OPEC

World Oil Outlook

2009

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 now 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

The past year has been one of much upheaval as the world faced a massive financial crisis and an ensuing deep economic contraction; one not witnessed since the 1930s. The implications have stretched far and wide, with its ripple effects carrying it far beyond the country where the crisis originated. It has ushered in some extraordinary changes in such a short period of a time.

And of course for the oil market in general and, OPEC in particular, the adverse impacts were dramatic too. This is especially evident when looking at oil price movements over the past year, with the OPEC Reference Basket price hitting highs of over $140/b in July 2008, before falling by more than $100 to below $40 only six months later. And this volatility could have been even more extreme without OPEC taking timely and proactive measures, both when prices were heading up, as well as down.

Few could have predicted the rapid and widespread adverse impacts that resulted from the US sub-prime mortgage crisis. Over-leverage, poor risk management, greed and speculation drove the financial system to the edge of a total meltdown when Lehman Brothers collapsed in September 2008. Whilst it is apparent that the world has now stepped back from the abyss, the lessons need to be taken on board.

From an oil market perspective, OPEC has clearly stated that the high oil prices in the middle of 2008 were not justified by physical supply and demand fundamentals. Price movements were exacerbated by massive direct and indirect investment inflows by non-commercial players looking to gain exposure to commodity markets. This was facilitated, among other things, by the possibility of high leverage and the absence of a cap on speculative activity.

OPEC has repeatedly called for better regulation and increased transparency in these markets, for the benefit of both producers and consumers alike. This call had a prominent place in the foreword of last year's WOO. There is evidently a need for this to be repeated here.

In putting together this year's publication, a number of important questions focused on the current crisis, in particular, just how long and deep this recession may be, and which path the economic recovery might follow. At present, despite the bold fiscal and monetary intervention from governments, global economic conditions remain gloomy, although some 'green shoots' have recently appeared. In addition, the potential impacts of government intervention, especially in the medium-term, in such areas as inflation, interest rates or the actual solvency of some countries, are difficult to predict. Perhaps the most important question, however, is whether this recession is a game-changer that indeed brings about profound changes in the longer term, much as happened after the Great Depression.

It is not the role of this publication, however, to delve into the details of such important potential developments and their implications. It concentrates on exploring the possible developments of oil supply and demand.

OPEC, as an Organization, has maintained its commitment to ensure stable supplies of crude oil to the market at all times, undertaking an ambitious programme of investment, aware of the importance of responding to the demand for its crude in a timely manner, while offering an adequate level of spare capacity. However, it is not without concern that the Organization observes a repetition of the past, where a large drop in oil demand leads to damagingly high levels of unused capacity.

Nevertheless, we also believe in the widely held view that low oil prices are not sustainable. The levels for most of the first half of 2009 were considerably below that required to attract industry-wide investments and ensure sufficient production capacity to meet future demand. Stable and fair prices should take into account energy supply, demand and investments, including such core issues as costs and human resources, over all timeframes.

And this is obviously true across the entire energy industry. Each energy source, each technology, and each project, has a price when it is viable; and a price when it is not.

The significance of this can be viewed when weighing up expected demand in the longer term. Whilst it is obvious that oil demand levels will drop in the short- to medium-term — leading to a rise in overall spare capacity — looking further out, demand will rebound again, particularly as the global economy recovers. And with oil, and fossil fuels in general, expected to retain their preeminence in the global energy mix it is essential that the petroleum resources, of which there are plenty, are developed in a timely manner. This will provide consumers with required supplies, producers with stable and adequate revenues for their non-renewable natural resources and investors with fair returns.

The WOO 2009 also underscores other drivers of uncertainty concerning future oil demand requirements. This year there are a number of downside risks stemming particularly from the global economy, unreliable market signals and major policy developments.

Whilst OPEC welcomes diversity in the overall energy mix, including renewables and nuclear, we need to give careful thought to how we proceed. The uncertainties are a major challenge for oil producers in general and OPEC Member Countries in particular. This is clearly illustrated in the demand and investment uncertainties explored in this year's WOO.

On the issue of climate change, 2009 is viewed as an important milestone, with the ongoing negotiations within the United Nations Framework Convention on Climate Change and its Kyoto Protocol. This year's WOO illustrates again the historical responsibility of developed countries regarding the state of the Earth's atmosphere. They account for the majority of cumulative greenhouse gas emissions and developing countries should be left to focus on evolving their economies, and eradicating poverty. In addition, developed countries, having the financial and technological capabilities, should take the lead in mitigation and adaptation.

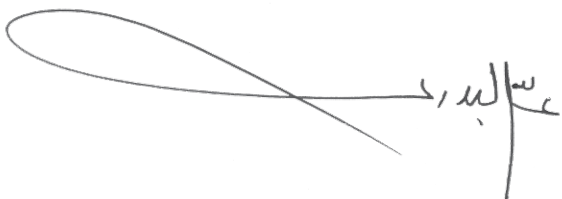
It is also essential for the industry to maintain its commitment to the sector's skills base, the backbone of the industry. The spotlight needs to be on keeping the younger generation interested and motivated. And then there is the importance of remaining committed to advancements in the research, development and deployment of technology. In particular, the focus needs to be on the early development and deployment of cleaner fossil fuel technologies, such as carbon capture & storage.

The overall goal is a stable and enabling environment to continue to develop, produce, transport, refine, deliver and use oil in an ever more efficient, environmentally-friendly and economic manner, to the benefit of both producers and consumers.

With this in mind, it is evident over the past year that the goalposts have shifted somewhat. The growing need for what some term 'counter-cyclical' action to help offset the market's cyclical behaviour has come to the fore, in both the global economy and the international oil market. This can be viewed in the announced stimulus packages to counteract the recession, and OPEC's actions focused on maintaining oil market stability. The upshot is that there is now an increasing consensus that markets need to function more efficiently, in terms of price discovery, risk management and liquidity, and appropriately reflect the true state of the physical supply and demand fundamentals.

Pointing a way forward is never an easy task, and it is important to stress that the WOO is not about predictions, but a means of presenting information and concepts across various key energy issues. It would be impossible to formulate one single direction for the energy future The WOO 2009 points at increasing interdependencies among all stakeholers. This is one reason that OPEC continues to stress the importance of a positive and constructive dialogue between producers and consumers.

The publication's goal is to provide a useful reference guide for the coming year: it is an important tool that helps further the common interest among all stakeholders for energy market stability as we look to bring more clarity to the oil market and develop solutions and ways forward in the years ahead.



Abdalla Salem El-Badri
Secretary General

Executive summary

The year that has passed between the publication of the 2008 edition of the World Oil Outlook (WOO) and the finalization of this year's has been one of unprecedented turbulence. Oil prices have roller-coastered: starting 2008 at US$92/b, the OPEC Reference Basket rose to a record $141/b in early July before falling to $33/b by the end of the year, the lowest level since summer 2004. The central element linked to this collapse in oil prices, of course, was the global financial crisis that originated in the US, and the ensuing deep recession in Organisation for Economic Co-operation and Development (OECD) countries and sharp slowdown of economic activity in developing countries. This, in turn, has choked demand for oil. Against this backdrop, a host of new challenges have arisen in preparing this outlook.

One of these challenges relates to assumptions for future price developments. For the Reference Case, the oil price assumption is the perception of the behaviour of upstream costs in general, and in particular, the cost of the marginal liquids barrel. Already in last year's reference case, the long-term real price assumption reflected the expectation that high costs would eventually peak and then decline as cyclical elements separate from structural ones. This has already started to occur. Over the projection period, nominal prices are assumed to stay in the range $70–100/b. However, it is important to note that this is an assumption, and does not reflect or imply any projection of whether such a price path is likely or desirable.

The assumptions made for economic growth for the medium- and long-term consider the potential depth and length of the global economic contraction. This includes the lessons learned from past recessions in OECD countries, and the possible implications of the responses by governments and monetary institutions around the world, in particular in terms of expansionary policies and monetary easing. There is a growing perception that the economic slowdown will be 'U-shaped', that is the recovery will gather momentum only gradually. Although the timing and strength of the recovery remain uncertain, for the Reference Case, it is assumed that the end of 2009 represents the bottom of the cycle, with the global economy actually contracting. In 2010, recovery is underway, but far from complete, and gains momentum in 2011. By 2012, the Reference Case assumes that economic growth is back to trend values.

Long-term world economic growth assumptions in the Reference Case are based upon demographic trends and productivity growth assessments. The strongest growth is expected in developing countries and regions, in particular China and South Asia, which expand at an average rate of 6.3% per annum (p.a.) and 4.7% p.a. respectively over the period 2009–2030. The average rate for global growth is 3% p.a. over the same timeframe. This is lower than the figure appearing in the previous WOO. This is partly due to the considerable downward revisions to economic growth prospects as the global financial crisis has evolved. Another reason is that the average growth for the world is calculated using updated purchasing power parity factors, which means that the weight is reduced for some of the fast growing developing countries, such as India and China.

Another major issue to address in developing the Reference Case is the extent to which energy policies are introduced into the outlook. In this year's Reference Case, two sets of policies have been incorporated: the United States (US) Energy Independence and Security Act (EISA), which has been passed into law, and the European Union's (EU) climate and energy legislative package, for which related directives have now been adopted by both the EU Council and the European Parliament.

Under all scenarios, energy use is set to rise. In the Reference Case, it increases by 42% from 2007–2030. Developing countries will account for most of these increases, by virtue of higher population and economic growth. However, energy use in developing countries will remain much lower on a per capita basis. Globally, renewable energy will continue to grow fast, but from a low base. Nuclear grows faster than in the previous outlook, while hydropower is also set to expand. Realistically, however, fossil fuels will continue to satisfy most of the world's energy needs, contributing more than 80% to the global energy mix over this period. And oil will continue to play the leading role to 2030.

The medium-term prospects for oil demand are adversely impacted by the lower economic growth assumptions. OECD oil demand falls from 47.5 mb/d in 2008 to 45.5 mb/d by 2010, and remains at that level to 2013. The main source of incremental oil demand will be developing countries. However, given the anticipated slow recovery, the annual increments in demand for 2010 and 2011 are below that of 2012, once economic growth is assumed to return to its trend potential. This, in total, represents a major reassessment from the previous reference case. By 2013, oil demand is 5.7 mb/d lower than in last year's outlook, with a difference of more than 4 mb/d already witnessed in 2009.

As we look further into the future, oil demand patterns become increasingly influenced by the implementation of policies. Efficiency improvements are stronger than previously assumed, and this, compounded with the downward revision to medium-term expectations due to the global recession, has led to a significant downward adjustment to oil demand in the longer term. Oil demand in the Reference Case is less than 106 mb/d in 2030, down from 113 mb/d last year.

Developing countries are set to account for most of the long-term demand increase, with consumption rising 23 mb/d over the period 2008–2030 to reach

56 mb/d. Almost 80% of the net growth in oil demand from 2008–2030 is in developing Asia. Nevertheless, per capita oil use in developing countries will remain far below that of the developed world. For example, oil use per person in North America will still be more than ten times that of South Asia. OECD oil demand falls over the entire projection period, having 'peaked' in 2005.

The transportation sector is the main source of future oil demand growth, accounting for over 60% of the total increase to 2030, although it is also lower than the previous year's assessment, due again to the current global economic slowdown, as well as the assumed greater efficiency improvements. The total stock of cars rises from just over 800 million in 2007 to well over 1.3 billion by 2030, with three quarters of this increase coming from developing countries. Car ownership per capita in developing countries rises rapidly from a low base of just 31 cars per 1,000 people in 2007 to 87 per 1,000 by 2030. This remains well below OECD levels, however, which average 530 per 1,000 by 2030. The expansion in commercial vehicles in developing countries is also stronger than elsewhere, accounting for over 80% of the increase.

Oil use is at the heart of much industrial activity. In addition to the petrochemicals industry, diesel and heavy fuel oil, in particular, are needed in construction and other major industries such as energy, iron and steel, machinery and paper. The strongest increase in the industry sector comes from developing Asia and OPEC Member Countries, particularly due to the fast growing oil demand for petrochemicals.

On the products side, the continuing shift to middle distillates over the entire period remains a dominant feature of the future demand slate. This is clearly reflected in the fact that out of 20 mb/d of additional demand by 2030, compared to 2008, almost 60% is for middle distillates.

Turning to supply, total non-OPEC oil supply is expected to continue to rise slightly over the medium-term, increasing by just over 1 mb/d for the years 2008–2013. This increase comes mainly from non-conventional oil. Non-OPEC crude oil plus natural gas liquids (NGLs) are expected to stay flat over this period, reaching a level in 2013 that is more than 3 mb/d below last year's reference case. This downward revision is largely the result of lower oil prices leading to cancellations and delays, debt financing becoming more difficult and lower earnings limiting equity finance. Non-conventional oil, mainly Canadian oil sands, continues to grow in the medium-term, but again the low oil price environment has dampened growth prospects compared to the previous outlook.

The Reference Case thereby points to demand for OPEC crude oil, having fallen in 2009 in the face of the global global economic contraction, thereafter rising slowly over the medium-term, returning back to 2008 levels by around 2013. Large investments are currently underway in OPEC Member Countries to expand upstream capacity. Although a low price environment may lead to the delaying or even postponing of some projects beyond 2013, spare OPEC crude oil capacity is nevertheless set to remain at comfortable levels. In the Reference Case, OPEC upstream development investment requirements to 2013 amount to around $110–120 billion.

In the long-term, total non-OPEC oil supply continues to rise as the increase in non-crude sources is stronger than the slight decline in total non-OPEC crude supply. Up to 2020, crude production increases in Russia, the Caspian and Brazil largely compensate for declines in the OECD. Non-conventional oil supply (excluding biofuels), mainly from Canadian oil sands, rises in the Reference Case by 4 mb/d from 2008–2030. The Reference Case also sees strong biofuels growth. On top of this, OPEC and non-OPEC NGLs are expected to grow. As a result of these developments, the amount of OPEC crude that will be needed continues to rise, reaching just over 41 mb/d by 2030, albeit some 2.5 mb/d lower than last year's reference case.

The expansion in Reference Case demand is largely met with non-crude supply from both OPEC and non-OPEC sources, leaving the contribution of crude only modest. Indeed, while global crude oil supply in 2015 is 71 mb/d, the same as 2008, by 2030 there is only a need for 77 mb/d. The resource base of conventional crude, together with non-conventional oil, is more than sufficient to meet future demand. Therefore, the key issue is not related to availability, but to deliverability and sustainability, as well as the uncertainties surrounding the extent to which increases in the demand for crude will actually materialize.

This points to the issue of investments along the entire supply chain, something that is crucial to both producers and consumers. Up to 2030, cumulative upstream investment requirements are estimated to amount to $2.3 trillion (2008 dollars) in the Reference Case. Costs have been sharply inflated since 2003, but a reversal, albeit still slow, has recently been observed, which might indicate a shift towards a new cost cycle. This has been factored into estimates for upstream investment requirements.

The possible implications of a recession that is deeper and longer than assumed in the Reference Case are explored in the Protracted Recession scenario. Risks for the global economy remain skewed toward the downside, despite recent economic data indicating a slowdown in the rate of contraction, and an improvement in business and consumer confidence. Interest spreads in the inter-bank lending markets have come down, but are still much higher than in 'normal' times. Risks stem in particular from possible delays in implementing policies to stabilize financial markets, the further deterioration of the health of banks that could lead to more tightness in credit availability, country rating downgrades, deflation dangers, and the insufficient access of emerging economies to foreign financing. In addition to the more pessimistic view of the rate of the global economic recovery, the Protracted Recession scenario also assumes that crude oil prices are significantly softer than in the Reference Case. In this scenario, world demand in 2013 is 2.4 mb/d lower than the Reference Case, with demand at 85.5 mb/d.

Low prices have significant impacts upon oil supply prospects, reducing both profitability and cash flows. Indeed, the first signs of a reaction to the recent oil price fall are appearing: the rig count has already fallen swiftly in the US, and a similar picture is emerging elsewhere. The link between price movements and upstream activity is nothing new. This has also been observed in the past. The economics of non-conventional oil supply would also be adversely affected by a prolonged soft price environment.

This scenario also has important implications on OPEC Member Country investment activity. Indeed, history has clearly shown the dilemma of having to make investment decisions in a climate of demand pessimism and low oil prices. OPEC Member Countries have concerns over the problem of security of demand, and the risk that large investments will be made in capacity that is not needed. The Protracted Recession scenario combines the mix of low oil prices, demand uncertainty, and significant initial levels of spare capacity, as a result of a tide of investments undertaken in the face of high oil prices. In this scenario, the additional element of the increased difficulty in securing credit compounds the investment hindrances.

In the Protracted Recession scenario, OPEC is assumed to respond to the increased demand for its oil as non-OPEC supply is reduced due to the low oil price, while upstream capacity investment is primarily focused on compensating for natural declines. Nevertheless, if non-OPEC supply continues to be affected through a lack of investment, then spare capacity in OPEC Member Countries would dwindle. The scenario suggests that spare capacity could be reduced to less than 3 mb/d by 2012 and below 2 mb/d by 2013. Should this tightness occur, prices must react. The lack of capacity that emerges is a result of the low prices that are assumed over the medium-term. This is similar to the period of low prices in 1998/1999 which was a driver for the capacity shortages that presaged the 2004–2008 price rise. In this scenario, history, to an extent, repeats itself, as low prices sow the seeds of unstable markets and price spikes.

The recent price turbulence, the ongoing global financial crisis, and many of the uncertainties that complicate upstream investment decisions are also relevant to the downstream. Rising oil prices from 2003–2008, together with refining tightness and high margins, have in recent years brought forward an increasing number of projects. However, several factors are now acting to delay, postpone or even cancel some projects. These include, among other things, the prospect of sharply reduced oil demand across almost all world regions, difficulties in arranging debt and equity financing and expectations of further falls in construction costs.

It is estimated that around 6 mb/d of new crude distillation capacity will be added to the global refining system from existing projects by 2015. Almost 50% of this new capacity is located in Asia, mainly China and India. In addition to distillation capacity, 5 mb/d of associated new conversion capacity and over 6 mb/d of desulphurization capacity is expected to be constructed worldwide from 2009–2015.

The implication of these capacity additions, in combination with demand projections and increases in non-crude supply, is for a sustained period of low refinery utilizations and hence, poor refining economics. In the Reference Case, the continuing increases in refineries' potential to run crude, and the slow return to positive additional required crude runs, result in the distillation capacity surplus widening to over 4 mb/d by 2010, and around 5 mb/d by 2012, where it remains for some years. If the current recession extends further than the Reference Case assumes, this surplus will evidently be even greater.

Indeed, in the Protracted Recession scenario the surplus crude run capability expands to well over 7 mb/d by 2014. The clear result is stronger downward pressures on refining margins. While last year's WOO foresaw that "an easing in the refining sector could begin as early as 2009 and intensify through 2010–2013", the results of this year's outlook go far beyond the effects previously envisaged, mainly due to the deep recession and the inclusion of policy impacts.

In the Reference Case, global crude runs will not have recovered to 2007 levels until sometime around 2015. And even when they do, it is expected that they will continue to rise slowly, so that by 2030 crude runs are only 9 mb/d above 2007 levels. On the basis that the Reference Case reflects the future, it is clear that the refining industry will face some major challenges and restructuring in order to maintain its viability.

The impacts are not, however, regionally uniform. As already identified in last year's WOO, the refining sector in the US & Canada is projected to be most impacted, by a combination of an ethanol supply surge, a decline in gasoline demand, as well as the continuing effects of dieselization in Europe that generates low-cost gasoline for US export. Based on the outlook, not only do crude throughputs in the US & Canada never recover to 2007 levels, they also steadily decline throughout the period to 2030.

Thus, it is expected that the OECD regions will suffer a seriously depressed period for refineries, especially those focused on gasoline rather than distillates. This indicates a need for widespread consolidation and closure to bring back operating rates and refinery viability. To examine this in more detail, a series of model cases to indicate the possible scale of the restructuring and consolidation needed were run as variants of the 2015 Reference Case. The results suggest that no less than 10 mb/d of closures, predominantly in the US & Canada, Europe and the OECD Pacific, are needed to restore utilization rates and refining margins to profitable levels.

The outlook in these three regions stands in stark contrast to that for developing regions, especially the Asia-Pacific. The vast majority of the refining capacity expansions to 2030 are projected to be in the Asia-Pacific and the Middle East, at around 10 mb/d and 3 mb/d respectively, out of a global total of 18 mb/d. Expansions in the Asia-Pacific are dominated by China with more than 5 mb/d.

In respect to conversion capacity, projections highlight a sustained need for incremental hydro-cracking as some 4.3 mb/d of the 5.4 mb/d of global conversion capacity requirements to 2030 — above existing projects — are for this process type. Conversely, recent substantial coking capacity additions together with expected declines in the supply of heavy sour crudes in the medium-term, is leading to a coking surplus. It means that coking additions only appear to be required after 2020. The requirements for catalytic cracking units are adversely impacted by declining gasoline demand growth and rising ethanol supply, especially in the Atlantic basin.

Substantial desulphurization capacity additions will be necessary to meet sulphur content specifications, with some 14.5 mb/d required to 2030, which is over and above existing projects of 6.4 mb/d. Taking these figures together, of the 21 mb/d of global desulphurization capacity additions from 2008–2030, more than 70%, or 15 mb/d, are for distillate desulphurization. The bulk of the remainder, 5 mb/d, is for gasoline sulphur reduction.

To have this capacity in place, the global refining system will require around \$780 billion (2008 dollars) of investment to 2030. The Asia-Pacific region should attract the highest portion of these investments.

Global oil trade, including crude oil, refined products, intermediates and non-crude based products, will see a moderate change in the period to 2015, recording less than a 2 mb/d increase from 2007–2015, rising from 52.5 mb/d to 54.6 mb/d. The same period, however, will experience a shift in the structure of this trade as crude oil exports are anticipated to decline by almost 1 mb/d, with the trade in oil products increasing by 3 mb/d. In the period beyond 2015, oil trade will resume its growth. By 2030, inter-regional trade increases by almost 12 mb/d, from 54.6 mb/d in 2015 to more than 66 mb/d by 2030. Both crude and products exports will increase from 2015–2030, but crude exports will gain bigger volumes than products. By the end of the forecast period, both crude and products exports will be approximately 7 mb/d higher than in 2007.

The tanker market is also exposed to a combination of the fallout from the current economic turmoil, stagnant medium-term demand for oil movements, even declining in the short-term, and a relatively large increase in tanker capacity over the next few years as a result of record order books. Longer term, growth in the inter-regional crude oil trade and refined products will necessitate increases in global tanker capacity. However, this is limited, with the global tanker fleet expected to expand by around 100 million deadweight tonnes, or 25%, by 2030, compared to its capacity at the end of 2008.

The estimations of price differentials points to a number of implications. A first and obvious consequence is that the excess refining capacity and excess gasoline output capability will lead to closures, especially of those refineries that are gasoline-oriented. Secondly, the projected differentials raise the question of how product demand will react. In this regard, several options exist that could alter the future demand pattern, such as higher naphtha demand in the petrochemical sector, increased demand for naphtha as a fuel, and shifting diesel demand back to gasoline, although the effects would likely be limited. A third and central question relates to refinery process technology as sustained wide differentials between naphtha/gasoline and diesel present incentives for adaptations and new developments in refinery processes and catalysts. These are aimed at converting surplus naphtha/gasoline to diesel either through the revision of fluid catalytic cracker operations or by converting naphtha more directly to diesel.

A principal theme that emerges from the outlook, in both upstream and downstream assessments, is cyclicality, with its ensuing challenges of making the appropriate investments in an environment of uncertainty and in an industry characterized by massive upfront capital requirements and long-lead times. This has been underscored as the current global financial and economic crisis has unfolded. The need for counter-cyclical measures to support stability in markets is now recognized more than ever.

It is evident from both the Reference Case and the Protracted Recession scenario that the overarching challenge facing the energy industry in general, and

OPEC in particular, stems from the large uncertainties about future demand levels for energy and oil. The uncertainties that lie ahead, and the corresponding difficulties associated with making appropriate and timely investment decisions, underline the importance of exploring other oil supply and demand paths outside of those depicted in the Reference Case. With this in mind, lower growth and higher growth scenarios have been developed.

In the *lower growth* scenario, downside demand risks from lower economic growth than in the Reference Case are coupled with a strong policy drive, over-and-above Reference Case assumptions, to further increase oil use efficiency in the longer term. In a *higher growth* scenario, the possibility of a swifter recovery from the global recession than assumed in the Reference Case is considered, combined with a more positive outlook for longer term growth prospects. The results show a wide range in OPEC upstream investment requirements. By 2020, investments under the *higher growth* scenario are $430 billion in real terms, whereas under the *lower growth* scenario they are just $180 billion. Even to 2013, which represents a timeframe over which investments are effectively locked in, requirements could be as low as $70 billion or as high as $170 billion.

In addition, there are various other challenges facing the oil industry. Clearly, for most individuals, businesses and governments, the dramatic changes to the economic landscape over the past year as the global financial crisis has unfolded are the current overriding concern. While the recession-driven demand destruction has demonstrated worries over security of demand, the current environment also clearly reveals the benefit of OPEC's counter-cyclical measures. For example, OPEC's substantial supply increase between 2002 and 2006 had a strong mitigating effect on pro-cyclical movements, when world demand sharply increased and non-OPEC supply declined. Reciprocally, OPEC's recent supply adjustment has had a similar effect in the face of the current deep global economic crisis and the ensuing steep oil demand decline.

The economic stimulus packages put in place are another example of the necessity of counter-cyclical policy measures. They demonstrate broad agreement on the requirement for sound regulation in financial markets. For oil, there is a need to improve the functioning of futures and over-the-counter (OTC) markets, by *inter alia*, upgrading the availability of, and access to information on paper oil market participants and transactions, better monitoring, imposing a cap on speculative activity, and strengthening regulations to close various loop-holes.

Further uncertainties and challenges include those related to upstream and downstream costs and the future availability of skilled human resources. On the cost issue, for the past few years, the oil industry has seen costs that have been significantly inflated, in part as a result of the low oil price environment and low margins ten years or so ago that led to the implementation of downsizing and cost-cutting strategies. While costs have fallen a little, the question is whether this cost behaviour is structural or cyclical. Regarding human resources, the past has shown that it is critical to maintain and enhance the adequacy of the industry's skills base, even during an economic downturn. There is a need to advance the numbers of students taking energy-related courses, and to make sure these are open to all students from across the world. More work needs to be done to help make the industry more attractive to employees, as well as to future graduates, including easing university enrolment across national boarders. To this end, further coordinated efforts should be undertaken by international oil companies, national oil companies, service companies, governments, regulators and academia.

The outlook points to rising environmental challenges. The oil industry has a good track record in reducing its environmental footprint. And with the world expected to rely essentially on fossil fuels for many decades to come, it is vital to ensure the early and swift development, deployment, diffusion and transfer of cleaner fossil-fuels technologies. This is true for both local and global environmental protection. The need to adapt to a carbon-constrained environment will make the use of these cleaner technologies all the more pressing. Of particular note is carbon capture and storage, a proven technology that has a high economic potential for mitigation. Developed countries, having the financial and technological capabilities, and bearing the historical responsibility for the state of the Earth's atmosphere, should take the lead in mitigation and adaptation efforts, as well as in providing technology and financial resources, as enshrined in the United Nations Framework Convention on Climate Change, its Kyoto Protocol and the Bali Action Plan.

Moreover, the outlook points to a broader set of challenges, such as the issue of sustainable development and its corollary, fighting energy poverty. It is important to remember that poverty eradication is the very first UN Millennium Goal. And a major part, as well as a catalyst in helping alleviate poverty, is making sure that every person has access to modern energy services. It is critical that the world community makes sure access to reliable, affordable, economically viable, socially acceptable and environmentally sound energy services is available to all.

Addressing all of these challenges should involve the strengthening and broadening of the dialogue between energy producers and consumers, in particular through the International Energy Forum. Cooperation among national, international and service companies should be enhanced, and should encompass, *inter alia*, the development, deployment and transfer of more advanced upstream and downstream technologies.

Section One

Oil supply and demand outlook to 2030

Chapter 1

World energy trends: overview of the Reference Case

Main assumptions

Oil price

The year that has passed since the publication of last year's World Oil Outlook (WOO) and the finalization of this year's has been one of unprecedented turbulence. Oil prices have roller-coastered: starting 2008 at US$92/b, the OPEC Reference Basket rose to a record $141/b in early July before falling to $33/b by the end of the year, the lowest level since summer 2004. The central element linked to this freefall, of course, was the financial crisis that originated in the US before spilling over to most other countries, which has led to rapidly deteriorating global economic conditions and prospects. This in turn has choked demand for oil. For the first time since the early 1980s, world oil demand contracted in 2008, by 0.3 mb/d, and it is expected to further decline by a hefty 1.4 mb/d in 2009, according to OPEC's April Monthly Oil Market Report (MOMR). The rapidly softening fundamentals, with burgeoning stock levels accompanied by a rise in production capacity in OPEC Member Countries has clearly contributed to the drop in oil prices. This is in addition to the now recognized fact that the unsustainably high price levels observed in the middle of 2008 were to a large extent due to significant speculative investment inflows in oil and product futures and over-the-counter (OTC) markets.

Against this backdrop, a host of new challenges have also arisen, and the input assumptions for OPEC's World Energy Model (OWEM), which is used to prepare the outlook. This is clearly borne out in the assumptions that need to be made concerning future price developments.

Although at present attention is inevitably fixed upon the low oil price environment, falling demand, and rising levels of unneeded capacity, it is important that the lessons learnt from the surge in prices to record levels in mid-2008 are not forgotten. The rise was not purely related to how supply and demand fundamentals were evolving – indeed, throughout the period of high oil prices, the market was always well supplied. It is important, therefore, to recognize the role played by regulated futures markets and unregulated OTC exchanges in driving the crude oil price, in particular through increased — though difficult to monitor — speculative activity. The emergence of oil as an asset class contributed significantly to the price volatility seen in the recent past. Indeed, at the Jeddah Energy Meeting of June 2008, it was already evident that there were widespread calls for improved financial market regulation. In addition, the ongoing financial turmoil has also provided more broad-based evidence of the possible adverse impacts of loosely regulated financial markets.

This is not to say, however, that fundamentals played no role over that period: as part of the explanation for the oil price rise stems from the low oil prices that prevailed for much of the 1980s and 1990s. This meant that investments were scaled down and cost-cutting strategies were implemented, leading to reductions in skilled labour, in the number of graduates in energy-related fields, and in research & development (R&D) investments. These low oil prices were bad for the oil industry, and in the longer term they were also bad for consumers, when the world was caught unprepared for the dramatic surge in energy demand in 2003–2004, and the emergence of developing countries as the key engine of commodity demand growth.

Thus, one lesson for the low oil price environment at the beginning of 2009 is that fundamentals are not necessarily fully reflected in oil price movements, whether upwards or downwards, and therefore an extrapolation can be misleading. To some extent, non-commercial investor activity in oil futures is necessary to provide liquidity and facilitate market price discovery and risk hedging functions. However, when left unchecked and with no cap, their activity tends to exacerbate price movements and weakens their correlation with fundamentals, especially when faced with such an uncertain environment as today. And as mentioned, low prices have historically sown the seeds of later price rises.

The decision in Oran, Algeria, in December 2008, to further reduce OPEC supply by a total of 4.2 mb/d against the September 2008 level reflects a decisive effort by OPEC Member Countries to restore oil market stability. Similar action has been seen elsewhere. In the face of falling demand, production has been cut in other industries to try to avoid a damaging build-up of inventories. This has occurred, for example, in the steel, lead, zinc, copper, automotive and electronics industries.

In making a long-term oil price assumption for the WOO's Reference Case, a key determinant is the perception of the behaviour of upstream costs and the cost of the marginal liquids barrel. In last year's reference case, the long-term real price assumption reflected the expectation that high costs would eventually peak and then decline as cyclical elements separate from structural ones. This has already started to occur. For the next decade, nominal prices are assumed to be in the range \$70–100/b. These are only assumptions and do not reflect any price path that could be considered likely or desirable. However, as we move forward, it is acknowledged in this Reference Case that two structural elements are likely to play a role in pushing upstream costs higher. On the one hand, the increasingly harsher conditions in developing and producing the marginal barrel and, on the other, the likelihood that, in the longer term, some environmental externalities will be internalized by way of regulation.

Medium-term economic growth

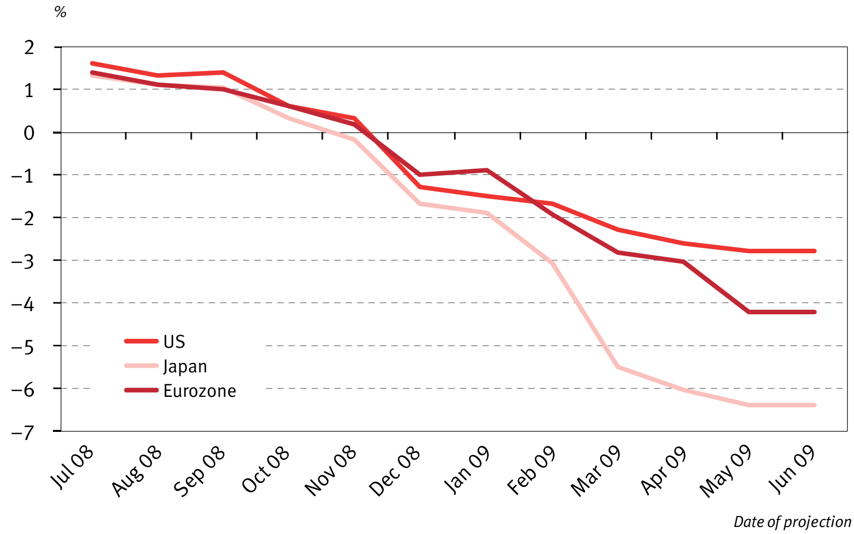
Given the current exceptional economic and oil market conditions, this year's WOO places additional emphasis upon the medium-term prospects for oil demand and supply. What has emerged as the central element affecting demand prospects for the medium-term is the global financial crisis, the resulting sharp contraction in the Organisation for Economic Co-operation and Development (OECD) countries' economic activity and the ensuing dramatic slowdown in output growth of the developing countries (DCs). The current contraction cycle could already be characterized as the deepest, the longest and the mostly wide spread since the Second World War.

All institutions, including OPEC, have revised downward drastically their projections for Gross Domestic Product (GDP) and oil demand growth in 2009. Figure 1.1 illustrates the rapid reassessment for short-term economic growth in the OECD. In the July 2008 edition of the OPEC MOMR, real GDP growth for 2009 in the three OECD regions was expected to be in the range 1.3–1.6%, but by June 2009 the US, the Eurozone and Japanese economies were expected to shrink by 2.8%, 4.2% and 6.4% respectively. Over this period, developing country growth expectations have also been dramatically lowered.

Despite some recent data signalling a slowdown in the rate at which economic output is deteriorating and a gradual return of confidence in financial markets, the consensus among macroeconomic forecasters remains that the economic slowdown will be 'U-shaped' rather than 'V-shaped', in other words the recovery will gather momentum only gradually.[1] Much rests on the success of the bold monetary and fiscal measures undertaken by governments to restore confidence in the banking sector and to provide stimulus to the economy.

Despite the generally positive response to these measures, the possibility of a lengthier global recession cannot be ruled out (this is explored in Chapter 4). For the Reference Case, however, it is assumed that the second half of 2009 represents the bottom of the cycle, with the global economy beginning to recover by the end of this year. In 2010, recovery is underway, but far from complete with OECD growth, for example, projected at just 0.4%, and DCs at 4.6%, both below trend growth values (see Table 1.1). By 2011, the growth is approaching the rates that had been supposed previously, and by 2012 the recession is assumed to be over, with growth now the same as in the previous reference case. A major question surrounds how liquidity injection, quantitative easing, fiscal incentives and

Figure 1.1
GDP growth forecasts for 2009: coming down fast



Source: OPEC MOMR, various issues.

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

	2009	2010	2011	2012	2013	2009–2013
North America	−3.0	0.5	1.7	2.6	2.6	0.9
Western Europe	−4.1	0.3	1.5	2.0	2.0	0.5
OECD Pacific	−5.2	0.2	1.5	2.0	2.0	0.1
OECD	**−3.8**	**0.4**	**1.6**	**2.2**	**2.2**	**0.6**
Latin America	−0.7	2.4	3.0	3.3	3.2	2.3
Middle East & Africa	1.7	3.3	3.3	3.5	3.5	3.1
South Asia	5.1	5.0	5.4	5.4	5.3	5.1
Southeast Asia	−1.6	2.5	3.3	3.8	3.8	2.4
China	7.0	7.3	7.7	7.7	7.7	7.4
OPEC	0.9	3.5	3.6	3.6	3.7	3.2
DCs	**2.9**	**4.6**	**5.1**	**5.2**	**5.3**	**4.6**
Russia	−4.7	2.5	3.0	3.3	3.2	1.7
Other Europe	−3.7	1.5	2.6	3.2	3.2	1.8
Transition economies	**−4.2**	**2.1**	**2.8**	**3.3**	**3.2**	**1.7**
World	**−1.3**	**2.1**	**3.0**	**3.5**	**3.5**	**2.3**

other growth stimulus measures taken today will affect medium- and even long-term inflation, interest rates, country ratings, productivity and thus growth potential. The possibility of a prolonged adverse impact upon economic growth cannot be ruled out. This is explored in the context of analyzing downside uncertainties in Chapter 5.

Table 1.2 documents the revisions that have been made for the 2009–2011 GDP growth assumptions, compared to the reference case appearing in the WOO 2008. The changes result in a cumulative loss in GDP of 8% compared to the previous assumption for the OECD, 11% for transition economies, and 4% for developing countries.

Table 1.2
Changes to real GDP growth Reference Case assumptions in the medium-term compared to WOO 2008

% p.a.

	2009	2010	2011
OECD	–6.0	–1.9	–0.7
DCs	–3.0	–0.9	0.0
Transition economies	–9.1	–1.8	–0.5

Long-term economic growth

Demographics

There are many important linkages between economic growth and demographics. Population growth rates, together with changes in age structure, affect the pool of working age people, and the resulting labour force expansion is a key determinant of economic growth potential. Population growth can also bring with it economies of scale that can contribute to the potential. However, there are also demographic-related hindrances to an economy. Age structure changes have a host of implications, for example, related to health care costs, state pension expenditures and savings rates, and feasibly, as a consequence, interest rates. There is also a concern that population growth that is too strong can be an obstacle to sustainable development. For all of these reasons, as well as the possible result of demographic developments on energy demand, it is important to look at the expected population growth patterns over the period to 2030.

Since 1970, the world's population has risen by more than three billion to reach the current level of 6.8 billion people. The population growth rate, however, has been steadily declining in all world regions and this slowdown will continue in the future, at least over the projection period to 2030. As can be seen from Table 1.3, the rate of expansion of the world's population throughout the 1980s and 1990s averaged close to 2% per annum (p.a.), but this fell to 1.4% p.a. over the period 1990–2007. World population is expected to grow by an average of 1% p.a. over the years to 2030, reaching 8.3 billion, an increase of 1.6 billion from 2007. These figures are based upon the medium variant projections from the United Nations Department of Economic and Social Affairs (UNDESA). Practically all of this growth will occur in developing countries. Some world regions will even experience declining population levels, mainly due to low fertility rates, with the OECD Pacific seeing a fall in its aggregate population within the next decade. It should also be noted that the population of some transition economies, including Russia, is already contracting (Figure 1.2).

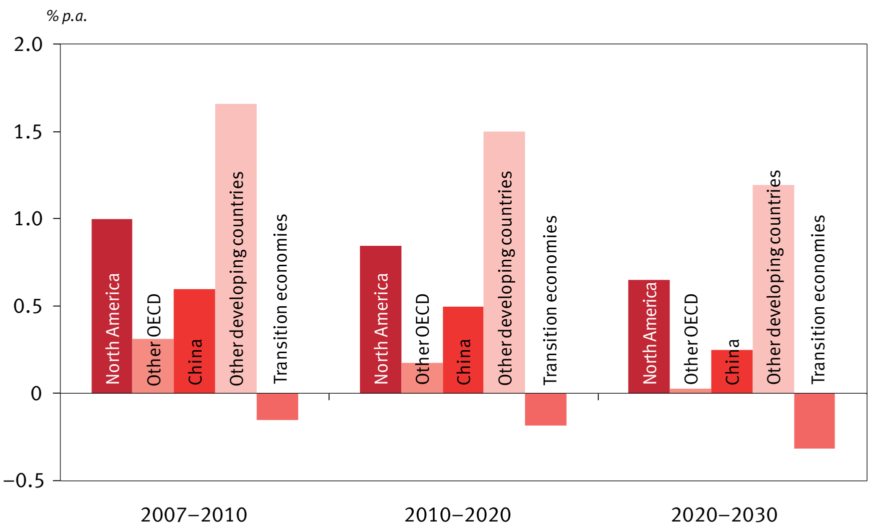
Demographic projections are couched in relatively robust terms. Firstly, the population over the next two decades will predominantly consist of those already alive. Secondly, birth and death rates tend to change slowly, and perceptible trends

Table 1.3
Population levels and growth

	Levels *millions*		Growth *millions*	Growth *% p.a.*		
	2007	**2030**	**2007–2030**	**2007–2030**	**2007–2015**	**2015–2030**
North America	451	539	88	0.8	0.9	0.7
Western Europe	541	567	27	0.2	0.3	0.1
OECD Pacific	201	197	–4	–0.1	0.1	–0.2
OECD	**1,193**	**1,304**	**111**	**0.4**	**0.5**	**0.3**
Latin America	421	526	106	1.0	1.2	0.9
Middle East & Africa	821	1,302	481	2.0	2.2	1.9
South Asia	1,567	2,078	511	1.2	1.5	1.1
Southeast Asia	630	783	153	0.9	1.2	0.8
China	1,329	1,458	129	0.4	0.6	0.3
OPEC	378	553	175	1.7	1.9	1.5
DCs	**5,145**	**6,700**	**1,555**	**1.2**	**1.3**	**1.1**
Russia	142	123	–18	–0.6	–0.5	–0.6
Other transition economies	196	196	0	0.0	0.1	0.0
Transition economies	**338**	**320**	**–18**	**–0.2**	**–0.2**	**–0.3**
World	**6,676**	**8,323**	**1,648**	**1.0**	**1.1**	**0.9**

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

Figure 1.2
Average annual population growth rates



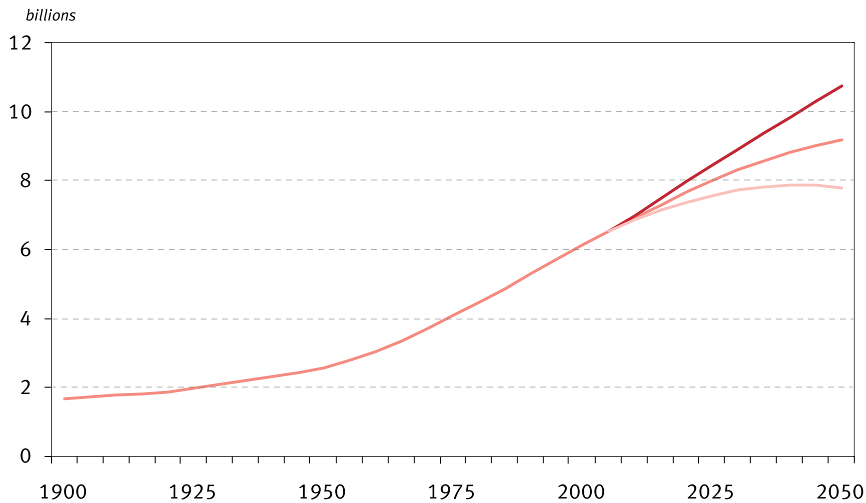
Source: UNDESA, Population Division.

are embodied in these projections. Nevertheless, it is worth noting that, although demography is a relatively exact discipline, it is subject to a number of uncertainties. In particular, alternative feasible projections of fertility rates can give rise to markedly different future population figures. Figure 1.3 illustrates the low and high variants of the United Nations (UN) population forecasts, as well as the medium variant used in the Reference Case. The figures vary only due to alternative assumptions for fertility patterns.[2] The figure extends to 2050 to illustrate the full range of expectations.

For the period to 2030, the average growth in the low variant is 0.7% p.a., while the high variant case sees average growth of 1.3% p.a. Thus, with these variants the aggregate population is subject to a +/–0.3% p.a. deviation that will contribute to uncertainty over future energy demand patterns. This points to a difference in expected world population between the high and low variants of 1.2 billion in 2030 and around 3 billion by 2050. This is often overlooked.

In OECD countries, the proportion of the population that is of working age (defined as people aged 15–64 years old) is currently around 67%. However, this figure is already shrinking, as the ageing of the population continues. This means that the

Figure 1.3
UN projections of world population to 2050: high, medium and low variants



Source: UNDESA, Population Division.

available labour force in Western Europe will begin to decline before total population starts to fall, while the labour force percentage in the OECD Pacific is already decreasing. North America continues to experience labour force growth, a key element in expectations for stronger future GDP growth in North America relative to other OECD regions. Over the period to 2030, the North American workforce is expected to increase by 32 million, while the rest of the OECD will decline by 29 million. According to UN calculations, by 2030, the share of the working age population in the OECD will be down to 62%. This decline may, to an extent, be mitigated by increases in the retirement age, made all the more likely given the continuous rise in average life expectancy.

In developing countries, the labour force is set to grow. The key exception to this is China, where the share of the working age population will fall from the current level of 72% to 67% by 2030. Taken together with the total population growth, this implies that the Chinese labour force will begin to shrink after 2015. Other developing country regions will see the share of the working population gradually rise, as predominantly young populations see a more rapid rate of workforce entry than the rate of retirement. Russia and other transition economies, on the other hand, will continue to see a diminishing workforce share in the total population. Figure 1.4 demonstrates these projections in terms of average annual growth rates.

Figure 1.4
Average annual growth rates of working age populations

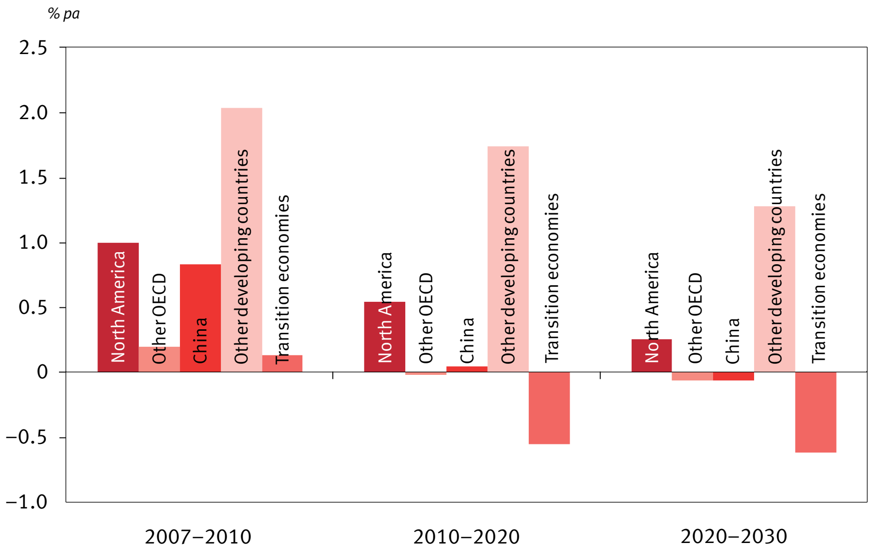
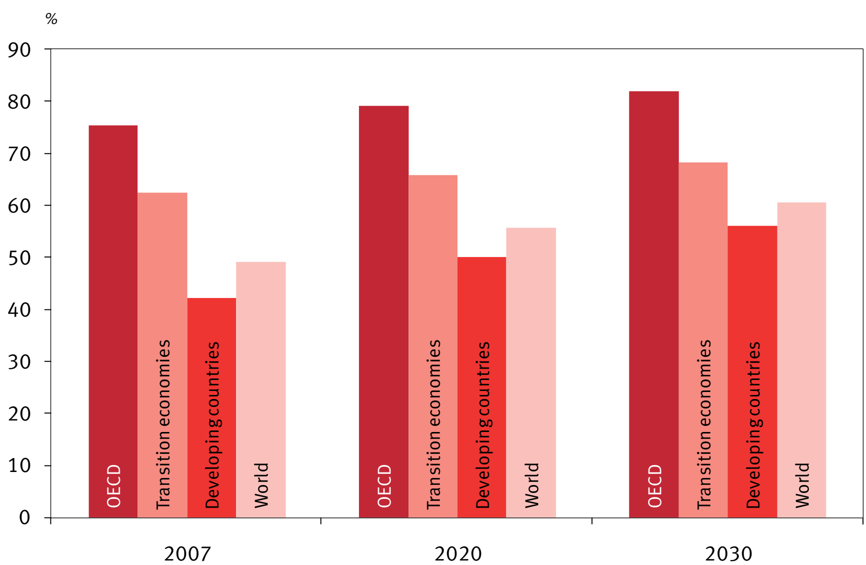


Figure 1.5
Urban population as percentage of total



Source: *UNDESA, Population Division.*

Chapter 1

Table 1.4
Population by urban/rural classification

millions

	2007		2030		Increase 2007–2030	
	Urban	Rural	Urban	Rural	Urban	Rural
North America	364	87	469	70	105	–16
Western Europe	391	150	444	123	54	–27
OECD Pacific	145	56	155	41	10	–15
OECD	**900**	**293**	**1,069**	**235**	**169**	**–58**
Latin America	343	77	463	63	120	–15
Middle East & Africa	314	506	660	642	346	135
South Asia	455	1,112	866	1,213	394	117
Southeast Asia	287	344	488	295	203	–50
China	537	792	879	579	342	–213
OPEC	231	147	404	149	148	27
DCs	**2,168**	**2,978**	**3,760**	**2,940**	**1,554**	**1**
Russia	103	38	94	29	–9	–9
Other trans. economies	108	88	124	72	11	–10
Transition economies	**211**	**127**	**218**	**101**	**2**	**–20**
World	**3,279**	**3,397**	**5,047**	**3,276**	**1,724**	**–77**

Source: UNDESA, Population Division.

There will also be a strong shift in the population distribution between rural and urban areas. Today, half of the world lives in cities and towns, and the proportion is set to rise to more than 60% by 2030 (Figure 1.5). Africa, South Asia and OPEC regions will see growth in both urban and rural populations (Table 1.4). Elsewhere, however, population growth is only expected in cities. The dominant pattern for China is for a massive relocation from the land to the city.

Urbanization trends have important future implications, including for energy demand. For example, there should be increased access to modern energy services, in particular electricity, and there will be greater mobility requirements. There are also local, regional and global environmental urbanization implications. At the local level, a decreased reliance upon traditional fuels for cooking should have positive health impacts, but at the same time, local air pollution may worsen. And at the global level, the expected rise in electricity demand will have implications for CO_2 emissions, depending upon which primary energy source is used for its generation.

Economic growth

The other link to long-term real GDP growth relates to the assumptions made for what is termed factor productivity. Modern growth theory emphasizes the importance of technological advancement, as well as the relative productivity of human and physical capital. Recent work has, for example, stressed the significance in changes to human capital, such as through education, in understanding different regional growth rate patterns. For the purposes of the Reference Case, total factor OECD productivity growth 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.

World economic growth in the Reference Case averages 3% p.a. over the period 2009–2030 (Table 1.5). This is lower than last year's assumption for two reasons. Firstly, as noted earlier, there have been considerable downward revisions to short- to medium-term economic growth in light of the ongoing global economic crisis. On top of this, average world economic growth is calculated using updated purchasing power parity (PPP) factors, which reduce the weight of large, fast growing developing countries, such as India and China. South Asia (dominated by India) and China are

Table 1.5
Average annual real GDP growth rates in the Reference Case (PPP basis) *% p.a.*

	2009–2020	2021–2030	2009–2030
North America	1.8	2.4	2.1
Western Europe	1.3	1.6	1.4
OECD Pacific	1.1	1.5	1.2
OECD	**1.5**	**1.9**	**1.7**
Latin America	2.8	2.8	2.8
Middle East & Africa	3.2	3.2	3.1
South Asia	5.0	4.2	4.7
Southeast Asia	3.1	3.2	3.3
China	7.1	5.4	6.3
OPEC	3.3	3.3	3.4
DCs	**4.8**	**4.3**	**4.5**
Russia	2.2	2.5	2.3
Other transition economies	2.3	2.4	2.3
Transition economies	**2.2**	**2.5**	**2.3**
World	**2.9**	**3.1**	**3.0**

in fact the fastest growing regions over the projection, averaging 4.7% and 6.3% p.a. respectively. OECD countries grow by an average that is below 2%, while transition economies expand at 2.3% p.a.

Figure 1.6 demonstrates what this implies for the relative share of each region to the global economy. In 2008, North America and Western Europe were by far the largest economies, representing 25% and 23% of the global economy respectively, measured in 2005 prices. At this time, China was the third largest economy, but it accounts for just 11% of the world total. By 2030, real world output will have approximately doubled, and China will become larger than either of these two OECD regions, doubling its share of the world economy to 22% to become the largest economy in the world.

Yet the developments of GDP per capita paint a somewhat different picture. Figure 1.7 shows that the relative ranking does not undergo such a striking change: the OECD regions are, and will remain the regions with the highest GDP per capita, by some way. Among developing countries, China increases rapidly to become the wealthiest region per head, equivalent to that of North America in 1973, and that of Western Europe in 1992. However, it remains well under half of the North America per capita wealth by 2030. South Asia, on the other hand, although witnessing rising GDP per capita, through 2030, only reaches the level that has already been reached by China today.

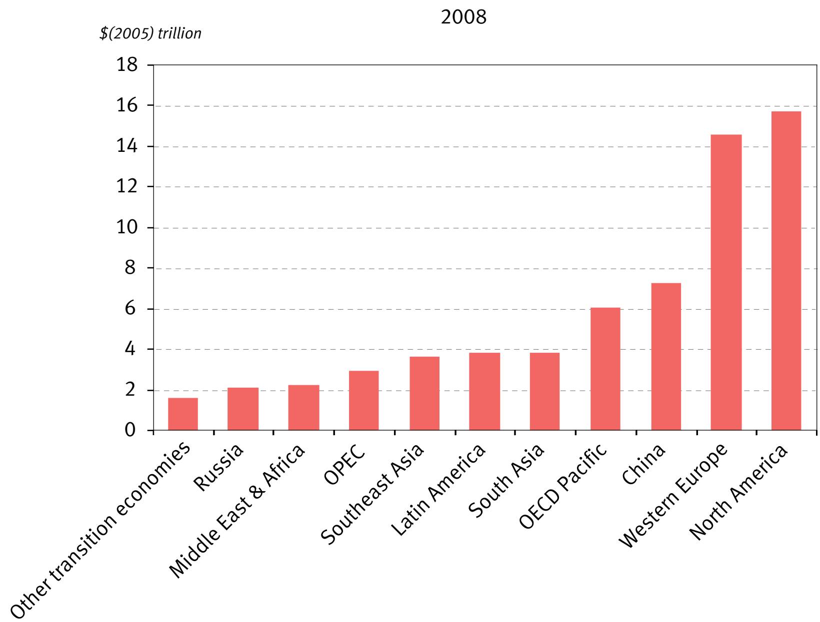
Energy policies

Another major issue to address in developing the Reference Case is the extent to which recently adopted or envisaged energy policies are factored into the outlook.

The WOO 2007 assumed that there was "no significant departure from current trends" with regard to energy policies. In the WOO 2008, while this assumption was retained, it had been amended to reflect the fact that "policy announcements are unlikely to be without impact", with the specific additional assumption that allowed for "more rapid increases in car fleet efficiencies", compared to WOO 2007 figures. However, in the 2009 WOO Reference Case, two sets of policy initiatives impact the outlook: the US Energy Independence and Security Act (EISA) and the European Union (EU) climate and energy legislative package.

The US EISA is already signed into law. In the WOO 2008, scenarios were developed to assess the potential impact on oil demand and the call on OPEC oil. That analysis pointed to the stricter Corporate Average Fuel Economy (CAFE) standards reducing demand by 1.1 mb/d in 2020, and 2.1 mb/d by 2030 (this was the central

Figure 1.6
Real GDP in 2008 and 2030



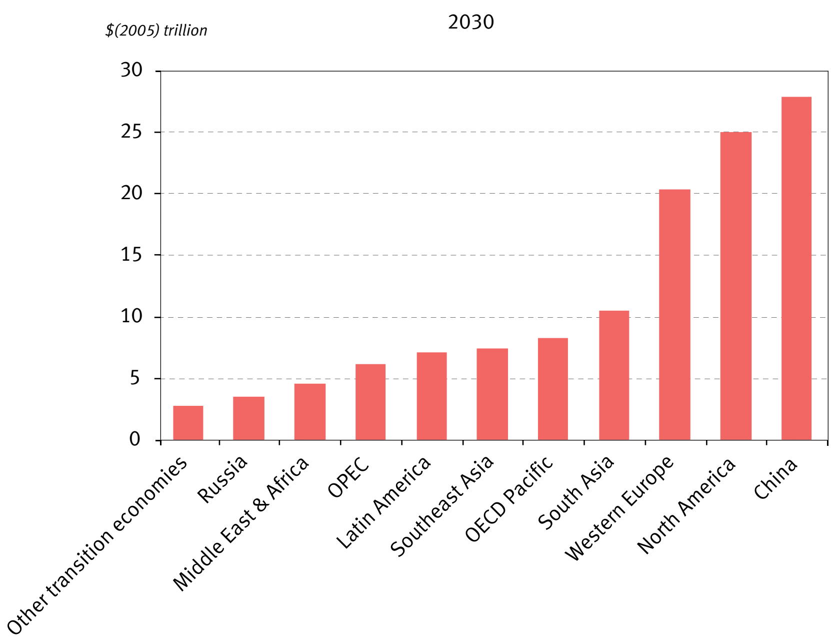
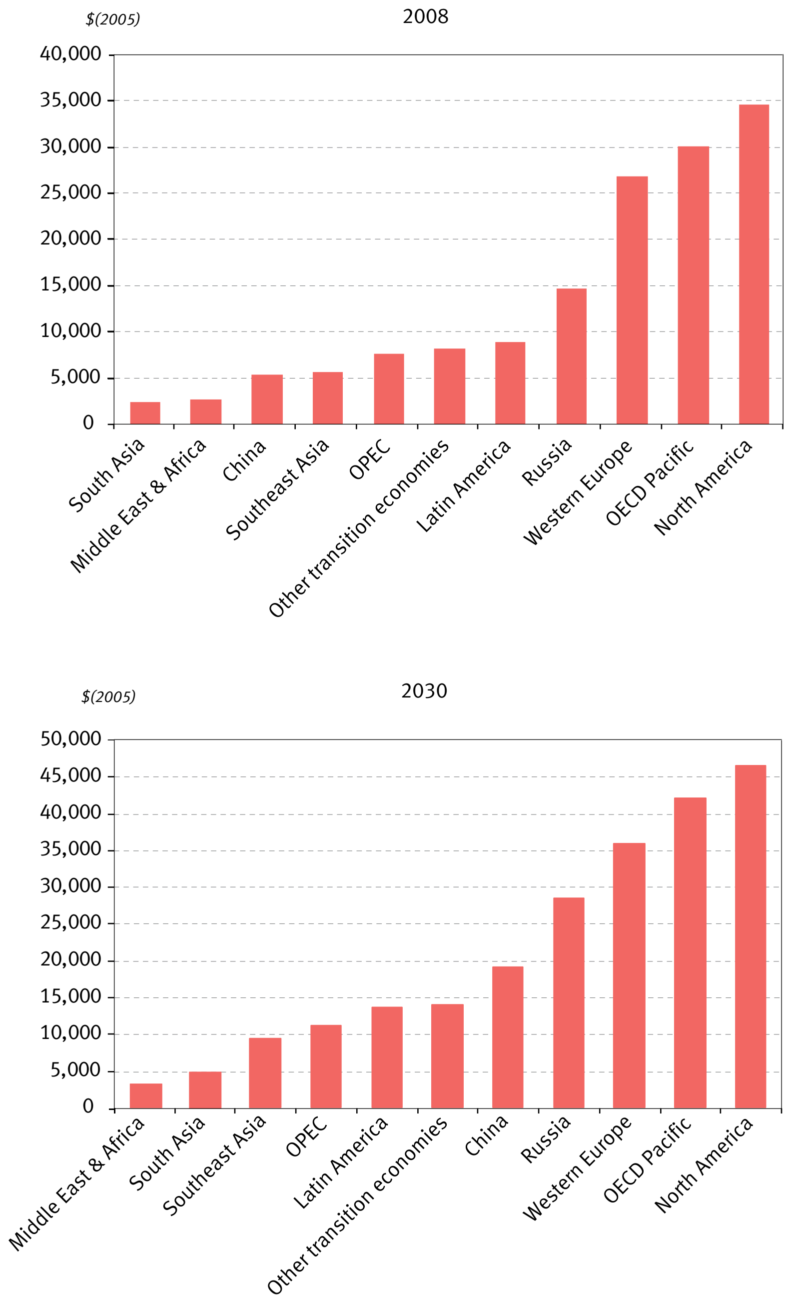


Figure 1.7
Real GDP per capita in 2008 and 2030



case — low and high cases were also developed, suggesting losses of 1.2 mb/d and 2.7 mb/d respectively by 2030). That central case scenario has now been incorporated into the Reference Case. This assumes a moderate spill-over to lorry efficiencies, and beyond 2020, some further efficiency improvement over and above previous reference case assumptions.

On top of the CAFE standards, there are ambitious biofuels targets contained in the new Renewables Fuels Standard, targeting the use of a minimum of 36 billion gallons of renewable and alternative fuels by 2022. The breakdown of how this target is to be achieved shows that most of the initial growth comes from corn-based ethanol, but after 2015, all of the increase is set to come from second generation biofuels.

The 2008 reference case already contained assumptions for expanded US biofuel use. However, the feasibility of reaching this target was questioned. In particular, there were doubts as to whether advanced biofuels could become commercially viable over the timeframe designated for the EISA targets to be met. Longer term constraints with regard to land and water availability and the possible impacts upon food prices, as well as negative full-cycle greenhouse gas balances also question the sustainability of large-scale use of corn-based ethanol in the US.

These conclusions remain in this year's WOO. Given that there are escape clauses in the EISA law that would allow for the suspension of the said targets, it is assumed that these are not fully met by 2022, and that, based on a bottom-up analysis, only one half of the additional biofuels target enters the Reference Case projection. This implies an increase of 0.3 mb/d over the 2008 reference case by this date. After 2022, it is assumed that modest advances in cellulosic biofuel technology supported by large subsidies would lead to the new 2030 Reference Case biofuels supply assumption for North America to reach 2 mb/d in 2030, compared to 1.2 mb/d in the WOO 2008. This higher biofuels supply has a slight impact upon energy-equivalent gasoline volumes, given their lower calorific content.

With regard to Western Europe, the WOO 2008 included a scenario where an assessment was made of the possible impacts of EU proposals for a package of implementation measures for climate and energy objectives, although a number of them are also geared towards economic competitiveness and energy security. The 2008 reference case did not include the impact of such measures, noting that approval was still needed "by both the Council of the EU and the European Parliament to become law". This has now happened. EU heads of state and government worked out a compromise deal in December 2008, and following this, the European Parliament approved the package. The so-called '20-20-20' package is in line with the original

Commission proposals of January 2008, and entails legally binding targets for the year 2020 that will oblige EU countries to reduce CO_2 emissions by 20% from 1990 levels, to improve energy efficiency by 20% and to reach a minimum 20% share for renewable energy.

Six proposals were agreed upon:

– *To revise the EU's Emissions Trading System (ETS)*
This is seen as a key tool in achieving the 20% greenhouse gas reduction by 2020. The revision involves expanding the coverage to include further industries such as petrochemicals, and the introduction of full auctioning by 2013. The Directive also provides for agreements with other mandatory greenhouse gas trading systems.

– *CO_2 reduction targets for sectors not covered by the ETS*
This foresees a 'corrective action' whereby countries will have to compensate for underachievement in the following year.

– *A legal framework for CCS*
The new directive sees the ETS setting aside up to 300 million allowances for carbon capture & storage (CCS) projects, with an estimated resulting funding of €6–9 billion. This is suggested to be sufficient for nine or 10 demonstration projects.

– *Binding targets for CO_2 emissions from new cars*
The new legislation sees a binding target of 120g CO_2/km, phased in over the period 2012–2015, with fines payable by manufacturers for excessive emissions. This represents a reduction of 25% from current levels. A long-term target, although not yet binding, of 95 g/km by 2020 is also included in the agreement.

– *A binding target of 20% renewable energy in the energy mix by 2020*
Energy produced from hydro, solar, wind, biomass or geothermal sources in the EU is to rise to 20% by 2020. This includes a 10% share of renewables in the transport sector.

– *GHG reduction targets along the entire fuel supply chain*
The fuel quality directive sees GHG reductions of 6% from 2010 levels by 2020. This covers the entire life-cycle of transport fuels.

There are five specific changes to the new Reference Case.

– Since its launch in January 2005, the performance of the EU ETS has not been as smooth as originally envisaged. Yet the expansion of coverage, as well as the phasing in of full auctioneering is likely to bring about greater efficiency improvements than previously assumed in both the industry and power sectors. The Reference Case introduces an additional eventual efficiency increase in Western Europe's industrial sector. In addition, the share of coal is lower than the previous reference case, especially in the electricity generation sector. Nevertheless, some resistance is expected to limit the damage to the regional coal sector, and some competition with gas is expected, especially in light of security of supply concerns. The share of renewables in electricity generation also rises at faster rates.

– The CO_2 targets for new passenger cars represent a significant challenge for car manufacturers. To an extent, it is assumed that this target will not be fully met, as some manufacturers may choose to pay the fines (this has happened in the past with firms exporting to the US). The impact of greater efficiencies upon the whole car stock will initially be limited, growing over time, as the stock gradually turns over. It is assumed that efficiency improvements for Western Europe's transportation sector in the longer term increase by 0.5% p.a. compared to the previous reference case.

– The renewables target of 20% was identified in the WOO 2008 as being ambitious, with CCS likely to have to become an integral part of measures to reach the targets. CCS is to receive financial support from the ETS, but this will probably turn out to be insufficient and it is still unlikely that the target will be reached. The renewables share is increased from previous levels, but not to EU target levels.

– The 10% renewables target for the transportation sector translates into a volume of biofuels that is 0.4 mb/d higher by 2020 than in the previous reference case. There is still doubt, however, as to whether this level of biofuels supply is achievable in the timeframe. Thus, the new Reference Case increases the longer term projection for biofuels supply from Western Europe by 0.4 mb/d by 2030, compared to the previous reference case.

– These assumptions will already go some way to achieving the overall target for CO_2 reduction, including that in sectors not covered by the ETS. However, the residential/commercial/agriculture sector is likely to receive increased support for efficiency improvements, especially given the provision for 'corrective action' outlined above. An additional eventual rate of efficiency improvement of 0.2% p.a. is assumed to occur in the energy demand for these sectors.

