacity requirements

Since 2002, after a decade of relative stagnation, the global tanker market has experienced a period of rapid capacity expansion. At the end of 2002, global tanker capacity stood at less than 300 million dead weight tonnes (dwt). By the end of 2009, however, this capacity reached the level of 429 million dwt; an increase of over 40%. Moreover, as indicated by current order books, large increases are expected to continue at least this year and in 2011, with more moderate levels in 2012.

In the midst of this capacity growth, however, was the global economic recession of 2008 and 2009. This led to a lower tonne-mile demand and thus to a capacity surplus. The lower tonne-mile demand is a result of lower crude and products movements across all regions, while the capacity oversupply is a consequence of the huge deliveries of tankers and the lower scrapping rate.

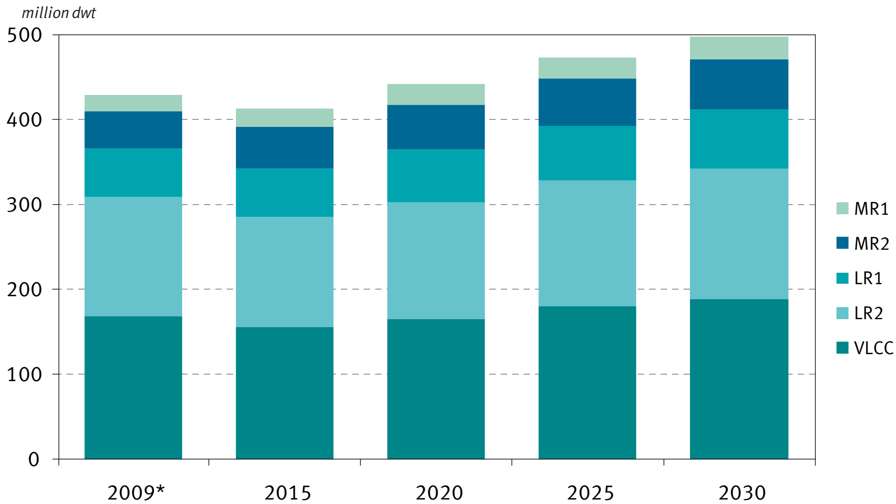
The slowdown in westbound oil trade, which constitutes the bulk of long haulage, had the greatest impact on the reduced tonnage demand, with rates last year pushing some ship owners to the verge of collapse. Some relief, however, was provided by the increased use of floating storage, driven by the crude oil market's contango structure. At certain times this absorbed some 40 million dwt of spare tanker capacity in 2009 and 2010, with floating storage at almost 300 million barrels.

Under such market conditions, characterized by lower demand for oil movements, capacity oversupply, lower scrapping rates and large order books, the medium-term expectation is for a surplus of tonnage across all tanker categories, and in turn, depressed freight rates. In the long-term, however, the renewal of scrapping activities and the anticipated growth in the inter-regional trade in crude oil and refined products will gradually absorb this capacity oversupply and lead to a balanced market with reasonable freight rates.

This expectation is based on the estimated tanker capacity requirements in Figure 8.10. These estimations show that the global tanker fleet capacity is anticipated to expand by almost 70 million dwt by 2030, reaching the level of close to 500 million dwt, from a global capacity of 429 million dwt at the end of 2009.[42] However, capacity requirements by 2015 are lower than the currently existing tonnage, estimated at 414 million dwt, with significant market implications. After 2015, capacity requirements are expected to grow again to the level of more than 440 million dwt by 2020 and 474 million dwt by 2025.

For the entire forecast period, the required average growth for global tanker capacity is estimated at 0.7% p.a., which is lower than the projected oil demand growth. This comparison is misleading, however, as the huge tanker capacity increase during 2009, almost 50 million dwt, inflated the base year number used for the assessment. In reality, between 2015 and 2030, it is projected that the required tanker capacity grows faster than demand because of a combination of expanding total oil movements, a higher share of product movements and a change in oil trade routes. By taking into account the available routes, the major growth is expected to be seen on routes to the Asia-Pacific, from both the Middle East and West Africa. On the other side, the decline in tonnage demand will be on routes to the US & Canada and

Figure 8.10
Outlook for tanker capacity requirements by category



* *Data for 2009 represents existing tanker fleet capacity at the end of the year.*

Europe. An additional factor is the growing local oil demand in producing regions like Latin America, the Middle East and Russia, which eliminates some barrels from global movements.

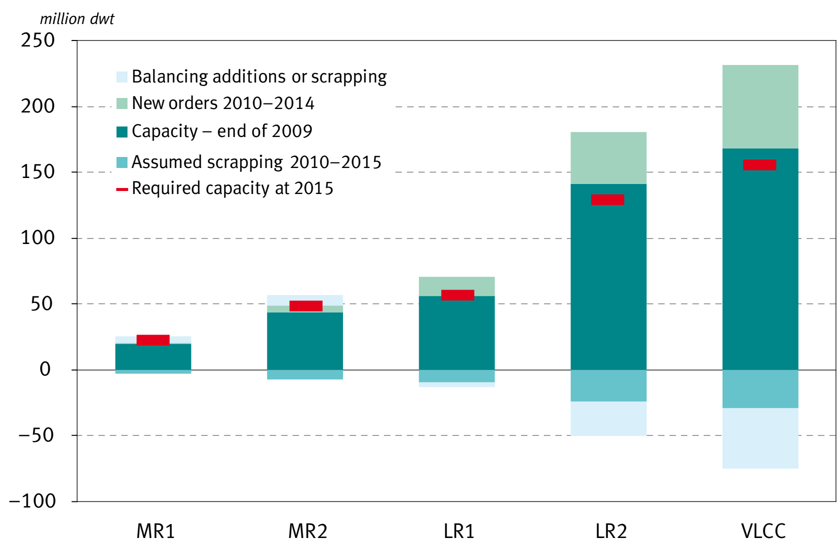
In respect to tanker categories, the largest increase is expected in the category of Very Large Crude Carriers (VLCC). This is required to expand by 20 million dwt by 2030, compared to 2009. The global capacity of Large Range 2 (LR2) tankers is also projected to grow, by 13 million dwt over the same period. However, these expansions are primarily after 2015, when crude exports are expected to resume growth. By the end of the forecast period, Large Range 1 (LR1) and Medium Range 2 (MR2) tankers are expected to grow by 13 and 15 million dwt respectively, as the trade in oil products expands. The average annual growth rates for these categories from 2009–2030 are 1% and 1.4% respectively, significantly higher than those for crude carriers. In addition, Medium Range 1 (MR1) tankers are assumed to grow at 1.5% p.a.[43]

The outlook for the medium-term tanker market stands in stark contrast to that for the long-term, given the significant capacity surplus. From capacity existing at the end of 2009, the removal of 15 million dwt will be required in order to balance the market in 2015. The actual surplus capacity is due to a variety of factors. Growing tonnage demand and high tanker market earnings that prevailed in the period before the recession discouraged scrapping and meant that companies ordered new tankers. When the economic recession hit in 2008, however, oil trade was substantially affected. It led to a collapsing tanker demand and left the market with a significant capacity surplus and an exceptionally large order book.

In total, order books as of June 2010 show that around 122 million dwt of tanker capacity has been ordered for the years 2010–2014. As shown in Figure 8.11, around half of this new tonnage, 63 million dwt, will be for VLCCs. Significant additions are also foreseen for LR2 vessels, around 39 million dwt, and another 14 million dwt is for LR1 tankers. What needs to be emphasized is the fact that all this capacity is entering the market at a time of when significant overcapacity exists. One positive is that deliveries from the order book are expected to slow down by 2012, and come to a standstill by 2014.