This year's OECD Pacific projections take into account the May 2008 revision to Japan's 'Law Concerning the Rational Use of Energy', aimed at stepping-up energy saving measures for factories and offices, residences and buildings. In June 2008, a partial amendment was also passed to Japan's 'Law Concerning the Promotion of the Measures to Cope with Global Warming'. As a result, around 50% of businesses will be required to report CO_2 emissions, up from 13%. Other measures in the revision include the setting up of climate change action centres. This is the fourth time the Law has been revised. To the extent that these revisions reemphasize efficiency and climate change objectives, rather than represent new, additional measures, only a minor revision to Reference Case figures has been regarded as necessary.

For non-OECD regions, no additional policy assumptions are introduced into the Reference Case compared to last year's WOO. China's revised 'Energy Conservation Law' of April 2008 is part of a long-term goal to encourage energy efficiency. The revised law aims to tighten regulation. As such, it can be considered a continuation of previous policies. A new Energy Law is being planned for introduction in 2009, specifically targeting renewable energy — the Chinese government body for overseeing energy policy has also recently finalized a proposal for billions of dollars of incentives for solar farms and rooftop panels, which will come from the government's economic stimulus fund — and energy efficiency. This needs to be closely monitored as a candidate for amending future reference cases.

India's government approved a new 'Integrated Energy Policy' in December 2008. The new energy policy reportedly focuses on developing a road map to achieve sustainable growth and energy security. The policy would make energy markets more competitive through the market-based energy pricing of coal and petroleum. Implementation details are not yet available. Thus, the Reference Case does not take into account this policy for its projections. Nevertheless, as with China, the close monitoring of the implementation of Indian energy policy is important and might lead to future additional revisions to reference case assumptions.

Finally, 'The Bali Action Plan' marked the opening in 2007 of negotiations for long-term cooperative action to enhance implementation of the UN Framework Convention on Climate Change (UNFCCC), as well as the continuation of the work to agree on further commitments for Annex-I parties under the Kyoto Protocol. The completion of these negotiations is set for December 2009 at COP-15/CMP-5 in Copenhagen. It is still too early to know whether a comprehensive agreement on climate change is likely to result from the meeting, nor is it possible to anticipate what its content would be. Therefore, the current Reference Case includes only the climate change mitigation measures to the extent described above. More stringent abatement policies are considered in a scenario analysis later in this outlook.

Energy demand

Energy use has increased steadily, quadrupling since 1960, as a result of economic growth, rising population and social progress. The reliable, efficient and economic supply of energy has helped world economies grow, create jobs and improve the living conditions of billions of people.

Under all scenarios, energy use is set to rise. In the Reference Case, it increases by 42% from 2007–2030. Developing countries will account for most of these increases, by virtue of higher population and economic growth. However, energy use in developing countries will remain much lower on a per capita basis. Moreover, a large part of the world population will continue to lack access to modern energy services.

Globally, renewable energy will continue to grow fast, but from a low base. Nuclear grows faster than in the previous outlook, at an average of 1.6% p.a., while hydropower is also set to expand. Realistically, however, fossil fuels will continue to satisfy most of the world's energy needs, contributing more than 80% to the global energy mix over this period. And oil will continue to play the leading role to 2030, although its overall share will fall (Figure 1.8 and Table 1.6). Gas is expected to grow at fast rates, while coal retains its importance in the energy mix. The trends in shares suggest, however, that coal could become the dominant fuel by the middle of the century.

Figure 1.8
World supply of primary energy by fuel type

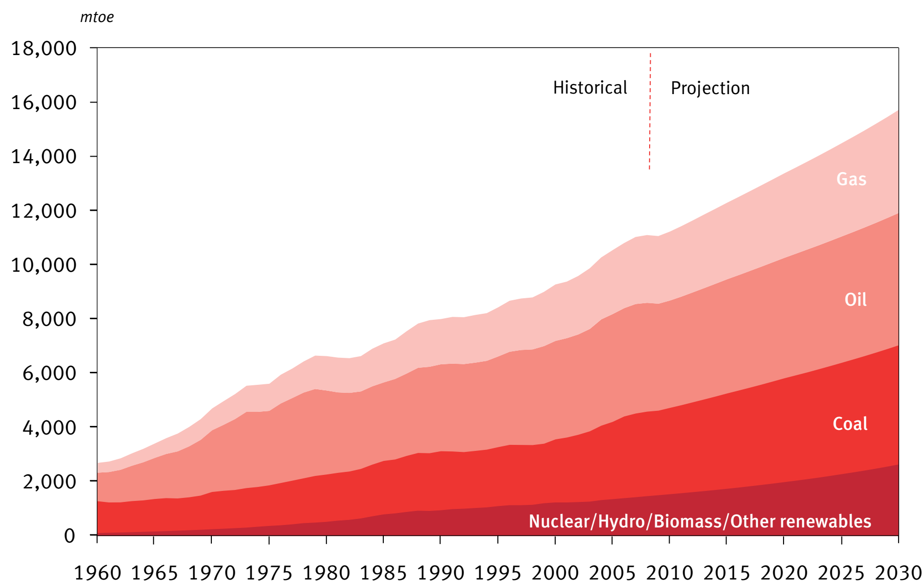


Table 1.6
World supply of primary energy in the Reference Case

	Levels mtoe				Growth % p.a.	Fuel shares %			
	2007	2010	2020	2030	2007–30	2007	2010	2020	2030
Oil	4,045	3,967	4,457	4,902	0.8	36.4	35.1	33.1	31.0
Coal	3,129	3,225	3,871	4,438	1.5	28.2	28.5	28.8	28.1
Gas	2,479	2,551	3,124	3,808	1.9	22.3	22.6	23.2	24.1
Nuclear	736	759	873	1,065	1.6	6.6	6.7	6.5	6.7
Hydro	268	289	366	448	2.3	2.4	2.6	2.7	2.8
Biomass	394	446	618	840	3.4	3.5	3.9	4.6	5.3
Other renewables	59	73	151	303	7.4	0.5	0.6	1.1	1.9
Total	**11,109**	**11,310**	**13,461**	**15,804**	**1.5**	**100.0**	**100.0**	**100.0**	**100.0**

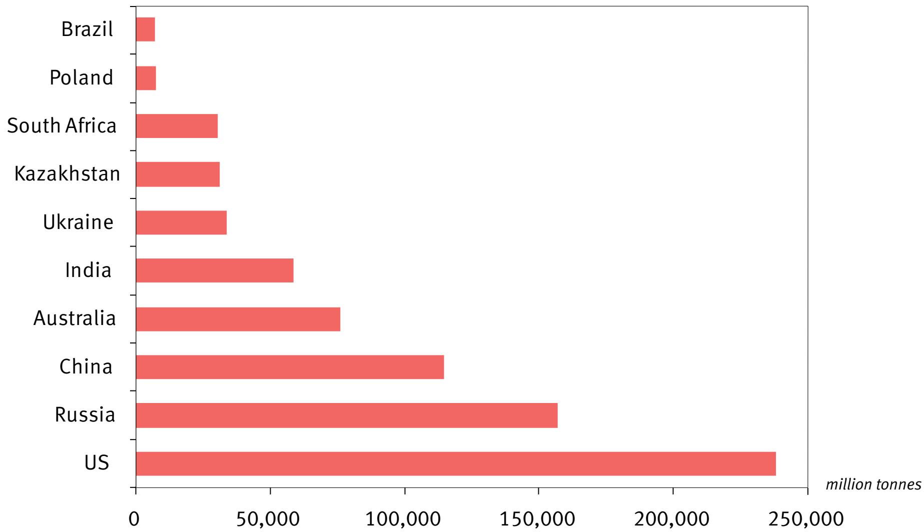
Coal

Close to 40% of the global electricity generated comes from coal. And, unsurprisingly, coal use is predominantly for the electricity generation sector, which utilizes more than three times as much as the industry sector, incorporating such sectors as iron and steel. The prospects for future coal use are therefore inevitably bound to the evolution of the electricity sector.

Coal use has recently been growing faster than oil or gas use, particularly in China. This has been driven by several forces. One important perspective is energy security. There is inevitably a strong appeal in using a fuel for which there is an abundance of easily accessible resources. This is certainly the case for China, Russia, the US and India, which between them account for more than two-thirds of the world's coal reserves, and are correspondingly among the world's largest coal users (Figures 1.9 and 1.10). In China and India, there has been talk of constructing a new coal-fired plant every week, and in the US in 2007, there were 150 proposals for new plants. It is possible that coal's prospects in Europe are also currently undergoing some kind of resurgence, especially given the large reserves in the region's biggest producer, Poland. Indeed, across the EU, 50 new coal-fired plants are being considered for construction over the next few years.

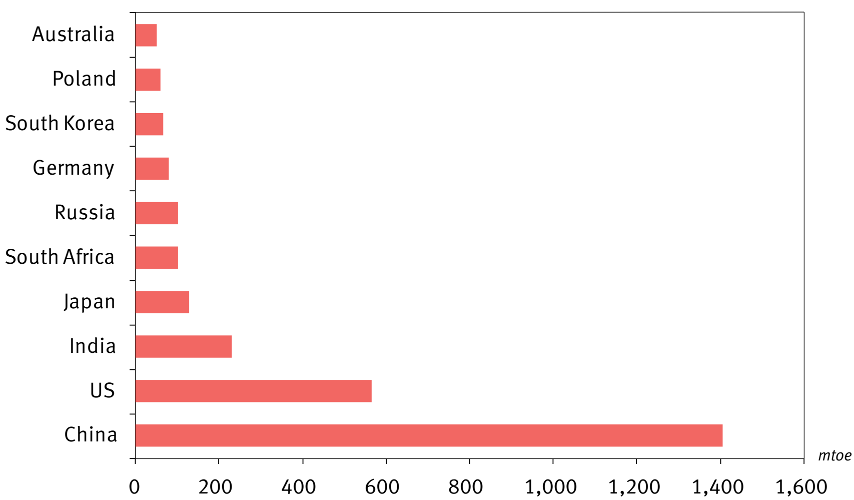
However, there is an opposing force to the potential for future coal use, which relates to climate change concerns given coal's high carbon content. It begs the question: what is coal's role in an increasingly carbon-constrained world? An important technology that would allow coal to fit into this is CCS. This explains, for example,

Figure 1.9
Coal reserves, 2008 (Top 10 countries)



Source: *BP Statistical Review of World Energy, 2009.*

Figure 1.10
Coal demand, 2008 (Top 10 countries)



Source: *BP Statistical Review of World Energy, 2009.*

why CCS is an integral part of the EU climate change objectives. There is also scope for developing a new generation of processes, as well as implementing existing ones, to improve the efficiency of coal use. Certainly, if stringent CO_2 emissions targets are to be met, it will be paramount to develop and disperse appropriate technologies for coal use to remain at its current level.

The Reference Case, however, is not carbon-constrained, other than to the extent that the policies highlighted are taken on board. Reference Case projections for coal appear in Table 1.7. Developing country demand growth rises by an average of 2.6% p.a. There is assumed to be little growth in Russia's use of coal, with future power plants expected to take advantage of domestic natural gas or new nuclear. These are similar results to the previous assessment.

Table 1.7
World coal and gas demand growth, 1990–2007 and 2007–2030 *% p.a.*

	Coal		Gas	
	1990–2007	**2007–2030**	**1990–2007**	**2007–2030**
North America	1.2	–0.1	1.3	0.0
Western Europe	–1.9	–0.7	3.2	0.3
OECD Pacific	2.8	–1.1	4.3	0.4
OECD	**0.4**	**–0.4**	**2.2**	**0.2**
China	5.2	2.6	8.5	4.3
OPEC	0.8	3.5	5.9	4.5
Other developing countries	4.1	2.6	7.4	3.9
DCs	**4.9**	**2.6**	**6.8**	**4.2**
Russia	–3.1	0.1	0.0	1.3
Other transition economies	–3.0	0.0	–1.1	1.0
Transition economies	**–3.1**	**0.1**	**–0.4**	**1.3**
World	**2.0**	**1.5**	**2.3**	**1.9**

For the OECD, the picture has changed somewhat from the 2008 reference case, with coal use projections lower than before. This is due to the joint effects of reduced demand in the early years of the projection, as a result of lower economic growth because of the global financial crisis, and the impact of a rising renewables share in the energy mix. In North America, coal use is approximately flat. Coal's share in electricity generation continues to fall in the Reference Case, and the assumption is made that despite the spate of applications for new coal-fired based generation, efficiency gains are likely to compensate for the introduction of any additional plants. In addition, nuclear is expected to play a greater role in US electricity generation. Coal use in Western Europe is projected to fall at an average annual rate of 0.7%, but this decline could be even swifter if the renewable energy targets are fully met. This fall is assumed to take place despite the apparent resurgence of coal in discussions about future energy needs. In the OECD Pacific the assumed increase in nuclear and renewables will limit the role that coal will play in electricity generation.

The Reference Case assumes that the opposing influences of energy security and the environment are relatively balanced, albeit with environmental pressures slightly prevailing. The outlook for coal use, however, could be markedly different should either factor come to dominate energy planning over the coming two decades.

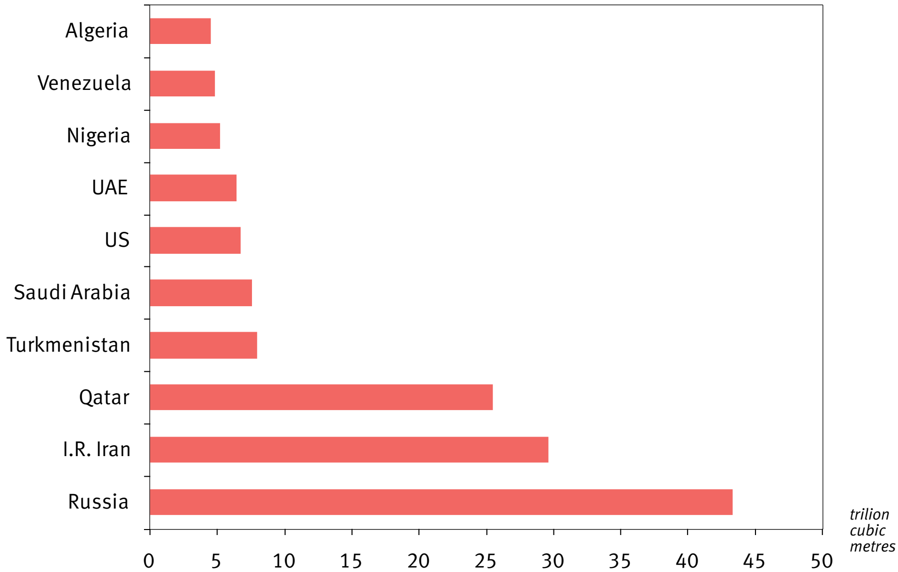
Natural gas

Natural gas is the fuel that has the most diverse range of uses across sectors. While electricity generation represents the largest portion of global gas use, there is also considerable industry usage, particularly in petrochemicals, as well as the residential/commercial/agricultural sector, for heating and cooking. Nevertheless, the importance of electricity generation to natural gas prospects remains strong. For example, in the OECD in the 1970s, less than 20% of total gas usage was in this sector, but this figure has now doubled. A similar pattern is observable in developing countries. And Russian gas use is concentrated mostly in electricity generation, at around two-thirds of all demand.

Close to three-quarters of the world's gas reserves are in either OPEC Member Countries or Russia. Figure 1.11 shows the latest assessment of natural gas reserves, for the top ten countries of the world, while the top consumers appear in Figure 1.12.

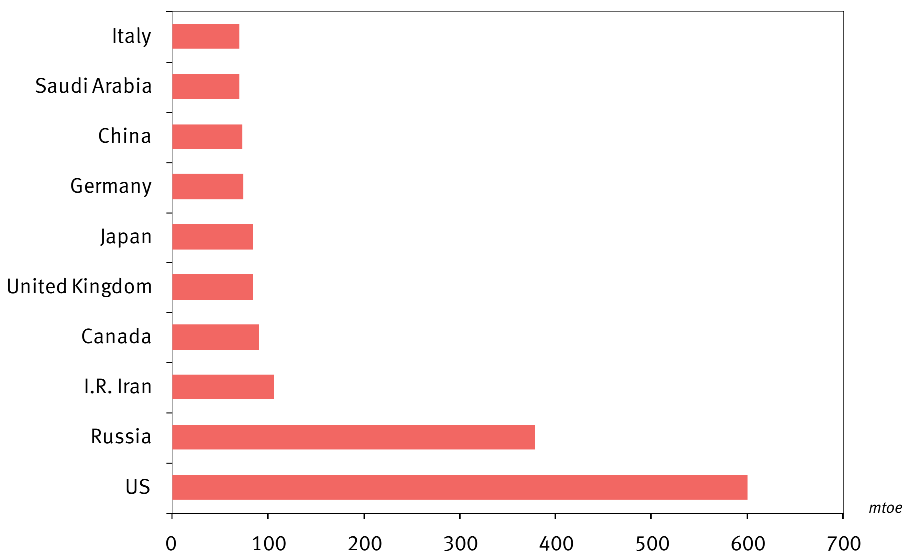
The Reference Case projections for gas use are shown in Table 1.7. The evolution of gas demand from 1960–2030 is shown in Figure 1.13. The largest consumer of gas is the US, but growth prospects are considered to be limited, particularly due to the expected limits on future supply growth. The Reference Case therefore sees North America's gas demand remaining flat. Gas demand has increased sharply over the past two decades in Western Europe and the OECD Pacific, with average annual increases over the period 1990–2007 of 3.2% and 4.3% respectively. While some future growth is to be expected, the supply network is not anticipated to continue to expand as swiftly, so average growth for 2007–2030 is down to 0.3–0.4% p.a.

Figure 1.11
Natural gas reserves, 2008 (Top 10 countries)



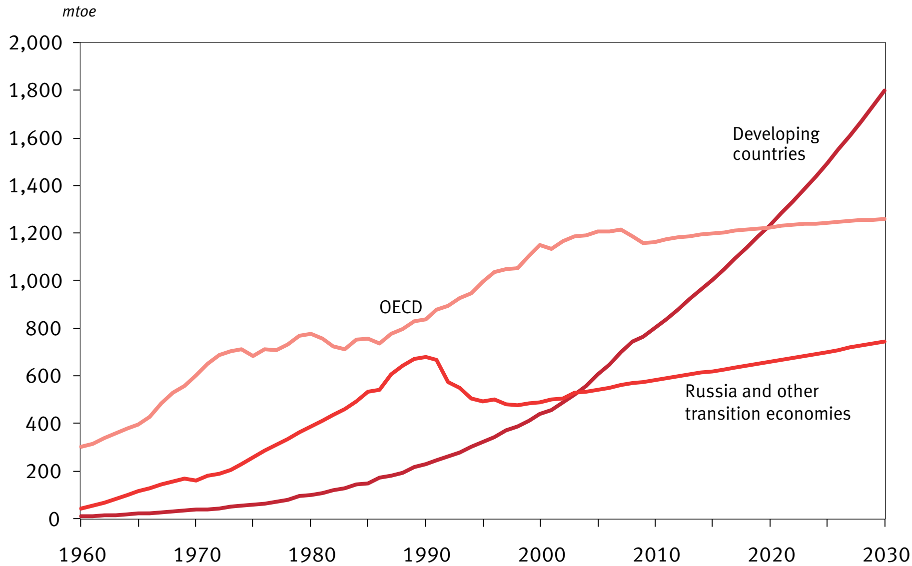
Source: BP Statistical Review of World Energy, 2009.

Figure 1.12
Natural gas demand, 2008 (Top 10 countries)



Source: BP Statistical Review of World Energy, 2009.

Figure 1.13
Natural gas demand, 1960–2030



Source: *Energy balances of OECD and non-OECD countries, IEA/OECD, Energy Statistics Yearbook, United Nations.*

As a result, total OECD gas demand increases by just 5% over the entire projection period.

In contrast, gas demand in developing countries is expected to grow rapidly. The rate of expansion is projected to be lower than over the past two decades, mainly a result of slowing economic growth, but also because earlier high growth rates were from a low base. For the period to 2030, an average increase of 4.2% p.a. is predicted. This means that, by 2020, developing countries will be consuming more gas than OECD countries.

Two-thirds of gas use in the transition economies group is in Russia, the second largest global consumer. Before the collapse of the Former Soviet Union, transition economy gas use was approaching OECD levels. Following the collapse, however, demand fell significantly and in recent years growth has only been modest. Today, gas use is lower than in developing countries. The scope for efficiency gains remains considerable, and price signals can be expected to accelerate these trends, although there is still an ongoing debate as to the social acceptability of such measures. The Reference Case sees steady growth averaging just over 1% p.a.

Non-fossil fuels: nuclear, hydro, commercial biomass, other renewables

Hydropower

With a current share of approximately 16%, hydropower remains the third largest contributor to global electricity generation. While the sustainable potential in developed countries has already been largely exploited, developing countries, where considerable resources remain untapped, are expected to continue developing hydropower, although environmental concerns and the impact of population resettlement could constrain the full exploitation of the available resources.

Between 2007 and 2030, global demand for hydropower in the Reference Case will grow at an average annual rate of 2.3% p.a. The fastest growth will be witnessed in China, with an average growth rate of 4.4% p.a. Demand for hydropower will be highest in Latin America by 2030, surpassing the current leader North America.

Nuclear

Today, the total installed nuclear capacity is some 370 gigawatts (GW), which provides 15% of the world's electricity supply. There are 436 reactors in operation in over 30 countries, and nuclear power provides 25% or more of the electricity needs for 16 countries.

Over the last few years there has been much talk of a 'nuclear renaissance' reversing the stagnation witnessed by nuclear power since the mid 1980s. Some governments, especially in developed countries have initiated support and subsidy schemes in an effort to jump-start the industry.

Earlier this year, the Swedish Government's new energy plan proposed doing away with plans to phase out the country's current nuclear build and offered the green light for a new generation of nuclear reactors. There have also been many positive noises made for new nuclear build in the US, as well as the UK, though no concrete proposals as yet.

The two developed countries currently leading the way are France, where majority state-owned group EDF has a reactor under construction at Flamanville on the Normandy coast, with plans for another at Penly, near Dieppe, and Finland, where construction of the Olkiluoto plant continues.

However, in the spring of 2009 the Olkiluoto plant dealt a severe blow to hopes for a nuclear comeback with delays announced to the construction of the plant, originally scheduled for completion in the Summer of 2009. Intended to be the most powerful reactor ever built, with a modular design that would make it faster and cheaper to build, the plant's €3 billion price tag has climbed at least 50%. And the plant's owner and contractor are no longer willing to make certain predictions on when it will go online.

In addition, several other reasons are casting doubt on a true nuclear comeback. Firstly, there is the issue of a human resources shortage. Since the late 1980s, the nuclear industry has not appealed to young engineers and operators since it was assumed that existing plants, nearing the end of their licensed lifetimes, would not be hiring. Moreover, research and development opportunities dwindled significantly. In fact, university enrollment in nuclear engineering programmes declined so sharply that many educational institutions closed them.

Secondly, as a consequence of the safety concerns that were heightened by the nuclear incidents in the late 1970s and mid 1980s, utilities have been forced to build-in very high cost safety measures. And on top of this, there remain many question marks over how to deal with the nuclear waste issue. It means that nuclear power continues to be viewed as expensive and risky. This has proven to constitute a significant barrier to obtaining proper financing and insurance.

Nevertheless, many developing countries, in particular China and India, are currently embarking on large nuclear new-build progammes. These will push the global average growth rate of nuclear to 1.6% p.a. between 2007 and 2030. China's nuclear power is assumed to grow at 7.6% p.a., compared to 1.2% pa for OECD countries.

Commercial biomass

Modern biomass use is growing the world over, including in the industrial, residential/agriculture and commercial sectors, but especially as an input to electricity generation and for biofuels production. Global modern biomass use expands in the Reference Case between 2007 and 2030 at an average annual rate of 3.4% p.a., with growth in OECD countries greater than that in developing countries.

With regards to biofuels, which represents the fastest growth component in biomass use between 2007 and 2030, it has become increasingly clear that biofuels have their limitations. The large-scale expansion of first-generation biofuels — those that are produced from grains, sugar, seeds and other food crops — are now widely seen as having been a contributing factor to rising food prices. Furthermore, it is evident that even the environmental benefits of biofuels have recently come under closer scrutiny. It has been recognized that they negatively impact water resources, both in terms of physical availability and access to water, as well as biodiversity, in terms of soil erosion and nutrient leaching due to large-scale mono-cropping.

Second-generation biofuels, which do not rely on food crops, are seen as potentially resolving most of the sustainability concerns surrounding biofuels. However, these are still largely in the R&D phase and are not expected to become commercially available and contribute significantly to biofuels supply before 2020.

Since the fourth quarter of 2008, the global financial crisis and the ensuing credit squeeze has also put the brakes on biofuels expansion in the medium-term, with tight credit, and very small, sometimes negative margins. Long-term, however, policy initiatives in the US and the EU in particular, will drive the expansion of biofuels, with an emphasis on second-generation biofuels.

Globally, biofuels supply will reach 158 million tonnes oil equivalent (mtoe) by 2030, expanding from 2007 at an average annual rate of 6.7% p.a. Although supply in developing countries will still be lower than that in developed countries by 2030, it will grow at the brisker rate of 7.6% p.a. between 2007 and 2030.

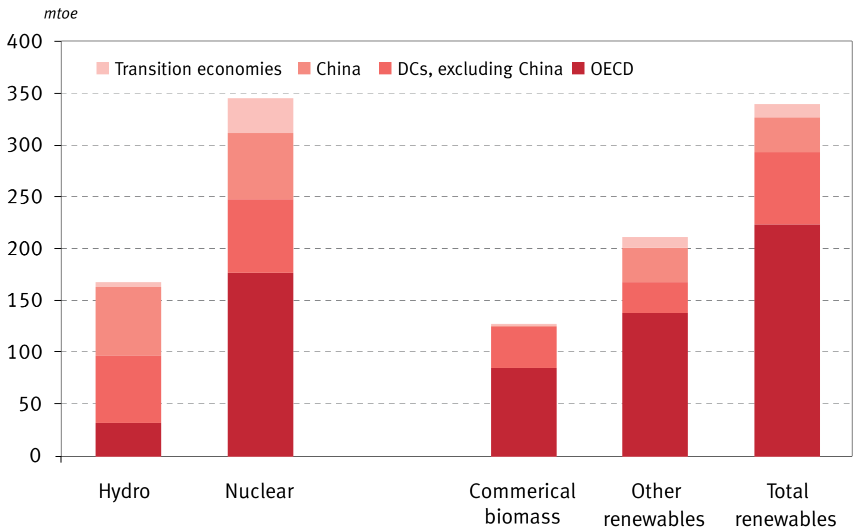
Other renewables

Solar, wind, tidal and small hydro, in addition to geothermal, are kept high on the agenda of many governments as sources of energy that can potentially achieve the two goals of securing energy supply and mitigating climate change. The stance of President Barack Obama on alternative energy has provided some much-needed encouragement to the industry in the US in the face of the global financial crisis, which negatively affected several renewables projects. In other regions, such as the EU, renewables are also expected to enjoy the support of governments in various forms. Nevertheless, renewables, starting from a low base, are still expected to contribute only modestly to global energy supply, even by 2030. The largest growth over the entire forecast period will be in power generation, where modern biomass will grow at 4.2% p.a. and other renewables by 6.9% p.a.

Non-fossil fuels in power generation

Figure 1.14 shows the growth by region of the non-fossil fuels contribution to power generation between 2007 and 2030. In total, the global growth of hydropower, nuclear and renewables in electricity generation is expected to be 855 mtoe. Nuclear will grow the most globally in absolute terms, with most of the growth coming in OECD countries. However, in this region, renewables will grow more than nuclear. Developing countries, including China, will lead the growth in hydropower, while China on its own will show relatively strong growth in hydropower, nuclear and other renewables, but not in terms of modern biomass.

Figure 1.14
Increase in non-fossil fuel inputs to electricity generation, 2007–2030



Oil demand

Oil demand in the medium-term

Medium-term assumptions underscore a gradual rise in the OPEC Reference Basket price to $70/b in nominal terms, with the global economic contraction reaching its bottom in the second half of 2009 and slowly expanding thereafter, taking until 2012 to come back to potential trend growth. In addition, the high prices observed in 2008 led undoubtedly to some demand destruction, and this has been factored into short-term figures. Moreover, as previously discussed, policies are introduced to improve efficiencies, particularly in the transportation sector, as well as to encourage the introduction of alternative fuels, such as biofuels. The introduction of policies geared to greater vehicle efficiencies are expected to adversely impact longer term demand potential, as the targets become increasingly stringent, and as the vehicle stock turns over. However, the key impact on medium-term demand prospects will be from the lower economic growth assumptions.

Indeed, lower economic growth affects oil consumption in all sectors. In the transportation sector, key to demand growth, the number of vehicles, both private passenger cars, as well as commercial vehicles, will be lower. Efficiencies will increase, as a result of driving behaviour and purchasing decisions. The airlines passenger occupancy rate and freight load factor will also be affected. In industry, lower economic growth feeds straight into reduced levels of manufacturing, which has consequences for oil consumption, particularly in the petrochemicals sector. Lower global trade levels will filter through to the lower use of marine bunkers. Even the extent to which oil is used for electricity generation will be affected, as lower electricity demand has its first impact upon oil use due to it typically being a swing fuel. As the economy recovers, effects could include a certain amount of "rebound".

The OWEM addresses these sectoral patterns explicitly, and has been used to simulate the medium-term demand patterns, given the assumptions for medium-term economic growth already outlined. The results appear in Table 1.8. The corresponding annual demand growth is depicted in Figure 1.15.

OECD oil demand falls from 47.5 mb/d in 2008 to 45.5 mb/d by 2010, and remains flat at that level in the following years. Only a slight increase in demand is expected from Russia. This means that the main source of incremental oil demand will be from developing countries. However, given the expected 'U-shaped' economic recovery, which affects developing countries too, the annual increments in demand

Figure 1.15
Annual growth of oil demand in the medium-term

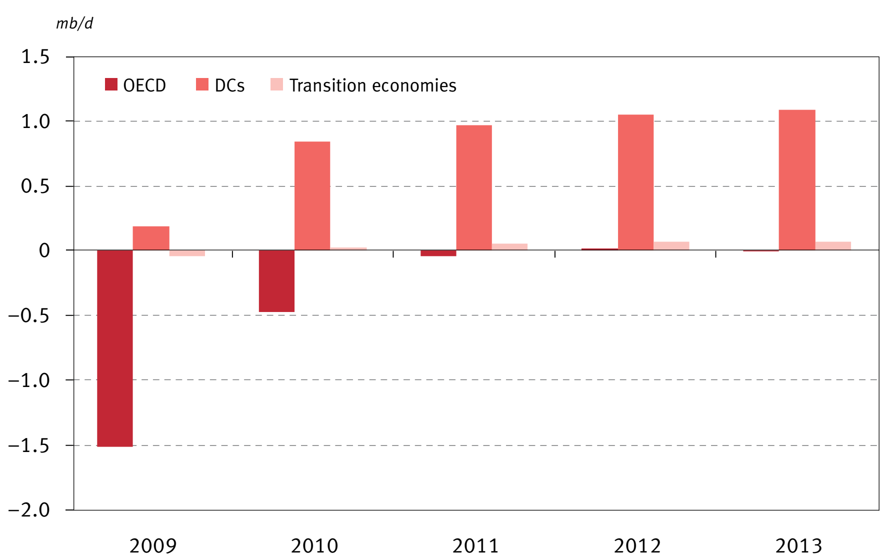
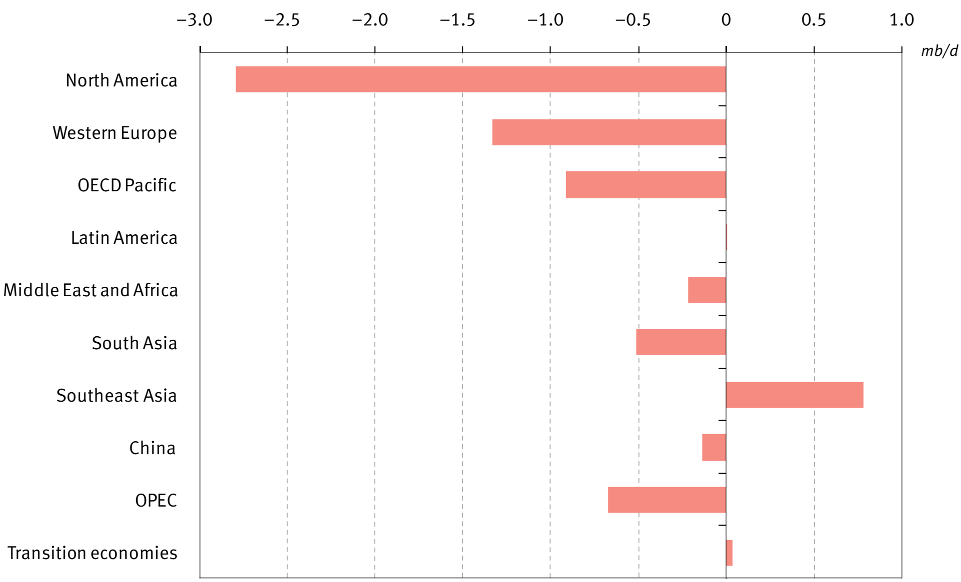


Table 1.8
Medium-term oil demand outlook in the Reference Case

mb/d

	2008	2009	2010	2011	2012	2013
North America	24.3	23.7	23.4	23.4	23.5	23.5
Western Europe	15.2	14.8	14.6	14.6	14.6	14.5
OECD Pacific	8.0	7.6	7.5	7.5	7.5	7.4
OECD	**47.5**	**46.0**	**45.5**	**45.5**	**45.5**	**45.5**
Latin America	4.8	4.8	4.8	4.9	5.0	5.0
Middle East & Africa	3.2	3.2	3.3	3.4	3.5	3.6
South Asia	3.5	3.3	3.5	3.6	3.8	4.0
Southeast Asia	5.8	5.8	5.9	6.0	6.1	6.3
China	8.0	8.0	8.3	8.7	9.1	9.5
OPEC	7.7	8.0	8.2	8.3	8.5	8.6
DCs	**33.0**	**33.1**	**34.0**	**34.9**	**36.0**	**37.1**
Russia	3.1	3.1	3.2	3.2	3.2	3.3
Other transition economies	2.0	1.9	1.9	1.9	2.0	2.0
Transition economies	**5.1**	**5.0**	**5.1**	**5.1**	**5.2**	**5.3**
World	**85.6**	**84.2**	**84.6**	**85.6**	**86.7**	**87.9**

Figure 1.16
Changes to oil demand Reference Case projections in 2013 compared to WOO 2008



for 2010 and 2011 are below that of 2012, once trend economic growth is assumed to resume. In 2012 and 2013, average global demand growth is 1.1 mb/d p.a.

These figures represent a major reassessment from the 2008 reference case. By 2013, oil demand is 5.7 mb/d lower than last year. Figure 1.16 illustrates where these revisions have taken place. Clearly the dominant impact has been a drastic reduction in oil demand in OECD countries, with North America seeing the most dramatic downward shift.

These revised demand patterns are used below with the medium-term assessment of non-OPEC supply to develop a set of projections for the amount of OPEC crude that may be required over the medium-term.

Oil demand in the long-term

In the long-term, oil demand patterns become increasingly influenced by the implementation of policies that have been factored into the Reference Case.

Efficiency improvements are greater than previously estimated, and this, together with the downward revision to the medium-term expectations due to the current global recession, has led to a significant downward revision for oil demand in the longer term. Oil demand in the Reference Case rises by 20 mb/d from 2008–2030, when it reaches almost 106 mb/d (Table 1.9). This is down from an estimated figure of 113.3 mb/d in the WOO 2008.

As with the medium-term, developing countries are set to account for most of the rise, with consumption rising by 23 mb/d over the period 2008–2030 to reach 56 mb/d (Figure 1.17). Almost 80% of the net growth in oil demand from 2008–2030 is in developing Asia. OECD oil demand falls over the entire projection period, having 'peaked' in 2005. Nevertheless, it is important to stress once more the fact that energy poverty will remain a pressing issue over this period. Focussing just on oil, per capita oil use in developing countries will remain far below that of the developed world. For example, oil use per person in North America in 2030 will still be more than ten times that of South Asia (Figure 1.18).

As in previous assessments, the transportation sector is identified as being the main source of future oil demand growth (Figures 1.19–1.22). However, for the first time, there is an anticipated decline in oil use in this sector in the OECD. This arises from the combined effects of more rapid efficiency improvements and saturation. This is addressed in more detail in Chapter 2. For developing countries, the growth in transportation is the single most important sectoral source of demand increase, but the combined

Chapter 1

Table 1.9
World oil demand outlook in the Reference Case

mb/d

	2008	2010	2015	2020	2025	2030
North America	24.3	23.4	23.6	23.4	23.1	22.8
Western Europe	15.2	14.6	14.5	14.3	14.1	13.8
OECD Pacific	8.0	7.5	7.4	7.2	7.0	6.8
OECD	**47.5**	**45.5**	**45.5**	**45.0**	**44.3**	**43.4**
Latin America	4.8	4.8	5.2	5.6	5.9	6.2
Middle East & Africa	3.2	3.3	3.7	4.2	4.7	5.2
South Asia	3.5	3.5	4.4	5.5	6.7	8.2
Southeast Asia	5.8	5.9	6.6	7.4	8.2	9.0
China	8.0	8.3	10.4	12.3	14.1	15.9
OPEC	7.7	8.2	9.0	9.8	10.6	11.5
DCs	**33.0**	**34.0**	**39.3**	**44.8**	**50.2**	**56.1**
Russia	3.1	3.2	3.3	3.5	3.6	3.7
Other transition economies	2.0	1.9	2.1	2.2	2.3	2.4
Transition economies	**5.1**	**5.1**	**5.4**	**5.7**	**5.9**	**6.1**
World	**85.6**	**84.6**	**90.2**	**95.4**	**100.4**	**105.6**

Figure 1.17
Growth in oil demand, 2008–2030

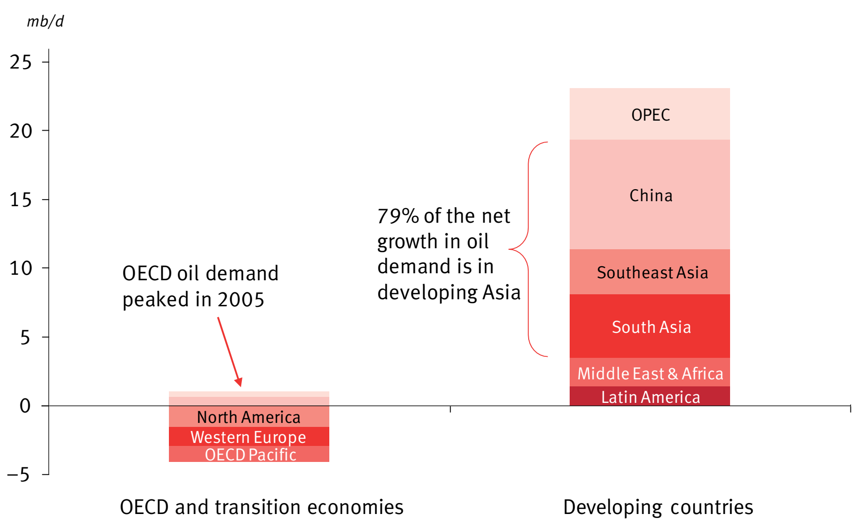


Figure 1.18
Oil use per capita in 2030

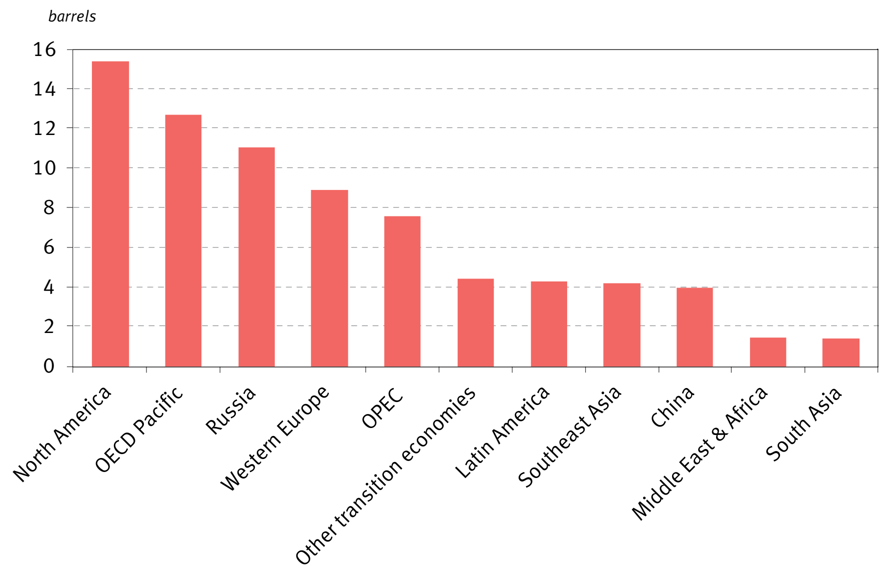


Figure 1.19
Annual global growth in oil demand by sector

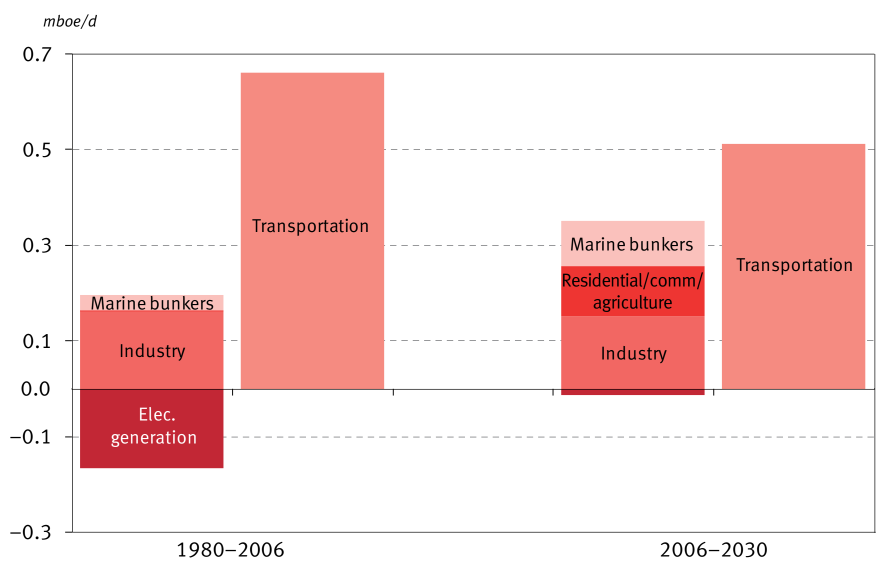


Figure 1.20
Annual growth in oil demand by sector in OECD countries

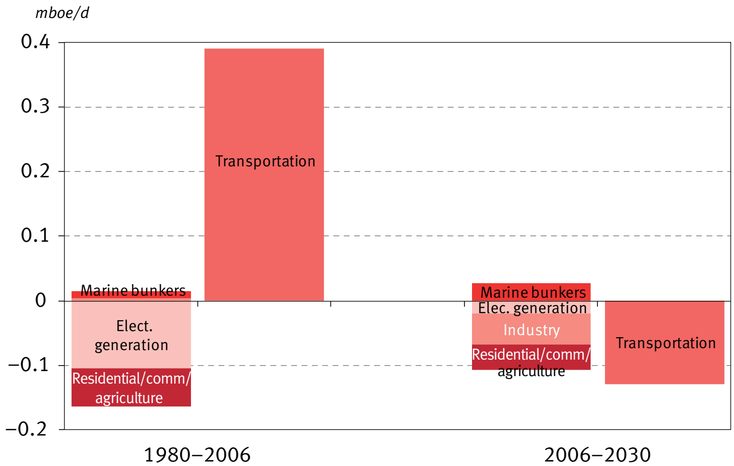


Figure 1.21
Annual growth in oil demand by sector in developing countries

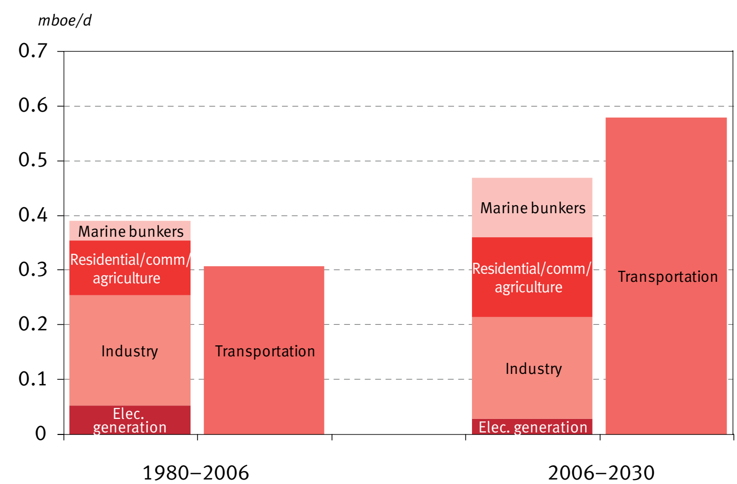


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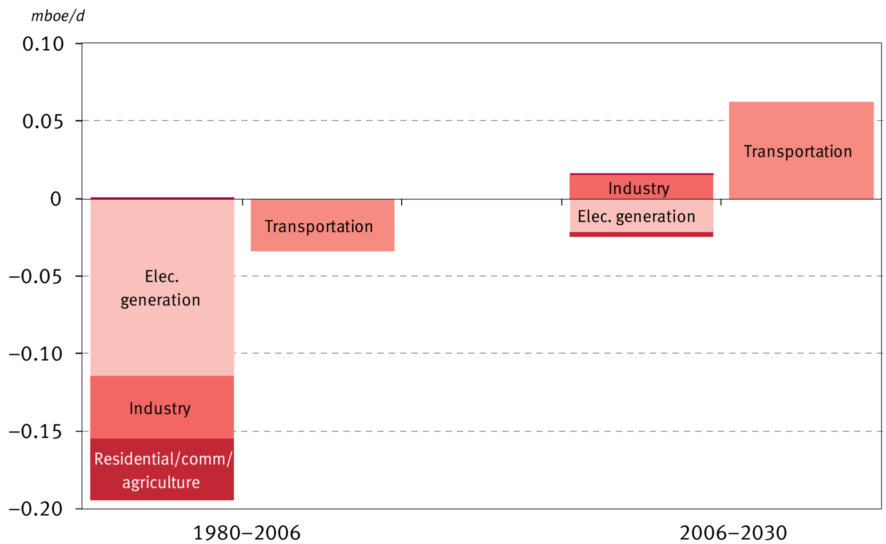
Figure 1.22
Annual growth in oil demand by sector in transition economies



volumes of other sectors amount to an increase almost as large. For Russia and the other transition economies, practically the only source of increase is transportation.

Oil supply

Oil supply in the medium-term

The medium-term oil supply prospects are derived using a bottom-up approach and an extensive database of country-specific investment projects that allows for the assessment of net additions at a country level. The total profile is the sum of the incremental volumes from new fields, combined with expected observed declines in existing fields.

Non-OPEC crude oil and natural gas liquids (NGLs) supply is expected to remain flat in the medium-term, at just over 45 mb/d. Increases from Brazil, some Asian countries, Russia and the Caspian compensate for decreases in OECD countries (see Chapter 3).

These bottom-up projections have been risk-assessed in the context of the lower oil price environment and the current economic crisis, effects of which feed through various channels. What is evident is that lower prices are leading to cancellations and delays, although this is partly offset by cost declines, debt financing, which has become more difficult, and in addition, lower earnings are limiting equity finance.

A medium-term assessment has also been made for biofuels and other non-conventionals. Biofuels are expected to grow by just 0.7 mb/d over the period 2008–2013, mainly from the US, Brazil and China. Other non-conventional oil is mainly oil sands from Canada, which is expected to increase by 0.4 mb/d from 2008–2013. However, in 2013 it is some 0.9 mb/d lower compared to the previous WOO. Once again, the low oil price environment has dampened expectations.

As a result, non-OPEC supply is more than 4 mb/d lower by 2013 than in the 2008 reference case, despite the introduction of Indonesia to this grouping. The revisions by region are shown in Figure 1.23.

Combining these assessments, the growth in conventional and non-conventional non-OPEC oil is shown in Figure 1.24. This pinpoints, for example, that, after increases in other transition economies' supply (mainly the Caspian), the largest rise in medium-term oil supply comes from biofuels and other non-conventional oil. The projections for medium-term oil supply, conventional plus non-conventional, appear in Table 1.10. Total non-OPEC supply is expected to continue to rise slightly over the medium-term, increasing by just over 1 mb/d from 2008–2013, but as mentioned, this increase is considerably below what had previously been expected.

Figure 1.23
Changes to non-OPEC oil supply Reference Case projections in 2013 compared to WOO 2008

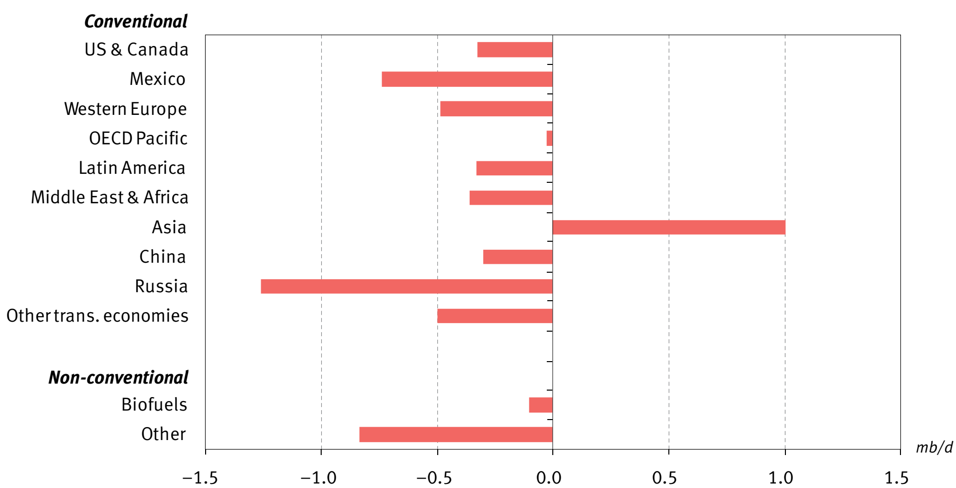
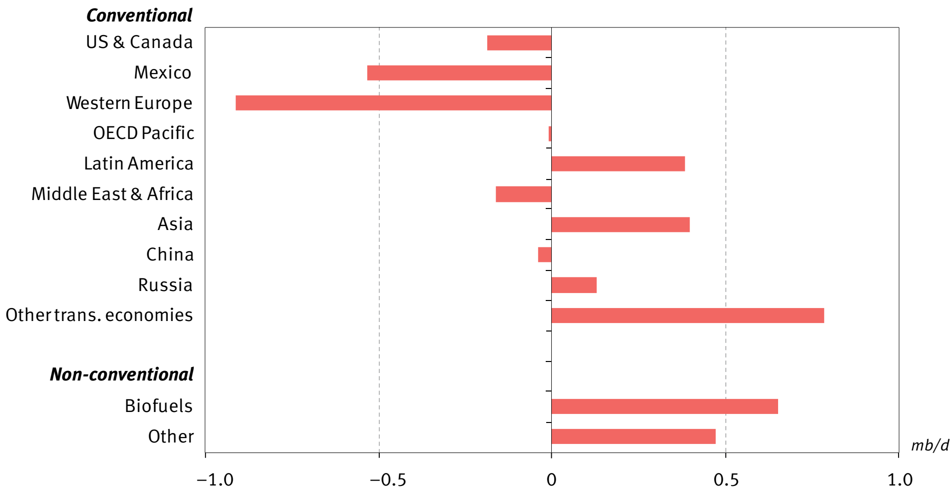


Figure 1.24
Growth in non-OPEC supply, 2008–2013



The non-OPEC supply outlook together with the demand projections gives the expected amount of OPEC oil required over the medium-term. This also appears in Table 1.10. The slowdown in oil demand growth, together with the increasing non-OPEC supply, means that the total amount of oil that will be required from OPEC, including NGLs, falls in 2009, but recovers thereafter. Over the period to 2013, however, there are also expected to be increases in the supply of OPEC NGLs and gas-to-liquids (GTLs), together increasing by 1.4 mb/d from 2008–2013. The Reference Case therefore points to a level of OPEC crude that gradually increases over the period 2010–2013. By 2013, the Reference Case volume of OPEC crude oil is approximately the same as production levels in 2008.

Large investments are currently underway in OPEC Member Countries to expand upstream capacity. Figure 1.25 presents estimates of expected capacity over the medium-term. Combining this with the required OPEC crude that is implied by the Reference Case, spare production capacity is calculated and this is also shown in the Figure. Clearly, OPEC crude oil spare capacity is set to rise over the medium-term compared to average 2008 levels. Reference Case crude spare capacity settles in the medium-term at just over 6 mb/d, in line with OPEC's objective of supporting market stability. However, if spare capacity rises too high, for example, if oil demand takes longer to recover than in the Reference Case, this might induce downward pressures on prices. The current outlook, very much affected by the impacts of the recession and consuming countries' policies, illustrates clearly the security of demand challenge facing producing countries. Efforts

Table 1.10
Medium-term oil supply outlook in the Reference Case *mb/d*

	2008	2009	2010	2011	2012	2013
US & Canada	10.8	10.7	10.9	11.0	11.2	11.2
Mexico	3.2	3.0	2.8	2.7	2.7	2.6
Western Europe	5.0	4.8	4.6	4.4	4.3	4.2
OECD Pacific	0.6	0.7	0.7	0.6	0.6	0.7
OECD	**19.6**	**19.2**	**19.0**	**18.9**	**18.8**	**18.7**
Latin America	4.1	4.3	4.4	4.4	4.5	4.6
Middle East & Africa	4.4	4.4	4.4	4.4	4.3	4.2
Asia	3.8	3.9	4.1	4.1	4.2	4.2
China	3.8	3.9	3.9	3.9	4.0	4.0
DCs, excl. OPEC	**16.1**	**16.5**	**16.7**	**16.8**	**16.9**	**17.0**
Russia	9.8	9.7	9.6	9.8	9.8	9.9
Other transition economies	2.9	3.2	3.4	3.5	3.7	3.7
Transition economies	**12.7**	**12.9**	**12.9**	**13.3**	**13.5**	**13.6**
Processing gains	1.9	1.9	1.9	2.0	2.0	2.1
Non-OPEC	**50.3**	**50.4**	**50.6**	**50.9**	**51.2**	**51.4**
of which: non-conventional	3.1	3.2	3.5	3.7	4.0	4.2
NGLs	5.5	5.6	5.7	5.8	5.9	6.0
OPEC NGLs	**4.3**	**4.6**	**4.7**	**4.9**	**5.2**	**5.5**
OPEC GTLs*	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**
OPEC crude	**31.2**	**28.0**	**29.3**	**29.9**	**30.5**	**31.0**
World supply	**85.8**	**83.1**	**84.7**	**85.8**	**87.0**	**88.2**

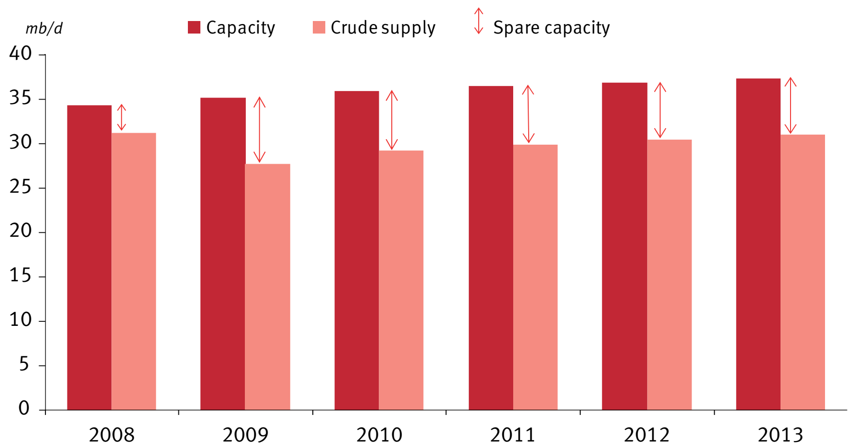
* *Includes other non-conventional oil, mainly MTBE. Future growth in non-conventional oil is expected to be dominated by GTLs.*

by OPEC Member Countries to expand capacity to secure a cushion, in the face of the relative upstream tightness that had previously emerged, had suggested that medium-term expansion needs to 2013 were around $165 billion. The new reality is that it could now be considerably lower (see Chapter 3).

Oil supply in the long-term

The long-term supply paths are linked to the resource base, using the mean estimates from the US Geological Survey (USGS) of ultimately recoverable reserves (URR). The ratio of remaining resources to current production is calculated to ensure that

Figure 1.25
OPEC crude capacity and crude supply in the medium-term



long-term sustainable feasible paths are projected. In some cases, above ground constraints dominate the paths. The feasibility is monitored beyond the projection period 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 does not thereby assume that the resource base is sufficient to satisfy expected world oil demand growth: it is a result of the methodology employed.

Table 1.11 presents the supply projections to 2030. Non-OPEC liquids supply is shown by region, and includes oil from crude, NGLs, and non-conventional oil, such as oil sands, coal-to-liquids (CTLs), GTLs and biofuels. Total non-OPEC oil supply rises throughout the projection period. This is because the increase in non-crude sources is stronger than the expected slight decline in crude supply (Figure 1.26). Indeed, non-OPEC non-conventional oil supply increases by more than 7 mb/d over the entire period 2008–2030. The key growth is expected to come from Canadian oil sands and biofuels in the US, Europe and Brazil. On top of this, non-OPEC NGLs are also expected to increase, from 5.5 mb/d in 2008 to 7.2 mb/d in 2030. These developments are also explained in detail in Chapter 3.

Over the long-term, OPEC NGLs also increase rapidly, rising by close to 4 mb/d over the whole period 2008–2030. A small increase in GTLs supply is also expected. The Reference Case demand figures, non-OPEC supply expectations, and the increase

Table 1.11
World oil supply outlook in the Reference Case *mb/d*

	2008	2010	2015	2020	2025	2030
US & Canada	10.8	10.9	11.5	12.1	12.5	13.1
Mexico	3.2	2.8	2.5	2.5	2.4	2.3
Western Europe	5.0	4.6	4.0	3.8	3.7	3.6
OECD Pacific	0.6	0.7	0.7	0.7	0.7	0.7
OECD	**19.6**	**19.0**	**18.7**	**19.1**	**19.3**	**19.6**
Latin America	4.1	4.4	4.9	5.6	6.0	6.2
Middle East & Africa	4.4	4.4	4.2	4.1	4.0	3.8
Asia	3.8	4.1	4.2	4.3	4.2	3.8
China	3.8	3.9	4.0	4.0	4.2	4.4
DCs, excl. OPEC	**16.1**	**16.7**	**17.3**	**18.0**	**18.3**	**18.3**
Russia	9.8	9.6	10.2	10.5	10.6	10.6
Other transition economies	2.9	3.4	4.0	4.4	4.7	5.1
Transition economies	**12.7**	**12.9**	**14.2**	**14.9**	**15.4**	**15.7**
Processing gains	1.9	1.9	2.2	2.3	2.5	2.7
Non–OPEC	**50.3**	**50.6**	**52.4**	**54.3**	**55.4**	**56.3**
of which: non-conventional	3.1	3.5	5.0	6.8	8.6	10.7
NGLs	5.5	5.7	6.2	6.8	7.0	7.2
OPEC NGLs	**4.3**	**4.7**	**5.8**	**6.7**	**7.4**	**8.0**
OPEC GTLs*	**0.0**	**0.1**	**0.3**	**0.4**	**0.4**	**0.5**
OPEC crude	**31.2**	**29.3**	**32.0**	**34.3**	**37.4**	**41.1**
World supply	**85.8**	**84.7**	**90.5**	**95.7**	**100.7**	**105.9**

* *Includes other non-conventional oil, mainly MTBE and orimulsion. Future growth in non-conventional oil is expected to be dominated by GTLs.*

in non-crude OPEC supply suggests that the amount of OPEC crude required will continue to rise after the medium-term period, reaching just over 41 mb/d by 2030.[3] This figure is 2.5 mb/d lower than in the 2008 reference case. The share of OPEC crude in total supply by 2030 is 39% (Figure 1.27).

Due to the strong increase in non-crude supply, from both OPEC and non-OPEC sources, and the moderate increase in demand that the Reference Case expects, the need for total crude supply increases are only modest. Supply in 2015 is 71 mb/d, the same as in 2008, while by 2030 there is only a need for less than 77 mb/d of crude oil supply globally, around 6 mb/d above 2008 levels. Figure 1.28 illustrates the

Figure 1.26
Incremental OPEC and non-OPEC supply in the Reference Case

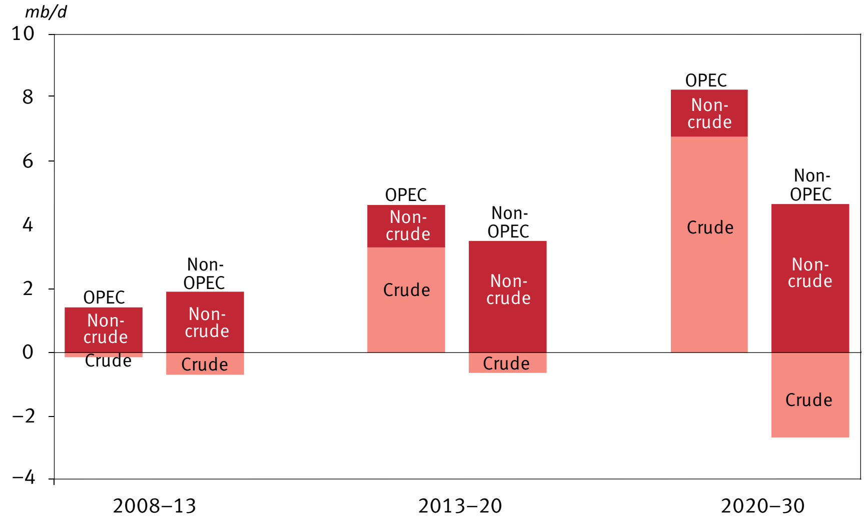


Figure 1.27
World oil supply 1970–2030: OPEC crude oil share will not be much different from today

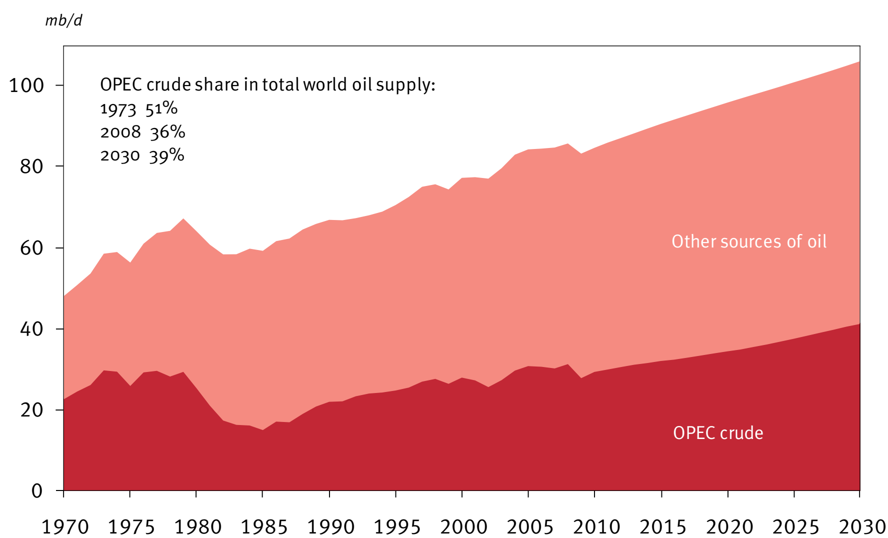


Figure 1.28
Incremental crude and non-crude oil supply in the Reference Case

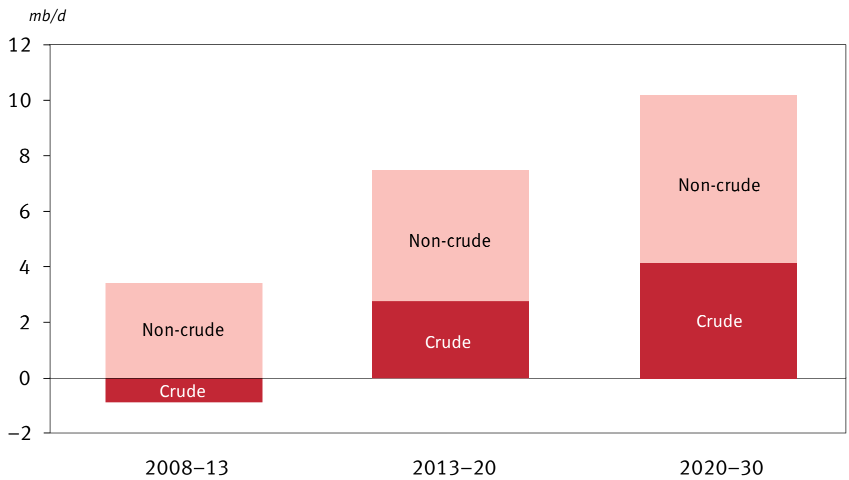
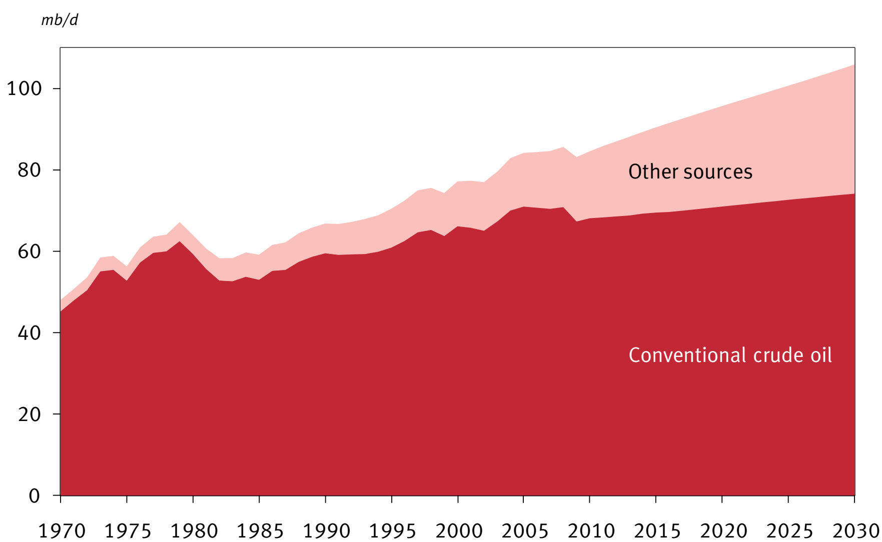


Figure 1.29
World oil supply 1970–2030: crude and other sources of oil



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incremental supply, separated between crude and non-crude, and clearly demonstrates the importance of non-crude to future supplies. Figure 1.29 illustrates the split between crude and non-crude oil sources in terms of actual volumes. An important take-away from this outlook is that the resource base of conventional crude, together with non-conventional oil, is more than sufficient to meet future demand. The key issue is therefore not related to availability, but to deliverability and sustainability.