The implications of this predicament are well demonstrated in Figure 8.11. If an annual average scrapping rate of 15 million dwt is assumed for the period to 2015, a comparison of future capacity requirements, existing capacity and new orders, indicates that the tanker market will still have a capacity excess of more than 50 million dwt by 2015, if all tankers already ordered are delivered. This outlook also underscores a distinct contrast between the larger and smaller tanker classes. A capacity surplus of around 60 million dwt is projected for the VLCC and LR2 tanker categories com-

Figure 8.11
Tanker fleet capacities and requirements, 2009–2015

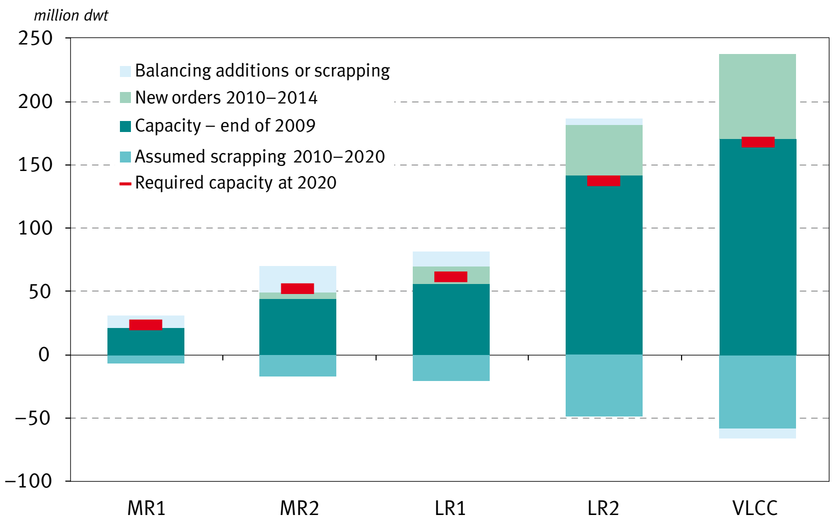


bined. Conversely, smaller tankers for product movements will require further additions of around 15 million dwt beyond existing known orders for this period. These required additions in the categories MR2 and MR1 are in line with increases in product movements.

Figure 8.12 extends this analysis for the period to 2020 assuming the same rate of annual scrappage and no changes in the order book (no additional tanker construction beyond existing orders). In this case, a gradual increase in tanker movements and the removal of excess capacity through tanker demolition will result in a relatively balanced market for LR2 and VLCC vessels. In smaller vessels, MR1 through to LR1, a combined additional capacity of around 40 million dwt will be required. Around half of this capacity, 19 million dwt, is projected to be for MR2 tankers because of expanding product exports over this period.

The projected large tanker capacity excess in the medium-term raises the question of whether there will be more cancellations, especially concerning delivery dates in 2011 and 2012. Calculations presented in this WOO suggest that around 40% of the existing tanker order book, especially for VLCC and LR2 tankers, is vulnerable to cancellation. Some signs of this trend are already visible as order book levels from June 2010 show a decline of around 20 million dwt VLCC tankers compared to the situation in December 2009. On the other hand, cancellations may not progress much

Figure 8.12
Tanker fleet capacities and requirements, 2009–2020



Chapter 8

further if investors see an opportunity to buy new tankers now, given that prices have dropped almost 35% below the levels of two years ago.

Another question relates to the rate of tanker scrappage and floating storage. Existing overcapacity could encourage tanker owners to scrap vessels that were kept in the market for some time because of favourable conditions a few years ago. Thus, the assumed rate of 15 million dwt per year might prove to be low, although it is higher than experienced in the past few years. This could help to restore balance to the market sooner than projected. Moreover, some tankers could be leveraged as floating storage although this only provides a temporary solution under specific market conditions. What is clear is that if none of this takes place, then the tanker market is sailing into a sustained period of depressed freight rates and questionable profitability.

Chapter 9

Downstream challenges

In assessing the findings of the downstream outlook it is important to detail the implications and challenges for refining over the medium- to long-term. This will help provide a more complete picture of the possible futures for the industry.

A new downstream outlook

With the dust now beginning to settle after two years of global economic upheaval, the severity of the cycle that the refining industry has undergone is becoming ever more apparent. From what many have termed a 'golden age' that lasted from 2004 through to mid-2008 with demand growth and refining tightness, the industry is now suffering from a severe demand collapse and surplus capacity.

One clear and specific aspect of this is the contrast that has evolved between OECD and non-OECD regions. The latter are continuing their role in delivering the bulk of the world's demand growth, whereas in the OECD demand seemed to have peaked or at least reached a plateau. This is being further reinforced by energy and climate change policy initiatives, which are expected to push for further downward trend in the OECD. From a regional perspective, this situation has created a contrast between the Atlantic and Pacific Basins. Dominated by Europe and the US, the former is the centre of the refining surplus. Conversely, the Asia-Pacific is the hub of growth. These shifts will reshape the global downstream in the years to come and, consequently, future decisions will need to take into account this new environment.

Decline in market share

At the same time, the proportion of crude oil needing to be refined per barrel of incremental product continues to decline as the percentage share of biofuels, GTLs, CTLs, NGLs and other non-crudes in the total supply carries on rising. The impact is significant. Both the volume and proportion of non-crudes in the total supply roughly doubles between 2005 and 2030, cutting the share of crude oil from the range of 90% to below 80%. From 2008 levels, the growth opportunity in crude oil refining is only about 9 mb/d, across a period where demand is projected to have risen in total by some 20 mb/d. For 2010–2030, the potential for incremental crude is a little better at a projected 10 mb/d, but the inexorable rise of non-crudes in total supply remains a significant factor impacting the need for refining expansion.

Capacity competition – expansion or closure

Before the global recession, smaller, older and less efficient refineries were already under pressure, unless they benefitted from special circumstances such as local crude supply, a niche market and/or specialty products. And what we have seen recently is a wave of new large scale, highly complex and more efficient plants, with this trend expected to continue in the future. This can be viewed in the Reliance-built refineries in India, which have set new standards across all these dimensions. Moreover, expansions in the Middle East and, to some degree, the US, are also raising the bar on what constitutes a 'world scale', 'world class' refinery.

Moreover, much of the new capacity, such as that in India and the Middle East, for example, is export-oriented. And at the same time, existing refineries in the US, Europe and Japan are facing reduced local demand for their products. Thus, these refineries will have additional export capacity, fuelling competition.

The stage is thus set for an extended period of intense competition for both the established markets (Europe, the US & Canada) and those witnessing growth (Asia-Pacific, the Middle East, Latin America and Africa). Some refineries in OECD regions will inevitably close, but it should be recognized that many of these have more products available for the global marketplace. Many US refineries, notably in the Gulf Coast, are highly complex and flexible in nature so they are able to provide products of advanced specifications, and are mostly debt free. While recent projects have placed more emphasis on distillates, these refineries will be looking for markets for their gasoline. European refineries, though on average less complex, must maintain gasoline output and other co-products in order to keep producing profitable distillates. These will join the new large refineries in India and the Middle East to compete for markets in Latin America, Africa and Asia. The scale of the Reliance and new Middle East refineries, in particular, combined with their integration with petrochemicals, will lead to them applying severe cost pressures on the market.

With all this in mind, it is expected that refineries in the US, Europe and Japan will be the ones that suffer the largest number of closures. In fact, since the beginning of 2009 over 1 mb/d of capacity in these regions has been shut, although some of this has subsequently been reactivated. More closures, however, are under consideration and majors such as Chevron, Shell, Total and ConocoPhillips are looking to divest themselves of refineries and other downstream assets. Some of these may be bought by expanding companies from India and China, such as Essar Oil and CNPC. Therefore, the prospect is for a substantial reshaping and reordering of refining capacity and refinery ownership over the next few years. If refiners in OECD regions, however, are slow to bring about closures and attempt to compete strongly in international markets, the next few years could be a period where refining margins suffer further strains.

Distillate gains; gasoline bust?

If anything approaching this WOO's projections for product differentials (Chapter 6) materializes, the industry is facing a significant collapse in margins for naphtha and gasoline and the re-emergence of strong economics for distillates. Additionally, and critically, just as a single refinery can switch at a certain point when the economic dynamics of the refinery change, so there is evidence that the industry as a whole – and certainly major regions – can do so too. The recent history of differentials *versus* crude – and their sharp swings – also illustrates the point that step changes can and do occur in refining economics, even over short periods. So the mix of a refinery's products, in particular the proportions of distillate *versus* gasoline/naphtha will be key factors affecting future margins and profit. Similarly, distillate *versus* gasoline/naphtha yields in crude oils are likely to have a marked impact on a crude's relative price. Very light crudes, and condensates, with their high yields of gasoline/naphtha, are expected to be disadvantaged.

Demand and technology responses

Demand and processing changes could have appreciable impacts on the gasoline/gasoil imbalance and relative pricing. For refiners, the years ahead present a number of technology and process challenges, as well as opportunities. These include:

- Potentially re-working FCC yields to move away from gasoline toward distillate and also propylene;
- Considering associated needs for increased distillate hydro-treating and/or cracking;
- Potentially adapting to a trend whereby VGOs are progressively pulled away into expanding hydro-cracking capacity such that FCCs take in more resid, which also fits with raising distillate yield;
- Assessing the impact of higher crude prices *versus* low natural gas and coal/coke prices – on a Btu basis – on the economics of carbon rejection (FCC, coking) *versus* hydrogen addition (hydro-cracking);
- Weighing the potential for resid hydro-cracking *versus* the more traditional route of either coking plus FCC or resid hydrodesulphurization plus resid FCC (RFCC) for deep upgrading. Resid hydro-crackers have recently been built, for example at Porvoo in Finland, which processes Urals resid;
- Consideration of how to maximize value from naphtha/gasoline fractions. Isomerization additions would act to raise light naphtha octane for blending into

gasoline. Should it become commercial, some form of oligomerization could play a role to convert such fractions to gasoil/diesel;

- Consideration of the possible opportunity or need to process more light crude and/or condensate and the associated processing impacts, such as potential limitations on light ends capacity; and
- Adapting technology processes to the pressures resulting from the likely regulations to limit refinery emissions.

On the demand side, however, a question mark remains over the possible reaction to wider gasoline/gasoil price differentials. This very much depends on taxation policies as end-consumer prices at pump stations typically differ substantially from those at the refinery gate. The question is to what degree will governments respond over time by shifting taxes/subsidies and, subsequently, how will consumers react in terms of changing vehicle ownership – and thus demand – back toward gasoline?

Refining investments: risks and rewards

Once again, this year's downstream outlook underlines that 'caution' remains the watchword in respect to refining investment decisions. New, large-scale, modern, efficient refineries will have advantages over older units. However, the former obviously bear much higher capital carrying/depreciation charges. An older, largely depreciated refinery can remain viable on a cash cost basis, especially if oil prices remain relatively high, thereby tending to widen light/heavy differentials and margins. Over the next few years, a lot will depend on the pace at which capacity in the US, Europe and Japan is rationalized. As stated, a slow pace of closure will strain the economics of all participants in the global refining sector.

What recent closures are showing is that vulnerability is not confined solely to those refineries deemed at risk previously; the small and simple refineries with less than 100,000 b/d of capacity. A number of the recent closures have been for refineries of mid-range complexity, with a capacity up to or beyond 200,000 b/d.[44] Thus, today, 200,000 b/d is not necessarily viewed as 'safe'. Arguably, the breakpoint for the minimal closure risk has moved up to the 250,000–300,000 b/d range, driven by the 300,000–600,000 b/d scale of most major new projects. Factors that will help keep refineries viable include: scale; access to local crude production; access to local or protected markets/location in an inland market where competition is difficult; production of specialty products; integration with petrochemicals or other company assets; high standards of operating efficiency; ability to produce transport fuels to advanced standards, notably ultra-low sulphur, Euro V or equivalent; and high distillate yields. Conversely, the absence of such favourable factors will render refineries vulnerable.

The overall conclusion is that the 'base case' outlook is for severe competition. This is particularly true for markets that also have rising biofuels/non-crudes supply, an ongoing gasoline/distillate imbalance and the absence of wide upgrading margins on FCC and coking. This leads to a lack of certainty for good returns on new – or existing – refineries over at least the medium-term, other than those supplying into high growth, preferably domestic, markets and where ideally there is some level of protection, for instance, in China.

At present, the refining industry finds itself in a period where the economics of every refinery and every project, whether large or small, needs to be subjected to severe scrutiny, with consideration of downside risk, as well as upside potential. On top of this base case outlook, there is also the additional prospect for progressively expanding energy and climate change legislation, both country-specific and global. Arguably, the likelihood and possible impacts of such legislation to the refining industry now need to be factored in as risks in any refining investment decision.

Energy and climate change policy impacts

Energy and climate change measures in Europe is already a fact and it is expected that legislation will be expanded over time. Outside Europe, climate and energy policy legislation remains a subject of often heated debate, particularly in the developed world. This has been viewed in recent discussions in both the US and Australia.

It is expected that legislation in some form or other is likely to move ahead in some regions, with knock-on impacts for oil demand, probably oil supply and almost certainly to refining in the affected regions. Depending on the specifics of any legislation, it may lead to opportunities for refiners who are in regions not impacted. The prospect of growing climate controls and costs in Europe, the US and Japan could severely curtail refining investments there and accelerate exits and closures. The presence or absence of 'cross border fees' that affect the degree to which refining is disadvantaged in 'carbon regime' regions translate into opportunities in 'non-carbon regime' regions. Whatever the actual details, however, it appears inevitable that it will mean a reduction in global oil demand and potentially by a substantial amount over the longer term.

Europe

In Europe energy and climate change legislation is already well established, with most developments now more evolutionary than revolutionary. The EU has established a series of energy policy objectives targeted at increasing renewable energy sources, reducing emissions and improving energy efficiency. In addition, the EU has the most comprehensive and developed ETS, a programme which has had its share of teething problems, but which is now functioning relatively effectively. The first two phases of the ETS (2005–2008 and 2008–2013) have been based on the 'grandfathering' principle[45] of emission cap allocations. For the third phase post-2013, however, the introduction of the 'benchmarking' principle is being considered.

For the refining sector, at the request of EUROPIA,[46] CONCAWE[47] and Solomon Associates[48] have developed a benchmarking methodology based on Solomon's energy benchmarking. The methodology uses the CO_2 weighted tonne (CWT) concept, which characterizes refineries based upon their CO_2 efficiency. The approach attributes a CWT to each refinery linked to its units, which is independent of the actual fuel used. This CWT constitutes a refinery's reference characteristic in terms of CO_2. The benchmark itself is based upon the ratio of tonnes of CO_2 actually emitted per CWT. It is proposed to set the benchmark as the average of refineries that are in the group of the best (most efficient) 10% of plants.

At this stage, there remain several unanswered questions for refiners; ones that need to be addressed during the adoption procedure. The first critical questions are when and at what level will the benchmark be set. Will the reference be the first decile of all refineries in the EU? And, will the benchmark be fully introduced by 2013? If attainment of the benchmark is required as of 2013, it has been reported that related costs will jump to €1.6 billion/year, assuming the market price of CO_2 remains at €25/tonne.[49] Secondly, there are concerns over the issue of carbon leakage if European refineries are exposed to international competition and a high ratio of potential CO_2 cost *versus* gross margin. Thirdly, it is unclear what portion of electricity generated within refineries will be auctioned. And finally, a monitoring body and reporting system would need to be established to ensure transparency and the reliability of the trading system.