Upstream investment

These supply increases, after offsetting the natural decline of existing mature fields, imply the need for investments along the entire supply chain. In this regard, attention has been increasingly turned to how costs might evolve. There are indications that, following a period of rising costs, the industry is witnessing a change in direction, with forces at work that could create significant downward pressure on costs. This has been factored into estimates for upstream investment requirements.

Table 1.12 shows the assumptions for the costs per b/d of capacity. These estimates do not include the investment necessary for additional infrastructure, such as for pipelines and terminals. Non-OPEC capacity additions are two-to-three times more costly than in OPEC, and over time, this difference becomes progressively larger. The highest cost region is the OECD. At an aggregate level, average costs stay close to $16,000 per b/d, as a gradual rise in non-OPEC costs is balanced by a steady eventual move towards the less costly OPEC oil.

In estimating upstream investment requirements, there is also a need to account for capacity required to compensate for the natural declines in producing

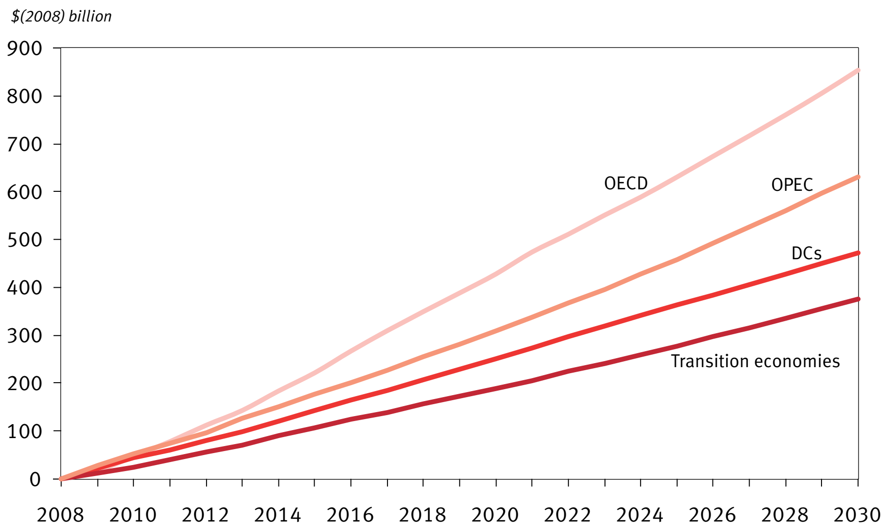
Table 1.12
Assumptions for the calculation of upstream oil investment requirements
Cost per b/d conventional oil *($1,000 (2008))*

	2010	2015	2020	2025	2030
North America	21.0	22.0	22.0	22.0	22.0
Western Europe	21.5	24.0	26.0	27.5	28.5
OECD Pacific	16.0	18.0	20.0	22.0	23.0
China	17.0	19.0	19.0	18.0	18.0
OPEC	12.0	12.0	12.0	12.0	12.0
Other developing countries	17.0	18.0	18.5	20.0	20.5
Russia	18.0	19.0	20.0	21.0	21.5
Other transition economies	18.0	18.0	18.0	18.0	18.0

fields (see Box 3.2). This can take many forms. For existing fields, it can include workovers, infill drilling, improved recovery schemes, while some new field developments will also replace such declines, and not lead to a net capacity increase.

Up to 2030, cumulative upstream investment requirements (2008 dollars) amount to $2.3 trillion (Figure 1.30).

Figure 1.30
Cumulative upstream investment requirements in the Reference Case, 2009–2030



CO_2 emissions

The global patterns of energy use in the Reference Case are contingent upon a number of assumptions, in particular for economic growth and policy developments. As described earlier in this Chapter, world economic growth averages 3% p.a. over the period 2009–2030, and from a policy perspective elements of the EU climate and energy package, as well as the US EISA, have now been incorporated. Today, it is also important to address the implications of fossil fuel supply and demand paths in terms of GHG emissions. Indeed, the Conference of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC) and the Meeting of the Parties to the Kyoto Protocol in Copenhagen in December 2009 is due to witness the culmination of the two current negotiation processes, focused on enabling the full, effective and sustained implementation of the Convention and on reaching agreement on further commitments for Annex I Parties (industrialized countries) to the Kyoto Protocol. And as much as present country- and regional-specific policies have already been incorporated in the Reference Case, the outcome of Copenhagen may well provide signals for further revisions to projections in future editions of the WOO.

The Ad Hoc Working Group on Long-Term Cooperative Action (AWG-LCA), which met 1–12 June 2009 in its sixth session, considered a Chair's negotiation text that covered the main core issues included in the Bali Action Plan.[4] This focused on a shared vision for long-term cooperative action, enhanced action on mitigation and adaptation, and enhanced action on technology transfer and the provision of financial resources. It is still too early to predict what the final outcome might be in December.

The parallel track of negotiations relates to the further commitments of Annex I Parties to the Kyoto Protocol for the post-2012 commitment period. Under this track too, negotiations have been slow and the outcome remains unclear. Table 1.13 shows some indications of the quantitative emissions limitations or reductions objectives (QELROs).

In addition to the expected discussions over targets and timetables, the use of project- and market-based mechanisms for emissions abatement is a focus of attention. There are also issues related to forestry, and the adverse impacts of response measures on developing countries in general and fossil fuel exporting countries in particular.

Furthermore, the Bali Action Plan calls for enhanced action on technology transfer. More resources from developed countries are needed in regard to technology development, deployment, diffusion and the transfer of environmentally sound technologies to developing countries. These would support mitigation and adaptation actions, but the main question focuses on the methods and means to generate the necessary resources, and the ways to access these funds. The provision of resources is a commitment from Annex I Parties under both the Convention and the Kyoto Protocol.

Alongside these four core issues, it is also important to take on board actual developments from both individual countries and regions. For example, it is evident that the previously distinct policy gap between the EU and the US on how to tackle the climate change challenge appears to be narrowing. The US is currently witnessing much debate over proposals to initiate a countrywide 'cap and trade' market for emission reductions. It is expected that this will follow a similar path to the EU ETS, which despite being beset by a number of challenges, is now in its second commitment period. The scheme covers more than 10,000 installations in the energy and industrial sectors, which are collectively responsible for close to half of the EU's emissions of CO_2 and 40% of its total greenhouse gas emissions.

Table 1.13
Proposals by countries of QELROs targets for 2020 GHG emissions in Annex I parties, as of end June 2009

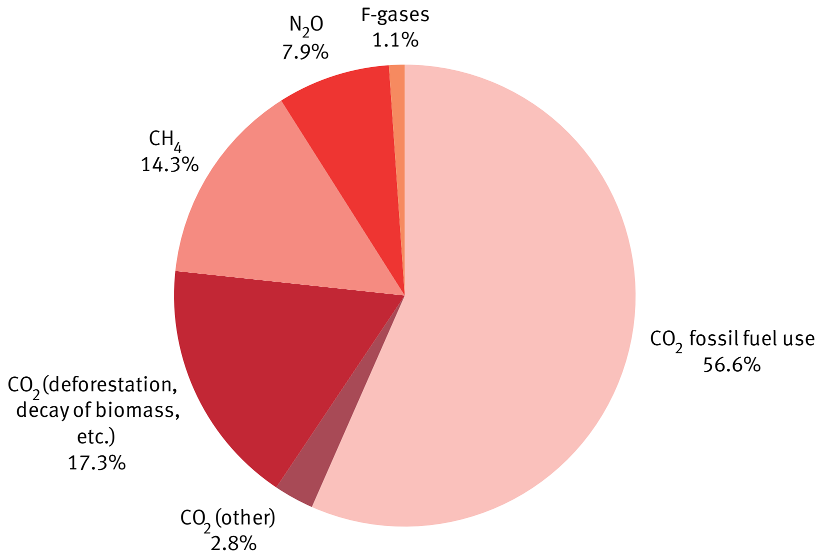
Party	QELRO	Base year
Australia	–5% to –15%	2000
Belarus	–5% to –10%	1990
Canada	–20%	2006
European Union	–20% to –30%	1990
Iceland	–15%	1990
Japan	–15%	2005
Liechtenstein	–20% to –30%	1990
Norway	–30%	1990
Russia	–10% to –15%	1990
Switzerland	–20% to –30%	1990
Ukraine	–20%	1990

It is instructive to place the Reference Case outlook into the context of the issues outlined. However, it should be noted that the implications for emissions on the OPEC energy model's output is restricted to the impacts of the combustion of fossil fuels. This means that greenhouse gas emission implications in the Reference Case are limited to CO_2 emissions. This clearly has limitations, given that CO_2 emissions from fossil fuel use accounted for no more than 57% of total anthropogenic emissions in 2004 (Figure 1.31).

While the fastest increase in emissions will come from developing countries, in line with their stronger growth and expanding energy use, there will remain a clear imbalance from the per capita emissions perspective. In 1970, Annex I countries emitted 12 times more CO_2 per person than in non-Annex I, and by 2008 it was still four times higher. Looking ahead, the Reference Case points to the expectation that by 2030 Annex I countries will emit, on average, almost three times more CO_2 per capita than non-Annex I countries (Figure 1.32).

However, cumulative emissions are even more telling, since they are relevant to possible impacts on the climate. In 2006, Annex I emissions were responsible for 78% of the global total (Figure 1.33). Despite the stronger expected growth in emissions from developing countries in the Reference Case, the cumulative contribution from Annex I will continue to dominate. By 2030, for example, they still account for two thirds of cumulative CO_2 emissions.

Figure 1.31
Share of different anthropogenic GHGs in total emissions in 2004 in terms of CO_2-eq



Source: IPCC Fourth Assessment Report of the Intergovernmental Panel on Climate Change, 2007.

Figure 1.32
Per capita CO_2 emissions in the Reference Case

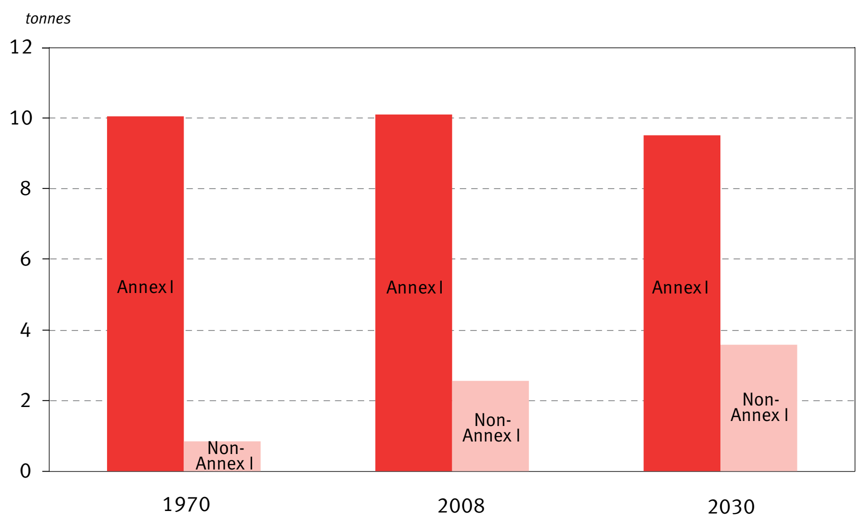
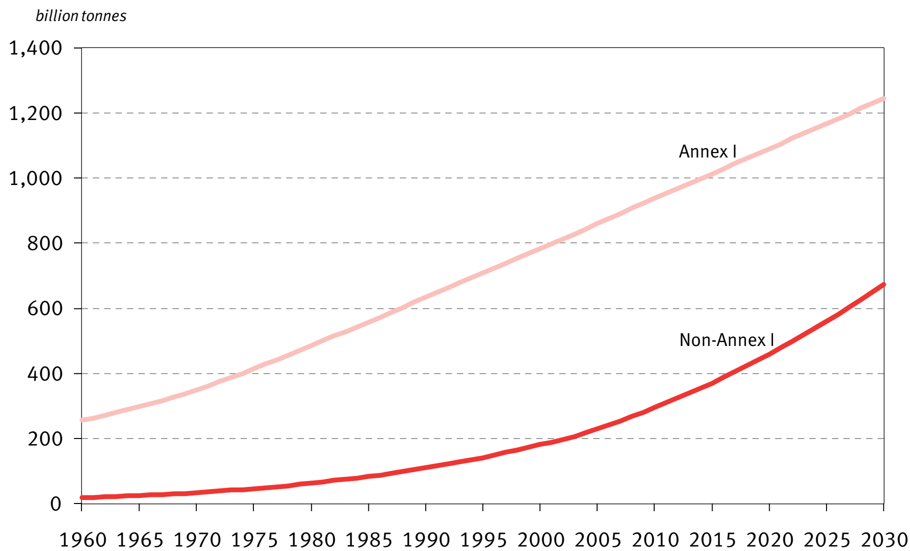


Figure 1.33
Cumulative CO_2 emissions since 1900



The outcomes from Copenhagen could naturally entail different paths for CO_2 emissions than seen in the Reference Case. The Intergovernmental Panel on Climate Change (IPCC) Third Assessment Report (TAR), issued in 2001, had already presented four classes of CO_2 concentration stabilization scenarios, namely at 450, 550, 650 and 750 parts per million (ppm). Working Group III, in its contribution to the 2007 IPCC Fourth Assessment Report (AR4), looked at new literature published since the TAR, noting that recent multi-gas studies had explored even lower stabilization levels. The assessment developed six categories of post-TAR concentration stabilization scenarios. Categories I and II are more extreme than considered previously. Table 1.14 shows that it is Categories III and IV, however, which have received the most coverage in terms of literature.

Figure 1.34 shows Reference Case global CO_2 emissions together with the IPCC estimated range of emissions consistent with the Category III concentration stabilization. Despite the fact that the Kyoto targets have been almost reached, the Reference Case path is consistent with Category III concentration stabilization, except toward the end of the projection period. The same comparison appears in Figure 1.35 for Category IV (485–570 CO_2 ppm) and in this instance, the Reference Case path remains in the range given by the 118 studies reviewed by the IPCC.

Table 1.14
Characteristics of post-TAR stabilization scenarios

Category	CO_2 concentrations *ppm*	CO_2-eq concentrations *ppm*	no. of scenarios
I	350–400	445–490	6
II	400–440	490–535	18
III	440–485	535–590	21
IV	485–570	590–710	118
V	570–660	710–855	9
VI	660–790	855–1130	5

Source: IPCC, 2007: Summary for Policymakers in: Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change.

To reach Category III concentration stabilization, there would be a need to reduce net emissions from Reference Case levels by the end of the period. The assumed mitigation portfolio includes improved energy efficiencies across all sectors, fuel switching away from higher carbon content fossil fuels, and the increased share of non-fossil fuels in the energy mix. However, over the period to 2030, it is assumed that no contribution is made by CCS or sinks. The portfolio of abatement options in the modelling work typically allows for CCS and sinks to make significant contributions to net reductions of CO_2 emissions, but only in the longer term, post-2030. This, therefore, is a major exclusion, the impacts of which are outlined below.

The impacts upon oil demand are highly dependent upon the extent to which price signals are supported by efficiency regulation, especially in the transportation sector. It is assumed that considerably swifter improvements to average vehicle efficiencies occur compared to the Reference Case.

Without CCS the impact upon fossil fuels is likely to be significant, and will affect both stationary and non-stationary sources of CO_2 emissions. Implications for oil demand specifically are subject to a wide range of assumptions, but a central estimate suggests that global demand would plateau some time after 2020 (Figure 1.36).

If the Reference Case price were to be maintained, the amount of OPEC crude that would need to be supplied would initially remain approximately flat, but then in the years after 2020 it begins to decline, perhaps falling towards 25–30 mb/d. Alternatively, and more plausibly, oil prices would remain soft, and any fall in demand would be subsequently borne by a fall in both OPEC and non-OPEC supplies. However, persistently low oil prices have been shown to bear the seeds of oil market instability,

Figure 1.34
CO_2 emissions pathways for Category III concentration stabilization

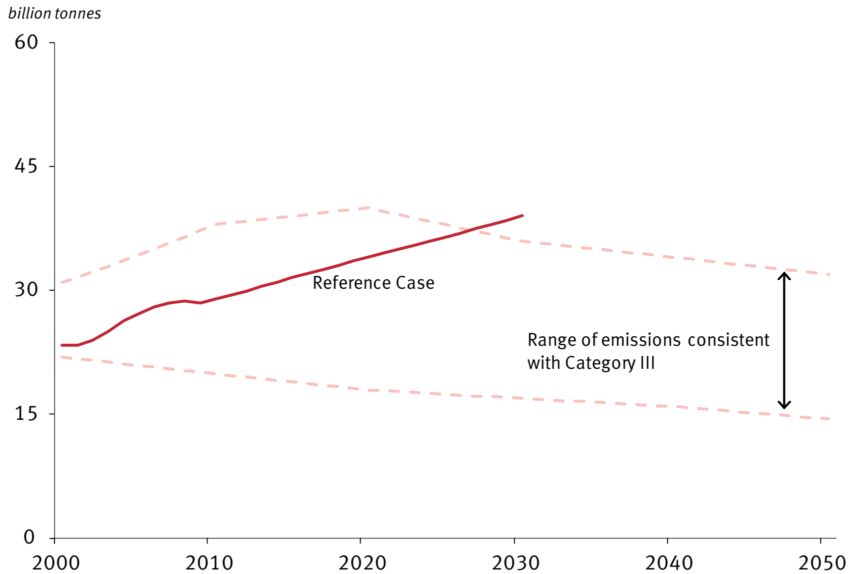


Figure 1.35
CO_2 emissions pathways for Category IV concentration stabilization

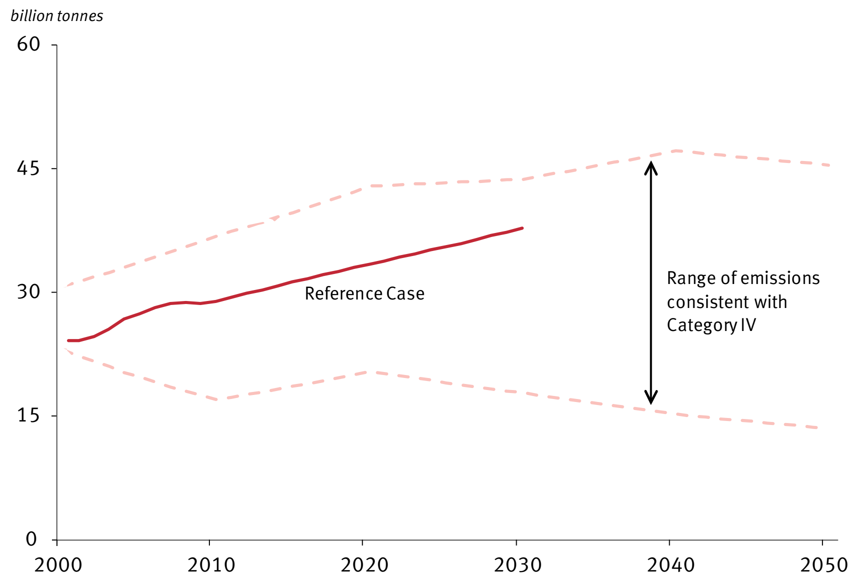
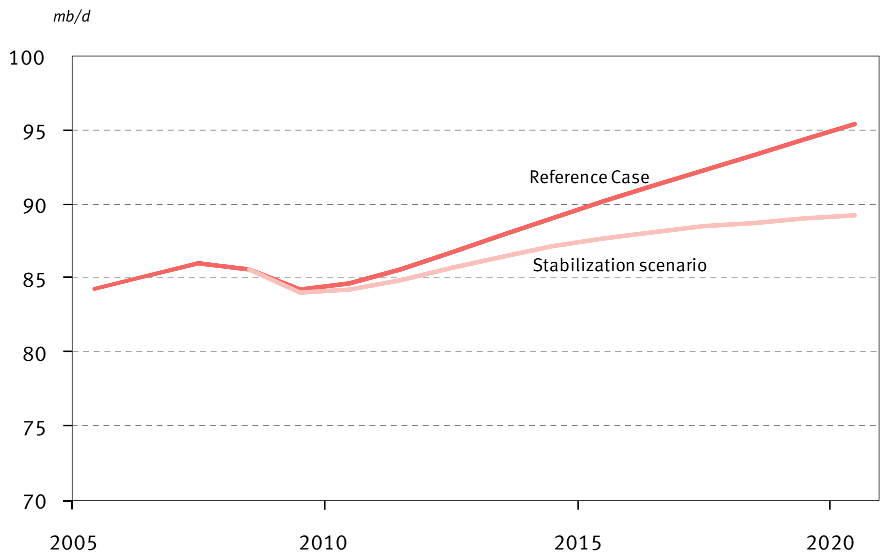


Figure 1.36
World oil demand in Category III stabilization scenario



especially if the downward pressures upon oil demand are somewhat mitigated. Moreover, low prices, as well as discouraging oil investment, would make it less economically viable to invest in alternative energy resources and technology, as well as reduce the incentive to use energy efficiently.

Although the above analysis has emphasized the possible implications of alternative emission paths for CO_2, it is important to bear in mind that climate change mitigation measures need to be comprehensive. This means addressing the net emissions of all greenhouse gases, as well as taking advantage of the full range of technologies available and sinks. Cost-effective abatement options include reducing emissions from deforestation and forest degradation, CCS, and non-CO_2 abatement measures, such as reducing methane emissions, on top of energy conservation. Indeed, the IPCC undercores the fact that a multi-gas approach and the inclusion of carbon sinks reduces mitigation costs substantially.

Consequently, any serious effort to achieve low net emission paths, such as portrayed in the scenario, must include the rapid development, deployment, diffusion and transfer of relevant technologies. These include, for example, early CCS demonstration programmes, which then need to lead to the wide-scale commercial development of CCS.

Comparison of projections

It has become common practice to compare the assumptions and projections of three institutions: the Energy Information Administration of the US Department of Energy (DOE/EIA) and its *International Energy Outlook*, with the 2009 publication released in May 2009 used here; the *World Energy Outlook* of the International Energy Agency (IEA), the latest being released in October 2008; and the OPEC WOO 2009.

Oil demand

A comparison of oil demand reference case projections for the years 2015 and 2030 is shown in Table 1.15. The expectations for future demand all incorporate the US EISA and the EU climate and energy package. As a result, demand for 2030 has once more been revised downwards across the board. OPEC, the IEA and the DOE/EIA demand projections for 2030 are now around 105–106 mb/d (although the IEA figures exclude biofuels use as well as marine bunkers at the regional level).

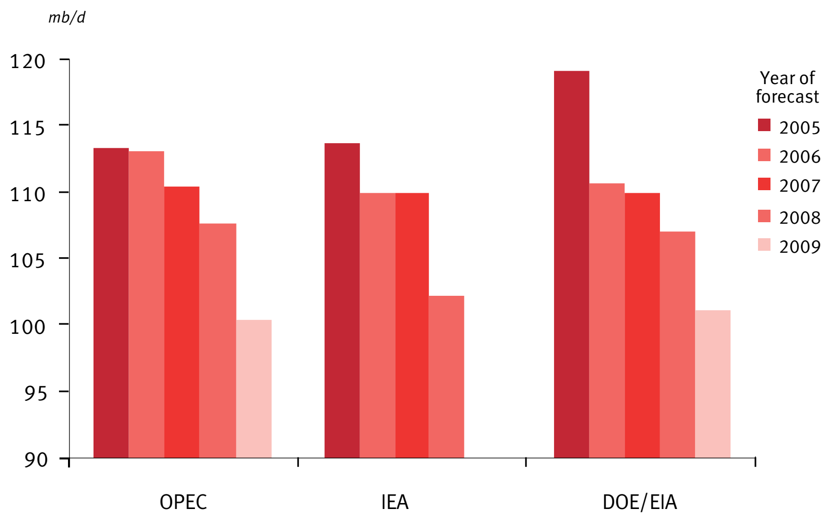
Table 1.15
Oil demand in reference case projections *mb/d*

	2015			2030		
	OPEC	IEA	EIA	OPEC	IEA	EIA
OECD	**45.5**	**45.7**	**47.2**	**43.4**	**43.9**	**50.0**
DCs	**39.3**	**38.9**	**38.2**	**56.1**	**51.8**	**51.1**
of which: China	10.4	11.3	10.0	15.9	16.6	15.3
Transition economies	**5.4**	**5.7**	**5.2**	**6.1**	**5.9**	**5.5**
World	**90.2**	**94.4**	**90.6**	**105.6**	**106.4**	**106.6**

Note: IEA figures exclude biofuels, as well as marine bunkers at the regional level.

The latest reference case projections continue the trend to revise downwards the expectations for oil demand. Figure 1.37 compares the changing demand expectations for the year 2025. The IEA projection does not incorporate the short-term demand destruction that has resulted from the global financial crisis. Indeed, the IEA has undertaken a dramatic downward revision for 2009 global oil demand, with the initially forecast growth in July 2008 of almost 1 mb/d eventually changed to a contraction of 2.4 mb/d, a loss in demand of over 3 mb/d. Further downward revisions to IEA projections could therefore be expected.

Figure 1.37
Changing world oil demand projections for 2025



This lowering of demand expectations is a reminder that there is probably a need to continue to revise projections downwards because policies are geared to reducing demand. Indications of future oil supply needs that are based solely on reference case figures could be misleadingly skewed towards the high side. There is clearly a need to continuously review the extent to which future reference cases should include policy developments.

Of note is that broadly similar assumptions are made for economic growth for OECD regions. While for developing countries, there is less agreement, there is general concurrence across all organizations that China and South Asia (predominantly India and Pakistan) will see the highest growth rates in the world, but at lower rates than has been seen in the past. There is also a tacit agreement that the impact of higher oil prices on economic growth, while present, is of a low order of magnitude.

The most interesting differences in opinion across organizations stem from the comparison of the future development of oil intensities. This is a reflection of the extent to which efficiency improvements and fuel switching have been incorporated into reference case forecasts. This points to the need to constantly revisit the energy policies that are incorporated into the reference case projections. For example, policies that have been signed into law, such as the US EISA, have been introduced across the board. But a major question surrounds the extent to which ambitious policy targets should be included in reference case projections. This includes, for example, some elements of the EU targets for the contribution of biofuels and renewables.

More significantly, the greatest differences for oil intensity developments are in developing countries. Efficiencies and fuel switching in non-OECD countries are thereby the key source of divergences regarding the oil demand outlook. The WOO figures for intensity improvements in developing countries are generally more conservative than the others. This may point to further downside risks to demand. It is clearly important to continue to monitor policy developments in non-OECD regions, and to assess the extent to which these possible shifts should be incorporated into reference case figures.

Oil supply

The revision process has not been limited to demand. There have been some major changes to non-OPEC supply projections over the past few years. Typically, downward revisions have been made. Figures for OPEC supply have also been revised downwards. The comparison appears in Table 1.16.

There are some differences among these projections. However, all agree that Western Europe supply will fall; Russian production is not expected to continue to increase as it has in the past, but rather it is likely to reach a plateau and expectations for the level of that plateau have recently come down; and, Caspian supply will continue to rise to around 4 mb/d by 2015, and further still thereafter, although the actual scale of the long-term increase is not certain.

There has been a downward revision in the DOE/EIA projection mainly due to lower than previously forecast Russian and Caspian oil. There has also been a downward revision to non-OPEC supply in the latest IEA outlook.

Table 1.16
Oil supply in reference case projections

mb/d

	2015			2030		
	OPEC	IEA*	EIA	OPEC	IEA*	EIA
OECD	18.7	18.6	21.5	19.6	20.8	24.8
DCs, excl. OPEC	17.3	14.7	17.4	18.3	13.4	21.3
Transition economies	14.2	14.3	13.6	15.7	16.6	16.8
Non-OPEC incl. processing gains	52.4	49.9	52.5	56.3	53.5	62.8
OPEC (incl. NGLs)	38.1	44.4	38.1	49.6	52.9	43.8

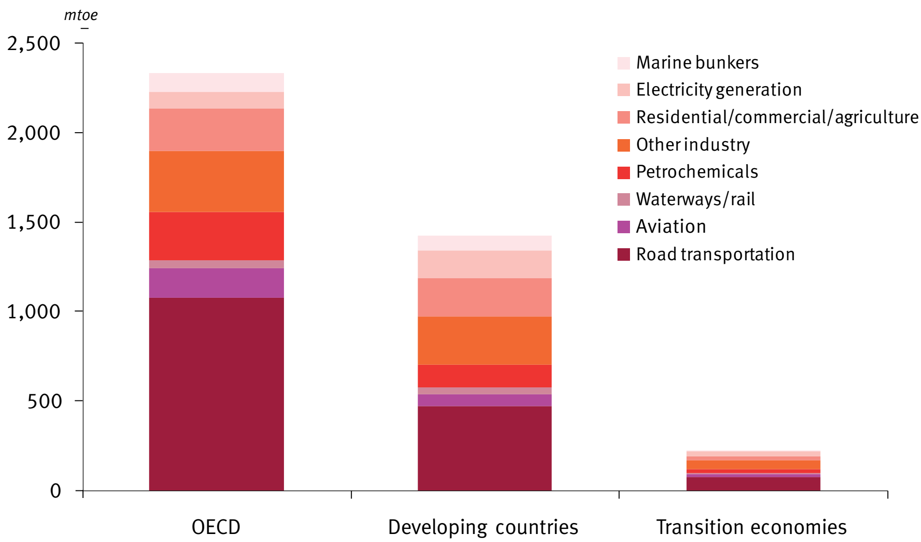
* *IEA figures exclude biofuels.*

Chapter 2

Oil demand by sector

This Chapter documents the sectoral oil demand outlook. Figure 2.1 shows the level of oil consumption by sector for the OECD, developing countries, and transition economies, while Figure 2.2 presents this distribution in relative terms.

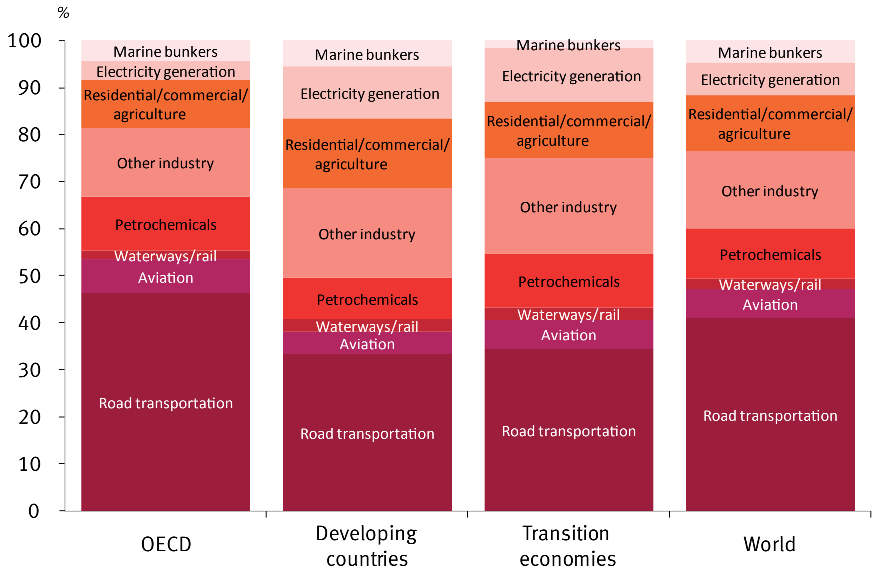
Figure 2.1
Oil demand by sector in 2006



Source: OECD/IEA Energy Balances of OECD/non-OECD countries, 2008.

Worldwide, road transportation accounted for over 40% of world oil consumption in 2006, and this share continues to rise. However, other sectors are also important for assessing future oil use. The next largest sector is industry, which includes the petrochemical sector. Increasingly, the data for this sub-sector is improving in quality, and discernible trends are emerging that could have important consequences for future demand. These are explored in more detail later. Non-road transportation is also important for oil demand, and this has been further split into aviation and other uses (mainly waterways and railways). This distinction is useful because the impetus for increasing air travel, through greater passenger and cargo traffic, is rather different to, for example, trends in diesel use in the rail sector, as electrification continues to further displace oil consumption.

Figure 2.2
The distribution of oil demand across sectors in 2006



Source: OECD/IEA Energy Balances of OECD/non-OECD countries, 2008.

The dominance of transportation in total oil demand is particularly evident in the OECD, where its share rose from 35% in 1971 to 55% by 2006. Nevertheless, the move towards car ownership saturation and the impacts of policies that target the sector are limiting factors for future potential. On the other hand, there is still substantial growth potential in developing countries. The likely growing importance of all transportation sectors to oil demand, especially in developing countries, leads us to pay particularly close attention to these sectors. In particular, assessment of how oil demand will evolve is closely linked to better understanding where the automotive industry is heading (see Boxes 2.1 and 2.2).

Road transportation

Passenger car ownership

The potential for growth in passenger cars and commercial vehicles is analyzed separately, given the different driving forces for the two types of vehicles. In particular, the idea of saturation is important for passenger car ownership. There are, however, some limitations to the usefulness of this split especially where official data on passenger cars does not include Sports Utility Vehicle (SUV) ownership (in 1993 the US Federal

Highway Administration started to include SUVs with 'trucks' rather than with cars). Nonetheless, corrections to these data sets are usually possible and in the case of the US it results in a large shift of vehicles from commercial to passenger. For example, over 80% of light trucks in the US (less than circa 4.5 tonnes) are for personal use.[5] The adjusted passenger car and commercial vehicle time series confirm the US as the country with the highest number of cars per head in the world (see Table 2.1). The assumption for passenger car saturation in North America has been increased from last year's WOO to 650 per 1,000 people.

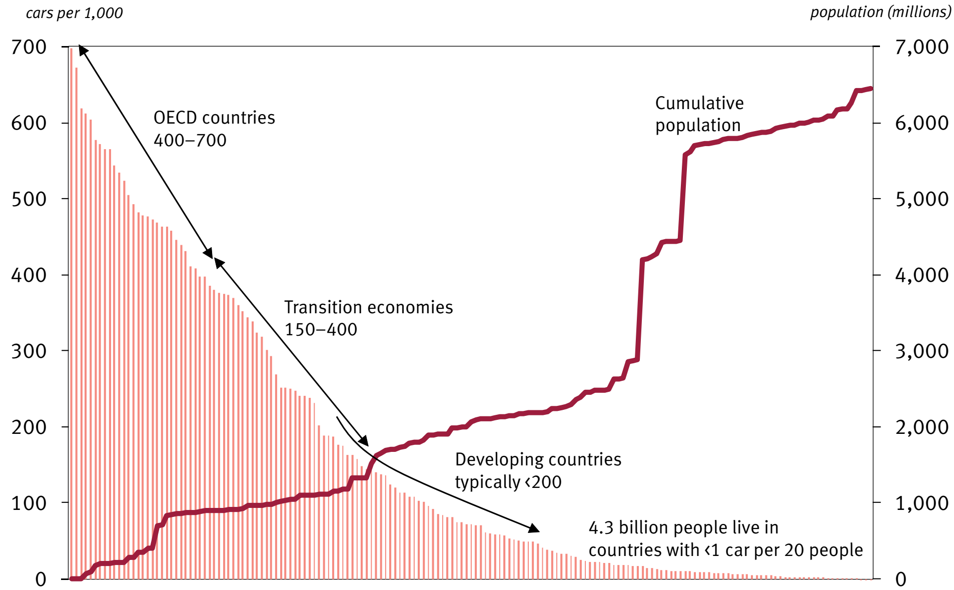
Table 2.1
Vehicle and passenger car ownership in 2006

	Cars *per 1,000*	Population *millions*	Vehicles *millions*	Cars *millions*
North America	574	446	289	256
Western Europe	434	539	269	234
OECD Pacific	418	201	109	84
OECD	**484**	**1,186**	**665**	**574**
Latin America	111	415	59	46
Middle East & Africa	25	786	29	20
South Asia	10	1,543	22	15
Southeast Asia	42	622	42	26
China	18	1,321	37	24
OPEC	53	370	30	22
DCs	**30**	**5,057**	**219**	**153**
Russia	188	142	33	27
Other transition economies	152	196	32	30
Transition economies	**167**	**338**	**65**	**57**
World	**119**	**6,581**	**949**	**783**

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

The fact that developed countries are at, or are approaching saturation levels is in contrast to the extremely low levels of car ownership in many developing countries, as demonstrated in Table 2.1 and Figure 2.3. It is unsurprising that the huge potential for growth in these countries is giving rise to strong growth in the stock of vehicles. For example, the number of cars in China increased in 2006 by 25%. And average annual growth rates for all vehicles over 2000–2006 exceeded 10% for many countries. This is the result of ownership levels that are exceptionally low with 4.3 billion people living in countries with an average of less than 50 cars per 1,000 people. There are

Figure 2.3
Passenger car ownership per 1,000 in 2006



Sources: *International Road Federation, World Road Statistics 2006 and other editions, OPEC Secretariat database.*

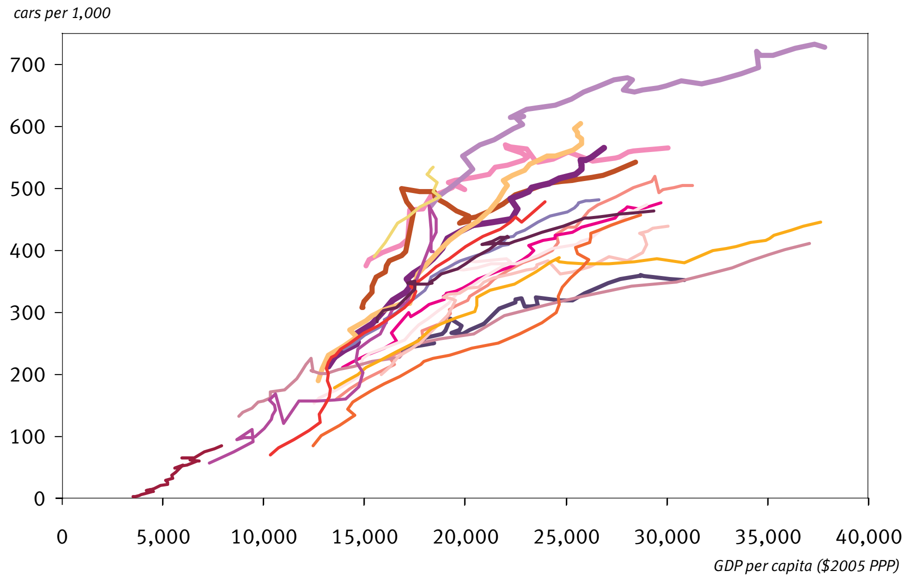
even harsher extremes that can be identified: in both Bangladesh and Ethiopia there is just one car per 1,000 people.

Yet growth in car ownership continues in OECD countries. In 2006, there were 10 million more cars in OECD countries than in 2005. This increase was 45% more than that in developing countries. For now, the sheer size of the existing stock in the OECD ensures that even a relatively moderate car stock growth will add more cars to the roads than in developing countries.

However, longer term patterns are likely to reverse this trend. The relatively distinct ownership levels demonstrated in Figure 2.3 emphasize the likelihood that saturation will increasingly become a limiting factor in OECD countries. In the OECD, ownership levels are over 400 per 1,000; transition economies are in a broad range of 150–400 per 1,000; and developing countries are typically below 200 per 1,000, with most below 100 per 1,000.

The broad variations in the number of cars per head across countries are due to more than different levels of development. Variations can also be traced, for example, to different age structures, as well as geographical and cultural differences. Even within the OECD there has been a wide variety of patterns that have been observed over the past four decades (Figure 2.4).

Figure 2.4
Development of car ownership in OECD countries, 1970–2006



Chapter 2

Box 2.1
The auto-industry: where is it heading?

Today, road transportation is the largest oil consuming sector in the world, with a total share of over 40%. It is also expected to witness the fastest oil demand growth, since in the Reference Case it needs on average more than 0.3 mb/d of additional oil annually for the period 2008–2030.

It is clear that the importance of the transportation sector requires careful and multifaceted analysis when developing future oil demand projections. In addition to the usual economic, policy and technology dimensions, it is essential to better understand the strategies, business processes and R&D programmes, as well as consumer preferences and the inherent constraints of the auto-manufacturing industry.

The worldwide automotive industry produced 73 million vehicles — cars and commercial vehicles — in 2007. Leading the way in terms of production was Japan with 11.6 million, followed by the US with 10.8 million; China, 8.9 million; Germany, 6.2 million; South Korea, four million; and France with three million. Spain, Brazil, Canada, Mexico and India, each assembled between two and three million vehicles, with the UK and Russia just below this level.[6]

To put this in some context, the level of industry output is equivalent to a global turnover of more than €2 trillion, which is greater than the GDP of the eighth largest economy in the world. The auto-manufacturing sector also employs around nine million people, with each actual job in the industry believed to support five others outside of it.[7] It is evident that in many countries the automotive sector is one of the key engines of economic activity.

Regionally, while the US and the EU will remain major. markets, the high vehicle sales growth is expected to be limited to the large developing countries, such as China, India, Brazil and Russia, driven by the relatively low vehicle ownership, fast growing disposable income, an accelerating urbanization trend and expanding trade.

In 2008, the industry witnessed considerable upheaval. In fact, it was a year that will probably be remembered for decades to come, with anticipated profound and lasting repercussions. The automotive sector was first weakened by substantially more expensive transportation fuels, with gasoline prices rising above $4 per gallon in the US, for example. In addition to the discernable impact of a reduction in driving mileages, it also caused a noticeable shift in consumer preferences, particularly in the US.

The situation was further exacerbated by the onset of the global recession, the associated massive credit crunch and the bursting of the housing and equity bubbles. This all helped push towards a substantial decline in automotive sales and placed pressure on the balance sheets of auto-manufacturers. Indeed, many had relied on financing to allow potential consumers to purchase new cars, and moreover, major automakers often earned huge returns from their financial arms during the previous expansionary economic cycle.

It means the industry now faces a huge problem of excess capacity. It is estimated that the world's major auto-manufacturers have the capacity to assemble 90 million vehicles per year. However, the recent collapse in demand means that global production will fall to about 60 million units in 2009. Accounting for around half of this surplus assembly capacity are North America and Western Europe, which each have an excess capacity of about seven million units each.

These global excess capacity conditions could continue for several more years. This is evident in past experiences. The Western European automotive downturn of the mid-seventies and early eighties saw sales drop abruptly by 17% and 10% respectively, and in each instance it took over two years for the industry to recover these volumes. Furthermore, during the structural crisis of the 1990s when sales dropped 16%, it took the industry three years to return to pre-crisis sales levels.

In this current crisis, sales have fallen by an even higher figure, between 20% and 25%, and it is therefore likely that sales volumes will take at least 3–4 years to return to 2007 levels. However, it is important to recognize that there are a number of caveats and uncertainties to this timeframe. This includes the sector's current restructuring, government intervention and the evolving credit tightness.

Auto-industry suppliers are also facing extremely difficult times. In particular, higher financing costs, as well as in some instances an absence of credit and insurance credit, have pushed some suppliers to bankruptcy, and others to the edge, with a knock-on snowball effect across the entire industry.

Looking ahead, there will be a number of major factors affecting the supply of automobiles, the most important of which are labour, material costs, production processes, technology and competition. As in the past, auto-manufacturers will no doubt consider all these issues and look to evolve, in order to survive and remain competitive. Staying one step ahead of the competition is the name of the game. With this in mind, the 2009 KPMG Auto Survey[8] suggests that innovation and technology are likely to be at the heart of industry efforts to recapture profitability in the coming years.

Two drivers are important in this connection: environmental policies, in terms of fuel efficiency and exhaust emissions, and consumer preferences.

The drive for improved fuel efficiencies will lead to a continuous improvement in vehicle characteristics, such as vehicle weight, rolling resistance, aerodynamic drag and accessory loads. It will also help push towards improvements in powertrain technology — engine and transmissions — in particular that of the liquids-fuelled internal combustion engine.

Others are pointing to hydrogen as being an answer to improved fuel efficiencies and better environmental credentials. However, its low energy density, the lack of adequate infrastructure, high costs, storage difficulties, safety issues and consideration of well-to-wheel emissions constitute some of the many hurdles facing hydrogen in becoming an accepted automotive fuel. Thus, the transition to compete in the market will likely take many decades.

At present, it seems that a more realistic option is partial or full hybridization. However, hybrids remain costly, and their fuel efficiency is sensitive to city/motorway duty-cycle and to load accessories such as air-conditioning (see Box 2.2).

Consumer preferences, the other driver, are decidedly blurred in the long-term. To what extent environmental factors influence a purchasing decision, or whether there is a shift towards alternative modes of transport, along with the usual social, safety and economic factors, remains to be seen, although it is to be expected that these influences will probably differ from one region to another. It should also be noted that regulatory policies, such as fuel taxation and congestion charges, may have a discernable impact on consumer choices and car segmentation shifts.

For the foreseeable future it is apparent that the diesel engine will remain the most efficient internal combustion engine, enjoying a significant fuel efficiency advantage over the spark-ignited engine, as well as hybrids in duty-cycles with less city driving.

Given the current automotive industry situation, and the drivers discussed above, it is considered most likely that liquids fuels, similar to today's gasoline or diesel fuel, will remain the preferred fuel by 2030, with the internal combustion engine maintaining its dominance in the industry.

For developing countries, the assumption is made that lower saturation levels will be more relevant than OECD developments might suggest. Alternatives to the US suburban growth culture are considered likely, but there continues to be considerable debate as to how much lower the saturation levels might be. For countries at very low ownership levels, it is not about saturation, but rather the inherent constraints such as available infrastructure that may limit ownership growth.

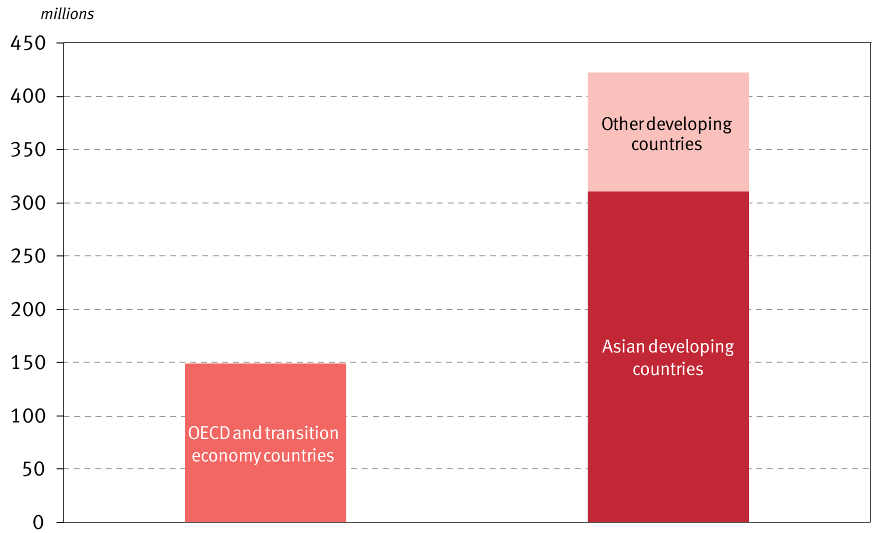
The total stock of cars rises from just over 800 million in 2007 to well over 1.3 billion by 2030. Passenger car ownership levels to 2030 are shown in Table 2.2. The volume increase is also depicted in Figure 2.5. As previously mentioned, the current trend, with OECD volumes increasing faster than those for developing countries, will be reversed in the longer term. While an additional 110 million cars will be on OECD roads by 2030, the increase in developing countries will be almost four times more. Developing Asia will account for more than half of the global increase in passenger car volumes. The share of developing countries in the global car stock, though more than doubling from 20% in 2007 to over 40% by 2030, still remains less than the OECD despite a much higher population.

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	557	584	603	259	259	295	325	1.0
Western Europe	440	436	463	489	238	238	260	277	0.7
OECD Pacific	424	427	442	449	85	86	89	88	0.2
OECD	**488**	**481**	**508**	**530**	**582**	**583**	**644**	**691**	**0.7**
Latin America	115	122	141	162	49	53	69	85	2.5
Middle East & Africa	26	29	39	48	22	26	42	63	4.8
South Asia	11	14	32	69	17	23	60	143	9.6
Southeast Asia	44	48	67	91	27	31	48	71	4.2
China	20	26	62	115	26	36	89	167	8.4
OPEC	51	56	73	95	19	23	35	52	4.4
DCs	**31**	**36**	**56**	**87**	**160**	**192**	**342**	**582**	**5.8**
Russia	199	218	286	344	28	30	38	42	1.8
Other trans. economies	157	174	232	286	31	34	46	56	2.6
Transition economies	**175**	**193**	**253**	**309**	**59**	**65**	**84**	**99**	**2.3**
World	**120**	**121**	**139**	**165**	**802**	**840**	**1,070**	**1,372**	**2.4**

Car ownership per capita in developing countries also increases more rapidly than in the OECD, given the low base values, moving from on average 31 per 1,000 in 2007 to 87 per 1,000 by 2030. The energy poverty issue is demonstrated in these figures in the form of 'car-poverty'. Only Latin America vaguely approaches recently observable ownership levels in OECD countries. By 2030, it reaches 162 cars per 1,000, which is similar to the average ownership in Austria in 1970, Cyprus in 1983, Greece in 1992, and South Korea in 2000. The Southeast Asia region now includes Indonesia, which currently has less than 20 cars per 1,000. This results in a downward revision to ownership levels per 1,000, both now and in the future. China and South Asia demonstrate the fastest growth rates in both ownership per capita and absolute volumes. The lowest ownership levels are in South Asia and the Middle East & Africa. Though it should be noted that cheap cars such as Tata's Nano might have a future impact by making it easier to switch from motorcycles and mopeds to cars. Finally, OPEC car ownership remains under 100 per 1,000 over the projection period.

Figure 2.5
Increase in number of passenger cars, 2007–2030

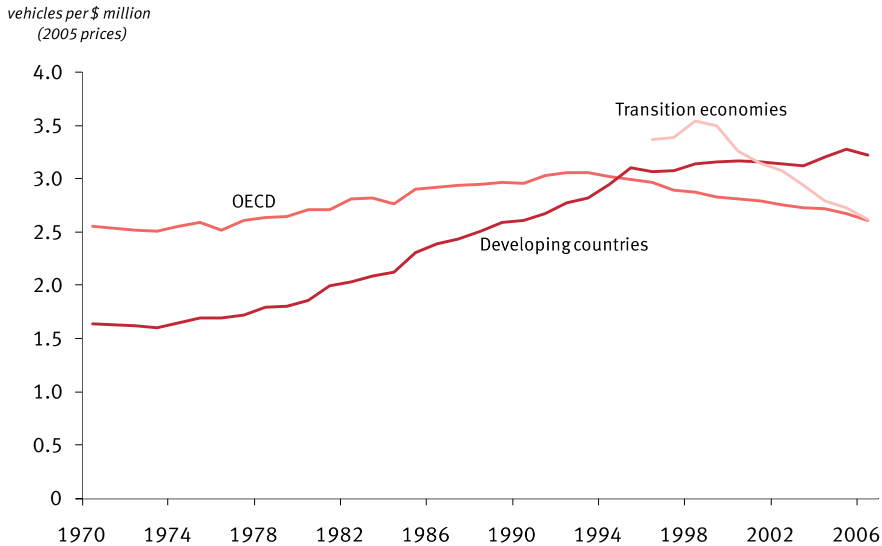


Commercial vehicles

The 'intensity' of passenger car ownership, as measured by cars per capita, is closely linked to development levels, with the highest ownership rates in the OECD, and the lowest in the poorer developing countries. The most useful corresponding indicator for commercial vehicle volumes is trucks and buses per dollar of economic output, which is referred to here as the corresponding 'intensity'. This indicator reveals that there is no parallel robust relationship between commercial vehicle intensity and development levels. Figure 2.6 shows the development of commercial vehicles per unit of GDP, on average, for the OECD, developing countries and transition economies, from 1970–2006. The ratio for OECD countries has been on a downward trend since the early 1990s, reflecting a structural change in OECD economies towards a higher share of the economic output for the tertiary sector, while developing countries on average now use more trucks and buses than the OECD for each dollar of output.

The use of commercial vehicles is closely linked to economic activity, changing trade patterns and the GDP structure, and patterns have clearly been changing. For instance, over the years 1990–2006, the share of industrial value-added in developing countries' GDP rose, on average, from 47% to 58%, while the corresponding share for OECD countries fell from 37% to 31%. Put another way, 85% of the increase in real industrial output over the years 1990–2006 has been in

Figure 2.6
Commercial vehicle intensities: volume per unit of GDP, 1970–2006



developing countries. Commercial vehicles are not exclusively used in connection with industrial output, for example, the series includes buses, but there is a strong linkage. The contrasting evolution of intensities for OECD and developing countries in Figure 2.6 are therefore unsurprising. Moreover, it is expected that the future difference will be even greater.

Table 2.3 contains the Reference Case projection for trucks and buses. As expected, developing countries growth is stronger than other regions. Total volumes in 2030 are approximately double 2007 numbers, and, of the 174 million increase over that time, 81% will be in developing countries, with 51% in developing Asia (Figure 2.7). Already by 2015, there will be more trucks and buses in developing countries than in the OECD.

Oil use per vehicle

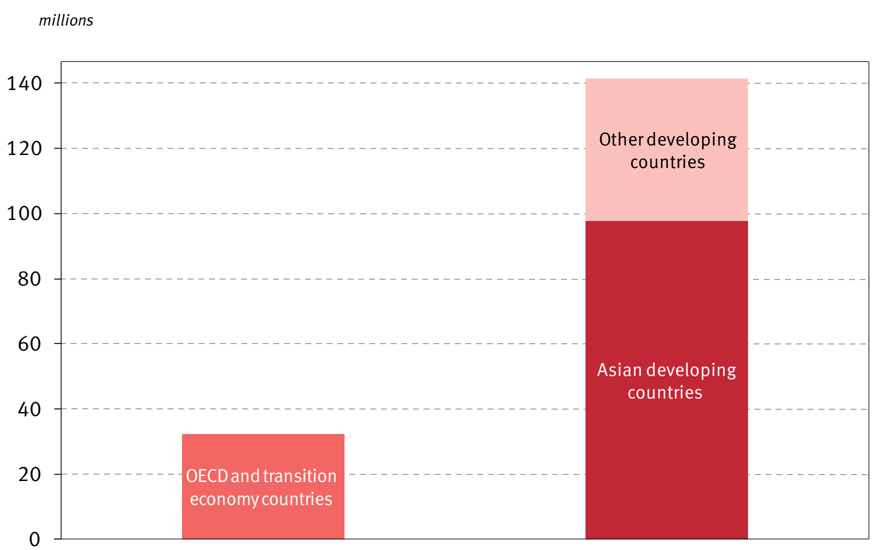
Oil use per vehicle is a pivotal variable. At the aggregate level, it reflects, *inter alia*, efficiencies, consumer purchasing and driving behaviour, the rates of introduction of new technologies, and the relative strength of gasoline and diesel demand growth. Increased biofuels use also has an impact upon volumes. Of particular significance in this Reference Case is the impact that consumer country policies could have on the variable. As described in Chapter 1, the major change in

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	35	33	36	38	41	44	1.0
Western Europe	35	37	40	44	49	54	1.9
OECD Pacific	26	25	26	26	26	26	0.1
OECD	**95**	**95**	**101**	**109**	**116**	**124**	**1.1**
Latin America	15	16	19	22	25	29	2.9
Middle East & Africa	10	13	17	23	30	38	5.9
South Asia	8	10	15	21	29	39	7.2
Southeast Asia	19	21	27	34	42	52	4.4
China	12	14	19	24	30	36	4.9
OPEC	9	10	12	15	17	20	3.5
DCs	**74**	**84**	**109**	**139**	**173**	**215**	**4.8**
Russia	6	6	6	7	7	7	0.8
Other transition economies	3	3	4	5	5	6	2.5
Transition economies	**9**	**9**	**10**	**11**	**12**	**13**	**1.5**
World	**178**	**189**	**220**	**258**	**302**	**352**	**3.0**

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



assumptions for policy implementation concerns the US EISA and the EU climate and energy package. These have important implications with regard to oil use per vehicle.

The WOO 2008 contained policy scenarios that calculated the possible impacts of these measures, but these were not incorporated fully into the Reference Case. It will be recalled that the original 1975 US Energy Policy Conservation Act that introduced CAFE standards allowed a lower efficiency for light trucks (including SUVs). The EISA, which raises CAFE standards from the current 25 miles per gallon (mpg) to 35 mpg by 2020, applies equally to SUVs. The average efficiency increase of new cars is therefore set to increase by more than 3% from the first year of implementation. The medium-term impacts of this new policy are limited, however, because the law will be applied in 2011, and the effects will then be felt gradually as the stock of vehicles turns over.

The longer term Reference Case impacts are subject to uncertainties for two key reasons. Firstly, the legislation covers the period to 2020, but assumptions are needed for the possible continued drive towards higher rates of efficiency – as in the WOO 2008, the assumption is made that further improvements are introduced, but at a more modest pace than for the period to 2020. And secondly, the EISA does not explicitly address truck efficiency targets, but there is an intention to do so. The assumption made in the Reference Case is for a technology 'spillover' to truck and bus efficiencies that is consistent with the medium-case explored in 2008. The net result is to further reduce oil use per vehicle in North America by an average of 1% p.a. over the period 2007–2030.[9]

For the EU, and as underlined in Chapter 1, the recently adopted climate and energy legislative package involves a binding target of 120g CO_2/km, phased in over the period 2012–2015, with fines payable by manufacturers for not meeting these targets. This is a major reduction from current levels, amounting to a change of around 4% p.a. A long-term target of 95g CO_2/km by 2020 is also included in the agreement. The impact of greater efficiencies upon the whole car stock will initially be limited, as with North America, but it will grow over time as the car stock turns over. The net assumption for this effect is to increase efficiency improvements for Western Europe's road transportation sector by 0.5% p.a. in the period to 2030, compared to the previous reference case. This is consistent with the scenario analysis in the WOO 2008, which looked at the impact of the EU policy.

The assumptions over the period 2007–2030 are documented in Table 2.4. At the global level, average efficiency improvements are now at 1.6% p.a., compared to 1.1% p.a. in last year's WOO.

Table 2.4
Average growth in oil use per vehicle

% p.a.

	1971–1980	1980–1990	1990–2007	2007–2030
North America	–1.6	–0.7	0.2	–1.7
Western Europe	–0.7	–0.4	–0.8	–1.4
OECD Pacific	–1.6	0.4	–0.7	–1.2
OECD	**–1.3**	**–0.5**	**–0.3**	**–1.5**
Latin America	–4.7	–3.0	–0.8	–1.4
Middle East & Africa	–0.5	–1.4	–1.3	–2.3
South Asia	5.0	–2.1	–6.5	–2.5
Southeast Asia	1.3	–0.3	–2.5	–2.0
China	–5.1	–5.1	–3.0	–3.4
OPEC	2.5	–0.6	–1.3	–1.4
DCs	**–1.6**	**–1.9**	**–1.9**	**–2.1**
Russia	n/a	n/a	–5.9	–0.2
Other transition economies	n/a	n/a	–4.6	–0.5
Transition economies	**2.0**	**–2.1**	**–5.6**	**–0.3**
World	**–1.1**	**–0.8**	**–0.7**	**–1.6**

Road transportation demand projections

The projections for passenger car ownership patterns and commercial vehicle volumes combined with the assumptions for oil use per vehicle and average efficiency gains generate figures for road transportation demand in the Reference Case (Table 2.5). Demand rises by less than 8 mboe/d over the period 2007–2030, considerably lower than in last year's assessment. This downward revision of close to 4 mboe/d is the result of the severe global economic contraction in the initial years

Box 2.2
Plug-in hybrids: plugged in, or plugged out?

Plug-in hybrid electric vehicles (PHEV) are considered by many to be the next logical step to hybrid electric vehicles (HEV). While the HEV relies ultimately on the fuel in its tank to obtain its energy requirements, the PHEV obtains a portion of its energy needs — when it is not travelling — through being plugged into the electricity network. Thus, the PHEV provides an opportunity for fuel switching in the transportation sector, as in the main, fuels other than oil are used to supply electricity to the grid.

There is clearly potential for PHEVs, and their development has received much government impetus in recent years. However, a number of question marks remain. It begs the question: just what can be deemed realistic for the development and expansion of PHEVs?

The commercial success of the PHEV ultimately depends on the development of appropriate battery technologies. The fact that PHEVs need to plug into the electricity grid implies specific battery requirements. For example, there is the importance of battery storage capacity, which will determine the distance that can be travelled using the electric drive of the vehicle, the charge depleting (CD) range, and how many recharging stops are required.

In CD mode, a PHEV can be designed to use only electricity from the battery or for a blended operation where both electricity and liquid fuel are utilized to power the vehicle. The blended operation allows for a smaller electric powertrain. As a conventional powertrain is less expensive than an electric powertrain, on a per-kilowatt basis, downsizing the electric powertrain is desirable for cost reasons. For an all-electric design, the battery must also be capable of providing the full power required by the vehicle.

Battery cell design may be optimized to deliver either higher energy or higher power and cell designs involve a trade-off in this respect. Greater power is achieved by using thin film electrodes, and a greater capacity by leveraging thicker electrodes. Thus, there is a distinction to be made between batteries that have a high energy-to-power ratio and those that have a high power-to-energy ratio.

A pure battery electric vehicle (BEV) that relies only on battery energy for its entire driving range, requires a high energy-to-power ratio battery. On the flip side, a HEV needs a high power-to-energy ratio battery. And in between these is the PHEV, where the ratio of energy to power rises as the CD range expands. It should be noted that as the ratio of power increases, the total battery system mass required for increasing the CD range of a PHEV — including additional vehicle structural components — increases too.

It is evident that batteries for PHEVs need to be larger in volume and heavier in weight than those that have so far been used for HEVs, mainly nickel-metal hydride (NiMH) batteries. With this in mind, Lithium-ion (Li-ion) batteries are taking centre stage. These can achieve higher specific power and energy levels, making them more suitable for PHEV applications. In addition, Li-ion batteries are potentially cheaper than NiMH. However, the current state of development of Li-ion batteries, for demanding applications in transportation, remain short of industry targets, for example, those set by the United States Advanced Battery Consortium (USABC).

Lithium, a relatively rare element that is never found naturally in its pure form, is predominantly marketed as lithium carbonate (Li_2CO_3), which is produced by electrolysis from lithium brine deposits. This is then used as the raw material for the manufacture of Li-ion batteries.

In its *Mineral Commodity Summaries 2009*, the USGS estimates that the lithium global reserve base is 11 million tonnes. This includes those resources that are currently economic, marginally economic, and some of those that are sub-economic. Another study, from Meridian International Research (MIR) in 2008, shows that the economically recoverable lithium reserves from brine are lower than previously estimated, at only four million tonnes of lithium.

In terms of Li_2CO_3 demand, the last decade witnessed robust growth at over 7% p.a. In 2007 the figure was 93,000 tonnes, up 7.4% from 2006. In fact, batteries are the fastest growing sector for Li_2CO_3 demand, averaging growth of 25% p.a. since the mid-1990s, driven by the increase in its demand for laptop computers and mobile telephones. MIR projects that demand from the existing battery sector — non-automotive demand — will continue to grow over the next decade also by at least 25% p.a., far outstripping the expected overall lithium market growth of 4–5% p.a.

MIR also forecasts high and low Li_2CO_3 production scenarios. In its high growth scenario, production is anticipated to be around 235,000 tonnes by 2015. It considers that this represents an optimistic projection based on a best possible combination of events for the development of new resources and the continued smooth production of resources already under exploitation. In the low scenario, which assumes no development of new resources and the imposition of environmental constraints on current production areas, global production in 2015 is only 170,000 tonnes.

Alongside these production scenarios need to be placed ones for battery demand.

The MIR's high non-automotive demand scenario, with battery demand continuing to grow at the recent brisk rate of 25% p.a. and demand in the non-battery sector at 4.7% p.a., leads to some 32,000 tonnes of Li_2CO_3 being available to the automotive market by 2015, when combined with the high production scenario.

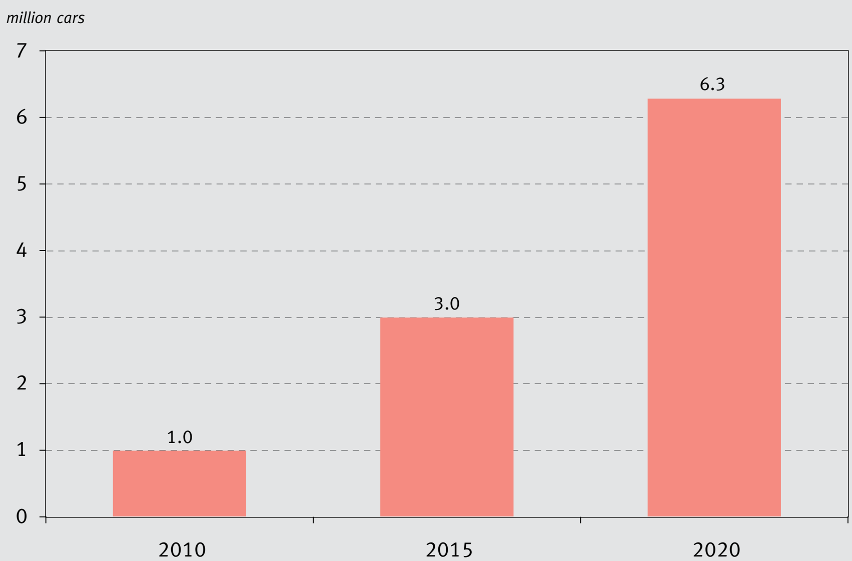
In an extension of MIR's high production scenario, production is assumed to grow at 14% p.a. from 2007–2015, and by 10% p.a. post-2015, while in the extension of its low non-automotive demand scenario, there is a growth rate of 3.5% p.a. post-2015, compared to 5.5% p.a. from 2007–2015.

Combining these scenarios, Li_2CO_3 availability for vehicle battery requirements reaches 110,000 tonnes in 2015 and 230,000 tonnes in 2020. And based on these projections, the estimated total number of PHEVs whose manufacture could be supported from the perspective of the raw material availability for Li-ion batteries is shown in the figure below.

What is evident is that the raw material availability for cathode manufacturing, based on Li-ion batteries, constitutes a limiting factor to the penetration of PHEVs.

A potential mitigating factor in this is the possibility of battery recycling. The recycling issue raises two key questions. Firstly, can a given battery be recycled to prevent environmental damage? And secondly, can the materials recovered in recycling be used to make new batteries?

Projection of PHEV-40 vehicles supported by lithium carbonate supply/demand scenarios*



* *This assumes that a PHEV could be driven for 40 miles in all-electric mode using a 17-kWh battery. Such a battery requires approximately 35kg of raw lithium carbonate, including purification losses.*

The recycling of lead acid batteries is an efficient process, with an established recycling infrastructure, but at present no such system exists for Li-ion batteries, although small-scale recycling is performed by a few operators. The current recycling processes depend on cobalt recovery for economic feasibility, but future automotive batteries are likely to use little or no cobalt. According to the Argonne National Laboratory, it means that new and improved processes to recover additional materials economically from cell chemistries will be required. A number of these processes are currently being tested.

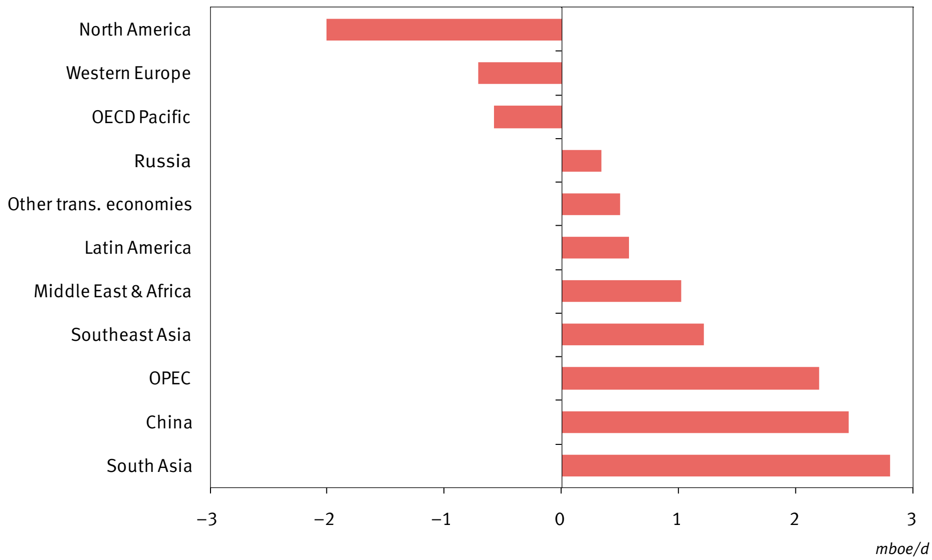
Table 2.5
Oil demand in road transportation in the Reference Case

mboe/d

	Levels				Growth
	2007	2010	2020	2030	2007–2030
North America	12.8	11.5	11.4	10.8	–2.0
Western Europe	6.3	6.0	5.8	5.6	–0.7
OECD Pacific	2.6	2.4	2.3	2.0	–0.6
OECD	**21.7**	**19.8**	**19.5**	**18.4**	**–3.3**
Latin America	1.9	2.0	2.3	2.5	0.6
Middle East & Africa	1.2	1.3	1.7	2.2	1.0
South Asia	0.9	1.0	2.1	3.7	2.8
Southeast Asia	1.8	1.9	2.5	3.1	1.2
China	1.8	2.0	3.4	4.2	2.4
OPEC	2.6	3.0	3.8	4.8	2.2
DCs	**10.2**	**11.2**	**15.8**	**20.4**	**10.2**
Russia	0.9	0.9	1.1	1.2	0.3
Other transition economies	0.8	0.8	1.0	1.3	0.5
Transition economies	**1.6**	**1.7**	**2.1**	**2.4**	**0.8**
World	**33.5**	**32.7**	**37.5**	**41.2**	**7.8**

of the projection period and the greater efficiency improvements assumed. Practically all growth comes from developing countries, though some increase is expected in transition economies. For the first time, road transportation demand is expected to fall in all OECD regions throughout the entire projection period, despite the rise in vehicle stock. According to the outlook, OECD road transportation appears to have peaked in 2007. Figure 2.8 illustrates these developments for the net growth in road transportation demand from 2007–2030. Here it can also be seen that over 80% of the net increase in road transportation oil demand takes place in developing

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



Asia. By 2030, developing countries consume more oil in this sector than OECD countries.

Aviation

Aviation oil demand in 2007 was less than one-sixth of that for road transportation, accounting for a little over 6% of world demand. The OECD currently accounts for around two-thirds of world aviation oil demand, more than double that consumed in developing countries. The US alone accounts for over one-third of world demand. 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. Nevertheless, as with road transportation, the greatest percentage growth rates have been in Asian developing countries, where over the period 1990–2007 there was an average increase of 7% p.a. Despite China witnessing the highest demand growth over this period, at an average of almost 17% p.a., even by 2030 it remains lower than the US and EU. Indeed, this growth has been from a very low base, and over the past two decades OECD volume growth has continued to outstrip that of developing countries.

The increase in the Reference Case over the period 2007–2030 is almost 2 mboe/d, and while growth is expected in all regions, the expansion in developing

Table 2.6
Oil demand in aviation in the Reference Case *mboe/d*

	Levels				Growth
	2007	2010	2020	2030	2007–2030
North America	1.8	1.8	1.9	2.0	0.2
Western Europe	1.1	1.1	1.1	1.2	0.1
OECD Pacific	0.4	0.4	0.5	0.6	0.1
OECD	**3.3**	**3.3**	**3.5**	**3.8**	**0.4**
Latin America	0.2	0.2	0.2	0.2	0.1
Middle East & Africa	0.2	0.2	0.2	0.3	0.1
South Asia	0.1	0.1	0.2	0.2	0.1
Southeast Asia	0.4	0.4	0.5	0.7	0.2
China	0.2	0.3	0.5	0.7	0.5
OPEC	0.2	0.3	0.3	0.4	0.1
DCs	**1.4**	**1.5**	**2.0**	**2.5**	**1.1**
Russia	0.2	0.3	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	**5.0**	**5.1**	**5.9**	**6.7**	**1.7**

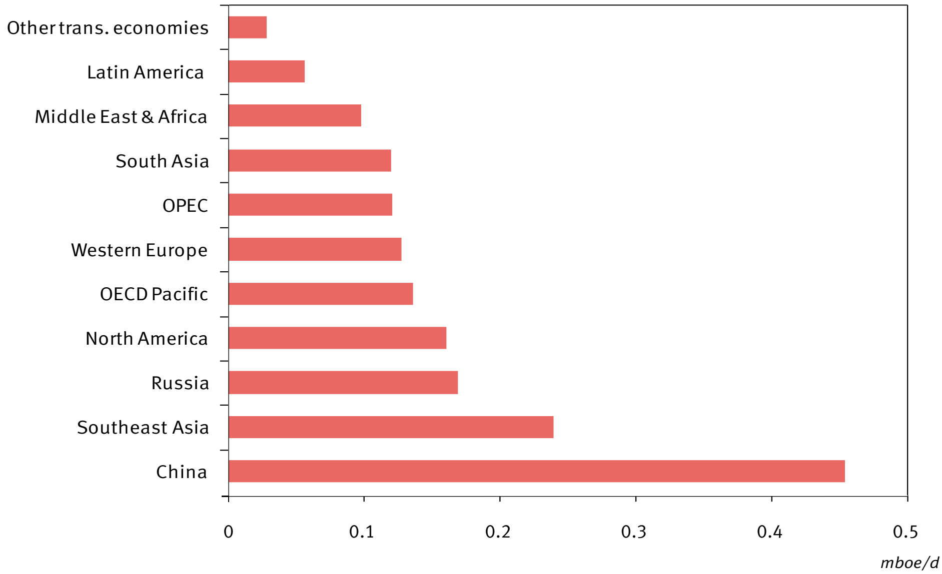
countries will be around three times higher than that for the OECD (Table 2.6). As with the recent historical patterns, the fastest percentage growth is in China, with the country also witnessing the largest single increase in aviation oil demand at close to 0.5 mboe/d (Figure 2.9). Despite this, by 2030 OECD countries will continue to account for a higher proportion of aviation oil demand than developing countries (see Box 2.3)

Other transportation: domestic waterways and railways

Oil use in the transportation sector, other than road and aviation, is mainly accounted for by diesel trains and domestic navigation in waterways, but these currently account for only 2% of oil use. International marine bunkers are treated separately later.

The world's four largest countries by land mass are also the top four users of oil in diesel locomotives. The US, China, Russia and Canada, together with the world's seventh largest country by land mass, India, account for more than three-quarters of the global oil use in railways. Europe is another relatively large user, accounting for close to 10% of global consumption. Long-distance travel by train, often in preference

Figure 2.9
Growth in aviation oil demand, 2007–2030



Box 2.3
The aviation sector: up, up and away

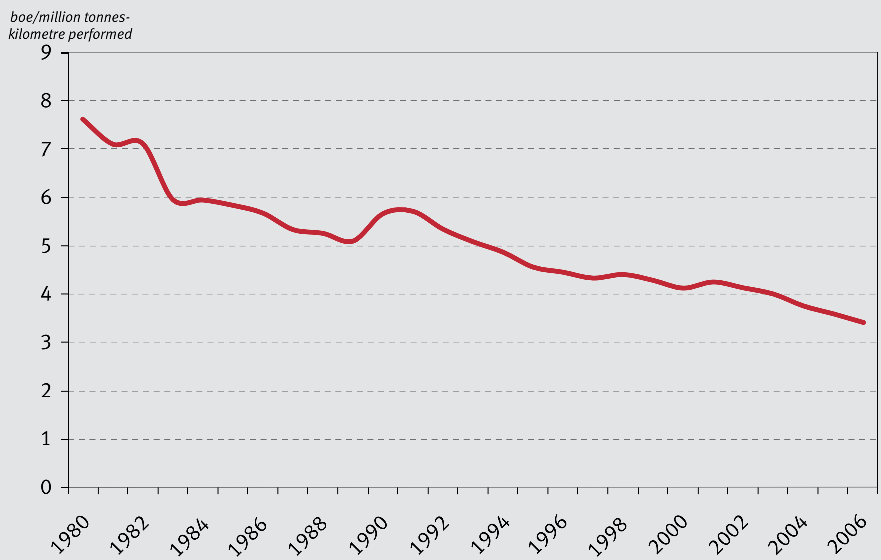
There is no mistaking the fact that air transport has witnessed a boom period. Both passenger numbers and freight loads have increased dramatically. In 2007, more than two billion passengers used airline transport, compared to just over 500 million in 1980. And freight expanded from almost eight million tonnes a year in 1980, to over 43 million tonnes in 2007. On a p.a. basis, the growth rates are 6% and 6.4% respectively.

The aviation evolution could easily be described as phenomenal, driven by an increased demand for mobility, travel being taken over increasingly longer distances, expanding international trade and the ensuing demand for ever-faster modes of transport. Today, air transport for a growing number of individuals and businesses is no longer an aspiration, it is the norm. Nevertheless, it is of interest, and important, to place this growth alongside demand for aviation fuel. What is evident is that the two have not followed the same path.

Between 1980 and 2006, aviation oil demand increased from 2.7 mboe/d to 4.9 mboe/d, a growth rate of 2.3% p.a. While this is ahead of the total rate for the entire transportation sector, it is well below the percentage growth for passengers and freight already highlighted. The only moderate rise is due in the main to the huge efficiency gains witnessed in the sector.

Indeed, from 1980–2006, fuel intensity decreased appreciably by 3.1% p.a. While 7.6 boe were needed to perform one million tonnes-kilometre in 1980, only 3.4 boe were necessary by 2006 (see figure below). 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.

Global trend of aviation energy intensity (1980–2006)



Looking ahead, the aviation industry can be expected to witness further efficiency and technology improvements. This includes the continued development and introduction of new materials, such as lighter composite materials, which may then result in new airplane designs that makes travel not only more efficient, but also more comfortable. 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. And projects aimed at improving computer-based simulation systems, are anticipated to help reduce energy consumption and waste in the design process, lower test facility costs and reduce test flight hours.

These technological advances will also help reduce the environmental footprint of aviation, although it should be noted that the sector contributes only marginally to greenhouse gas emissions. In fact, the aviation sector — domestic and international — accounts for no more than 2% of all global CO_2 emissions. Other non-CO_2 effects, such as contrail cirrus or soot aerosol, add only a small fraction of the CO_2 radiative forcing.[10]

What is clear, however, is that the anticipated aviation fuel intensity improvements will only partially compensate for the increase in traffic, and thus aviation oil demand will continue to grow.

Firstly, because kerosene is a fuel of choice for aviation, given its physical and thermodynamic characteristics. There have been recent efforts to develop alternative fuels, such as South Africa's SASOL semi-synthetic aviation fuel, a 50-50 blend of petroleum derived and synthetic kerosene, Virgin has also recently flown an aircraft using biofuels, and the US has put together the Commercial Aviation Alternative Fuel Initiative. However, in addition to cost competitiveness, any alternative fuel has to be compatible with kerosene and satisfy very stringent safety and operational conditions. Thus, kerosene is expected to remain the primary aviation fuel for the foreseeable future.

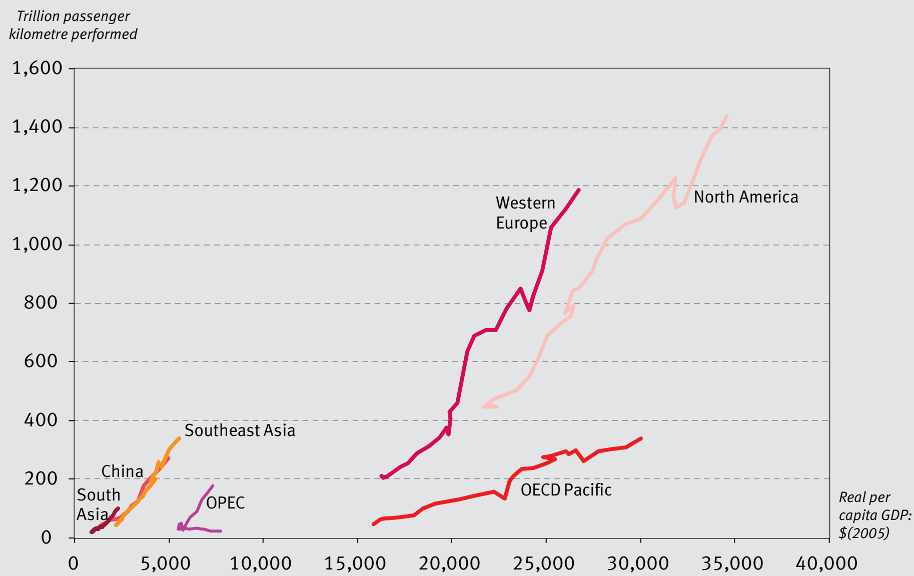
And secondly, due to the role of emerging economies, such as China and India, whose populations are becoming more upwardly mobile and an increasing factor in aviation traffic and aviation fuel growth. At the same time, however, it should be remembered that in 2008 OECD countries still accounted for about 66% of total aviation fuel consumption.

Mapping per capita air travel against per capita GDP by country confirms the fact that there is a huge potential for air traffic growth in developing and emerging economies. The latter group are not only witnessing faster air transport growth than the mature, often saturated, developed countries, they also represent a much larger share of the world's population. Over the period from 2000–2007, OPEC Member Countries witnessed a passenger traffic growth rate of 21.5%, China 17.1% and Russia 16.1%.

These developments also underscore the major role played by economic growth in the expansion of the aviation sector. From an individual perspective, changes in personal income can have a significant impact on the level of consumer purchasing power and the propensity to spend. And from a business standpoint, a better economic situation can obviously increase the demand for both air freight transportation and business travel. It is clear that air traffic is increasing in response to higher per capita income in all regions (see figure over).

On the flip side, an economic downturn, or some non-economic variables can have the opposite effect, such as perception-changing events like 9/11, wars, and the outbreak of disease. This can be seen in the context of the recent financial crisis. It is forecast that passenger traffic and freight will decline 13% and 5.7% respectively in 2009, with all regions, except the Middle East, experiencing a fall in volumes. Though, according to the International Air Transport Association, the future looks more positive, with passenger traffic expected to head back to positive growth in 2010.

Passenger kilometre performed *versus* per capita GDP (1980–2007)



In the WOO 2009 Reference Case, world aviation traffic is expected to grow by 5% p.a. over the period 2007–2030, with China witnessing the largest growth. This expansion, along with ongoing fuel intensity improvements — with all regions expected to see improvements in aviation fuel intensity ranging from 1% to 3.7% p.a. — and higher passenger load factors, is anticipated to result in moderate aviation fuel demand growth. Over the period 2000–2006, China experienced the highest annual growth rate of over 11%, followed by South Asian countries at 8%, while the Latin American and North American regions witnessed a negative growth rate of around –1%.

The outlook, however, has a number of downside risks. This includes the role of saturation levels, especially in the West European and North American market, further congestion and infrastructural restrictions in China, India and the OECD Pacific, fuel price volatility, and tighter regulations.

to long-distance road-haulage and travel over mountainous regions are examples of why diesel locomotives are still in use. The two dominant users, however, are the US and China, which account for close to 60%.

Current and future rail transportation developments in China are particularly interesting. Under the current five-year railway development plan approved by the government, every year 4,000 km of new track will be laid, which equates to an annual growth of 5%; 3,000 km of existing tracks will be electrified, a 15% rate of annual growth; and further fast passenger trains and large capacity freight trains will be introduced. Currently, demand for the railway system in place is overwhelming – according to the Chinese Minister of Railways, China has just 6% of the world's operational railway capacity, but each year it moves 23% of the world's total rail passengers and freight. While the growth in electrified railways will dominate new track construction, diesel still predominates in the railways sector, with a 61% share in 2006. There is also a strong trend for coal-powered trains, which as recently as 1980 accounted for all train stock, to be replaced by diesel or electric locomotives. It is likely that China will be the key to any future increased oil use in railways.

Domestic navigation oil use is obviously dominated by countries with access to rivers or coastline. Once again, China is the largest user, although combined, OECD countries account for over half of the total use.

The waterway system plays an important role in China's freight transportation, accounting for a rising share of over 60% of the total freight kilometres performed. Most of this cargo movement is coastal, and is closely related to the domestic movement of goods that are ultimately destined for foreign markets. Thus, China's export growth will be linked not only to increases in marine bunkers, but also to domestic waterways use.

Table 2.7 presents the oil demand Reference Case projections for domestic waterways and railways. As expected, the only significant future increase comes from China, where an average annual movement of 6% p.a. leads to a demand increase of 1.6 mboe/d over the period 2007–2030. While additional small increases are also expected in other developing countries, oil use in these sectors in the OECD will see a net decline.

Other sectors

Industry

Oil use is at the heart of much industrial activity. In addition to the petrochemical industry, diesel and heavy fuel oil are particularly needed in major industries such

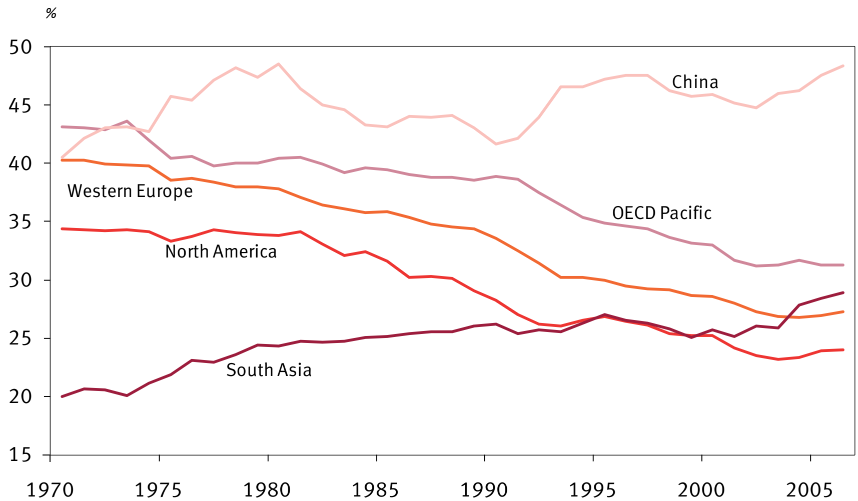
Table 2.7
Oil demand in domestic waterways and railways in the Reference Case *mboe/d*

				Levels	Growth
	2007	2010	2020	2030	2007–2030
North America	0.4	0.4	0.4	0.4	–0.1
Western Europe	0.3	0.2	0.2	0.2	–0.1
OECD Pacific	0.2	0.2	0.1	0.1	–0.1
OECD	**0.9**	**0.8**	**0.7**	**0.7**	**–0.2**
Latin America	0.1	0.1	0.1	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	0.2	0.1
China	0.6	0.7	1.4	2.2	1.6
OPEC	0.0	0.0	0.0	0.0	0.0
DCs	**0.9**	**1.0**	**1.7**	**2.6**	**1.8**
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**	**2.6**	**3.5**	**1.6**

as construction, energy, iron and steel, machinery and paper. The share of industry in GDP is therefore an important indicator for future oil consumption trends. In OECD countries, this share has fallen markedly, as the tertiary sector has risen in importance (Figure 2.10). This development is expected to continue. Trends in developing countries have typically pointed to a growth in the importance of industry. Nevertheless, the future picture is likely to be mixed. For example, while it is expected that South Asia, primarily India, will continue to witness a growth in the share of industry in GDP, it is assumed that Chinese industrial value-added will contribute a gradually declining share to the economy. This is in line with stated government objectives in the 11th Five Year Plan to increase the share of the service sector by 0.6% each year over the period to 2010, at the expense of industry's share.

Figure 2.11 shows how the share of petrochemical oil use in total industrial oil consumption has evolved since 1980. In both the OECD and developing countries the relative importance of the petrochemical sector in overall industry use is on the increase. For the OECD, however, this is in part a reflection of the decline in non-petrochemical oil use. Indeed, the share of the chemical sector in total OECD GDP

Figure 2.10
Share of industry value-added in GDP



Source: World Bank World Development Indicators, OPEC Secretariat.

has been steadily declining. For developing countries, the steepest rise in the share has been witnessed in China and Southeast Asia.

Projections for the total industry sector are shown in Table 2.8, while Figure 2.12 summarizes the total change in consumption to 2030. The main increase is in developing countries, which see demand in 2030 over 4 mboe/d higher than in 2007, reaching more than 13 mb/d, more than half of the world oil demand in this sector. The strongest expansion comes from developing Asia and OPEC as petrochemical oil use continues its robust growth in these regions. In fact, 86% of the net oil demand increase in industry over the period 2007–2030 is in non-OECD Asia. A decline in oil use in this sector is expected for all OECD regions, while Russia and other transition economies will see a small rise in oil use. The revised Reference Case involves, in particular, a reassessment of South Asian demand, which is now stronger than in the previous outlook, as both the share of industry and the chemical sector in total GDP continues to rise.

Residential/commercial/agriculture

Oil use trends in the residential sector are affected by the move away from traditional fuels in developing countries, as a result of rising urbanization

Figure 2.11
The share of petrochemicals in industrial oil use

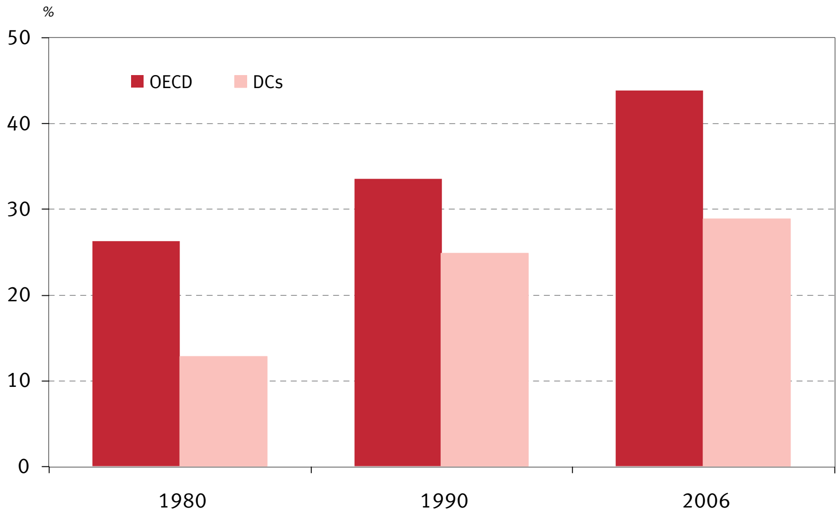
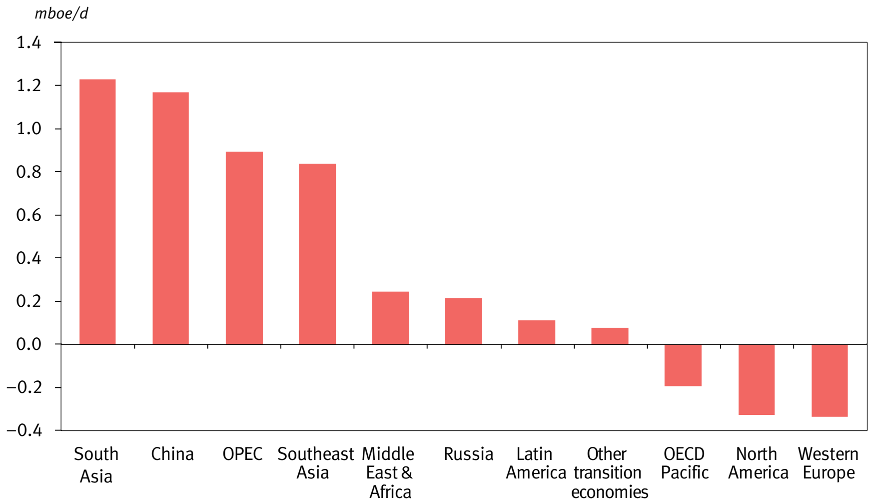


Table 2.8
Oil demand in industry in the Reference Case

mboe/d

	Levels				Growth
	2007	**2010**	**2020**	**2030**	**2007–2030**
North America	5.8	5.4	5.4	5.4	–0.4
Western Europe	3.7	3.6	3.4	3.3	–0.4
OECD Pacific	2.7	2.4	2.4	2.4	–0.3
OECD	**12.1**	**11.4**	**11.3**	**11.1**	**–1.1**
Latin America	1.0	1.0	1.1	1.1	0.1
Middle East & Africa	0.6	0.6	0.7	0.9	0.2
South Asia	1.3	1.3	1.8	2.5	1.1
Southeast Asia	1.5	1.6	2.0	2.4	0.8
China	2.8	2.9	3.5	3.7	0.9
OPEC	1.9	2.1	2.4	2.8	0.9
DCs	**9.2**	**9.6**	**11.6**	**13.3**	**4.1**
Russia	0.9	1.0	1.1	1.2	0.2
Other transition economies	0.5	0.5	0.5	0.6	0.1
Transition economies	**1.5**	**1.5**	**1.7**	**1.7**	**0.3**
World	**22.8**	**22.5**	**24.5**	**26.1**	**3.3**

Figure 2.12
Increases in oil demand in industry, 2007–2030



facilitating access to commercial energy, social progress and increasing average personal wealth. For example, the average proportion of the population in developing countries living in urban areas is expected to increase from 42% in 2007 to 56% by 2030, while average real GDP per capita more than doubles in the Reference Case over this time.

For the agricultural sector, oil use continues to improve productivity in many parts of the world in such activities as tilling, sowing, the application of fertilizers and pesticides, harvesting and post-harvesting, and the transport of harvested crops. In OECD countries, agriculture generally accounts for a small share of total energy consumption, currently around 2% of the total final consumption. It is typically higher in developing countries, for instance, it is close to one-fifth of total oil consumption in Namibia, Argentina and Bangladesh. The only scope for increased agricultural oil use is in developing countries.

Table 2.9 shows the projections to 2030 for this sector. Of demand in 2007 of just under 10 mboe/d, 49% is accounted for by the OECD and 46% by developing countries. An increase in demand in the Reference Case of over 3 mboe/d is expected over the projection period in developing countries. Although over half of this increase is in Asian developing countries, with Latin America and the Middle East and Africa also registering sizeable gains. Falling demand is expected in OECD regions and transition economies, the result of fuel switching, ongoing efficiency improvements and a

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

	Levels				Growth
	2007	**2010**	**2020**	**2030**	**2007–2030**
North America	1.7	1.6	1.5	1.4	–0.3
Western Europe	2.0	1.9	1.7	1.6	–0.4
OECD Pacific	1.1	1.0	0.9	0.9	–0.2
OECD	**4.7**	**4.4**	**4.1**	**3.8**	**–0.9**
Latin America	0.6	0.6	0.9	1.1	0.5
Middle East & Africa	0.6	0.6	0.7	0.9	0.4
South Asia	0.6	0.6	0.9	1.2	0.5
Southeast Asia	0.6	0.6	0.6	0.7	0.1
China	1.4	1.5	2.1	2.7	1.3
OPEC	0.7	0.8	0.9	1.1	0.4
DCs	**4.4**	**4.6**	**6.2**	**7.7**	**3.3**
Russia	0.2	0.2	0.2	0.2	–0.1
Other transition economies	0.3	0.3	0.3	0.3	0.0
Transition economies	**0.5**	**0.5**	**0.5**	**0.4**	**–0.1**
World	**9.6**	**9.5**	**10.8**	**12.0**	**2.4**

lack of scope for further demand increases, due to such issues as saturation effects and no population growth.

Electricity generation

Historical average rates of annual growth in electricity demand are shown in Table 2.10, together with implicit income elasticities, defined as the ratio of demand growth to GDP growth. For developing countries, electricity demand continues to rise at a rate similar to, or greater than economic growth. However, even in OECD countries there is a strong link between electricity and GDP growth.

Nevertheless, there are major differences in the driving forces behind increased electricity use. In richer countries, demand growth can only come from population expansion and the increased use of electric appliances. Continued efficiency gains through more rigorous standards, static populations and saturation in the demand for space and water heating, cooling and lighting, as well as for appliances, suggests that the link between economic growth and electricity demand will soften. But it should be remembered that there are still 1.6 billion people

Table 2.10
Electricity demand growth, 1971–2006

	Electricity demand growth % p.a.			Implicit income elasticities		
	1971–1980	1980–1990	1990–2006	1971–1980	1980–1990	1990–2006
North America	4.3	2.8	2.0	1.2	0.9	0.7
Western Europe	4.4	2.6	1.8	1.4	1.1	0.8
OECD Pacific	5.4	4.6	3.0	1.2	1.1	1.4
OECD	**4.5**	**3.0**	**2.1**	**1.3**	**1.0**	**0.8**
Latin America	8.8	4.9	4.3	1.5	3.7	1.5
Middle East & Africa	7.5	5.0	4.5	2.0	1.7	1.2
South Asia	6.7	9.4	5.8	2.0	1.7	1.0
Southeast Asia	9.6	7.5	6.7	1.3	1.3	1.4
China	9.0	7.7	10.0	1.5	0.8	1.0
OPEC	14.9	8.4	5.8	3.0	n/a	1.6
DCs	**9.0**	**7.0**	**7.0**	**1.7**	**1.7**	**1.2**
Russia	4.9	–1.3	–0.8	1.0	–1.1	3.7
Other transition economies	7.5	16.8	–1.6	1.5	6.6	–5.3
Transition economies	**5.2**	**3.3**	**–1.4**	**1.0**	**1.9**	**n/a**
World	**5.1**	**3.7**	**2.8**	**1.3**	**1.2**	**0.8**

without access to electricity. A difference in growth patterns between OECD and some developing countries is therefore to be expected, given the scope for the eradication of energy poverty. This is defined as the "inability to cook with modern cooking fuels and the lack of a bare minimum of electric lighting to read or for other household and productive activities at sunset".[11] The wide gulf in electricity use per capita between OECD and developing country regions is demonstrated in Figure 2.13.

For this outlook, the emphasis is upon oil demand, although, as described earlier, the electricity generation sector is important for both coal and natural gas demand growth prospects. Even over the relatively short time from 1990–2006, a considerable switch away from oil occurred (Figure 2.14). And it is expected that the share of oil in this sector will continue to fall, although it will nevertheless still be used as a swing energy for peak power production.

No net increase is expected for oil used in electricity generation (Table 2.11). A gradual fall in the OECD and Russia will be compensated by slight increases in some

Figure 2.13
Per capita electricity use in 2006

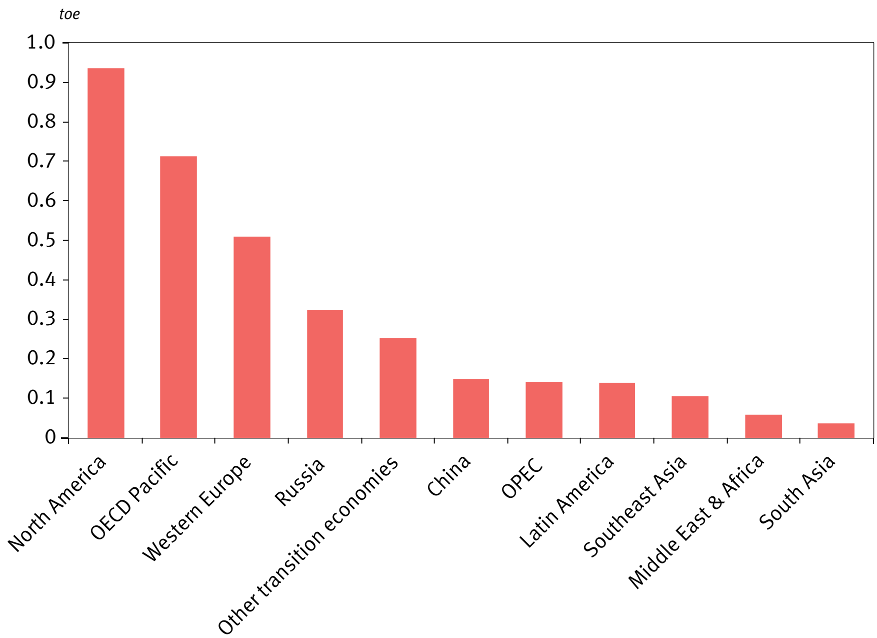


Figure 2.14
Oil share in electricity generation

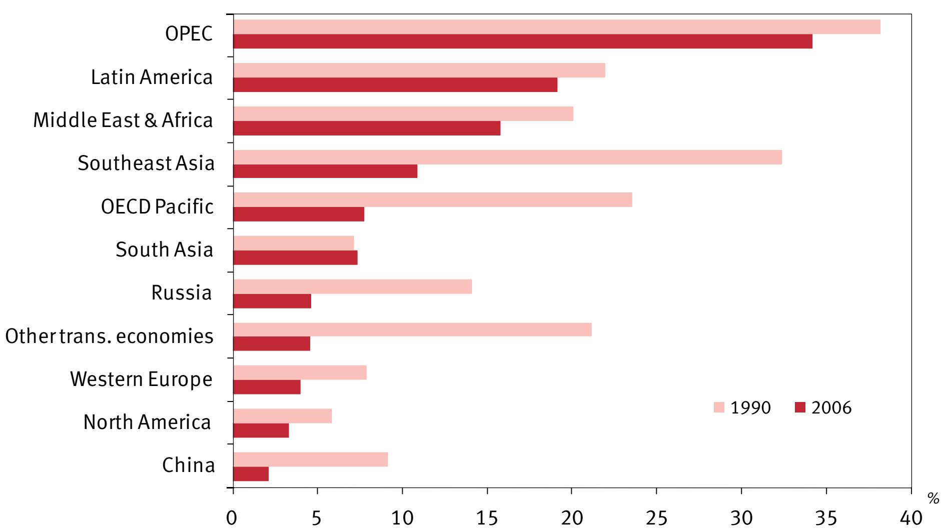


Table 2.11
Oil demand in electricity generation in the Reference Case *mboe/d*

	Levels				Growth
	2007	2010	2020	2030	2007–2030
North America	0.7	0.7	0.7	0.7	0.0
Western Europe	0.5	0.5	0.4	0.3	–0.2
OECD Pacific	0.6	0.5	0.4	0.3	–0.3
OECD	**1.9**	**1.7**	**1.6**	**1.4**	**–0.4**
Latin America	0.4	0.4	0.4	0.4	0.0
Middle East & Africa	0.5	0.5	0.6	0.8	0.3
South Asia	0.4	0.3	0.5	0.6	0.3
Southeast Asia	0.4	0.4	0.4	0.4	0.0
China	0.3	0.3	0.3	0.2	–0.1
OPEC	1.3	1.4	1.4	1.4	0.1
DCs	**3.3**	**3.3**	**3.6**	**3.8**	**0.6**
Russia	0.3	0.3	0.2	0.2	–0.2
Other transition economies	0.2	0.2	0.1	0.1	–0.1
Transition economies	**0.5**	**0.5**	**0.3**	**0.3**	**–0.3**
World	**5.6**	**5.5**	**5.5**	**5.5**	**–0.1**

developing country regions, in particular in Africa and South Asia, where oil-based power in remote areas can provide access to modern energy services. Continued fuel switching leads to a fall in China, while demand is static in most other regions.

Marine bunkers

Finally, demand in marine bunkers grows by almost 3 mboe/d over the period 2007–2030 (Table 2.12). The key to growth will be developing Asia, accounting for 79% of world growth. Upward pressures from increased trade will be tempered by ongoing efficiency improvements, from the turnover of stock, and the growing average size of ships. Possible regulation aimed at reducing air pollution from ships could have important implications for both the product used in this sector and the absolute level of oil employed. This issue is addressed in Box 7.1 in Section Two.

There is little doubt that demand for marine fuels has increased significantly in recent years. And whilst the current global economic downturn will clearly have some negative short-term demand impact, the advancement of globalization and international trade will see marine fuel consumption continue to expand.

Table 2.12
Oil demand in marine bunkers in the Reference Case

mboe/d

	Levels				Growth
	2007	2010	2020	2030	2007–2030
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	0.1	0.1	0.1	–0.1
OECD	**1.8**	**1.6**	**1.8**	**1.9**	**0.0**
Latin America	0.1	0.1	0.2	0.3	0.1
Middle East & Africa	0.1	0.1	0.1	0.2	0.0
South Asia	0.0	0.0	0.0	0.0	0.0
Southeast Asia	0.7	0.7	1.0	1.4	0.7
China	0.2	0.3	0.7	1.6	1.4
OPEC	0.3	0.3	0.4	0.5	0.2
DCs	**1.5**	**1.5**	**2.4**	**4.0**	**2.5**
Russia	0.0	0.0	0.1	0.2	0.1
Other transition economies	0.0	0.0	0.0	0.1	0.0
Transition economies	**0.1**	**0.1**	**0.1**	**0.2**	**0.1**
World	**3.4**	**3.2**	**4.3**	**6.1**	**2.7**

Demand by product

Despite the fact that expected efficiency improvements combined with slower economic growth reduce future demand in the transportation sector, compared to our previous projections, the continuing shift to middle distillates over the entire period remains a dominant feature of the future demand slate. This is clearly reflected in the fact that out of the increase in demand of 20 mb/d by 2030 compared to the 2008 level, almost 60% is for middle distillates (see Table 2.13 and Figure 2.15).

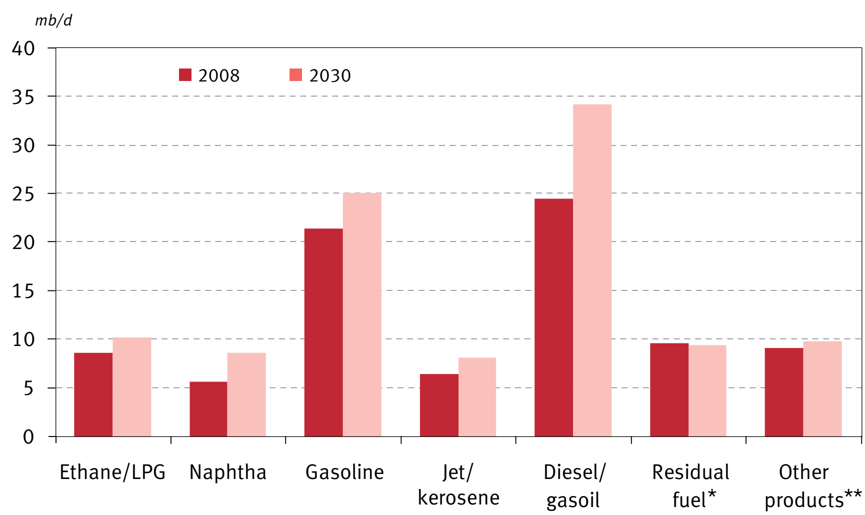
Within the product group of gasoil/diesel, it is diesel used for transport that is growing rapidly in most countries, whereas gasoil for heating is being negatively impacted by the shift towards the increased use of natural gas and/or electricity and renewable energy for heating. A combination of these trends is also reflected in the 1.6% p.a. projection for the future growth of diesel/gasoil consumption, appreciably above the growth for jet/kerosene and gasoline. Rising gasoil/diesel demand also leads to a shift from gasoline to diesel that is clearly visible in the global demand figures for these products. In 2008, the difference in demand was around 3 mb/d. By 2020, projected gasoil/diesel demand is 6.5 mb/d higher than for gasoline and by 2030 the difference exceeds 9 mb/d.

Table 2.13
Global product demand, shares and growth, 2008–2030

	Global demand mb/d					Growth rates % p.a.		Shares %	
	2008	2015	2020	2025	2030	2008–2015	2015–2030	2008	2030
Light products									
Ethane/LPG	8.7	9.0	9.3	9.7	10.2	0.5	0.9	10.1	9.7
Naphtha	5.6	6.2	6.8	7.7	8.7	1.3	2.3	6.6	8.2
Gasoline	21.4	22.3	23.1	24.1	25.1	0.6	0.8	25.1	23.8
Middle distillates									
Jet/kerosene	6.5	6.8	7.3	7.6	8.1	0.7	1.2	7.6	7.7
Gasoil/diesel	24.5	27.2	29.7	32.1	34.2	1.5	1.6	28.7	32.4
Heavy products									
Residual fuel*	9.7	9.5	9.4	9.4	9.4	–0.2	–0.1	11.3	8.9
Other**	9.1	9.3	9.7	9.8	9.8	0.2	0.4	10.7	9.3
Total	**85.6**	**90.2**	**95.4**	**100.4**	**105.6**	**0.8**	**1.1**	**100.0**	**100.0**

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

Figure 2.15
Global demand by product, 2008 and 2030



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

A critical question in this respect is how the future structure of the car fleet in developing countries will evolve. In particular, will it follow the European path of diesel-based engines or will it be dominated by gasoline-driven cars? The Reference Case projections assume an increasing share of diesel cars in developing countries, however, not to the levels experienced in Europe. Moreover, a moderate decline of new diesel car registrations and a 'revival' of gasoline engines is also foreseen in Europe.

The low nature of the average gasoline growth rate is largely the result of declining demand in North America and Europe, particularly given the large share of these two regions, at 56%. Global gasoline demand increases in other regions see rates ranging between 1% and 4% p.a.

Another prominent observation relates to high growing naphtha demand, especially in developing Asian countries. Although the current worldwide recession has strongly depressed demand for this product, naphtha growth rates over the medium- and long-term horizons are above the average for liquid products. Indeed, between 2015 and 2030, this product records the highest average annual growth of all product categories, with an average of 2.3% p.a. As described earlier, this is largely the result of high petrochemicals demand growth in most developing countries, mainly in Asia. This contrasts with the stagnant or declining naphtha demand in OECD regions (see Box 2.4).

Trends in kerosene and jet kerosene demand also reflect structural changes within this product group. The main change is the continuing shift from kerosene used for lighting and heating in the domestic sector as well as for industrial use to the transportation sector, in particular to aviation as jet fuel. This makes the overall growth lower than it would have been if jet kerosene was considered alone. Moreover, jet kerosene and naphtha are the two products most affected by the current economic downturn. Consequently, demand changes for the jet/kerosene group in the period to 2015, at an average of 0.7% p.a., are well below longer term growth, which averages 1.2% p.a. over the period 2015–2030. Finally, as for other products, there are regional variations in projected demand changes. These range between declining demand in Western Europe and North America (–0.1% p.a. between 2015 and 2030) to strong increases in Africa, Asia and, in particular China, which sees an average growth of 4.5% p.a.

In contrast to light products, the demand for products at the heavy end of the slate are expected to either decline, in the case of residual fuel oil, or to expand only modestly for other heavy products. Similar to the case of jet/kerosene, fuel oil is used across different sectors, particularly in electricity generation, marine bunkers and

Box 2.4
Petrochemicals: an important contributor to oil demand growth

The contribution of the petrochemical industry to global crude oil demand may be viewed as small, when compared to automotive fuels, the major outlet. Nevertheless, the share of this industry in total oil demand is significant, and to future oil demand growth its role is expected to increase.

Over the past few decades the production of basic petrochemicals, such as light olefins and aromatics, from oil-derived feedstocks such as naphtha, as well as from natural gas liquids has seen the sector become a mainstay of the industry sector, in both developed nations and more recently in developing countries. The continuous growth and diversification of the products offered has transformed hundreds and thousands of industrial and everyday consumer goods.

Going forward, the expected growth in the petrochemicals industry can be more clearly viewed when set alongside presumed oil demand growth.

In 2007, 8.6 mb/d of oil amounting to about 10% of total oil demand was cracked for olefins and aromatics production. In 2008, global demand for naphtha alone was 5.6 mb/d, representing 6.6% of total oil demand, but this is forecast to rise appreciably. When oil demand rebounds as the world comes out of the current economic downturn, demand for naphtha is foreseen to reach 6.2 mb/d by 2015 and then to grow at a higher rate of 2.3% p.a. to reach 8.7 mb/d by 2030, representing more than 8% of global oil demand. This is about twice as much as the average foreseen growth in total oil demand over the same period.

Despite this expected growth, however, it should be noted the petrochemical industry, as is the case with most heavy capital intensive industries with long project lead times and output strongly correlated with the economy, remains highly cyclical. The industry peaks when demand is comparable with the installed capacity and results in high capacity utilization rates, as well as inflated operational margins and cash flows. This high profitability triggers a wave of expansion projects that can lead to overcapacity, especially in the face of an economic downturn. This is certainly the case today.

There are a number of coinciding factors that are having a significant say in the current situation. Alongside the state of the global economy that has led to a tightening in the availability of credit for projects, there is also a cut back in consumer demand for all petrochemical-based commodities.

The economic downturn also came in a period when there was a wave of petrochemical projects expected to come on-line, particularly in the Middle East and the Asia-Pacific. Many of the projects in the Middle East region were based on the availability of hydrocarbon feedstocks at favourable costs and on the proximity to the emerging Asian growth markets. And as such, they may have been based on competition with existing capacity rather than a foreseen growth in absolute global demand.

Nevertheless, looking beyond the present situation, given the expected growth rates highlighted, there is clearly much for the industry to remain positive about.

It is also important to note that the industry is witnessing a geographic shift from the traditional production regions of North America and Western Europe to the developing economies of the Asia-Pacific and the Middle East.

This is perhaps best viewed when looking at ethylene production, the most important olefin produced worldwide — primarily by steam cracking naphtha and ethane — as its production capacity is a good measure of the relative size of the petrochemical industry in a given country or region.

The global installed capacity for ethylene production was about 125 million tonnes per year in 2007. By region, 30% of production was in the Asia Pacific, 28% in North America, 19% in Western Europe, 11% in the Middle East and other regions contributed 12%.

By 2013, however, with capacity forecast to expand to 148 million tonnes, there are expected to be some shifts in where ethylene production is located. North America's share is forecast to drop to 20% and Western Europe's to 15%, while other regions witness an increase with the Middle East share at 20% and the Asia-Pacific with over one third of global capacity at 34%.

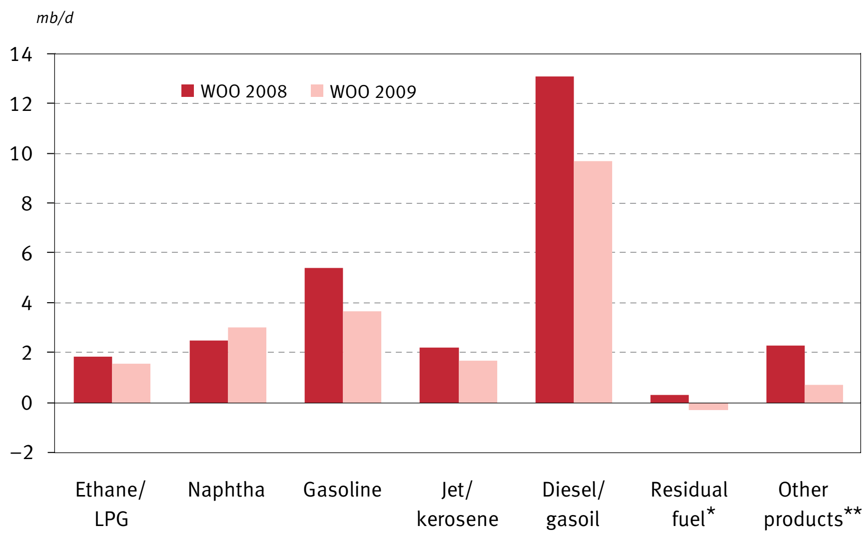
Other important petrochemical intermediates are propylene, butadiene, benzene, toluene and xylenes, which are co-produced with ethylene or obtained from other oil refinery streams such as fluid catalytic cracking, off-gas and naphtha reformate. And these products are also expected to see a geographic production shift to the Middle East and the Asia-Pacific.

The upshot is that the traditional producing regions of North America and Western Europe will face increasing competition, both locally and in export markets. This is expected to result in some consolidation and capacity rationalization, although it is clear that these regions will continue to be key demand regions for end products.

It is the Asia-Pacific and Middle East regions that will host most of the foreseen industry expansion. The main reasons for this are the favourable feedstock availability, the fact that demand for basic petrochemical materials is anticipated to grow mainly in the Asia-Pacific, particularly China and India, and moreover, the conversion of these materials into end products and consumer goods is enjoying a cost advantage all along the manufacturing chain in these regions.

internal refinery use, and demand prospects are subject to opposing trends. While electricity generation and the refinery use of fuel oil face competition with natural gas in most regions, leading to demand decreases, the expected growth in international trade will partially compensate for losses through demand increases for bunkering. In the Reference Case, fuel oil is a major bunker fuel. However, tightening product specifications for international bunkers could lead to an increased future use of middle distillates, an alternative which is discussed in Section Two. Finally, the group of other heavy products, which consists of a mixture of various streams, is expected to grow broadly in line with regional total demand changes. Needless to say, this change in product mix, along with overall product demand growth, will necessitate the expansion of refinery downstream conversion capacities to increase the desired product yields.

Figure 2.16
Global product demand growth between 2008 and 2030 compared to WOO 2008



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

Figure 2.16 summarizes demand projection revisions to 2030 in comparison to last year's WOO. The bulk of the downward demand revision is associated with expected efficiency improvements in the transport sector and the impacts of the current recession. This is reflected in lower increases in diesel/gasoil followed by gasoline and jet/kerosene. These three products are 5.7 mb/d lower in 2030 compared to the WOO 2008, or 74% of the demand reduction. Global demand for fuel oil was revised downwards by 0.6 mb/d, the category of other heavy products by 1.6 mb/d and ethane/LPG by 0.3 mb/d. The only product where faster growth is expected, compared to last year estimations, is naphtha.

Chapter 3
Oil supply

The overview of the Reference Case presented in Chapter 1 indicated that total non-OPEC liquids supply will continue to increase over the period to 2030, largely due to non-crudes. This means that demand for OPEC crude over the medium-term is below 2008 levels, with growth in the longer term coming at a lower pace than in last year's WOO. This Chapter presents the underlying detailed determinants of this oil supply outlook. Firstly, the medium-term supply paths of the Reference Case non-OPEC crude plus NGLs are described, detailing the prospects for individual countries on the basis of a bottom-up assessment of the production behaviour of individual fields and upstream investment activities. This takes advantage of an extensive database, containing over 220 new development projects in over 30 non-OPEC countries. Longer term supply prospects for crude supply are then examined, linked to the remaining resources. The medium- and long-term outlooks for non-conventional oil and biofuels are then discussed, followed by a review of OPEC Member Country upstream investment activity.

Medium-term non-OPEC crude and NGLs

This year's medium-term outlook for non-OPEC crude and NGLs supply has been evaluated in the context of the recent lower oil price environment and the global economic crisis. The impact of these developments feeds through various channels. This includes, *inter alia*, changed economics, with lower prices leading to project cancellations and delays, although this is partly offset by recent cost declines in some areas (see Box 3.1); debt financing becoming more difficult; lower earnings and stock valuations limiting equity finance; and a lower risk-appetite, in particular for smaller companies.

It should also be observed that the impact of these factors on non-OPEC supply varies between each producing country and different companies involved. It is evident that those major International Oil Companies (IOCs) and National Oil Companies (NOCs) with strong financial positions are less affected than the often more financially exposed smaller companies. Reduced investments by a number of these smaller producers is likely to have an immediate impact on production in a number of mature regions, including the North Sea, the onshore US lower 48, the Western Canadian Sedimentary Basin (WCSB) and West Siberia in Russia. It should also be noted that in some instances lower prices could lead to higher short-term output, when companies seek higher cash flows and liquidity by overproducing wells and/or postponing maintenance and some investments in mature fields. This behaviour was observed during the 1998–1999 period of low prices.

Box 3.1
How much will it cost?

Upstream costs attributed to finding, developing and producing oil, including those concerning the human resource, are obviously a crucial component of any company's investment decisions. Despite the fact that costs have fallen from the highs experienced last year, due in part to the impact of the global financial crisis, this movement can only be described so far as negligible when weighed against the oil price drop over the same time period. Costs remain a core industry issue, and it is evident they will continue to play a major role in all aspects of current and future projects.

It is important to stress that cost movements have both cyclical and structural explanations. For example, oil services and commodities costs, the pace of investment, as well as currency exchange rates and the availability of skilled labour for construction and operations are principally cyclical. On the other hand, structural changes come from the continued move toward deeper water, deeper wells and harsher environments, coupled with smaller discoveries and more stringent health, safety and environment regulations. It should be noted, however, that the unit costs of equipment and services tend to decline as a result of economies of scale, technology deployment and diffusion, and the sharing of best practices.

Nonetheless, whether cyclical or structural, the cost issue is, and will remain a significant challenge; one that needs to be frequently evaluated in order to provide a better understanding of how costs might evolve.

Looking back to mid-2008, upstream costs were clearly inflated. The average worldwide unit capital cost of adding one new barrel of oil or gas had more than doubled since 2000, due on the whole to higher finding and development costs. This period saw the oil industry witness huge increases in the cost of raw materials, as well as in all segments of petroleum services. Moreover, the cost to find and develop the marginal barrel had almost tripled. It should be noted that the oil sands projects and some of the deep and ultra deepwater projects are still considered to be the industry's benchmark for marginal costs.

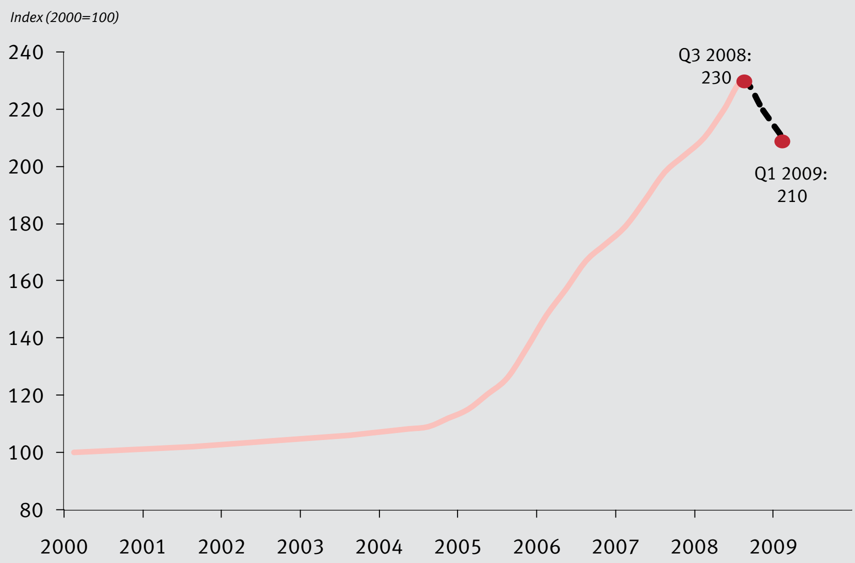
This rising costs trend was in some measure the result of the low oil prices of ten years or so ago. It was a time when many companies implemented downsizing and cost-reduction strategies, in particular in the petroleum services sector. However, the expansion in the need for these services has rocketed since 2003, leading to higher utilization rates, and in turn upward cost pressures. In addition, as a result of these cost-cutting initiatives, many young people were also put off following a career in the oil sector, with the knock-on impact felt when the sector's return to growth started to outstrip the supply of human capital.

In the current low oil price environment, set alongside the ongoing global economic crisis and the recently observed low earnings of many companies in the industry, the ability to finance new projects has become more difficult. This has led to a slowing down in the pace of investment in new upstream projects, and in some instances, project cancellations and delays. These have also occurred at the same time as a fall in prices for many raw materials. For example, cement, steel, as well as a number of other commodities have seen prices fall from a 2008 third quarter peak.

However, as already mentioned, this fall in costs has been minimal when set alongside the drop in the oil price. For example, the OPEC Reference Basket price averaged \$43/b in the first quarter of 2009, a fall of over 70% from last summer's peak of \$141/b. In contrast, costs, according to the IHS/CERA Upstream Capital Costs index, had declined by just 8.5% at the end of the first quarter of 2009 when compared to the third quarter of 2008 (see figure below).

It should be recognized that to some degree this is part of a natural time delay between the two, with costs typically following the price path nine-to-12 months

IHS/CERA upstream capital costs index (UCCI)



Source: IHS/Cambridge Energy Research Associates.

later. This is because of the time lag evident in the feeding through of commodity price reductions to the costs of final products and oil field services, such as production facilities, pipelines, well equipment, rigs, workovers and other services.

Additionally, it is apparent that specific industry sectors have notable cost differences. For example, the Canadian oil sands and ultra-deepwater sectors, where the availability of equipment and services remains a somewhat restrictive factor, may take much longer to react to developments than the conventional onshore sector.

There is also evidence that some project developers have placed a number of project developments on the 'back-burner', waiting to see if costs fall further. The upshot is that this may help in further easing the tightness in the availability of equipment and services.

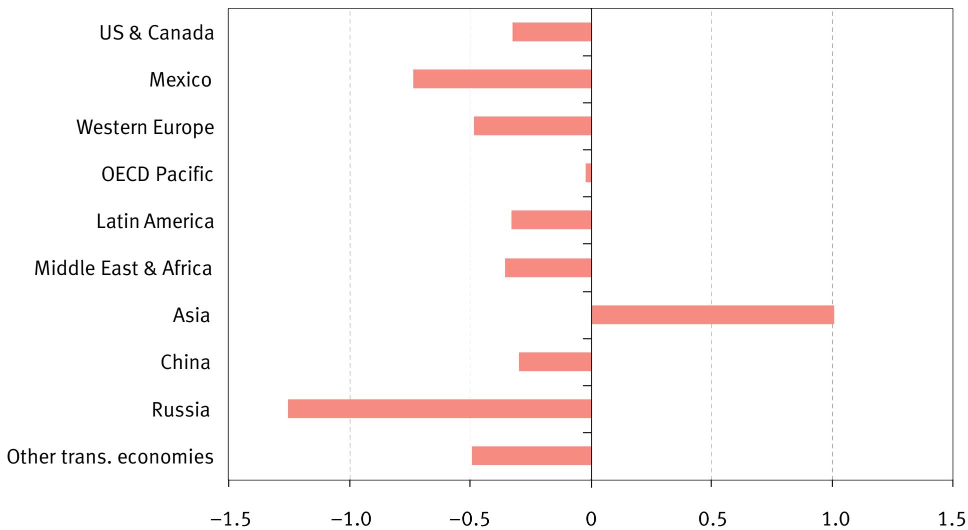
In recent months, however, the prices of some commodities, such as those for cement and steel, have risen slightly. And the very nature of some operating costs, such as personnel costs and those attached to fixed-term contracts, means that these remain firm. Personnel costs are seldom cut to reduce costs, even when the industry is experiencing job losses. And fixed-term contracts, such as those for deepwater vessels, where numbers remain a limiting factor, are often for periods of over three years.

In the medium-term, the majority of projects that are at an advanced development stage are likely to proceed. It is the projects that have not yet been approved or sanctioned that are mainly at risk of being delayed, postponed or cancelled in the present economic climate. In addition, as costs decline, companies are in some instances delaying projects in the expectation that costs will fall further, and in others, renegotiating contract terms. The projects most at risk are those with high-costs and/or in a harsh environment, such as deepwater Gulf of Mexico and Brazil, the Arctic region, enhanced oil recovery (EOR) projects and the Canadian oil sands.

As a result of this bottom-up analysis, non-OPEC crude plus NGLs supply by 2013 is expected to be more than 3.3 mb/d lower than in the 2008 WOO reference case (Figure 3.1), with 600,000 b/d representing the downward revision of the base year of 2008. These figures would have been even higher without this year's addition of Indonesia to the Asia region grouping. The adjustment for 2008 is mainly due to downward revisions for Russia and Mexico and unexpected supply disruptions in the US Gulf of Mexico, Azerbaijan and Brazil.

However, the impact of these factors will not prevent the production of non-OPEC crude and NGLs from new projects offsetting the observed decline rate in

Figure 3.1
Changes to Reference Case non-OPEC crude and NGLs supply in 2013 compared to WOO 2008



existing fields. Total non-OPEC crude and NGLs supply is expected to stay in the range of 45.1–45.4 mb/d from 2008–2013 (Table 3.1). This medium-term projection is derived from a database of country specific investment projects. In this calculation the factors taken into account include: remaining reserves for currently producing countries; fields under development; announced plans for individual fields; discoveries awaiting further delineation and appraisal, or what could be deemed 'probable developments'; and observed decline rates at a country level, with a focus on more mature producing countries (see Box 3.2). It is important to highlight that in some instances, condensate and heavier NGLs are blended directly into the crude oil streams and separate figures are not available.

Crude oil plus NGLs supply in the US and Canada is expected to stay in the range of 8.6–8.8 mb/d from 2008–2013. In the US, the Gulf of Mexico is the main source of crude oil production growth. This continues to be driven by rapid advancements in deepwater drilling and production technology, as well as improvements in seismic imaging technologies. As a result, many large discoveries have been made in deepwater, which is where a number of the large medium-term projects are located. By 2013, US Gulf of Mexico production — shelf and deepwater — is expected to reach over 1.6 mb/d, from around 1.1 mb/d in 2008. The new big deepwater projects include Tahiti, Cascade and Chinook, Shenzi and Great White, with a number of smaller fields coming on-stream too. That is not to say, however, that all projects

Table 3.1
Medium-term non-OPEC crude & NGL supply outlook in the Reference Case *mb/d*

	2008	2009	2010	2011	2012	2013
United States	6.7	6.8	6.8	6.8	6.8	6.7
Canada	2.0	1.9	2.0	1.9	1.9	1.9
US & Canada	**8.8**	**8.8**	**8.8**	**8.7**	**8.7**	**8.6**
Mexico	**3.2**	**3.0**	**2.8**	**2.7**	**2.7**	**2.6**
Norway	2.5	2.3	2.3	2.1	2.0	2.0
United Kingdom	1.6	1.4	1.4	1.3	1.3	1.2
Denmark	0.3	0.3	0.3	0.2	0.2	0.2
Western Europe	**4.6**	**4.4**	**4.2**	**4.0**	**3.9**	**3.7**
Australia	0.5	0.6	0.6	0.6	0.5	0.5
OECD Pacific	**0.6**	**0.7**	**0.7**	**0.6**	**0.6**	**0.6**
OECD	***17.2***	***16.8***	***16.5***	***16.1***	***15.9***	***15.5***
Argentina	0.8	0.7	0.7	0.7	0.7	0.7
Brazil	1.9	2.0	2.2	2.2	2.3	2.4
Colombia	0.6	0.6	0.6	0.6	0.6	0.5
Latin America	**3.7**	**3.8**	**3.9**	**3.9**	**4.0**	**4.1**
Oman	0.7	0.8	0.8	0.8	0.8	0.8
Syrian Arab Republic	0.4	0.4	0.3	0.3	0.3	0.3
Yemen	0.3	0.3	0.3	0.3	0.3	0.2
Middle East	**1.6**	**1.6**	**1.6**	**1.6**	**1.5**	**1.5**
Congo	0.3	0.3	0.3	0.4	0.4	0.4
Egypt	0.7	0.7	0.7	0.6	0.6	0.6
Equatorial Guinea	0.4	0.4	0.4	0.4	0.4	0.4
Gabon	0.2	0.3	0.2	0.2	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	0.9	1.0
Indonesia	1.0	1.1	1.1	1.1	1.1	1.1
Malaysia	0.7	0.8	0.8	0.8	0.8	0.8
Vietnam	0.3	0.4	0.4	0.4	0.4	0.4
Asia	**3.7**	**3.8**	**4.0**	**4.0**	**4.0**	**4.1**
China	**3.8**	**3.8**	**3.8**	**3.8**	**3.8**	**3.7**
DCs, excl. OPEC	***15.4***	***15.7***	***15.9***	***15.9***	***15.9***	***16.0***
Russia	**9.8**	**9.7**	**9.6**	**9.7**	**9.8**	**9.9**
Kazakhstan	1.4	1.5	1.6	1.7	1.8	1.8
Azerbaijan	0.9	1.1	1.1	1.2	1.2	1.2
Other transition economies	**2.9**	**3.2**	**3.3**	**3.5**	**3.6**	**3.7**
Transition economies	***12.7***	***12.9***	***12.9***	***13.2***	***13.4***	***13.6***
Total non-OPEC crude & NGLs	**45.2**	**45.4**	**45.2**	**45.2**	**45.2**	**45.1**

Box 3.2
Decline rates: business as usual

The topic of decline rates is one of great interest to the oil industry as even small changes or divergences can have a significant effect on future oil supply projections. The subject is one followed closely by the OPEC Secretariat, both in terms of research, and in the analysis of a number of studies recently released.

An initial assessment of decline rates starts with individual wells and reservoir zones and progresses to entire fields, basins and countries. It is important to appreciate, however, that there is no magic wand that provides an exact figure for decline rates. Even an operator can only estimate what future decline rates might be for its fields. For an outside observer, the task is even more difficult, with many issues to consider, including: data availability; production profile assumptions; reservoir characteristics; technologies used; investment levels; and above ground disruptions.

Therefore, the reported production for any field can only be used to approximate the observed decline rate and not the natural decline rate.

In general, most fields have three main phases: the 'build up phase', which lasts until the field reaches close to its maximum designed production capacity; the 'plateau phase', when the field continues to produce somewhere near the level of its maximum production capacity; and the 'decline phase', when production falls below a certain level. However, when and how these phases happen is distinct to each field. They are not uniform, with technical, management, economic and regulatory considerations all affecting field development and production.

Thus, any decline rate figure reached can only be considered an estimate. However, this does not diminish its significance. In making oil supply projections, it is essential to make a thorough assessment.