On the one hand, it is obvious that the 'likely' implications constitute a further significant dent in the already questionable profitability of the refining business. On the other, however, the ETS in this form would provide a substantial stimulus to reduce CO_2 emissions from refineries. Therefore, the question arises as to what options are available to refiners to reduce CO_2 emissions from their operations. Although CCS may be part of the solution for reducing CO_2 emissions, this may be 10 years or so from now.[50]

Given the implementation of the third phase of the ETS is set for 2013, it is necessary to focus on more practical, already available and less costly solutions. This includes switching to imported natural gas and improving energy efficiency. Switching to natural gas may be required by the future Directive on Industrial Emissions, but there is still the question about what to do with fuel oil, especially when bunkers go low-sulphur. Will there be cost-effective technology to reduce fuel oil output? Another option is to reduce energy intensity. This will – in most cases – reduce emissions, as well as lessen operating costs since energy represents more than 50% of the operational expenditure in a typical refinery. Improved energy intensity could be achieved through various means. For example, through the implementation of operational best practices and investments in new more efficient units and processes, although in practical terms, the latter option is generally limited to larger sites. For the major part of the European refining sector, however, efforts and projects in this regard will not be sufficient to reach the benchmark. Thus, there is a significant compliance cost that remains an additional burden for refiners.

US

In the US, the situation with respect to energy and climate change legislation remains fairly active and fluid. While the bulk of recent attention has been on developments in the US House of Representatives and the Senate, it is important to recognize that there are multiple initiatives at play in the US. The situation continues to evolve at the federal, regional and state levels with potential significant implications for oil markets and refining, across regions, the country and potentially beyond US borders.

At the federal level, the change in the US Administration in January 2009 heralded a more concerted effort to implement energy and climate change legislation. Under the preceding George Bush Administration, at least three Senate 'climate change' bills had been proposed, but none passed the draft stage. In contrast, under the Barack Obama Administration, a detailed energy and climate change bill – The American Clean Energy and Security (ACES) Act of 2009 or the Waxman-Markey bill – had already passed the House of Representatives by June 2009. Although this bill has now stalled, it remains an important reference source for the possible implications of energy and climate change legislation upon the refining sector.

Nevertheless, consensus-building efforts continue and it is possible that new draft legislation from the US Senate could generate momentum at some point in the future. In addition to ACES that passed the House of Representatives, draft bills circulating at the federal level include: the Senate Clean Energy Jobs and American Power Act or otherwise known as the Kerry-Boxer bill; the American Clean Energy Leadership Act (ACELA), sponsored by Senator Jeff Bingaman; and the Carbon Limits and Energy for America's Renewal (CLEAR) Act.

In parallel, separate bills focus on different mechanisms, with 'cap and trade' being the most prominent. The House ACES Act included a comprehensive cap and trade scheme that would have embraced some 80% of the US's GHG emissions. This essentially covers all industrial sectors including oil and gas production, refining and consumption. Under cap and trade, a limit is set for total emissions of CO_2 equivalent (CO_2-eq) gases from the relevant parts of the economy. For example, in the ACES Act, this limit drops to 17% below 2005 levels by 2020, 42% by 2020 and 83% by 2030. Organizations either directly emitting GHG gases or deemed responsible for emissions from their products when combusted – including refineries – must either reduce their emissions below their allocated allowance and/or purchase carbon allowances that allow them to legally emit.

Other approaches favour limited cap and trade, for example, for the electricity sector only, plus what are called 'fees' as the term 'carbon tax' tends to be avoided. Another approach put forward is the so-called 'cap and dividend'. Under this approach, carbon revenues generated would in the main be passed back to consumers/taxpayers in the form of a 'dividend'. Thus the scheme would, in principle, change how taxpayers were taxed – higher costs on energy in turn for lower effective taxes elsewhere. As an example, the CLEAR Act would pass back 75% of the carbon allowance auction revenues to all US individuals except the wealthiest 20%, who are also likely to be the largest energy consumers. The remaining 25% would be leveraged for an energy and climate fund dedicated to supporting key climate change programmes.

Additionally, it is important to note that draft bills such as the CLEAR Act require so-called 'border equalization fees' for the 'production-process carbon' in imported energy-intensive commodities. The bill calls for these fees to be consistent with the WTO and other trade agreements. They would be applied only to imports from countries without comparable carbon limits or fees and restricted to domestic industries that have international exposure and competition; ones that are demonstrably disadvantaged when shouldering the costs of their carbon emissions. The focus here is on industries where fuel is a substantial portion of costs, such as refining, steel, cement and chemicals. Obviously, the US refining industry could be severely disadvantaged *versus* non-US refiners depending on the design of the US carbon regime.

While developments at the US federal level have garnered most attention, it is essential to recognize that significant state and regional initiatives also exist. Occupying its traditional role as a leader in energy and environmental regulation, California has implemented two key pieces of legislation. The California Global Warming Solutions Act of 2006 (AB32) established a state-wide GHG emissions cap for 2020, and made the California Air Resources Board (CARB) responsible for monitoring and reducing GHG emissions. Specifically, the law calls for state-wide GHG emissions to be reduced to 1990 levels by 2020 and to 80% below 1990 levels by 2050. The required GHG inventory and reporting under the Act includes: petroleum refineries; hydrogen plants; cogeneration facilities; as well as cement and electricity generating plants. Recognizing that California alone, is one of the top 10 economies in the world, and that its actions tend to be followed elsewhere in the US, this law has potential far-reaching implications, not least for the future scale of refining[51] and the level of crude oil imports into California.

Following on from AB32, the Low Carbon Fuel Standard (LCFS) for transportation fuels was established in California in January 2007. This law went into effect in January 2010. Specifically, it calls for a 10% reduction in the GHG intensity of California transport fuels by 2020. Thus, it establishes a new mechanism for measuring and regulating carbon; one that is finding its way into other environmental legislation, both in the US and Europe.

California, however, is not alone in the US in moving forward with energy and climate change legislation at the state level as no fewer than three regional GHG initiatives now exist in the US. These include the Western Climate Initiative, the Northeast Regional Greenhouse Gas Initiative and the Midwest Greenhouse Gas Reduction Accord. While these groups themselves acknowledge that a federal system would be the most logical, the revenues generated under state/regional cap and trade and/or cap and dividend mechanisms would accrue to the states directly and not to the federal government. This, and the potential for stalled progress at the federal level, implies that these regional schemes should continue to be monitored.

Japan

Elsewhere, Japan has a long history of carbon regulation. In 1997 the Japan Business Federation (Japan Keidanren) developed and agreed to the 'Keidanren Voluntary Action Plan on the Environment', a voluntary emissions cap and trade programme. The goal was to reduce the emission levels of 2010 below those of 1990, with members of the Voluntary Action Program (VAP) setting their own emissions targets. The programme was integrated into Japan's Voluntary Emissions Trading Scheme (JVETS) in 2005. The programme was then expanded in October 2008. The scheme established a national system for pricing and implementing a cap and trade programme. Voluntary in participation, it captured 70% of Japanese industry. Companies are able to use both the Kyoto Protocol mechanism credits and domestic trading credits.

Separately from carbon legislation, in November 2009 Japan passed the Innovation for Green Economy and Society Bill. Moreover, Japan has been the most aggressive nation in setting carbon targets in the wake of last year's UN climate change summit in Copenhagen. Its government has pledged a strong goal of cutting 2020 emissions by 25% *versus* 1990 levels.[52] It has also stated making carbon trading an objective. On 12 March 2010, Japan's Cabinet endorsed the draft of cap and trade legislation. The legislation calls for a carbon tax starting in April 2011. The proposed bill would combine a cap for certain industries, with a limit by unit of production for others.