With this in mind, the OPEC Secretariat's recent work has looked to quantify the average annual observed decline rate of crude oil production in major non-OPEC producing regions and countries for the present decade. In estimating these figures, the impacts of technical and above ground issues, such as weather-related and geopolitical events, were specifically accounted for where possible.

Building from disaggregated data for individual countries, the production-weighted average annual observed decline rate for non-OPEC over the period since

2000 is estimated to be around 4.6% p.a. It is interesting to note that this has been fairly stable over the years covered. This implies that the volumes of non-OPEC crude oil that have been replaced as a result of the observed decline rate have averaged around 1.8 mb/d p.a. so far this decade.

The future general decline rate trends will of course be influenced by the balance between giant and small, and onshore and offshore fields in the non-OPEC field portfolio, technological advances, and investment levels in producing fields. Given past experience, however, it is expected that there will be no significant changes in trends, as fields evolve through the life-cycle of 'build-up', 'plateau' and 'decline'.

From a regional perspective, the research points to the highest decline rates being observed in the more mature producing areas of the OECD, when compared to other non-OPEC regions. The OECD Pacific and Western Europe regions show the highest decline rates, with their production-weighted annual observed decline rates averaging around 9.3% and 8.6% p.a. respectively. For developing countries (non-OPEC) these p.a. figures are much lower, and vary from 4.6% in Latin America to 5.8% in the Middle East, with Asia and Africa in between, at 5.1% and 5.6% respectively.

In the US and Canada, the figures are relatively stable, at 4.9% and 4% p.a. respectively, with the US benefitting from the adoption of EOR techniques in the onshore US Lower 48 region. In Mexico, the average annual observed decline rate is around 7% p.a., mainly due to the steep decline at the massive Cantarell field that is believed to have entered a sustained decline around 2005.

In Russia, Azerbaijan and Kazakhstan, the decline rates for older fields are relatively low. The countries produced more in 2008 than in 2000 as oil production continued to recover from the collapse in Russian oil production witnessed in the 1990s, and both Azerbaijan and Kazakhstan became major producers. The regional aggregate production-weighted average annual observed decline rate is around 3.1% p.a. This lower decline rate reflects in part the fact that Russian oil production has refocused on investing in existing fields to help slow decline rates, and in some cases, increase production.

In China, the use of infill drilling and the extensive development of EOR projects have been under way for some years. This has helped to keep the country's annual observed decline rate at around 3% p.a.

The overall figures for non-OPEC underscore a number of key takeaways. Firstly, the figures calculated by OPEC appear to be in-line with other estimates, such as the IEA's *World Energy Outlook 2008*, and CERA's report, *Finding the Critical*

Numbers: What Are the Real Decline Rates for Global Oil Production? Secondly, the non-OPEC production-weighted average annual observed decline rate is higher than that in OPEC Member Countries. And thirdly, whilst there are fluctuations, the general overall trend for decline rates is relatively stable and is expected to remain so in the coming years.

under consideration will start production. In total, around 350,000 b/d of production originally due on-stream by 2013 has now been deferred, and other projects are at risk of being postponed. Nevertheless, deepwater US Gulf of Mexico remains a growth area, and expanding oil production here will offset production declines in other areas, namely shallow US Gulf of Mexico, Texas, Louisiana, Alaskan North Slope and California. As a result, US crude and NGLs production is projected to stay flat at around 6.8 mb/d over the medium-term.

In Canada, the production of conventional crude and NGLs will stay approximately flat at 1.9–2.0 mb/d. The decline in the WCSB will be partially offset by new production from the Hibernia, Terra Nova, White Rose and Cohasset/Panuke fields. These are located on the east coast in offshore Newfoundland. In the medium-term, production from offshore Newfoundland is expected to increase to about 400,000 b/d and then plateau at around 350,000 b/d.

Mexican crude oil and NGLs production is expected to decline from 3.2 mb/d in 2008 to 2.6 mb/d by 2013. However, there remain significant uncertainties ahead. When comparing this year's figure for 2013 with that in the WOO 2008, projected supply has now been lowered by over 740,000 b/d, due to the continuing decline in the giant Cantarell field. In addition, difficulties in financing new projects and securing deep offshore rigs have affected new production in deepwater areas. The drop off in Cantarell, however, is expected to be partially offset by new production at the Ku Maloob Zaap complex. Other increments will come from the Tabasco — Littoral, Mison, Ixtal — Manik, Ayin-Alux and Faja de Oro Marina fields, as well as the Bellota-Chinchorro and Jujo-Tecominoacan fields in the onshore region.

In Western Europe, crude oil and NGLs production is expected to fall to 3.7 mb/d in 2013, down from 4.6 mb/d in 2008, driven mainly by field declines in the mature North Sea. Compared to the WOO 2008, this year's supply figure for 2013 is over 500,000 b/d lower. Given the maturity of the fields, this downward trend is inevitable despite increasing levels of exploration activity. The actual pace of the decline in the medium-term will depend heavily on the effectiveness of ongoing brown-field development projects in the largest oil fields. Nonetheless, achieving further increases in recovery rates for the most mature North Sea oil fields will remain a major challenge, given the large amount of reserves growth that has already been witnessed.

In the Norwegian Shelf, the low oil price environment, as well as project funding difficulties, has adversely affected crude and NGLs production levels, but to a lesser degree than in the UK. This is due in part to the fact that most of the current production, as well as new developments, are controlled by large oil companies. Nevertheless, declines in mature fields and uncertainties surrounding new investments, due to higher costs, have increased the medium-term risk. With this in mind, crude oil and NGLs production in Norway is expected to decline from around 2.5 mb/d in 2008 to 2 mb/d in 2013. This figure has been revised down by over 250,000 b/d, when compared to last year's WOO. There are, however, a phase of new oil field developments scheduled to start over the next few years including many significant late life EOR projects, such as those in Ekofisk, Oseberg, Gullfaks and Statfjord. Other new developments include, most notably Skarv and Idun, the Yme redevelopment, Gjoa, the Valhall redevelopment, Goliat, Trestakk and Volund, as well as condensate production from the major Tyrihans N&S, Vega and Gudrun gas fields. However, most new start-ups are located in the Northern Norwegian Sea, where development and operating conditions are harsher. This could mean that some of these projects are subject to delays.

In the UK, crude oil and NGLs production is expected to continue its steady decline, falling from around 1.6 mb/d in 2008 to 1.2 mb/d in 2013. Indeed, the majority of producing fields are well into the decline phase, and fields that are expected to be brought on-stream in the near future will not stem the general production decline. This is despite there being a number of substantial new developments including Shelley, Ettrick, Don West & Southwest, Athena, Affleck, the Lyell redevelopment, Causeway Phase I, Cheviot, Huntington, Perth and Bugle. It should also be recognized that activity in the UK sector of the North Sea last year was supported by the higher oil price and the government's efforts to attract new investment through improved fiscal terms. However, given the current lower oil price environment, the presence of a fairly large number of small operating companies with weaker financial positions than the industry majors, as well as other factors such as costs, then it is to be expected that an increasing number of proposed projects will be at risk. The upshot is that this is likely to delay or cancel the start-up of some projects, and as a result, production by 2013 is now expected to be 200,000 b/d lower when compared to last year's WOO.

Crude oil and NGLs production in non-OPEC Latin America is expected to increase from 3.7 mb/d in 2008 to 4.1 mb/d by 2013. This growth is anticipated to continue out to 2015 when the figure reaches 4.3 mb/d. Brazil, which has a significant reserve base and already accounts for around 50% of production from this region, will be the main source of growth.

The majority of Brazil's current production comes from the post-salt Campos basin, and this area is expected to see significant future growth. The Marlim Leste, Marlim Sul Module 2-3, Frade, Golfinho Module 3, Urugua-Tambua, as well as the Tupi pre-salt pilot production in the Santos basin, are set to add at least 600,000 b/d by 2011. Further major projects, each with production capacity in excess of 100,000 b/d, will also support Brazil's output growth in the medium-term. The expectations for continued supply growth have been underpinned by several important discoveries in recent years, notably Roncador, Peregrino, Papa-Terra, Whale Park fields, Tupi, Guara, Iara, and many others in the new and potentially major ultra-deep pre-salt fields. However, all these discoveries are in deepwater, which will obviously require major investment and cutting edge production technology (see Box 3.3). Overcoming these challenges and securing the required financial resources for these high-cost projects will be a central component in shaping Brazil's future production. In the current global economic downturn, it is also evident that the risks associated with these developments have increased. Accordingly, over 300,000 b/d of production originally due on-stream by 2013 has now been deferred. Nevertheless, Brazilian crude oil and NGLs production is expected to increase from about 1.9 mb/d in 2008 to 2.4 mb/d in 2013.

For non-OPEC Middle East & Africa, crude oil and NGLs production is expected to decline slightly from 4.2 mb/d in 2008 to 4.1 mb/d by 2013. For 2009, the 2013 figure has been revised down by around 350,000 b/d when compared to the WOO 2008.

In the Middle East region, where the major non-OPEC producing countries are Oman, Syria, Yemen and Bahrain, the slow decline trend is a normal characteristic of large, more mature fields. In addition, in light of the current financial crisis, many high cost EOR projects in Oman are expected to be delayed. The situation will be similar in the Yemen, where many new projects are also anticipated to see delays. In total, 2013 production from non-OPEC Middle East has been revised downward this year by over 150,000 b/d, when compared to last year's figures. As a result, crude oil and NGLs production in the non-OPEC Middle East is expected to fall slightly from 1.6 mb/d in 2008 to 1.5 mb/d in 2013.

The present financial crisis is also adversely affecting the production prospects of non-OPEC Africa. As a result, the combined 2013 production outlook for Sudan, which has also been impacted by an escalation in tensions in its oil producing regions, as well as Congo and Chad, has been revised down by around 220,000 b/d. In Egypt,

Box 3.3
Is it a new era for Brazilian oil?

More than 280km off Brazil's coast, trapped under a few kilometres of water, rock, and salt, lie billions of barrels of light, sweet crude. It has been described as the largest discovery of oil in the Western Hemisphere in a generation and it has the potential to be one of the most important long-term growth areas for world oil resources and production. It begs the question: could these finds catapult Brazil into a new role as a major global oil producer and exporter?

What is evident is that the very early figures and evaluation of Brazil's pre-salt finds generally point towards a positive response to this question. Thus far, there have been a number of new discoveries in the pre-salt Santos basin: Tupi; Jupiter; Carioca; Guara; Parati; Caramba; Bem Te Vi; Iara; Azulao; and Iguacu. There are also pre-salt discoveries located under existing fields to the north of the Campos basin: offshore Espirito Santo-Cachalote; Baleia Franca-pre-salt; Baleia Ana-pre-salt; Baleia Azul-pre-salt; Jubarte-pre-salt; Cachareu; and Pirambu. The majority of these discoveries are also large and of good crude quality. For example, Tupi has estimated recoverable reserves of between five and eight billion barrels of medium gravity low sulphur crude oil.

There is certainly much to encourage the developers, led by Brazil's Petrobras, but it is also clear there remain many technical, operational, fiscal and resource challenges.

As with any new finds on this scale, the initial issue is one of understanding the nature and complexity of the reservoirs. At present, most of the discoveries are at the appraisal stage, and it will require a number of years before comprehensive development plans can be implemented. However, what is known is that the water is deep, at over 2km, and the salt layer below is of the same thickness, which is likely to make drilling particularly challenging and expensive.

This plays out in the lack of rigs that are capable of drilling in deepwater and through such thick salt layers. Petrobras is believed to need a significant number of deepwater rigs to explore, appraise and develop its acreages, and while some of these can be leased, many may need to be built. Taken as a whole, the scale and complexity of these pre-salt discoveries will require major investments and cutting edge production technology.

In addition, there are industry-wide challenges, such as the recent high costs, although these are now falling slightly, the shortage of skilled labour and expertise, and the oil price. According to Petrobras, the breakeven price required for the pre-salt projects is around \$40/b, while other studies have put the price at between \$45/b and \$60/b.

In its most recent business plan, for the period 2009–2013, Petrobras said it plans to invest more than \$111 billion on the pre-salt developments over the next ten years or so, though it should be recognized that the company is also developing other projects, both domestic and international, which will obviously compete for resources. And it expects oil production from the pre-salt reservoirs — including the shares of its partners — to reach over 0.5 mb/d by 2015, and then just over 1.8 mb/d in 2020.

These are impressive numbers, and in May 2009 Petrobras began lifting crude from the Tupi field, although full field development is unlikely to start before 2015. The company also has a history of developing innovative solutions to new and challenging problems, and has built operational capacity and skills in a number of deep and ultra deepwater projects.

For the oil industry as a whole, it underlines how reserves keep on expanding as the technological and physical barriers are increasingly pushed back. It is a trend that has been with the industry since its very beginning, and one that is expected to continue.

How this all pans out remains to be seen, but it is clear the global oil industry will continue to watch with interest the development of the Brazilian pre-salt resources, as these major new discoveries move from appraisal to development and on to production.

on the other hand, the medium-term outlook has been revised slightly upward due to an increase in NGLs production. In total, production in 2013 from Africa has been revised downward this year by around 200,000 b/d. Despite these regional and country-specific revisions, some 'actual' growth is expected from non-OPEC African producers, mainly Sudan and Congo. Increased investment in a new onshore development in Congo is anticipated to contribute to a ramp up in production over the next five years, together with the start up of Congo's first deepwater project. Considerable growth has occurred in Sudan in recent years, although not as quickly as anticipated only a few years ago. In general, crude oil and NGLs production in non-OPEC Africa is expected to stay flat at around 2.6 mb/d from 2008–2013.

The production of crude oil and NGLs in other Asian countries, which now includes Indonesia, is expected to expand in the medium-term from 3.7 mb/d in 2008 to around 4.1 mb/d by 2013. Oil production is likely to increase in India, Indonesia and Malaysia. Elsewhere, it is foreseen to remain broadly flat in countries such as Vietnam, Brunei, Papua New Guinea, Pakistan and Thailand. Since most of the operating companies in other Asia countries are NOCs, or medium- to large- IOCs, the economic crisis is not expected to largely affect the region's crude oil supply. Nevertheless, the risk for new development projects has increased slightly for some countries, most notably Malaysia and India, and to a lesser extent Vietnam. Accordingly, around 150,000 b/d of production originally due on-stream from these countries by 2013 has now been deferred.

China has extensively adopted a number of advanced technologies, as well as EOR practices, to help sustain its production. Offsetting declines from the country's mature fields will come through the development of new offshore fields. For example, in the next five years, much of the increase in oil output will come from the South China Sea, which is considered to be an under-explored rich hydrocarbon province. However, the fall in oil prices and the relatively high costs for some new development projects have meant that some of China's NOCs have scaled back their operations in these areas. As a result, crude oil and NGLs production from China in 2013 has been revised downwards by approximately 300,000 b/d. Crude oil and NGLs production in China is expected to stay flat over most of the medium-term at around 3.8 mb/d.

The recent lower oil price and difficulties in funding new projects are also negatively impacting the short- and medium-term crude oil production growth from transition economies. Many projects are expected to be delayed or postponed in the short- and medium-term, and in addition, sustaining production levels and offsetting declines in the mature regions will be affected too. As a result, and comparing figures with the 2008 edition, the region has seen its 2013 production revised down by over 1.7 mb/d. Nevertheless, even with these downward revisions, particularly in the three largest producing countries, Russia, Azerbaijan and Kazakhstan, the region will continue to lead total non-OPEC volume growth in the medium-term, with crude oil and NGLs production anticipated to grow from around 12.7 mb/d in 2008 to 13.6 mb/d by 2013. And despite having their figures revised down this year, Kazakhstan and Azerbaijan will still see significant production growth over the medium-term.

The fall-off in Russian oil production growth rates, first witnessed in 2005, continued into 2006 and 2007, and became negative in 2008. The challenging financial conditions of a number of Russian companies, the scarcity of credit and a drop off in funding from western investors have led to a cutback in investment plans. This reduction in capital expenditure is expected to have a significant impact on Russia's future production. Consequently, its 2013 level has been revised downwards by slightly more than 1.2 mb/d when compared to last year. One of the keys to a recovery in Russian growth rates will be incentives from the government for additional investments, and in particular new field developments. Despite the decline in Russian production in 2008, crude oil and NGLs production is expected to increase gradually after 2010 from 9.6 mb/d to 9.9 mb/d by 2013, and by a further 0.2 mb/d by 2015. However, this represents a lower average yearly volume growth rate compared to that witnessed in the 2001–2004 period. In addition to the current global economic crisis, the major uncertainties in the production outlook are largely above ground and include changes in the Russian export tax, the tax regime for new oilfield developments, its role in pioneering new approaches to oilfield practices, and the constraints in Russian export infrastructure.

In the coming years, the mature Volga-Urals region is anticipated to witness a production decline as its largest producing fields become further depleted. And new developments such as Vankorskoye, Russkoye and Uvatskoye, are more often located in remote parts of Western Siberia. Production from Timan-Pechora is expected to double in the medium-term, as existing developments in the northern Nenets region continue apace. Production of NGLs associated with the development of large-scale gas resources located in the Barents Sea could provide additional volumes in the longer term. Despite declines in the North Caucasus and Pre-caspian basins, the giant Astrakhan field is expected to remain the region's key producing field. Increases in liquids production are also expected in East Siberia and the Far East (Sakhalin Island).

As with Russia, oil production growth rates in the other transition economy countries are being impacted by the ongoing financial crisis and the recent lower oil price levels. It is anticipated that a number of projects will be delayed. As a result, around 500,000 b/d of production originally due on-stream in this region by 2013 has now been deferred to beyond this timeframe. However, crude oil and NGLs production in the region, with Azerbaijan and Kazakhstan the major producers, is still expected to grow. The forecast is for an increase from 2.9 mb/d in 2008 to around 3.7 mb/d by 2013. This trend is expected to continue to at least 2020. In Azerbaijan the bulk of this expansion is expected to come from the deepwater Azeri Chirag Guneshli project. Two other large contributors to oil production growth in Azerbaijan over the next decade will be the shallow water Guneshli field and Shah Deniz. Its future growth will also depend on the success of offshore exploration in the Caspian Sea. Expected increases in Kazakhstan are primarily the result of expansions at the Tengiz and Karachaganak fields. However, delays are likely in the start-up for phase III of the Karachaganak project. The start-up of the Kashagan development has also now been pushed back to 2013.

Long-term non-OPEC crude and NGLs

For the longer term, the oil resource base is used to develop a set of feasible supply paths. A series of logistics curves are developed mapping cumulative discoveries

Table 3.2
Estimates of world oil and NGLs resources*

billion barrels

	Mean
US & Canada	400.2
Mexico	87.6
Western Europe	119.1
OECD Pacific	22.1
OECD	**628.9**
Latin America	135.1
Africa & Middle East	114.2
Asia	104.7
China	86.9
DCs excl. OPEC	**440.9**
Russia	454.5
Other transition economies	181.2
Transition economies	**635.7**
Non-OPEC	**1,705.5**
OPEC	**1,651.3**
World	**3,356.8**

* *Cumulative production, proven reserves, reserve growth, undiscovered resources.*
Source: Mean estimates by United States Geological Survey, World Petroleum Assessment 2000; OPEC Secretariat.

to cumulative drilling, with the resource constraint integrated as the corresponding asymptote. Table 3.2 documents the assumptions for the URR of oil and NGLs, based upon the most recent USGS figures. The values in the table have been amended to account for countries in Asia and Africa that are now producing oil, but were not included in the USGS assessment, such as Vietnam, Papua New Guinea, Philippines, Thailand, Chad, Sudan, South Africa, Mauritania and Uganda. In addition, with Indonesia being incorporated within the Asia region this year, resources for that grouping have more than doubled. As a result of this change, the total URR for non-OPEC is now greater than for OPEC. Nevertheless, the remaining resources are still greater in OPEC Member Countries.

The long-term outlook for crude oil plus NGLs supply by region appears in Table 3.3. All OECD regions see a steady decline. Both the US & Canada and Western Europe fall by more than 2 mb/d over the period 2008–2030, while Mexico's output is also expected to decline further. Total non-OPEC crude oil plus NGLs

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

	2008	2010	2015	2020	2025	2030
US & Canada	8.8	8.8	8.4	7.8	7.3	6.7
Mexico	3.2	2.8	2.5	2.5	2.4	2.3
Western Europe	4.6	4.2	3.5	3.1	2.8	2.4
OECD Pacific	0.6	0.7	0.6	0.6	0.6	0.6
OECD	**17.2**	**16.5**	**15.0**	**14.0**	**13.0**	**12.0**
Latin America	3.7	3.9	4.3	4.9	5.1	5.1
Middle East & Africa	4.2	4.2	4.1	3.9	3.7	3.5
Asia	3.7	4.0	3.9	4.0	3.8	3.4
China	3.8	3.8	3.7	3.5	3.4	3.4
DCS, excl. OPEC	**15.4**	**15.9**	**16.0**	**16.3**	**16.1**	**15.4**
Russia	9.8	9.6	10.2	10.5	10.5	10.5
Other transition economies	2.9	3.3	4.0	4.3	4.7	5.0
Transition economies	**12.7**	**12.9**	**14.1**	**14.8**	**15.2**	**15.6**
Non-OPEC	**45.2**	**45.2**	**45.2**	**45.2**	**44.4**	**42.9**

supply is expected to remain at a steady plateau of just over 45 mb/d until 2020, before beginning a gradual decline. This occurs largely because of increases from Brazil, Russia and other transition economies, which make up for decreases over the next decade in OECD countries.

Conventional crude and NGLs supply in the US & Canada, after maintaining a plateau of 8.4 mb/d, is expected to begin a gradual decline from 2015, with output reduced to 6.7 mb/d by 2030. The ratio of remaining resources — total original resources as estimated by the USGS minus cumulative production — to annual production for this region has been in steady decline for decades, as has the actual level of production of crude plus NGLs. A continued steady fall in production is consistent with the estimated resource base.

For the US, in the longer term there is considerable exploration potential in the deepwater Gulf of Mexico. The fields in this area will continue to be a source of crude oil production growth, but this is not sufficient to outweigh declines elsewhere. Production from the Arctic National Wildlife Refuge (ANWR) area to the east of Prudhoe Bay has the potential to help offset some of the declines from other regions, but no production is expected from the ANWR until after 2020. Combining these trends, total US crude and NGLs production is projected to maintain a steady plateau of 6.7 mb/d until 2016, before declining gradually thereafter to 5.5 mb/d by the end of the forecast period.

In Canada, the production of conventional crude and NGLs in the western part of the country is expected to show a continued decline. On the other hand, production from offshore Newfoundland is anticipated to be maintained at near its current level, through a combination of continued investment to increase recovery from existing fields and new discoveries. However this will not be sufficient to offset declines elsewhere. Conventional crude and NGLs supply in Canada is expected to decline gradually from 2 mb/d in 2008 to around 1.6 mb/d in 2020, and then further to 1.2 mb/d by 2030. It is clear that Canada also has significant non-conventional reserves. The outlook for non-conventional oil supply is discussed later in this Chapter.

Mexico has the dual challenge of above ground difficulties and relatively limited resources, as within four years it will have produced half of its total estimated available oil, including resources yet to be discovered. As a result, Mexican crude oil production is expected to decline to 2.5 mb/d by 2015, from 3.2 mb/d in 2008. And in addition, the uncertainties apparent in the medium-term, also play out in the longer term. The anticipated exploration and development of Mexico's deepwater Gulf of Mexico province later this next decade, as well as the full development of the Chicontepec onshore field that has been on-stream since the early 1950s, but never fully exploited, may slow the output decline after 2015. Total output is expected to reach 2.3 mb/d by 2030.

These decline trends also hold true for Western Europe. In 2009, almost half the resource base has already been produced and further declines in North Sea supply are inevitable. Western Europe's crude oil production is expected to decline from 4.6 mb/d in 2008, to 3.5 mb/d by 2015 and then 2.4 mb/d by 2030. In the longer term, the keys to slowing the pace of this decline will be the ability to maximize recovery from mature fields and the success of satellite field development opportunities. Incremental finds within the traditional areas of the North Sea will probably make a limited, but relatively important contribution.

Norway currently accounts for just over half of Western Europe's production. In the longer term the potential for large discoveries is most likely to be in frontier provinces, such as the Barents Sea. As in the medium-term, the decline in Norwegian production is expected to continue over the long-term. The Reference Case outlook for total crude and NGLs production in Norway sees a decline from around 2.5 mb/d in 2008 to 1.9 mb/d by 2015, and then to 1.1 mb/d by 2030. Though the UK North Sea is clearly a mature oil region, it is believed some significant resources remain, particularly for heavy oil, such as those at Bressay. Developing these resources, however, will depend on technological advances that allow companies to tap into these undeveloped fields. Thus, the timing of their exploitation is uncertain, although it is likely to be a lengthy process. UK crude oil and NGLs production is expected to continue its steady decline, falling to around 1.1 mb/d by 2015 and 0.6 mb/d by 2030, from 1.6 mb/d in 2008.

As a result, the total supply from OECD crude oil plus NGLs is set to fall by more than 5 mb/d over the period to 2030.

The prospects for the supply of crude and NGLs in non-OPEC developing countries is in contrast to that of OECD countries. Most regions will be able to maintain supply at close to current levels, with some rising, for at least the next decade. The net result of the regional projections is for total developing country supply from crude and NGLs to gradually increase over the next decade, before beginning a gradual decline.

The major region for this supply growth is Latin America, with production of crude oil and NGLs in non-OPEC Latin America increasing in the Reference Case from 3.7 mb/d in 2008 to a plateau of over 5 mb/d by 2025. The key country for this increase is Brazil, whose total URR of 71 billion barrels represents more than half of the entire non-OPEC Latin America region. Brazilian crude and NGLs production is expected to increase to 2.7 mb/d by 2015 from about 1.9 mb/d in 2008. Given its reserve base, Brazil has the potential for further increases in production with an expectation of 4 mb/d by 2030. In the longer term, supply growth from Brazil is underpinned by several recent large ultra deep offshore pre-salt discoveries (see Box 3.3), as well as the anticipated strong potential for 'yet to be found' accumulations.

For the other main Latin American producers, crude oil and NGLs production is forecast to decline. Argentina's crude and NGLs production is expected to fall moderately to under 0.7 mb/d by 2015, and to continue declining in the longer term, reaching around 0.3 mb/d by 2030. Argentina's oil fields are mostly mature and future reserve growth is expected to be limited. In Colombia, the production of crude and NGLs is expected to start declining after 2010, averaging around 0.5 b/d by 2015, a fall of 0.1 mb/d from 2008 levels, before contracting further to just 0.2 mb/d by the end of the forecast period. Production of crude and NGLs from other non-OPEC Latin America countries, the largest producer being Trinidad and Tobago, is anticipated to remain stable over the medium-term, and then rise to around 0.5 mb/d in 2020 and 0.6 mb/d by 2030.

For the non-OPEC Middle East & Africa region, medium-term patterns for crude and NGLs supply will be maintained in the longer term, with the aggregate supply from the region declining from around 4.2 mb/d in 2008 to 3.5 mb/d by 2030.

Supply increases from some African countries, including Sudan, Mauritania, the Ivory Coast and Uganda, will not be enough to compensate for declines in the Yemen, Syria and Oman. Production of crude and NGLs in Oman, currently the largest non-OPEC producer in the Middle East region, is expected to stay flat at just over 0.7 mb/d out to 2020, before falling at a relatively slow rate to around 0.6 mb/d in 2025 and just over 0.5 mb/d by 2030. Egypt is currently Africa's largest non-OPEC producing nation. However, since the country's strategic shift from oil to gas in the mid-1990s, oil and NGLs production has been in decline. Production of crude and NGLs is forecast to fall from 0.7 mb/d in 2008 to just under 0.6 mb/d in 2015, and then further to 0.5 mb/d in 2020 and 0.3 mb/d by 2030. And in Sudan, crude and NGLs production is expected to average around 0.5 mb/d in 2015, and reach 0.6 mb/d by 2030.

Production of crude oil and NGLs in Asian countries, including Indonesia, is expected to increase to around 4 mb/d by 2015, from 3.7 mb/d in 2008. A steady plateau is then expected, before there is a gradual decline in the early part of the next decade. In 2030, crude oil and NGLs output is 3.4 mb/d. Over the next ten years, crude and NGLs production is expected to increase mainly in India, Malaysia and Vietnam. Elsewhere in Brunei, Papua New Guinea, Indonesia, Pakistan and Thailand, oil production is expected to remain broadly flat over the same time period.

In the long-term, there is significant potential for reserves growth in China. Continued investment in EOR projects should slow the rate of decline and improve recovery factors in major onshore fields. The development of new offshore fields will also help offset the impact of declines from mature fields. After plateauing over most of the medium-term, a slow decline in China's production of crude and NGLs is expected, with output estimated to fall to 3.4 mb/d in 2030.

Large growth rates in Russian oil production were witnessed at the beginning of this century, but these increases began to slow from 2005, and last year saw the first decline in a decade. While this trend is set to continue in the short-term, by 2011 Russian supply is expected to register a rise once again. Declines in mature regions are anticipated to be offset by increased investments and the opening up of new producing regions. In the long-term, the resource base is not a constraint for Russian production. The URR for Russia exceeds that of all developing countries together, and only 30% of this has so far been produced. Thus, as for the medium-term, it will be above ground issues that continue to predominate, including possible changes to the Russian tax regime for new oilfield developments and its role in pioneering new approaches to oilfield practices, as well as Russian export infrastructure constraints. With all this in mind, further rises are expected for Russian supply of crude and NGLs, but it is thought that a sustainable plateau of 10.5 mb/d will be reached within a decade.

Supply from the other transition economies is predominantly accounted for by the Caspian region. As with Russia, the resource base is sufficient to allow a continued growth as only 15% of the URR has so far been produced. The Reference Case sees crude and NGLs supply rising steadily from 2.9 mb/d in 2008 to 5 mb/d by 2030. The major player in this increase will be Kazakhstan, with output increasing to 2.1 mb/d by 2015 and then to 3.1 mb/d in 2030. This is primarily the result of the expansion of the Kashagan field: phase one with 75,000 b/d is expected to start during 2013, with additional phases taking production to 450,000 b/d around two-to-three years later and then to 900,000 mb/d by 2018. The field could plateau at around 1.5 mb/d after 2020. For the other main producer of the region, Azerbaijan, production is expected to increase to 1.2 mb/d in 2015, but growth beyond this period is anticipated to be limited.

Non-conventional oil (excluding biofuels)

In the medium- to long-term, almost all of the world's non-conventional oil supply will come in the form of oil sands, synthetic oil from natural gas (GTLs), coal (CTLs) and shale oil. The medium-term supply outlook by region in the Reference Case appears in Table 3.4. Non-OPEC non-conventional oil (excluding biofuels) rises from 1.8 mb/d in 2008 to 2.2 mb/d by 2013.

Canadian oil sands are expected to witness the single largest increase of non-conventional oil. With over 170 billion barrels of bitumen viewed as being economically recoverable,[12] resources are no constraint to supporting a strong increase in supply. Technological advances, concerns over security of supply, and the high oil price

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

	2008	2009	2010	2011	2012	2013
US & Canada	1.3	1.3	1.4	1.5	1.7	1.7
Western Europe	0.2	0.2	0.2	0.2	0.2	0.2
OECD Pacific	0.0	0.0	0.0	0.0	0.0	0.1
OECD	**1.6**	**1.5**	**1.6**	**1.7**	**1.9**	**2.0**
Middle East & Africa	0.2	0.2	0.2	0.2	0.2	0.2
China	0.0	0.0	0.0	0.1	0.1	0.1
Developing countries, excl. OPEC	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**
Non-OPEC	**1.8**	**1.6**	**1.8**	**1.9**	**2.1**	**2.2**

environment up to the summer of 2008 motivated the industry to commit huge investments to oil sands projects. As a result, a number of large projects were planned to be developed over the next five-to-seven years.

However, the recent decline in oil prices, high costs, which have only recently begun to marginally fall, a lack of clarity regarding future CO_2 emissions abatement regulations, and the current global economic crisis have led to project cancellations and delays. In addition, many projects are still facing some technical problems in reaching their nameplate capacity. Regarding the cost issue, while prices of natural gas, steel and other commodities have fallen, labour costs, which usually drop more slowly than commodity prices, have been slower to respond. As a result, to break even the new oil sand projects need a West Texas Intermediate (WTI) price in the range of \$50–70/b, depending on the recovery scheme. However, production from existing oil sands projects is economically viable at lower oil prices. The medium-term outlook for Canadian oil sands supply has been evaluated taking into account all these factors.

In the medium-term, the majority of projects that are at an advanced development stage are expected to be relatively unaffected. It is the projects where investment decisions have not yet been sanctioned and/or not yet submitted for regulatory approval that are most at risk of being postponed or cancelled in the present economic climate. Since the third quarter of 2008, the industry has witnessed many delays in the execution of projects, as many companies such as Shell, Total, Suncor Energy Inc., Petro-Canada, StatoilHydro, as well as others, reduced their investment plans in the Canadian oil sands. For example, Suncor Energy Inc. has slowed construction on its Voyageur upgrader and the 200,000 b/d Firebag expansion in northern Alberta; Shell has delayed the second expansion of its Athabasca Oil Sands Project (AOSP); Petro-Canada has deferred a decision on it Fort Hills oil sands development and postponed construction of their integrated upgraders; Total has delayed mine and upgrader projects; and StatoilHydro has withdrawn its regulatory application for the Kai Kos Dehseh project. In total, around 1 mb/d of production originally due on-stream by 2013 has now been deferred.

Accordingly, in the medium-term, oil sands production is anticipated to increase moderately from about 1.2 mb/d in 2008 to around 1.6 mb/d in 2013, around 900,000 b/d lower than the 2008 WOO reference case.

Shale oil and GTLs are not expected to grow over the medium-term, but an increase in CTLs is expected. Synthetic liquid from oil shale and GTLs is expected to stay at around 10,000 b/d and more than 50,000 b/d respectively. On the other hand, CTLs supply will almost double from about 160,000 b/d in 2008 to more than 300,000 mb/d by 2013, mainly from South Africa, China and the US.

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

mb/d

	2008	2010	2015	2020	2025	2030
US & Canada	1.3	1.4	2.1	3.1	3.8	4.6
Western Europe	0.2	0.2	0.2	0.2	0.2	0.2
OECD Pacific	0.0	0.0	0.1	0.1	0.1	0.1
OECD	**1.6**	**1.6**	**2.4**	**3.4**	**4.1**	**4.9**
Latin America	0.0	0.0	0.0	0.0	0.1	0.1
Middle East & Africa	0.2	0.2	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**	**1.8**	**2.8**	**3.9**	**4.9**	**6.0**

In the longer term, despite the large resource base and the long list of probable oil sands development projects, the expansion rate has a number of constraints. For example, the transportation infrastructure may limit output feasibility, while a dearth of qualified labour, water shortages and the degradation of the surface water quality, as well as the availability and costs of natural gas, may all act to constrain output. Moreover, additional possible costs associated with greenhouse gas emissions could represent a key challenge for the Canadian oil sands industry. If the cost of CO_2 emissions from oil sand projects is internalized, through either a cap-and-trade system or increased direct taxes, this will inevitably impact project economics. However, this year's Reference Case projection assumes that any future government emission-constraining policies will be only slightly tougher than those in place today,[13] and will not hamper oil sands growth. As a result, the longer term Reference Case sees supply from the Canadian oil sands expanding from 1.2 mb/d in 2008 to about 2 mb/d by 2015, and then to around 3 mb/d by 2020. Further growth is expected in the following years, and by 2030 it reaches almost 4 mb/d. The figure has been reduced by around 1 mb/d from last year's projection.

Over the long-term, shale oil and GTLs will continue to make only a small contribution, but the supply of CTLs will rise. Together their contribution will hit 2 mb/d by 2030, around 0.5 mb/d lower than the 2008 WOO reference case. Synthetic liquid from shale oil is expected to increase from just 10,000 b/d in 2008 to over 50,000 b/d by 2020, and to around 300,000 b/d by 2030. The main growth area is the US. Liquid production from GTLs in non-OPEC countries is forecast to reach 350,000 b/d by 2030, from a 2008 figure of 50,000 b/d. Supply is expected to come mainly from South Africa, Australia, Malaysia and China. CTLs supply will grow from below 0.2 mb/d in 2008 to 0.5 mb/d by 2020, and then 1.2 mb/d by 2030, with South Africa, China and the US remaining the main producers. However, it should be remembered that CTLs and GTLs projects are highly capital intensive and have experienced cost overruns in the past. Moreover, both of these processes suffer from inherently low efficiencies, and in addition, CTLs necessitate the use of large amounts of water.

Non-OPEC non-conventional oil (excluding biofuels) thereby rises in the Reference Case by 4.2 mb/d over the period 2008–2030, reaching 6 mb/d by 2030 (Table 3.5). The figure is 1.5 mb/d lower than last year's projection.

Biofuels

The economic expansion cycle from 2001–2008 led to a significant expansion in the global demand for petroleum products. In addition, with the oil price on an upward trend until mid-2008, and in conjunction with demand growth, a number of investors looked to tap into the market for petroleum substitutes. It was evident that many saw biofuels as the product with the greatest potential to substitute for oil in the transportation sector.

In addition, biofuels were also thought of as one of the key options to limiting greenhouse gas emissions from the transportation sector, as well as a way to reduce oil imports by some countries. Thus, policies were developed for and extended to biofuels, and consumers began to embrace more fuel efficient vehicles and renewable fuels.

It was also evident that biofuels production costs exceeded the market value of the fuels. Thus subsidies and/or mandates were required to ensure their market share. The subsidies and mandates offered by a growing number of nations were justified on the premise of public benefits: local energy security, global warming mitigation, local economic growth, or a combination of all of these.

The confluence of factors — high oil prices, a surplus of energy investment dollars, growing subsidies and mandates, positive public relations, and the potential for carbon tax credits — created a seemingly safe haven for biofuels investors. By 2007, new investment in biofuels reached \$18.5 billion,[14] and biofuels global production capacity — from ethanol and biodiesel — reached 1.4 mb/d.

Despite this growth, however, it was becoming increasingly apparent that a number of challenges for biofuels production were emerging.

The initial upshot of all this new investment was a rise in superfluous capacity, particularly for biodiesel production. In the EU, the largest global biodiesel producer, almost 60% of its 0.25 mb/d of production capacity lay idle in 2007. In the US, biodiesel production capacity reached 0.17 mb/d in 2008, while available feedstocks were limited to 0.07 mb/d or less, and production only reached 0.04 mb/d.

In addition, the ambitious biofuel targets mandated in the US, the EU and elsewhere, initially contributed to extremely optimistic assessments about the profitability of biofuels. By 2007, however, biofuels feedstock prices had become correlated with petroleum prices, which virtually eliminated any profits that investors predicted.

Furthermore, food prices were on an upward spiral as biofuels production and demand for food oils and corn increased. The result was the much talked about food versus fuel debate. The expansion of biofuels production was contributing to competition with food supplies, although the development was also impacted by rising energy costs, escalating fertilizer costs, expanding world incomes, increasing food demand, a dearth of agricultural investment and weak agricultural policies.

The expectations for biofuels led to a large inflow of investments by non-commercials into commodity markets, creating large volatility that exacerbated the food price crisis around the world. Corn prices increased from an average of $2 a bushel in 2006 to nearly $8 in June 2008, before plummeting to less than $4 a bushel in October of the same year. In mid-May 2009, the Chicago Board Of Trade's (CBOT) July corn futures posted a three-and-a-half month high, closing at $4.21 per bushel.

It was clear biofuels had their limitations and these were being recognized. In its drive to lead the world in combating climate change, the European Commission had proposed its *'Energy Policy for Europe'* plan, which had included a 10% binding minimum target for the share of biofuels in EU transport fuels for all member states by 2020. However, by mid-2008, the Commission was reconsidering its proposal as the global food crisis gathered pace, and the role played in the race to divert food or feed crops into biofuels was acknowledged.

Since the fourth quarter of 2008, the global financial crisis and the ensuing credit squeeze has also put the brakes on the biofuels expansion. For instance, Verasun, the second-largest producer of ethanol in the US, filed for bankruptcy in October 2008. And since then, several other producers have halted production or sought bankruptcy protection. In February 2009, industry sources estimated that the offline ethanol production capacity in the US was between 15% and 20% of existing capacity.

With tight credit and very small, sometimes negative margins driving the industry, it is likely there will be a period of consolidation in 2009, even though, under the Renewable Fuels Standard (RFS) mandated by the EISA of 2007, the requirement for ethanol is set to grow by 0.15 mb/d to 0.79 mb/d from 2008. And this period of transition could extend beyond 2009, even if the economy begins to improve later in the year.

The financial crisis has also impacted the expansion of Brazil's ethanol production. While the full effect is still unknown, since the Brazilian ethanol industry is dominated by private family-owned enterprises that are not bound by public disclosure rules, there are signs that foreign investment has fallen. For example, in February 2009, Indian companies, Hindustan Petroleum, Bharat Petroleum, and Indian Oil, cancelled plans to invest in production. The estimated investment of $600 million would have resulted in an initial production capacity of 500 million litres of ethanol. And one large ethanol maker has recently filed for bankruptcy to restructure $100 million of debt, with more bankruptcies expected. In addition, a number of orders for new equipment have been cancelled or postponed.

Given the above recent adverse developments, the Reference Case sees global biofuels supply growth significantly reduced in the medium-term compared to last year's WOO. In 2009, supply will grow by only 0.17 mb/d, compared to the phenomenal growth of 0.32 mb/d recorded one year before. Growth will fall further in 2010 to 0.13 mb/d, steady at 0.11 mb/d, before picking up again in 2015.

In this year's Reference Case, it should also be noted that two sets of policies have been partially incorporated into the projections: the US EISA, which has now passed into

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

	2008	2009	2010	2011	2012	2013
US & Canada	0.7	0.7	0.8	0.8	0.8	0.9
Western Europe	0.2	0.2	0.2	0.3	0.3	0.3
OECD	**0.8**	**0.9**	**1.0**	**1.0**	**1.1**	**1.2**
Latin America	0.4	0.4	0.5	0.5	0.5	0.5
Asia	0.1	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	**0.5**	**0.6**	**0.7**	**0.7**	**0.8**	**0.8**
Non-OPEC	**1.3**	**1.5**	**1.7**	**1.8**	**1.9**	**2.0**

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

	2008	2010	2015	2020	2025	2030
US & Canada	0.7	0.8	0.9	1.2	1.4	1.8
Western Europe	0.2	0.2	0.4	0.5	0.7	1.0
OECD	**0.8**	**1.0**	**1.3**	**1.7**	**2.2**	**2.8**
Latin America	0.4	0.5	0.6	0.7	0.9	1.1
Middle East & Africa	0.0	0.0	0.0	0.0	0.1	0.1
Asia	0.1	0.1	0.1	0.2	0.2	0.3
China	0.0	0.1	0.2	0.2	0.3	0.4
DCS, excl. OPEC	**0.5**	**0.7**	**0.9**	**1.1**	**1.5**	**1.9**
Non-OPEC	**1.3**	**1.7**	**2.2**	**2.9**	**3.7**	**4.7**

law, and the EU climate and energy package, which has received approval from both the Council of the EU and the European Parliament. Nevertheless, in the medium-term, the impacts of the financial crisis are likely to cancel out the effects of these policies.

Over the medium-term, and similar to last year, the Reference Case assumes no breakthroughs in cellulosic biofuels technologies. First-generation technologies continue to supply the vast bulk of biofuels. But sustainability issues place a limitation on how much first-generation biofuels can be produced. The Reference Case sees global biofuels supply expand in the medium-term, between 2008 and 2013, by 0.7 mb/d (Table 3.6).

In 2015, supply from first-generation biofuels in the US and the EU is assumed to have reached its maximum sustainable potential. Thereafter, second-generation biofuels are observed to contribute to supply in both regions from 2015, albeit modestly. Nevertheless, it is expected that the policy targets in both regions will not be fully met. Of the EU 2020 target for 0.9 mb/d of biofuels consumption, less than 0.6 mb/d will be supplied domestically. In the US, the RFS mandates that 2.3 mb/d of road transportation biofuels be brought to market by 2022, of which only 0.95 mb/d should come from first-generation biofuels. The Reference Case sees total US biofuels supply in 2022 at only 1.2 mb/d, 20% of which is from second-generation technologies. It is important to stress that this is an assumption. At this stage, second-generation biofuels technologies are still in the R&D phase.

The Reference Case recognizes that once second-generation technologies become a commercial reality, they could contribute significantly to biofuels supply all over the world. The Reference Case assumes that operators, especially, in established producing regions, will gradually adopt these technologies beyond 2020. This leads to global biofuels supply increasing by close to 2 mb/d from 2020–2030, reaching 4.7 mb/d by that date (Table 3.7).

OPEC upstream investment activity

It was noted in Chapter 1 that OPEC spare capacity is set to rise. Indeed, it is estimated that by the end of 2008 total OPEC crude production capacity had reached more than 34 mb/d, well over the production of 28.3 mb/d for the first quarter of 2009.[15] Increases in capacity reflect the significant efforts by OPEC Member Countries and is a clear reflection of OPEC's policy laid down in both its Statute and Long-Term Strategy, 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 also to "offer an adequate level of spare capacity".[16] However, the economic crisis and the ensuing steep decline in oil demand has led to the emergence of spare capacity at a pace and scale that was unexpected, and potentially damaging.

Prior to the onset of the global financial crisis, the OPEC Secretariat's upstream project database contained over 150 OPEC Member Country projects that had been expected to come on-stream between 2009 and 2013. These were due to add over 14 mb/d of gross crude and NGLs capacity. This huge undertaking was aimed at not only meeting the expected rise in demand for OPEC crude, but also to compensate for expected declines in existing producing fields, and offer an adequate cushion of spare capacity.

However, given current market conditions and the dramatic fall in demand and prices, there have inevitably been some revisions to these investment plans. The expectation for demand growth has not materialized. As we have seen in Chapter 1, the recession has led to falling demand and, consequently, OPEC's crude supply is now considerably lower in 2009, by almost 3 mb/d, compared to the WOO 2008, although the difference gradually narrows over the medium-term. This means that with OPEC showing its willingness to absorb the fall in demand, the cushion of OPEC's spare crude capacity is already high and growing. And it is evident that the investment challenge has been further complicated by the fact that as prices softened towards the end of 2008, the high-cost environment persisted.

With all this in mind, it has clearly been essential for OPEC Member Countries to review investment plans. It is understandable that any country or investor would be unwilling to invest in capacity that is not needed, especially when they are affected by the global financial and economic crisis, and the substantial drawdown in stocks. They also face large and competing social and developmental needs. In addition, it is widely recognized that over-investing could contribute to the persistence of unsustainably soft prices, and therefore future price volatility.

Of the projects that had previously been considered to contribute capacity additions to 2013, over 35, with a total of around 5 mb/d of crude and NGLs capacity, are now expected to be delayed or even postponed until after 2013. This revision reflects the fact that the surge in investment plans in OPEC Member Countries that were aimed at addressing perceived market tightness, particularly in 2007 and the first half of 2008, would in actuality have turned out, at least partially, to be for unneeded capacity. All of this underscores again the genuine concerns over security of demand.

In terms of investments, the estimated OPEC upstream investment requirement for the medium-term over the period 2009–2013 has fallen from $165 billion to around $110–120 billion. It should be noted, however, that these estimates are based upon upstream project development requirements at the field gate, and do not include the infrastructure required beyond the field.

Chapter 4

Protracted Recession scenario

At the time of writing, the global economy in 2009 was expected to contract for the first time in six decades. The IMF, in its April 2009 *World Economic Outlook*, reported that the current decline represents "by far the deepest global recession since the Great Depression", and that risks are "still weighing on the downside". The Reference Case assumption for economic growth in 2009 already reflects the global downturn, with, as described in Chapter 1, a gradual recovery thereafter and a return to trend growth no earlier than 2012.

The IMF has noted that the downward skew to the risks on the global economy stems in particular from: possible delays in implementing policies to stabilize financial conditions, leading to a further deterioration in the financial strength of banks in advanced economies that could mean an "even deeper and prolonged recession"; deflation risks that could reinforce this, since the expectation of falling prices could lead to the postponement of spending; emerging economies not having sufficient access to foreign financing; and, the possibility of rising protectionism.[17]

It is therefore essential to explore alternatives to the Reference Case that investigate the possible scale of these downside risks, and what they might mean for oil. Indeed, the IMF has also investigated lower growth scenarios: one is a modest reduction from their reference case, involving a 1% reduction in annual growth below baseline rates over the years 2009–2011; and the other is a 'prolonged slowdown' scenario that assumes a 2% drop in annual growth compared to the baseline for all world regions over the years 2009–2013.[18] The latter assumption was made on the basis of the magnitude of the slump experienced in Japan in the 1990s.

Clearly, with some recent economic data indicating a slowdown in the rate of contraction, and an improvement in business and consumer confidence, the likelihood of such scenarios has subsided. However, there is not yet a return to pre-crisis 'normality', and banking system confidence remains low when judged by interest spreads in the inter-bank lending market.

In this WOO, an alternative set of economic growth rates has been assumed in the Protracted Recession scenario that lies between these two sets of IMF assumptions. Compared to the Reference Case, growth in each world region is reduced over the five years 2009–2013 by 1%, 2%, 1.5%, 1% and 0.5% respectively. The resulting economic growth rates are shown in Table 4.1 and summarized in Figure 4.1. The

Protracted Recession scenario thereby reduces world output by an additional 6% by 2013, compared to the Reference Case.

These assumptions are considerably more pessimistic than the April 2009 IMF forecast, which, for example, saw global economic growth of 1.9% in 2010, subsequently adjusted upwards in June.

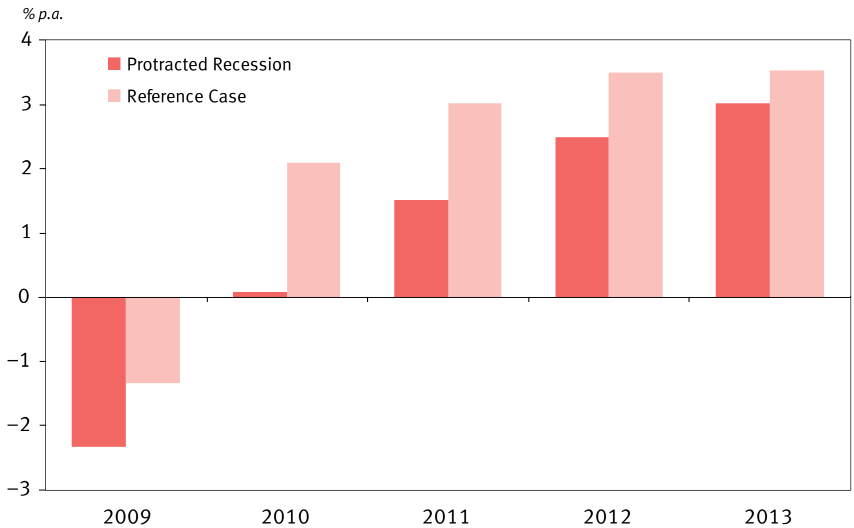
In addition to the more pessimistic view of the rate of recovery for the global economy, the Protracted Recession scenario must also make an assumption for the development of crude oil prices. If Reference Case prices are assumed to still emerge, this would imply that any oil demand reductions associated with lower economic growth would be fully absorbed by OPEC in the form of downward production adjustments, relative to the Reference Case. This would in turn imply that OPEC crude output would probably need to remain approximately flat over the years to 2013. Under such circumstances, simulations suggest that spare capacity could reach unsustainably high levels of around 9–10 mb/d over the medium-term.

A more realistic price assumption in this scenario is for prices to remain considerably softer than in the Reference Case. The scenario therefore assumes that the OPEC

Table 4.1
Economic growth assumptions in the Protracted Recession scenario *% p.a.*

	2009	2010	2011	2012	2013
North America	–4.0	–1.5	0.2	1.6	2.1
Western Europe	–5.1	–1.7	0.0	1.0	1.5
OECD Pacific	–6.2	–1.8	0.0	1.0	1.5
OECD	**–4.8**	**–1.6**	**0.1**	**1.2**	**1.7**
Latin America	–1.7	0.4	1.5	2.3	2.7
Middle East & Africa	0.7	1.3	1.8	2.5	3.0
South Asia	4.1	3.0	3.9	4.4	4.8
Southeast Asia	–2.6	0.5	1.8	2.8	3.3
China	6.0	5.3	6.2	6.7	7.2
OPEC	–0.1	1.5	2.1	2.6	3.2
DCs	**1.9**	**2.6**	**3.6**	**4.2**	**4.8**
Russia	–5.7	0.5	1.5	2.3	2.7
Other transition economies	–4.7	–0.5	1.1	2.2	2.7
Transition economies	**–5.2**	**0.1**	**1.3**	**2.3**	**2.7**
World	**–2.3**	**0.1**	**1.5**	**2.5**	**3.0**

Figure 4.1
Global economic growth in the Protracted Recession and Reference Case scenarios

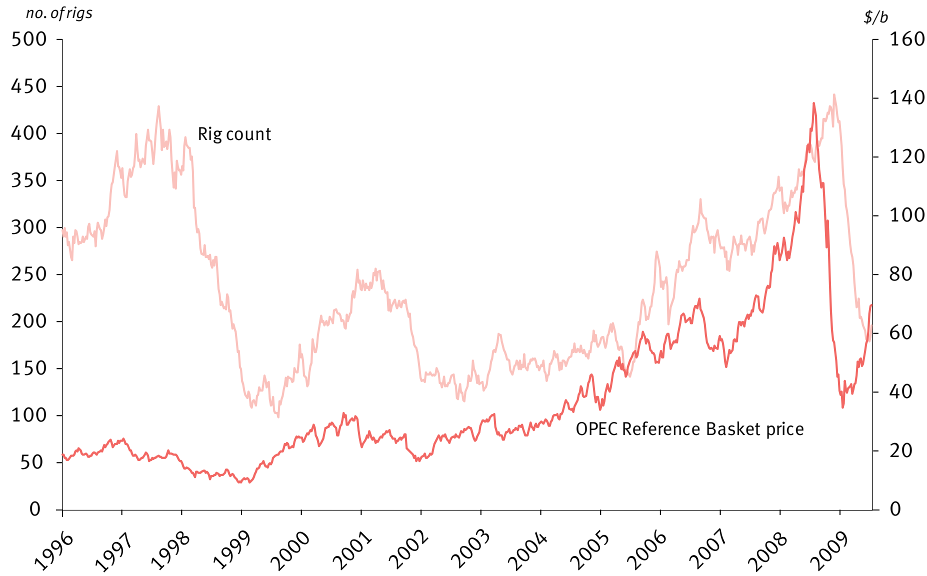


Reference Basket price remains at $40/b for the period 2009–2012. Although the low oil price might provide some support for oil demand, this is likely to be modest, especially given the large tax buffer in place in many countries. Indeed, by 2013, world demand is 2.4 mb/d lower than the Reference Case, with demand at 85.5 mb/d.

Low prices have significant impacts upon oil supply prospects. With other factors remaining the same, in particular, the assumption of no change to costs or fiscal conditions, lower oil prices reduce both profitability and cash-flow, and in addition exploration and production (E&P) activity are affected. Indeed, the first signs of a reaction to the oil price fall are observable: the rig count has already begun to fall swiftly in the US (Figure 4.2), and a similar picture is emerging elsewhere. This is similar to the behaviour in the 1998–1999 period.

Oil companies are reviewing expenditure plans for exploration, while some projects are likely to be affected by contractors or sub-contractors not being able to finance their activities by bank credits. Moreover, production levels are already being affected by the low oil price. Both low prices and the gloomy credit environment are leading to delays in the development of the large offshore reserves in Brazil. In Russia, LUKOIL has strongly reduced capital for its expenditures plan for 2009–2011. The impact of the price and financial situation is also particularly visible for the oil sands expansion projects where a line of project deferrals and cancellations is reducing the short- to

Figure 4.2
US oil rig count fell with the low oil price



medium-term prospects for Canada's oil supply outlook. Part of the reason for the deferrals is that companies are waiting for costs to come down.

The link between price movements and upstream activity is nothing new. This has also been observed in the past. However, the possibility of an extended period of recession, with the ongoing financial crisis and associated credit squeeze coupled with persistently low prices and costs that were higher than in the past, would likely combine to create a perfect storm for the upstream, as well as downstream, investment environment.

The non-OPEC response to this low price is assumed to be unaffected by adjustments to fiscal conditions. Costs are already assumed to fall in the Reference Case, and it is supposed that there is little further scope for reductions, apart from the fact that average global costs will fall as the highest cash cost output is hit first. The Protracted Recession is very much a reflection of the credit crisis, which has seen a number of major insurance companies and investment banks fail and others receive government aid. In this scenario, the assumption is that policies to stabilize financial conditions are not only delayed, but are insufficient to halt the further worsening of the financial strength of banks. This has significant implications for oil supply prospects.

On top of the reaction of non-OPEC conventional oil supply, the economics of non-conventional oil production would also be adversely affected by the prolonged soft price that is assumed. Again, the industry is already seeing the deferral and cancellation of projects, in particular for biofuels and oil sands supply. While these deferrals have been factored into the Reference Case, as described in Chapter 3, the Protracted Recession scenario would involve even further reductions to the expected contribution of these sources of liquid supply.

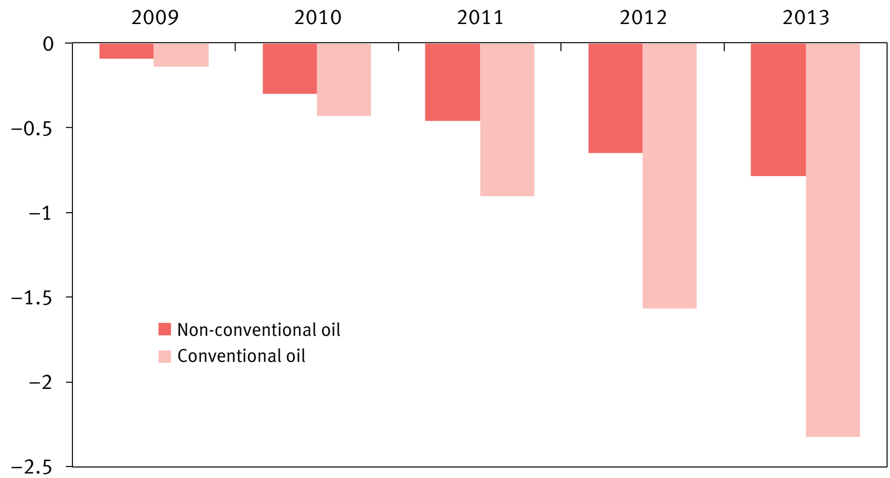
Under this scenario, existing oil sands projects are expected to continue producing, as these will continue to be viable at $40/b for the OPEC Reference Basket price. For new projects, only those in the advanced construction phase, in particular the *in situ* projects, are expected to proceed, resulting in some growth over the medium-term. As a result, oil sands production is expected to grow by less than 0.2 mb/d to around 1.4 mb/d by 2013, around 0.3 mb/d lower than the Reference Case.

The exceptionally high oil price recorded in the first half of last year brightened the prospects for developing biofuels as an alternative. However, this picture has dramatically altered since the end of the year, as biofuels margins weakened when the fall in the price of gasoline/diesel exceeded the relatively modest fall in feedstock prices. More generally, a sustained oil price of $40/b, as assumed in the Protracted Recession scenario is too low for new advanced-biofuels projects to be commercially sanctioned. This is especially true for those projects that attracted investment while oil was above $100/b. Even existing producers could halt production if they see sustained negative cash margins, as the biofuels industry can adapt relatively quickly to the vagaries of the market, in comparison to other non-conventional oil producers. Therefore, in this scenario, global biofuels supply will only grow 0.1 mb/d by 2013, to reach 1.5 mb/d.

Thus, both non-OPEC conventional and non-conventional supply are hit by the low price and credit squeeze (Figure 4.3). Moreover, since E&P spending is reduced considerably, medium-term prospects are also strongly affected. By 2013, non-OPEC conventional oil is 2.3 mb/d lower than in the Reference Case, while non-conventional supply is down by almost another 1 mb/d.

This scenario also has important implications for investment activity in OPEC Member Countries. Indeed, history has shown clearly the dilemma of having to make investment decisions in a climate of demand pessimism and low oil prices. Oil market developments over the period 1985–1999 are particularly instructive. The combination of large amounts of spare capacity, low oil prices, and falling demand reduced both the incentive and, to a large extent, the ability to invest in additional capacity.[19] Indeed, unique to OPEC is the problem of security of demand, and the threat that

Figure 4.3
Change in non-OPEC supply: Protracted Recession scenario compared to Reference Case



large investments will be made in capacity that is not needed. The Protracted Recession scenario also contains this mix of low oil prices, demand uncertainty, and significant intial levels of spare capacity, as a result of a tide of investments that had been undertaken in the face of high oil prices.

This scenario's implications for oil supply and demand and the amount of oil that OPEC would be expected to supply are presented in Table 4.2. Since the non-OPEC supply response to the low oil price is negative, and since the low price provides some measure of demand support, OPEC crude supply is actually expected to rise after 2009, reaching 2008 volumes by 2012.

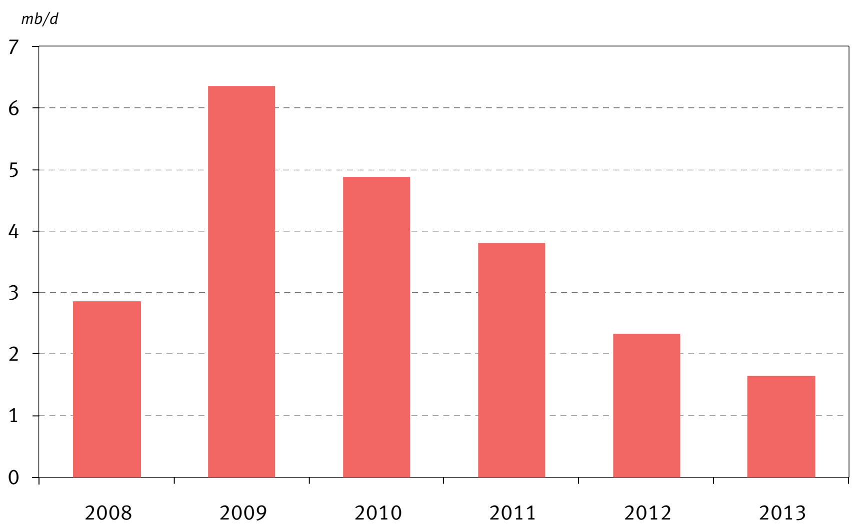
Table 4.2
Supply and demand in the Protracted Recession scenario *mb/d*

	2009	2010	2011	2012	2013
World demand	**83.9**	**83.8**	**84.3**	**85.1**	**85.4**
Non-OPEC supply	**50.2**	**49.9**	**49.5**	**49.0**	**48.3**
of which: non-conventional	3.1	3.2	3.3	3.4	3.5
OPEC crude	**28.0**	**29.1**	**29.8**	**30.9**	**31.5**

In the scenario, OPEC is assumed to respond to the increased need for its oil as non-OPEC supply is reduced because of the low oil price, while investment in upstream capacities is primarily focused upon compensating for natural declines, which is still a considerable amount. For the years 2009–2011, this is sufficient to maintain spare capacity at levels above those seen in 2008.

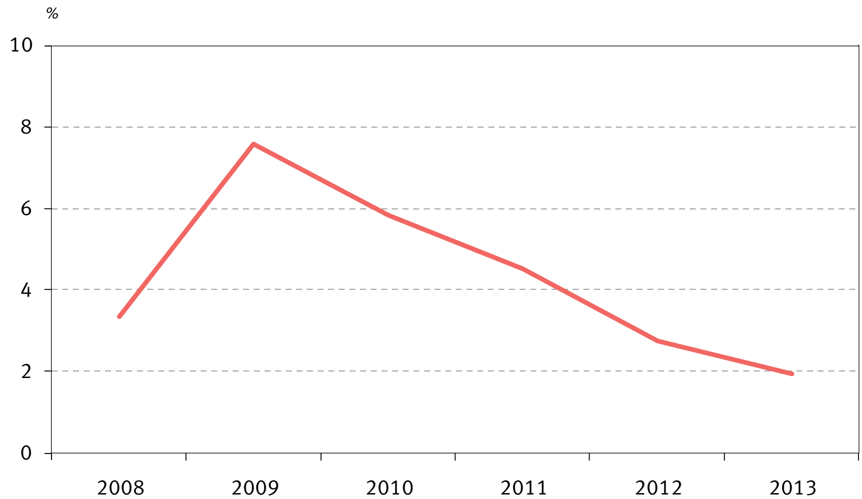
Nevertheless, if non-OPEC supply continues to be affected through a lack of investment, and remembering that the average time for an upstream project to move from the planning phase to being on-stream is around 4–7 years, then spare capacity in OPEC Member Countries could dwindle further after 2011. This suggests that spare capacity could be reduced to less than 3 mb/d by 2012, and below 2 mb/d by 2013 (Figure 4.4). This implies that OPEC spare capacity will have fallen to below 5% of world demand by 2011 (Figure 4.5), or expressed differently, OPEC upstream capacity utilization rates will have risen to over 90% by 2012.

Figure 4.4
OPEC spare capacity in the Protracted Recession scenario



Should this tightness occur, prices must react. The lack of capacity that emerges is a result of the low prices that are assumed over the medium-term. Prices would rise as capacity shortages increasingly characterize markets. The period of low prices in 1998/1999 was an important driver for the capacity shortages that presaged the 2004–2008 price rise. In the Protracted Recession scenario, history, to an extent, repeats itself, as low prices sow the seeds of unstable markets and price spikes.

Figure 4.5
OPEC spare capacity as a percentage of world oil demand in the Protracted Recession scenario



This medium-term scenario demonstrates the inherent cyclical nature of oil markets if unsustainably low prices prevail for long periods of time. There are both take-aways and questions stemming from this scenario:

– Prices that are too low are not sustainable and are likely to lead to price volatility;

– The global financial crisis and corresponding credit crunch could have dramatic implications for the supply side;

– Faced with a protracted economic downturn that points to a sustained contraction in the amount of OPEC crude oil required, capacity expansion plans may need to be constantly revised in order to avoid large amounts of unneeded capital expenditure and unused capacity;

– Concern over security of demand is compounded by the context of the ongoing recession;

– Impacts of a low price upon non-OPEC supply are genuinely unknown – they may be weaker, but they may be even stronger than portrayed in the scenario;

– Much of the reaction to low prices depends on costs and the way that fiscal policies evolve;

– Investment decisions are subject to long-lead times, so the ability to react to evolving capacity utilization is limited, at least in the short-term; and

– The question of who should absorb the demand losses points at the benefit of cooperation among producers in managing the downward business cycle and thus dampening its cyclical tendencies.