A full cap and trade system with a set limit, however, was strongly opposed by industry groups with many raising job-related concerns. A cap per unit produced is seen as an easier option. Nonetheless, it is opposed by environmental groups as many believe that it will mean that Japan misses its stated targets. The proposed legislation is opposed by nine major Japanese industry groups, including – it is understood – refining. Japanese industry groups point to the recent recession and a lack of similar regulation in China and India. Japan's pledge to cut emissions is contingent upon all major emitters agreeing to an international emissions treaty.

China

China has opposed a strict cap on carbon emissions and is instead moving toward regulation on carbon per unit of GDP, as well as increased renewable energy investment and energy efficiency. At the March 2010 opening meeting of the National People's Congress, two plans were simultaneously proposed. The first proposal, a draft cap and trade policy framework sought to develop methodologies for meeting 2020 emissions targets. China announced before the Copenhagen summit that it would lower CO_2 emissions per unit of GDP by 40–45% by 2020, compared to the 2005 level. To date, however, no draft legislation has been produced, but it is likely that any cap would be per unit rather than an overall national cap.

The second proposal, in the form of a government work report, outlined a plan to develop low-carbon technologies, as well as renewable energy sources. The plan calls for increasing forest cover, advancing energy conservation and developing recycling. The 12th five-year plan for national economic development (2011–2015) will include provisions focused on renewable energy, energy efficiency and low-carbon living.

In its recent submission to the UNFCCC, China proposed targets that combine both proposals.[53]

Canada

Canada has largely taken a 'wait-and-see' approach to the implementation of carbon legislation, with any decision hinging upon US legislation and its impact on Canadian oil sands. In November 2009, with the election of President Barack Obama, Canada signalled a shift towards a nationwide cap and trade system. However, with delays and uncertainty now evident in US efforts, the Canadian government is re-evaluating its options. It should also be noted that a large percentage of Canadian emissions would be covered under participation in the US regional Western Climate Initiative, which includes British Columbia, Manitoba, Ontario, and Quebec with Saskatchewan and Nova Scotia observing. Critically, however, it excludes Alberta, the centre of the Canadian oil sands industry, as well as a major conventional crude producing state.

As the US has backed away from a federal cap and trade policy, alternative actions have been gaining traction in Canada. Foremost among these is the possibility of a carbon tax. This simpler and more direct approach avoids the complications and uncertainty of a cap and trade type market, but on the other hand, it may not bring the same leverage of market forces to bear.

Australia

Australia has twice recently voted down proposed cap and trade legislation, under the guise of the Carbon Pollution Reduction Scheme (CPRS). The plan has long been in development, with its roots traced back to a 2006 discussion paper. In May 2009, CPRS legislation was introduced to Parliament, but was voted down in August 2009. Adjusted legislation was re-introduced in October 2009 but was voted down again within 10 days. CPRS legislation was once more introduced in February 2010, but to date this has not been voted upon.

Similar to the proposed US EPA regulations, the CPRS plan targets emitters of over 25,000 tonnes CO_2/yr. Upstream producers or importers will be liable for fuels and transportation emissions including transport fuels, LPG, LNG, coking coal, natural gas, ethane, CNG, syngas and propylene. The legislation includes a framework for passing emissions obligations down the supply chain. Obligation Transfer Numbers (OTN) may be quoted by the downstream companies when they obtain a supply of fuel. They will then assume CPRS obligations for the fuel. This mechanism can then be used to export fuels and products out of Australia with no CPRS cost. The use of LPG, refinery grade propylene or ethylene as a production feedstock requires an OTN, while other feedstocks do not.

The Australian Treasury envisages that this regulation will have a significant impact on the refining industry. Transport fuel demand is expected to peak in 2026 and, dependent upon the scenario, domestic refining is expected to decline between 35% and 52% by 2050. It is expected that carbon costs will make conventional fuels less competitive, leading to greater fuel diversification.

Implications for the refining sector

While there is current uncertainty about how carbon legislation will evolve and what form any eventual enacted legislation will take, it is evident that this type of legislation will impact the refining industry, and of course the wider global oil market. To simplify some of the potential outcomes, the following are likely to apply in all countries and regions that implement carbon legislation:

- Demand for ex-refinery petroleum products will decline. Potentially three drivers will cause this. The first is the explicit conservation/efficiency measures, for instance, the newly tightened US CAFE standards for vehicle fuel efficiency and the EU standards for tighter vehicle CO_2 emissions. The second is the higher product prices due to carbon costs being directly imposed or passed through from the upstream. And thirdly, support and incentives for alternative and renewable energies, notably biofuels. This includes the US RFS-2 standard and the EU's energy and climate change legislation that mandate sustained large increases in the supply of biofuels;
- Costs for refiners within carbon regime regions are likely to increase. The EU, and now the US, have recognized the need to 'square the circle' in enforcing higher efficiency standards within domestic refining without unduly affecting a refineries' competitiveness globally. For instance, the increased costs to refiners to pay for carbon allowances may be offset by border equalization fees. However, there is no certainty that domestic refineries will be fully protected. Draft EU proposals would apply no cost carbon allowances only to the most energy efficient refineries – measured it would appear on a Solomon type scale that recognizes their ranking relative to other refineries of similar complexity. US Senate level efforts have laid down the principle that domestic refining is critical to energy security, however, if legislation along the lines of the Waxman-Markey bill went ahead, it would seriously disadvantage US refining;
- The prospect of reduced ex-refinery product demand, combined with rising carbon, and thus potentially operating costs, the likely existence of uncertainty in carbon pricing and allowance cost recovery, and the potential higher capital costs for new equipment, are likely to combine to reduce incentives and increase the difficulties for refiners to invest in carbon regime regions;
- To the extent that carbon regime costs for refiners do rise, and disincentives for investment play out, carbon legislation is likely to reinforce the weeding out and closure of capacity in the regions where it occurs, potentially leading to capacity reductions that exceed the levels of demand reduction;
- Associated with this, support for CCS and the evolution of CCS technology will impact both supply levels of crude oil and refining;

- The impact will also be felt on oil market economics and in the trade for crude oils and products. Whether carbon legislation encompasses costs based solely on carbon content or on the full life-cycle carbon footprint/intensity, the relative economics of crude oils will be affected. Broadly, light, low sulphur conventional crudes, especially those produced onshore and/or with high distillate yields, will be advantaged, and heavy, sour crudes disadvantaged, especially those produced energy-intensively, such as via EOR and/or from extra heavy oil or oil sands. Moreover, if LCFS legislation is implemented, the economic impacts will trace all the way back to the well. As a result, trading patterns for crudes could be materially altered and improvements in energy efficiency encouraged; and
- The imposition of carbon regimes and costs on top of 'base' oil economics will likely increase market and price volatility. New procedures could impact the complexity of operation and compliance in affected regions and could curb a refiners' ability to respond rapidly when presented with opportunistic crude cargoes.

The extent of possible implications for refiners resulting from ongoing legislative proposals is well illustrated in the potential implication of the US Waxman-Markey bill. While the focus here is on the US, the implications apply to any region that today or in the future has similar carbon legislation.

In August 2009, the US EIA released its analysis of the potential impacts of the bill.[54] Recognizing that the EIA analysis arguably did not capture the full implications for US refining, the American Petroleum Institute (API) undertook a separate study.[55] This used the EIA's projections of carbon allowance costs, impacts on US crude oil and biofuels supply and product demand, and on costs of electricity, natural gas and construction, to assess the consequences for the US and the global refining industry. The study indicated that, because the bill required US refiners to cover the bulk of the costs of their own refinery CO_2 emissions – and as there was no offsetting border equalization fee or equivalent in the bill – US refiners' operating costs would increase substantially. Consequently, and depending on the level of carbon allowance cost, they would be adversely impacted, especially those in coastal regions. Conversely, refiners outside the US and other carbon regimes regions would stand to gain.

Chapter 9

The EIA developed optimistic (low carbon cost), and pessimistic (high carbon cost) scenarios. Its carbon cost outlook varied from a low range of \$22 in 2015 and \$65 per tonne CO_2-eq in 2030, to a high range of \$65 in 2015 and \$190 in 2030. It projected US demand reductions at 0.7–0.9 mb/d by 2020 and 0.9–1.7 mb/d by 2030. Set against these, reductions in US refinery throughputs were estimated at 1–1.5 mb/d by 2020 and 2 mb/d to over 4 mb/d by 2030. Largely offsetting these reductions, capacity additions and incremental investments would accrue to refiners in non-carbon regime regions. Thus, while the regulation could reduce US refiners' CO_2 emissions by as much as 41%, the net global reduction in refinery emissions would be small, at most 3%. And this would stem essentially from the reduction in processing corresponding to the lower US petroleum product demand. A separate study, by the Energy Policy Research Foundation Inc.,[56] focused more narrowly on the impacts on US refinery operating costs and cash flows. Its conclusion was that there was the potential for a greater number of closures than those already highlighted.

It is clear that carbon legislation is still at a formative stage, but the implication is that it could do as much to reshape global refining, oil markets and economics over the next 20 years, as will regional economic and population growth. Its potential to reduce demand growth and further increase competition for product markets sends a clear signal that project developers will need to remain cautious about any downstream expansion or investment decisions.

Footnotes

1. http://www.ief.org/Events/Documents/CANCUN%20MINISTERIAL%20DECLARATION.pdf.
2. 'Canadian Oil Sands Supply Costs and Development Projects (2009-2043)', Canadian Energy Research Institute, November 2009.
3. 'Affordable, Low-Carbon Diesel Fuel from Domestic Coal and Biomass', National Energy Technology Laboratory, US Department of Energy, January 2009, using GHG emission values in the range of $5–101/t CO_2-eq.
4. In contrast to the physical oil market, the paper oil market refers to transactions on established exchanges, such as Nymex and ICE, where crude oil futures and options are bought and sold, as well as to OTC derivative markets where bilateral contracts are made.
5. Entities not involved in the production, processing or merchandising of a commodity.
6. Futures market participants who engage in futures trades on behalf of investment funds or clients.
7. http://www.nber.org/cycles.html.
8. http://www.imf.org/external/pubs/ft/weo/2009/01/pdf/c3.pdf.
9. The International Monetary Fund, in its World Economic Outlook, October 2010, was slightly more optimistic regarding the speed of recovery.
10. The April 2009 meeting of the G20 committed over $2 trillion of fiscal stimuli in funds in response to the crisis.
11. http://www.imf.org/external/pubs/ft/spn/2009/spn0921.pdf.
12. http://ec.europa.eu/economy_finance/thematic_articles/article14761_en.htm.
13. More detailed analysis on selected OECD countries can be found at: http://www.opec.org/opec_web/static_files_project/media/downloads/archive/WGW2009.pdf.
14. Preliminary estimates based on the Global Subsidies Initiative document available at: http://www.globalsubsidies.org/files/assets/relative_energy_subsidies.pdf.
15. Excluding traditional fuel use in developing countries.
16. Shale gas is part of what is called unconventional gas, with tight gas and coalbed gas. In conventional reservoirs, natural gas is generally stored in interconnected pores of sandstones and carbonates rocks and could easily flow towards the wellbore. The gas has been, most often, generated by a source rock rich in organic matter that has been thermally matured during the burial process. Gas is then expelled and trapped in a porous rock adequately preserved by a sealing mechanism, usually formed by an impermeable rock such as salt or shale. In unconventional reservoirs, natural gas is stored as free gas in the often poorly connected micropores and fractures and as adsorbed gas on the internal surfaces of the organic matter. Permeability is very low, of the order of the micro-darcy at best. As a result, unconventional gas accumulations tend to be present over a large area, but are difficult to produce commercial volumes. The key to unlock shale gas resources is the ability to enhance the deliverability of the wells by combining and optimizing two mature technologies: horizontal drilling and hydraulic fracturing.
17. Clean Cities, Alternative Fuel Price Report, US Department of Energy, April 2010.

18. http://www.world-nuclear.org/info/inf17.html.
19. Renewable Energy Policy Network for the 21st Century, 'Renewables 2010 – Global Status Report'.
20. 'Resilient production costs support long- and short-term oil prices', IHS CERA World Oil Watch, December 2009.
21. Defined as lorries (rigid motor vehicles designed, exclusively or primarily, to carry goods) plus buses (designed to seat more than nine persons, including driver).
22. IHS Herold 2010, Global Upstream Capital Spending Report.
23. Definitions of shallow, deep and ultra deepwater can vary, but the most common definitions are: shallow water, less than 500m; deepwater, between 500m and 1,500m; and ultra deepwater, greater than 1,500m.
24. http://www.ethanolrfa.org/pages/statistics#B.
25. The World Oil Refining Logistic and Demand (WORLD) model is a trademark of EnSys Energy & Systems, Inc. OPEC's version of the model was developed jointly with EnSys Energy & Systems.
26. For example, Turner, Mason & Company; Purvin & Gertz Inc.; Hart Energy Publishing, etc.
27. Published in Oil & Gas Journal on a regular basis.
28. World refined product outlook: a cold winter isn't enough, IHS/CERA report, 28 January, 2010.
29. Increases in refining capacity achieved through minor 'debottlenecking' within existing facilities, often during maintenance turnarounds.
30. 'China Refining Industry 2009', C1 Energy Limited, www.c1energy.biz.
31. Based on Purvin & Gertz, http://www.gasandoil.com/goc/features/fex90426.htm.
32. Indian Oil Corp., Bharat Petroleum Corp., Hindustan Petroleum Corp., Oil & Natural Gas Corp.
33. The Reliance II refinery is reported to have a capacity of 580,000 b/d on 24° API crude oil and 650,000 b/d if running lighter 28° API crude. It is reliably reported to be running closer to 650,000 b/d since start-up, possibly because of a lighter selected crude slate.
34. The Reference Case does not assume a major breakthrough in cellulosic ethanol technology, which would further increase ethanol supplies.
35. A combination of finished gasolines and RBOBs/CBOBs for final blending at terminals with ethanol (Reformulated Blendstock for Oxygenate Blending/Conventional Blendstock for Oxygenate Blending).
36. Some specifics on the African refining sector are also available in the report 'Sub-Saharan Africa Refinery Project, Volume II-A: Refinery Study', ICF International & EnSys Energy, June 2009, http://siteresources.worldbank.org/ INTOGMC/Resources/ssa_refinery_study_vol_2.pdf.
37. Percentage calculated on a weight basis.
38. Percentage calculated on a volume basis.