Chapter 5

Industry challenges: a raft of uncertainties

It is evident from the Reference Case and the Protracted Recession scenario previously explored that the overarching challenge facing the energy industry in general, and OPEC in particular, stems from the large uncertainties about the future demand levels for energy and oil. Moreover, with the current dismal economic climate adding extra layers of uncertainty, there is an increasing likelihood for game-changing discontinuities that may lead to a diversity of responses from government policymakers, industry leaders, investors, financiers, as well as consumers. And from the perspective of OPEC Member Countries, the uncertainties have an additional knock-on impact as they provide an unclear picture about the amount of investment required.

However, it should not be forgotten that there are various other underlying issues, some of which are further explored in this Chapter, such as the role of financial markets in relation to the price of oil; inflated upstream costs; the future availability of skilled human resources; the environmental conundrum; the development, deployment and transfer of technology; and, more broadly, the issue of sustainable development and its corollary, fighting energy poverty.

Lower and *higher growth* scenarios

The uncertainties that lie ahead, and the corresponding difficulties associated with making appropriate and timely investment decisions, make it important to explore alternative paths of oil supply and demand to those depicted in the Reference Case. With this in mind, lower growth and higher growth scenarios have been developed, with the following assumptions:

– In the *lower growth* scenario, the downside demand risks that have been identified over the medium-term from the threat of a protracted recession are now coupled with a strong policy drive, over-and-above Reference Case assumptions, to further increase oil use efficiency in the longer term. Moreover, the stimulus packages being implemented to address the global recession are assumed in the *lower growth* scenario to have longer term constraining effects upon economic growth potential. This is partly due to the low pace at which the current monetary accommodation is withdrawn, as well as much lower productivity gains and the absence of a strong economic engine. Furthermore, there is a real threat to losing the benefits of trade liberalization if protectionism becomes an established feature of the future world economy. There is also the additional issue of the threat of insolvency in some countries.

– In a *higher growth* scenario, the possibility of a swifter recovery from the global recession than assumed in the Reference Case is considered, combined with a more positive outlook for longer term growth prospects.

The *lower growth* scenario reflects the downside risks to demand that are more substantial than upside potential. Specifically, efficiencies for all types of vehicle advance at faster rates than in the Reference Case. Additionally, in this scenario, the world economy is assumed to expand initially at the rates assumed for the Protracted Recession scenario, and then in the longer term at annual rates that are 0.5% lower than the Reference Case.

Table 5.1 summarizes the results for the *lower growth* scenario. Already by 2015, global oil demand is more than 4 mb/d lower than in the Reference Case, and by 2030 it is almost 13 mb/d lower, reaching just under 93 mb/d. Average demand increases from 2015–2030 are reduced to 0.5 mb/d p.a. Slightly lower oil prices than in the Reference Case are also assumed to emerge, leading to lower non-OPEC supply. However, the main impact is upon the amount of crude oil that would need to be supplied by OPEC. The level is now more than 5 mb/d below the Reference Case by 2020, and almost 11 mb/d lower by 2030 (Table 5.2). This means that the amount of crude oil that would be required from OPEC would stay approximately constant, at close to 30 mb/d. This is assuming that most of the loss in demand is absorbed by lower OPEC supply. Higher OPEC levels would, of course, be consistent with this scenario if lower prices are assumed.

Table 5.1
Oil demand in the *lower growth* scenario *mb/d*

	2015	2020	2025	2030
OECD	43.2	41.5	39.6	37.8
DCs	37.6	41.8	45.5	49.4
Transition economies	5.2	5.3	5.4	5.4
World	**85.9**	**88.5**	**90.5**	**92.7**
Difference from Reference Case				
OECD	–2.3	–3.5	–4.6	–5.6
DCs	–1.7	–3.0	–4.7	–6.7
Transition economies	–0.2	–0.4	–0.5	–0.7
World	**–4.3**	**–6.9**	**–9.9**	**–12.9**

Table 5.2
OPEC crude and non-OPEC oil supply in the *lower growth* scenario *mb/d*

	2015	2020	2025	2030
Non-OPEC	51.7	52.9	53.7	54.4
OPEC crude	28.7	29.2	29.8	30.6
Difference from Reference Case				
Non-OPEC	−0.7	−1.4	−1.8	−1.9
OPEC crude	−3.3	−5.1	−7.7	−10.5

In the *higher growth* scenario, economic growth is assumed to be 0.5% higher than the Reference Case. This is also assumed to be accompanied by slightly higher oil prices than the Reference Case.

In this scenario, world oil demand is almost 2 mb/d higher by 2015 than in the Reference Case, and 8 mb/d higher by 2030 (Table 5.3). The higher prices would provide support for additional non-OPEC conventional and non-conventional oil supply, although the overall impact is not large, with output around 1 mb/d higher by 2015 compared to the Reference Case and 1.9 mb/d by 2030 (Table 5.4). As a result, the amount of OPEC crude oil required by 2015 is about 1 mb/d higher than in the Reference Case, and by 2030 the figure is 7 mb/d.

Table 5.3
Oil demand in the *higher growth* scenario *mb/d*

	2015	2020	2025	2030
OECD	46.4	46.7	46.9	46.8
DCs	40.1	46.5	53.2	60.6
Transition economies	5.5	5.8	6.1	6.5
World	**92.1**	**99.1**	**106.3**	**113.9**
Difference from Reference Case				
OECD	1.0	1.8	2.6	3.4
DCs	0.8	1.8	3.0	4.5
Transition economies	0.1	0.2	0.3	0.4
World	**1.9**	**3.7**	**5.9**	**8.3**

Table 5.4
OPEC crude and non-OPEC oil supply in the *higher growth* scenario *mb/d*

	2015	2020	2025	2030
Non-OPEC	53.4	56.1	57.5	58.1
OPEC crude	33.1	36.6	41.7	48.1
Difference from Reference Case				
Non-OPEC	1.0	1.8	2.0	1.9
OPEC crude	1.2	2.3	4.3	7.0

The uncertainty surrounding world oil demand in these two scenarios is consequently substantial. It could be between 89–99 mb/d by 2020, and 93–114 mb/d by 2030 (Figure 5.1). By 2020, the amount of crude oil needed from OPEC is as low as 29 mb/d, or as high as over 36 mb/d, a gap of more than 7 mb/d. And by 2030, the OPEC crude requirement could be as low as 31 mb/d, or as high as 48 mb/d (Figure 5.2).

These scenarios imply significant uncertainty for investment needs in OPEC Member Countries. In the *lower growth* scenario, investment would only be necessary to compensate for production declines in existing facilities, while the *higher growth* scenario requires additional net capacity over the projection period.

In estimating the investment requirements, adjustments are made to the decline rates and unit costs according to each scenario. For the *higher growth* scenario, a larger percentage of new capacities in smaller fields, which are generally more complex, are assumed to gradually appear, resulting in a slight increase in average decline rates over the longer term. In the *lower growth* scenario, the share of maintaining current capacity is greater, implying lower average unit costs per b/d of capacity.

Figure 5.3 shows the resulting wide range in OPEC upstream investment requirements. By 2020, the difference between the *higher growth* and *lower growth* scenarios reaches $250 billion in real terms. Even to 2013, the medium-term period described in Chapter 1, which represents a timeframe over which investments are effectively locked in, requirements could be as low as $70 billion or as high as $170 billion, a $100 billion uncertainty range.

The aftermath of the global financial crisis

The *high growth* and *low growth* scenarios demonstrate the large level of uncertainty over the needs for OPEC future upstream capacity, both in terms of volume and investment.

Figure 5.1
World oil demand in the three scenarios

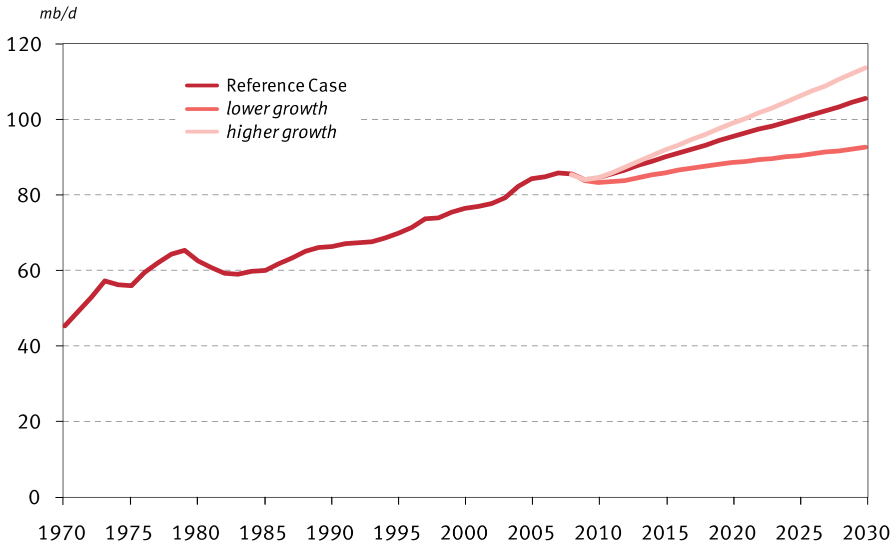


Figure 5.2
OPEC crude oil supply in the three scenarios

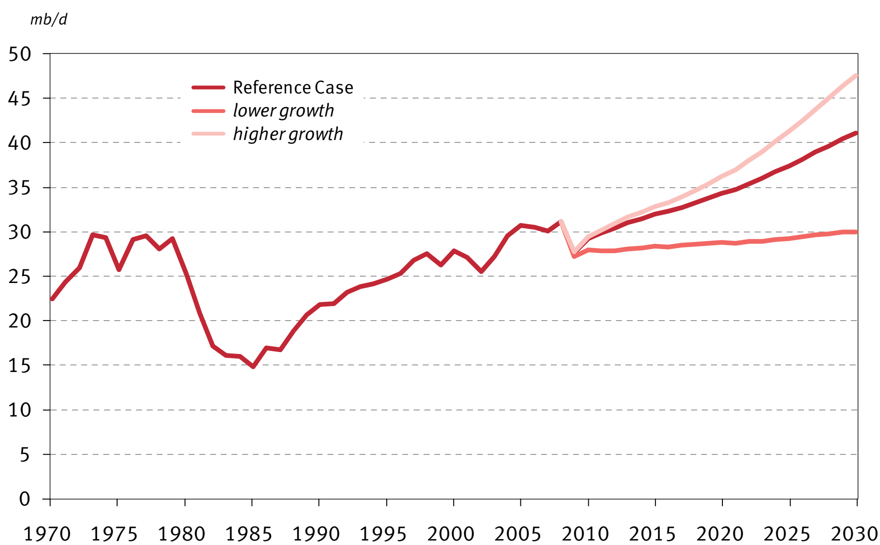
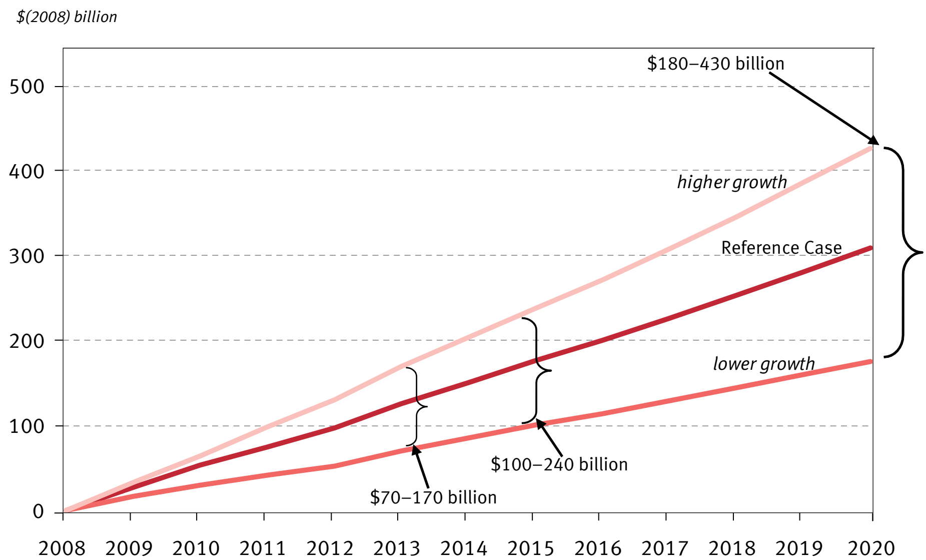


Figure 5.3
Cumulative OPEC investment requirements: how much is needed?



The skew towards downside risks, especially for volume needs, stems from policies that are inherently geared towards demand reduction, while uncertainties relating to future economic growth have been dealt with in the scenarios symmetrically. However, there has been a dramatic change in the economic landscape over the past year as the global financial crisis has taken hold. It is evident that for many individuals, businesses and governments, this is the current overriding concern. And for the oil market, there are ever more worries about the impact the crisis may have on the short- medium- and long-term outlooks. The security of demand issue has been illustrated in Chapter 4 by the significant recession-driven demand destruction. It should be recalled, for example, that while the WOO 2008 foresaw world demand of 92.3 mb/d in 2012, this WOO now expects it to reach just 86.7 mb/d, a major downward revision of 5.6 mb/d. For the year 2009 alone, expectations for global oil needs have fallen from an estimate in July 2008 of an increase over 2008 of close to 1 mb/d, to estimates by April 2009 of a fall of 1.4 mb/d.

The current environment clearly demonstrates the benefit of having counter-cyclical measures in place, in a timely manner, to address ad-hoc disturbances to markets and to mitigate pro-cyclical and volatility-enhancing features. Indeed, OPEC's decisions ensure a well-supplied and balanced physical market.

For example, OPEC's supply increase of close to 5 mb/d between 2002 and 2006 had a strong mitigating effect on pro-cyclical movements, when world demand sharply increased and non-OPEC supply declined, especially in the aftermath of Hurricanes Rita and Katrina. This was made possible thanks to OPEC's spare capacity, the only actor in the market to offer such an important instrument for the benefit of the world at large. Reciprocally, OPEC's recent 4.2 md/d cumulative supply adjustment has had a similar effect in the face of the current deep global economic crisis and the ensuing steep oil demand decline.

These types of counter-cyclical measures are now a well-recognized support to stability. And this is not only true for the oil market. The financial sector is also welcoming the use of counter-cyclical instruments. In fact, they are viewed as one of the key elements of the proposed financial reforms that are focused on making the banking system immune to excesses and over-leverage, and resilient in times of downturn.[20]

To better appreciate the issues at hand, and how it all links the short-, medium- and long-terms, it is important to look to the past. For example, thinking back to the 1990s, there were downturns in a number of OECD countries at the start of the period, and towards the end of the decade many sectors and economies were impacted by the fallout from the Asian financial crisis. It led to weak oil prices for much of the decade and an actual price collapse, with the OPEC Reference Basket falling to just over $11 in early 1999. It meant that the industry was deprived of the required amounts of capital and the demand to invest adequately for the future. In turn, the industry's crisis response, characterized by downsizing, mergers and acquisitions and deep cost cuttings, left it short of skilled labour and with an ageing workforce, as well as significantly reduced budgets for R&D into innovative technologies.

These developments have impacted the industry in the years since. Thus, it is important to learn lessons from the past in order to develop a sustainable energy future.

The economic stimulus packages put in place are another example of the need for counter-cyclical policy measures, and it is to be hoped that they will restore confidence and put the world economy back on track. They also demonstrate broad agreement on the need for sound regulation and integrity in financial markets. It means, looking at where the crisis originated, namely the banking sector, and taking the necessary measures to quickly restore confidence. Thereafter, the needed reforms must be put in place to make sure it never happens again. The focus should be on reining in financial speculation, everywhere, and in a coordinated manner.

But beyond the more immediate impacts that the global financial crisis will, and might have upon oil demand, and the corresponding challenge of adapting to revised investment requirements, there is also the potential for the emergence of longer term downside pressures. For example, a growing concern is that long-term economic growth potential might be adversely affected by the stimulus measures, for example, by raising inflation and interest rates if the monetary easing is not withdrawn in time. Moreover, future demand growth for businesses and individuals may be affected by structural changes to credit availability, stemming from capped leverage, larger reserves requirements, limited securitization and stricter ratings. It could also impact consumer choice. For example, it could give rise to substantially different levels and types of cars purchased. In addition, government involvement in key industries — for instance, the partial nationalization of the US car industry — could point to growing government control and an imposition of the 'car technology' of the future. All of this further emphasizes downside risks to demand.

The oil industry is also feeling the fallout of the crisis through impacts upon such areas as project funding and liquidity. Project deferrals and cancellations are already occurring, as noted in earlier Chapters. It remains to be seen how this will impact operations moving further forward in the medium- and long-term. It is likely that there will be differing impacts upon NOCs compared to IOCs, as well as between small and large companies, given the differences in project financing. However, these adverse impacts are observed for all energy sectors, not just oil.

Financial markets and oil prices

Oil price volatility in the recent past has been extreme. The OPEC Reference Basket Price rose to record levels in July 2008, reaching more than $140/b, although this was no indication of a shortage of oil. The market was well-supplied with crude and stock levels were high. Non-fundamental factors have clearly played a driving role in the extreme price volatility, characterized by the largest daily price movement in oil market history on 22 September 2008 – around $16/b.

The emergence of oil as a financial asset class led to increased activity by non-commercials, with enhanced liquidity and volatility. In many respects, the paper oil market witnessed a transformation into an investment market, with prices exhibiting the characteristics of financial assets, rather than simply reflecting oil market fundamentals. As part of the EU-OPEC Dialogue, a joint study on the impacts of financial markets on oil prices and volatility has recently been undertaken.

The dramatic fall that has taken place since the crisis took hold globally is now seriously threatening the long-term oil market stability. Oil prices need to be at a level that is supportive to the industry's expansion. It is essential they do not threaten the very sustainability of planned industry-wide investments. It should be remembered that here has been much recent talk of project cutbacks, delays and cancellations. And this is not just an oil industry issue. It impacts all forms of energy. It is essential to find and sustain a stable and realistic price. We need only recall the past, to see how low oil prices can damage the industry's future. Yet speculative behaviour is now contributing to distort price signals towards the downside.

Recent developments clearly point to the need for improving the functioning of futures and OTC markets, by *inter alia*, upgrading the availability of, and access to information on paper oil market participants and transactions, better monitoring, imposing a cap on speculative activity, and strengthening regulations to close various loop-holes. International cooperation is also critical in this regard.

Upstream costs

For the past few years, the oil industry has found itself in a period when costs have been significantly inflated, in part as a result of the low oil price environment ten years or so ago, which led to the implementation of downscaling and cost-reduction strategies, in particular in the services sector. While costs have fallen a little from the peak of the third quarter of 2008, due in part to the onset of the global financial crisis, it is evident that the fall has been relatively small when compared to the oil price drop over the same time period (see Box 3.1).

To some extent this is natural, with costs following the trajectory of prices nine-to-12 months later. However, in the second quarter of 2009 the prices of a number of commodities, such as cement and steel, appeared to return to an upward trend and it should also be noted that, despite the fact that the industry is witnessing a number of job losses, wages remain at similar levels to past years.

In addition, there are costs differences between specific industry sectors. For example, despite some significant capacity building, costs in offshore and deep offshore remain stubbornly high as shortages in the availability of rigs and other infrastructure continues to bite. On the other hand, onshore costs have fallen. In some instances, it is also evident that some project developers now have a 'wait and see' approach to costs, by putting on hold projects to see if costs fall further.

It all leads to the much debated industry question: is this cost behaviour structural or cyclical? It is not an easy question to answer, but whatever viewpoint is put forward it is clear that the cost issue remains a huge challenge facing the industry.

Human resources

Concerns over the availability of human resources to meet the industry's anticipated future growth remains a major challenge, despite the fact that in the current global economic downturn there is now observably more talk about industry job losses. However, it should be stressed that the past has shown the industry that it is critical to maintain and advance the adequacy of the industry's skills base, even during an economic downturn. The world economy will return to growth, which points to increasing energy demand, and with energy being the 'backbone' of the global economy it is essential that the necessary human resources are available.

Today, this is extremely important as the industry faces far more competition for talent from the expanding service and knowledge economies, and there is a significant percentage of the current workforce expected to retire in the next ten years.

There is a need to advance the numbers of students taking energy-related courses, and to make sure these are open to all students from across the globe. They will be the ones that drive the industry in the decades ahead. And in turn, it will be important to continually broaden the ways and means of training and keeping the talented people the industry takes on.

While many examples can be cited to demonstrate the efforts being undertaken by some NOCs, including those of all OPEC's Member Countries, IOCs and service companies, both individually and collectively, to provide higher education and training to thousands, clearly more work needs to be done globally to help make the industry more attractive to employees, as well as to future graduates, including easing university enrolment across national boarders. To this end, further coordinated efforts should be undertaken by the various players, including IOCs, NOCs, service companies, governments, regulators and academia. The work of the International Energy Forum Secretariat (IEFS) in this area, for example, holding a Symposium on human resources in April 2009 in Qatar is clearly welcome.

Technology and the environment

Advancements in technology have helped expand production, improved recovery rates and at the same time facilitated a continuing increase in the estimates of global URR. The barriers are all the time being pushed back. In fact, USGS estimates of URR have practically doubled since the early 1980s and continue to rise.

There is no doubt that technology will remain pivotal to the industry's future. Thus, it is essential that the evolution of technology continues, so that the industry can carry on developing, producing, transporting, refining and delivering oil to end-users in an ever more efficient, timely, sustainable and economic manner. There are a wide variety of new and existing technologies with the potential for enormous gains in efficiency and output, in areas such as advanced drilling and completion, hydrocarbons in ultra deep reservoirs, new GTLs technologies and new frontier exploration.

Nonetheless, challenges remain and this is particularly evident when looking at some of the ways that upstream activity can have impacts upon the environment. This is particularly relevant when looking at the developments of non-conventional crude. For example, Canadian oil sands projects now not only have to confront the challenge of their relatively high production costs, they also have to face up to the necessity of reducing their overall emission levels, as well as considering the impacts on water resources. And looking at both the medium- and long-terms, how this plays out will have a significant impact on the levels of non-OPEC supply, as the Canadian oil sands, alongside Russian developments, are expected to be major factors in non-OPEC supply growth.

It is important to recognize, however, that the oil industry has a good track record in reducing its environmental and emissions footprints. And with the world expected to rely essentially on fossil fuels for many decades to come, it is essential to ensure that the early development and deployment of cleaner fossil-fuels technologies continues, and at a swifter pace. This is true for both local and global environmental protection. The need to adapt to a carbon-constrained environment will make the use of these cleaner technologies all the more pressing. Of particular note is CCS, a proven technology that can be cost effective, and one that has a high mitigation potential. The IPCC Special Report on CCS states that by 2100, the technology could contribute the equivalent of 15–55% of the CO_2 mitigation effort needed to stabilize concentrations.

To date, there are a handful of industrial-scale CCS demonstration projects underway, one being located in an OPEC Member Country, Algeria. OPEC has also held a number of joint roundtables with the EU on the CCS issue. Nevertheless, developed countries, having the financial and technological capabilities, and bearing the historical responsibility, should take the lead in moving CCS towards full-scale deployment.

Sustainable development objectives

It is important to remember that poverty eradication is the very first UN Millennium Goal. And a major part, as well as a catalyst in helping alleviate poverty, is making sure that every person has access to modern energy services. With more than two billion people in developing countries not having access to these services, the need is extremely acute.

This energy divide entrenches poverty by limiting access to healthier livelihoods, education, economic opportunity, and information, and given that many billions still rely on traditional biomass, it can also erode environmental sustainability at the local, national, and global levels. Thus, it is critical that the world community makes sure access to reliable, affordable, economically viable, socially acceptable and environmentally sound energy services is available to all. This will not only enhance their living standards, but also help them adapt better to the impacts of climate change. It needs to be remembered that it will often be those who have the least resources to combat climate change, who will be most impacted.

The Riyadh Declaration from the Third Summit of Heads of State and Government of OPEC Member Countries in November 2007, stated that Member Countries, "while joining the international community in the efforts to achieve the Millennium Development Goals, take the interests of fellow developing countries into full account in our petroleum production and investment decisions, as well as our development assistance programmes and initiatives."

In fact, OPEC Member Countries have a sound record of actions aimed at supporting social and economic development in many countries around the globe. This includes through the establishment of their own aid institutions, as well as many effective bilateral and multilateral aid agencies. Among these is the OPEC Fund for International Development (OFID), set up in 1976 to "reinforce financial cooperation between OPEC Member Countries and other developing countries and promote South-South solidarity." The least-developed countries are accorded the highest priority and have consequently attracted much of OFID's resources. By the end of May 2009, the level of cumulative development investment extended by OFID alone stood at over $10.5 billion.

Cooperation and dialogue

Another outcome of the Third OPEC Summit was the call to "strengthen and broaden the dialogue between energy producers and consumers through the International Energy Forum and other international and regional fora, for the benefit of all."

Given the anticipated future growth of investment requirements in all segments of the oil industry, cooperation among national, international and service companies should be enhanced, taking into account the diverse national circumstances and priorities, the permanent sovereignty of nations over their natural resources, the interests of host countries and the objective of investors for a fair return on their capital.

This cooperation should encompass the important area of anticipating and encouraging the development, deployment and transfer of more advanced upstream and downstream technologies, to explore more successfully for oil, to enhance oil recovery, to reduce costs, and to further reduce the local and global environmental footprint of oil production and consumption. It should contribute to achieving unhindered access to, and a better transfer of, technology.

Section Two

Oil downstream outlook to 2030

Chapter 6

Distillation capacity requirements

Developments in oil markets and prices over the last few years have had a dramatic impact on the downstream sector and in particular refining. After a long period of capacity adjustment that led to moderately rising utilization rates, a demand jump in 2004 ushered in an era of refining tightness and record high margins. Partly underpinned by rising oil prices, as well the massive financial investment inflows into crude and product futures and OTC markets, this situation continued unabated until mid-2008. Since then, however, refiners have faced a reversal of fortunes and with it some major challenges. Refining margins have collapsed, with naphtha, and at times gasoline, selling at spot prices below those for crude oil. The fundamental change that has led to this situation is the drop in global oil demand as a result of the massive global financial crisis and the ensuing deep economic contraction.

Although conditions for the downstream industry have changed dramatically, it is evident that the core issues and questions facing the industry remain the same as in last year's WOO, albeit with differing consequences. Over both the medium- and long-term, a central question is how will refining cope with a heavily reduced oil demand base acting in conjunction with other developments, such as the shift in the crude and product slates and the rising share of non-crude supply. And this leads to a follow-up question: will the recent reversal in margins be sustained, or will it change, and by how much? There are a number of factors that feed into this, including: projects; non-crude supply levels that essentially bypass refineries; crude quality; and demand recovery, growth and mix.

Rising oil prices from 2003–2008, alongside refining tightness and high margins, brought forward an increasing number of projects. As of early 2007, there were some 14 mb/d of refinery projects at various stages, from announcement to construction. By early 2008, the level had grown to over 20 mb/d. And by the first quarter of 2009, some 35 mb/d of projects could be identified, essentially all with start-up dates in the period to 2015. However, with oil demand in the Reference Case projected to rise by only 4.6 mb/d from 2008–2015, and 10 mb/d by 2020, with non-crudes supply also rising sharply, it is clear that many of these projects are not needed. There is a realization that constructing even a significant portion of them would lead to a sustained refining surplus. Following the recent period of refining tightness, it is becoming increasingly likely that a repetition will be seen of the refining industry's historical tendency to be cyclical.

There are a number of core factors acting to delay, postpone or even cancel projects (see Box 6.1). Firstly, the current financial crisis is causing difficulties in funding both debt arrangements and equity requirements. Secondly, refinery construction costs have increased by around 75% since 2000. This in itself has put many projects on hold. It should also be noted that recent cost reductions have also led to project reassessments, often with requests for revised bids and attendant delays. For instance, a series of major Middle East projects falls into this category. The third issue is the post-crisis prospect of sharply lower global oil demand than previously thought. It is therefore essential to seek a realistic assessment of how many refinery projects are likely to go ahead, and by when.

A further important parameter for refining is non-crude supply. Driven by policy measures and increasing natural gas production over the medium- to long-term, as already highlighted in Section One, this is projected to rise at a faster rate than oil demand, thus reducing the required crude oil volume. The effect of this shift is already visible in the US where additional supplies of ethanol are impacting refinery economics.

It is also important to examine how the make-up of the crude supply and the resulting quality of the global crude slate will impact refining requirements and economics over the medium- to long-term. In the past, an often quoted concern of refiners was that the crude slate was becoming heavier, thus adding to the difficulties in producing lighter products, especially middle distillates. However, a detailed analysis of the make up and quality of the future crude supply set out in Chapter 7 suggests that this paradigm needs to be altered as there are no signs the crude slate will become heavier. This is particularly true in the medium-term, where several developments and existing upstream projects suggest the opposite. Nonetheless, this may not necessarily mean the task of producing the required future product slate becomes uniformly easier due to an increasingly wider spread between the lighter and heavier ends of the future barrel driven by the increase in production of condensates, NGLs and synthetic crude. Chapters 7 and 10 assess how future crude quality will combine with other developments to influence refining capacity requirements, investments and margins.

Another major driver for future refining capacity is the level and quality of product demand. Of most consequence is the severe drop in oil demand from recent levels and the pace and extent to which demand will recover. Even more so than a year ago, the expectation now is that oil demand in industrialized regions will be flat to declining, with essentially all growth coming from developing regions, led by China and India. Geographically, the outlook is for marked differences between a predominantly low/no growth Atlantic basin and a growth-oriented Pacific basin. Developments in the US and Europe are especially contributing to sustaining the gasoline-diesel imbalance that has emerged over the last few years. Results in Chapters 7 and 10 quantify the effects of this imbalance between naphtha/gasoline and distillate, and the associated consequences for capacity requirements and margins. Chapter 10 further reviews the implications of these projections as it is believed that more than forecasting what will likely happen, they are signalling that further changes in product demand and/or refinery process technology will need to take place.

To assess the impact of the above factors on the downstream sector the WORLD[21] modelling system was employed. This is closely linked to OWEM, which is used in Section One. However, because of trade flows, the regional formation is based on geographic rather than institutional definitions. The 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

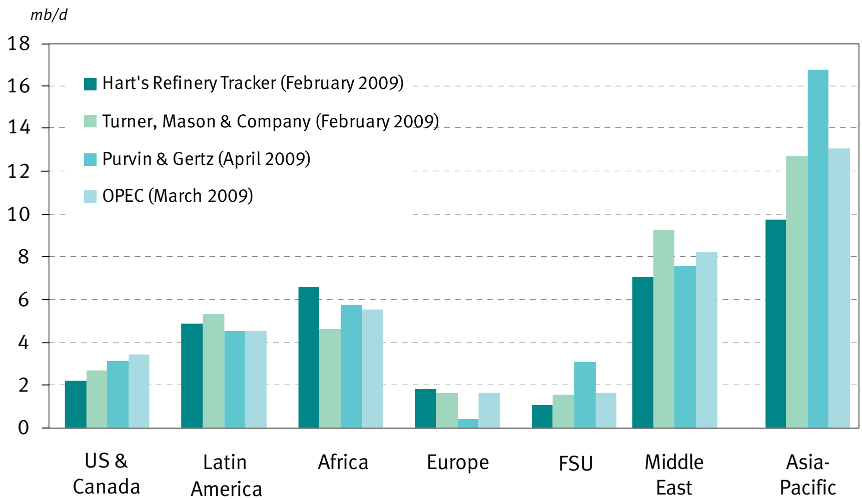
In past decades, the refining industry has recorded several cycles of excess and tight capacity. In the 1970s, the industry experienced periods of rapid expansion fuelled initially by rising demand and anticipated sustained growth. The 1980s was a period of industry consolidation, with falling demand in the first half of the period leading to a series of refinery closures. Over the decade, this meant that global refining capacity declined from more than 82 mb/d to 73 mb/d.

In the 1990s, oil demand continued to grow, initially absorbing the available refining capacity and improving utilization rates. And in the second half of the decade, the industry responded to the upward demand trend with another wave of capacity additions that again created a surplus at the start of the current decade.

However, the industry's response post-2000 lagged behind the emerging demand structure changes, notably a shift from fuel oil to light products, in particular middle distillates, especially diesel fuel. The lack of investments at the beginning of this decade resulted in a capacity deficit, especially in respect to upgrading processes. This became more apparent after a surge in the consumption of refined products in 2004 and 2005. This sudden demand increase for light products and middle distillates, combined with stricter product specifications in developed countries, created a much tighter refining sector situation and led to increased margins and profitability.

As a result, the refining industry experienced a so-called 'golden period' between 2004 and 2008, which attracted many investors and led refiners to consider numerous options for further capacity expansion. It is a process that accelerated during 2008. In 2007, the list of announced projects totalled around 14 mb/d, but in 2008 this

Figure 6.1
Announced crude distillation capacity increases



increased to 22 mb/d. Today, several specialized institutions report (Figure 6.1) that there is potential for around 40 mb/d of additional crude distillation capacity if all announced projects are successfully implemented.

Many of these projects might be required in the future either because of expected demand increases or as replacements for older refineries. However, given the present economic downturn and the relatively weak demand prospects in the medium-term it is doubtful that a significant percentage of these projects will be implemented before 2015. With the oil demand contraction experienced in 2008 and expected for 2009, global demand by 2015 will be little more than 5 mb/d higher than in 2007 in the Reference Case, and even less under the Protracted Recession scenario. Set against this, there are currently some 4 mb/d of projects reported to be under construction and, as discussed in more detail later, even some of these have witnessed delays. In parallel, between 2009 and 2015, continued supply growth is projected for biofuels and other non-crude streams, which will reduce demand for the refinery processing of crude oil. These supply and demand developments will strongly limit the start-up of new projects, beyond those that are already under construction or in an advanced engineering stage.

Another reason supporting the careful evaluation of current projects is related to construction costs. In the period 2004–2008, the downstream industry experienced significant increases in construction costs. In the past years, the acute cost escalation has caused many refinery projects to be reassessed, with resulting delays and cancellations. However, it should be noted that by late 2008, the industry began to witness a gradual decline in construction costs. According to the IHS CERA[22] downstream construction cost index, costs started declining in the third quarter and accelerated in the last quarter of 2008, falling more than 5% from the highest level. Similarly, the Nelson-Farrar[23] index declined by 4.7% in the fourth quarter of 2008 compared to the previous quarter. Moreover, the industry expectation is that these costs will drop further. And with the prospect of costs continuing to drop in the near term, it has also served to influence refiners to delay projects.

In addition to the demand and cost issues, there are several other factors that weigh in favour of prudence when assessing what proportion of announced projects will be completed, and by when. In the US and Europe particularly, the situation for refiners is becoming more and more complicated and uncertain, particularly in light of the adopted mandates for biofuels supply, transport fleet efficiency/emissions and carbon regimes. There are also risks to the economics of new major projects in China and India, stemming from uncertainties regarding pricing policy for petroleum products and on tax-breaks for new investments. Pricing and taxation uncertainties are creating issues for projects in other countries as well.

Box 6.1
Sentiment for refining projects shifts

In response to falling demand and costs, many refiners have deferred or are considering deferring their investment plans due to demand uncertainties, in expectation of lower capital costs, and because of difficulties securing the required financing. This is especially true for a number of major new projects that have yet to move to the construction stage.

For example, some US projects already under construction are experiencing delays. This includes the Motiva expansion project of 325,000 b/d in Port Arthur, Texas, which has been delayed from 2010 to 2012. Marathon also announced it would delay the completion of its Detroit refinery expansion to mid-2012 in an effort to cut spending. The project had been scheduled for completion in 2010.

Other world regions are following the same trend. In the Middle East, plans for the single biggest global project, the 625,000 b/d Al-Zour refinery, have been deferred. Total's senior vice president of strategy and development, Jean-Jacques Mosconi, was even more specific in his comments on the joint Saudi Aramco/Total project for a new refinery in Jubail, Saudi Arabia, hinting that the joint venture will be delayed until it can be executed for under $10 billion. "We're strongly relying on a sharp drop of costs moving below $10 billion", he said to the 2009 European Fuels Conference,[24] suggesting that the aim was to bring costs down to the range of $8 billion. These developments will also impact other projects in the region such as the Saudi Aramco/ConocoPhillips Yanbu project in Saudi Arabia and new UAE refineries in Fujairah and Ruwais.

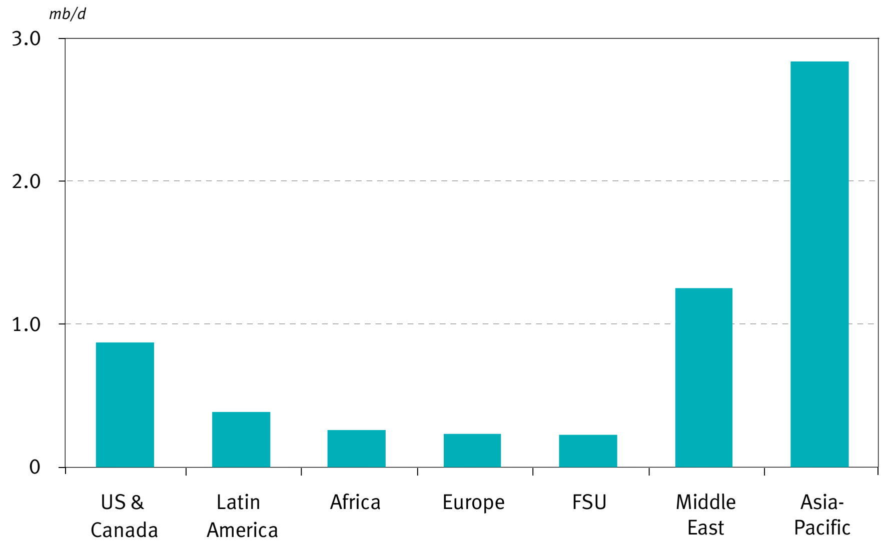
In India, grassroots refinery projects in Mangalore and Vadinar have been put on hold, together with other projects in the country. Elsewhere in the Asian region, the Balikpapan refinery project in Indonesia is also on hold, with developers saying there is the possibility of resuming plans once the market stabilizes.[25] In Turkey, various sources have reported delays in previously announced projects for new refineries in Ceyhan and Izmir. The same is true for the Petrobras-PDVSA joint project in Pernambuco, Brazil, the Qatar Petroleum project in La Skhira, Tunisia, and the new refinery project in Mellita, Libya.

Obviously, the above list is not exhaustive, nevertheless, it is long enough to demonstrate that a realistic assessment of announced projects is critical in evaluating the sector's outlook. This is particularly relevant for the medium-term perspective due to the long project implementation lead-times significantly restricting the manoeuvring room for refiners to respond and adjust to changing future market requirements.

The approach to assessing all announced projects remains unchanged from last year's WOO. All identified projects are allocated into one of four major categories according to the likelihood of their implementation within the period to 2015. The criteria centred on their current status, commitments undertaken by investors, as well as regional and domestic conditions supporting or discouraging their execution. Different rates of implementation and delay were associated with the top three categories, 'almost certain', 'probable' and 'possible'. The projects listed under the last category of 'unlikely/ speculative projects' were effectively excluded. This contained projects that were either competing for the same market or where a realistic assessment indicated that they would clearly not materialize before the target horizon of 2015. In order to reflect the increased likelihood for project delays, a set of factors for each category was used to arrive at a more realistic estimation of additional capacity projected for a particular year.

As a result of applying the above methodology to listed projects, it is estimated that around 6.1 mb/d of new crude distillation capacity will be added to the global refining system in the period to 2015 (Figure 6.2).

Figure 6.2
Distillation capacity additions from existing projects, 2009–2015



New capacity additions to 2015 are dominated by developments in Asia, mainly China and India, with almost 50% of additional capacity, or 2.8 mb/d, located in this region. Moreover, most of the Asian projects are already at an advanced construction stage, with some of them coming on-stream during 2009. This is the case for India's massive expansion of the Jamnagar facility, which now has an additional crude distillation capacity of 580,000 b/d. The actual construction of this refinery was finished at the end of 2008, but the initial testing period had to be interrupted due to technical difficulties. Testing then resumed at the beginning of 2009. Since the facility will only impact the market with additional throughputs in 2009, it was kept in the list of projects with a start-up this year. Other advanced projects in the region are the new refinery in Dung Quat, Vietnam, as well as two grassroots refineries in China, namely Huizhou, Guangdong and Quanzhou, Fujian.

The Middle East remains the second biggest contributor to future refining expansion in the medium-term, even after Kuwait's huge Al-Zour project was deferred. In fact, it should be noted that this development increases the chances for expanding Kuwait's existing Mina Abdullah refinery. The contribution from the Middle East is projected to be 1.3 mb/d of additional capacity from 2009–2015. This is expected to come mainly from grassroots projects in Saudi Arabia, such as those in Jubail and Yanbu, and possibly Jizan and Ras Tanura, although it is likely that not all of them will be before 2015. Some additions could also be expected in the UAE, Qatar, Iran and Iraq. Contrary to the Asian expansion that is primarily expected within the period 2009–2012, Middle East projects are predominantly scheduled for the latter part of the forecast period, from 2012–2015.

The third biggest contributor will be the US & Canada, dominated by developments in the US refining sector. Here, around 0.9 mb/d of new capacity is expected through the expansion of existing facilities, though some of these projects are already at the size of new world-scale refineries, such as the Motiva project in Port Arthur, Texas, and Marathon's expansion at its Garyville refinery in Louisiana. Moreover, many of the US projects are geared towards configuring refineries to receive an increasing amount of Canadian syncrude, thus switching from light crude feedstocks, toward heavier ones.

Despite the high number of announcements, there are not many projects in other regions that a have real chance of implementation before 2015. In total, all other regions will likely add around 1.1 mb/d of new distillation capacity. The biggest portion, 0.4 mb/d, will be realized in Latin America mainly through expansion projects in existing refineries in Minatitlan, Mexico; Barrancabermeja, Colombia; and Paulinia, Brazil. Several countries in the region, led by Venezuela, Brazil and Argentina, as well as some smaller Caribbean states, have plans for major grassroots refineries. However, it is not believed that these projects will be operational before 2015.

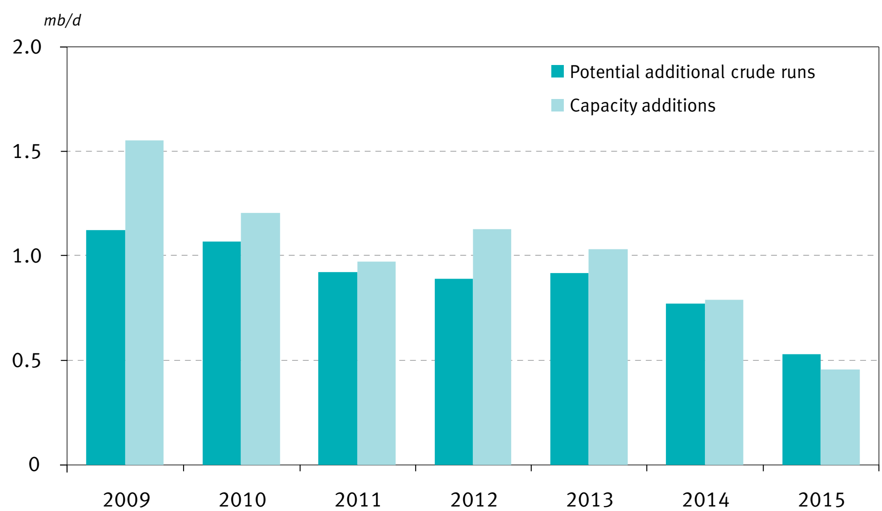
A similar situation is apparent in Africa, where there are more than 20 new refinery projects, but with the exception of the Lobito refinery in Angola, none of them are currently under construction. This is reflected in a projection that only 0.3 mb/d of distillation capacity will be added in this region.

The remaining two regions, Europe and the countries of the FSU, are each projected to expand their refining systems by 0.2 mb/d of distillation capacity. In Europe, this will be achieved by expansion projects in Spain and Greece, while increases in the FSU are scattered through several existing refineries in Russia and Belarus. However, many projects in these two regions are oriented towards adding conversion and hydro-treating capacity to match the rising demand for middle distillates, and to meet required quality specifications.

Besides the announced projects, refining capacity expansion is also being achieved through some minor projects within existing facilities. These are often during maintenance turnarounds, and are usually focused on small expansions in the crude distillation and major upgrading units. The extent of these additions typically varies significantly between regions. In a global context, it is generally believed that capacity creep — defined as expansions that are not visible in project lists — will add within the range of 0.2–0.5% to crude distillation capacity each year. Thus, the level to be allowed for creep depends, among other factors, on the comprehensiveness of the project list.

The WOO uses a very detailed list of projects, which covers a significant number of minor projects in the range of less than 5,000 b/d. Therefore, the outlook opted for additions resulting from capacity creep at the lower end of the range. Adding in the effect of capacity creep, crude distillation capacity should expand by 7.1 mb/d by 2015, from 2008 levels. Figure 6.3 presents the yearly increments of distillation capacity resulting from both existing projects and capacity creep. Furthermore, it also highlights the potential for additional crude runs, based on the annual capacity increases. This also takes into account average utilization rates, as well as the fact that year-on-year new capacity gradually becomes available. While the figures for capacity additions represent total increases at the end of the year, the potential for additional crude runs reflects the yearly average capacity contributing to the supply of refined products. For the entire period 2009–2015, the potential for additional crude runs could increase by 6.2 mb/d, considering average utilization rates for available capacity subject to any potential capacity closure.

Figure 6.3
Additional distillation capacity and crude runs from existing projects, including capacity creep



Admittedly, both distillation capacity additions and the resulting crude runs might seem to be relatively low, especially for the final two years of the forecast period. One could argue that for this latter part of the period there is still a sufficient time span to start and complete some additional projects, which at the moment are off the radar in the current climate. To what extent this happens will very much depend on future global economic developments and possible oil demand responses. However, this relatively slow capacity expansion growth could potentially sow the seeds for a resumption of tightness, if demand recovers faster than projected.

In particular, this argument is valid in respect to the expansion of secondary processes, mainly conversion and hydro-treating. The most recent refining tightness was related more to the lack of conversion processes to supply adequate light products and to a shortfall in desulphurization capacity to meet strict quality specifications in major consuming regions, than to distillation units. Therefore, it is equally important to also focus on these processes before any conclusion can be reached. Typically, additions to secondary refining processes materialize through smaller upgrading projects in existing facilities. These projects are less costly and have shorter lead times. Correspondingly, the implementation rates and delay factors used for the assessment of secondary processes are moderately higher then those for crude distillation units.

An analysis of existing projects indicates that relatively strong demand increases in the past few years, combined with high prices and healthy margins, have provided strong incentives for investments in secondary processes. Trends toward increasing the overall share of lighter products, especially diesel, have led to a higher proportion of conversion capacity additions compared to distillation units. Typically, this proportion is in the range of 40–50%, however, for projects coming on-stream in the next few years it will rise on average to around 80%. In respect to sulphur removal processes, tighter specifications on sulphur content in OECD countries and several major developing countries have forced an expansion of hydro-treating capacity. This momentum is still visible in the number of projects under construction for the period to 2012, so much so that the total capacity additions for hydro-treating will even exceed those for distillation units.

Table 6.1 provides an indicator of what could be expected in respect to secondary processes for the period to 2015. In assessing announced projects, it is estimated that a total of 5.1 mb/d of new conversion capacity could be constructed globally from 2009–2015. The majority of this capacity will come from hydro-cracking units (2.1 mb/d) followed by coking (1.9 mb/d) and FCC units (1.1 mb/d). Driven by increasing diesel demand, hydro-cracking units are to be expanded in almost all regions except for the Caspian region and some parts of Africa. More than 30% of the new coking units will be built in the US & Canada, followed by substantial

Table 6.1
Estimation of secondary process additions from existing projects *mb/d*

	By year		
	Conversion	Desulphurization	Octane units
2009	1.0	1.5	0.3
2010	0.6	1.0	0.3
2011	0.9	1.0	0.3
2012	1.0	1.1	0.4
2013	0.8	0.8	0.2
2014	0.5	0.7	0.2
2015	0.3	0.3	0.1
	By region		
	Conversion	Desulphurization	Octane units
US & Canada	1.1	0.8	0.3
Latin America	0.3	0.6	0.1
Africa	0.2	0.2	0.1
Europe	0.6	0.3	0.1
FSU	0.3	0.2	0.0
Middle East	0.8	1.6	0.5
Asia-Pacific	1.8	2.9	0.8
World	5.1	6.4	1.9

additions in India and China, with the rest coming mostly from Europe and the Middle East. FCC units are planned mainly for China, India and the Middle East, while there are only a few projects for the US & Canada and almost none for Europe and Africa.

From the perspective of desulphurization capacity, this will increase by 6.4 mb/d in the period to 2015, out of which more than 50%, or 3.5 mb/d, should be on-stream within the next three years. The Asia-Pacific leads the way at 2.9 mb/d, with the Middle East next with 1.6 mb/d of new capacity. This partly reflects the recent trends for cleaner products within these regions — predominantly based on Euro III/IV/V specifications — but also an effort by export oriented refineries to provide low or ultra-low sulphur products for customers in developed countries. Both the US & Canada and Latin America will add close to 1.4 mb/d of desulphurization units respectively. The remaining capacity additions are shared by Europe, with 0.3 mb/d, and Africa and the FSU, both with 0.2 mb/d. In North America and Europe, the additions relate mainly to the completion of modifications to comply with ultra-low sulphur gasoline and diesel standards, which will be in place fully by 2010/2011. However, additions in these two regions are limited as many refineries have already added and/or revamped capacity. Within Europe, the majority will be added in the southern and eastern parts of the continent, as the northern part is already complying with the new standards.

Octane unit additions comprise mainly catalytic reforming processes and these will account for 1.4 mb/d globally, out of 1.9 mb/d of total octane units. This capacity will be constructed primarily in regions where gasoline demand increases are expected, such as Asia-Pacific (0.5 mb/d), Middle East (0.4 mb/d), Latin America and Africa (0.1 mb/d each), as well as in the gasoline-dominated North American market (0.2 mb/d). In addition to reforming, isomerization (0.3 mb/d) and alkylation (0.2 mb/d) units are also planned. As these processes are mostly gasoline-related, the regional distribution of additions is similar to that for reforming process capacity.

A key question related to estimations for the expansion of the global refining system concerns the potential for the incremental output of specific refined products. Refiners have some flexibility in optimizing the final product slate, either through altering the feedstock composition and/or through adjusting process unit operating modes, but this flexibility is limited for any one unit and in any given refinery. Bearing this in mind,

Figure 6.4
Potential incremental product output from existing projects

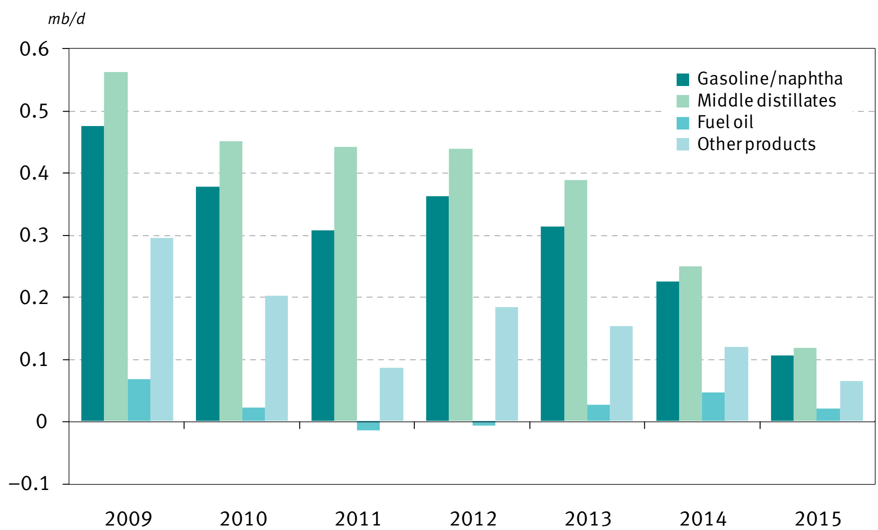


Figure 6.4 presents an estimation of the potential incremental output of refined products that result from existing projects grouped to major product categories.

The projected capacity expansion would allow for around 6.1 mb/d of additional products to be available by 2015, compared to 2008 levels. The bulk of the increase is for middle distillates (2.7 mb/d) and light products, naphtha and gasoline (2.2 mb/d). The capacity for fuel oil is set to remain approximately the same, with other products accounting for the remaining 1.1 mb/d.

A concern expressed in last year's WOO was the extent to which refiners could produce the necessary incremental product volumes to satisfy expanding demand, particularly for middle distillates. This year, however, with the present economic situation, falling oil demand, and weak, as well as uncertain prospects for the next few years, the question has flipped. It is now important to ask as to what extent the expansion of the refining system will put pressure on industry utilization rates and margins, and in turn, how this might adversely affect the economics of existing and newly constructed facilities. Will refineries survive or will some be forced to shutdown their operations? And what kind of implications could this have for the years thereafter, when demand growth resumes?

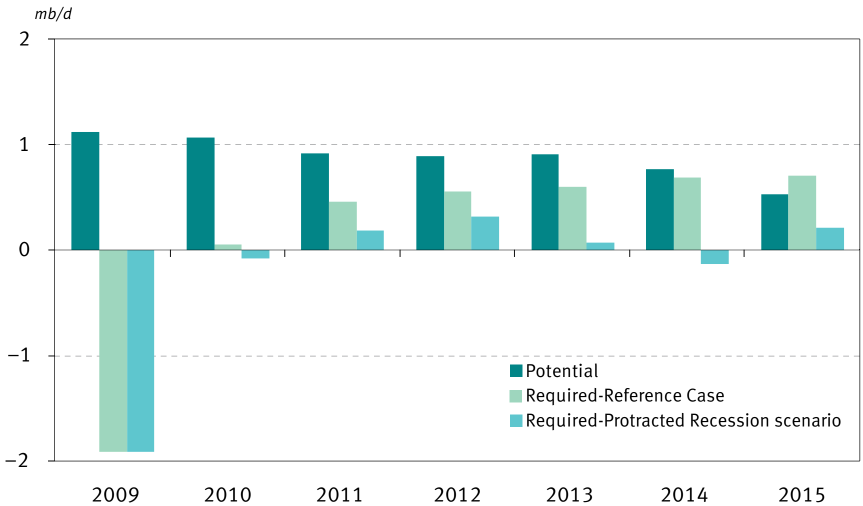
Medium-term outlook

In the preceding two outlooks, the listed refinery projects were compared with the incremental refinery throughput requirements based on demand growth. The projections from two years ago highlighted a clearly visible deficit in refinery capacity additions relative to needs. While those last year indicated that the deficit could be short-term, and possibly overcome as early as 2010 by a swing to surplus, based on new projects coming on-stream.

For this year's WOO, the exercise was repeated and updated. Part of the update comprises the rigorous review of refinery projects, as already described. The demand side update entails applying recent global oil demand projections, as well as looking at the impacts of non-crude supply, which reduces the barrels of additional refinery throughput needed per additional barrel of demand. In addition, the analysis takes into account the phasing of capacity additions and allows for typical capacity utilization rates to deliver the assessed effective potential for incremental crude runs, to arrive at an average additional capacity for each year.

Figures 6.5 and 6.6 show the results of this latest assessment. Figure 6.5 compares the required potential — based on expected distillation capacity additions available — with the required incremental refinery runs from 2009–2015 resulting from

Figure 6.5
Incremental global refinery crude runs, required and potential*



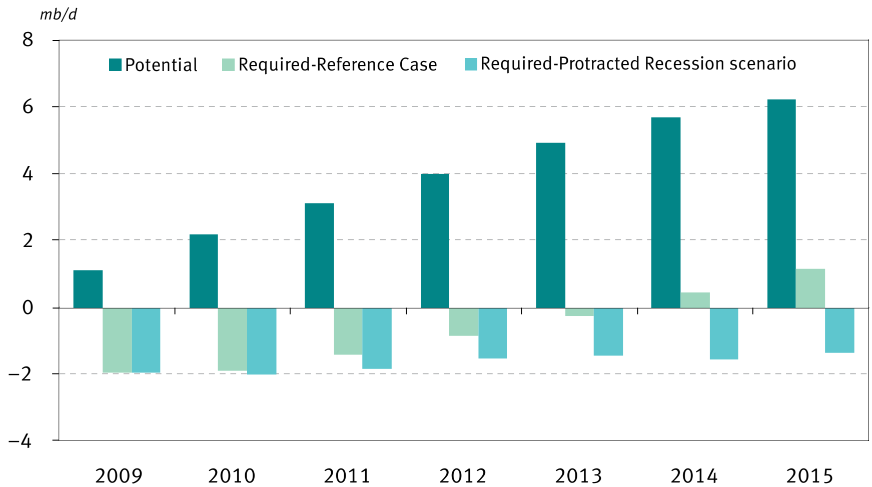
* *Potential: based on expected distillation capacity expansion.*
Required: based on projected demand increases.

the Reference Case and Protracted Recession scenario for demand projections. The impact of the current economic crisis is clearly evident already in the Reference Case comparison, with a reduction in required runs of 1.9 mb/d in 2009, compared to 2008. In 2010, there is almost no increase, and thereafter, there is a gradual recovery with annual increments in the range of 0.5–0.7 mb/d through to 2015. Set against this, the potential incremental refinery crude runs, based on assessed nameplate capacity additions, less a factor for expected maximum utilizations,[26] averages around 1 mb/d each year from 2009–2013.

Figure 6.6 illustrates the cumulative effect of the additions to potential crude runs against projected requirements for the Reference Case and the Protracted Recession scenario. In the Reference Case, the increment of 1.1 mb/d of capability versus the decline of 1.9 mb/d needed in 2009 creates a gap or surplus of 3 mb/d this year. The continuing increases in potential crude runs, as well as the slow return to positive required runs, result in this surplus widening to over 4 mb/d by 2010 and around 5 mb/d by 2012. It remains at this level until 2014, and only then starts to narrow.

The implication of these projections is for a sustained period of low refinery utilizations, and hence, poor economics and the increasing potential for refinery closures.

Figure 6.6
Additional cumulative refinery crude runs, required and potential*



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

To examine this more closely, a series of model cases was run as variants of the 2015 Reference Case. These reinforced the scale of the restructuring and consolidation potentially required in the refining sector.

In the first case, the closure of 5 mb/d of capacity across the US and Europe has a minimal impact on refinery margins since it primarily removed surplus capacity. In the second, shutting down a further 2 mb/d in the two regions, for a combined total of 7 mb/d, brings about noticeable improvements in margins and led to an 81.8% global average utilization rate. A third case, with 10 mb/d of capacity closures spread across the industrialized and, to a limited degree, developing regions, was needed to restore refinery margins to levels at least broadly similar to those obtained in last year's 2015 reference case. The 10 mb/d of closures restores global refinery utilization to 85.4% in 2015, slightly above the 84.4% reference case level from last year. Thus, this implies that closures in the order of 7–10 mb/d will be needed, predominantly in the US & Canada and Europe, to restore refining viability.

Whereas incremental surplus crude run capability peaks at around 5 mb/d in the Reference Case, in the Protracted Recession scenario it reaches 6 mb/d as early as 2013 and expands to well over 7 mb/d by 2014. In other words, required refinery crude runs in the Protracted Recession scenario do not return to 2008 levels until

2015, rather than by 2013/2014 in the Reference Case. In addition, the required incremental runs remain below those in the Reference Case through to 2015. In this scenario, the potential impact for the refining sector is even more severe than in the Reference Case. The refining capacity overhang that has rapidly developed, alongside current difficulties associated with project financing, will almost certainly act to deter projects. However, with some 30+ mb/d of projects listed, it should be pointed out that any capacity additions that go ahead will act to increase the global surplus. The implication is that all projects, both currently under way and planned, need to be subjected to rigorous scrutiny, with a reassessment of costs, markets and other factors such as recent policy initiatives announced by the US administration aiming at improving auto fuel economy standards.

While last year's WOO foresaw that "an easing in the refining sector could begin as early as 2009 and intensify through 2010–2013", the results of this year's outlook go far beyond the effects previously envisaged, mainly due to the deep recession and the inclusion of policies. The challenge of how to deal with this new paradigm for oil supply, demand and refining, are set to be with the industry for some time.

Long-term distillation capacity outlook

Capacity surplus that will likely be built in the medium-term, unless eliminated through refinery closures, will substantially impact long-term developments in the refining sector by depressing utilization rates, thus affecting economics, and limiting future capacity requirements. Moreover, further expansion of non-crude supplies combined with an expected demand shift from developed to developing countries will lead to some refining capacity 'relocation', primarily toward the Asia-Pacific where major demand increases are projected. These trends are clearly visible in the estimation of required distillation capacity additions to 2030.

Table 6.2 compares required distillation capacity additions and demand projections in the Reference Case for the period 2008–2030. Known projects in this table represent capacity additions from existing projects that are expected to be on-stream before 2015. New units correspond to the further additions — consisting of major new units and capacity expansion through de-bottlenecking — that are required to balance the global refining system. As mentioned earlier, by 2015, over and above the 6.1 mb/d of known projects that are projected to be on-stream, an additional 2.1 mb/d of new units is found to be required. These additional projects are needed in the Asia-Pacific, Latin America and the FSU. By 2020, the global refining system will require a further 3.6 mb/d of new capacity, with an extra 2.9 mb/d and 3.2 mb/d needed by 2025 and 2030 respectively.

Table 6.2
Global demand growth and refinery distillation capacity additions by period
Reference Case

mb/d

	Global demand growth	Distillation capacity additions			
		Known projects	New units	Total	Annualized
2008–2015	4.6	6.1	2.1	8.2	1.2
2015–2020	5.2	0.0	3.6	3.6	0.7
2020–2025	5.0	0.0	2.9	2.9	0.6
2025–2030	5.2	0.0	3.2	3.2	0.6
	Global demand growth	**Distillation capacity additions**			
		Known projects	**New units**	**Total**	**Annualized**
2008–2015	4.6	6.1	2.1	8.2	1.2
2008–2020	9.9	6.1	5.7	11.8	1.0
2008–2025	14.8	6.1	8.6	14.7	0.9
2008–2030	20.1	6.1	11.9	18.0	0.8

The table also highlights the annualized pace of total capacity additions needed from 2015–2030, which averages approximately 0.6–0.7 mb/d p.a. This compares to the 1.2 mb/d rate for 2008–2015, which is driven predominantly by projects under way. This figure is more reflective of recent history and contributes to the medium-term capacity surplus.

It is significant that, beyond the 8.2 mb/d of known projects and new units anticipated to be on-stream by 2015, the Reference Case shows that only an additional 3.6 mb/d of additions will be needed by 2020. This expands to 6.5 mb/d in 2025 and 9.8 mb/d in 2030. Thus, today's projects potentially represent a substantial proportion of the total additions needed over the next 10–15 years. Under the Protracted Recession scenario, requirements would be curtailed further, particularly in the period to 2020.

Table 6.3 presents the outlook in terms of refinery crude throughputs and utilizations. Lower future demand growth, as a consequence of the current economic crisis, acts to depress refinery crude throughputs over the short-, medium- and long-terms. In the Reference Case, global crude runs will not have recovered to 2007 levels until sometime around 2015. And even when they do, it is expected that they will continue to rise slowly so that by 2030 crude runs are only 9 mb/d, or less than 13%, above 2007 levels. On the basis that this Reference Case reflects the future, the refining

Table 6.3
Total distillation unit throughputs *mb/d*

	Global	US & Canada	Latin America	Africa	Europe	FSU	Middle East	Asia-Pacific
2007	72.2	17.0	6.6	2.6	13.7	6.0	5.4	21.0
2015	72.4	16.0	6.4	3.1	12.5	6.4	6.7	21.3
2020	74.9	15.3	6.7	3.4	12.1	6.7	7.3	23.4
2025	78.0	14.5	7.2	3.6	12.4	6.9	7.6	25.9
2030	81.2	14.6	7.2	4.0	12.5	6.9	8.0	28.1

industry cannot be called a significant growth industry and maintaining its viability will be a major challenge to all stakeholders.

The impacts are not, however, regionally uniform. As already identified in the last year's WOO, the US & Canada is projected to be most impacted, driven by a combination of an ethanol supply surge, flattening demand growth with a decline in gasoline, as well as the continuing effects of dieselization in Europe that generates low-cost gasoline for US export. Based on the outlook, not only do crude throughputs in the US & Canada never recover to 2007 levels, they also steadily decline throughout the period to 2030. In line with this, and with no refinery closures built into the model cases, refinery utilization rates remain well below their recent peaks of around 90%. It slides to the mid-70s percentage level in the medium-term and further to under 70% by 2030.

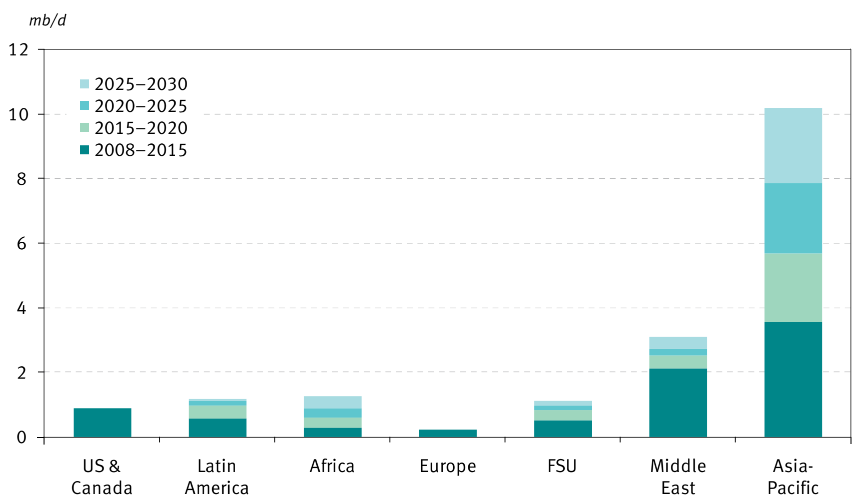
Europe is expected to follow a similar route to that of the US & Canada. Flat demand and the impact of additional biofuels supply in the range of 1 mb/d, means that no refinery capacity expansion beyond current projects is projected to be required in the period to 2030. Rather, as in the US & Canada, regional refinery throughputs are anticipated to drop relative to the recent highs of close to 15 mb/d, and remain at, or slightly above 12 mb/d to 2030. Utilization rates are projected to drop to a little above 70%, again signifying the potential for a very substantial capacity rationalization. Although not shown directly in the summary tables, flat to declining demand creates the same situation for the OECD Pacific region, with no new refinery capacity needed to 2030, and utilizations — barring closures — in the range of 70%.

Expectations for developing regions differ significantly from those described for major industrialized regions. This is especially valid for both the Asia-Pacific and the Middle East where projected demand increases will lead to an expanding refining sector to 2030 (Figure 6.7) and better utilization rates. Out of a global total of 18 mb/d of required distillation capacity expansion from 2008–2030, the Asia-Pacific region will see more than 10 mb/d and the Middle East more than 3 mb/d. Expansions in the Asia-Pacific are dominated by China with 5.4 mb/d, with the Rest of Asia region at 4.3 mb/d.