39. Gasoline desulphurization reported here excludes naphtha desulphurization and focuses primarily on deep desulphurization of FCC gasoline streams.
40. On a weight basis, the coke yield on a coking unit can often be around 30%.
41. Oil here includes crude oil, refined products, intermediates and non-crude based products.
42. All projections presented in this Chapter are indicative only. They represent the minimum required capacity for a given time horizon as they are the result of an optimization process.
43. MR1 movements are not captured by the model since these tankers are mainly used for intra-regional trade. Therefore, they are assumed to grow proportionally to the capacity expansion of smaller MR2 and LR1 tankers.
44. Total, Dunkirk, France 160,000 b/d; Valero, Aruba 235,000 b/d; Valero, Delaware City, US 210,000 b/d.
45. A principle where individual companies' previous emissions levels would be used to set their future permit allowances.
46. EUROPIA is a non-profit organization that represents the downstream sector (refining and marketing) of Europe's oil industry (www.europia.com).
47. CONCAWE is an institution for conservation of clean air and water in Europe (www.concawe.be).
48. http://solomononline.com/.
49. Improving energy efficiency in TOTAL refineries to reduce CO_2 emissions, TOTAL Refining & Marketing presentation to the 2nd Downstream CO_2 & Energy Efficiency Conference, 3–4 February 2010, Rotterdam, The Netherlands.
50. Recently, two CCS projects, in Norway and the Netherlands, were scrapped as uneconomic.
51. Potential environmental legislation may be one factor behind Chevron's dispute over the possible closure of its 240,000 b/d refinery in Richmond, California.
52. It should be noted that the EU and most nations that pledged cuts did so *versus* 2005 levels, a significant difference in scale to the Japanese pledge.
53. http://unfccc.int/files/meetings/application/pdf/chinacphaccord_app2.pdf.
54. 'Energy Markets and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009', SR/OIAF/2009-05, August 2009.
55. 'Waxman-Markey (H.R. 2454) Refining Sector Impact Assessment', 22 October 2009, http://www.api.org/Newsroom/refining_sector.cfm.
56. http://www.eprinc.org/pdf/refining-waxman-markey-ogj.pdf.

Annex A

Abbreviations

ACES	American Clean Energy and Security
ACELA	American Clean Energy Leadership Act
API	American Petroleum Institute
b/d	Barrels per day
boe	Barrels of oil equivalent
BTLs	Biofuels-to-liquids
CAFE	Corporate Automobile Fuel Efficiency
CARB	California Air Resources Board
CBOB	Conventional Blendstock for Oxygenate Blending
CCS	Carbon capture and storage
CDM	Clean Development Mechanism
CFTC	Commodity Futures Trading Commission
CHP	Combined heat and power
CLEAR	Carbon Limits and Energy for America's Renewal Act
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
CONCAWE	Conservation of Clean Air and Water in Europe
CPRS	Carbon Pollution Reduction Scheme
CSP	Concentrated solar thermal power
CTLs	Coal-to-liquids
CWT	CO_2 weighted tonne
DCs	Developing countries
DOE/EIA	(US) Department of Energy/Energy Information Administration
dwt	Dead weight tonnes
ECAs	Emission control areas
EISA	(US) Energy Independence and Security Act
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
EPC	Engineering, procurement and construction
ESPO	Eastern Siberia Pacific Ocean
EST	Eni slurry technology
ETFs	Exchange traded funds
EU	European Union
EU ETS	EU Emissions Trading Scheme

EUROPIA	European Petroleum Industry Association
E&P	Exploration and production
FAME	Fatty-acid methyl ester
FCC	Fluid catalytic cracking
FSA	Financial Services Authority
FSU	Former Soviet Union
GDP	Gross domestic product
GHG	Greenhouse gas
GSI	Global Subsidies Initiative
GTLs	Gas-to-liquids
GW	Gigawatt
IEA	International Energy Agency
IEF	International Energy Forum
IFQC	International Fuel Quality Centre
IMF	International Monetary Fund
IMO	International Maritime Organization
IPCC	Intergovernmental Panel on Climate Change
IRF	International Road Federation
IRR	Internal rate of return
JVETS	Japan's Voluntary Emissions Trading Scheme
kWh	Kilowatt hour
LCFS	Low Carbon Fuel Standard
LCO	Light cycle oil
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LR1	Large Range 1 (50,000–79,999 dwt)
LR2	Large Range 2 (80,000–159,999 dwt)
LTS	(OPEC's) Long-Term Strategy
MARPOL	Marine Pollution
mb/d	Million barrels per day
MDGs	Millennium Development Goals
MEPC	Marine Environmental Protection Committee
METI	Ministry of Economy, Trade & Industry
MMS	Minerals Management Service
MOMR	OPEC's Monthly Oil Market Report

mpg	Miles per gallon
MR1	General Purpose Vessels (16,500–24,999 dwt)
MR2	Medium Range Vessels (25,000–49,999 dwt)
MTBE	Methyl tetra-butyl ether
mtoe	Million tonnes of oil equivalent
MW	Megawatt
NGLs	Natural gas liquids
NGOs	Non-governmental organizations
NOC	National Oil Company
NOx	Nitrogen oxides
OECD	Organisation for Economic Co-operation and Development
OFID	OPEC Fund for International Development
OPEC	Organization of the Petroleum Exporting Countries
ORB	OPEC Reference Basket (of crudes)
OTC	Over-the-counter
OTN	Obligation Transfer Numbers
OWEM	OPEC's World Energy Model
p.a.	Per annum
ppm	Parts per million
PPP	Purchasing power parity
PV	Photovoltaics
R&D	Research and development
RBOB	Reformulated Blendstock for Oxygenate Blending
RFCC	Resid FCC
RFS	Renewable Fuels Standard
Sinopec	China Petrochemical Corporation
SOLAS	Safety of Life at Sea
SOx	Sulphur oxides
SRD	Straight-run diesel
Tcf	Trillion cubic feet
toe	Tons of oil equivalent
ULS	Ultra low sulphur
UN	United Nations
UNDESA	United Nations Department of Economic and Social Affairs
UNFCCC	United Nations Framework Convention on Climate Change

UN MDGs	United Nations Millennium Development Goals
URR	Ultimately recoverable reserves
USGS	United States Geological Survey
VGO	Vacuum gasoil
VLCC	Very large crude carrier (160,000 dwt and above)
WNA	World Nuclear Association
WOO	World Oil Outlook
WORLD	World Oil Refining Logistics Demand Model
WRFS	World Refining & Fuels Services
WTI	West Texas Intermediate
WTO	World Trade Organization

Annex B

OPEC World Energy Model (OWEM) definitions of regions

OECD

North America

Canada
Guam
Mexico
Puerto Rico
United States of America
United States Virgin Islands

Western Europe

Austria
Belgium
Czech Republic
Denmark
Finland
France
Germany
Greece
Hungary
Iceland
Ireland
Italy
Luxembourg
Netherlands
Norway
Poland
Portugal
Slovak Republic
Spain
Sweden
Switzerland
Turkey
United Kingdom

OECD Pacific

Australia
Japan
New Zealand
Republic of Korea

Developing countries

Latin America

Anguilla
Antigua and Barbuda
Argentina
Aruba
Grenada
Guadeloupe
Guatemala
Guyana

Bahamas
Barbados
Belize
Bermuda
Bolivia
Brazil
British Virgin Islands
Cayman Islands
Chile
Colombia
Costa Rica
Cuba
Dominica
Dominican Republic
El Salvador
Falkland Islands (Malvinas)
French Guiana
Haiti
Honduras
Jamaica
Martinique
Montserrat
Netherland Antilles
Nicaragua
Panama
Paraguay
Peru
St. Kitts and Nevis
St. Lucia
St. Vincent and the Grenadines
Suriname
Trinidad and Tobago
Turks and Caicos Islands
Uruguay

Middle East & Africa

Bahrain
Benin
Botswana
Burkina Faso
Burundi
Cameroon
Cape Verde
Central African Republic
Chad
Comoros
Congo
Congo, Democratic Republic
Djibouti
Egypt
Malawi
Mali
Mauritania
Mauritius
Mayotte
Middle East, Other
Morocco
Mozambique
Namibia
Niger
Oman
Réunion
Sao Tome and Principe
Senegal

Equatorial Guinea
Eritrea
Ethiopia
Gabon
Gambia
Ghana
Guinea
Guinea-Bissau
Ivory Coast
Jordan
Kenya
Lebanon
Lesotho
Liberia
Madagascar
Rwanda
Seychelles
Sierra Leone
Somalia
South Africa
Sudan
Swaziland
Syrian Arab Republic
Togo
Tunisia
Uganda
United Republic of Tanzania
Western Sahara
Yemen
Zambia
Zimbabwe