Nonetheless, an element of uncertainty exists in these projections. This relates to a number of policies adopted by major consuming and producing countries in these regions. For example, in respect to China, an assumption built into these projections is that the country will not match all its domestic demand growth via internal refinery expansion projects, and that — as a consequence — imports of refined products will remain significant. In 2020, net product imports to China are projected to be 2 mb/d, and in 2030 it is 2.5 mb/d. This compares to total Chinese oil demand of 16.1 mb/d by 2030. However, should China expand its domestic refineries and essentially fully meet domestic demand, then product imports to China will be replaced by crude imports. Given the potential for surplus capacity worldwide, including in Japan where refiners have been striking deals to deliver products into China, it is believed that a certain level of product imports is likely to continue. Similarly, some producing countries may opt for building export oriented refineries, thus shifting some of the required distillation capacity from one region to another.

In the FSU, capacity expansion is mainly restricted to domestic increases, with only limited options for product exports. Total capacity is projected to grow by

Figure 6.7
Crude distillation capacity additions in the Reference Case by period, 2008–2030



1.1 mb/d in the period 2008–2030. This is broadly in line with projections for demand changes, growing from 4.1 mb/d in 2008 to 5.1 mb/d in 2030. The moderate increase in product exports will be to Asian countries, which will allow for slightly higher utilization rates than those currently seen in the region. However, the FSU refining capacity growth may also be susceptible to, and constrained by, demand in Europe.

In Latin America and Africa, there is moderate demand growth projected to 2015, 0.6 mb/d and 0.7 mb/d respectively, and appreciable growth, 2 mb/d and 2.2 mb/d, in the full period from 2008–2030. Capacity additions and utilization rates in both these regions are expected to grow steadily. Within the forecast period, capacity additions are expected to be in the range of 1.2–1.3 mb/d in each region.

A similar situation applies to the Middle East, with medium-term demand growth to 2015 of 0.9 mb/d and long-term growth of 2.9 mb/d from 2008–2030. Crude throughputs are projected to expand from 5.6 mb/d in 2008 to 8 mb/d in 2030. The potential for expansion is driven in part by regional demand growth, but also by the possibilities to export increasing volumes of refined products – over 2.5 mb/d by 2030. Refined product exports are, however, projected to be exceeded in volume by NGLs and other streams.

Increasingly over time, it is the Asia-Pacific that dominates crude capacity and demand growth. In the Asia-Pacific, demand is expected to increase 3.5 mb/d by 2015 and 14.7 mb/d by 2030. China accounts for more than 60% of the increase to 2015 and 50% from 2008–2030. Demand in the Pacific Industrialized region, however, is projected to decline 0.4 mb/d by 2015 and 1 mb/d by 2030, when compared to 2008. Nevertheless, the Asia-Pacific as a whole accounts for a steadily rising proportion of total distillation capacity additions. It comprises 44% of additions for 2008–2015, which then rises to almost 75% in the period 2025–2030.

Chapter 7

Conversion and desulphurization capacity requirements

A significant fall in demand for cleaner products, with gasoline, petrochemical feedstocks, jet/kerosene and diesel fuels all witnessing declines, has led to the recent severe reductions in refinery distillation capacity requirements. Sufficient distillation capacity is a necessary pre-condition for the adequate functioning of the refining sector, but this capacity must also be supported by suitable conversion and product quality related units. The importance of these 'secondary' processes has grown as the trend toward lighter products and more stringent quality specifications has increased. This all begs the question: to what extent will the need for less crude distillation capacities translate into significantly reduced secondary processing requirements?

To provide an answer to this question, several factors have to be considered to make an adequate assessment of the appropriate level of secondary processes. This includes expected future demand volumes, the demand mix and quality specifications of refined products, and the quality of feedstock available to refiners. Projected demand levels and its structure have been discussed in Section One, and to complete the picture the expected major developments in respect to the quality of the global crude slate and current and future product quality specifications are presented in this Chapter.

Crude quality

In addition to the various streams constituting oil supply, the crude oil quality, typically measured in terms of API gravity and sulphur content, will play an ever more important role in determining future refining requirements. As the global product slate increasingly leans towards the need for lighter products, heavier crude oil will require increased conversion capacity to allow for the production of a higher percentage of light products. The upshot is the need for higher capital investment and greater operational costs. Moreover, heavier crude streams typically contain more sulphur which, in turn, will necessitate additions in intermediate processes, notably hydro-treating, hydrogen and sulphur recovery. Despite the fact that there are some exceptions to this general rule, for example, synthetic crudes and high TAN streams,[27] projections for quality characteristics in respect to API gravity and sulphur content comprise one important driver for future downstream investment requirements. Therefore, a detailed analysis has been undertaken to assess the likely crude quality trends, particularly taking into account recent changes and revised crude supply projections. All results presented in this Chapter include conventional crude oil, condensates and synthetic crudes.

Figures 7.1 and 7.2 present the results of the analysis when countries are clustered into non-OPEC and OPEC groups respectively. The average crude quality for total non-OPEC crude oil production is expected to improve, with the average API gravity projected to increase from 32.9° API in 2005 to around 33.5° API by 2030. The average sulphur content is expected to decline from 1.05% to 0.9%. For OPEC Member Countries, future trends are dominated by Middle East developments. The average crude quality will slightly improve in the period up to 2015 from 34.4° API in 2005 to 35.1° API, with the level of sulphur content also improving slightly. By 2030, the OPEC crude slate will be broadly at today's levels in respect to its quality, and possibly marginally higher in respect to sulphur content. All these major trends closely follow patterns presented a year ago, although at slightly modified levels. However, part of the overall shift in both non-OPEC and OPEC levels is also derived from the re-allocation of Indonesia from OPEC to the non-OPEC group.

At the global level, developments in OPEC and non-OPEC countries interplay to provide a relatively stable future crude slate (Figure 7.3). This is especially true in respect to the API gravity, which is projected to improve to 34.2° API by 2015,

Figure 7.1
Non-OPEC crude quality outlook

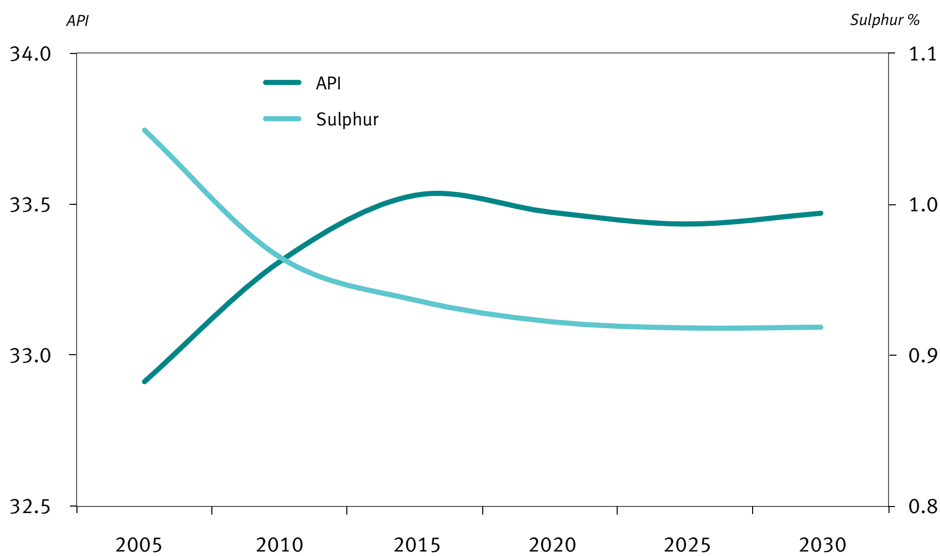


Figure 7.2
OPEC crude quality outlook

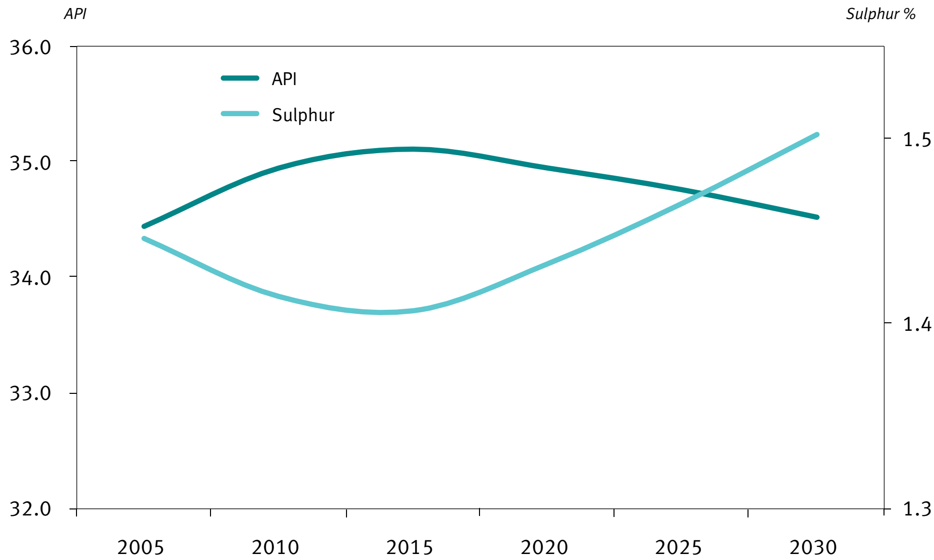
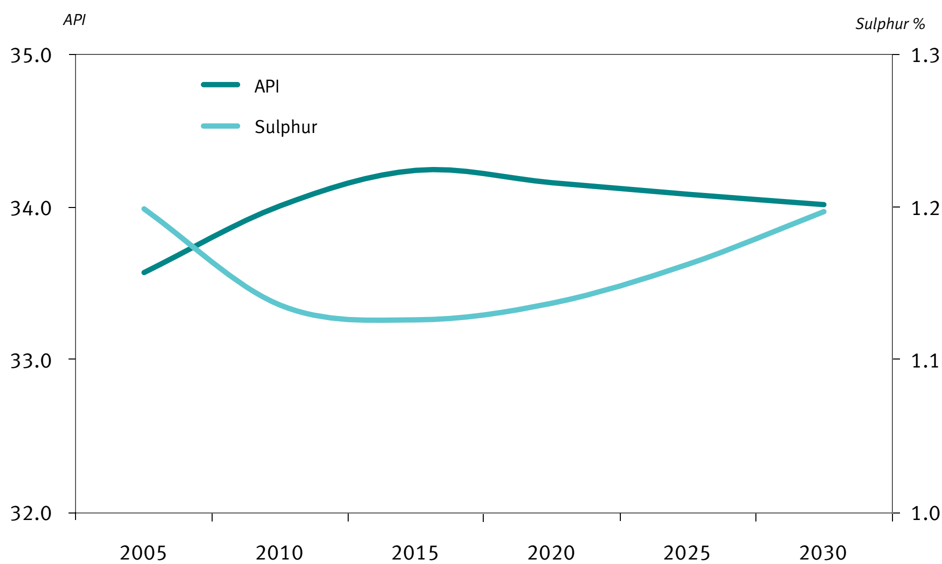


Figure 7.3
Global crude quality outlook



Chapter 7

before moving marginally back to around 34° API by 2030. This is from an estimated average 33.6° API in 2005. In respect to sulphur content, the expected variations are somewhat wider, but still below the 10% level. The global crude slate is projected to turn sweeter in the period to 2015, reaching 1.1% average sulphur content from 1.2% in 2005. It will then turn a little sourer, with an average sulphur content of approximately 1.2% in 2030.

In the past, refiners have often voiced concerns that the crude slate is becoming heavier, thus adding to difficulties in producing lighter products, especially middle distillates. In light of the trends mentioned, however, this perception needs to be altered.

The WOO 2009 sees no signs that the average crude slate will get heavier, particularly in the medium-term, where several developments and existing upstream projects suggest the opposite. Nevertheless, this may not necessarily mean that the task of producing the required future product slate becomes uniformly easier. This is because of the increasingly wide spread between the lighter and heavier ends of the future barrel, driven by the increase in NGLs and condensates production. Compared to last year's projections, a dramatically lower future crude supply combined with upward revisions for condensates and NGLs, alongside declining naphtha/gasoline demand, will amplify the problem of the naphtha/gasoline surplus. At the other end, the growth in syncrudes, especially in the form of rather heavy DilBit and SynBit, will only partially help solve the dilemma of expanding middle distillates, thus necessitating additional investments and technological solutions to meet expected demand. At the same time, a medium-term heavy crude production decline coincides with a large increase in coking capacity, which it is projected will lead to surplus coking availability.

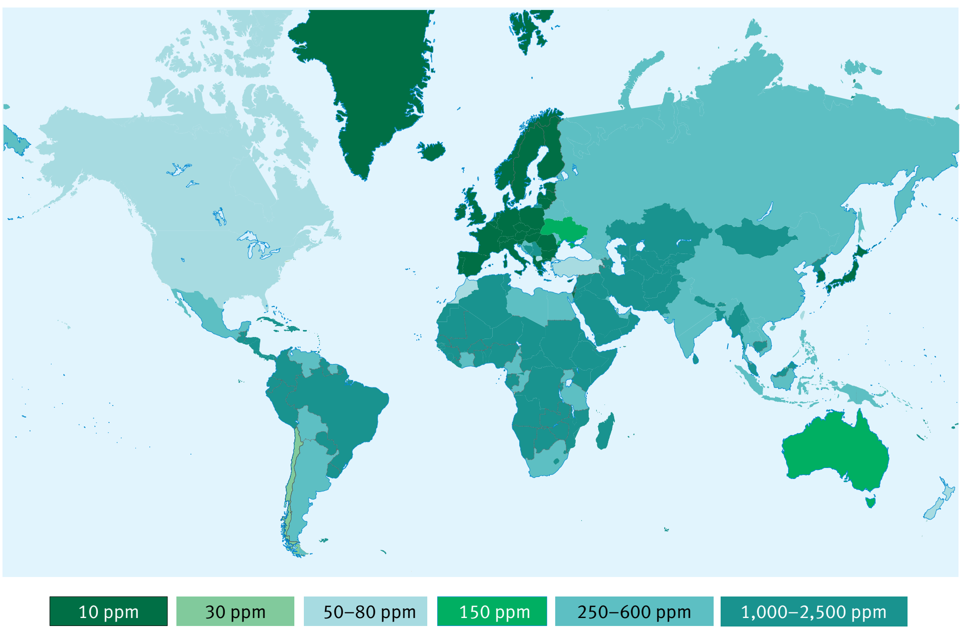
Refined products quality developments

Another factor affecting future downstream investment requirements relates to finished product quality specifications. In the past, refiners worldwide 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 has turned to the sulphur content, especially in Europe, Japan and the US. It has meant that diesel fuel and gasoil, alongside gasoline, have also now been set targets. The aim is to produce almost sulphur free transport fuels, or ultra low sulphur fuels, and thus enhance their environmental credentials. The next step, which has already begun in a number of countries, will be to extend stricter sulphur specifications 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.

At the global level, however, there is no coordination to this process, and little also 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 7.4 and 7.5, which show maximum sulphur content levels (these may differ from levels actually used) worldwide in gasoline and on-road diesel fuel respectively, as of March 2009.

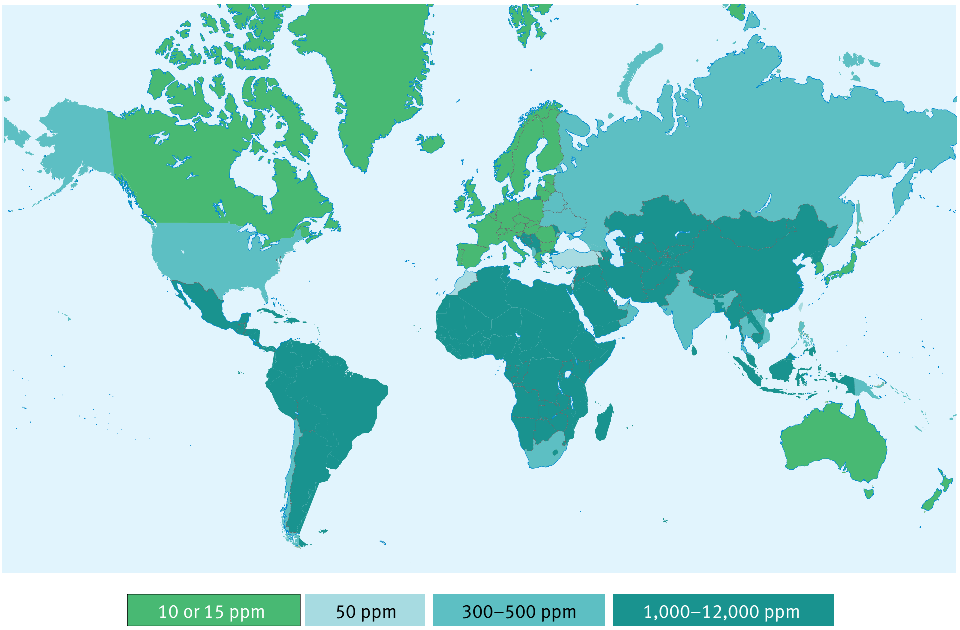
In developed countries, the trend is toward the widespread use of ultra low sulphur gasoline. The US ultra low sulphur gasoline programme — 80 and now 30 ppm — was phased in as of 2004. Canada implemented a 30 ppm sulphur limit in 2005. Effective as of January 2009, the EU requires 10 ppm. And Japan is also at 10 ppm. However, despite significant improvements in a number of other countries, in general, other regions remain somewhat behind. The gasoline sulphur limit in China is currently at 500 ppm, however, stricter quality requirements of 50 ppm are imposed in Beijing and other big cities. Moreover, it is expected that nationwide limits will be lowered to 150 ppm in the near future. A similar type of policy is being applied in India too. Selected urban centres currently follow the

Figure 7.4
Maximum sulphur limits for gasoline in 2009



Source: Hart's International Fuel Quality Centre (IFQC), March 2009.

Figure 7.5
Maximum sulphur limits for diesel in 2009



Source: IFQC, March 2009.

150 ppm gasoline standard, while the rest of the country is at 500 ppm. By 2010, however, these limits are expected to be altered to 50 and 150 ppm respectively. Significant improvements in gasoline quality specifications are also ongoing in other regions, especially the Middle East and Russia, albeit from much softer existing requirements.

Specifications for diesel fuel not only vary between countries and regions, but also often by sector. In the EU, for example, the European Fuel Quality Directive requires on-road diesel fuel sulphur content to be set at 10 ppm in 2009, with off-road diesel sulphur at the same level in 2010, and diesel used for inland waterways vessels at a much higher level of 300 ppm. Ultra low sulphur limits for on-road diesel fuel are also in place in Japan, Australia and New Zealand. South Korea is currently at 50 ppm and plans to adopt new standards of 10–15 ppm by 2010. In the US & Canada, 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 is also expected by 2010 from the current limit of 500 ppm. However, it is estimated that more than 90% of diesel consumption in these two countries is already in the category of ultra low sulphur fuel.

Major developing countries could be viewed as lagging in this process, but it should be noted that improvements there are also significant. In China, the average commonly in-use fuel sits between 600–1,000 ppm, but the country plans to adopt Euro III (350 ppm) and perhaps Euro IV (50 ppm) emission standards by 2010. Even greater progress is expected in Beijing and some other cities where the current limit of 50 ppm is expected to drop to 10 ppm by 2012. However, China's nationwide limit for sulphur content in on-road diesel fuel remains at 2,000 ppm. India is following a similar path. It currently has a 500 ppm level for on-road diesel nationwide, with 350 ppm in selected cities. The Indian government has, however, already issued a notification to introduce Euro III emission standards for nationwide use by 1 April 2010, as well as Euro IV standards in major urban centres by the same date. Similar improvements are to be reported for countries such as Russia, Thailand, Kuwait, Qatar, Chile and Argentina. 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.

Turning to long-term assumptions, expectations for future product quality specifications remain unchanged from last year's WOO.[28] In respect to gasoline, future quality initiatives will focus primarily on sulphur, benzene and aromatics. Projected gasoline qualities for 2010–2025 are shown in Table 7.1. Gasoline quality specifications, as well as those for other fuels, are assumed to be unchanged for the rest of the forecast period from 2025–2030.

Looking ahead, diesel sulphur presents the largest challenge to the sector due mainly to the fact that it is expected to have the greatest need for refinery processing

Chapter 7

Table 7.1
Expected regional gasoline quality specifications*
(maximum sulphur content in ppm)

Region	2010	2015	2020	2025
US & Canada	30	30	<10	<10
Latin America	500	300	100	50
Europe	15	10	<10	<10
Middle East	850	200	100	50
FSU	450	250	85	50
Africa	700	330	125	120
Asia-Pacific	135	75	50	45

* *Estimated regional weighted average quality specifications are based on volumes of fuel of current specifications in individual countries.*

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

additions. Table 7.2 summarizes regional diesel fuel quality from 2010–2025 for both on-road and off-road diesel. 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. By 2015, on-road diesel is projected to be below 500 ppm in all regions except Africa. Africa will reduce sulphur levels by 74%, but on-road diesel sulphur will still be above 500 ppm.

Table 7.2
Expected regional diesel fuel specifications*
(maximum sulphur content in ppm)

Region	2010	2015	2020	2025
US & Canada	15	15	10	10
Latin America	500	250	50	50
Europe	15	15	10	10
Middle East	1,600	350	265	175
FSU	390	225	130	30
Africa	2,600	680	650	650
Asia-Pacific	230	150	100	100

* *Estimated regional weighted average quality specifications are based on volumes of fuel of current specifications in individual countries.*
Source: Hart's WRFS and IFQC.

While there is little room for developed countries to further improve product specifications, major shifts are expected to occur in most of the developing world. China and India, for example, together with countries in Latin America and elsewhere, have announced plans to progressively adopt the EURO III/IV/V standards for both diesel and gasoline. This includes constraints on benzene (gasoline), aromatics (both fuels), gravity (diesel), cetane (diesel), as well as 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 East. However, more will be needed across all regions if the proposed targets are to be met.

Other products, such as heating oil, jet kerosene and fuel oil are also anticipated to be targets for tighter specifications. In North America, heating oil is expected to be reduced to 500 ppm by 2020 and in Europe to 1,000 ppm by 2015 and then eventually 500 ppm. 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/countries 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 in 2025.

An important change regarding sulphur content limits for fuel oil used as marine bunkers was recently adopted by the Marine Environment Protection Committee (MEPC) of the International Maritime Organization (IMO). It is a development that has potentially far-reaching implications. In October 2008, after a long debate, the IMO decided on a gradual reduction of the sulphur content in bunker fuel from the current 4.5% to 3.5% in 2012 and 0.5% in 2020. The decision also covered the reduction of sulphur content in the Emissions Control Areas (ECAs) from the current 1.5% to 1% by 2010 and 0.1% 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. The details and implications of this regulation are discussed in Box 7.1.

Box 7.1
Marine bunkers: another element of uncertainty for refiners

The emissions limits agreed by the IMO in October 2008 will have significant implications for both the shipping and refining industries. There are many complex inter-industry issues involved, and it is important that all stakeholders quickly get to grips with the possible connotations and consequences.

The major revision in question was that finalized by the IMO MEPC to Annex VI of the International Convention for the Prevention of Pollution from Ships (The MARPOL Convention). This sets forth several provisions aimed at reducing marine vessel emissions.

The first strengthens and extends the concept of ECAs established in the original 2005 Annex VI. The original ECAs were limited to controlling SOx emissions, but the new ones allow countries to cover SOx, NOx and/or particulates emissions.

The second calls for significant reductions in NOx emissions from marine engines. Although these tightening regulations are expected to be met predominantly by marine engine design, the quality of marine fuels will play a role.

And the third sets out progressively tightening standards for the sulphur content of marine fuels. The current global standard of a maximum sulphur content of 4.5% for intermediate fuel oil (IFO) fuels drops to 3.5% on 1 January 2012, and then to 0.5% on — potentially — 1 January 2020. The new regulation requires a study to be completed by 2018 to assess whether sufficient fuels can be produced at the 0.5% sulphur level by the global refining system and allows for a deferral of the implementation date to 2025 if major difficulties are envisaged. The regulation also tightens the current 1.5% sulphur standard for ECAs to 1% from 1 July 2010, and then to 0.1% from 1 January 2015.

In addition, the regulation also allows for the possibility of the equivalent SOx emissions standards to be met via the use of on-board scrubbing systems. However, there are number of issues and questions concerning on-board scrubbers, particularly with regard to the complexities of use and costs, which means their actual potential remains uncertain.

The industry view prevailing at this time is that refiners would be reluctant to enter into the major investments required to produce a product that only has a narrow market, and does not have a large value increase versus the low quality residual stream starting point. Rather, the general opinion is that refiners would prefer to make incremental investments to install either residual hydro-cracking or coking plus gasoil hydro-cracking.

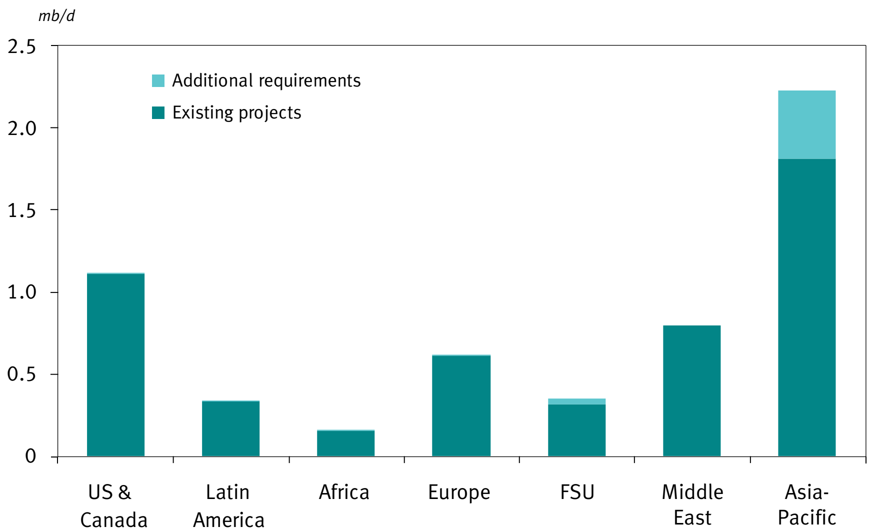
In summary, while the regulations laid out in MARPOL Annex VI Revised are clear, they are also flexible and leave open a wide margin of uncertainty as to how compliance will be achieved. Therefore, the IMO will continue to monitor developments over the next few years. Scrubbing potential will continue to be assessed as will the ability of the refining industry to invest to convert IFO to distillate. The future could comprise either a complete switch to distillate marine fuels worldwide or the widespread use of on-board scrubbers, or a combination of both. However, even partial conversion of IFO grades to distillates will have a major impact on refining.

Capacity requirements

To shed light on the adequacy of conversion and desulphurization capacity to meet required product demand, the assessment of refinery projects was extended into a projection of incremental supply potential by major refined product group. This was then compared with the projected incremental demands on a regional basis. As reviewed in Chapter 6, based on the announced or estimated configuration of existing refining projects, the projections show a total of 5.1 mb/d of new conversion capacity worldwide within the period 2008–2015. Driven by increasing diesel demand, most of this capacity will come from hydro-cracking units (2.1 mb/d), followed by coking

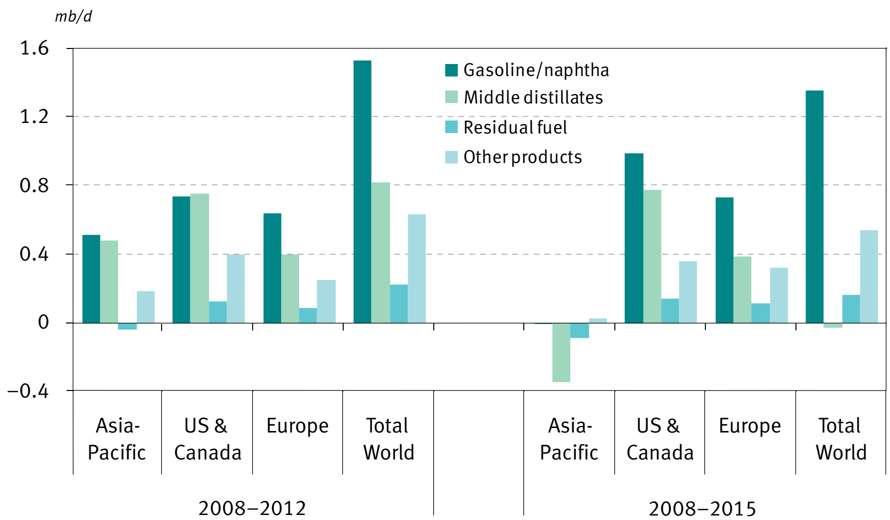
(1.9 mb/d) and FCC units (1.1 mb/d). As presented in Figure 7.6, the location of these processes will, to a great extent, mirror that of distillation capacity, since in most cases they come from the same expansion projects. However, some of the conversion capacity is the consequence of projects that are geared to alter refinery configuration rather than to expand capacity. This is mainly the case in Europe, the US & Canada, the Pacific OECD countries of the Asia-Pacific and Russia.

Figure 7.6
Conversion capacity requirements by region, 2008–2015



These new units, combined with distillation capacity and further secondary additions, predominantly hydro-crackers, create the potential for additional global output from the major product groups in the medium-term. This is presented in Figure 7.7 for the periods to 2012 and 2015. The period to 2012 was chosen for an additional comparison since the bulk of conversion capacity from existing projects is expected to materialize within this period. Data for the major refining markets, and for the global world, reinforces the situation faced by the global refining sector – one with major surpluses of incremental product output. Only the Asia-Pacific region shows a potential deficit by 2015, otherwise all regions show substantial surpluses already by 2012 and these do not materially improve by 2015. What is also striking is the contrast between distillates and gasoline/naphtha. Globally, capacity for incremental distillate is in surplus to 2012, but it moves to a more balanced position by 2015, although there is a deficit in the Asia-Pacific. Conversely, for naptha/gasoline, aside from the Asia-Pacific where in 2015 there is a balance, there is a global surplus that is mainly

Figure 7.7
Expected surplus/deficit of incremental product output from existing refining projects



concentrated in the Atlantic basin. The forces creating this situation include rising ethanol supply, declining gasoline demand, continuing dieselization in Europe as well as projects that are often distillate oriented, but inevitably increase the gasoline/naphtha supply capability. In contrast to naphtha/gasoline, residual products appear to be far more closely in balance. This maintains the situation that has developed recently, whereby residual fuel differentials relative to crude have narrowed from the wide spans that were witnessed 2–3 years ago. In brief, the outlook is for a sustained incremental demand for distillates, a sustained surplus for naphtha/gasoline and a relative balance for residual fuels.

Figures 7.8 through to 7.11, as well as Table 7.3, summarize the results and projections for secondary processing to 2030. What they reinforce is the sustained need for incremental hydro-cracking, with some 4.3 mb/d, from a total of 5.4 mb/d of additional conversion capacity required by 2030. This is due to hydro-cracking being the primary means to produce incremental distillate once straight run fractions from crude have been maximized. The need for continued investments in additional hydro-cracking capacity and to run these units with high energy and hydrogen costs maintains the wide distillate margins relative to crude oil, as well as to other light products. This observation is valid for the entire forecast period and keeps the crack spreads at relatively high levels even at times of low utilization rates.

Box 7.2
The Atlantic basin: mapping the future gasoline and diesel imbalance

While the effects of the current and projected gasoline and diesel imbalance are global, there is one region that stands out: the Atlantic basin. And the imbalance here is extremely significant given that the countries bordering the Atlantic dominate both gasoline and distillate consumption. In the gasoline market, this region represents 70% of the global consumption, led by the US at around 40%, and for distillates it comprises 60% of the total consumption, with Europe the principal market at over 25%.

The reasons for the imbalance can be traced back to European policies supporting 'dieselization' that over the last 10–20 years have led to a rising proportion of diesel fuel in European transport. Both commercial truck and passenger vehicle fleets have moved increasingly to diesel from gasoline under incentives such as fuel taxation rates, road taxes and initial purchase incentives. While this improved fleet fuel efficiencies, it also caused an imbalance between gasoline and distillate.

Nevertheless, the growing European gasoline surplus several years ago coincided with rising US gasoline demand. It meant that European refiners were able to export gasoline surpluses to the US East Coast, which helped meet the shortfall in the US gasoline market. In 2008, Europe exported over 1 mb/d of gasoline and imported over 0.5 mb/d of diesel.

From 2006 onwards, however, events combined to alter this dynamic. At first this led to a greatly exacerbated imbalance that substantially widened gasoline and diesel price differentials, but more recently it has eased somewhat. It begs the questions: what has happened since 2006, and what are the possibilities for the future?

The historical evidence of gasoline and distillate product price differentials *versus* crude oil — prior to around 2003 — underscores that it made little difference to a refiner whether gasoline or distillate was produced. Differentials between the two product groups fluctuated across the seasons, but rarely exceeded $1–2/b on yearly averages. In 2003, Europe's dieselization move started to pull diesel prices ahead of those for gasoline, and at the same time, events in the US accelerated the trend.

State methyl tetra-butyl ether (MTBE) bans and the 2005 US Energy Policy Act led to US refiners essentially eliminating the use of MTBE in 2006 as oxygenate, replacing it with ethanol. The supply of ethanol was already expanding under an initial Renewable Fuel Standard,[29] but a bigger boost then came under an expanded Renewable Fuel Standard that was built in to the 2007 EISA. This called for

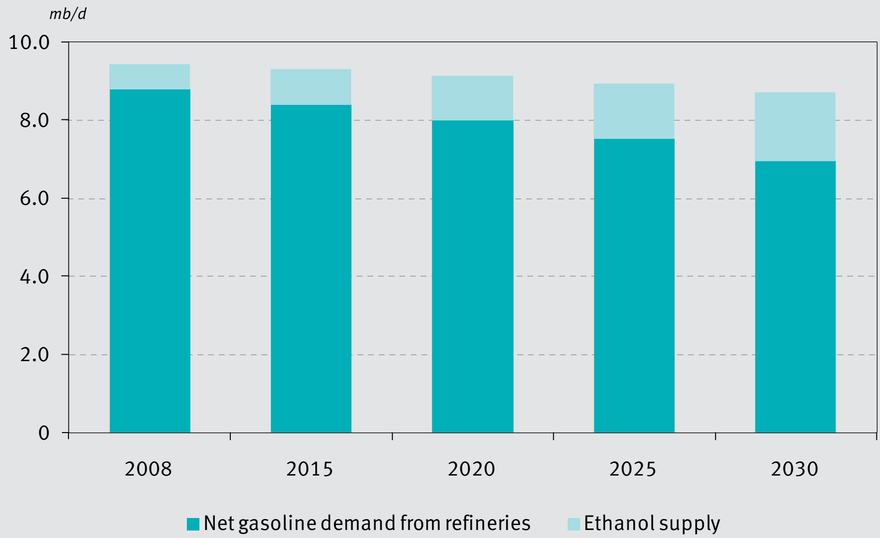
36 billion gallons per year of biofuels by 2022 and set tighter fuel economy CAFE standards. This, in association with high corn crunch spreads often at levels close to $1 per gallon, all helped US ethanol supply advance swiftly to 0.6 mb/d in 2008. Combined with Brazil's rising ethanol supply, as well as the growing diesel demand in Europe and much of the developing world, it triggered declines in gasoline differentials to crude of $5/b or less when distillate premiums surged to the $15–25/b range in mid-2008.[30]

This development, however, did not last. Since mid-2008, the global economic crisis has reduced demand for light products and middle distillates, particularly diesel. At the same time, refinery expansions, including those for hydro-cracking, came on-stream and inventory levels for both crude and products built to historically high levels. In the US, the corn crunch spread is lower than operating costs for most plants. It has led to the refining industry experiencing the sharp reversal of margins, with the huge margins that diesel was enjoying over gasoline largely evaporating. However, despite narrowing differentials, the underlying problem of the gasoline and diesel imbalance remains present in the region and will likely re-emerge after the current turmoil has settled.

Indeed, a central finding of this year's WOO is that the imbalance is structural and will likely reassert itself. There are several reasons for this. Firstly, the demand structure in the Atlantic basin is expected to continue to favour distillate over gasoline. While concern over the distillate imbalance has brought forth EU proposals for Member Countries to raise taxes on diesel to reduce its advantage over gasoline,[31] it is evident that EU road taxes still favour diesel vehicles. EU proposals to impose tighter restrictions on vehicle CO_2 emissions will also tend to benefit diesel. And despite the fact that purchases of all vehicles have dropped markedly — arguably slowing the trend towards diesel cars — most older vehicles in the EU fleet are gasoline powered and thus their gradual removal, currently aided by incentives, will tend to sustain the current vehicle mix.

In the US, rapid ethanol expansion has hit the buffers somewhat, with bankruptcies and deferred projects, but production continues to rise. High gasoline prices and now rising unemployment have cut vehicle miles travelled with US gasoline consumption down close to 6%, versus its peak in 2007. Light duty vehicle sales have plummeted from 16 million to 9 million p.a., but the trend is towards smaller, more fuel efficient vehicles. Over the longer term, the new CAFE standards will also have an impact. As a result, total US gasoline consumption is projected to continue to decline (see figure over). The new US administration's drive for energy efficiency and alternatives will affect all fuels, but gasoline in the US has by far the largest scope for change.

Total gasoline demand and ethanol supply in the US and Canada, 2008–2030



Efficiency trends are also impacting distillate fuels. For instance, high prices and the current economic downturn are removing many smaller less efficient truck operators from roads in the US and elsewhere. There is also a gradual shift to more efficient and newer transport models. For example, new aircraft have helped US airline fuel efficiency improve by an average of 3% p.a. since the mid 1980s. And there is also a move to more fuel-efficient transport modes: air to truck, truck to rail, and even rail to barge.

Many of these developments are taken into account in this year's WOO, but despite these, it is evident that distillates are expected to be the main factor in future oil demand growth.

It should also be noted that the new IMO regulations to reduce emissions from ships, as well as the establishment of ECAs will raise global demand for marine distillate as heavier residual type bunker fuels are replaced. The EU has already set up two ECAs plus an in port/inland low sulphur diesel rule. The US has also applied to establish ECAs on the US coasts, with Canada following suit. These will likely be in place by 2015.

In short, the small differentials between gasoline and diesel in the first half of 2009 look temporary, with the structural imbalance expected to resurface. This clearly has implications for refining in the Atlantic basin.

Refinery projects recently completed or under way in Europe and the US have placed more emphasis on distillates and hydro-cracking. Driven by high diesel prices relative to gasoline, refiners have been gradually increasing output of diesel, although yields have only risen by 2–4% on average. This is because existing refinery configurations have limited scope for reallocating gasoline and naphtha into diesel. New FCC catalysts will shift gasoline to distillate to a limited degree, but barring new technology that would condense naphtha/gasoline to diesel, the industry is left with no alternative than to look at high cost hydro-cracking to generate more distillate.

This, and gasoline surpluses, will continue to produce refining margins and crack spreads that are highly differentiated depending on whether the yield is oriented to gasoline or to distillates. WOO projections are for Atlantic basin gasoline differentials versus crude to be barely positive going forward, while distillate differentials move back into the $10–20/b range.

As a result, regional gasoline oriented refineries look to be vulnerable. The imbalance, combined with major demand losses, presage a wave of refinery reconfigurations and closures on both sides of the Atlantic. Trading patterns will also be impacted. The US East Coast will become even more competitive, with refineries here, in the US Gulf, eastern Canada, the Caribbean, Europe and elsewhere vying to supply gasoline, in part as a means to co-produce higher value distillates. However, with lower demand, more ethanol and more US gasoline capacity, suppliers across the board are likely to be impacted, with those not integrated into downstream distribution and sales potentially the hardest hit. European gasoline flows into the US may be curtailed, promoting supply cutbacks and/or expanded exports to Africa, Latin America and possibly Asia, with consequences for reduced netbacks. On the diesel side, European hydro-cracker projects will dampen, but not eliminate distillate imports. US projects and refinery revamps will raise the country's ability to export distillate, especially to Europe, but with potential for movements to Latin America, Asia and Africa.

It all points to the diesel and gasoline imbalance in the Atlantic basin continuing to be a defining parameter in refining economics and activity for the short-, medium- and long-terms.

Conversely, recent substantial coking capacity additions, together with the expected decline in the supply of heavy sour crudes in the medium-term, leads to a coking surplus. This is evident in the lack of capacity additions to 2015. In fact, coking additions only appear to be required after 2020. Catalytic cracking is adversely impacted by declining gasoline demand growth and rising ethanol supply,

Figure 7.8
Global capacity requirements by process type, 2008–2030

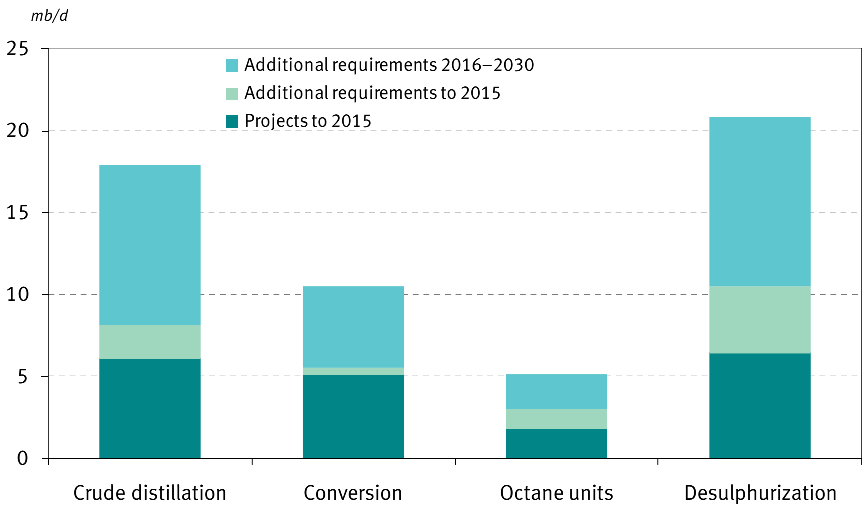
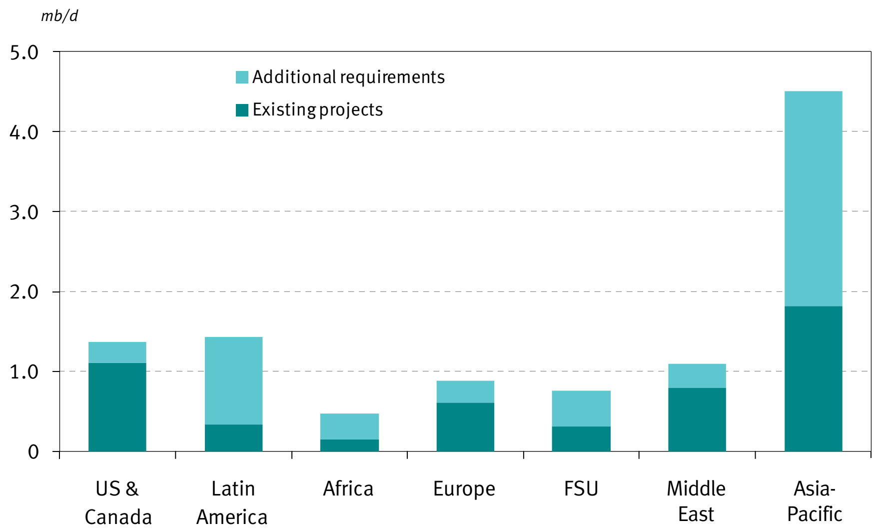


Table 7.3
Global capacity requirements by process, 2008–2030

mb/d

	Existing projects	Additional requirements to 2015	Additional requirements to 2030
Crude distillation	**6.1**	**2.1**	**11.9**
Conversion	**5.1**	**0.5**	**5.4**
Coking/Visbreaking	1.9	0.0	0.5
Catalytic cracking	1.2	0.1	0.6
Hydro-cracking	2.1	0.4	4.3
Desulphurization	**6.4**	**4.1**	**14.5**
Vacuum gasoil/Fuel oil	0.0	0.2	0.9
Distillate	4.9	2.7	10.3
Gasoline	1.6	1.2	3.3
Octane units	**1.9**	**1.2**	**3.3**
Catalytic reforming	1.4	0.5	1.8
Alkylation	0.2	0.0	0.1
Isomerization	0.3	0.7	1.5
Lubes	**0.0**	**0.5**	**0.9**

Figure 7.9
Conversion capacity requirements by region, 2008–2030



especially in the Atlantic basin. Consequently, projected increases beyond current projects are viewed as minimal until after 2020, and are then concentrated in non-OECD regions that witness gasoline demand growth, particularly the Asia-Pacific. Moreover, FCC and secondarily coking units suffer in the outlook as they comprise 'swing' units for gasoline production. Consequently, utilizations are relatively depressed. As Table 7.3 and Figure 7.8 illustrate, total conversion additions to 2015 are 5.6 mb/d. This is not far below total crude unit additions. This increase in relative conversion capacity is a factor contributing to the reduced utilizations for FCC and coking units.

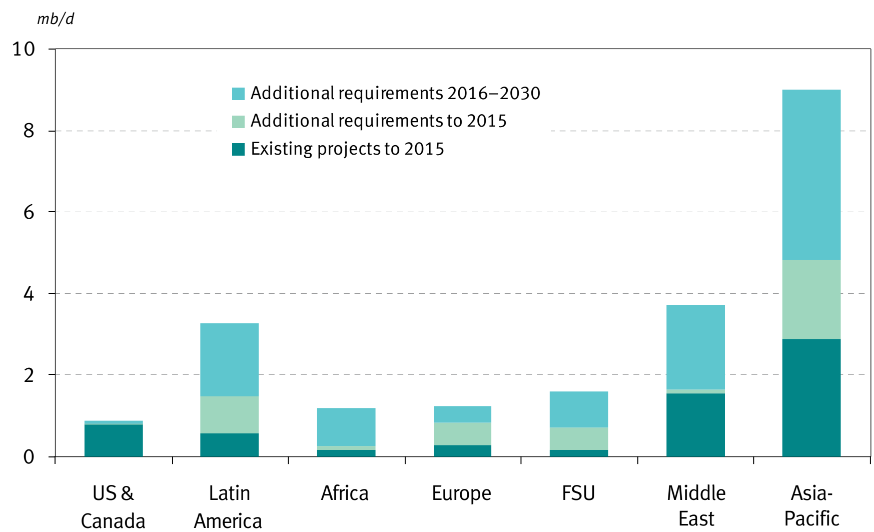
On a regional basis, conversion capacity requirements beyond 2015, which in reality means beyond existing projects, will be dominated by the Asia-Pacific. The region attracts more than 50%, or close to 3 mb/d, of future additions (Figure 7.9). A significant increase should also take place in Latin America (1.1 mb/d), with demand there expected to grow. Whereas Asia-Pacific requirements lean towards hydrocracking, those in Latin America are more balanced and include reasonable shares for coking and catalytic cracking. Additional conversion requirements in other regions are fairly limited.

Substantial desulphurization capacity additions will also be necessary to meet sulphur content specifications, with some 14.5 mb/d required to 2030, which is over and above existing projects of 6.4 mb/d (Figure 7.10). The bulk of these units are projected to come on-stream in the Asia-Pacific (9 mb/d) and in the Middle East (3.7 mb/d), driven by the expansion of the refining base, demand and stricter quality specifications. The Latin American refining system will also add significant volumes (3.3 mb/d). Relatively low desulphurization capacity additions are projected for the US & Canada and Europe, where almost all transport fuels are already at ultra low sulphur standards except for some Southeast European countries. In other regions, due to the limited existing capacity, even modest sulphur reduction implies considerable capacity additions. A summary of desulphurization capacity additions for various time horizons, including those coming from existing refining projects, is presented in Figure 7.10.

Of 21 mb/d of global desulphurization capacity additions from 2008–2030, more than 70%, or 15 mb/d, are for distillate desulphurization and the bulk of the remainder, 5 mb/d, for gasoline sulphur reduction (Figure 7.11). Moreover, continuing expansions are needed for catalytic reforming and isomerization units. These are driven in part by rising gasoline pool octanes. They also enable additional naphtha to be blended into gasoline.

It should also be noted that this analysis was conducted assuming no change in marine bunker regulations. A shift to marine distillate would substantially increase

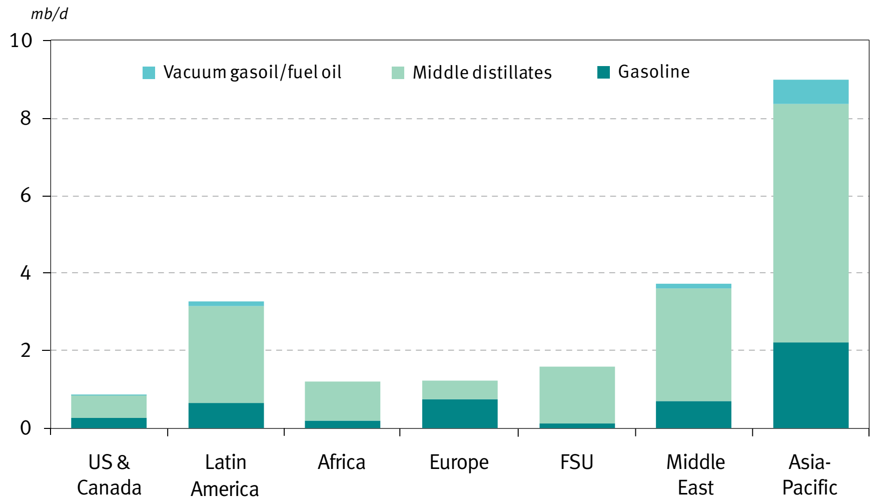
Figure 7.10
Desulphurization capacity requirements by region, 2008–2030



Chapter 7

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

Figure 7.11
Desulphurization capacity requirements by product and region, 2008–2030



Crude and product pricing and differentials

Under the Reference Case where sustained distillates growth implies high utilization rates for hydro-crackers and the ongoing investments in such units, distillate price differentials relative to crude and other products reflect the resulting premium of producing incremental distillate barrels. Conversely, where streams such as naphtha/ gasoline are in surplus, and where associated key units, most notably catalytic cracking are running well below the maximum utilization rate, then the price differentials reflect the industry's relative difficulty in finding a home for these products.

Moreover, both higher unit capital costs for process investments and higher crude prices push in the direction of wider light/heavy and sweet/sour differentials on crudes and products, and vice versa. 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 and thus lighter/sweeter crudes benefit from a premium. Reciprocally, lower prices tend to reduce processing costs and hence the light/heavy differentials.

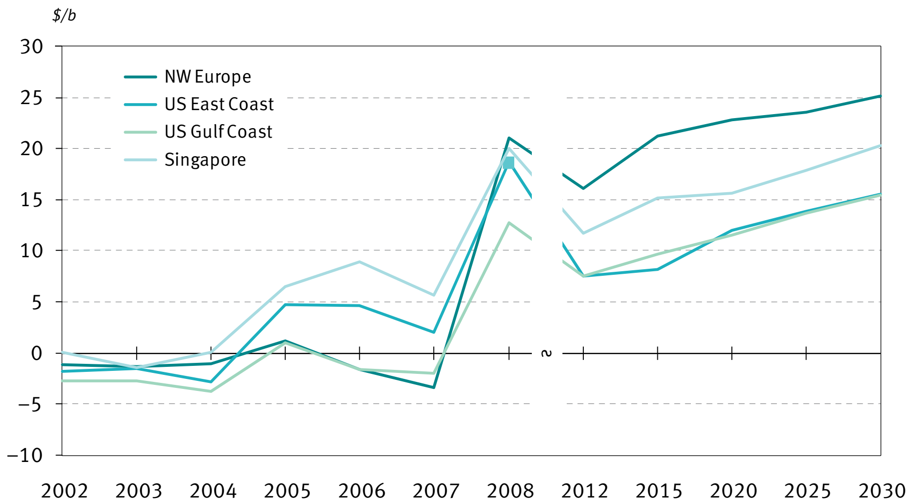
These various effects are reflected in the crude and product price differentials indicated by the model. It is important to note, however, that model cases for horizons such as 2015–2030 are executed in 'long-run' mode. Thus, for example, if the crude slate is adjusted, then the model will reflect the long-run impact by allowing the refining system to adjust its investments and operations. It means that the differentials estimated by the model highlight long-run trends, under a global cost minimization hypothesis. By comparison, prices, as well as most differentials and margins that are used in the industry on a daily basis are all short-term. This is where the market has essentially no ability to alter available capacity to react to any significant development. In addition, in reality, actors in the refining sector do not necessarily adjust in a manner that minimizes global costs. Bearing this in mind, price differentials produced from modelling horizons that are 10 or 20 years in the future must be treated only as indicative.

The model results broadly suggest a return to more moderate crude price differentials that were witnessed in the period 2000–2004. It is a shift from the historically high levels seen in the 2005 to mid-2008 period, when crude prices were moving upwards and the refining system was tight. The relatively narrow differentials are expected for 2015 as the outlook points to a significant capacity surplus, as well as to additional non-crudes supplies and a somewhat better global crude slate. Differentials then remain moderate to 2030 as the low rate of demand growth combined with continuing increases in the supply of non-crudes helps to maintain moderate capacity utilization rates and hence a surplus capacity in the major industrialized regions. However, the negative differentials for heavy sour crude grades are expected to widen, reflecting the decline in residual fuel demand and a projected longer term increase, albeit slight, in the supply of heavier grades.

Figure 7.12 reflects the major global trend in product differentials, namely the impacts of a continuing shift toward gasoline surplus as a result of a number of drivers. This includes the increasing ex-refinery gasoline production capability; flat or declining gasoline demand in the US, Europe and Japan; rising supplies of ethanol, as well as condensates and light sweet crudes; and distillate tightness, due to sustained demand growth in Europe and globally, particularly for diesel. It is evident from the historical data — up to 2008 — that for several years the markets have been experiencing a shift from a situation where, on an annual average basis, there was typically a small premium of around \$2–3/b for gasoline over gasoil/diesel, to one where gasoline prices being below gasoil/diesel is the norm. To put it succinctly, the market is seeing a progressive rise in the price of gasoil/diesel relative to crude, and a decline in that of gasoline relative to crude.

The modelling projections for 2008–2030 indicate a partial recovery from the recent high levels in the period to 2012, but in general there is a continuation in the

Figure 7.12
Gasoil-gasoline price differentials in major markets
Historical and projected



shift to wider premiums for distillate over gasoline. In the period to 2012, the recent demand reduction for distillate fuels and for gasoline/naphtha streams, combined with a relatively slow economic recovery and rapid increases in global conversion capacity, will likely result in moderated price differentials for these products. However, this reversal of the general trend towards wider premiums is seen as a temporary phenomena. The underlying premise in the longer term is that, unless there is a policy shift, the world continues to call for a rising proportion of gasoil/diesel (and jet fuel) in total demand, with gasoline demand rising more modestly. There will also be major regional declines in the US and some other industrialized regions, and an increasing supply of alternative fuels, particularly ethanol. Inverse diesel/gasoil-gasoline differentials are projected to be most severe in Europe, which is not surprising given that dieselization is expected to continue in the region, albeit at a slowing pace.

The trend to a gasoil/diesel tightness and to a gasoline surplus, as well as the resulting price differentials, raises a question as to whether, and how governments and consumers might respond over time to the higher pump prices for diesel versus gasoline. For example, this might take the form of shifting taxes and subsidies to the advantage of gasoline and disadvantage of diesel, plus there are obviously potential implications for gasoline and diesel vehicle ownership. Thus the question is: to what extent might regional and global demand shift back partially toward gasoline? This issue is discussed further in Chapter 10.

Potentially offsetting such a shift are the possible impacts of new marine fuels regulations (see Box 7.1). Unless on-board scrubbing technologies prove to be successful commercially, and acceptable environmentally, the regulations as proposed by the IMO presage a total shift by around 2020 or 2025 to marine fuels of either 0.1% or 0.5% sulphur. This means a partial or possibly even total conversion from IFO to distillate grades. Even a partial shift will appreciably increase the proportion of distillates in global demand, augmenting the strains on refining to produce an ever greater yield of distillates and the associated effects on price differentials. The uncertainties lie in the rate of adoption of the new IMO regulations, the timing of the implementation of regional ECAs at the 0.5% and 0.1% sulphur standards, as well as the degree to which scrubbers are used. For these reasons, the Reference Case presented in this outlook does not assume any shift from IFO to distillate fuels in marine bunkers. However, it does assume a change in maximum sulphur levels as agreed by the IMO.

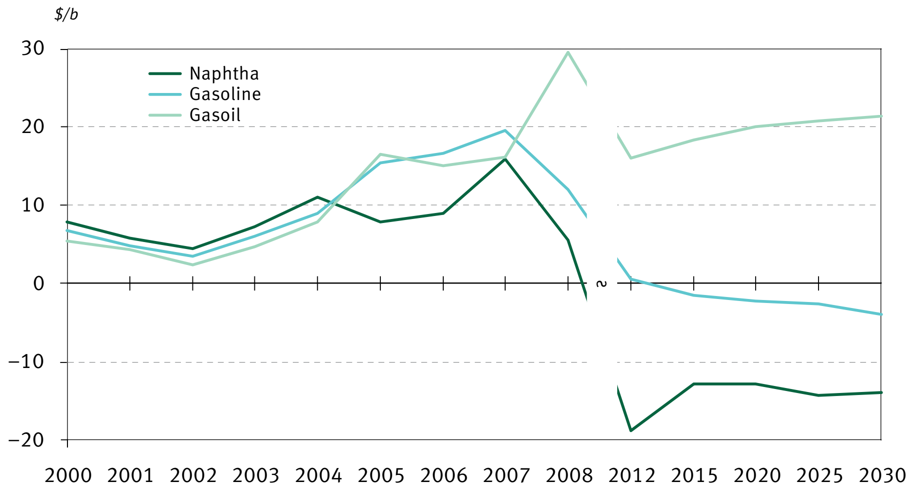
Figure 7.13 expands on Figure 7.12 by showing price differentials — again historical and projected — for naphtha, gasoline and gasoil versus Brent crude oil for a typical European market. Rotterdam prices were used for historical data, with price differentials for other markets showing a similar trend.

The figure reinforces the view that the differential for diesel, and other distillates, versus crude oil will recover, and then continue to rise, returning to and potentially surpassing the \$10–\$20/b premium witnessed in the last two years. It also supports the expectation that differentials for naphtha and gasoline will continue to decline. Although gasoline prices relative to crude will inevitably rise in the summer each year and then drop in the winter, the outlook is for gasoline prices to follow recent trends. This means that on average it will be at, or below the crude price, with the situation deteriorating in the longer term. The year round average gasoline differentials versus crude are indicated to sit in the \$0–\$5/b range. Especially marked, however, is the projection for weak and declining naphtha differentials versus crude. In the last two years, naphtha prices have slipped steadily relative to crude, dropping to \$10–\$20/b below crude in late 2008. The model projections present a similar continuation of these negative differentials.

A central message in all this is that the industry surpluses and deficits that have recently emerged, and which have been reflected in price differentials that differ markedly from those obtained in the years before 2005, are not a short-term phenomenon. Rather, they appear to represent a set of changes that is altering the fundamental balances within the refining system, and in a manner that will take years, not months, to adapt to.

The principal trend remains the shift to distillate and away from gasoline. This, in turn, is showing itself in both present day and projected future refining economics.

Figure 7.13
Price differentials for major products*
Historical and projected



* *Price differentials are for Rotterdam market calculated versus Brent.*

Whereas the proportion of gasoline to distillate yield was of little concern to a refiner up until only two-to-three years ago, because there was relatively little difference between annual average gasoline and distillate prices, today and in the future, the ability to produce distillate rather than gasoline is now arguably one of, or perhaps the major factor determining a refinery's margins.

The added focus placed on naphtha differentials serves to highlight the intimate link between naphtha and gasoline and the projected consequences of these defined trends on demand for products such as NGLs/condensates, ethanol and gasoline. It signifies that the refinery supply system may have substantial difficulties in fully utilizing or disposing of the volumes of naphtha boiling range materials coming onstream.

Most probably, the industry is set to react to the imbalances foreseen in this, and earlier outlooks, and that have now been accentuated by the latest global developments. This will be further reviewed in Chapter 10.

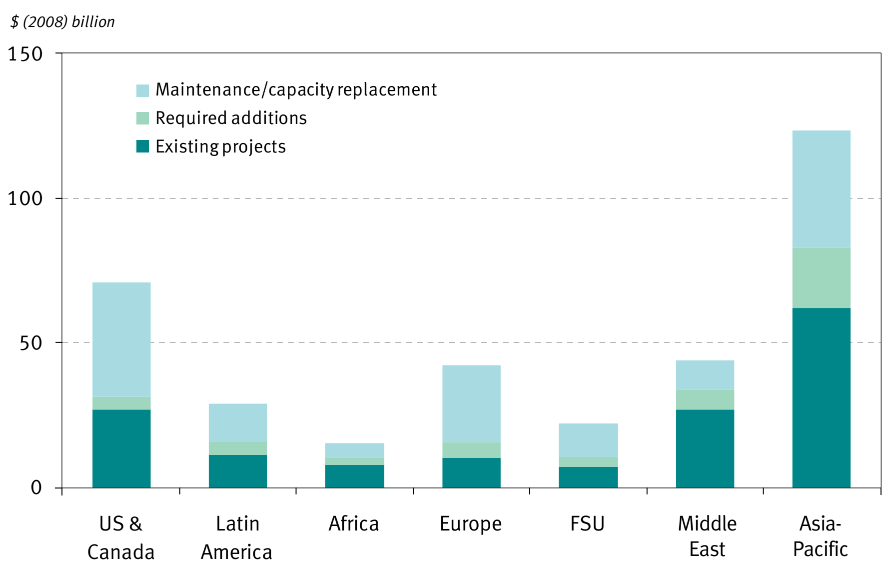
Chapter 8

Downstream investment requirements

Substantial capital investments are required for the expansion of the refining system. For the entire forecast period to 2030, investments are estimated to be around $780 billion, and this does not include the related infrastructure investments beyond the refinery gate, such as those required to build port facilities, storage or pipelines. The $780 billion consists of three major components, as presented in Figures 8.1 and 8.2 for the periods 2008–2015 and 2008–2030 respectively.

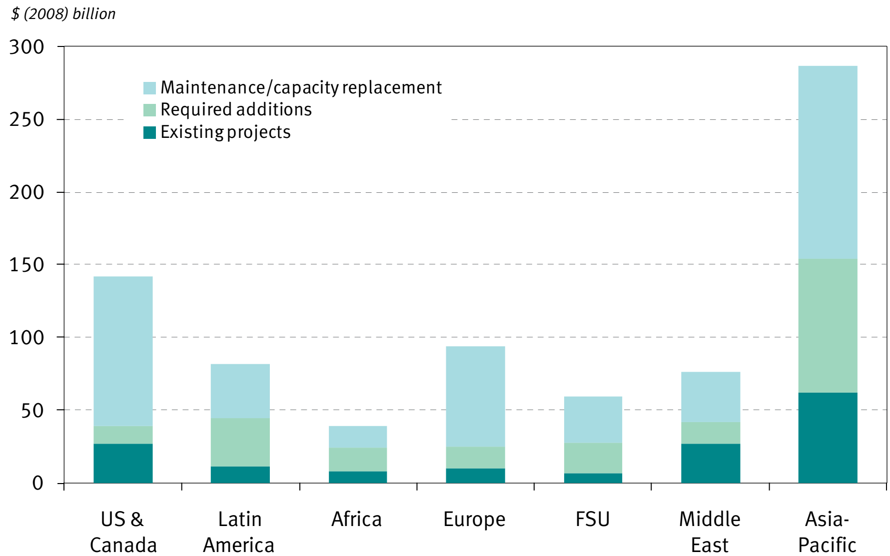
The first investment category focuses on existing projects that are expected to be pursued. The second category, required additions, comprises capacity additions — over and above known projects — that are projected as needed by 2015 and 2030 respectively. The third category of investment centres on maintenance and capacity replacement, and relates to the ongoing annual investments necessary to maintain and gradually replace the installed stock of process units. Following industry norms, the maintenance and replacement level was set at 2% p.a. of the value of the installed base.

Figure 8.1
Refinery investments in the Reference Case, 2008–2015



Chapter 8

Figure 8.2
Refinery investments in the Reference Case, 2008–2030



Consequently, the amount of investment needed within this category depends on the size of the existing primary and secondary capacity, and will increase proportionally to capacity additions over time.

In the period to 2015, the total required refinery processing investment is projected to be $350 billion. This consists of around $150 billion to cover the cost of existing projects, $50 billion for further process unit additions, such as revamps, debottlenecking/creep and major new units, and the remaining $150 billion for system maintenance and ongoing replacement.

Regionally, the highest level of investment in new units over the period will be in the Asia-Pacific, with around $60 billion for projects already identified as coming onstream, $20 billion for additional ones that will be required before 2015 and another $40 billion for capacity maintenance and replacement. China alone accounts for more than 50% of the Asia-Pacific total. The region requiring the next largest investment is the US & Canada with a total requirement of around $70 billion. Of this, however, 55% is for replacement, which stems from the region's large installed base of complex refining capacity. Indeed, in 2008, almost 25% of distillation capacity and 35% of secondary units were located in this region. In Europe, the share of maintenance and replacement cost is even higher, approaching 65%. Here, new unit investments are limited and focused mainly on hydro-cracking and desulphurization for diesel. On the other hand, the Middle East has maintenance and replacement costs that constitute less than 25% of investment requirements to 2015. The region is projected to require close to $35 billion for the expansion of its refining system and another $10 billion for replacement. Latin America is projected to see investment levels of close to $30 billion. From this, around $10 billion is directed to existing projects. The FSU is expected to see similar proportions for new and replacement capacity, albeit with moderately lower investments. The lowest level of investment is projected for Africa, totalling around $15 billion for the period to 2015.

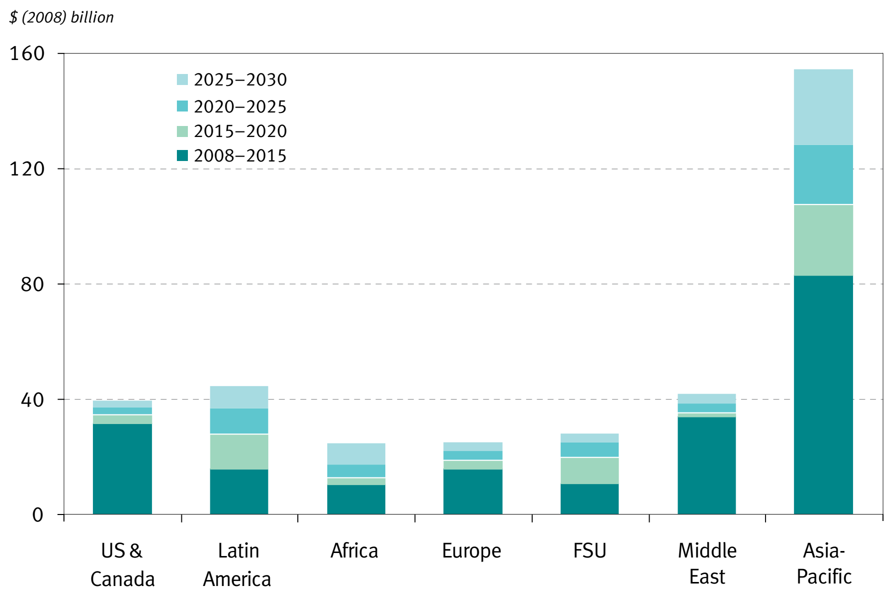
Figure 8.2 extends the time horizon of investment requirements to 2030. It is evident again, as in the medium-term, that the most significant region for long-term downstream investments is the Asia-Pacific, driven by the region's strong demand growth. Out of the $780 billion required globally by 2030, almost 40%, or $290 billion, should be dedicated to the Asia-Pacific. For other regions, the same geographical pattern is broadly maintained as that for the period to 2015, especially when direct investments related to capacity expansion are considered. Beyond existing projects, investments in the US & Canada, as well as Europe, become increasingly focused on those for maintaining existing capacity and secondarily, for compliance on the quality for the expected growing volumes of distillate. Relative to the period 2008–2015, in 2015–2030, investment requirements expand appreciably in Latin America and Africa, driven by rising demand. Middle East investment will also expand from $45 billion in the period 2008–2015 to around $75 billion cumulative from 2008–2030.

Global refining investments for the entire forecast period are expected to comprise around $150 billion for existing projects, $200 billion for required additions, and more than $420 billion for maintenance and replacement costs.

Both the projected levels and the structure of future downstream investments are not substantially dissimilar to those presented in last year's WOO. However, some differences do exist. The current cost of existing projects is around $10 billion higher than last year's estimation, despite the fact that distillation capacity resulting from these projects is lower. An increase in costs comes from a higher level of investments in secondary processes, especially desulphurization and hydro-cracking. However, the additional requirements expected to balance the system, given supply and demand levels to 2030, are significantly lower this year, by around $100 billion, because of the lower demand projections. To some extent, the lower requirements for future expansion are compensated by an increase in replacement and maintenance unit costs.

It is also worth noting the distribution of direct investments — excluding annual replacements — by time period (Figure 8.3). This figure underlines the fact

Figure 8.3
Projected refinery direct investments by region*, 2008–2030



* *Excludes maintenance/replacement costs.*

that a good part of the required direct investments is already underway in the form of existing or scheduled projects that should be on-stream before 2015. After this period, investments are anticipated to slow down as demand increases are partially satisfied by surplus capacity. Additional investments will mainly be needed because of a demand reallocation from developed to developing countries, especially in the Asia-Pacific.

Required direct investments of around $350 billion for the period 2008–2030 could potentially be higher because of the new IMO regulations on marine bunker fuel quality specifications. Estimations of future investment requirements presented in this outlook are formed on basis of there being no shift in the current structure of bunkers fuel demand — from IFO grades to distillates — as well as no change in marine fuels regulations beyond 2012. This is because there remain a number of uncertainties related to this regulation. However, estimations made to assess the impact of these changes indicate that additional investments in the range of $50–$150 billion would be required by 2020 to comply with the IMO regulations. The actual figure will depend on the volumes of IFO to be converted and on the extent to which the underlying refining system is 'slack', with spare capacity, or 'tight'.

Chapter 9

Oil movements

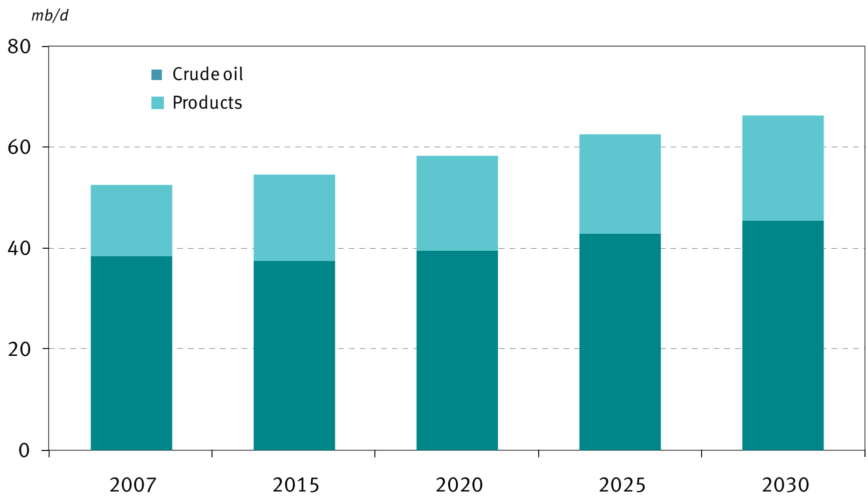
The outlooks contained in the 2007 and 2008 editions of the WOO projected that trade in crude oil and refined products would significantly increase in the future as a result of the growing gap between where oil is produced and where it is consumed. While this year's perspective restates the global trend towards growing volumes in oil trade, it is apparent that this is at a much slower pace than anticipated before the recent global economic slowdown. The current crisis has not removed regional distribution in oil supply and demand, but significantly lower demand levels in the future will lessen the volumes of both crude oil and oil products being moved between the major regions.

In addition to projected regional demand levels, another element impacting oil movement trends is the location of future refining capacity. The principles upon which the WORLD modelling system is constructed generally means locating additional required capacity in consuming regions, because of the lower transport costs for crude oil as opposed to oil products. This is unless construction costs for building the required capacity outweigh the advantage of transport costs. However, oil producing countries could increase their domestic refining capacity and benefit from the value-added through oil refining; this tendency is already being observed. Moreover, presented projections do not generally assume that crudes or products continue to move from one region to another because of ownership interests or term contracts. This means that oil gravitates to the regions where it is most efficiently used irrespective of ownership interests in crude production or in the refining capacity of importing regions.

Because of the above reasons, and due to the fact that oil is a fungible commodity traded globally, there is a great level of uncertainty associated with any projections about future movements. Therefore, the volumes of oil imports and exports presented in this outlook should be considered an indication of certain trends and future options for resolving regional supply and demand imbalances, rather than projections of specific movements.

As presented in Figure 9.1, oil trade[32] between 18 model regions as defined in Annex C will see a moderate change in the period to 2015, recording more than a 2 mb/d increase from 2007–2015, rising from 52.5 mb/d to 54.6 mb/d. The same period, however, will experience a shift in the structure of this trade as crude oil exports are expected to decline by almost 1 mb/d and the trade in oil products should increase

Figure 9.1
Inter-regional crude oil and products exports, 2007–2030



by 3 mb/d. This structural change in the medium-term is the result of several factors such as the increase in the Middle East's refining capacity; demand decline in Europe, the US & Canada and the OECD Pacific region, which makes refining capacity available for export; the growing non-crude supply; and the relatively stagnant production of crude oil.

In the period beyond 2015, oil trade will resume its growth, albeit at a lower rate than projected previously. By 2030, inter-regional trade increases by almost 12 mb/d, from 54.6 mb/d in 2015 to more than 66 mb/d by 2030. This compares to last year's WOO projection of 77 mb/d by 2030. Both crude and products exports will increase from 2015–2030, but crude exports will gain bigger volumes than products. By the end of the forecast period, both crude and products exports will be approximately 7 mb/d higher than in 2007. Combined together, the international trade in crude and products will represent around 63% of global oil supply, a ratio similar to the one in 2007.

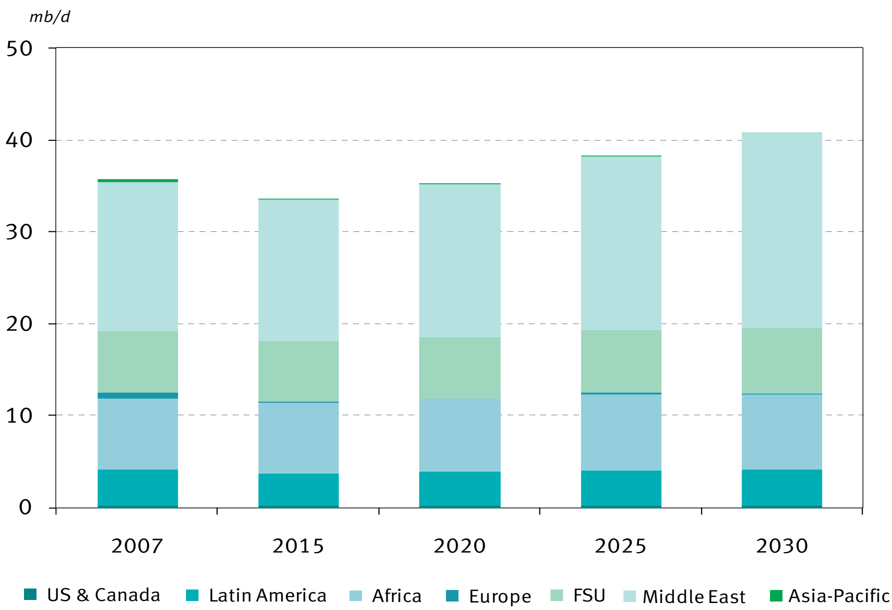
Crude oil

For the purpose of understanding the key trends in the movement of crude oil only the major seven regions have been considered. Since this eliminates some movements, for example, between sub-regions in the US & Canada, and intra-trade in Latin America, Africa and the Asia-Pacific, the total trade volumes are lower than reported earlier in this Chapter.

In the period to 2015, crude oil movements between the major regions are projected to decline by more than 2 mb/d, from almost 36 mb/d in 2007 to less than 34 mb/d by 2015 (Figure 9.2). Although the growth in global crude oil trade will resume around 2015, by 2020 the traded volumes will still be lower than they were in 2007, at 35.4 mb/d. Recent projections indicate that this volume could surpass 38 mb/d in 2025, and approach 41 mb/d by 2030. Thus, in terms of volume, the increases in crude movements are rather moderate, with a change more likely in trade direction than in total volume.

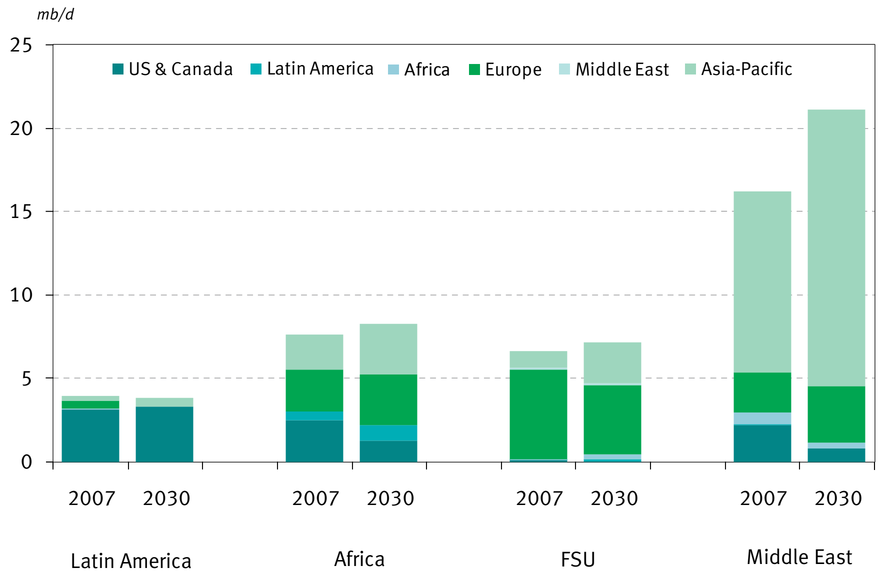
Figure 9.3 details the key changes in the flow of crude oil from the perspective of major exporters between 2007 and 2030. In line with the conclusions from last year's WOO, it underscores the future role of the Middle East as the major crude oil exporter, as well as the increasing share of Asia-Pacific imports from this region. The Asia-Pacific will also be the destination for an increasing percentage of exports from

Figure 9.2
Global crude oil exports by origin*, 2007–2030



* *Only trade between major regions is considered.*

Figure 9.3
Major crude exports by destination, 2007–2030

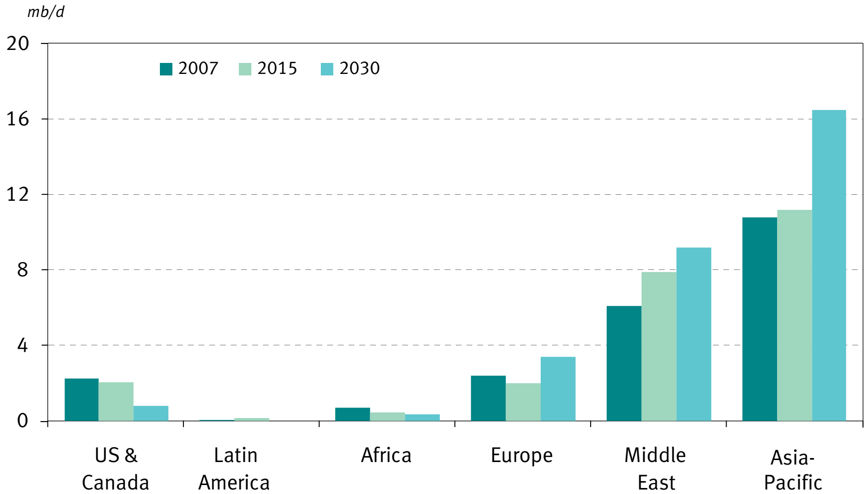


Africa and the FSU, with Russia likely to significantly enhance its crude exports to the region as new pipelines to China and Russia's east coast become operational over this period.

A further key observation is the prospect for a changing pattern of crude oil imports to Europe and the US & Canada. In the case of the US & Canada, a combination of lower demand, the expansion of non-crude supply and significant increases in Canadian synthetic crude production that offset declines in conventional crude, result in lower crude imports. Transportation economics indicate that the decline should come from the Middle East & Africa while imports from Latin America will stay comparable to current levels. In the case of Europe, crude imports will also decline, but only until around 2020. In the following ten years, European crude imports are expected to rise moderately, mainly to compensate for the domestic loss in crude supply. It is anticipated that these imports will mainly come from Russia and the Middle East & Africa, but with declining proportions from Russia.

The Middle East is already the key crude exporting region and its role in this respect will likely grow despite the foreseen lower crude exports in the medium-term. Total crude exports from this region are projected to stand at 16 mb/d in 2015, 17 mb/d in 2020 and above 21 mb/d in 2030. This compares to 16.3 mb/d in 2007.

Figure 9.4
Destination of Middle East crude oil exports and local supply, 2007–2030



As presented in Figure 9.4, the most important destination for Middle East crude oil exports in 2030 will be the Asia-Pacific, which accounts for almost 17 mb/d of these exports. It will remain the most dominant regional flow for the global trade in crude oil. Another important partner for the Middle East will be Europe with imports projected at 3.4 mb/d by 2030. If demand in the US & Canada on the one hand, and in Asia-Pacific on the other, develop as projected, then the model shows that Middle East crude exports will likely be more eastward oriented by 2030.

The growing share of the Asia-Pacific in global crude oil imports is clearly illustrated in Figure 9.5. By 2030, demand in the Asia-Pacific will increase by around 15 mb/d, compared to 2007. However, crude production will decline by more than 1 mb/d during the same period. Therefore, the growing gap between demand and the local production in these regions has to be filled by imports, primarily in the form of crude oil from all producing regions, mainly from the Middle East, as already underscored, and supplemented by Russian, Caspian, African and marginally crudes from the Americas (Figure 9.6). The four regions that make up the Asia-Pacific are projected to have total refinery crude inputs of more than 28 mb/d by 2030, out of which 23 mb/d will be covered by imports. The major trade partner will continue to be the Middle East, which satisfies almost 17 mb/d of Asian crude demand. Another two important partners will be Africa, with slightly above 3 mb/d of crude exports predominantly from West Africa, and the FSU region at around 2.5 mb/d.

Figure 9.5
Global crude oil imports by region, 2007–2030

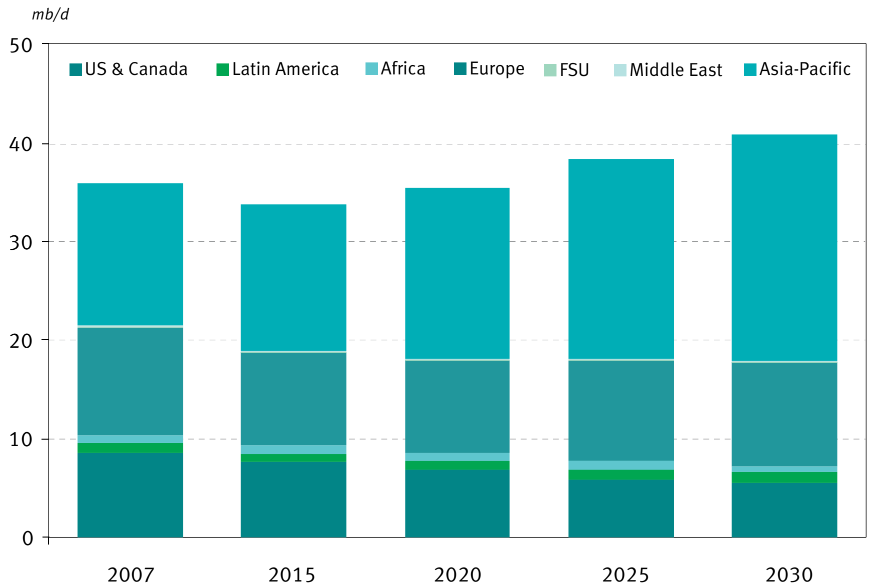
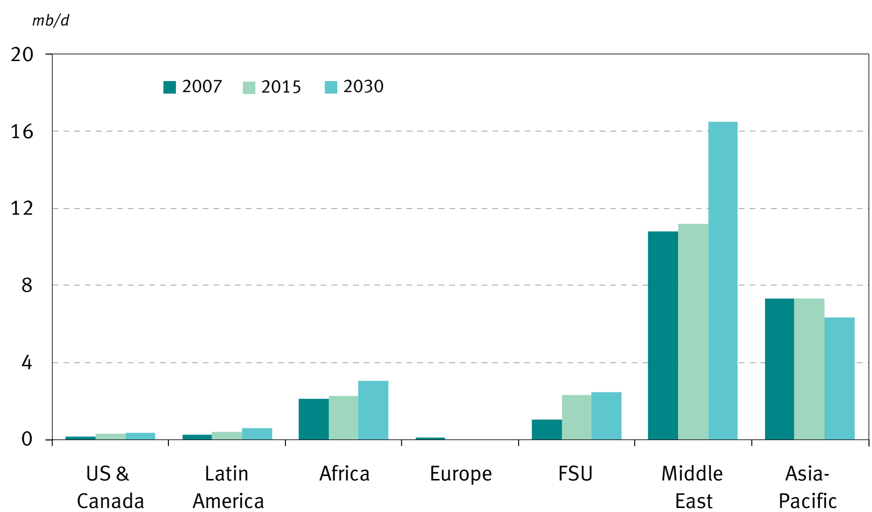


Figure 9.6
Asia-Pacific crude oil imports by origin and local supply, 2007–2030



Products

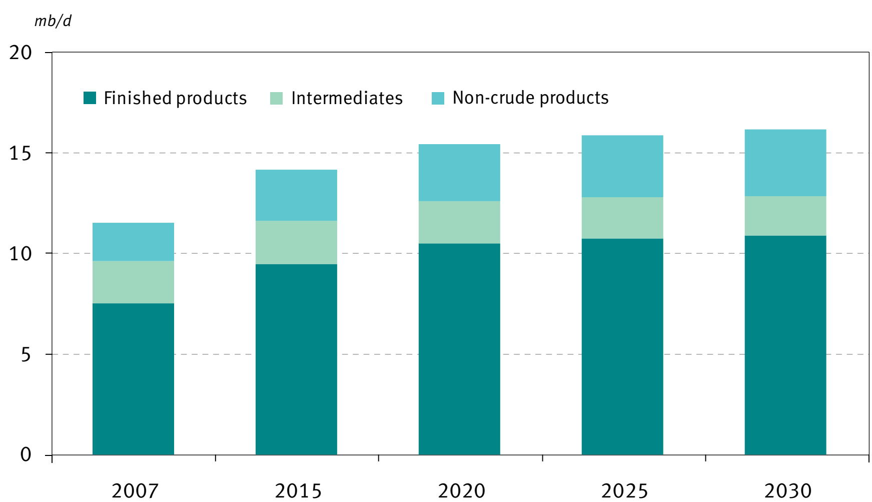
Product movements are an integral part of the downstream sector and are thus affected by issues discussed in previous Chapters, with the most important being:

– the growing volumes of non-crude based products;
– the growing demand for middle distillates worldwide;
– the growing demand for petrochemical naphtha, especially in the Asia-Pacific;
– the gasoline and diesel imbalance in the Atlantic basin;
– the expanding spare refining capacity in regions with falling demand, in particular the US & Canada and Europe; and
– the placement of future new refining capacity.

In a similar manner to the breakdown of crude oil movements, the analysis of product movements is also restricted to seven major regions, instead of the 18 model regions. In this case, the major inter-regional movements of liquid products rises to more than 16 mb/d by 2030, an increase of close to 5 mb/d compared to 2007 (Figure 9.7).

The first factor contributing to these rising volumes relates to the growing trade of non-crude based products that is driven primarily by the expanding production of

Figure 9.7
Global exports of liquid products, 2007–2030



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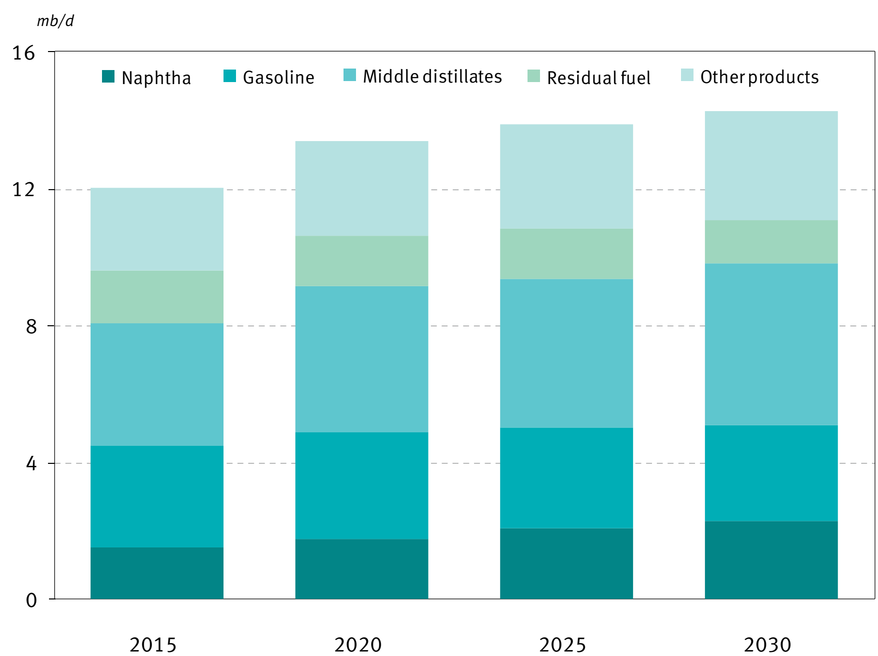
NGLs and related product output from natural gas plants. It is also supported by projected increases in GTLs production, especially in the long-term. The global increase in this category of liquid products is projected to be around 1.5 mb/d from 2007–2030.

Other factors, such as the expected trade expansion in middle distillates and naphtha are evident in Figure 9.8. The trade in both products is projected to increase by around 1 mb/d from 2015–2030. However, while imports of middle distillates are spread between the Asia-Pacific, Europe, Africa and Latin America, naphtha is almost entirely absorbed by the Asia-Pacific, driven by the rapid expansion of the petrochemical industry in China, India and several other countries in the region. Trade in gasoline and fuel oil should remain relatively stable in terms of volume, although the regional pattern of gasoline flows is likely to alter. There are two drivers supporting this move: the continued gasoline and diesel imbalance in the Atlantic basin and an increasing level of spare refining capacity in regions with falling demand, particularly the US & Canada and Europe.

In the Reference Case, these factors will lead to increased competition in the international gasoline markets as both regions, Europe and the US & Canada, face up

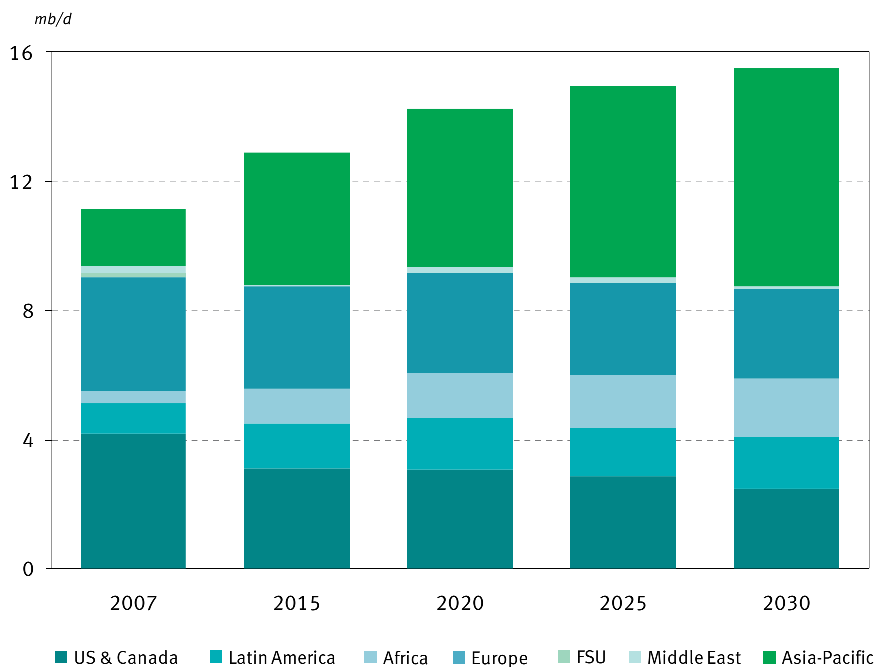
Figure 9.8
Global exports of finished products, 2007–2030



to the problem of a gasoline surplus due to their high installed gasoline production capacity, falling demand and increased ethanol supplies (see Box 7.2). Consequently, this is expected to depress gasoline prices and impact future refining capacity additions in regions where gasoline is projected to grow.

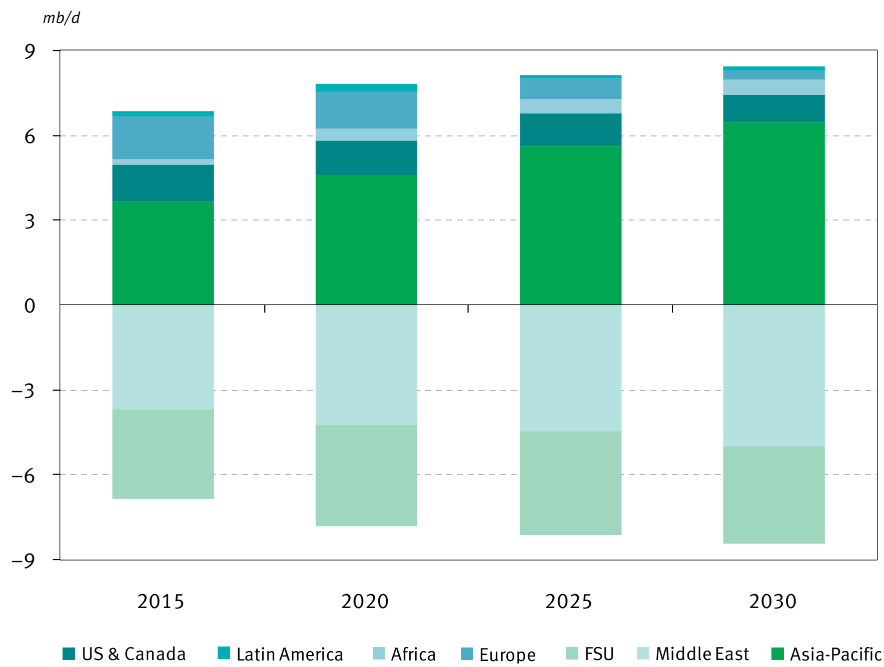
However, to what extent Europe and the US & Canada succeed in placing their gasoline surplus — as well as other products — in other regions depends heavily on the policies adopted in these other regions. For example, current model runs for the 2030 Reference Case show almost 3 mb/d of product imports into China, some 2 mb/d into the Rest of Asia region and almost 2 mb/d to Africa. If those countries and regions build more refining capacity than that projected, then this will further cut other region's refinery throughputs and utilizations. Obviously, there is a trade off, as when crude is shipped somewhere else and then processed, and then shipped again to its final destination, there is a lot of transport inefficiency versus shipping crude straight to refineries located in the place it finally ends up. On the one hand, this cost increase weighs against the cost of incremental refining in the final destination, and on the other, it raises various 'policy' questions.

Figure 9.9
Global products imports by region, 2007–2030



The regional pattern of product imports is depicted in Figure 9.9. It highlights several emerging trends. The most visible one depicts rising product imports to the Asia-Pacific, which reach almost 7 mb/d by 2030. These products are expected to be predominantly from the Middle East, which will then be a net exporter of 5 mb/d of products (Figure 9.10). The US & Canada will gradually reduce their product imports from around 4 mb/d in 2007 to 3 mb/d in 2020, and then further to about 2.5 mb/d in 2030. The net product imports of the region will also decrease correspondingly to less than 1 mb/d by 2030. A similar pattern of declining product imports is also expected in Europe. Over the period 2007–2030, the decline in net product imports is in the range of 1.5 mb/d. Elsewhere, growing product imports are projected for both Latin America and Africa where demand increases are faster than refining capacity additions. During the entire forecast period, only the FSU and the Middle East are projected to keep their status as net product exporters. FSU net exports will expand in the period to 2020, reaching a peak of 3.7 mb/d, and decline moderately thereafter as local demand reduces options for product exports. Thus, the only region expected to witness continuous growth in net product exports will be the Middle East, adding

Figure 9.10
Net imports of liquid products by region, 2015–2030



almost 3 mb/d to its net exports by 2030 compared to 2007 levels. In terms of total product exports, the Middle East is projected to export 5 mb/d of products by 2030. This compares to the 2.4 mb/d recorded in 2007.

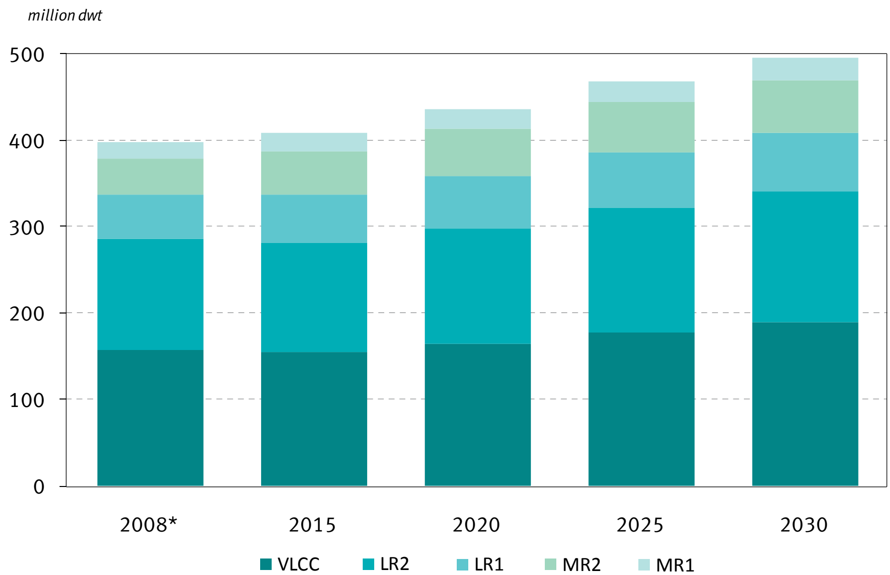
Tanker capacity requirements

Similar to the situation in the refining sector, the tanker market is also exposed to a combination of the fallout from current economic turmoil, stagnant demand for oil movements in the medium-term — even declining in the short-term — and a relatively large increase in tanker capacity over the next few years as a result of record order books. Longer term, however, the anticipated growth in the inter-regional trade in crude oil and refined products will necessitate increases in global tanker capacity. However, these increases are limited and, on an annual basis, lower than capacity increases experienced by the industry in the past few years.

Translated into numbers, projections show that the capacity of the global tanker fleet is expected to expand by almost 100 million deadweight tonnes (dwt) by 2030, reaching the level of 496 million dwt, from a global capacity of 398 million dwt at the end of 2008 (Figure 9.11).[33] However, only 11 million dwt of new capacity will be required for the period to 2015, despite the fact that the order book for this period is full, a situation that is discussed in more detail later. For the entire forecast period, the required average growth for global tanker capacity is close to 1% p.a., which is marginally lower than the projected demand growth. The main thrust of this growth comes from the substantial expansion in imports to the Asia-Pacific. On the flip side, the declining trend for imports to the US & Canada and Europe, as well as increasing local demand in Latin America, the FSU and the Middle East, somewhat negates overall global growth.

With the exception of a temporary decline in capacity requirements for large crude carriers — Very Large Crude Carriers (VLCC) and Large Range 2 (LR2) vessels — in the period to 2015, the WOO 2009 indicates that all tanker categories will grow, but at varying rates. By 2030, in terms of tonnage, the largest increase is actually expected in the category of VLCCs, which expand by more than 31 million dwt compared to 2008. Global capacity of LR2 tankers is also projected to grow, witnessing an increase of 23 million dwt over the same period. It should be noted, however, that these expansions are primarily for the later part of the forecast period, after 2015, when crude exports are expected to resume their growth. The fastest growing categories will be the Large Range 1 (LR1) and Medium Range 2 (MR2) tankers, which is consistent with the notion, as discussed earlier, that products exports will grow faster than crude exports. The average annual growth rates for these categories from 2008–2030 are 1.7% and 1.4% respectively, significantly higher than those for crude carriers. In addition, Medium Range 1 (MR1) tankers are also assumed to grow at 1.4% p.a.[34]

Figure 9.11
Outlook for tanker capacity requirements by category, 2008–2030



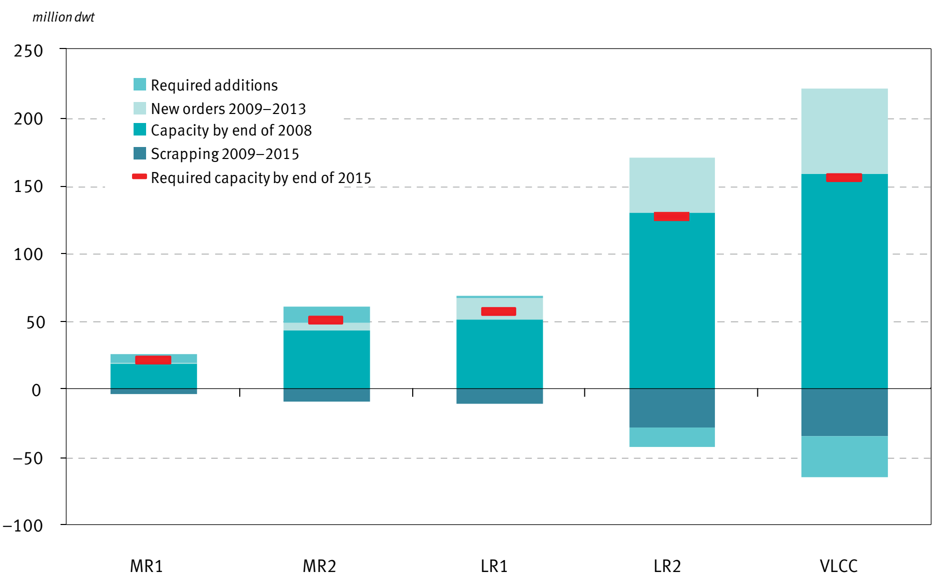
* *Data for 2008 represents existing tanker fleet capacity at the end of the year.*

Despite the fact that this year's numbers see a generally lower future tonnage required, the conclusion drawn last year that in respect to refined products the likely shift will be from MR2 to LR1 class vessels, with crude increasingly transported by VLCCs, still holds.

Turning to the medium-term outlook, an overview of the global situation is presented in Figure 9.12. What is striking is that there is an exceptionally high level of new tanker orders for the period. In total, order books show that around 125 million dwt of tanker capacity has been ordered for the years 2009–2013. Around half of this new tonnage, 62 million dwt, will be for VLCCs. Significant additions are also foreseen for LR2 vessels, around 40 million dwt, and another 16 million dwt is for LR1 tankers. This is a continuation of the substantial capacity expansion experienced during 2008 when around 350 new tankers entered the market, representing around 34 million dwt of additional capacity. Out of this, more than 21 million dwt were for the crude market and 13 million dwt for product movements, some of them as part of the phasing out of single hull tankers to comply with IMO legislation. This move was also evident in the higher rate of demolitions, compared to previous years, which removed more than 14 million dwt from the market.

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 have a capacity excess of around 25 million dwt by 2015, if all tankers already ordered are built. This outlook also underscores a distinct contrast between the larger and smaller tanker classes. A capacity surplus of more than 40 million dwt is projected for the VLCC and LR2 tanker categories combined. This is illustrated as negative requirements for capacity additions in Figure 9.12. Conversely, smaller tankers for product movements will require additions of around 20 million dwt beyond the existing known orders for this period. These required additions are predominantly in the categories of MR2, LR1 and MR1 tankers. The expected excess in large tanker capacity raises the question of whether there will be cancellations in new tanker orders; especially for those with delivery dates at the end of the order period. WOO 2009 projections suggest that around 20% of the existing tanker order book is vulnerable to cancellation. This is the level that would bring the market back into a more balanced situation, with freight rates likely restored to reasonable levels.

Figure 9.12
Tanker fleet capacities and requirements, 2008–2015



Chapter 9

Chapter 10
Downstream challenges

This Chapter brings together the key findings for the refining sector that result from the trends outlined in the outlook, and reviews the implications for the industry and the challenges it may face over the medium- to long-term.

Changing downstream fundamentals

Last year's WOO painted a medium-term picture where assessed project additions, demand growth and an increase in biofuels supplies underlined the prospect for a continuation in the trend toward tighter distillate and slacker gasoline markets, resulting in a growing gasoline and diesel imbalance, and the emergence of an easing in refinery utilizations, particularly in the Atlantic basin.

It is evident that this situation remains present in this year's outlook, but it is palpable that this picture has now been somewhat overshadowed by the impacts of the current global economic crisis. This year's analysis grapples with, and attempts to assess, the impacts to the downstream industry of a massive downward revision to oil demand. In 2009, global demand in the Reference Case is projected to be 84.2 mb/d, which is almost 2 mb/d lower than 2007. In 2015, the demand level is now projected to be 90.2 mb/d, which is 6 mb/d below last year's 2015 figure. And this trend continues to the long-term with this year's demand projection for 2030 set at 105.6 mb/d, much lower than last year's figure of 113.2 mb/d.

What is happening today, and what is projected to happen over the next few years is, in many ways, the inverse of what happened to the refining industry in the early part of this decade. In the period 2002–2006, the refining sector was in many respects caught unprepared by a combination of factors that led to significant market tightness. These included: an historical lack of refining investment and low margins; a sudden surge in global demand, notably from 2004; demand increases predominantly skewed towards lighter and cleaner products; and stable crude slates, including heavy crude supplies not declining.

Today and over the next few years, it is evident that other 'opposite' factors are expected to be the main industry drivers. Firstly, demand growth has obviously been replaced by a severe demand decline. Just as the 2002–2006 period did, the decline emphasizes the changing demand for light clean products, but this time down, not up. In other words, current indications and projections highlight that it is demand for gasoline, jet fuel and naphtha that are being most severely hit.

At the same time, however, the industry is entering a period where the quality of global supply is becoming lighter. This is driven largely by the rising supply of NGLs and condensates, as well as medium to light crudes, which then combine with declines in certain heavy crudes, such as Mexican Maya. Moreover, despite biofuels having some serious questions raised about its economic and environmental credentials over the past year or so, its supply, most notably ethanol, has increased. At the same time, the industry has a range of major capacity additions that either have recently come on-stream, for example, with Reliance and Essar in India, and the Sinopec-led project in Fujian, China, or are under construction and therefore projected to be on-stream within the next 2–3 years. Moreover, the ratio of secondary upgrading — FCC, coking and hydro-cracking — to crude distillation capacity is high, and this again coincides with a period when light products are seeing the largest demand reductions.

The secondary additions are led by increases in hydro-cracking capacity. This looks likely to be used for sustained high utilizations because of the underlying long-term growth in distillate fuels – and the potential for marine fuels regulations to reinforce this. In contrast, coking and FCC capacity additions are continuing in a period when heavy crude supplies, such as from Mexico, and/or projected oil sands growth in Canada are being cut, and thus there is less available coker feedstock. The likely result will be a growing coking surplus. As for FCC capacity, there are regions of the world where additional units are arguably necessary to meet local needs. Globally, however, crude unit, FCC and coking expansions are raising the capabilities for gasoline production at the very same time that gasoline demand is dropping in the US, the world's largest gasoline consuming economy, and in Europe, where the shift to diesel is expected to continue.

The analysis indicates that the mechanism operating in the refining sector to balance naphtha/gasoline supply and demand under these circumstances is one that is viewed as a departure from the 'norm'. Growing NGLs, condensate and ethanol supplies bring additional naphtha/gasoline streams into the supply network. There is potentially some flexibility to raise petrochemical naphtha demand, but this is limited.[35] In general, the petrochemical sector has arguably been hit earlier, and harder, by the economic crisis, than demand for other fuels. Hence, the recent existence of naphtha prices well below that for crude. Once demand for petrochemical naphtha is filled, there are only two places for the naphtha/gasoline streams to go. The first is for gasoline. And the second is for usage as a fuel, for example, in refinery fuel or potentially external fuel uses such as those in the industry and power sectors. However, the impact of such a shift is likely to remain limited. Thus the naphtha/gasoline streams are anticipated to predominantly move to gasoline.

Faced with this, the most likely way for refineries to react is by reducing the volumes of gasoline streams coming from secondary processing, such as those from FCC and coking units. This mechanism then contributes to severe reductions in FCC and coking utilizations as they bear the brunt of being the 'swing' gasoline production units. Other gasoline units, however, benefit. Catalytic reformer utilizations remain high since they convey a triple benefit. They raise naphtha octane so that it can be more readily blended into gasoline. They cut naphtha volumes since the reformate volume yield is less than 100% and they also produce hydrogen. Isomerization units also benefit since they too raise naphtha octane.

The net effect of these major demand, supply, capacity and operational shifts is clear. The economic crisis and associated demand loss is turning what would otherwise have likely been a moderate and fairly typical cyclical refining downturn, into a far more severe downturn with major and prolonged surpluses.

The sustained nature of the challenges facing the refining sector is reflected in the projected continuation of weak, even declining gasoline margins relative to crude, in protracted negative naphtha margins and in sustained distillate premiums, throughout the period to 2030. The WOO 2009, however, interprets these more as a signal of a trend, rather than what will necessarily happen. It should be recognized that such strained margins and refining imbalances for a short period will probably have a limited impact on the industry, but if sustained for a longer period they raise the prospect that something will occur to redress them. With this in mind, there are several developments that could potentially influence and modify the situation.

A first and obvious implication is that the excess refining capacity and excess gasoline output capability will lead to closures, especially of refineries that are gasoline oriented, as already discussed in Chapter 6. Secondly, the projected differentials raise the question of how demand will react. Increased demand for naphtha as a fuel would absorb volume, but it would also sustain depressed prices because of naphtha's then low fuel value. The relative weakness in gasoline prices could — or should when considering price elasticities — encourage incremental gasoline demand, particularly at the expense of diesel with its comparatively high prices. However, both gasoline and distillate prices are driven first and foremost by the crude price and, more importantly, taxes. Arguably, sustained crude prices as assumed in this outlook should be sufficient to encourage consumers to buy fuel efficient vehicles. Moreover, legislation, as now enacted in the US, with stricter CAFE standards, as well as in Europe, with pending tightened vehicle CO_2 emission standards, and potentially elsewhere, is likely to restrain the potential for a resurgence in gasoline demand.

There are signs that new car sales in Europe are shifting modestly back toward gasoline powered vehicles, away from diesel. However, it should be noted that the older vehicles being retired are almost entirely gasoline. And current and prospective incentives to take old cars off the road in both Europe and the US will predominantly remove the least efficient gasoline vehicles. On the other hand, diesel consumption is more closely related to economic growth, being tied much more tightly to such areas as trade and construction, than to personal use. This explains why diesel demand has been hit hard in the current economic downturn. Nevertheless, it also means that diesel can be expected to be the main engine of demand growth when economic growth is restored.

Another important question raised by this year's analysis relates to refinery process technology. It is evident that the naphtha/gasoline and diesel differentials that are apparent in this year's results present incentives for adaptations and new developments in refinery processes and catalysts.

Fundamentally, the price differential projections are highlighting the fact there is too much naphtha/gasoline and too little diesel. It points to an incentive to convert from the former to the latter. The first and most obvious way to address the imbalance is through a revision of FCC operations. One option to achieve this is through the introduction of FCC 'high distillate yield' modes. These represent proven technology and reportedly many refiners are now adapting their FCC units to yield less gasoline and more distillate, as well as propylene, since that is a growth product. There is also a trend towards a rising proportion of resid in FCC feed. The driver for this is twofold. Firstly, vacuum gasoil is being pulled away to hydrocrackers, reducing its availability as an FCC feedstock and, secondly, residual feeds yield higher proportions of cycle oil. FCC adaptation is, however, only a partial answer. Yields today can only be switched partially to distillate and the resulting cycle oil requires further processing, via either desulphurization or hydro-cracking, to produce high quality diesel stocks.

A second route is to convert naphtha (or C_3, C_4 streams) more directly to diesel. Processes exist to polymerize or oligomerize C_3, C_4 or potentially C_5 light olefins to diesel boiling range streams. The light olefins could come from the FCC, from the coker or from the steam cracking of naphtha. Existing polymerization units, however, have a number of disadvantages, including a difficult to manage solid catalyst and a poor quality distillate product that requires further processing. New process variants are reported to use zeolite catalysts and the claimed advantages of this include a higher quality diesel product. This route may therefore open up the prospect to consume naphtha and NGL streams, plus coker and FCC light olefins, in order to generate more diesel. Steam cracking represents a potentially high cost route, but it may be justified by the large price differentials — potentially up to $30/b — indicated by the projections. It may also be particularly attractive where refineries are integrated with steam cracking petrochemicals facilities. Nevertheless, for the widespread use of this technology, the costs need to be significantly reduced. In such a case, the introduction of these or equivalent technologies into refineries would move naphtha, gasoline and diesel prices back closer together – towards the historically smaller differentials that existed until last year.

Potential consequences for refinery projects, capacity and closure

The refining industry has just experienced its largest ever demand drop, and driven by lower future demand growth and the rising supply of non-crudes, future prospects do not point to a return to anything approaching previously expected capacity requirements. The 2015 reference case in last year's study projected a worldwide average refinery utilization level of 84.4%. In contrast, this year's Reference Case sees a global average refinery utilization in 2015 of 76.6%. Last year's projection of the 2015 worldwide crude unit throughput was 79.6 mb/d; in this year's Reference Case, however, it is lower by more than7 mb/d, at 72.4 mb/d. This consists of 6 mb/d due to lower demand and more than 1 mb/d as a result of the higher supply of non-crude streams.

The implication is for a seriously depressed period for refineries, especially those focused on gasoline. The projected very low utilizations, especially in OECD regions, indicate the need for widespread consolidation and closures to restore operating rates and refinery viability. As presented in Chapter 7, this year's analysis indicates that closures of the order of 7–10 mb/d will be needed, predominantly in the US & Canada and Europe, to bring global refinery utilizations back to the range of 80–85%, and in turn, restore refining viability.

An underlying premise in the current outlook is that much of the cost increase that has been sustained recently will be maintained throughout the forecast period. Specifically, a refinery capital cost escalation of 60% over the 2000 base level was assumed for 2015, and the subsequent years to 2030. It is evident, however, that costs are now falling back from their 2008 peaks that implied an 80% increase over the 2000 base level and this is leading a number of companies to request revised bids and in some instances delay projects. It underlines the uncertainty surrounding the trajectory of capital costs and lead times and this will clearly impact the scale and timing of refining investment decisions. Recognizing that there are well over 30 mb/d of announced projects today, a further slide in construction costs could encourage more projects to go ahead. If this happens, it could arguably exacerbate the global surplus capacity by 2020. On the other hand, while cost reductions could act to encourage projects, the current extremely difficult financing environment is also likely to constrain, or eliminate a number of projects.

Even if the 2015 this year's projected Reference Case proves to be overly pessimistic, it is difficult to escape the conclusion that the refining industry is passing through a step change of historic proportions. It is entering a period of acute challenges, and one which calls for substantial closures to restore the industry's balance and viable economics. Within this, the ongoing shift to larger refineries puts increasing pressure on smaller and even medium-scale refineries, especially those that do not possess a competitive advantage or some form of protection. Factors that will help keep such refineries viable include: location in an inland market where competition is less demanding; the production of specialty products; integration with petrochemicals or other company assets; high standards of operating efficiency; the ability to produce transport fuels to advanced standards, notably ultra-low sulphur, Euro V or equivalent; and the ability to produce high distillate yields. Conversely, the absence of such favourable factors will render refineries vulnerable.

The outlook is not uniform worldwide. In particular, there is a marked contrast between the Atlantic and Pacific basins. The former, dominated by the US and Europe, is characterized by flat to negative growth, hence a capacity surplus, essentially no distillation capacity net additions, and by a sustained gasoline/diesel imbalance. Conversely, the Pacific basin — the OECD Pacific aside — increasingly dominates demand and capacity growth. The Asia-Pacific is projected to command 47% of all capacity additions to 2020, beyond the 2008 base, and 57% from 2008 to 2030. The Middle East sees the next largest additions comprising respectively, 22% and 18% over the two timeframes.

Driven in part by local demand reduction and imbalances, and in part by the co-product nature of refining — the need to produce less profitable gasoline, naphtha and residual fuel in order to produce profitable distillates — refineries in the US & Canada and Europe can be expected to increasingly look for export markets, particularly for gasoline. And in turn, the reduced netback available for that gasoline is clearly a factor contributing to the sustained poor gasoline margins foreseen in this outlook.

Future absolute crude price levels will play a role in either increasing or alleviating the pressure on refineries. Crude prices at the level assumed in this outlook may help some larger, more efficient gasoline oriented refineries to stay viable on a cash basis, particularly if their capital cost is significantly depreciated. Periods of low prices, will increase the pressure on weaker refineries to close.

Coal and natural gas prices, relative to crude, will also influence future refining economics. A lower price for natural gas, relative to crude, will tend to make hydrogen addition processes, such as hydro-cracking, more valuable. Conversely, delayed coking particularly, which operates via carbon rejection, can be disadvantaged depending in part on the level of petroleum coke prices. These are closely linked to coal prices. A common view is that coal prices may well not maintain British thermal unit (Btu) parity with crude, in part because of actual or expected carbon regimes. This then makes coking less attractive. The prices contained in the WOO 2009 for both natural gas and coal were below Btu parity with crude oil. Thus they reinforce the trend away from coking and FCC, toward hydro-cracking. The interplay of crude oil, natural gas and coal prices will be an important factor in driving refining economics in the years to come.

Moreover, as also stated in last year's publication, driven by diesel demand, European refineries are undertaking a range of hydro-cracker projects. These will increase the region's ability to produce distillates, but arguably means that the region is reaching the limits of its ability to produce more domestic diesel. This regional and global trend toward distillate demand and the relatively high costs of gearing installed capacity toward maximum distillate production will continue to support distillate prices. It is distillate — more so than gasoline prices — that will increasingly set refining margins and drive differentials.

Potential for carbon regimes

Above and beyond what has happened over the past year, refiners could also face a further future reduction in demand, as well as higher operating and capital costs, as a result of emerging carbon regimes. Moreover, they will likely result in significant changes in the relative attractiveness of different refining modes and crude oil feedstocks.

In the US, the new Administration and the Congress are currently moving forward on new carbon and climate change legislation. While this may take some time to come to fruition, it is widely believed that some form of US carbon regime is now more about when, than if. At the state-level, in California, following a state executive order, the California Air Resources Board (CARB) released proposed regulations for a Low Carbon Fuel Standard in April 2009. This aims to reduce transportation fuel emissions by 10% in 2020. In addition, in April 2009, the EPA published findings that greenhouse gases from new vehicles and industrial plants pose a danger to the public, kicking off a process that will likely result in the tighter regulation of CO_2 emissions. The EPA's findings come two years after the US Supreme Court ordered the agency to determine whether these emissions contribute to harmful air pollution, under the Clean Air Act, or whether the science is too uncertain. The EPA's move sets the stage for the agency to revisit the auto industry's fuel economy standards, as well as set emissions standards for plants, including refineries.

It should also be noted that a series of US Federal bills have been in existence for some time. Some contain a provision that would take carbon concerns all the way back to the production of each stream of crude oil, which is already implicitly contained in the EISA of 2007. In a manner analogous to EU proposals, the federal Low Carbon Fuel Standards would be enacted to reduce the carbon intensity of transport and potentially other fuels. In terms of conventional processing though, the provisions for lifecycle greenhouse gas emissions call for refiners to demonstrate carbon intensity reductions through 'life cycle analysis' methods. This means defining and allocating the carbon emissions associated not only with the production of the fuel from crude oil in the refinery, but also back through the supply chain, encompassing the production and transportation of the crude oil, and in the case of syncrudes, their upgrading. Under this scheme, understandably, the most energy and hydrogen intensive processes, such as hydro-cracking, desulphurization and hydrogen production, would be the ones most impacted. In terms of refinery types, deep conversion refineries processing heavy sour crude oils would be the most adversely affected in regards of throughput losses.

In March 2009, the EPA issued a proposed Mandatory Reporting Rule on CO_2 emissions. Under this rule, organizations emitting more than 25,000 tonnes per year of CO_2 must report their emissions. The rule includes petroleum refineries, suppliers of fossil fuels, chemical manufacturers, vehicle and engine manufacturers and others. It calls for the first annual reports for the year 2010, to be filed in March 2011. The rule replaces a voluntary reporting system.

The new scheme clearly lays the groundwork and is a necessary prerequisite for a carbon regime wherein CO_2 will have a cost. The carbon content of a fuel therefore now becomes a critical matter. Reflecting this, the EPA has issued tasks to develop accurate and finely distinguished carbon contents across the range of fuels. Standardized testing methods will therefore need to be agreed upon for determining the CO_2 content of such products as gasolines, jet fuels, diesel and residual fuels. It means that the testing for and reporting of the CO_2 content of fuels will become an integral element of refining and supply. Generally, domestic US refiners and blenders will have the obligation to establish and report the carbon content of almost all their products, as well as for NGLs and petroleum intermediate stream feedstocks. Critically, this rule impacts all suppliers of crude oils, NGLs, intermediate feedstocks and finished products within, and to the US. This underlines that the reporting includes both importers and exporters, as well as domestic suppliers.

In Europe, carbon costs are also expected to play an increasingly greater role, with existing and future EU directives likely to lead to stricter carbon emission standards for transport vehicles, as well as for industry plants, including refineries.

Since January 2005, the EU ETS has been in operation. The 'cap and trade' scheme, which then covered around 10,000 large installations in the EU, was set up to enable companies that exceed individual CO_2 emissions targets to buy allowances from others that emit less than their designated allowance. The first phase, however, was beset with problems, particularly the fact that pollution credits were over allocated by several countries during the initial implementation phase, forcing carbon prices to fall, and to some extent undermining the scheme's credibility.

The second phase (2008–2012) has been extended to cover several greenhouse gases, not just CO_2, as well as more major industrial emitters. It has also been described in some quarters as being 'tougher', although criticisms in some quarters remain. This includes the expectation that a number of companies will continue to benefit from 'windfall' profits, particularly those in countries that have a high level pass-through of CO_2 costs into wholesale power prices, and those countries that have significant levels of free allowances for the power sector.

For the period beyond the second phase, the Council of the EU adopted in April 2009 'the climate-energy legislative package' that includes provisions for a revised ETS effective 1 January 2013. From this date, it is proposed that heavy industry, including refining, will contribute significantly to the EU's overall target of cutting greenhouse gas emissions. Based on this legislation, emissions permits will no longer be given to industry for free. They will be auctioned by member states from 2013 onwards. ETS sectors must start by purchasing 20% of their emissions permits at auctions in 2013. That rate will rise gradually to 70% in 2020, with a view to reaching 100% by 2027.

To date, however, no final decisions have been made detailing the implementation mechanism. Nevertheless, this is evidently another element of uncertainty for refiners, and one the downstream sector needs to continually monitor.

The EU climate and energy package also includes a regulation for CO_2 emissions from new passenger cars applicable as of 2012, as described in Section One. The goal of this provision to reduce the average emissions for new cars to 120 g CO_2/km by 2015 and potentially moving as low as 95 g CO_2/km by 2020 will have significant implications for the refining industry in Europe and globally.

Australia has also recently looked to implement a 'Carbon Pollution Reduction Scheme' that also focuses on a cap and trade carbon-emissions trading system. The development was initially slated to come on-line in mid-2010, but in May this year the government, in proposing a new draft for the scheme, moved the date back to mid-2011. The global recession was cited as the reason for the delay, and in addition, the new draft proposed a number of further measures to "assist businesses during these difficult times". This included a one year fixed price period with permits costing $10 per tonne of carbon in 2011–12, with the transition to full market trading from 1 July 2012, and increased eligibility for free emissions permits. It also highlighted a commitment to reduce carbon pollution by 25 per cent below 2000 levels by 2020 if the world agrees to an ambitious global deal to stabilize levels of CO_2 equivalent in the atmosphere at 450 ppm or lower.

Recognizing the final form and timing of carbon regime legislations remains an uncertainty, but their impact will certainly impose further challenges to refining on top of those it already faces as a result of the current economic crisis.

Footnotes

1. See, for example, OECD Economic Outlook, Interim Report, March 2009, and World Economic Outlook, International Monetary Fund, April 2009.

2. The low and high variants assume respectively lower and higher fertility rates of 0.5 children per woman.

3. This takes into account the assumed need to also provide a small additional amount of oil for stocks.

4. The Bali Action Plan was agreed upon at the 2007 UNFCCC Conference on the island of Bali, Indonesia, charting the negotiation process designed to adopt a decision at the Copenhagen COP meeting in December 2009 on how to implement the Framework Convention.

5. See Transportation Energy Data Book: edition 27-2008, US Department of Energy. Available at http://cta.ornl.gov/data/Index.shtml.

6. Source: International Organization of Motor Vehicle Manufacturers. Available at www.oica.net.

7. Ibid.

8. See 'Momentum: KPMG's Global Auto Executive Survey 2009 – Industry concerns and expectations 2009-2013', KPMG International, 2009.

9. In May 2009, US President Obama announced a proposal to introduce similar efficiency standards, but even sooner, reaching 35.5 miles per gallon by 2016. This would impact demand even more than the Reference Case assumes.

10. International Civil Aviation Organisation, submission to the third session of the Ad Hoc Working Group on Long-Term Cooperative Action under the Convention, Accra, Ghana, August 2008.

11. 'Access to Energy and Human Development', Amie Gaye, United Nations Development Programme (UNDP), Human Development Report Office, 2007. Available at http://hdr.undp.org/en/reports/global/hdr2007-2008/papers/Gaye_Amie.pdf.

12. See 'Crude Oil: Forecast, Markets and Pipeline Expansions', Canadian Association of Petroleum Producers, June 2009.

13. The current carbon tax imposed by the Alberta government on oil sands producers, as well as other producers, is around \$15 per ton of CO_2 emitted. This tax applies

to emissions above 88% of those producers' historical per-barrel average. (See 'Alberta's 2008 Climate Change Strategy', Edmonton, Alberta: Government of Alberta, 2008).

14. UN Environment Programme (UNEP), 'Global Trends in Sustainable Energy Investment 2009'.

15. See Monthly Oil Market Report, June 2009, OPEC. Available at www.opec.org.

16. OPEC Long-Term Strategy, 2006, OPEC. Available at www.opec.org.

17. 'Global Economic Policies and Prospects', note by the Staff of the International Monetary Fund prepared for the Group of Twenty Meeting of the Ministers and Central Bank Governors, 13–14 March 2009, London, UK. Available at http://www.imf.org/external/np/g20/pdf/031909a.pdf.

18. 'The State of Public Finances: Outlook and Medium-Term Policies After the 2008 Crisis', Fiscal Affairs Department, International Monetary Fund, 6 March 2009. Available at: http://www.imf.org/external/np/pp/eng/2009/030609.pdf.

19. See, for example: 'The investment challenge' Bassam Fattouh and Robert Mabro, in 'Oil in the 21st Century: Issues, Challenges and Opportunities', ed. Robert Mabro, OPEC, 2005.

20. Financial Regulatory Reform: A New Foundation, US Treasury Department. Available at http://www.financialstability.gov/docs/regs/FinalReport_web.pdf.

21. 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.

22. IHS CERA Special Fourth Quarter 2008 Market Update, January 2009.

23. Oil & Gas Journal, Volume 107, Issue 17, 4 May 2009.

24. International Oil Daily, 12 March 2009.

25. Hart's Refinery Tracker, January 2009.

26. Calculated as 90% of incremental distillation capacity additions.

27. Volumes of acidic 'high TAN' (total acid number) crudes are growing. These require additional pre-treating and/or processing in crude units with either the metallurgy or the additives to counter the acid's corrosive effects.

28. Projections on fuel product specifications are mainly based on the HART World Refining & Fuel Services and International Fuel Quality Center (IFQC).

29. Renewable Fuel Standard Requirements for 2006: Direct Final Rule and Notice of Proposed Rulemaking, published by EPA on 30 December 2005, adopting the default standard for renewable fuel as set forth in the Energy Policy Act of 2005.

30. See also EU-OPEC joint study on refining: EU Petroleum Market Study prepared for European Commission by Purvin & Gertz, November 2007.

31. Excise duties on gas oil, IP/07/316, Brussels, 13 March 2007.

32. Oil here includes crude oil, refined products, intermediates and non-crude based products.

33. All projections presented in this section are indicative only and they represent the minimum required capacity for a given time horizon as they are the result of an optimization process.

34. 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.

35. For instance, new steam cracker projects in the Middle East are understood to use ethane and butane as feedstocks rather than naphtha.

Annex A

Abbreviations

ANWR	Arctic National Wildlife Reserve
AOSP	Athabasca Oil Sands Project
API	American Petroleum Institute
AR4	(IPCC) Fourth Assessment Report
AWG-LCA	Ad Hoc Working Group on Long-Term Cooperative Action
b/d	Barrels per day
BEV	Battery electric vehicle
boe	Barrels of oil equivalent
CAFE	Corporate Automobile Fuel Efficiency
CARB	California Air Resources Board
CBOT	Chicago Board of Trade
CCS	Carbon capture and storage
CD	Charge depleting
CO_2	Carbon dioxide
CO_2-eq	Carbon dioxide equivalent
CTLs	Coal-to-liquids
DCs	Developing countries
DOE/EIA	(US) Department of Energy/Energy Information Administration
dwt	Deadweight tonnes
ECA	Emission control areas
EISA	(US) Energy Independence and Security Act
EOR	Enhanced Oil Recovery
EU	European Union
EU ETS	EU Emissions Trading Scheme
E&P	Exploration and production
FCC	Fluid catalytic cracking
FSU	Former Soviet Union
GDP	Gross domestic product
GHG	Greenhouse gas
GTLs	Gas-to-liquids
GW	Gigawatt
HEV	Hybrid electric vehicle
IEA	International Energy Agency

IEFS	International Energy Forum Secretariat
IFO	Intermediate fuel oil
IFQC	International Fuel Quality Centre
IMF	International Monetary Fund
IMO	International Maritime Organization
IOC	International Oil Company
IPCC	Intergovernmental Panel on Climate Change
IRF	International Road Federation
Li-on	Lithium-ion
Li_2CO_3	Lithium carbonate
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
mb/d	Million barrels per day
MEPC	Marine Environmental Protection Committee
MOMR	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
NGLs	Natural gas liquids
NiMH	Nickel-metal hydride
NOC	National Oil Company
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
OWEM	OPEC's World Energy Model
p.a.	Per annum
PHEV	Plug-in hybrid electric vehicle
ppm	Parts per million
PPP	Purchasing power parity

QELROs	Quantitative emissions limitations or reductions objectives
R&D	Research and development
RFS	Renewable Fuels Standard
R/P	Reserves-to-production (ratio)
SUV	Sports utility vehicle
TAN	Total acid number
TAR	(IPCC) Third Assessment Report
toe	Tons of oil equivalent
UHBR	Ultra-high by-pass ratio
UN	United Nations
UNDESA	United Nations Department of Economic and Social Affairs
UNFCCC	United Nations Framework Convention on Climate Change
URR	Ultimately recoverable reserves
USABC	United States Advanced Battery Consortium
USGS	United States Geological Survey
VGO	Vacuum gasoil
VLCC	Very large crude carrier (160,000 dwt and above)
WCBS	Western Canadian Sedimentary Basin
WOO	World Oil Outlook
WORLD	World Oil Refining Logistics Demand Model
WTI	West Texas Intermediate

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

BP Statistical Review of World Energy

Cedigaz

Direct Communications to the Secretariat

Economist Intelligence Unit online database

ENI, World Oil and Gas Review

Energy Intelligence Research, The Almanac of Russian and Caspian Petroleum

EnSys Energy & Systems, Inc

Hart Downstream Energy Services, World Refining and Fuels Service

Hart Downstream Energy Services, Refinery Tracker

IEA, Quarterly Energy Prices & Taxes

IHS/Cambridge Energy Research Associates

IHS Global Insight

IMF, Direction of Trade Statistics

IMF, International Financial Statistics

IMF, World Economic Outlook

Intergovernmental Panel on Climate Change

International Civil Aviation Organization (ICAO), ICAO's data set, http://www.icao-data.com

International Fuel Quality Center, Worldwide Automotive Fuel Specifications

International Oil Companies, Annual Reports

International Road Federation, World Road Statistics

National Oceanic & Atmospheric Administration, 'Monthly Climatic Data for the World'

National Sources

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

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OECD, OECD Economic Outlook

OPEC Annual Statistical Bulletin

OPEC Monthly Oil Market Report

OPEC Secretariat studies and reports

Purvin & Gertz, Global Petroleum Market Outlook – Petroleum Balances

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Turner, Mason & Company

UN, Department of Economic and Social Affairs, online database

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UN, National Account Statistics

UN, UN Statistical Yearbook

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United States Geological Survey, World Petroleum Assessment 2000

United States Geological Survey, 'An Evaluation of the USGS World Petroleum Assessment 2000 – Supporting Data', Open-File Report 2007-1021

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Wood Mackenzie

World Bank, World Development Indicators

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World Resources Institute, http://earthtrends.wri.org

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Organization of the Petroleum Exporting Countries
Obere Donaustrasse 93
A-1020 Vienna, Austria
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