South Asia

Afghanistan
Bangladesh
Bhutan
India
Maldives
Nepal
Pakistan
Sri Lanka

Southeast Asia

American Samoa
Brunei Darussalam
Cambodia
Chinese Taipei
Cook Islands
Democratic People's Republic of Korea
Fiji
French Polynesia
Hong Kong, China
Myanmar
Nauru
New Caledonia
Niue
Papua New Guinea
Philippines
Samoa
Mongolia
Singapore

Indonesia
Kiribati
Lao People's Democratic Republic
Macao
Malaysia
Solomon Islands
Thailand
Tonga
Vanuatu (New Hebrides)
Vietnam

China

OPEC
Algeria
Angola
Ecuador
I.R. Iran
Iraq
Kuwait
S.P. Libyan A.J.
Nigeria
Qatar
Saudi Arabia
United Arab Emirates
Venezuela

Transition economies

Russia

Other transition economies
Albania
Armenia
Azerbaijan
Belarus
Bosnia and Herzegovina
Bulgaria
Croatia
Cyprus
Estonia
Serbia
Slovenia
Georgia
Kazakhstan
Kyrgyzstan
Latvia
Lithuania
Malta
Moldova
Montenegro
Romania
Turkmenistan
Ukraine

Tajikistan
The Former Yugoslav Republic of Macedonia
Uzbekistan

Annex C

World Oil Refining Logistics and Demand (WORLD) model definitions of regions

US & Canada

United States of America

Canada

Latin America

Greater Caribbean

Antigua and Barbuda
Bahamas
Barbados
Belize
Bermuda
British Virgin Islands
Cayman Islands
Colombia
Costa Rica
Dominica
Dominican Republic
Ecuador
El Salvador
Falkland Islands (Malvinas)
French Guiana
Grenada
Grenadines
Guadeloupe
Guatemala
Guyana
Haiti
Honduras
Jamaica
Martinique
Mexico
Montserrat
Netherlands Antilles
Nicaragua
Panama
St. Kitts & Anguilla
St. Lucia
St. Pierre et Miquelon
St. Vincent
Suriname
Trinidad & Tobago
Turks and Caicos Islands
Venezuela

Rest of South America

Argentina
Bolivia
Paraguay
Peru

Brazil
Chile
Uruguay

Africa

North Africa/Eastern Mediterranean

Algeria
Egypt
Lebanon
S.P. Libyan A.J.
Mediterranean, Other
Morocco
Syrian Arab Republic
Tunisia

West Africa

Angola
Benin
Cameroon
Congo, Democratic Republic
Equatorial Guinea
Gabon
Ghana
Guinea
Guinea-Bissau
Ivory Coast
Liberia
Mali
Mauritania
Niger
Senegal
Sierra Leone
Togo

East/South Africa

Botswana
Burkina Faso
Burundi
Cape Verde
Central African Republic
Chad
Comoros
Namibia
Réunion
Rwanda
Sao Tome and Principe
Seychelles
Somalia
South Africa

Djibouti
Ethiopia
Gambia
Kenya
Lesotho
Madagascar
Malawi
Mauritius
Mozambique
St. Helena
Sudan
Swaziland
United Republic of Tanzania
Uganda
Western Sahara
Zambia
Zimbabwe

Europe

North Europe

Austria
Belgium
Denmark
Finland
Germany
Iceland
Ireland
Luxembourg
Netherlands
Norway
Sweden
Switzerland
United Kingdom

South Europe

France
Greece
Italy
Portugal
Spain
Turkey

Eastern Europe

Albania
Bosnia and Herzegovina
Bulgaria
Poland
Romania
Serbia

Croatia
Czech Republic
Hungary
Montenegro
Slovakia
Slovenia
The Former Yugoslav Republic of Macedonia

FSU

Caspian Region

Armenia
Azerbaijan
Georgia
Kazakhstan
Kyrgyzstan
Tajikistan
Turkmenistan
Uzbekistan

Russia & Other FSU (excluding Caspian region)

Belarus
Estonia
Latvia
Lithuania
Moldova
Russia
Ukraine

Middle East

Bahrain
I.R. Iran
Iraq
Jordan
Kuwait
Oman
Qatar
Saudi Arabia
United Arab Emirates
Yemen

Asia-Pacific

OECD Pacific

Australia
New Zealand
Japan
Republic of Korea

Pacific High Growth – non OECD Industrializing

Brunei Darussalam
Hong Kong, China
Indonesia
Malaysia
Philippines
Singapore
Chinese Taipei
Thailand

China

Rest of Asia

Afghanistan
Bangladesh
Bhutan
Cambodia
Christmas Island
Cook Island
Fiji
French Polynesia
Guam
India
Democratic People's Republic of Korea
Lao People's Democratic Republic
Macao
Maldives
Mongolia
Myanmar
Nauru
Nepal
New Caledonia
Pakistan
Papua New Guinea
Solomon Islands
Sri Lanka
Timor
Tonga
Vietnam
Wake Islands

Annex D

Major data sources

American Petroleum Institute

Baker Hughes

Bank for International Settlements

BP Statistical Review of World Energy

Central Banks' reports

C1 Energy Limited

Canadian Energy Research Institute

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Consensus forecasts

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Hart Downstream Energy Services, Refinery Tracker

Hart's World Refining & Fuels Services

Haver Analytics

IEA, Quarterly Energy Prices & Taxes

IHS/Cambridge Energy Research Associates

IHS Global Insight, online database

IHS Global Insight, Future Powertrain Technologies: The Next Generation Update, 2015 to 2025, Final Report

IHS Herold

IHS Petroleum Economics and Policy Solutions database

IMF, Direction of Trade Statistics

IMF, International Financial Statistics

IMF, World Economic Outlook

Intergovernmental Panel on Climate Change

International Banks' reports

International Civil Aviation Organization (ICAO), ICAO's data set, http://www.icao-data.com

International Fuel Quality Centre

International Oil Companies, Annual Reports

International Road Federation, World Road Statistics

Markit Economics

National Oceanic & Atmospheric Administration, Monthly Climatic Data for the World

OECD Trade by Commodities

OECD/IEA, Energy Balances of non-OECD countries

OECD/IEA, Energy Balances of OECD countries

OECD/IEA, Energy Statistics of non-OECD countries

OECD/IEA, Energy Statistics of OECD countries

OECD, International Trade by Commodities Statistics

OECD, National Accounts of OECD Countries

OECD, OECD Economic Outlook

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OPEC Monthly Oil Market Report

OPEC, Who gets what from imported oil, 2009

OPEC World Oil Outlook, 2009

Plunkett Research, Automotive Industry Introduction, 2009

Purvin & Gertz, Global Petroleum Market Outlook – Petroleum Balances

Renewable Energy Policy Network for the 21st Century

Renewable Fuels Association

Society of Petroleum Engineers

Tanker Broker's Panel, London

The Conference Board

The Economist

Turner, Mason & Company

UN, Department of Economic and Social Affairs, online database

UN, Energy Statistics

UN, International Trade Statistics Yearbook

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UN Statistical Yearbook

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Wood Mackenzie

World Nuclear Association

World Oil

World Resources Institute, http://earthtrends.wri.org

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Yahoo Finance

Organization of the Petroleum Exporting Countries
Helferstorferstrasse 17
A-1010 Vienna, Austria
www.opec.org
ISBN 978-3-9502722-1-5

OPEC Secretariat
Helferstorferstrasse 17
A-1010 Vienna, Austria
www.opec.org
ISBN 978-3-9502722-1-5